American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_1 With respect to the structure for the bidding and negotiation process related to the sale of Kentucky Power.

a. Identify every corporation, investor group, or other person that was solicited to participate as a potential acquirer of Kentucky Power.

b. To the extent that there were various sequences in the bidding and negotiation process, describe each sequence and the corresponding result by potential acquirer (including Liberty).

c. By potential acquirer, indicate whether the potential acquirer moved to the next level, whether the participant withdrew, whether the participant was eliminated, etc.

RESPONSE

The Joint Applicants object to this request on the basis that it seeks information that is outside the scope of this proceeding and that is neither relevant to this proceeding or calculated to lead to the discovery of admissible evidence. In support of this objection the Joint Applicants state that information concerning the identities of persons and entities who were solicited and/or were involved in the bidding and/or negotiation process has nothing to do with the Commission's inquiry into this matter, which, pursuant to KRS 278.020(6) and (7), is whether Liberty has the financial, technical, and managerial abilities to provide reasonable service and that the proposed acquisition is in accordance with law, for a proper purpose, and consistent with the public interest. Furthermore, the information requested is highly-sensitive competitive information that, if disclosed, would result in serious competitive harm to both of the Joint Applicants.

Respondent: Counsel

American Electric Power Company, Inc.
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DATA REQUEST

KIUC 1_2 Please provide all offers, counteroffers and term sheets presented or made by AEP regarding the sale of Kentucky Power.

RESPONSE

The Joint Applicants object to this request on the basis that it seeks information that is outside the scope of this proceeding and that is neither relevant to this proceeding or calculated to lead to the discovery of admissible evidence. In support of this objection the Joint Applicants state that information concerning offers, counteroffers and/or terms sheets presented or made by AEP has nothing to do with the Commission's inquiry into this matter, which, pursuant to KRS 278.020(6) and (7), is whether Liberty has the financial, technical, and managerial abilities to provide reasonable service and that the proposed acquisition is in accordance with law, for a proper purpose, and consistent with the public interest. Furthermore, the information requested is highly-sensitive competitive information that, if disclosed, would result in serious competitive harm to both of the Joint Applicants.

Respondent: Counsel

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DATA REQUEST

KIUC 1_3 Please provide all documents received by AEP or Kentucky Power from potential acquirers of Kentucky Power (including Liberty). This should include all offers, counteroffers, and terms sheets received by AEP or Kentucky Power regarding the sale of Kentucky Power.

RESPONSE

The Joint Applicants object to this request on the basis that it seeks information that is outside the scope of this proceeding and that is neither relevant to this proceeding or calculated to lead to the discovery of admissible evidence. In support of this objection the Joint Applicants state that information concerning the documents received by AEP from potential acquirers of Kentucky Power has nothing to do with the Commission's inquiry into this matter, which, pursuant to KRS 278.020(6) and (7), is whether Liberty has the financial, technical, and managerial abilities to provide reasonable service and that the proposed acquisition is in accordance with law, for a proper purpose, and consistent with the public interest. Furthermore, the information requested is highly-sensitive competitive information that, if disclosed, would result in serious competitive harm to both of the Joint Applicants.

Respondent: Counsel

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DATA REQUEST

KIUC 1_4 Please provide all written criteria used by AEP for selecting an acquirer of Kentucky Power.

RESPONSE

The Joint Applicants object to this request on the basis that it seeks information that is outside the scope of this proceeding and that is neither relevant to this proceeding or calculated to lead to the discovery of admissible evidence. In support of this objection the Joint Applicants state that the written criteria used by AEP for selecting an acquirer of Kentucky Power has nothing to do with the Commission's inquiry into this matter, which, pursuant to KRS 278.020(6) and (7), is whether Liberty has the financial, technical, and managerial abilities to provide reasonable service and that the proposed acquisition is in accordance with law, for a proper purpose, and consistent with the public interest. Furthermore, the information requested is highly-sensitive competitive information that, if disclosed, would result in serious competitive harm to both of the Joint Applicants.

Respondent: Counsel

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DATA REQUEST

KIUC 1_5 Did AEP utilize a third-party consultant (such as an investment bank) to assist with bid analysis? If yes, please provide all documents provided by the third-party consultant to AEP regarding the analysis of bids to purchase Kentucky Power.

RESPONSE

The Joint Applicants object to this request on the basis that it seeks information that is outside the scope of this proceeding and that is neither relevant to this proceeding or calculated to lead to the discovery of admissible evidence. In support of this objection the Joint Applicants state that information concerning whether or not AEP utilized a third-party consultant to assist with bid analysis has nothing to do with the Commission's inquiry into this matter, which, pursuant to KRS 278.020(6) and (7), is whether Liberty has the financial, technical, and managerial abilities to provide reasonable service and that the proposed acquisition is in accordance with law, for a proper purpose, and consistent with the public interest. Furthermore, the information requested is highly-sensitive competitive information that, if disclosed, would result in serious competitive harm to both of the Joint Applicants.

Respondent: Counsel

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DATA REQUEST

KIUC 1_6 Please provide all documents submitted to the Board of Directors of each Joint Applicant regarding the sale of Kentucky Power.

RESPONSE

The Joint Applicants object to this request on the basis that it seeks information that is outside the scope of this proceeding and that is neither relevant to this proceeding or calculated to lead to the discovery of admissible evidence. In support of this objection the Joint Applicants state that information presented to the Joint Applicants' respective Board of Directors has nothing to do with the Commission's inquiry into this matter, which, pursuant to KRS 278.020(6) and (7), is whether Liberty has the financial, technical, and managerial abilities to provide reasonable service and that the proposed acquisition is in accordance with law, for a proper purpose, and consistent with the public interest. Notwithstanding the objection, please see the Joint Applicants' response to KPSC 1-67 and KPSC 1-68.

Witness: Peter Eichler

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DATA REQUEST

KIUC 1_7 Please provide all analyses and studies performed by or on behalf of any of the Joint Applicants (AEP, Kentucky Power, or Liberty) analyzing the costs and/or benefits to ratepayers of the proposed acquisition of Kentucky Power as compared to the costs and/or benefits to ratepayers that would result if no acquisition of Kentucky Power takes place.

RESPONSE

The Joint Applicants have not performed any analysis responsive to the request. As the Joint Applicants do not intend to seek recovery of the transaction costs from Kentucky customers, the cost of the acquisition will have no customer impact.

Witness: Brian K. West

Witness: Stephan T. Haynes

Witness: Peter Eichler

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DATA REQUEST

KIUC 1_8 Please provide all analyses and studies performed by or on behalf of any of the Joint Applicants (AEP, Kentucky Power, or Liberty) analyzing the impact on retail rates of the proposed acquisition of Kentucky Power as compared to the retail rates that would result if no acquisition of Kentucky Power takes place.

RESPONSE

The Joint Applicants did not conduct a comparative rate impact analysis between the scenarios contemplated in this question. Given that Kentucky Power's base retail rates are set through to January 1, 2024, Liberty's operating assumption was that base rates would remain unchanged for nearly two years from the transaction's anticipated close. For information on Liberty's research into the status quo of Kentucky Power's rates, please refer to the response to AG 1-120.

Witness: Brian K. West

Witness: Stephan T. Haynes

Witness: Peter Eichler

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DATA REQUEST

KIUC 1_9 Please provide all analyses and studies performed by or on behalf of any of the Joint Applicants (AEP, Kentucky Power, or Liberty) analyzing any change in service quality and reliability to ratepayers of the proposed acquisition of Kentucky Power as compared to the service quality and reliability that would exist if no acquisition of Kentucky Power takes place.

RESPONSE

There have been no analyses or studies performed as there is no expectation there will be any change in service quality and reliability to customers as a result of the proposed acquisition of Kentucky Power.

During the due diligence process Liberty's focus was reviewing Kentucky Power's current reliability and service quality performance. While Liberty did not perform any studies regarding any changes in reliability or service quality metrics, Liberty did observe the potential to explore opportunities to improve service quality and reliability in the future through the potential unification of voltages under one discretion given that the service territory is currently comprised of three different voltages.

Witness: Brian K. West

Witness: Stephan T. Haynes

Witness: Drew Landoll

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DATA REQUEST

KIUC 1_10 Explain whether Kentucky Power will incur any increased PJM charges resulting from the proposed transaction as a standalone member of PJM (as compared to being in the AEP Joint FRR plan) that it would not have incurred but for the proposed transaction. Please provide all analyses and studies to support your response.

RESPONSE

The Joint Applicants are not aware of any increased PJM charges that Kentucky Power would incur after closing as a result of the transaction related to the AEP Joint FRR Plan. Kentucky Power will continue to be a participant in the AEP Joint FRR Plan after closing until the end of the period they are committed to that plan as of the closing. As such, no study has been performed regarding any potential impacts of Kentucky Power leaving the AEP joint FRR plan.

Witness: Amanda R. Conner

Witness: Drew Landoll

American Electric Power Company, Inc.
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DATA REQUEST

KIUC 1_11 Throughout the Application and testimony, Joint Applicants state that up to 100 new jobs will be added in Kentucky.

a. For each of the 100 jobs, please list the job title, job description, and total compensation.
b. Please identify the AEPSC costs that will be avoided because of the 100 new local jobs.
c. Please identify the shared services costs that Kentucky Power will incur from Liberty for treasury, information technology, insurance, and risk management (among others) as set forth in the Application page 14 for the first three years post-closing.

RESPONSE

a. Please refer to the confidential attachment provided in response to Staff 1-19, JA_R_STAFF_1_19_ConfidentialAttachment_Liberty KY new jobs 3.xls, for additional details on the 100 jobs anticipated to be added in Kentucky.
b. Please refer to the "Incoming Project Costs" tab included in JA_R_STAFF_1_17_Attachment_Project Nickel Allocations.xlsx which has been provided in response to Staff 1-17. While some of the costs associated with the positions will be directly charged to Kentucky Power and others are anticipated to become part of Liberty's shared services departments that will be billed in accordance with the Algonquin Power & Utilities Corp. Cost Allocation Manual, the estimated 100 positions added in Kentucky are expected to displace centralized functions currently allocated to Kentucky Power from AEPSC.
c. Please refer to JA_R_STAFF_1_17_Attachment_Project Nickel Allocations.xlsx provided in response to Staff 1-17. Specifically, tabs "APUC Costs", "LUC Costs", "LABS", "LibCorp", and "Incoming Project Costs" provide the breakdown of the shared services functions estimated to be allocated to Kentucky Power.

Witness: Peter Eichler

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DATA REQUEST

KIUC 1_12 Please provide all analyses and studies performed by or on behalf of any of the Joint Applicants regarding the impacts to ratepayers of terminating Kentucky Power's participation in in the existing AEP Power Coordination Agreement among Kentucky Power, Wheeling Power Company, Appalachian Power Company, Indiana Michigan Power Company, and AEPSC.

RESPONSE

The Joint Applicants have not performed such analyses and have no documents responsive to this request.
.

Witness: Brian K. West

Witness: Stephan T. Haynes

Witness: Peter Eichler

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DATA REQUEST

KIUC 1_13 Please provide all analyses and studies performed by or on behalf of any of the Joint Applicants regarding the increased or reduced risk to ratepayers of PJM Capacity Performance charges that may result from terminating Kentucky Power's participation in the existing AEP Power Coordination Agreement.

RESPONSE

The Joint Applicants have not performed such analyses and have no documents responsive to this request.

Witness: Stephan T. Haynes

Witness: Drew Landoll

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DATA REQUEST

KIUC 1_14 Please provide all analyses and studies performed by or on behalf of any of the Joint Applicants regarding the impacts to ratepayers of terminating Kentucky Power's participation in the Affiliated Transactions Agreement for Sharing Material and Supplies (dated January 1, 2014) among AEP Generation Resources Inc. and AEPSC, as agent for Kentucky Power, Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, and AEP Generating Company.

RESPONSE

The Joint Applicants have not performed such analyses and have no documents responsive to this request.

Witness: Stephan T. Haynes

Witness: Peter Eichler

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DATA REQUEST

KIUC 1_15 Please provide all analyses and studies performed by or on behalf of any of the Joint Applicants regarding the impacts to ratepayers of terminating Kentucky Power's participation in the Grid Assurance LLC Amended and Restated Subscription Agreement (dated April 2, 2019).

RESPONSE

The Joint Applicants have not performed such analyses and have no documents responsive to this request.

Witness: Brian K. West

Witness: Stephan T. Haynes

Witness: Peter Eichler

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DATA REQUEST

KIUC 1_16 No studies have been performed by or on behalf of either AEP or Kentucky Power regarding the impacts to ratepayers of terminating Kentucky Power's participation in in the AEP System Tax Allocation Agreement.

RESPONSE

The Joint Applicants have not performed such analyses and have no documents responsive to this request.

Witness: Allyson L. Keaton

Witness: Michael McCuen

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DATA REQUEST

KIUC 1_17 Please provide all analyses and studies performed by or on behalf of any of the Joint Applicants regarding the impacts to ratepayers of terminating Kentucky Power's participation in the AEP System Utility Money Pool Agreement.

RESPONSE

The Joint Applicants have not performed such studies and have no documents responsive to this request.

Liberty intends to transition Kentucky Power into its own money pool and expects minor savings to customers. The cost of the money pool for Kentucky Power for the 9-months ending September 30, 2021 was 0.32% and for Liberty was 0.27%. 0.27% is the rate for commercial paper that Liberty incurs externally.

Witness: Stephan T. Haynes

Witness: Michael Mosindy

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DATA REQUEST

KIUC 1_18 Please provide all analyses and studies performed by or on behalf of any of the Joint Applicants regarding the impacts to ratepayers of terminating Kentucky Power's sale of receivables to AEP Credit, Inc.

RESPONSE

The Joint Applicants have not performed such studies and have no documents responsive to this request.

Terminating Kentucky Power's sale of receivables to AEP Credit is not expected to have a major impact on customers and if necessary, the receivables will be financed with short term debt. The cost of short-term debt for Liberty through the money pool for the 9 months ending September 30, 2021 was 0.27%, which is the Commercial Paper rate that Liberty incurs externally.

Witness: Stephan T. Haynes

Witness: Michael Mosindy

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DATA REQUEST

KIUC 1_19 When does Kentucky Power intend to submit an application to the Commission addressing replacement of the 390 MW of capacity currently provided to Kentucky Power under the Rockport Unit Purchase Agreement ("UPA"), which expires December 2022?

RESPONSE

In compliance with the Commission's order dated February 22, 2021, Kentucky Power plans to make a written filing identifying the capacity replacement for the Rockport UPA and the expected costs sometime in the first half of 2022.

Witness: Brian K. West

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DATA REQUEST

KIUC 1_20 When the Rockport UPA expires, what is the expected amount of fixed cost savings to Kentucky Power?

RESPONSE

The expected amount of non-fuel savings associated with the expiration of the Rockport UPA in 2023 is approximately $50.8 million.

Witness: Brian K. West

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DATA REQUEST

KIUC 1_21 Does Kentucky Power intend to meet its Fixed Resource Requirement obligations after the Rockport UPA expires through the New Power Sale Agreement to be entered into pursuant to the Bridge Power Coordination Agreement ("Bridge PCA")?

RESPONSE

Yes. Kentucky Power intends to purchase, at the BRA price, the amount of MW it is short from an FRR capacity standpoint from other AEP operating companies in the combined FRR plan that have capacity length, as necessary to facilitate an orderly transition.

Witness: Amanda R. Conner

American Electric Power Company, Inc.
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DATA REQUEST

KIUC 1_22 Refer to Section 4.8(b) Intercompany Arrangements – Power Coordination of the Stock Purchase Agreement.

a. Please provide a copy of the Bridge Power Coordination Agreement ("Bridge PCA").
b. For each PJM Planning Year from 2022 through 2025, please provide the amount of capacity (in MW) available from the AEP Parties to Kentucky Power under the Bridge PCA.
c. Does Kentucky Power intend to submit the Bridge PCA for Commission approval? If so, when?

RESPONSE

a. Joint Applicants have not yet executed the Bridge Power Coordination Agreement and, therefore, have no documents responsive to this request.

b. The FRR obligations for 2022 through 2025 have not been finalized as such the amount of capacity available from the AEP Parties cannot be determined at this time.

c. The PCA is a FERC tariff and will be submitted to FERC for approval in a public docket.

Witness: Amanda R. Conner

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
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DATA REQUEST

KIUC 1_23 Refer to Section 4.8(b) Intercompany Arrangements – Power Coordination of the Stock Purchase Agreement.

a. Please provide a copy of the New Power Sale Agreement.
b. For each PJM Planning Year from 2022 through 2025, please provide the amount of capacity (in MW) needed by Kentucky Power to satisfy its Fixed Resource Requirement commitment.
c. What is the pricing structure contemplated under the New Power Sale Agreement? Will the pricing structure be based upon PJM RPM clearing prices?
d. What is the expected cost per MW-day of capacity that will be purchased by Kentucky Power under the New Power Sale Agreement after the termination of the Rockport UPA in 2022?
e. Does Kentucky Power intend to submit the New Power Sale Agreement for Commission approval? If so, when?

RESPONSE

a. Joint Applicants have not yet executed the New Power Sale Agreement and therefore have no documents responsive to this request.

b. The final FRR obligation for 2022 through 2025 will not be available until sometime closer to the Third Incremental Auction of the respective planning years. However, based on the BRA information for 2022/2023, the FRR requirement is approximately 1028 MWs. Based on our most recent forecasts, the estimated obligations for the other planning years are as follows: approximately 1034 MWs for 23/24 and 1039 MWs for 24/25.

c The pricing structure would be based on the RPM Base Residual Auction (BRA) Clearing Price because that is the opportunity cost of the other AEP FRR Companies for a short term sale of capacity length.

d. The BRA for 23/24 through 24/25 have not occurred. However, the BRA price for 22/23 is $50/MW-Day.

e. No. It is a FERC jurisdictional sale. The retail cost recovery review of such costs would occur in Kentucky Power's annual Purchase Power Adjustment update filings.

Witness: Amanda R. Conner

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DATA REQUEST

KIUC 1_24 Refer to Section 4.8(b) Intercompany Arrangements – Power Coordination of the Stock Purchase Agreement, discussing the terms of the Bridge PCA:

a. Please provide the rationale for Kentucky Power remaining a transmission owner within AEP's Load Zone in PJM rather seeking to establish a standalone transmission zone in PJM for Kentucky Power.

b. Please provide all analyses and studies performed by or on behalf of any of the Joint Applicants regarding the benefits to Kentucky Power of remaining a transmission owner in the AEP Load Zone as compared to establishing a standalone transmission zone for Kentucky Power.

c. Please provide the rationale for continuing the approximately $20 million annual transmission subsidy paid by Kentucky Power customers to AEP affiliate companies rather than establishing Kentucky Power as a standalone transmission zone in PJM.

RESPONSE

a. In the Consolidated Transmission Owners Agreement, Section 7.4, Transmission Rate Zone Size, reads: "For purposes of developing rates for service under the PJM Tariff, transmission rate Zones smaller than those shown in Attachment J to the PJM Tariff, or subzones of those Zones, shall not be permitted within the current boundaries of the PJM Region; provided, however, that additional Zones may be established if the current boundaries of the PJM Region is expanded to accommodate new Parties to this Agreement."

b. No such studies or analyses have been performed given the response under part (a) of this question.

c. The rationale is provided in the response under part (a) of this question.

Witness: Amanda R. Conner

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DATA REQUEST

KIUC 1_25 Please provide a breakdown, as follows, of the AEP East Zone CP demands (the NSPL) for the years 2020, 2021, and projected 2022 as used in the development of the NITS formula rate revenue requirement per MW (for example, in the 2022 formula rate the NSPL was 21,944.6 MW):
a. By AEP East Transmission Agreement Operating Company (i.e., Kentucky Power, APCo, I&M, OPCo, WPCo, KNG)
b. By other non-AEP Operating Company loads. Provide this information by state. Also provide a list identifying the name of the utility or Load Serving Entity ("LSE") associated with each such load, the MW load included in the zonal CP demand, the state in which the LSE is located.
Please provide this information in excel and in the same format as used by Kentucky Power in its response to AG-KIUC 2-30 in Case No. 2020-00174.

RESPONSE

a.-b. The Joint Applicants object to this request on the grounds that it is not reasonably calculated to lead to the discovery of admissible evidence and is overly broad, in that it concerns FERC-jurisdictional transmission rates, formula rate protocols, and their inputs. The Joint Applicants further object to the extent the request seeks information about entities other than Kentucky Power because these other entities are not subject to the jurisdiction of the Commission and are subject to regulatory and legal requirements under state and federal law other than those of the Commonwealth of Kentucky. Subject to these objections, and without waiving them, the Joint Applicants state as follows:

Please refer to JA_R_KIUC_1_25_Attachment1. Note Kingsport's 1CP is included in APCo's for reporting purposes. Because there were changes that began on June 1, 2020, the attachment contains two columns of data for the 2020 calendar year.

It should be noted that the NSPL for 2022 of 21,944.6 MW listed in the question was preliminary. The final NSPL for 2022 is 22,925.3 MW.

Witness: Amanda R. Conner

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DATA REQUEST

KIUC 1_26 Please provide the actual 12 CP demands for each AEP Operating Company for the years 2020 and 2021, as used to allocate transmission costs in the AEP East Transmission Agreement. Also provide the projected 12 CP demand for each Operating Company for the year 2022.

RESPONSE

The Joint Applicants object to this request on the grounds that it is not reasonably calculated to lead to the discovery of admissible evidence and is overly broad, in that it concerns FERC-jurisdictional transmission rates, formula rate protocols, and their inputs. The Joint Applicants further object to the extent the request seeks information about entities other than Kentucky Power because these other entities are not subject to the jurisdiction of the Commission and are subject to regulatory and legal requirements under state and federal law other than those of the Commonwealth of Kentucky. Subject to these objections, and without waiving them, the Joint Applicants state as follows:

Please see JA_R_KIUC_1_26_Attachment1.

Witness: Amanda R. Conner

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DATA REQUEST

KIUC 1_27 Please provide any memos, emails, and other documents in the possession of any Joint Applicant addressing the Bridge PCA, including, but not limited to drafts of the Bridge PCA and memoranda, emails and other documents addressing specific issues that need to be addressed in the Bridge PCA.

RESPONSE

The Joint Applicants object to this request on the basis that the information sought is protected from disclosure by the attorney-client privilege, the work-product doctrine, and the Joint Applicants' Common Interest Agreement. Notwithstanding the objection the Joint Applicants state there are no non-privileged documents responsive to this request.

Witness: Peter Eichler

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DATA REQUEST

KIUC 1_28 Please provide a detailed narrative addressing how Kentucky Power will be charged for transmission services after the transaction closing. In this narrative, please address the following:

a. Will Kentucky Power be treated as any other non-affiliate transmission user in the AEP Zone, such as "Vance Olive?"
b. Will Kentucky Power's transmission costs be included in the calculation of the AEP Zonal charge, as they are currently?
c. Please provide a schedule showing the various components of Kentucky Power's transmission charges after the closing. This request is not seeking the actual or projected costs to Kentucky Power, but rather a table showing which costs would be included in Kentucky Power's charges.

RESPONSE

a. Yes

b. Yes

c. Components of Kentucky Power's transmission charges after closing are described in PJM's guide to billing available at the following link: https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/guide-to-billing

Witness: Amanda R. Conner

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DATA REQUEST

KIUC 1_29 Under the PJM tariff, is Kentucky Power required to continue in the AEP Zone for transmission pricing after the closing? Does Kentucky Power have any option with regard to continuing in the AEP Zone or becoming a standalone transmission zone?

RESPONSE

In the Consolidated Transmission Owners Agreement, Section 7.4, Transmission Rate Zone Size, reads: "For purposes of developing rates for service under the PJM Tariff, transmission rate Zones smaller than those shown in Attachment J to the PJM Tariff, or subzones of those Zones, shall not be permitted within the current boundaries of the PJM Region; provided, however, that additional Zones may be established if the current boundaries of the PJM Region is expanded to accommodate new Parties to this Agreement." Accordingly, Kentucky Power would need to remain in the AEP Transmission Zone as long as Kentucky Power remains a member of PJM.

Witness: Amanda R. Conner

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DATA REQUEST

KIUC 1_30 Please provide any study performed by Kentucky Power/AEP that addresses the expected transmission costs that would be incurred by Liberty during the 5 years following the transaction closing compared to expected transmission costs that would be incurred by Kentucky Power if it remained an AEP Operating Company. Included all supporting workpapers, including excel spreadsheets with formulas intact. If an analysis was performed covering a shorter projection period, please provide it in the alternative.

RESPONSE

No such study has been performed and, therefore, the Joint Applicants have no documents responsive to this request.

Witness: Amanda R. Conner

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DATA REQUEST

KIUC 1_31 With regard to the AEP Power Coordination Agreement, please explain how Schedule A, Section A-3 operates with respect to capacity resource performance charges. Specifically, in the event that one FRR Operating Company has a unit that fails to meet the capacity performance requirements (underperforms), but another FRR Operating Company has one or more overperforming units, please explain the following:

a. Would the combined FRR Companies be charged any capacity resource performance charges.
b. Under Section A-3, would the underperforming Company be required to pay compensation to the overperforming Company (again assuming that there was no charge from PJM to the combined FRR Companies. If such payments among under and overperforming Companies would be made, how would such charges be determined?

RESPONSE

a. Under the current PJM tariff, the hypothetical scenario where one unit in the FRR plan underperforms during a capacity performance interval and another unit over-performs during the same capacity performance interval in an amount that offsets the underperformance, the combined FRR plan and Operating Companies would not be billed by PJM for a capacity performance charge.

b. No. This provision of the PCA divides any incurred capacity performance penalties among the units and Operating Companies that contributed to the billed charge from PJM.

Witness: Stephan T. Haynes

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
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DATA REQUEST

KIUC 1_32 Have any Kentucky Power generating units (including Rockport) failed to meet the PJM capacity resource performance requirements at any time since the implementation of the PJM capacity performance requirements. For any such events, please provide the following information:
a. The date of the event and the hours during which a Kentucky Power generating unit failed to meet the requirement.
b. Whether AEP was able to substitute another over performing unit to avoid a PJM penalty.
c. A quantification of the penalty, had it not been offset by an over performing AEP unit.

RESPONSE

a.-c. Please see JA_R_KIUC_1_32_ConfidentialAttachment1.

Witness: Amanda R. Conner

JA_R_KIUC_1_32_PublicAttachment1 has been redacted in its entirety.

American Electric Power Company, Inc.
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DATA REQUEST

KIUC 1_33 Please provide any studies, memoranda, and/or analyses prepared by or for Liberty that address the transmission charges that Kentucky Power will incur from PJM and/or AEP for each of the next 5 years (or less if 5 years is not available).

RESPONSE

As per the terms of the Bridge PCA addressed in Witness Eichler's testimony, Kentucky Power will remain in both PJM and the AEP East Zone for at least the next 24 months. Given this fact, Liberty did not conduct such an analysis. However, the exit from AEP's transmission agreement that will accompany the closing of the transaction will revert Kentucky Power's transmission cost allocation from 12 CP to 1 CP, which Liberty believes will be beneficial for Kentucky Power's customers, barring low-probability / high impact events.

Witness: Drew Landoll

American Electric Power Company, Inc.
Kentucky Power Company
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DATA REQUEST

KIUC 1_34 To the extent that Kentucky Power/Liberty decides to exit PJM following the study referred to on page 7 of Mr. Eichler's testimony, what is the expected timeline for such exiting to become effective? This would include the earliest possible date of notice to PJM for such exiting.

RESPONSE

Please see response to Staff 1-38. Given the current stage of the proposed acquisition, Liberty has not commenced the study regarding the relative merits of a potential exit from PJM. As indicated by Witness Eichler on p. 34 lines 3-6 of his testimony, Liberty will enter into the Bridge PCA and would remain a transmission owner and load serving entity for its service territory in the PJM and in AEP's Load Zone in the PJM through January 1 of the calendar year after it is no longer a party to the consolidated FRR plan.

Witness: Peter Eichler

American Electric Power Company, Inc.
Kentucky Power Company
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DATA REQUEST

KIUC 1_35 In the event that Kentucky Power/Liberty exited PJM, how would AEP Kentucky Transmission Company recover the revenue requirement for its assets? Would these transmission assets be rolled into Kentucky Power's retail rate base?

RESPONSE

Given the current stage of the proposed acquisition, Liberty has not commenced the study regarding the relative merits of a potential exit from PJM. Accordingly, it has not yet studied the implications on Kentucky Transmission Company of this potential outcome.

Witness: Peter Eichler

American Electric Power Company, Inc.
Kentucky Power Company
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DATA REQUEST

KIUC 1_36 On page 34 of Mr. Eichler's testimony, he states as follows:
"The Bridge PCA will also provide that Kentucky Power would remain a transmission owner and load serving entity for its service territory in the PJM and in AEP's Load Zone in the PJM through January 1 of the calendar year after it is no longer a party to AEP's FRR plan."
Does Liberty, and Mr. Eichler believe that Kentucky Power will no longer be included in AEP's load zone after January 1 of the calendar year after it is no longer a party to AEP's FRR plan? If so, does Liberty and Mr. Eichler believe that Kentucky Power would be able to establish its own load zone within PJM? Please provide a full explanation for your responses, including an explanation of whether the PJM Consolidated Transmission Owner's Agreement (CTOA), Section 7.4 would no longer apply to Kentucky Power "after January 1 of the calendar year after it is no longer a party to AEP's FRR plan."

RESPONSE

Please see the response to KIUC 1-29.

Witness: Drew Landoll

American Electric Power Company, Inc.
Kentucky Power Company
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DATA REQUEST

KIUC 1_37 Please provide any study performed by or for Liberty that addresses the expected transmission costs that would be incurred by Liberty during the 5 years following the transaction closing compared to expected transmission costs that would be incurred by Kentucky Power if it remained an AEP Operating Company. Included all supporting workpapers, including excel spreadsheets with formulas intact. If an analysis was performed covering a shorter projection period, please provide it in the alternative.

RESPONSE

An analysis of transmission costs to be incurred relative to AEP's transmission costs was not completed.

Witness: Peter Eichler

American Electric Power Company, Inc.
Kentucky Power Company
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DATA REQUEST

KIUC 1_38 Liberty has indicated it will make a decision in the near future as to whether or not to exit PJM. Should the dispatch provisions of the new Mitchell Operating Agreement account for the possibility that Kentucky Power would exit PJM while Wheeling Power Company remains in PJM? How would Liberty satisfy its NERC reliability requirements if it exits PJM?

RESPONSE

Liberty is expected to complete its analysis regarding participation in PJM following transaction close. If any amendments to the Mitchell Plant Ownership Agreement, Mitchell Plant Operations and Maintenance Agreement, or resolutions by the Operating Committee are required following this analysis, these amendments and/or resolutions will be discussed between Kentucky Power and Wheeling Power at that time.

Witness: Peter Eichler

American Electric Power Company, Inc.
Kentucky Power Company
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DATA REQUEST

KIUC 1_39 Please confirm that the Mitchell units have never been transferred among AEP affiliates at any price other than Net Book Value.

RESPONSE

AEP is not aware of any similar transfer of ownership interests in the Mitchell Plant among AEP affiliates at any point during the operating life of the plant. The three prior transfers of the Mitchell Plant – from Ohio Power Company to AEP Generation Resources, Inc. ("AEPGR"), and from AEPGR in equal shares to the Company and Wheeling Power Company, respectively – were the result of a corporate reorganization of Ohio Power Company due to the deregulation of generation in Ohio. Those transfers, which were made at adjusted net book value, realigned ownership of the plant among AEP affiliates to address Ohio's mandatory generation divestiture mandate. The proposed Buyout transaction, if it occurs, is distinguishable because it is voluntary at Wheeling Power's option, will based on the future economics of the plant in comparison to the option of retiring the plant, and will likely occur when the companies are no longer affiliates.

Transfers at net book value between plant co-owners would typically happen between regulated utilities under circumstances where there is alignment on the remaining useful life of the plant based on the investments they have equally made. Although the Mitchell Plant may be operated beyond 2028 by Wheeling Power, the value of the plant to Kentucky Power terminates as of December 31, 2028 because Kentucky Power will not be investing in the ELG environmental control equipment necessary for the plant to operate after that date due to orders of the KPSC rejecting the CPCN for that investment. Thus, for purposes of the buyout transaction, if net book value is used, the plant should be deemed to be depreciated to zero as of the end of its useful life to Kentucky customers, which is through 2028 and not 2040.

Witness: Stephan T. Haynes

American Electric Power Company, Inc.
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DATA REQUEST

KIUC 1_40 Please provide Liberty's projected post-acquisition operating budget of all Kentucky Power revenues and expenses for the next five years.

RESPONSE

Liberty's expectation is to initially assume budgets currently in place at Kentucky Power. During its ownership, Liberty will continually evaluate and update the operating budgets of Kentucky Power with the view of identifying opportunities to reduce costs to the extent customer service and safety can be maintained. Liberty intends to create the 2023 budget in the fourth quarter of 2022.

Witness: David Swain

American Electric Power Company, Inc.
Kentucky Power Company
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DATA REQUEST

KIUC 1_41 Please provide Liberty's projected post-acquisition capital budget for Kentucky Power for the next five years

RESPONSE

Liberty intends to initially assume Kentucky Power's capital plan. Once under Liberty ownership, the plan will be revisited with the intention of delivering customer benefits. A near-term capital budget was provided as part of the disclosure schedule section 4.1(c) to the Stock Purchase Agreement.

Witness: David Swain

American Electric Power Company, Inc.
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DATA REQUEST

KIUC 1_42 Please provide Liberty's projected post-acquisition capital structure for Kentucky Power for the next five years.

RESPONSE

Liberty intends to assume Kentucky Power's current capital structure of 43.25% until 2024 at which time it is assumed that the equity thickness will be modestly strengthened to 45% and remain at that level. While this projection has been used for planning purposes, Liberty acknowledges that any change in equity thickness will be taken in the spirit of ensuring the financial strength of Kentucky Power while balancing customer affordability and is ultimately subject to the approval of the KPSC for the purposes of rate recovery.

Witness: Peter Eichler

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DATA REQUEST

KIUC 1_43 Refer to the Stock Purchase Agreement at page 95 of 933.

a. Why do Kentucky Power's capital expenditures related to "Renewables" increase from $6.9 million per month beginning January 2022 to approximately $14 million per month in January 2023?

b. Please explain in detail the specific "Renewables" capital expenditures used to calculate the amounts listed on page 95.

RESPONSE

a. The increase in spend for renewables between January 2022 and January 2023 is due to the addition of a second, 150MW solar project in the forecast.

b. The forecast assumed that spend for the solar projects were spread evenly over two years. The first project, Kentucky Power 150MW Solar Project in Service 12/13/2023 had expenditures spread from January 2022-December 2023, with the project closing to Plant in Service at year end 2023. The second project, Kentucky Power 150MW Solar Project In Service 12/31/2024, had expenditures spread from January 2023 – December 2024, with the project closing to Plant in Service at year end 2024.

Witness: Brian K. West

Witness: Stephan T. Haynes

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DATA REQUEST

KIUC 1_44 Please describe all solar projects that Kentucky Power is currently developing.

RESPONSE

Kentucky Power executed a lease option for approximately 2,195 total acres near Hazard, KY, in the Company's service territory. It is a 6-year option term with three 2-year option renewals. In addition, the Company submitted a GIA request with PJM in September 2021 for a 100 MW solar project. PJM's queue for new renewable projects is approximately 4-5 years, so any regulatory filing for a certificate of public convenience and necessity would not occur for several years at a minimum.

Witness: Brian K. West

American Electric Power Company, Inc.
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DATA REQUEST

KIUC 1_45 When does Kentucky Power intend to submit an application to the Commission requesting a Certificate of Public Convenience and Necessity for any solar projects?

RESPONSE

Please see the Joint Applicants' response to KIUC 1-44.

Witness: Brian K. West

American Electric Power Company, Inc.
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DATA REQUEST

KIUC 1_46 Please provide the letter of intent that Kentucky Power entered into regarding building and preparing a site for an entity in connection with its 250 MW equivalent of high-capacity computing hardware.

a. Please provide an estimate of the costs that would be incurred by Kentucky Power to build and prepare the site for the entity owning the high-capacity computing hardware.
b. Please provide all analyses and studies performed by or on behalf of Kentucky Power addressing the costs and/or benefits to other ratepayers of the contemplated project?
c. Please explain the electric pricing for the entity if the high-capacity computing hardware begins operations in Kentucky Power's service territory.
d. Will the addition of the entity's high-capacity computing hardware load impact Kentucky Power's Fixed Resource Requirement obligations? If so, how?

RESPONSE

The Joint Applicants object to this request on the basis that it seeks information that is outside the scope of this proceeding and that is neither relevant to this proceeding nor calculated to lead to the discovery of admissible evidence. Joint Applicants further object to subparts a.-d. of this request as seeking speculation and information outside the scope of Joint Applicants' possession, custody, or control. Joint Applicants have no obligation to perform in response to a discovery request an analysis or calculation that they have not previously performed.

Respondent: Counsel

American Electric Power Company, Inc.
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DATA REQUEST

KIUC 1_47 Please provide the most recent AEP fundamentals forecast.

RESPONSE

Please see JA_R_KIUC_1_47_Attachment1 for the requested information.

Witness: Chad M. Burnett

American Electric Power Company, Inc.
Kentucky Power Company
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DATA REQUEST

KIUC 1_48 Please refer to the testimony of Mr. Swain at page 6.

a. Please provide the "long-term strategic plan" for Kentucky Power.
b. Please provide the capital and O&M budgets prepared by senior management for Kentucky Power.
c. Please provide an example of the "annual scorecard" that will used for evaluating the operations of Kentucky Power.

RESPONSE

a. Since Liberty is not yet the owner of Kentucky Power, it would be premature to have developed a long term strategic plan. It is anticipated that the plan would be developed once Liberty is the owner and is entrenched in the community and the Company's operations.

b. Liberty's plan regarding Kentucky Power's O&M and capital plans is to adopt the current company forecasts at the time of closing, and immediately begin to focus on identifying opportunities to contain or reduce O&M to the benefit of Kentucky customers.

c. Please see below an example of the 2021 scorecard measures from Liberty's Central Region where Empire District Electric Company is located.

Area	**Metric**
Health & Safety	Lost Time Injury Rate
Health & Safety	Recordable Injury Rate
Health & Safety	At Fault Motor Vehicle Accident Rate
Health & Safety	Completion of 2021 Priority Actions
Physical/Cyber Security	Completion of 2021 Priority Actions
Reliability	Electric - SAIDI
Reliability	Electric - SAIFI
Reliability	Gas - Response Time
Reliability	Gas - Leak Rate
Reliability	Gas - Damage Prevention

Reliability	Water - Unplanned Disruption
Reliability	Water - Leak Rate
Operational Excellence	Completion of 2021 Priority Actions, with Central Focus on Electric Modality
Operational Excellence	JD Power scores
Operational Excellence	Call Response times
Operational Excellence	Completion of 2021 Priority Actions
Operational Excellence	Customer First - Timeline
Operational Excellence	Customer First - Business Support/Change Network
Operational Excellence	Customer First - Training
Operational Excellence	Business Group Profit
Operational Excellence	Rate Case Filings
Operational Excellence	Regulatory Outreach
Operational Excellence	New Regulatory Framework
Growth	Capital Plan Delivery with Capital Policy
Growth	Compounded Annual Growth Rate
Growth	Customer Savings Plan
Growth	Grid Modernization
Growth	Bolivar Acquisition
Growth	Acquisition Support
Growth	New Customers
Growth	New GPM
Growth	Tuck Ins
Growth	Innovation Spend
Sustainability	2020 Engagement plans delivered
Sustainability	Engagement scores
Sustainability	2021 Engagement plans developed
Sustainability	Ensure all managers and above have up to date development plans
Sustainability	Execute on succession plan
Sustainability	Hiring managers completing interview training
Sustainability	Execute plan-attract diversity candidates
Compliance	Completion of 2021 Priority Actions
ESG	Completion of 2021 Priority Actions

Witness: David Swain

American Electric Power Company, Inc.
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DATA REQUEST

KIUC 1_49 Please refer to the Transition Service Agreement ("TSA").

a. For each month over the first 24 months post-closing, please provide the expected payment by Kentucky Power to AEPSC under the TSA.
b. Will any TSA costs be recovered in Kentucky Power's Environmental Surcharge, Purchase Power Adjustment, Decommissioning Rider, or any other non-base rate recovery mechanism? If yes, please provide the amount by month for each non-base rate recovery mechanism.
c. For each month over the first 24 months post-closing, please provide a comparison of expected costs under the TSA versus the shared service expenses paid to AEPSC which are currently reflected in rates.

RESPONSE

a. As the transition planning activities are ongoing, the full scope and nature of certain service categories is yet to be finalized. The development of requested budgets will follow the finalization of scope of services.

b. Liberty does not anticipate any of these costs would impact Kentucky Power's Environmental Surcharge, Purchase Power Adjustment, Decommissioning Rider, or any other non-base rate recovery mechanism.

c. Please see the response to (a).

Witness: Peter Eichler

American Electric Power Company, Inc.
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DATA REQUEST

KIUC 1_50 Refer to the definition of "transaction expenses" set forth at Appendix I-13 to the Stock Purchase Agreement, which states as follows: *"Transaction Expenses" means all fees, costs and expenses, solely to the extent that any Acquired Company has or will have any Liability in respect thereof, in each case, to the extent (a) incurred or payable in connection with the negotiation, preparation and execution of this Agreement and the Ancillary Agreements or the consummation of the transactions contemplated hereby or thereby on or prior to Closing and (b) not paid prior to the Reference Time, including, for the avoidance of doubt, (i) amounts payable to legal counsel, accountants, advisors, investment banks, brokers and other Persons advising any Seller or the Acquired Companies in connection with the transactions contemplated hereby or by any Ancillary Agreement, (ii) all bonuses and change in control payments payable in connection with the execution of this Agreement or any Ancillary Agreement or the consummation of the transactions contemplated hereby or by any Ancillary Agreement and (iii) the amount of the employer portion of any payroll, social security, Medicare, unemployment or similar or related Taxes payable with respect to the amounts set forth in the immediately preceding clause (ii).*

a. Refer to the Direct Testimony of Mr. Eichler at 7, wherein he lists various commitments by "Liberty's management," including that it will "[n]ot seek recovery of the transaction premium or transaction costs in Kentucky Power's rates." Provide the definitions of the terms "transaction premium" and "transaction costs" and source the definitions to the Stock Purchase Agreement or the source that was or will be relied on to determine the scope of this commitment. If none, then so state.

b. Confirm that the term "transaction expenses" as that term is defined in the Stock Purchase Agreement does not cover "fees, costs and expenses" that are incurred before and after the acquisition date to implement the terms set forth in the Stock Purchase Agreement, (e.g. the requirement that Liberty purchase directors and officers tail insurance, among others), and/or that are incurred before and after the acquisition date to integrate the acquired companies into Liberty, (e.g., IT systems integration, local employee hiring expenses, relocation expenses, rents or other expenses/costs to acquire office space to house new local

employees, removing AEP signage and replacing with Liberty signage, among others).

i. If confirmed, then indicate whether Liberty agrees that it will not seek recovery of such "transition" and/or "integration" "fees, costs, and expenses."

ii. If Liberty does not agree that it will not seek recovery of such "transition" and/or "integration" "fees, costs, expenses," then provide all reasons why it will not agree to do so and why these "fees, costs, expenses" should be recovered from the utility's customers.

iii. If Liberty agrees that it will not seek recovery of such "transition" and/or "integration" "fees, costs, expenses," then provide an affirmative commitment to that effect and provide a list all such "fees, costs, and expenses" or categories of such "fees, costs, and expenses" subject to that commitment.

RESPONSE

a. The term "transaction premium" as used on page 6 of Witness Eichler's Testimony is intended to mean the difference between the value of Kentucky Power and the actual price paid to acquire the company pursuant to the Stock Purchase Agreement.

The term "transaction costs" as used on page 6 of Witness Eichler's Testimony encompasses the term "Transaction Expenses" as used in the Stock Purchase Agreement as set forth above.

b. Liberty cannot commit at this time to not seek recovery of an undefined set of costs, described only as "fees, costs, and expenses incurred after the acquisition to implement the terms set forth in the Stock Purchase Agreement" as many of the terms of the Stock Purchase Agreement are related to the ongoing, normal and necessary operation of Kentucky Power. However, Liberty cannot recover any such "fees, costs and expenses" until after a thorough review as part of a future rate case.

Witness: Peter Eichler

American Electric Power Company, Inc.
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DATA REQUEST

KIUC 1_51 Indicate whether the acquired Kentucky Power and/or Kentucky Transco will record an acquisition or transaction premium on their accounting books. If so, confirm that whether to record an acquisition or transaction premium on the acquired company's or the acquiring company's accounting books is at the discretion of the acquiring company pursuant to GAAP. If this is not the case, then provide a corrected statement and a copy of all authorities relied on for the corrected statement.

RESPONSE

The acquisition premium will be recorded as a fair value adjustment and recorded in the holding company. Liberty will not apply pushdown accounting.

Witness: Peter Eichler

American Electric Power Company, Inc.
Kentucky Power Company
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DATA REQUEST

KIUC 1_52 Please provide a calculation of the estimated acquisition or transaction premium that Liberty will record on its accounting books. Provide the calculation in Excel live format with all formulas intact showing the purchase price, transaction costs, net book equity, and every other component of Kentucky Power and Kentucky Transco used to calculate the premium.

RESPONSE

Please see response to KIUC 1-65.

Witness: Peter Eichler

American Electric Power Company, Inc.
Kentucky Power Company
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DATA REQUEST

KIUC 1_53 Please provide a calculation of the estimated acquisition or transaction premium that Kentucky Power and Kentucky Transco will record on each of their accounting books. Provide the calculations for each of the acquired companies in Excel live format with all formulas intact showing the purchase price, transaction costs, net book equity, and every other component used to calculate the premium.

RESPONSE

No transaction premium will be recorded on either Kentucky Power's or Kentucky Transco's accounting books.

Witness: Peter Eichler

American Electric Power Company, Inc.
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DATA REQUEST

KIUC 1_54 For each of the rate regulated utilities previously acquired by Liberty, indicate whether the acquisition or transaction premium was recorded on the acquired company's or Liberty's accounting books.

RESPONSE

Liberty confirms that none of its previously acquired regulated utilities had acquisition or transaction premiums recorded on their books.

Witness: Peter Eichler

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
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DATA REQUEST

KIUC 1_55 Please provide a calculation in live Excel format with all formulas intact of the book gains that will be recorded by AEP (before tax and after tax) upon the sale of its ownership in each of the acquired companies to Liberty.

RESPONSE

The Joint Applicants object to this request on the basis that it seeks information that is outside the scope of this proceeding and that is neither relevant to this proceeding or calculated to lead to the discovery of admissible evidence. In support of this objection the Joint Applicants state that information concerning any gains that will be recorded by AEP upon that sale of its ownership of Kentucky Power has nothing to do with the Commission's inquiry into this matter, which, pursuant to KRS 278.020(6) and (7), is whether Liberty has the financial, technical, and managerial abilities to provide reasonable service and that the proposed acquisition is in accordance with law, for a proper purpose, and consistent with the public interest.

Respondent: Counsel

American Electric Power Company, Inc.
Kentucky Power Company
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DATA REQUEST

KIUC 1_56 Describe the tax consequences to AEP of the sale of each acquired company to Liberty, including, but not limited to, the tax basis of each acquired company; calculation of the tax gain; applicable federal and state income tax rates; calculation of current income tax expense; calculation of deferred income tax expense; and calculation of ADIT by temporary difference.

RESPONSE

The Joint Applicants object to this request on the basis that it seeks information that is outside the scope of this proceeding and that is neither relevant to this proceeding or calculated to lead to the discovery of admissible evidence. In support of this objection the Joint Applicants state that information concerning any tax consequences to AEP upon that sale of its ownership of Kentucky Power has nothing to do with the Commission's inquiry into this matter, which, pursuant to KRS 278.020(6) and (7), is whether Liberty has the financial, technical, and managerial abilities to provide reasonable service and that the proposed acquisition is in accordance with law, for a proper purpose, and consistent with the public interest.

Respondent: Counsel

American Electric Power Company, Inc.
Kentucky Power Company
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DATA REQUEST

KIUC 1_57 For each of the rate regulated utilities previously acquired by Liberty, provide a list of the commitments offered or agreed to by Liberty and a list of all additional conditions imposed by the regulatory authority.

RESPONSE

Please see attached orders and associated stipulations for rate regulated utilities previously acquired by Liberty:

JA_R_KIUC_1_57_AttachmenArkansas - Pine Bluff Water - Order Approving Acquisition - 12-061-U Order No. 6.pdf
JA_R_KIUC_1_57_Attachment_Arkansas - EDE - Joint Stipulation 16-013-U Order No. 4.pdf
JA_R_KIUC_1_57_Attachment_Arkansas - EDE - Joint Stipulation 16-013-U.pdf
JA_R_KIUC_1_57_Attachment_Arkansas - LU (Arkansas Water) Corp. CCN Order. 19-064-U Order No 4.pdf
JA_R_KIUC_1_57_Attachment_Arkansas - Pine Bluff Joint Stipulation 12-061-U.pdf
JA_R_KIUC_1_57_Attachment_Illiniois - Midstates - 19-0254_Appendix_001.pdf
JA_R_KIUC_1_57_Attachment_Illinois - Midstates - 19-0254 Creal Springs Order.pdf
JA_R_KIUC_1_57_Attachment_Illinois - Midstates - 20-0487 Tamms Order .pdf
JA_R_KIUC_1_57_Attachment_Illinois - Midstates - 20-0487_Appendix_001.pdf
JA_R_KIUC_1_57_Attachment_Illinois - Midstates - Appendix A - 11-0559 app a.pdf
JA_R_KIUC_1_57_Attachment_Illinois - Midstates - Appendix B - 11-0559 app b.pdf
JA_R_KIUC_1_57_Attachment_Illinois - Midstates - Order -11-0559 order.pdf
JA_R_KIUC_1_57_Attachment_Illinois - Midstates -15-0155 Pittsburg Order.pdf
JA_R_KIUC_1_57_Attachment_Illinois - Midstates -15-0155_Appendix b-002.pdf
JA_R_KIUC_1_57_Attachment_Illinois- Midstates - 15-0155_Appendix a -001.pdf
JA_R_KIUC_1_57_Attachment_Iowa - Midsates - Order not Disapproving Proposal - SPU-2011-0008.pdf
JA_R_KIUC_1_57_Attachment_Kansas - EDE - Order Granting Joint Motion - 16-EPDE-410-ACQ.pdf
JA_R_KIUC_1_57_Attachment_Missouri - Midstates - Unanimous Stipulation and Agreemment- GM-2012-0037.pdf
JA_R_KIUC_1_57_Attachment_Missouri - Missouri Water - Order Approving Stipulation - WM-2018-0023.pdf

JA_R_KIUC_1_57_Attachment_Missouri - Missouri Water - Order Approving Transfer of Assets - WA-2019-0036.pdf
JA_R_KIUC_1_57_Attachment_Missouri - Missouri Water - Order Approving Transfer of Assets - WM-2020-0174.pdf
JA_R_KIUC_1_57_Attachment_Missouri - Missouri Water - Order Granting CCN - SA-2020-0067.pdf
JA_R_KIUC_1_57_Attachment_Missouri - Mo Water & EDE- Order Approving Transfer of Assets - WM-2020-0156.pdf
JA_R_KIUC_1_57_Attachment_Missouri - EDE- Order Approving Stipulation - EM-2016-0213.pdf
JA_R_KIUC_1_57_Attachment_Missouri order approving stips and agreements-authorizing merger.pdf
JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final Order - Cause No PUD 201600098 - Order 652551.pdf
JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final Order - CauMassachusetts - Blackstone Order - DPU 20-03.pdf
JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final Order - Cause Massachusett - NEGC - Order - DPU 13-07-A.pdf
JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final Order - Cause No PUD 2New Brunswick - Order- Matter 433.pdf
JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final Order - Cause No PUD 201New Hampshire - Order No 25,370.pdf
JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final Order - Cause No PUD 201600098 - Order 652551Bermuda.pdf
JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final Order - Cause No PUD 201600098Bermuda Annex Attachments.pdf
JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final Order - Cause No PUNew Brunswick - Decision -Matter 433.pdf
JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final Order - CausNew York - Order - 18-G-0133 and 18-G-0140.pdf
JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final Order - Georgia - Order Approving Join App - No. 36278.pdf
JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final Order -New Hampshire - Settlement Agreement - DG 11-040.pdf
JA_R_KIUC_1_57_Attachment_Arizona - Decision 73350 (Liberty LP Waiver Decision for Purchase of EDO).pdf
JA_R_KIUC_1_57_Attachment_Arizona - Decision 77741 (Purchase of Sulger Water assets by Liberty BV).pdf
JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final OrdCalPeco Acquisition Decision October 2010 Appendices.pdf
JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final Order -New HamArizona - Decision 77887 (Sulger amended).pdf
JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final Order -New HamCalPeco Acquisition Decision October 2010.pdf
JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final Order -New HampshCalPeco Acquisition Decision June 2012.pdf

JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final Order -New Hampshire - SeTexas - 2005 STM Order – Texas.pdf
JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final Order -New Hampshire - SettlemCalifornia - Park and AVR.pdf
JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final Order -New Hampshire - SettlemenPark and AVR Appendix A.pdf
JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final Order -New Hampshire - SettlemenPark and AVR Appendix B.pdf
JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final Order -New Hampshire - Settlement Agreement - DG 11-040.pdf
JA_R_KIUC_1_57_Attachment_Oklahoma - EDE - Final Order20200623_Texas Commission on Environmental Quality.pdf

Witness: Peter Eichler

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE JOINT APPLICATION OF UNITED WATER ARKANSAS, INC., UNITED WATER WORKS, INC. AND LIBERTY ENERGY UTILITIES CO. FOR ALL NECESSARY AUTHORIZATIONS AND APPROVALS FOR LIBERTY ENERGY UTILITIES CO. TO ACQUIRE ALL OUTSTANDING COMMON STOCK OF UNITED WATER ARKANSAS, INC. PURSUANT TO A CERTAIN STOCK PURCHASE AGREEMENT	)	DOCKET NO. 12-061-U ORDER NO. 6

ORDER

On August 13, 2012, United Water Arkansas, Inc. ("UWA"), United Waterworks Inc. ("UWI"), and Liberty Energy Utilities Co. ("LEUC") (collectively referred to in this Order as "Joint Applicants") filed a Joint Application in the above-styled Docket pursuant to Ark. Code Ann. §§ 23-3-101 and 23-3-102, for approval for UWI to sell, and for LEUC to purchase, all of the issued and outstanding common stock of UWA and to consummate any related transactions, as are necessary. In support of their Joint Application, they filed the Direct Testimony and Exhibits of Peter Eichler and of David Paseika on behalf of LEUC. The Joint Applicants also filed the Direct Testimony of Greg Sorensen on behalf of LEUC and the Direct Testimony of James C. Cagle on behalf of UWA.

The Joint Applicants provided the following information about the proposed transaction. UWA is an Arkansas corporation and a wholly-owned subsidiary of UWI, a Delaware corporation. UWA owns and operates a complete waterworks system in the City of Pine Bluff, Arkansas, and in certain territory adjacent to that municipality, and is a public utility under the terms and provisions of Ark. Code Ann. § 23-1-101. UWA

provides water service to approximately 17,500 residential, commercial, and industrial customers in its service area.

UWI is a wholly-owned subsidiary of United Water Resources Inc. UWI is the parent of a portfolio of regulated water utility operations in eight states. The states are Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Idaho and Arkansas. UWI and its subsidiaries provide water and wastewater services to approximately one million people in those eight states. UWI's utility subsidiaries are subject to regulation by the public utility commissions in each state in which they operate.

LEUC is a direct subsidiary of Liberty Utilities Co. (Liberty Utilities), a Delaware corporation. Liberty Utilities is owned by Algonquin Power & Utilities Corp. (Algonquin) a corporation created under the laws of Canada. Liberty Utilities is the entity under which all the regulated utilities owned in the United States are operated.

UWI and LEUC have entered into a Share Purchase Agreement ("SPA") dated July 20, 2012, pursuant to which UWI proposed to sell one hundred percent (100%) of the issued and outstanding shares of common stock of UWA to LEUC. As a result of the proposed transaction, UWA would become a wholly-owned subsidiary of LEUC, if the SPA is approved.

The Joint Applicants stated that if the SPA is approved, following the transfer of ownership of the UWA common shares from UWI to LEUC, the public utility operations of UWA will continue in Arkansas. UWA will continue to perform its obligations and commitments consistent with the Commission's rules, regulations, and decisions. Upon Commission approval of the transaction, LEUC will cause UWA to change its name in

accordance with the terms of the SPA and will provide appropriate notice to its utility customers.

On November 14, 2012, the Joint Applicants and the General Staff ("Staff") of the Arkansas Public Service Commission ("Commission"), (collectively referred to as the "Parties"), filed a Joint Motion ("Joint Motion") to Approve the Stipulation and Settlement Agreement, the Joint Stipulation and Settlement Agreement ("Agreement"), as Joint Exhibit No. 1, Stipulation Testimony of James C. Cable on behalf of UWA, Stipulation Testimony of Peter Eichler on behalf of LEUC, and the Stipulation Testimony of Staff witness Robert Daniel. The Parties agreed to waive the cross-examination of witnesses and requested that the hearing scheduled for December 19, 2012 be cancelled.

The Parties recommended the approval of the Application, as modified by and consistent with the terms set forth in the Agreement. The Agreement included a rate moratorium with LEUC agreeing that UWA will not file a Notice of Intent to File a Change in General Rates prior to October 31, 2013 and that UWA will provide 12 months of post-transaction operating data not later than 120 days after the date it files its rate case application. Additionally, the Joint Applicants agreed that no costs of the proposed transaction will be borne by ratepayers. Such costs include, but are not limited, to the acquisition premium costs, transition costs, severance costs related to termination of employees as a direct result of this transaction[1], or termination fees incurred in conjunction with the transaction.

The Joint Applicants agreed that all costs related to the transaction shall be

[1] Liberty Utilities noted that no terminations are expected as a result of this transaction.

recorded in separate accounts specifically maintained to account for the transaction. The detailed journal entries recorded to reflect the transaction shall be filed with the Commission no later than thirteen months after the date of closing or prior to any rate increase application, whichever comes first.

Further, the Parties agreed that the cost of capital as reflected in UWA's rates will not be adversely affected as a result of the transaction. LEUC and UWA affirmed that they will not oppose, in either a regulatory proceeding or by judicial appeal of a Commission decision, the application of the principle that the determination of the cost of capital can be based only on the risks attendant to the regulated operations of UWA. LEUC agreed that UWA's equity level will not fall below 40% of its total capitalization as a result of any dividend payments made to LEUC or any of its parent companies. LEUC also agreed the Accumulated Deferred Income Taxes ("ADIT") amount, character, and all other terms reflected on the books of UWA immediately prior to the transaction shall be unchanged by the transaction with the exception of adjustments related to the splitting of Pension and Other Post-Employment Benefits ("OPEB") accounts and funds and the reduction in plant related to any assets not purchased from United Water. ADIT will continue to be treated as a zero-cost source of capital. In calendar years 2013, 2014, and 2015, LEUC agreed to contribute up to $70,462 annually to its Pension Trust Fund and to contribute up to $902,721 annually to its OPEB Trust Fund, as more specifically outlined in the Agreement and in the Stipulation Testimony of Staff witness Daniel. In any rate case using a test year including any portion of calendar years 2013, 2014, or 2015, LEUC agreed to make a ratemaking adjustment to reflect that the full contribution of $211,386 to its Pension Trust Fund and $2,708,163 to its OPEB Trust

Fund have been made for determining the level of pension expense; OPEB expense; current, accrued, and other liabilities (CAOL); and any other applicable ratemaking treatment associated with pension and OPEB. Going forward, LEUC agreed to act prudently to properly fund its Pension and OPEB Trust Fund obligations in a timely and competent manner, as specifically outlined in the Agreement.

LEUC committed that UWA will conduct business as a separate legal entity and shall hold all of its assets in its own legal entity name. LEUC also committed that UWA will not grant or permit to exist any lien, encumbrance, claim, security interest, pledge, or other right in favor of any person or entity in its assets, other than liens or encumbrances entered into in the ordinary course of business. LEUC and UWA affirmed that the present legal entity structure that separates the regulated business operations from those unregulated business operations shall be maintained unless express Commission approval is sought to alter any such structure. LEUC and UWA further agreed that proper accounting procedures will be employed to protect against cross-subsidization of non-regulated businesses by UWA customers. The Joint Applicants also made certain agreements outlined specifically in the Agreement concerning how it will maintain its books and records and other commitments, described specifically in the Agreement.

Concerning the financing of the Agreement, the Application stated that LEUC seeks authorization, pursuant to Ark. Code Ann. §§ 23-3-103 and 23-3-104, to enter into an inter-company promissory note for the borrowing of unsecured long-term debt. The capital to be secured through the debt proceeds will be used for normal operations of UWA and for any legal purposes provided by law. The issuance of the inter-company

promissory note by UWA to LEUC will achieve the desired capital structure for UWA of 45% to 55% debt-to-equity. The Parties agreed that UWA can enter into a promissory note with LEUC for up to a maximum amount of $20.0 million of long-term debt in order to achieve the desired capital structure.

Staff witness Daniel in his Stipulation Testimony made the following recommendations. He stated that he supported the Agreement as being in the public interest and recommended its approval based upon the assurances provided by the Joint Applicants, the assurances included in the Agreement, the Company's model to deliver high quality water service to its customers, its financial capabilities, and customer service model. Staff witness Daniel stated that based upon the testimony provided by the Joint Applicants in their request, the issuance of the unsecured debt to achieve a more conservative capital structure for UWA appeared reasonable. Staff witness Daniel specifically recommended that UWA be limited to issue up to $20 million to meet the requirement of Ark. Code Ann. § 23-3-104(a)(2). Further, he recommended that the Company be required to file a report providing the purpose and identifying the specific terms of each issuance of securities, including the actual interest rate and maturity date, all fees and other relevant facts, and the detailed accounting entries to record the transactions. Staff witness Daniel detailed the reporting requirements as follows. The reports should be filed in this Docket within thirty (30) days of the issuance or effective date, as applicable. To the extent the report contains estimates, a follow-up report should be filed reflecting actual amounts. Staff witness Daniel stated that he would further note that Commission authorization of security issuances does not represent a finding of value for ratemaking purposes. A review of the

need for capital issuance(s) and any resultant rate recovery implications should be made in the context of subsequent proceedings. To that end, he recommended that the Commission expressly reserve for future consideration the ratemaking treatment of any security issuances.

No public comments have been filed in this Docket. No other Parties have filed to intervene or participate in this Docket.

THEREFORE, I find that the Agreement is in the public interest, is supported by the Record, and is hereby approved. The Joints Applicants shall comply fully with the Agreement and with the detailed recommendations in the Stipulation Testimony of Staff witness Daniel, including the reporting requirements. Commission authorization of security issuances does not represent a finding of value for ratemaking purposes. A review of the need for capital issuance(s) and any resultant rate recovery implications shall be made in the context of subsequent proceedings. The ratemaking treatment of any security issuances is expressly reserved for future consideration.

Based upon a thorough review of the prefiled Record, I do not believe that a hearing is necessary to add to this Record, so the hearing scheduled by Order No. 4 for December 19, 2012 is cancelled.

BY ORDER OF THE ADMINISTRATIVE LAW JUDGE PURSUANT TO DELEGATION.

This 27 day of November, 2012.

Susan E. D'Autreuil
Administrative Law Judge

Kristi K. Rhude
Secretary of the Commission

I hereby certify that this order, issued by the Arkansas Public Service Commission, has been served on all parties of record on this date by the following method:

X U.S. mail with postage prepaid using the mailing address of each party as indicated in the official docket file, or
X Electronic mail using the email address of each party as indicated in the official docket file.

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF LITCHFIELD PARK SERVICE COMPANY FOR A WAIVER UNDER A.A.C. R14-2-806 OR, IN THE ALTERNATIVE, NOTICE OF INTENT TO REORGANIZE UNDER A.A.C. R14-2-803.

DOCKET NOS. W-01427A-11-0419 AND SW-01428A-11-0420

DECISION NO. 73350

ORDER

Open Meeting
August 9, 2012
Phoenix, Arizona

BY THE COMMISSION:

FINDINGS OF FACT

A. Introduction

1. On November 22, 2011, Litchfield Park Service Company ("LPSCO" or "Company") filed applications ("Applications") with the Arizona Corporation Commission ("Commission") for both its water and wastewater operations, requesting an order from the Commission that either (i) declares that the affiliated interests rules (Arizona Administrative Code ("A.A.C.") R14-2-801, et seq.) do not apply to a transaction (the purchase of all outstanding shares of Entrada Del Oro Sewer Company, Inc. ("EDO") by Liberty Water Company ("Liberty Water")) or (ii) grants a waiver under A.A.C. R14-2-806 with respect to that transaction. Alternatively, LPSCO requests that the Commission approve the transaction under A.A.C. R14-2-803, a notice of intent to reorganize an existing public utility holding company.

2. On December 22, 2011, Docket Nos. W-01427A-11-0419 and SW-01428A-11-0420 were consolidated by the Hearing Division.

B. Background

3. Litchfield Park Service Company ("LPSCO or Company"), a wholly-owned subsidiary of Liberty Water Company ("Liberty Water"), is a public service corporation engaged in providing water and wastewater utility services in Maricopa County, Arizona. Its principal place of business is 12725 W. Indian School Road, Suite D-101, Avondale, Arizona.

4. At the present time, LPSCO provides water service to approximately 16,500 water customers and 18,500 wastewater customers. LPSCO's current rates and charges were authorized in Decision No. 72026 (December 10, 2010).

5. Entrada Del Oro Sewer Company, Inc. ("EDO") at the present time provides wastewater services to approximately 324 wastewater customers in Pinal County, Arizona. EDO's current rates and charges were authorized in Decision No. 68306 (November 14, 2005).

6. LPSCO's application presents the following description of the transaction and its relationship with EDO:

> On August 26, 2008, Liberty Water entered into a Stock Purchase Agreement with Sellers for the purchase of all outstanding shares of EDO's common stock (the "Stock Purchase Agreement"). A copy of the Stock Purchase Agreement will be provided subject to an appropriate confidentiality agreement. Liberty Water paid $635,000 cash to Sellers for EDO's common stock. The stock shares are escrowed and will be transferred once the Commission grants a waiver or, in the alternative, approves the Transaction. Liberty Water has also paid growth premiums totaling $279,000. To date the purchase price is $914,000. That amount will increase based on customer growth expected through 2018.
>
> Also on August 26, 2008, Liberty Water and EDO entered into an Agreement for Labor Services (the "Management Agreement"). A copy of the Management Agreement will be provided subject to an appropriate confidentiality agreement. By way of the Management Agreement, Liberty Water maintains and operates EDO's wastewater treatment plant.
>
> The Transaction does not involve the sale, lease, assignment, encumbrance or transfer or conveyance of any of EDO's utility plant, assets, revenue or property. The only change to EDO as a result of the Transaction is that EDO, which elected S-Corporation tax status, will revert back to a C-Corporation, as EDO will become a subsidiary of Liberty Water which is a

> C-Corporation.[1] Nevertheless, the Transaction will be transparent to EDO customers, as well as to LPSCO customers
>
> The Transaction between Liberty Water and EDO will not alter the utility service provided by LPSCO. LPSCO has provided and will continue to provide safe and reliable utility service to customers in its service territory. Moreover, LPSCO has operated and will continue to operate as a public service corporation and be subject to the Commission's authority and jurisdiction.

7. LPSCO has asked for a waiver to the above transaction. Staff recommends that if the Commission is inclined to grant a waiver, it should only apply to this transaction.

C. Explanation of Affiliate Interest Rules

8. The Rules cover the Commission's review of transactions between public utilities and affiliates. In general, A.A.C. R14-2-804 states that, in order to transact business with an affiliate, the utility must agree to provide the Commission with access to the books and records of the affiliate to investigate transactions between the two. The utility is also obligated to maintain necessary accounting records regarding transactions with each affiliate. The Rules were created so that the Commission could be made aware of transactions and other occurrences at the holding company level that may affect the regulated utility's operations or financial well-being--even if indirectly.

9. In the past, when dealing with certain other utilities with corporate parents, Staff has sometimes experienced difficulties obtaining information at the parent level that Staff believed was necessary for a complete analysis. Staff notes this concern now in hopes of avoiding any such delays or lack of cooperation in this and any future proceedings the Commission may have with the Company. Although Staff has not experienced problems obtaining requested information from LPSCO in the past.

10. Staff concludes that the Commission or other parties might have questions about the proposed transaction; therefore, it is not in the public interest to either declare that the Rules do not apply or to grant a waiver.

. . .

[1] EDO's 2008, 2009, and 2010 Utility Reports on file with the Commission incorrectly reflect that EDO is a C-Corporation.

D. Company's Alternative if its Waiver is denied

11. LPSCO requests that, in the event that its request for a waiver is denied, the Commission approve the transaction under A.A.C. R14-2-803 ("Rule 803"), a notice of intent to reorganize an existing public utility holding company. LPSCO provided in its Application all eleven components required in a notice of intent to reorganize as a public utility company pursuant to Rule 803.

12. The reorganization involves only the purchase and sale of common stock. The transaction does not involve the sale, lease, assignment, encumbrance or transfer or conveyance of any of EDO's utility plant, assets, revenue or property. The only change to EDO as a result of the transaction is that EDO, which elected S-Corporation tax status, will revert back to a C-Corporation. The transaction will also not alter the capital structure of LPSCO.

13. Staff recommends that this transaction, and only this transaction, should be approved under Rule 803, and agrees with the Company that a hearing is not necessary. Staff further concludes that this transaction should benefit rate payers, by permanently unifying the owner and operator of EDO; provide EDO with access to greater managerial, financial and technical expertise; and provide EDO with access to the equity capital markets.

14. Staff Recommendations:

Denial of the request for a waiver.

Approval of the reorganization subject to the following conditions:

a. LPSCO fully cooperates with any Staff inquiries or requests for information and/or documents regarding any transaction that Staff determines might have some detrimental effect, direct or indirect, on the Company's operational or financial health.
b. EDO is ordered to refrain from seeking an acquisition adjustment due to this transaction in any future rate case.
c. EDO is ordered to maintain its quality of service, including, but not limited to ensuring that the number of service complaints, the response time to service complaints and service interruptions should not increase as a result of the reorganization.
d. EDO and LPSCO are directed to maintain an equity position that represents no less than 35 percent of its total capitalization (aggregate of common equity, long-term debt and short-term debt).

15. Staff's recommendations are reasonable, and should be adopted.

CONCLUSIONS OF LAW

1. The Company is a public water service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. 40-250 and 40-252 and the Commission's Affiliated Interest Rules, A.A.C R14-2-801-806.

2. The Commission has jurisdiction over the Company and the subject matter of the application.

3. The public interest requires that the Commission apply the Affiliated Interests Rules in a manner that will maximize protection to ratepayers.

4. Approval of the transaction proposed in the Application would serve the public interest only if conditions are imposed to provide adequate protection to ratepayers.

5. The public interest requires that the transaction proposed in the Application be approved subject to the conditions recommended by Staff.

6. The transaction proposed in the Application, with the conditions set forth and discussed herein, is reasonable and in the public interest and should be approved.

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ORDER

IT IS THEREFORE ORDERED that Litchfield Park Service Company's request for a waiver from Commission review of the transaction proposed in the Application pursuant to A.A.C. R14-2-806, is hereby denied.

IT IS FURTHER ORDERED that the transaction proposed in the Application and Notice is hereby approved, as a reorganization of a holding company pursuant to A.A.C. R14-2-803, subject to the conditions set forth in Findings of Facts Nos. 13 and 14.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY THE ORDER OF THE ARIZONA CORPORATION COMMISSION

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, ERNEST G. JOHNSON, Executive Director of the Arizona Corporation Commission, have hereunto, set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this 21st day of August, 2012.

ERNEST G. JOHNSON
EXECUTIVE DIRECTOR

DISSENT: _____

DISSENT: _____

SMO:JMM:sms\RMM

SERVICE LIST FOR: Litchfield Park Service Company
DOCKET NO. W-01427A-11-0419 ET AL

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0000202186

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

ROBERT "BOB" BURNS – Chairman
BOYD DUNN
SANDRA D. KENNEDY
JUSTIN OLSON
LEA MÁRQUEZ PETERSON

IN THE MATTER OF THE JOINT APPLICATION OF LIBERTY UTILITIES (BELLA VISTA WATER) CORP. AND HEART CAB CO., INC. D/B/A SULGER WATER COMPANY #2 FOR APPROVAL OF (1) THE SALE OF HEART CAB CO., INC. D/B/A SULGER WATER COMPANY'S ASSETS TO LIBERTY UTILITIES (BELLA VISTA WATER) CORP. AND (2) THE TRANSFER OF HEART CAB CO., INC. D/B/A SULGER WATER COMPANY'S CERTIFICATE OF CONVENIENCE AND NECESSITY TO LIBERTY UTILITIES (BELLA VISTA WATER) CORP.	DOCKET NO. W-02465A-20-0029 W-02355A-20-0029 DECISION NO. 77741 **OPINION AND ORDER**

DATE OF HEARING: July 22, 2020

PLACE OF HEARING: Tucson, Arizona[1]

ADMINISTRATIVE LAW JUDGE: Julia L. Matter[2]

APPEARANCES: Ms. Shilpa Hunter-Patel, Attorney, on behalf of Liberty Utilities (Bella Vista Water) Corp.;

Mr. Thomas Sulger and Ms. Amie Sulger, on behalf of Heart Cab Co., Inc. d/b/a Sulger Water Company No. 2; and

Ms. Bridget Humphrey, Staff Attorney, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

BY THE COMMISSION:

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Arizona Corporation Commission ("Commission") finds, concludes, and orders that:

. . .

[1] The hearing was conducted via teleconference due to the COVID-19 pandemic.
[2] Administrative Law Judge Belinda Martin conducted the initial procedural conference in this matter.

FINDINGS OF FACT

Procedural History

1. On February 19, 2020, Liberty Utilities (Bella Vista Water) Corp. ("Liberty Bella Vista") and Heart Cab Co., Inc. d/b/a Sulger Water Company No. 2 ("Sulger") filed a joint application with the Commission for approval of the sale of Sulger's assets and the transfer of Sulger's Certificate of Convenience and Necessity ("CC&N") to Liberty Bella Vista.

2. On February 21, 2020, a Procedural Order was issued regarding consent to email service.

3. On March 20, 2020, the Commission's Utilities Division ("Staff") filed a Sufficiency Letter stating that the application had met the sufficiency requirements as outlined in the Arizona Administrative Code ("A.A.C.").

4. On March 25, 2020, by Procedural Order, a telephonic procedural conference was set for March 31, 2020.

5. On March 27, 2020, Liberty Bella Vista filed a Supplement to Application, attaching a copy of Sulger's 2018 Utilities Division Annual Report.

6. On March 31, 2020, the telephonic procedural conference was held as scheduled. The parties discussed extending the filing deadlines and timeclock due to the impact of the COVID-19 pandemic. Staff recommended, and the parties agreed, that the filing deadlines and timeclock should be extended by 60 days. The parties also expressed an interest in conducting the hearing telephonically or through videoconferencing. The request was taken under advisement.

7. On April 2, 2020, by Procedural Order, a hearing was set for July 22, 2020, at the Commission's offices in Tucson, Arizona. The Procedural Order established other procedural deadlines, including deadlines for the provision of public notice, and extended the timeclock for issuing a final decision in this matter until October 16, 2020.

8. On May 22, 2020, Liberty Bella Vista filed a Notice of Filing Certification of Notice, certifying that notice of the application and hearing was posted on Liberty Bella Vista's website on April 20, 2020, published in the *Herald/Review* in Sierra Vista, Cochise County on April 24, 2020, and mailed to customers on April 21, 2020.

9. On June 15, 2020, by Procedural Order, a telephonic procedural conference was scheduled for July 8, 2020, at 10:00 a.m., for the purposes of further discussing the hearing.

10. On June 24, 2020, Staff filed its Staff Report, recommending approval of the sale of Sulger's assets and transfer of its CC&N with conditions.

11. On June 30, 2020, a Procedural Order was issued directing that the hearing scheduled for July 22, 2020, at 10:00 a.m., would proceed in a telephonic or video-only format, and ordering Liberty Bella Vista and Sulger to provide additional notice to customers regarding the manner of the hearing.

12. On July 1, 2020, Liberty Bella Vista filed a Request to Modify Procedural Schedule, requesting an extension of the deadline to file comments to the Staff Report from July 8, 2020, to July 13, 2020, due to scheduling conflicts.

13. On July 6, 2020, a Procedural Order was issued granting Liberty Bella Vista's Request to Modify Procedural Schedule.

14. On July 8, 2020, the telephonic procedural conference was held as scheduled. The parties discussed the manner of conducting the telephonic hearing.

15. On July 10, 2020, Liberty Bella Vista filed proof that supplemental notice was mailed to Sulger's customers on July 2, 2020, and posted on Liberty Bella Vista's website on July 1, 2020.

16. On July 13, 2020, Liberty Bella Vista filed a Response to Staff Report.

17. On July 17, 2020, Sulger filed Additional Exhibits for Hearing to be Taken into Consideration, which included an invoice billed to Sulger dated June 7, 2020.

18. On July 21, 2020, Staff filed a Notice of Filing Exhibit S-1.

19. On July 22, 2020, the hearing was held as scheduled before a duly authorized Administrative Law Judge for the Commission. Mr. Thomas Sulger and Ms. Amie Sulger appeared telephonically on behalf of Sulger. Liberty Bella Vista and Staff appeared telephonically through counsel. One member of the public appeared telephonically to provide public comment. Staff and Liberty Bella Vista presented testimony and evidence during the hearing. At the conclusion of the hearing, the matter was taken under advisement pending submission of a Recommended Opinion and Order to the Commission.

20. On July 24, 2020, a letter from a customer regarding the application was filed in the docket.

Background

21. Sulger is an Arizona corporation providing water utility service to approximately 25 residential customers in Cochise County, Arizona, approximately 10 miles north of Sierra Vista along State Route 90. Sulger does not have any employees.[3]

22. Liberty Bella Vista is a Class B utility providing water service to approximately 11,000 customers in Cochise County and its CC&N covers approximately 25,250 acres. Liberty Bella Vista's affiliates provide utility services in Santa Cruz, Maricopa, and Pinal Counties. Liberty Bella Vista is wholly owned by Liberty Utilities (Sub) Corp., a Delaware corporation, which is a wholly-owned subsidiary of Liberty Utilities Co., a Delaware corporation. Liberty Bella Vista's ultimate parent company is Algonquin Power & Utilities Corp., a Canadian corporation whose shares are traded on the Toronto Stock Exchange.[4]

23. Sulger's CC&N was granted in Decision No. 50157 (August 13, 1979) and Decision No. 56522 (June 21, 1989), and covers approximately 537 acres.[5]

24. Sulger's existing water system consists of two wells, one 5,000-gallon pressure tank, three 100-gallon pressure tanks, and a distribution system serving 25 metered service connections. The Company does not have an above-ground storage tank.[6]

25. Sulger and Liberty Bella Vista do not provide wastewater utility service.[7]

26. Sulger does not anticipate any significant growth in its CC&N area in the next 5 years.[8] Staff concludes that the existing water system has adequate well production of 70 gallons per minute and adequate storage capacity to serve the present customer base and reasonable growth.[9] Staff's engineer clarified at the hearing that although Sulger does not have a storage tank, the well production capacity is sufficient to serve Sulger's customers without storage, but ADEQ requires storage for 24-

[3] Ex. S-1 at 1 and Attachment C at 1.
[4] Ex. S-1 at 1, Attachment A at 1, and Attachment C at 1; Ex. A-1 at 3; Tr. at 14-15.
[5] Ex. S-1 at 1.
[6] Ex. S-1, Attachment A at 1; Tr. at 19, 54.
[7] Tr. at 31.
[8] Ex. A-1 at 5.
[9] Ex. S-1, Attachment A at 2.

hour water demand and thus Staff expects Liberty to perform a system analysis and evaluate the need to install a storage tank.[10]

27. According to an Arizona Department of Environmental Quality ("ADEQ") Compliance Status Report dated February 26, 2020, Sulger's water system currently is delivering water that meets the water quality standards required by Title 40 Code of Federal Regulations Part 141, the National Primary Drinking Water Regulations, and A.A.C. Title 18, Chapter 4.[11]

28. Sulger is not located in an Arizona Department of Water Resources ("ADWR") Active Management Area. According to an ADWR Water Provider Compliance Report dated March 6, 2020, Sulger is in compliance with ADWR's requirements governing water providers and community water systems.[12]

29. According to Staff's Engineering Report, Liberty Bella Vista is in compliance with ADEQ and ADWR requirements, but two of Liberty Bella Vista's affiliates have outstanding compliance issues with ADEQ.[13] Liberty Bella Vista provided additional information indicating that the compliance issues have been addressed.[14]

30. The Commission's Compliance Section reported three outstanding compliance items for Sulger arising out of Decision No. 72052 (January 6, 2011) in Docket No. W-02355A-09-0275, which approved a rate increase and authorized Sulger to incur a loan from the Water Infrastructure Financing Authority ("WIFA") for capital improvement projects, including the installation of a 5,000-gallon storage tank and a 1,500-gallon pressure tank. The first compliance item required Sulger to file with Docket Control, no later than January 30th of each year starting in January 2012, copies of the prior year's monthly bank statements for the account opened to deposit financing surcharge funds. The second compliance item required Sulger to file with Docket Control by December 31, 2011, a copy of the ADEQ certificate of Approval of Construction for the 1,500-gallon pressure tank and the 5,000-gallon storage tank. The third compliance item required Sulger to file with Docket Control copies of the executed WIFA financing documents within 30 days after the transaction closed. According to the

[10] Tr. at 60-61.
[11] Ex. S-1, Attachment A at 3.
[12] Ex. S-1, Attachment A at 3.
[13] Ex. S-1 at 3 and Attachment A at 3-4.
[14] Ex. A-2; Tr. at 32-34, 59-60.

Staff Report, Sulger did not obtain the financing authorized in Decision No. 72052 and thus is unable to comply with the outstanding compliance items.[15] In addressing the outstanding compliance issues, Liberty Bella Vista intends to evaluate whether additional storage is needed and to file a plan accordingly.[16]

31. Liberty Bella Vista and Sulger have approved Curtailment and Backflow Prevention tariffs on file with the Commission. Liberty Bella Vista also has an approved Off-site Hook-up Fee tariff.[17]

32. Sulger will refund, before closing of the transfer, any refunds due on customer deposits.[18]

33. Sulger will transfer to Liberty Bella Vista two advances in aid of construction agreements that will require refunds on main extension agreements or refunds on meter and service line installations.[19]

34. Sulger is current on its property taxes.[20]

35. Written comments regarding the application were received by the Commission from one customer, who also presented public comment at the hearing. The customer did not oppose the application, but asked several questions, which were answered at the hearing, and the customer expressed concerns about receiving information regarding Liberty Bella Vista's rates and charges and emergency contact information. No other comments were received regarding the application.

Application

36. Sulger and Liberty Bella Vista's joint application seeks approval of the transfer of Sulger's CC&N and the sale of its assets to Liberty Bella Vista. According to the joint application, Sulger is a troubled small water utility that is not financially viable and is unable to continue with necessary maintenance or to make any capital improvements.[21] Staff agrees that Sulger does not have access to financial capital for necessary system improvements or adequate resources to continue to

[15] Ex. S-1, Attachment A at 4 and Attachment C at 2.
[16] Tr. at 39-40.
[17] Ex. S-1 at 3 and Attachment A at 5.
[18] Ex. S-1 at 2.
[19] Ex. S-1 at 2.
[20] Tr. at 51.
[21] Ex. A-1 at 2; Tr. at 26, 49.

maintain the water system in compliance with regulatory requirements.[22]

37. On February 13, 2020, Sulger and Liberty Bella Vista entered into an Asset Purchase Agreement to sell and transfer Sulger's assets and CC&N to Liberty Bella Vista. Under the terms of the Asset Purchase Agreement, Sulger's assets will be sold and its CC&N transferred to Liberty Bella Vista for the purchase price of $10,000, upon Commission approval. Liberty Bella Vista will assume certain liabilities of Sulger's, including an Advance in Aid of Construction agreement with Sierra Enterprises, LLC for $720, and an Advance in Aid of Construction agreement with Robert Mainord and Linda Poris for $720.[23] In addition, subsequent to the execution of the Asset Purchase Agreement, Sulger incurred a loan from one of its board members in the amount of $3,430.37 to replace the main well pump.[24] Liberty Bella Vista has agreed to repay the loan.[25]

38. Sulger's service territory is in close proximity to, but not adjacent to, Liberty Bella Vista's service territory. Because of the close proximity, Liberty Bella Vista will be able to operate the Sulger system using its existing staff.[26]

39. According to Staff, every applicant for a CC&N is required to submit to the Commission evidence that the applicant has received the required consent, franchise, or permit from the proper authority, authorizing the use of public roads or lands to construct, install, operate, and maintain a water or wastewater system. Liberty Bella Vista did not file a copy of a franchise agreement entered into with Cochise County for the CC&N area to be acquired from Sulger.[27]

40. Liberty Bella Vista will charge its authorized rates and charges, approved in Decision No. 75809 (November 21, 2016) and amended in Decision No. 77122 (March 13, 2019), to the customers acquired from Sulger, which will result in a rate reduction for Sulger's customers.[28] Sulger's customers with an average monthly consumption of 10,000 gallons currently pay $57.40 per month. Under Liberty Bella Vista's current rates, the same customer will pay $41.29, a monthly savings of $16.11. In addition, customers will have access to Liberty Bella Vista's low-income program, which

[22] Ex. S-1, Attachment C at 1.
[23] Ex. S-1 at 2; Ex. A-1 at 5; Tr. at 22-23.
[24] Ex. A-3; Tr. at 47-48.
[25] Tr. at 20.
[26] Ex. S-1 at 1-2; Tr. at 15.
[27] Ex. S-1 at 4.
[28] Ex. S-1 at 3.

Sulger does not have.[29]

41. According to Staff, the sale and transfer of Sulger to Liberty Bella Vista will not have any adverse impacts on customers and their water service.[30]

42. Staff states that Liberty Bella Vista is an established water utility that has the managerial, financial, and technical capability needed to operate the Sulger system, and that the sale and transfer is in the public interest.[31]

43. Staff states that the sale and transfer is consistent with Commission Decision No. 75626 (July 25, 2016), which encourages larger utilities to acquire and absorb smaller troubled utilities to the benefit of ratepayers.[32]

Staff's Recommendations

44. Staff recommends that:[33]

(1) The Commission grant the joint application for the sale of Sulger's assets and the transfer of Sulger's CC&N to Liberty Bella Vista.

(2) Liberty Bella Vista charge its existing rates and charges in the acquired service area.

(3) Liberty Bella Vista may not require Sulger's existing customers to pay a security deposit as a condition of transfer to its system.

(4) Liberty Bella Vista and Sulger shall be authorized to engage in any transactions and to execute, or cause to be executed, any documents necessary to effectuate the authorizations requested with the application.

(5) Liberty Bella Vista file all pertinent documents evidencing the consummation of the transaction within 30 days of the effective date of the order issued in this proceeding.

(6) Liberty Bella Vista file with Docket Control, as a compliance item in this docket, within two years of the effective date of an order in this proceeding, a copy of the county franchise agreement entered into for the acquired area.

(7) Liberty Bella Vista make an appropriate filing in Docket No. W-02355A-09-0275

[29] Ex. S-1, Attachment C at 2-3; Tr. at 24, 28-29, 65.
[30] Ex. S-1 at 2 and Attachment A at 2; Tr. at 72.
[31] Ex. S-1 at 2 and Attachment A at 2; Tr. at 60, 64, 70-71.
[32] Tr. at 64-65.
[33] Ex. S-1 at 4-5.

addressing Sulger's outstanding compliance items within 60 days of a Decision in this proceeding. Staff clarified at the hearing that Liberty Bella Vista's filing could indicate that Sulger did not go forward with the financing that had been approved and could request that the docket be closed so that the compliance issues do not remain outstanding.[34]

45. Staff further recommends that the Commission's Decision granting the transfer of Sulger's CC&N to Liberty Bella Vista be considered null and void, after due process, should Liberty Bella Vista fail to meet Condition Nos. 5, 6, and 7 above, within the time specified.[35]

46. Liberty Bella Vista objected to Staff's Condition No. 5 and requested 60 days to complete the transaction and file evidence with the Commission.[36] At the hearing, Staff agreed with Liberty Bella Vista's request.[37] Liberty Bella Vista did not object to any of the other recommended conditions.[38]

47. We find that it is in the public interest to approve the application, as recommended by Staff. We further find that Staff's recommendations and conditions, as modified at the hearing, are reasonable and appropriate, and we adopt them.

48. We also find that it is reasonable and appropriate to require Liberty Bella Vista to notify the customers acquired from Sulger of its authorized rates and charges, its low income program, and its contact information for customer service and emergencies, by means of an insert in its first billing to customers, and to file a copy of the notice with Docket Control within 10 days of the notice being sent. Staff agreed that it would be appropriate for Liberty Bella Vista to provide such notice to customers.[39]

CONCLUSIONS OF LAW

1. Sulger and Liberty Bella Vista are public service corporations within the meaning of Article XV of the Arizona Constitution and A.R.S. §§ 40-281, 40-282, and 40-285.

2. The Commission has jurisdiction over Sulger, Liberty Bella Vista, and the subject

[34] Tr. at 73-74.
[35] Ex. S-1 at 5.
[36] Ex. A-2.
[37] Tr. at 69-70.
[38] Tr. at 30.
[39] Tr. at 72.

matter of the application.

3. Notice of the application was provided in accordance with Arizona Law.

4. Liberty Bella Vista is a fit and proper entity to receive the assets and certificated area of Sulger, and it is in the public interest to approve the sale of assets and transfer of Sulger's CC&N to Liberty Bella Vista.

5. Staff's recommendations, as modified herein, are reasonable and in the public interest, and should be adopted.

ORDER

IT IS THEREFORE ORDERED that the joint application for approval of the sale and transfer of the assets of Heart Cab Co., Inc. d/b/a Sulger Water Company No. 2 and the transfer of its Certificate of Convenience and Necessity to Liberty Utilities (Bella Vista Water) Corp. is hereby approved.

IT IS FURTHER ORDERED that Heart Cab Co., Inc. d/b/a Sulger Water Company No. 2 is hereby authorized to transfer its water utility assets and Certificate of Convenience and Necessity to Liberty Utilities (Bella Vista Water) Corp.

IT IS FURTHER ORDERED that Liberty Utilities (Bella Vista Water) Corp. and Heart Cab Co., Inc. d/b/a Sulger Water Company No. 2 are authorized to engage in any transactions and to execute, or cause to be executed, any documents necessary to effectuate the authorizations requested with the application.

IT IS FURTHER ORDERED that Liberty Utilities (Bella Vista Water) Corp. shall charge its existing rates and charges in the certificated service area of Heart Cab Co., Inc. d/b/a Sulger Water Company No. 2.

IT IS FURTHER ORDERED that Liberty Utilities (Bella Vista Water) Corp. shall not require Heart Cab Co., Inc. d/b/a Sulger Water Company No. 2's existing customers to pay a security deposit as a condition of transfer to its system.

IT IS FURTHER ORDERED that Liberty Utilities (Bella Vista Water) Corp. shall file with Docket Control, as a compliance item in this docket, within 60 days of the effective date of this Decision all pertinent documents evidencing the consummation of the transaction.

IT IS FURTHER ORDERED that Liberty Utilities (Bella Vista Water) Corp. shall file with

Docket Control, as a compliance item in this docket, within two years of the effective date of this Decision, a copy of the county franchise agreement entered into for the acquired service area.

IT IS FURTHER ORDERED that Liberty Utilities (Bella Vista Water) Corp. shall make an appropriate filing in Docket No. W-02355A-09-0275 addressing Heart Cab Co., Inc. d/b/a Sulger Water Company No. 2's outstanding compliance items within 60 days of this Decision.

IT IS FURTHER ORDERED that Liberty Utilities (Bella Vista Water) Corp. shall notify the customers acquired from Heart Cab Co., Inc. d/b/a Sulger Water Company No. 2 of its authorized rates and charges, its low income program, and its contact information for customer service and emergencies, by means of an insert in its first billing to customers, and should file a copy of the notice with Docket Control, as a compliance item in this docket, within 10 days of the notice being sent to customers.

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IT IS FURTHER ORDERED that if Liberty Utilities (Bella Vista Water) Corp. fails to meet Condition Nos. 5, 6, and 7, as described in Finding of Fact No. 44 and modified in Finding of Fact No. 46, within the specified timeframe, this Decision shall be considered null and void, after due process.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN BURNS COMMISSIONER DUNN COMMISSIONER KENNEDY

COMMISSIONER OLSON COMMISSIONER MÁRQUEZ PETERSON

IN WITNESS WHEREOF, I, MATTHEW J. NEUBERT, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 2nd day of October 2020.

MATTHEW J. NEUBERT
EXECUTIVE DIRECTOR

DISSENT _____

DISSENT _____
JLM/ec

SERVICE LIST FOR: LIBERTY UTILITIES

DOCKET NO.: W-02465A-20-0029, ET AL.

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APSC FILED Time: 9/28/2016 4:16:23 PM: Recvd 9/28/2016 4:16:20 PM: Docket 16-013-U-Doc. 35

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE JOINT APPLICATION OF LIBERTY UTILITIES (CENTRAL) CO., LIBERTY SUB CORP., AND THE EMPIRE DISTRICT ELECTRIC COMPANY FOR ALL NECESSARY AUTHORIZATIONS AND APPROVALS FOR LIBERTY SUB CORP. TO MERGE WITH AND INTO THE EMPIRE DISTRICT ELECTRIC COMPANY	)	DOCKET NO. 16-013-U ORDER NO. 4

ORDER

On March 16, 2016, Liberty Utilities (Central) Co. (LU Central), Liberty Sub Corp. (LSC), and the Empire District Electric Company (EDE) (collectively "Joint Applicants") filed a Joint Application with the Arkansas Public Service Commission (Commission) pursuant to Ark. Code Ann. §23-3-101 and/or Ark. Code Ann. §23-3-102, and Rule 10.2 of the Commission's *Rules of Practice and Procedure* for approval of a merger transaction whereby LSC will merge with and into EDE with EDE being the surviving entity. On that same day EDE filed the Direct Testimony of Brad P. Beecher, and LU Central and LSC filed the Direct Testimonies of Peter Eichler, David Pasieka, and Christopher D. Krygier.

On June 29, 2016, the Joint Applicants, the Consumer Utilities Rate Advocacy Division of the Arkansas Attorney General's Office (AG), and the General Staff (Staff) of the Commission (hereinafter collectively the Parties) filed their *Joint Motion* (Joint Motion) *to Approve Stipulation and Settlement Agreement* (Agreement) *and Request to Cancel Hearing*. In support of the Joint Motion and Agreement, the Parties filed the Settlement Testimonies of LU Central and LSC witness Mr. Eichler, EDE witness Mr. Beecher, AG witness M. Shawn McMurray, and Staff witness Shannon Todd. On June 30, 2016, by Order No. 3, the Commission suspended the remaining procedural schedule and canceled the public hearing.

Direct Testimony of the Joint Applicants

Mr. Beecher, the President and CEO of EDE, provides a description of EDE's areas of operation, utility services provided, and the number of customers served. Beecher Direct at 2 – 3. He provides a description of the proposed transaction. The details of this transaction are covered by the other witnesses in greater detail and will be summarized in the discussion of those witnesses' testimonies. Mr. Beecher states that the transaction will be consistent with the public interest. He testifies that "there will be no impact on customers with respect to rates or service as a result of the transaction and that there will be a positive long term impact on [EDE]'s customers and employees as a result of the transaction." *Id.* at 6. Mr. Beecher adds that the transaction is the result of the efforts of a financial advisor engaged by EDE's board to explore strategic alternatives for EDE. *Id.* at 5. As support for his position, he cites the commitments of Liberty Utilities to make Joplin the regional headquarters for all regulated utilities owned by Liberty Utilities in the central states, to retain all of EDE's management team and workforce, and to operate EDE under the EDE brand for at least 5 years. Mr. Beecher states that EDE's board of directors will be offered a position on the regional board of directors described in the other witnesses' testimony. In addition to retaining all of EDE's workforce, Mr. Beecher states that the transaction will be a benefit to EDE's employees, as it will lead to an expansion of employment opportunities. *Id.* at 6 – 7.

Mr. Beecher testifies that customers will see no change to their day-to-day service or rates and that they will continue to be served safely, effectively, and efficiently without interruption by the same employees who serve them today. He states that a result of the transaction will be that EDE's customers will be served by a larger, more capable organization, and he states that EDE will continue its current level of involvement and charitable support in

the local communities. Mr. Beecher states that the merger will add scale for EDE and LU Central, providing opportunities to pursue efficiencies, share costs across a larger customer base, leverage best practices, and enhance service offerings. He further explains that the increase in scale and market diversification will also provide increased financial stability and strength. Mr. Beecher states that the proposed transaction will not change EDE's status as a regulated utility in Arkansas. *Id.* at 7 – 8.

Mr. Beecher testifies that the EDE board of directors has approved the transaction, noting that a copy of the resolution of the board approving the transaction is attached to the Joint Application. Mr. Beecher explains that, in the opinion of EDE, Liberty Utilities represents the core values that must exist in a merger partner. He offers Liberty Utilities' commitments and representations discussed in his testimony and the testimony of the witnesses for LU Central and LSC as support of the position. Mr. Beecher states that the transaction needs to be approved by EDE's shareholders, noting that each share of common stock will be entitled to one vote for or against the transaction. He states that a proxy containing the details will be mailed to the shareholders with an announcement of the meeting of the stockholders. Mr. Beecher testifies that the transaction will not have an impact on the tax revenues of the political subdivisions in which EDE's property is located. EDE will continue to be the owner of the network and properties after the close of the transaction. Mr. Beecher states that the transaction will have no effect on the Commission's authority to regulate EDE's operations. *Id.* at 8 – 10.

Mr. Pasieka, President of Liberty Utilities (Canada) Corp., describes the transaction for which the Joint Applicants are requesting approval. LU Central will acquire all issued and outstanding shares of EDE stock and then merge EDE with LSC, a wholly-owned subsidiary of

LU Central created solely for this transaction. EDE will emerge from the transaction as the surviving corporation. Following the merger, LSC will cease to exist and EDE will be a wholly-owned subsidiary of LU Central. Pasieka Direct at 4. Mr. Pasieka explains that the plan is for EDE and certain of Liberty Utilities Co.'s[1] (Liberty Utilities) existing utilities to be reorganized under LU Central with Mr. Beecher, the current CEO of EDE, assuming the role of the CEO of LU Central. These utilities include EDE and the natural gas and water utilities of Liberty Utilities located in Missouri, Illinois, Iowa, Arkansas, and Texas. He states that the EDE management team will provide services to all of the utilities within LU Central and that shared services may be provided where appropriate and in accordance with affiliate transaction rules and Commission orders. Each utility will continue to operate on a standalone basis, with separate tariffs, assets, and books and records. *Id.* at 5.

Mr. Pasieka testifies that the legal standard applicable to utility acquisitions in Arkansas is that the proposed acquisition must be approved if it is "consistent with the public interest," and he goes on to explain why LU Central's proposed acquisition of EDE satisfies this standard, discussing seven primary benefits. He first states that the merger will provide efficacy of scale. Mr. Pasieka explains that the scale is expected to result in greater management expertise, access to broader management capabilities, and an ability to capitalize on greater opportunities for future efficiencies. Second, he notes that increased management capability will be a benefit of the transaction. Mr. Pasieka states that the joint entity will enjoy expertise in: 1) electric utility operations serving over 270,000 customers, including vertical integration with a utility owned and developed renewable energy and conventional generation fleet; 2) gas utility operations serving over 330,000 customers, with expertise in the development of distribution

[1] Liberty Utilities Co. is the parent company of LU Central.

utility best practices, service territory expansion, alternate fuel procurement, and investment in gas transmission infrastructure; 3) distribution utility expertise in running large water operations serving in excess of 175,000 customers, including drought-prone areas; and 4) access to renewable energy development expertise that has already proven to be beneficial to the electric utilities Liberty Utilities owns in other jurisdictions, with investments in utility owned solar generation that is expected to reduce overall customer energy costs. *Id.* at 6 – 7.

Third, Mr. Pasieka discusses the benefits of enhanced regional senior leadership support. He states that by reorganizing Liberty Utilities' operations to include LU Central, each utility will now have access to senior level leadership of the utilities, which will be closer to the service territory than is currently the case, ensuring expeditious responsiveness to the local community and the emerging issues within each community. Fourth, Mr. Pasieka remarks that the board of directors for LU Central will include senior business and community leaders. In addition, all existing board members of EDE will be offered a position on the board. Mr. Pasieka states that the board is expected to provide guidance and counsel on local issues to ensure that the combined entity will enhance its understanding of local operating conditions and be able to better serve the needs of customers. Fifth, Mr. Pasieka explains that financial capabilities will be enhanced by combining the financial strength of two organizations with a BBB credit rating, which will ensure stronger access to financial markets. It will also provide momentum to work towards enhancing the company's credit rating in the future by providing increased diversification of modality and geography, and ultimately further diversifying the risks of both organizations. *Id.* at 7 – 8.

Mr. Pasieka concludes his testimony on the benefits of the merger by noting, as the sixth and seventh example of primary benefits, that jobs will be maintained after the merger and

that the transition will be seamless. He testifies that the rationale of the transaction is to enhance the capabilities of both organizations and as such, there will be no involuntary reductions associated with the transaction. Mr. Pasieka explains that Liberty Utilities has completed seven major transitions over the past five years that have been seamless from a customer perspective and has developed a core competence in merging utility operations into its own. He states that with the EDE transaction, this capability will be enhanced, as the acquisition is of a fully functioning standalone utility operation that will allow optimal staging of transition activities. Mr. Pasieka testifies that he is not aware of any detriments from the transaction that the Commission should consider. He states that if any detriments are identified then they are nullified by the commitments made in his testimony and those in the testimonies of Mr. Eichler and Mr. Krygier or are more than outweighed by the many beneficial aspects of the proposed transaction. *Id.* at 8.

Mr. Pasieka next discusses the standards for approving mergers utilized in Missouri, Kansas, and Oklahoma, noting that the proposed acquisition will meet the standards in place in each of the states. He explains that there are certain contingencies that must be satisfied before the transaction can be consummated. Mr. Pasieka states that while EDE's board has approved the transaction, EDE's current shareholders must approve the transaction. In addition to Arkansas, the utility regulatory commissions of Missouri, Oklahoma, and Kansas must approve the transaction, as must the Federal Energy Regulatory Commission. In addition, an application will be made with the Federal Trade Commission for approval under the Hart-Scott-Rodino Antitrust Improvements Act. *Id.* at 9.

Mr. Pasieka next explains the operating and customer service philosophy of Liberty Utilities. He provides a list of principles that guide Liberty Utilities' approach to customer

service: to provide high quality service to all its customers at a reasonable rate; to deliver service to customers primarily through customer service representatives located in and dedicated to the local utility service territory; to continuously improve its customer service; to give local management teams significant authority and autonomy to determine how best to meet customers' needs; to constantly seek ways to share information across companies and benefit from the knowledge and experience of affiliates, while still leaving decision-making in the hands of local management; and to satisfy all legal regulatory obligations.

Mr. Pasieka describes Liberty Utilities' local approach, noting that if a function touches its employees, its customers, or it regulators, then it is best done within the service territory. Liberty Utilities encourages employees to volunteer in local community events and participate in civic organizations such as the chamber of commerce and Rotary. He testifies that immediately after the transaction was announced, the management team set out to engage local communities. Meetings have been held with the state commissions in Arkansas, Missouri, Kansas, and Oklahoma and also with other state and local officials, current EDE employees, and retired EDE employees. *Id.* at 10 – 11.

Mr. Pasieka testifies that in other jurisdictions Liberty Utilities' affiliates have engaged an independent research firm to conduct annual customer service and satisfaction surveys. He provides a copy of the most recent customer satisfaction results to illustrate Liberty Utilities' commitment to good customer service and customer satisfaction and to show how the results are used to identify areas for improvement and to make improvement in those areas. He states that if the transaction is approved, then annual customer surveys will be implemented in EDE's service territory as well. In addition to the customer surveys, Liberty Utilities will evaluate

other ideas to improve customer service, like reopening walk-in centers in local communities. *Id.* at 12 – 13.

Mr. Pasieka explains Liberty Utilities' operational experience and the role it will play in EDE's post-merger operations. He provides a description of the states in which Liberty Utilities currently operates, the types of utilities operated, and the number of customers in each type of utility. He notes that after the transaction closes, Liberty Utilities' overall customer count will increase from approximately 560,000 to nearly 800,000. Mr. Pasieka states that the existing EDE senior leadership team will continue to run EDE's operations out of the current Joplin office and will assume additional oversight responsibilities for existing Liberty Utilities operations in Arkansas, Texas, Missouri, Iowa, and Illinois. He goes on to explain that Liberty Utilities uses a de-centralized approach to operating its regulated utility business, which emphasizes the importance of local management and local control of day-to-day business operations. When Liberty Utilities has acquired utilities in other states, it established a local headquarters in the service area to provide critical customer- and regulator-facing functions, including customer service and billing. In addition, Mr. Pasieka states that Liberty Utilities established local leadership teams empowered to make the right business decisions for customers and other stakeholders. He states that the commitment to EDE to maintain employees and the Joplin headquarters is consistent with Liberty Utilities' approach to management of its utility businesses. *Id.* at 13 – 14.

Mr. Pasieka states that where the quality and empathy of a service is not prejudiced and there is an economy of scale benefit, then Liberty Utilities will provide certain non-consumer, non-regulator, and non-employee facing services centrally as opposed to locally. Examples of

these services include treasury, information technology, insurance, and risk management. *Id.* at 14 – 15.

Mr. Pasieka asserts that this transaction will be consistent with the public interest, noting that nothing is changing as a result of the acquisition from a customer service or operational perspective, that EDE employees and its management team will be retained, and opportunities to achieve scale economies can be achieved from the acquisition. He also points to benefits that result from the savings of fees associated with the Securities and Exchange Commission listings, audit fees, and other public company costs. EDE will no longer be a publicly traded company after the transaction, he notes. Mr. Pasieka also identifies a benefit in the ability of Liberty Utilities to utilize a bill printing machine owned by EDE, noting that Liberty Utilities currently outsources that function. He also states that the transaction poses an opportunity to capture the benefit of scale with combining the customer information systems of Liberty Utilities and EDE into one system that will serve all Liberty Utilities operations. Mr. Pasieka concludes his testimony discussing further benefits to EDE, Liberty Utilities, and EDE's customers. He reiterates the benefits of the senior level management and expertise of both companies, their combined financial strength, the retention of EDE's employees, and the seamless transition that will result from the transaction. *Id.* at 18 – 22.

In Direct Testimony, Mr. Eichler, Vice President of Strategic Planning for Liberty Utilities (Canada) Corp., describes the principal legal entities involved directly in the transaction, financing for the transaction, the financial strength of Liberty Utilities post-closing, and implications of the transaction as they may bear on affiliate transactions and corporate cost allocations. He defers to Mr. Pasieka's testimony for the details on the features

of and rationale for the transaction. He states that EDE's shareholders will receive $34 per common share and EDE will maintain $900 million dollars of debt currently on its balance sheet for a total purchase price of $2.4 billion dollars. At the close of the transaction EDE will be a wholly-owned subsidiary of LU Central and will no longer be publicly traded. Mr. Eichler states that following the transaction, all of EDE's assets utilized for the electric, water, and natural gas utility operations and its fiber optic business will continue to be owned by EDE and the services will continue to be provided by EDE and its subsidiaries. Eichler Direct at 5 – 6.

Mr. Eichler testifies that the transaction is expected to strengthen Liberty Utilities' financial profile by creating a consolidated entity with combined utility rate base of approximately $2.9 billion serving nearly 800,000 gas, electric, and water customers. He explains that while EDE will maintain the debt currently on its books, future financing is expected to occur at the Liberty Utilities level. Thus, he notes, Liberty Utilities' credit rating will provide prudent access to capital for EDE. Based on discussions with Standard & Poor's, Mr. Eichler states that there are no anticipated changes to Liberty Utilities' current BBB credit rating and that the transaction will be supportive of maintaining the rating. *Id.* at 6 – 7.

Mr. Eichler moves on to discuss the financing of the transaction. He states that the total cash consideration required to purchase the shares of EDE is approximately $1.6 billion. This amount will be funded by a combination of equity sourced from Liberty Utilities' parent, Algonquin Power & Utilities Company (Algonquin), a publicly traded company on the Toronto Stock Exchange, and debt sourced by Liberty Utilities and contributed to LU Central to complete the acquisition of the EDE shares. It is expected that Algonquin will raise the equity necessary for the transaction and that the debt financing needed will be raised by Liberty Utilities. The financing of the $2.4 billion acquisition costs is expected to be comprised of $0.9

billion in debt currently on the books of EDE and approximately $1.5 billion in debt obtained by Liberty Utilities and equity obtained by Algonquin and subsequently invested in Liberty Utilities. *Id.* at 7 – 8.

Mr. Eichler states that the debt to equity ratio for Liberty Utilities and LU Central will initially be 55% equity and 45% debt. This will be a higher level of equity than the equity in EDE's debt to equity ratio. Mr. Eichler explains that Liberty Utilities and EDE are not seeking any approval of the higher level of equity for ratemaking purposes and that the higher level of equity is only a demonstration of enthusiasm and commitment for the transaction. He further explains that the $34 per common share purchase price to be paid for EDE represents a premium of 21% over the closing price for common shares on February 8, 2016. Mr. Eichler testifies that neither LU Central nor EDE will seek to recover the premium over the net book value of the assets associated with LU Central's acquisition of EDE in any future ratemaking proceedings. He states that the acquisition premium will be recorded as goodwill on LU Central's accounting records and that the commitment not to seek recovery of the acquisition premium in ratemaking will not impair LU Central's ability to fund its subsidiary utility operations in Arkansas or degrade its financial condition. *Id.* at 9 – 10.

Mr. Eichler next discusses the corporate cost allocations and affiliate transactions processes. He explains that Liberty Utilities and its subsidiaries operate under a shared services model in which certain services are provided to operating businesses from affiliates and charged to these utilities based on either a direct charge or defined costs allocation methodology. According to Mr. Eichler, a majority of the operating expenses are direct costs that can be directly attributed to a particular business. He provides the example of labor, the costs of which are tracked through time sheets and charged to the business for which the

employee is providing services. Mr. Eichler states that costs that cannot be specifically attributed to a particular business are allocated across all businesses in proportions determined by a defined cost allocation methodology based on guidelines set by the National Association of Regulated Utility Commissioners. The costs allocated in this manner are corporate costs, business service costs, and labor charges. Corporate costs include strategic management, capital markets costs, financial control costs, and head office administrative costs. Business services costs cover services such as accounting, administration, corporate finance, human resources, information technology, rates and regulatory affairs, environmental health, safety, security, customer service, procurement, risk management, legal, and utility planning. Labor charges are those costs other than labor-based time sheet costs and are allocated to the various Liberty Utilities subsidiaries based on a formulaic allocation methodology similar to that used for allocating corporate costs and business service costs. *Id.* at 11- 13.

Mr. Eichler testifies that the EDE acquisition will not result in any redundant labor or duplication of efforts. In fact, he states that the combination of the costs for the entities will result in less costs than those currently incurred by EDE. Mr. Eichler provides several reasons for these lower costs: 1) gaining efficacy of scale through distributing costs over 120,000 more customers than EDE serves today; 2) an anticipated reduction of $1.3 million in costs saved by virtue of EDE no longer being required to remain a public reporting issuer; and 3) although there will be no involuntary job losses within the EDE group, an additional $2.2 million in labor savings will emerge through natural attrition (supported by EDE's 2-6% rate of annual attrition through employee turnover and retirements). He estimates that these savings are expected to reduce the total administrative costs borne by EDE's ratepayers by $704,000 – a

decrease of 1.4%. Of this amount, he notes, approximately $16,000 pertains to Arkansas ratepayers. He states that the reduced levels of allocations will be reflected in future rate cases. Mr. Eichler provides an exhibit that shows the anticipated net savings of EDE through 2019. *Id.* at 13 – 14 and Direct Exhibit PE-2.

Mr. Eichler testifies that the cost allocation methodology used by Liberty Utilities was previously filed with the Commission in Docket No. 14-020-U, which was Pine Bluff Water's last general distribution rate case. He states that a revised cost allocation methodology will be filed with the Commission within six months of the closing of the EDE transaction. Mr. Eichler testifies that EDE will continue to be under the direct regulation of the Commission and that LU Central will commit to comply with the Commission's rules and regulations, including those on Affiliate Transactions. He states that the businesses undertaken by Liberty Utilities are "ring-fenced" and each entity is responsible for the portion of Liberty Utilities debt specifically related to that entity. He states that the result of this arrangement is that there is no cross-subsidization or collateralization between any businesses, regulated or unregulated. Eichler Direct at 14 – 15.

Mr. Krygier, Director of Regulatory and Government Affairs for Liberty Utilities Services Corp., testifies to certain key features of the proposed transaction and provides background on Liberty Utilities' current operations in Arkansas, which include the water and wastewater assets of Pine Bluff Water that service Pine Bluff and adjacent territories. Liberty Utilities sought authority to purchase that company in Docket No. 12-061-U. Liberty Utilities also operates a water and wastewater utility in White Hall, Arkansas. He states that due to the size of that utility, it does not fall under the Commission's regulation. Mr. Krygier explains that

Liberty Utilities is not consolidating assets of the regulated entities and envisions that each entity will continue to operate under its own tariffs. Krygier Direct at 3 – 5.

Mr. Krygier explains the benefits of the transaction but refers to Mr. Pasieka's testimony for further explanation of the benefits. He describes what the transaction will mean for Liberty Utilities' current operations in Arkansas, noting that current operations will be enhanced by EDE's becoming a subsidiary of LU Central and gaining access to senior management, a regional board to provide guidance from local business and community leaders, and efficacy of scale that will allow future opportunities to capitalize on efficiencies as they emerge. He explains that the proposed acquisition will not have any adverse rate impacts on EDE's retail customers. He further states that EDE will continue to utilize the rates, rules, and regulations and tariff provisions approved by the Commission and will continue to provide service to customers under the same until they may be modified according to applicable law. Mr. Krygier restates LU Central's commitment not to seek any merger-related adjustments for acquisition costs or any premiums paid over book value. *Id.* at 8 – 9.

Mr. Krygier testifies that EDE will continue to comply with any ongoing regulatory commitments that are currently in place for its electric operations. He states that LU Central will maintain EDE's performance on customer service. He further states that Liberty Utilities plans to keep all of EDE's employees, so there will be no disruption in the continued provision of good service to the customers of EDE. He notes that the Merger Agreement provides certain protections to EDE's current employees regarding their pay and benefits after the transaction. In testifying about the access to capital markets, Mr. Krygier references Mr. Eichler's testimony and states that Liberty Utilities anticipates meeting EDE's needs with debt and capital at rates as least as favorable as they are attained today. He further states that the expectation is that

long term costs of borrowing will be the same if not more competitive with the increased economies of scale from the combined entities. *Id.* at 9 – 10.

Mr. Krygier testifies that there will be no new or increased risk of inappropriate affiliate transactions if EDE becomes a subsidiary in a larger holding company structure. He cites Mr. Eichler's discussion of a cost allocation manual and cost allocation methodology from his testimony. Mr. Krygier states that the Commission should take into account the local impact of the proposed transaction when considering the public interest. He testifies that it is significant that Liberty Utilities plans to retain EDE's headquarters in Joplin, Missouri, asserting that this is good for the local economy and many surrounding communities, including those in Northwest Arkansas served by EDE. Mr. Krygier briefly discusses the purchase price of the common stock and the commitment that LU Central will not recover any of the premium over book value and that no regulated entity will seek to recover any transaction costs associated with the transaction. *Id.* at 10 – 12.

Mr. Krygier concludes his testimony by discussing customer service and commitment to community. He states that Liberty Utilities' philosophy on customer service is focusing on providing high quality customer service and that this approach will not change after the acquisition. He testifies that Arkansas EDE payment centers and pay stations that exist today will remain open and that Liberty Utilities will maintain EDE's current contact center metrics. Mr. Krygier states that EDE's involvement in Joplin and the surrounding area will not change, as it is a shared philosophy of LU Central. He also states that LU Central is committed to the same level of charitable contributions through EDE as EDE makes today. Mr. Krygier explains that customer reliability will be maintained through the transaction. He states that the transaction will not affect EDE's ongoing regulatory commitments and that the approval of the

transaction will not impact the regulatory commitments of affiliated regulated utilities. Mr. Krygier states that the transaction will not require relocation of EDE's books and records and that the Commission and the Staff will be provided appropriate access to EDE's books and records. *Id.* at 12 – 14.

The Proposed Settlement Agreement

The proposed Agreement, which is attached to this Order, recites the commitments made by the Joint Applicants and sets forth these additional terms upon which the Parties request that the Commission approve the transaction: First, the Joint Applicants offer certain ratemaking assurances: (1) a twelve month rate moratorium; (2) no costs of the proposed transaction will be borne by ratepayers; (3) LU Central and/or EDE will not seek to recover any severance costs or retention costs from ratepayers; (4) EDE fuel costs shall not be adversely impacted; (5) EDE will provide an analysis demonstrating that Administrative and General costs have not increased solely as a result of the transaction; (6) certain provisions concerning the cost of capital; (7) certain provisions on the segregation of assets; (8) Liberty Utilities will revise or modify its current cost allocation manual to reflect the acquisition of EDE and file its Affiliate Service Agreement; (9) LU Central fill follow certain accounting standards; (10) LU Central and EDE will follow certain standards in its books and records; and (11) other miscellaneous assurances. Second, the Joint Applicants agree to certain financing provisions concerning the capital structure, the acquisition premium, and refinancing of debt.

Settlement Testimony

Mr. Beecher testifies for EDE that the Agreement resolves all of the issues in this Docket and provides a description of the major provisions. He states that the merger benefits EDE and its customers by providing increased corporate capability and scale by making EDE a part

of the Algonquin family. He further states that the transaction will produce no negative impact with respect to rates or services. Beecher Settlement Testimony at 3 – 6.

On behalf of Liberty Central and LSC, Mr. Eichler states that all issues among the Parties have been resolved with the terms of the Agreement. He provides an overview of the settlement agreement with descriptions of the customer benefits and protections found in the Agreement. Eichler Settlement at 3 – 5. Mr. Eichler testifies that EDE will continue to provide safe and reliable service to its Arkansas customers after the merger. He states that the transaction is expected to strengthen Liberty Utilities' financial profile. Mr. Eichler explains that an investment grade credit rating for Liberty Utilities will provide prudent access to capital at a reasonable rate which will benefit EDE and ultimately its customers. He reiterates that the merger transaction will be seamless to the customer. *Id.* at 5 – 6.

Shawn McMurray testifies for the AG that the Agreement is in the public interest and that it should be approved by the Commission. McMurray Settlement Testimony at (unnumbered) 7.[2] He lists the ways in which the Agreement provides benefits and protections. He first notes that Liberty Utility agrees not to include goodwill or acquisition premium in rates under ¶ 3.4. Further on this point, he notes that Liberty Utility agrees to record the acquisition premium and the debt, equity, and other capital components used to finance the acquisition premium in the books for LU Central and not in the records of EDE. This action addresses a concern of overcapitalization similar to the one the AG raised in Docket No. 15-011-U regarding Source Gas Arkansas. Mr. McMurray also cites the commitment to exclude recovery of transaction and transition costs as well as the agreement to provide an

[2] The Testimony does not contain page numbers.

analysis demonstrating that administrative and general costs have not increased as a result of the transaction before the first rate case after the transaction. *Id.* at (unnumbered) 3 – 5.

Mr. McMurray testifies that the AG's office had a concern over Liberty Utilities' plans to use a capital structure of 55% equity and 45% debt, but notes that this concern was addressed by ¶ 3.9, which states that LU Central agrees that the cost of capital shall be determined in future rate cases, consistent with applicable law, regulations, and practices of the Commission. In addition, ¶ 5.3 addresses this concern by stating that the Agreement shall not be used or argued as establishing precedent for any methodology or rate treatment in future proceedings. Mr. McMurray states that the commitments found in ¶¶ 3.8-3.13 also address the AG's concern about capital structure. Mr. McMurray explains that the AG wanted to avoid EDE customers paying costs of refinancing EDE's existing debt and cites ¶ 4.3 as addressing that concern. The AG requested assurances that EDE customers would not be harmed by changes in treatment of ADIT, which he notes ¶ 3.13 addresses. Mr. McMurray cites ¶ 3.1 as addressing the AG's desire for assurance that rates should not increase as a result of the merger. *Id.* at (unnumbered) 6 – 7.

On behalf of Staff, Shannon Todd discusses Staff's review of the Joint Application and Direct Testimonies filed in support thereof, as well as her support of the Joint Stipulation and Settlement Agreement. She testifies to the standard that she applied to determine the reasonableness of the merger. She states that her review included ensuring that: 1) there would be no negative impact on the Commission's jurisdiction over EDE or on the delivery of service to its customers; 2) there would be no increase in rates for customers and no recovery of costs related to the transaction, including acquisition premium; and 3) LU Central and EDE

are in compliance with all applicable statutory requirements. Todd Settlement Testimony at 3 – 4.

Ms. Todd states that her review included the Joint Application and the testimony of witnesses supporting the Joint Application on LU Central's corporate structure, current credit worthiness, access to capital markets, experience in the utility industry, and background in utility management. She discusses the company commitments and ratepayer assurances made by the Joint Applicants. She notes that the Joint Applicants commit to: 1) the establishment of a "Central Region" headquartered in Joplin, Missouri; 2) offering Mr. Beecher the role of CEO of the Central Region; 3) the EDE brand being maintained for five years; and 4) EDE's current board of directors being offered positions on the regional board of directors. For the ratepayer assurances, she notes that the Joint Applicants commit not to seek recovery of the amount of premium over book value in future EDE rate cases, and that they also commit that neither EDE, nor other LU Central regulated entities, will seek to recover in rates the transaction costs associated with the acquisition. Ms. Todd states that there is a commitment from the Joint Applicants to maintain the same level of service currently provided by EDE to its customers and that EDE will continue to own all of its assets used for utility services and will continue to operate those services. *Id.* at 9 – 10.

Ms. Todd discusses ratepayer protections and assurances additional to the ones offered in the Joint Application that are contained in the Agreement. The Parties acknowledge the Joint Applicants' commitment in ¶ 3.1 of the Agreement not to file a notice of intent to file a rate case until twelve (12) months of actual historical information is available following the closing of the acquisition on January 31, 2017. Ms. Todd notes that, with the requirement of a 60 day notice before a rate application and the 10-month statutory suspension period, this

commitment will result in approximately two years of rate certainty and stability for ratepayers. *Id.* at 11.

In ¶ 4.2 the Parties "recognize that both the acquisition premium and the debt, equity, and other capital components used to finance the acquisition premium are recorded on the books of LU Central and are not recorded on the books of EDE." Ms. Todd states that the purpose of this paragraph is to confirm that there will not be any change in EDE's rate base or debt, or its equity and other capital components, She notes specifically that no acquisition premium or associated goodwill will be recorded on the books of EDE and that the transaction will therefore have no impact on the assets and capital component balances of EDE or its rate of return. *Id.* at 13.

Ms. Todd discusses the assurances given for cost of capital in the Agreement, noting that the Joint Applicants agree that the transaction will have no negative impact on the cost of capital currently reflected in EDE's rates. The Joint Applicants also agree that the cost of capital for EDE should be set commensurate with the risks attendant to the regulated operations of EDE. She further explains that the Agreement provides that LU Central and EDE agree that they will not oppose, either in a regulatory proceeding or by judicial appeal of a Commission decision, the application of the principle that the determination of cost of capital can be based only on the risks attendant to the regulated operations of EDE. Paragraph 3.13 sets forth LU Central's assurance regarding Accumulated Deferred Income Tax (ADIT). Ms. Todd explains that in that provision LU Central agrees that the ADIT amount, character, and all other terms reflected on the books of EDE immediately prior to the transaction shall be unchanged by the transaction with the exception of the adjustments related to the splitting of Pension and Other Post-Employment Benefits accounts and funds and the reduction in plant

related to any assets not purchased from EDE. Ms. Todd explains that this provision ensures ratepayers will continue to have the benefit of these funds which they have paid-in over time. *Id.* at 13 – 15.

Ms. Todd finds the merger is in the public interest. She supports the Agreement and recommends that the Commission approve the Agreement. She bases this on the assurances provided by the Joint Applicants and those in the Agreement. She also bases the finding on LU Central's model to deliver high quality electric service, its financial capabilities, and customer service model. She recommends that the Commission require LU Central to file documentation of the specific terms of each debt and equity issuance, including actual interest rate and maturity date, all fees and other relevant facts, and the detailed accounting entries to record the transactions. Ms. Todd states this report should be filed within 30 days of the closing. In addition she recommends that the Commission note that approval of financing structure does not represent a finding of value for ratemaking purposes, and that the Commission expressly reserves for future consideration the ratemaking treatment of any security issuances. *Id.* at 20 – 21.

Findings and Ruling

The Commission finds that the Settlement is supported by substantial evidence and is consistent with the public interest. In accordance with Ark. Code Ann. §§ 23-3-101(2) and 23-3-102(b)(2), an organization, reorganization, or a consolidation or stock purchase in another entity must be consistent with the public interest to be approved. The Joint Applicants have shown that Liberty Utilities has the experience and expertise to run public utility services in compliance with Arkansas laws and regulations and provide quality customer service to EDE's Arkansas customers. The fact that Liberty Utilities will retain EDE's management team and

workforce reinforce the Commission's finding that EDE's current level of customer service will be maintained. The Joint Applicants' agreement to a rate moratorium and commitments to not recover the costs of the acquisition premium to be paid as well as the transaction and transition costs, *inter alia*, establishes that the transaction will not cause Arkansas ratepayers an adverse impact from the costs of the transaction. In this same vein, the commitments from the Joint Applicants on the recording of the acquisition premium and the debt, equity, and other capital components with LU Central and the assurances on the cost of capital provide additional protections to the Arkansas ratepayers in future rate proceedings. The Commission also notes that the efficacy of scale that may result from the transaction would be beneficial to Arkansas ratepayers. The Commission further finds that there should be no negative impact on the Commission's jurisdiction over EDE and that LU Central and EDE are in compliance with all applicable statutory requirements.

On the basis of these findings, the Agreement, and the testimonies filed in this Docket, the acquisition, as described and conditioned by the Joint Stipulation and Settlement Agreement attached as Joint Motion Exhibit 1 to the Joint Motion filed on June 29, 2016, in this Docket, is approved. The Commission further orders that LU Central file documentation identifying the specific terms of each debt and equity issuance, including the actual interest rate and maturity date, all fees and other relevant facts, and the detailed accounting entries to record the transactions. This report shall be filed in this Docket within 30 days of the closing of the transaction. To the extent a report contains estimates, a follow-up report should be filed reflecting actual amounts. Further, approval of financing structure does not represent a finding of value for ratemaking purposes. Therefore, the Commission expressly reserves for future consideration the ratemaking treatment of any security issuances.

BY ORDER OF THE COMMISSION.

This 28th day of September, 2016.

Ted J. Thomas, Chairman

Elana C. Wills, Commissioner

Lamar B. Davis, Commissioner

I hereby certify that this order, issued by the Arkansas Public Service Commission, has been served on all parties of record on this date by the following method:

___U.S. mail with postage prepaid using the mailing address of each party as indicated in the official docket file, or

X Electronic mail using the email address of each party as indicated in the official docket file.

Sonya Johnson (acting)
Michael Sappington, Secretary of the Commission

APSC FILED Time: 6/29/2016 11:27:51 AM: Recvd 6/29/2016 11:27:13 AM: Docket 16-013-U-Doc. 29

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE JOINT APPLICATION OF LIBERTY UTILITIES (CENTRAL) CO., LIBERTY SUB CORP., AND THE EMPIRE DISTRICT ELECTRIC COMPANY FOR ALL NECESSARY AUTHORIZATIONS AND APPROVALS FOR LIBERTY SUB CORP. TO MERGE WITH AND INTO THE EMPIRE DISTRICT ELECTRIC COMPANY	)	Docket No. 16-013-U

JOINT MOTION TO APPROVE STIPULATION AND SETTLEMENT AGREEMENT AND REQUEST TO CANCEL HEARING

Come now Liberty Sub Corp. (LSC), Liberty Utilities (Central) Co. (LU Central), The Empire District Electric Company (EDE), the Consumer Utilities Rate Advocacy Division of the Attorney General's Office (AG) and the General Staff of the Arkansas Public Service Commission (Staff) (collectively known as the Parties) and for their Joint Motion (Joint Motion) to Approve Stipulation and Settlement Agreement (Agreement) and Request to Cancel Hearing state as follows:

1. The Parties have reached unanimous agreement on all issues in Docket No. 16-013-U. This Agreement is set forth in and attached hereto as Joint Motion Exhibit 1. By this Joint Motion, the Parties are requesting that the Arkansas Public Service Commission (Commission) approve the Agreement.

2. As support for the Agreement and concurrent with the filing of this Joint Motion the following witnesses are sponsoring Settlement Testimonies:

- Peter Eichler for LU Central and LSC
- Brad P. Beecher for EDE

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- M. Shawn McMurray for the AG
- Shannon Todd for Staff

3. As there are no longer any disputed issues, the Parties recommend that the current procedural schedule be suspended and ask that the hearing be cancelled and for the Commission to decide the case on the filed record now before it.

Respectfully submitted,

GENERAL STAFF OF THE ARKANSAS PUBLIC SERVICE COMMISSION

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CERTIFICATE OF SERVICE

I certify that a copy of the foregoing has been delivered to all Parties of Record by electronic mail via the Electronic Filing System, this 29th day of June 2016.

/s/ *Christina L. Baker*
Christina L. Baker

JOINT MOTION EXHIBIT 1

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE JOINT APPLICATION OF LIBERTY UTILITIES (CENTRAL) CO., LIBERTY SUB CORP., AND THE EMPIRE DISTRICT ELECTRIC COMPANY FOR ALL NECESSARY AUTHORIZATIONS AND APPROVALS FOR LIBERTY SUB CORP. TO MERGE WITH AND INTO THE EMPIRE DISTRICT ELECTRIC COMPANY	))))))))	Docket No. 16-013-U

JOINT STIPULATION AND SETTLEMENT AGREEMENT

Come now Liberty Sub Corp. (LSC), Liberty Utilities (Central) Co. (LU Central), The Empire District Electric Company (EDE), the Consumer Utilities Rate Advocacy Division of the Attorney General's Office (AG) and the General Staff of the Arkansas Public Service Commission (Staff) (collectively known as the Parties) who hereby unanimously agree to the following terms in settlement of all the outstanding issues in the above-styled Docket.

1. GENERAL

1.1. On March 16, 2016, LU Central, LSC and EDE (collectively known as the Joint Applicants), submitted a Joint Application to the Arkansas Public Service Commission (Commission) pursuant to Ark. Code Ann. §23-3-101 and/or Ark. Code Ann. §23-3-102, and Rule 10.2 of the Commission's Rules of Practice and Procedure for approval of a merger transaction (the Merger) whereby LSC will merge with and into EDE with EDE being the surviving entity of the Merger. No Action

1.2. EDE is a Kansas corporation qualified to do business in the State of Arkansas. EDE is also qualified to conduct business in the States of Kansas,

Missouri and Oklahoma. It is a public utility as defined in Ark. Code Ann. §23-1-101. As a public utility, EDE is subject to the jurisdiction of the Commission as it is engaged in the generation, transmission and distribution of electrical power. EDE serves approximately 170,000 retail customers, of which approximately 4,400 are located in Arkansas. EDE's electricity comes from seven company-owned generating facilities, plus purchased power, and it delivers electric energy across an interconnected transmission and distribution system that spans over 10,000 square miles. EDE's principal office is at 602 S. Joplin Avenue, Joplin, Missouri 64802. No Action

1.3. LU Central is a Delaware corporation and is a wholly-owned subsidiary of Liberty Utilities Co. and is an indirect subsidiary of Algonquin Power & Utilities Corp. (APUC). LU Central is not a "public utility" as defined by Arkansas law and it will not become a public utility if this merger is approved, although certain of its activities and transactions may be subject to the Commission's rules governing affiliate transactions. No Action

1.4. LSC is a Kansas corporation that is a wholly-owned subsidiary of LU Central. It is a special purpose corporation formed for the sole purpose of merging with and into EDE. No Action

1.5. Liberty Utilities Co. (Liberty Utilities), a wholly-owned subsidiary of Liberty Utilities (Canada) Corp., owns all of the regulated utilities operating in the United States. Liberty Utilities is the parent corporation of LU Central. Liberty Utilities has been providing regulated water service in Arkansas through its subsidiary Liberty Utilities (Pine Bluff Water) Inc. No Action

JOINT MOTION EXHIBIT 1

1.6. APUC is a publicly-traded corporation registered on the Toronto Stock Exchange and is incorporated under the laws of Canada, with its principal place of business in Oakville, Ontario. APUC has three business units; (i) a power generation unit that includes 35 renewable power generating facilities representing over 1,150 MW of installed generating capacity; (ii) a utility service unit, Liberty Utilities (Canada) Corp. that owns and operates regulated utilities in eleven states that provide retail water, sewer, electric and natural gas utility service to approximately 560,000 customers and (iii) a recently formed transmission group responsible for evaluating and capitalizing upon natural gas pipeline and electric transmission asset opportunities in North America. APUC is not a "public utility" as defined by Arkansas law, and is not an applicant in this case although it is the ultimate parent of EDE. No Action

1.7. On February 9, 2016, the Joint Applicants entered into an Agreement and Plan of Merger (Merger Agreement), whereby LSC will merge with and into EDE, with EDE being the survivor of the Merger. EDE will continue to operate the public utility assets as a jurisdictional public utility in Arkansas, pursuant to EDE's existing Commission approved Certificate of Public Convenience and Necessity and Arkansas law. No Action

1.8. In the Merger Agreement, the board of directors of EDE, subject to stockholder approval, and the boards of directors of LU Central and of LSC agree that LSC shall be merged into EDE, in accordance with the Kansas General Corporation Code and the Agreement, and the separate corporate existence of LSC will cease, with EDE being the surviving corporation. Immediately following, LSC will cease to exist. As a consequence of the merger, LU Central will acquire all of the

capital stock of EDE. EDE shareholders are to receive thirty-four dollars ($34.00) per common share in cash. The aggregate purchase price, including existing EDE debt, is approximately $2.4 billion. No Action

2. THE TRANSACTION:

2.1. LU Central and LSC will acquire all of the capital stock of EDE through a merger. At the close of the all-cash transaction, EDE will become a wholly owned subsidiary of LU Central. Complete

2.2. As a subsidiary of LU Central, EDE's utility operations will continue to be regulated by each of the five regulatory commissions that currently regulate EDE, including the Commission. Complete/No Action

2.3. Liberty Utilities will establish a "Central Region" which will be headquartered in Joplin, Missouri. This regional office will provide senior leadership to the current operations of EDE and Liberty Utilities' gas operations in Missouri, Illinois, and Iowa, and Liberty Utilities' water operations in Missouri, Arkansas, and Texas. Complete

2.4. EDE will continue to operate as a jurisdictional public utility in Arkansas, pursuant to EDE's existing Commission approved Certificate of Public Convenience and Necessity and Arkansas Law. Complete

2.5. EDE will continue to utilize the rates, rules, regulations and other tariff provisions on file with and approved by the Commission, and will continue to provide service to its customers under those rates, rules and regulations, and other tariff provisions until such time as they may be modified by Commission action. Complete

2.6. There will be no changes to the EDE service area as a result of the acquisition. Complete

2.7. LU Central shall cause EDE and its subsidiaries to maintain and operate their respective businesses under the "Empire District" brand for a period of at least five (5) years following the closing of the merger, provided that such use may also include a "Liberty Utilities" company brand or similar co-branding designation. Complete

2.8. Following the completion of the acquisition of the shares of EDE, all of EDE's assets utilized for the provision of electric, water and natural gas utility operations, as well as its fiber optic line of business will continue to be owned by EDE and these services will continue to be provided by EDE and its existing subsidiary companies: Empire District Industries, Inc. (EDI) and Empire District Gas Company (EDG). Continue Tracking

2.9. All the utilities within LU Central will continue to operate in the same fashion as they do today. Complete

2.10. LU Central has committed to retain all of EDE's management team and its workforce following closing of the transaction. No involuntary reductions in EDE's current administrative, professional and field workforce and its existing management team are expected as a result of this transaction. Complete

2.11. LU Central will honor the terms and conditions of EDE's existing severance packages. Complete

2.12. A regional board of directors will be established to provide guidance and counsel on local issues and enhanced customer service. All existing board members of EDE will be offered a position on the board. Complete

JOINT MOTION EXHIBIT 1

2.13. EDE and certain of Liberty Utilities' existing utilities will be reorganized under LU Central, with Bradley Beecher, the current CEO of EDE assuming the role of the CEO of LU Central. Complete

3. RATEMAKING ASSURANCES

Rate Moratorium

3.1. The Parties acknowledge that EDE will not file a notice of intent to file a rate case until twelve months of actual historical information is available following the closing of LU Central's acquisition of EDE. In the event the rider for the recovery of Riverton 12 provided for in Section 3.2 is not approved by the Commission, this Section 3.1 shall have no effect. Complete

3.2. This provision does not preclude EDE from filing an application to request a rider which will allow it to recover its costs associated with converting the Riverton 12 generating facility from a combustion turbine to a combined cycle gas turbine. Complete

3.3. This provision does not preclude EDE from filing an application to request recovery of costs pursuant to Act 310 as modified by Act 1000, except as it relates to recovery of the costs associated with converting the Riverton 12 generating facility from a combustion turbine to a combined cycle gas turbine, as provided in the previous section. Complete

Acquisition Premium, Transaction Costs and Transition Costs

3.4. No costs of the proposed transaction will be borne by ratepayers. Such costs include but are not limited to: (1) acquisition premium costs (i.e., amounts recorded in NARUC USOA Account 114 - Utility Plant Acquisition Adjustments or Account 116 - Other Utility Plant Adjustments and defined as the difference between

the cost to the accounting utility of utility plant acquired and the original cost of such property, less the amounts credited to accumulated depreciation), including the return on those costs or the amortization thereof, (2) transition costs defined as one-time, temporary costs related to effecting the transaction that do not create a long lived or future benefit to ratepayers, severance costs related to termination of employees as a direct result of this transaction,[1] or termination fees incurred in conjunction with the transaction, or (3) transaction costs, defined as one-time costs required for items such as equity financing and regulatory approvals, including but not limited to LU Central or EDE personnel costs incurred as a result of the transaction. All costs related to the transaction shall be recorded in separate accounts specifically maintained to account for the transaction. The detailed journal entries recorded to reflect the transaction shall be filed with the Commission no later than thirteen months after the date of closing or prior to any rate increase application, whichever comes first. Complete

Severance Costs

3.5. LU Central and/or EDE will not seek to recover any severance costs or retention costs incurred as the result of the transaction from ratepayers. To the extent that any severance costs are incurred as a result of the transaction, those severance costs shall not be allocated to EDE or any other affiliate operating under LU Central. Follow-up with Accounting

Fuel Costs

3.6. EDE fuel costs shall not be adversely impacted as a result of this transaction. Complete

[1] LU Central notes that no terminations are expected as a result of this transaction.

JOINT MOTION EXHIBIT 1

Affiliate Costs

3.7. At the time of EDE's first rate case filing after the transaction closes, EDE shall provide an analysis demonstrating that Administrative and General costs have not increased solely as a result of the transaction. Continue Tracking - Phillip

Cost of Capital

3.8. The cost of capital (COC) as reflected in EDE's rates will not be adversely affected as a result of the transaction. Complete

3.9. LU Central agrees the COC shall be determined in future rate cases, consistent with applicable Law, regulations and practices of the Commission. Complete

3.10. LU Central and EDE will not oppose, in either a regulatory proceeding or by judicial appeal of a Commission decision, the application of the principle that the determination of the cost of capital can be based only on the risks attendant to the regulated operations of EDE. Complete

3.11. LU Central agrees that EDE's equity level will not fall below 40% of its total capitalization as a result of any dividend payments made to LU Central or any of its parent companies. Continue Tracking - Arthur Kacprazak

3.12. LU Central agrees that the appropriate external capital structure shall be determined in a manner consistent with past Commission precedent. Such external capital structure shall include an appropriate level of short-term debt consistent with Commission precedent regarding appropriate benchmarked levels of short-term debt. Complete

3.13. LU Central agrees that the Accumulated Deferred Income Taxes (ADIT) amount, character, and all other terms reflected on the books of EDE immediately

prior to the transaction shall be unchanged by the transaction with the exception of adjustments related to the splitting of Pension and Other Post-Employment Benefits (OPEB) accounts and funds and the reduction in plant related to any assets not purchased from EDE. ADIT will continue to be treated as a zero-cost source of capital. Complete

Segregation of Assets

3.14. LU Central agrees that EDE will not comingle its assets with the assets of any other person or entity, except as allowed under the Commission's Affiliate Transaction Rules.

3.15. LU Central commits that EDE will conduct business as a separate legal entity and shall hold all of its assets in its own legal entity name.

3.16. LU Central commits that EDE will not grant or permit to exist any lien, encumbrance, claim, security interest, pledge, or other right in favor of any person or entity in its assets, other than liens or encumbrances entered into in the ordinary course of business.

3.17. LU Central and EDE affirm that the present legal entity structure that separates the regulated business operations from those unregulated business operations shall be maintained unless express Commission approval is sought to alter any such structure. LU Central and EDE further agree that proper accounting procedures will be employed to protect against cross-subsidization of non-regulated businesses by EDE customers.

Cost Allocations

3.18. Liberty Utilities already has in place a cost allocation manual that sets forth a cost allocation methodology to be used by all regulated utilities entities, including Liberty Utilities' current Arkansas operations, based largely on the guidelines established by NARUC. Liberty Utilities will revise or modify its current cost allocation manual, as needed, to reflect the acquisition of EDE within six (6) months following the closing of the transaction, and provide a copy to the Commission. LU Central commits it will file with the Commission an executed copy of the Affiliate Service Agreement within thirty (30) days of closing of the transaction.

Accounting Standards

3.19. LU Central shall not permit any subsidiary to make any material change in financial accounting methods, principles or practices, except to the extent as may have been required by a change in applicable Law or Generally Accepted Accounting Principles (GAAP) or by any Governmental Entity (including the Securities Exchange Commission (SEC) or the Public Company Accounting Oversight Board).

3.20. LU Central affirms there will be no change in accounting for Arkansas held assets of LU Central or EDE unless reviewed and approved by the Commission.

Books and Records

3.21. LU Central and EDE accounting records will be maintained in accordance with the National Association of Regulatory Utility Commissioners (NARUC) Uniform System of Accounts as adopted by the Commission including the "NARUC

Regulations to Govern the Preservation of Records of Electric, Gas and Water Utilities."

3.22. EDE commits it will maintain separate books and records, system of accounts, financial statements, and bank accounts.

3.23. LU Central, its affiliates, and EDE (collectively the Entities) agree to produce or deliver any or all accounting records and related documents requested by the Commission. The Entities may, with Commission approval, provide verified copies of original records and documents. The Entities further agree that the preferred method of production or delivery of records is by electronic access or electronic submission. If electronic access or electronic submission is not available or is deemed unsatisfactory by the Commission for its purposes, the Entities agree that the requested records and related documents, or legible verified copies thereof, shall be physically produced and delivered to the Commission in a timely manner.

3.24. LU Central will maintain adequate records to support, demonstrate the reasonableness of, and enable the audit and examination of all centralized corporate costs that are allocated to or directly charged to EDE.

3.25. LU Central shall make commercially reasonable efforts to provide Staff and the AG access to any independent auditor's workpapers and reports of all entities who may allocate, assign, or direct charge costs to EDE.

3.26. LU Central will adopt the individual plant-in-service, depreciation reserve, and contributions-in-aid-of-construction balances on EDE's books on the date of the sale. LU Central agrees to use the depreciation rates approved by the Arkansas

Public Service Commission in Docket No. 13-111-U for all utility plant-in-service either on EDE's books or allocated to EDE until the next general rate case.

Other

3.27. LU Central commits that in future rate case proceedings, LU Central and EDE will support its assurances provided in this document with appropriate analysis, testimony, and necessary journal entries fully clarifying and explaining how any such determinations were made.

3.28. LU Central and EDE agree to reaffirm and honor any prior commitments made by EDE to the Commission and to comply with any previously issued Commission orders applicable to EDE or its previous owners.

3.29. LU Central and EDE agree to maintain or improve EDE's current quality of service, consistent with the requirements of Commission rules.

3.30. LU Central agrees to provide Staff and the AG with copies of any customer notifications related to this transaction at least 72 hours prior to issuance for input from Staff and the AG regarding content of said notifications. The customer notification materials may include, but are not limited to, a press release upon closing, a letter to the customers welcoming them to Liberty Utilities, and a bill insert in the first bill.

3.31. LU Central affirms it would need to assess the impact of any state or Federal order prior to extending any benefits/conditions to Arkansas ratepayers. LU Central will provide state and Federal regulatory agency orders when they become available.

JOINT MOTION EXHIBIT 1

4. FINANCING

4.1. LU Central plans to use a reasonable and prudent investment grade capital structure comprised, initially of 55% equity and 45% total debt. LU Central will be provided with appropriate amounts of debt and equity from Liberty Utilities to maintain such a capital structure. LU Central will, in turn, use the capital provided by Liberty Utilities to contribute the necessary capital to its utility subsidiaries including EDE. LU Central will provide the Commission with details on any debt and equity instruments associated with the acquisition, and provide copies of such instruments within 30 days of closing of the transaction. LU Central agrees that the appropriate capital structure for EDE will be determined in the next general rate case and nothing in this agreement constitutes a pre-condition to be placed on any future ratemaking proceeding.

4.2. The Parties recognize that both the acquisition premium and the debt, equity, and other capital components used to finance the acquisition premium are recorded on the books of LU Central and are not recorded on the books of EDE, and therefore, are not reflected in the rate base or capital structure of EDE.

4.3. If Liberty refinances any or all of EDE's existing debt, for reasons other than to obtain a lower interest rate that provides demonstrated net benefits to EDE's customers over the period until the debt would have otherwise matured, ratepayers should be protected by allowing no remaining unamortized debt issuance costs and no losses on reacquired debt for such refinanced debt.

JOINT MOTION EXHIBIT 1

5. RIGHTS OF THE PARTIES

5.1. This Agreement is designed to complete and resolve all the issues in this docket. This Agreement is made upon the explicit understanding that it constitutes a negotiated settlement which is in the public interest. Nothing herein shall constitute an admission of any claim, defense, rule or interpretation of law, allegation of fact, principle, or method of ratemaking or cost-of-service determination or rate design, or terms or conditions of service, or the application of any rule or interpretation of law, that may underlie, or be perceived to underlie, this Agreement

5.2. This Agreement is expressly contingent upon its approval by the Commission without any modification. The various provisions of the Agreement are interdependent and unseverable. The Parties shall cooperate fully in seeking the Commission's approval of the Agreement. The Parties shall not support any alternative proposal or settlement agreement while this Agreement is pending before the Commission or otherwise attempt to continue litigating issues in the case as the intent of this Agreement is to resolve all issues.

5.3. Except as to matters specifically agreed to be done or occur in the future, no Party shall be precluded from taking any position on the merits of any issue in any subsequent proceeding in any forum. This Agreement shall not be used or argued as establishing precedent for any methodology or rate treatment in any future proceeding or represented to be a Party’s acquiescence to any opposing position presented in this proceeding.

5.4. In the event the Commission does not accept, adopt, and approve this Agreement in its entirety and without modification, the Parties agree that this

Agreement shall be void and of no effect. In that event, however, the Parties agree that (a) no Party shall be bound by any of the provisions or agreements hereby contained herein; b) all Parties shall be deemed to have reserved all their respective rights and remedies in this proceeding; and (c) no Party shall introduce this Agreement or any related writings, discussions, negotiations, or other communications of any type in any proceeding.

Respectfully submitted,

GENERAL STAFF OF THE ARKANSAS PUBLIC SERVICE COMMISSION

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THE EMPIRE DISTRICT ELECTRIC COMPANY

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ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE PETITION OF LIBERTY UTILITIES (ARKANSAS WATER) CORP. TO BECOME A REGULATED PUBLIC UTILITY AND FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO OWN AND OPERATE WATER AND SEWER FACILITIES	)))))))	DOCKET NO. 19-064-U ORDER NO. 4

ORDER

On November 8, 2019, Liberty Utilities (Arkansas Water) Corp. (LUAW or the Company) petitioned the Arkansas Public Service Commission (Commission) for an order (1) declaring LUAW to be a public utility pursuant to the definitions in Ark. Code Ann. §§ 23-1-101(9)(A)(ii)(b) and 23-1-101(9)(G)(i)(a) and Rule 6.11 of the Commission's *Rules of Practice and Procedure* (RPPs), (2) approving on an interim basis and subject to refund the rates currently charged by LUAW, and (3) issuing a Certificate of Public Convenience and Necessity (CCN) authorizing LUAW to operate as a public utility in Arkansas and to own and operate the utility facilities formerly held by Liberty Utilities (White Hall Water) Corp. (WHW), Liberty Utilities (White Hall Sewer) Corp. (WHS), and Liberty Utilities (Woodson-Hensley Water) Corp. (Woodson-Hensley) (together the Merged Entities). The Petition further states:

> In part, this filing stems from of an arbitration proceeding between WHW and WHS and the City of White Hall, Arkansas, regarding service rates, as well as an Application for a Declaratory Order filed before the APSC by the Office of Arkansas Attorney General Leslie Rutledge ("Attorney General") (Docket No. 19-015-U). The arbitration proceeding was settled, with WHW and WHS agreeing to seek to be regulated by the Commission. As described herein, WHW and WHS were merged into Liberty Arkansas Water. In an effort to resolve all of the issues presented in Docket No. 19-015-U, the Merged Entities, Liberty Utilities (Pine Bluff Water) Corp., Liberty Utilities Co. ("Liberty Utilities"), the Attorney General, and the City of White Hall entered into a settlement agreement. Included in that

> settlement agreement was a commitment that Liberty Utilities would seek to have its unregulated water and sewer utilities operating in Arkansas regulated by the Commission. Although the Commission ultimately did not approve the settlement agreement, the parties to the settlement agreement have continued to work collaboratively in an effort to resolve their respective positions. The filing of this Petition and request for a CCN by Liberty Arkansas Water honors Liberty Utilities' commitment to seek to have its unregulated water and sewer utilities operating in Arkansas regulated by the Commission. This filing is also designed to resolve the various issues raised in the arbitration and Attorney General proceedings.

Petition ¶¶ 8, 9, 10 & 11 (Doc. #1).

LUAW presented the direct testimonies of Michael D. Beatty, Patsy Mulvaney, and Sherri Richard in support of its Petition. Mr. Beatty testifies that LUAW is a "Class B" "public utility." Beatty Direct at 14 (Doc. #4). He states that LUAW's continued ownership and operation of the utility facilities formerly held by the Merged Entities, as a public utility subject to the jurisdiction of the Commission, is necessary or convenient for the public service and is in the public interest. He also states that LUAW is amply qualified to provide the proposed water and sewer services and is able to comply with all applicable rules and regulations pertaining to the provision of regulated water and sewer services, including the Commission's special rules for water utilities. Finally, Mr. Beatty states that LUAW has the financial, managerial, and technical qualifications to safely and reliably operate the water and wastewater systems and associated facilities described herein and to provide its current and future customers with an adequate supply of reliable and safe water service and safe and reliable wastewater service. *Id.* at 15.

In her Direct Testimony, Ms. Richard presents an overview of LUAW's financial status, submits a history of why it seeks to be regulated by the Commission, and identifies benefits to customers of LUAW that Commission regulation will provide. She

further discusses the employment structure of those in charge of management and operations and presents current rates and charges for water and wastewater service. Richard Direct at 7-14 (Doc. #3).

In her Direct Testimony, Ms. Mulvaney provides an overview of the LUAW's customer support and billing operations. She further identifies metering and billing issues experienced by the Merged Entities. She states that these issues have been reported to the Commission's Consumer Services Section. Mulvaney Direct at 7-9 (Doc. #2).

The Office of Arkansas Attorney General Leslie Rutledge (AG) witness Christina Baker filed Direct Testimony on June 30, 2020. Ms. Baker requests that the Commission "(1) acknowledge that LUAW has elected to be under the jurisdiction of the Commission, and is therefore, a public utility; and (2) grant LUAW's request for a CCN to operate as a public utility in Arkansas." She states that LUAW has elected to be under the jurisdiction of the Commission and "it is merely asking that the Commission issue a declaration acknowledging that the Company is now a public utility." She opines that the request is reasonable and in the public interest and should be granted. Baker Direct at 12 (Doc. #11).

The General Staff (Staff) of the Commission witness Robert Booth identifies multiple issues and recommendations but generally concludes that LUAW has satisfied the requirements for a CCN as a Class B water utility. Booth Direct at 5-19 (Doc. #12). He recommends a rate moratorium and additional ratepayer protections, plus a plan to deal with issues on complying with Commission orders and regulations. *Id*. at 19-25.

In her Rebuttal Testimony, Ms. Richard accepts all of Staff's recommendations except the following four issues: (1) rate moratorium; (2) regulatory treatment of acquisition premiums and discounts; (3) recovery of future Administrative and General Costs (A&G) for LUAW; and (4) cost of capital rates to be calculated in the first rate case. Richard Rebuttal at 4-6 (Doc. #15). She proposes to develop a remediation plan to address operational, recordkeeping, and compliance issues. *Id*. at 7-9.

On August 7, 2020, LUAW, Staff, and the AG, (collectively, the Parties), filed a *Joint Motion to Approve Settlement Agreement and Request to Suspend Procedural Schedule and to Waive Hearing* (Joint Motion). The Parties state they have reached an agreement on all issues regarding LUAW's Petition filed in this Docket on November 8, 2019. Attached to the Joint Motion is Joint Motion Exhibit No. 1, the proposed Settlement Agreement (Agreement). In this negotiated Agreement, the following matters are agreed to:

1. The Parties stipulate and agree that LUAW meets the statutory, Commission RPPs, and National Association of Regulatory Utility Commissioners (NARUC) Uniform System of Accounts requirements and criteria to be declared to be a Class B utility.

2. The Parties stipulate and agree that, through the acceptance and adoption of the following terms and conditions related to this matter, LUAW meets the requirements necessary for the Commission to declare LUAW to be a public utility and to issue a CCN to allow LUAW to operate as a public utility under the jurisdiction of the Commission and to own and operate the utility facilities formerly WHW, WHS, and Woodson-Hensley, and that the issuance of such CCN is in the public interest:

a. LUAW agrees its Cost of Capital shall be determined in future rate cases, consistent with applicable law, regulations, and practices of the Commission.

b. LUAW agrees that the appropriate external capital structure shall be determined in a manner consistent with past Commission precedent.

c. LUAW agrees to not comingle its assets with the assets of any other person or entity except as allowed under the Commission's *Affiliate Transaction Rules*.

d. LUAW agrees to conduct business as a separate legal entity and hold assets in its own name.

e. LUAW agrees not to grant or permit to exist any lien, encumbrance, claim, security interest, pledge, or other right in favor of any person or entity in its assets, other than liens or encumbrances entered into in the ordinary course of business.

f. LUAW affirms that the present legal entity structure that separates the regulated business operations from those unregulated business operations shall be maintained unless express Commission approval is sought to alter any such structure.

g. LUAW affirms that accounting records will be maintained in accordance with the NARUC Uniform System of Accounts as adopted by the Commission including the "NARUC Regulations to Govern the Preservation of Records of Electric, Gas and Water Utilities."

h. LUAW affirms that it will maintain separate books and records, system of accounts, financial statements, and bank accounts.

i. LUAW affirms that it will agree to produce or deliver any or all accounting records and related documents requested by Staff, the Attorney General, or the Commission.

j. LUAW affirms that it will maintain adequate records to support, demonstrate the reasonableness of, and enable the audit and examination of all centralized corporate costs that are allocated to or directly charged to LUAW.

k. LUAW affirms that in future rate case proceedings, LUAW will support its assurances provided in this document with appropriate analysis and testimony.

l. LUAW agrees it will never seek to recover, and ratepayers will never pay, either directly or indirectly, any acquisition premium costs or purchase discount costs, transition or transaction costs, arbitration costs or regulatory costs incurred in conjunction with the purchase of White Hall Water Company, White Hall Sewer Company, and/or Woodson-Hensley Water Company including Banner Township Water Company, or of the issuance of the currently requested CCN to operate as a public utility under the jurisdiction of the Commission.

m. LUAW agrees to a baseline or bench-mark for A&G costs for its current operation as set forth in Sheri Richard's Direct Exhibit SR-1 at page 55 of 57, which totals $742,419. At the time of its first rate case,

LUAW shall explain, by cost category, any increases in A&G costs compared to the baseline by cost category and the basis for the increase, further explaining the ratepayer benefit(s) associated with each increase in cost category.

n. Company agrees to file a remediation and compliance plan within sixty (60) days of the issuance of a Commission order approving the granting of a CCN addressing Staff's issues related to Unaccounted for Water, Water Production Records, Recordkeeping related to APSC *Special Water Rules*, and strict adherence to all other Commission Rules & Regulations.

o. Company agrees to improved Regulatory Performance, as discussed in the testimony of Sheri Richard.

p. Company agrees to a Rate Moratorium for LUAW rates. LUAW will not file a rate case prior to one full year after a final order is issued in this docket. The Company further agrees that it will coordinate with Liberty Utilities (Pine Bluff Water) Inc. (PBW) and its affiliates to ensure that a PBW rate case shall not be filed during any pending LUAW rate case. PBW's commitment is set forth in a letter attached to this Agreement.

q. The AG agrees to withdraw its Initial Brief filed on June 30, 2020, Document No. 10, contemporaneously with the filing of testimony supporting this Settlement.

r. The parties agree to file agreed-upon tariffs, which include the rates reflected on Revised Exhibit K,[2] within thirty (30) days of the filing of this

> Settlement Agreement. Such rates shall be interim, subject solely to refund, from the date of a Commission order approving this Settlement Agreement or by October 9, 2020, whichever is the earlier date, until the date new rates are ordered by the Commission to be implemented in LUAW's first rate case. Nothing in this term is intended to create any opportunity or right for LUAW to collect any additional sums related to this interim rate provision.

Joint Motion at 1-9 (Doc. # 19).

Settlement Testimony in support of the Agreement was filed by LUAW witness Richard, AG witness Baker, and Staff witness Booth. All three witnesses state that the Agreement resolves all issues in this Docket, provides customer benefits to LUAW customers, and is in the public interest. Ms. Richard states that the Company agrees to a baseline or bench-mark for A&G costs for its current operation. She explains that the A&G baseline of $742,419 was derived from the CCN Application Exhibit SR-1, and is the combined 2019 amounts for the three entities. Richard Settlement at 4 (Doc. #23).

Ms. Baker identifies ratepayer protections provided by the Agreement. She states that LUAW has agreed to protect its ratepayers from certain costs connected with its purchase of WHW, WHS, and Woodson-Hensley, as well as from certain costs specifically related to the issuance of the CCN requested in this Docket. She further states that LUAW has agreed that it will not file a rate case prior to one full year after a final order is issued in this Docket, and that its current, interim rates will be subject to refund based on the outcome of its next general rate case. Baker Settlement at 4 (Doc. #20).

Mr. Booth states the Agreement has Staff's direct case as its foundation and provides significant ratepayer protections. In addressing ratepayer protections regarding cost recovery, Mr. Booth states that LUAW has agreed that it will never seek to recover, and ratepayers will never pay, either directly or indirectly, any acquisition premium costs or purchase discount costs, transition or transaction costs, arbitration costs or regulatory costs incurred in conjunction with the purchase of WHW, WHS, and/or Woodson-Hensley including Banner Township Water Company or of the issuance of a CCN to operate as a public utility under the jurisdiction of the Commission. According to Mr. Booth, any costs related to this proceeding or Docket No. 19-015-U will not be sought to be recovered from ratepayers. Booth Settlement at 3-4 (Doc. #22).

Mr. Booth also discusses how LUAW will address A&G costs. He states that at the time of its first rate case, LUAW shall explain, by cost category, any increases in A&G costs compared to the baseline by cost category and the basis for the increase, further explaining the ratepayer benefit(s) associated with each increase in cost category. *Id*. at 4-5. As to quality of service issues identified in his Direct Testimony, Mr. Booth stated the Agreement provides that LUAW will file a remediation and compliance plan (Plan) within 60 days of the issuance of a Commission Order granting LUAW a CCN. The Plan will address Staff's issues related to Unaccounted for Water, Water Production Records, Recordkeeping related to the Water Rules, and require strict adherence to all other Commission Rules & Regulations. *Id*. at 5-6. Mr. Booth also states that LUAW has agreed to improved regulatory performance and to a rate moratorium with an agreement not to file a rate case prior to one full year after a final Order is issued in this

Docket. *Id*. at 6-7. Mr. Booth further notes that LUAW has agreed to coordinate with PBW and its affiliates to ensure that a PBW rate case shall not be filed during any pending LUAW rate case. A letter from PBW confirming its commitment is attached to the Agreement. *Id*. at 7.

On August 20, 2020, LUAW gave notice to the Commission and all parties, of the registration of its fictitious name under which it will conduct business in the future. LUAW advises that on August 10, 2020, it registered the fictitious name of Liberty-Arkansas Water with the Arkansas Secretary of State and such filing was duly accepted. LUAW further states that the name change will become effective prior to the filing of any compliance tariff filing necessitated by an order of the Commission entered in this proceeding.

On October 2, 2020, pursuant to the Agreement, LUAW filed agreed-upon compliance tariffs, with a cover letter stating that the tariffs had been reviewed and approved by the Staff and the AG.[1]

After considering all matters of record in this proceeding, including the testimony filed by the Parties, and all other matters of law and fact pertaining hereto, the Commission finds that the Settlement Agreement is in the public interest and should be approved.

Accordingly, it is ORDERED that:

1. The Settlement Agreement filed on August 7, 2020, is approved;

[1] The Agreement entered into by the Parties provided that LUAW would file agreed-upon tariffs by September 8, 2020, within 30 days of the date the Agreement was filed (August 7, 2020). LUAW failed to comply with this provision of the Agreement (Part II.4.r.). LUAW filed the tariffs on October 2, 2020, with a cover letter stating that the tariffs had been reviewed and approved by the Staff and the AG. No explanation was provided for why these tariffs were filed so much later than provided in the Agreement.

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2. The Commission expects LUAW to strictly comply with the provisions of this Agreement, especially the provisions that provide for improved regulatory performance (including compliance with Commission Rules), timely filing of, and conformance to, a remediation and compliance plan, and maintaining and providing access to accurate business records.

3. Liberty Utilities (Arkansas Water) d/b/a Liberty-Arkansas Water is hereby granted a CCN to operate as a water and sewer utility subject to the Commission's regulatory authority as specifically provided in the Settlement Agreement; and

4. LUAW's proposed tariffs filed on October 2, 2020, are approved. Such rates shall be interim, subject solely to refund, from the date of this Order until the date new rates are ordered by the Commission to be implemented in LUAW's first rate case.

BY ORDER OF THE COMMISSION.

This 7th day of October, 2020.

Ted J. Thomas, Chairman

Kimberly A. O'Guinn, Commissioner

Justin Tate, Commissioner

I hereby certify that this order, issued by the Arkansas Public Service Commission, has been served on all parties of record on this date by the following method:

___U.S. mail with postage prepaid using the mailing address of each party as indicated in the official docket file, or
✓ Electronic mail using the email address of each party as indicated in the official docket file.

Mary Loos

Mary Loos, Secretary of the Commission

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BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE JOINT APPLICATION OF UNITED WATER ARKANSAS, INC., UNITED WATERWORKS, INC. AND LIBERTY ENERGY UTILITIES CO. FOR ALL NECESSARY AUTHORIZATIONS AND APPROVALS FOR LIBERTY ENERGY UTILITIES CO. TO ACQUIRE ALL OUTSTANDING COMMON STOCK OF UNITED WATER ARKANSAS, INC. PURSUANT TO A CERTAIN STOCK PURCHASE AGREEMENT	)	**DOCKET NO. 12-061-U**

JOINT MOTION TO APPROVE JOINT STIPULATION AND SETTLEMENT AGREEMENT

Comes now United Water Arkansas, Inc., (UWA), United Waterworks Inc. (UWI) and Liberty Energy Utilities Co. (LEUC), hereinafter jointly referred to as "Applicants" and the General Staff (Staff) of the Arkansas Public Service Commission (Commission), hereinafter collectively referred to as "Petitioners" or "Parties", and for their Joint Motion to Approve Joint Stipulation and Settlement Agreement (Joint Motion), state as follows:

1. Staff and Applicants have reached an agreement on the issues in Docket No. 12-061-U. This Joint Stipulation and Settlement Agreement (Agreement) is set forth in and attached hereto as Joint Exhibit 1. Petitioners support the Agreement as a reasonable resolution of the issues in this Docket and as being in the public interest. By this Joint Motion, the Petitioners are requesting that the Administrative Law Judge expeditiously approve the

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Application as modified by and consistent with each of the terms set forth in the Agreement.

2. As support for the Agreement and concurrent with the filing of this Joint Motion, UWA and UWI are filing the Stipulation Testimony of James C. Cagle, LEUC is filing the Stipulation Testimony of Peter Eichler and Staff is filing the Stipulation Testimony of Robert Daniel.

3. The Parties support the cancellation of the hearing set on December 19, 2012, and request that the Administrative Law Judge make her decision based on the pleadings in the record, including this Joint Motion and attached Joint Exhibit 1. If the Administrative Law Judge determines that a hearing is necessary the Parties recommend that a hearing be held no later than December 14, 2012.

4. The Petitioners further agree to waive cross-examination of one another's witnesses at any hearing.

WHEREFORE, the Parties request that the Administrative Law Judge expeditiously approve the Application as modified by and consistent with each of the terms set forth in the Joint Stipulation and Settlement Agreement attached hereto, and grant them all other necessary and proper relief.

Respectfully submitted,

GENERAL STAFF OF THE ARKANSAS PUBLIC SERVICE COMMISSION

By: */s/ Cynthia L. Uhrynowycz*
Cynthia L. Uhrynowycz
Dawn Guthrie

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UNITED WATER ARKANSAS, INC.,
UNITED WATERWORKS INC., AND
LIBERTY ENERGY UTILITIES CORP.

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CERTIFICATE OF SERVICE

I, Cynthia Uhrynowycz, do hereby certify that a copy of the foregoing pleading has been delivered to all parties of record by electronic mail on this 14th day of November, 2012.

/s/ Cynthia Uhrynowycz

JOINT EXHIBIT NO. 1

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE JOINT APPLICATION OF UNITED WATER ARKANSAS, INC., UNITED WATER WORKS, INC. AND LIBERTY ENERGY UTILITIES CO. FOR ALL NECESSARY AUTHORIZATIONS AND APPROVALS FOR LIBERTY ENERGY UTILITIES CO. TO ACQUIRE ALL OUTSTANDING COMMON STOCK OF UNITED WATER ARKANSAS, INC. PURSUANT TO A CERTAIN STOCK PURCHASE AGREEMENT	**)**	**DOCKET NO. 12-061-U**

JOINT STIPULATION AND SETTLEMENT AGREEMENT

United Water Arkansas, Inc., (UWA), United Waterworks Inc. (UWI) and Liberty Energy Utilities Co. (LEUC, hereinafter jointly referred to as "Applicants" and the General Staff (Staff) of the Arkansas Public Service Commission (Commission), (collectively Parties), agree to the following terms as set forth in this Stipulation and Settlement Agreement (Agreement).

A. GENERAL

1. UWA is an Arkansas corporation and a wholly owned subsidiary of UWI, a Delaware corporation. UWA owns and operates a complete waterworks system in the City of Pine Bluff, Arkansas, and in certain territory adjacent to said municipality, and is a public utility under the terms and provisions of Ark. Code Ann. § 23-1-101. UWA provides water service to approximately 17,500 residential, commercial and industrial customers in its service area. UWA's mailing address is P.O. Box 6070, Pine Bluff, Arkansas 71611.

2. UWI is a wholly owned subsidiary of United Water Resources Inc. UWI is the parent of a portfolio of regulated water utility operations in eight states. The states are Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Idaho and Arkansas. UWI and its subsidiaries provide water and wastewater services to approximately one million people in those eight states. UWI's utility subsidiaries are subject to regulation by the public utility commissions in each state in which they operate.

3. LEUC is a direct subsidiary of Liberty Utilities Co. (Liberty Utilities), a Delaware corporation. Liberty Utilities is owned by Algonquin Power & Utilities Corp. (Algonquin) a corporation created under the laws of Canada. Liberty Utilities is the entity under which all the regulated utilities owned in the United States are operated.

4. UWI and LEUC have entered into a Share Purchase Agreement (SPA) dated July 20, 2012, pursuant to which UWI proposed to sell one hundred percent (100%) of the issued and outstanding shares of common stock of UWA to LEUC. As a result of the proposed transaction, UWA would become a wholly-owned subsidiary of LEUC.

5. Following the transfer of ownership of the UWA common shares from UWI to LEUC, the public utility operations of UWA will continue in Arkansas. UWA will continue to perform its obligations and commitments consistent with the Commission's rules, regulations and decisions. Upon Commission approval of the transaction, LEUC will cause UWA to change its name in accordance with the terms of the SPA and will provide appropriate notice to its utility customers.

6. Staff has thoroughly investigated the issues presented in this docket, having conducted extensive discovery and participated in meetings with UWA, UWI and LEUC in an effort to better understand, analyze, and evaluate the assertions made and authorizations sought by Applicants. A complete discussion of the issues has been undertaken by Parties, with each being a strong advocate for its respective position. As a result, Parties hereby recommend the approval of the Application as modified by and consistent with the following terms:

B. RATEMAKING ASSURANCES

Rate Moratorium

1. LEUC affirms that UWA will not file a Notice of Intent to File a Change in General Rates prior to October 31, 2013. UWA will provide 12 months of post-transaction operating data not later than 120 days after the date it files its rate case application.

Acquisition Premium and Transaction Costs

2. No costs of the proposed transaction will be borne by ratepayers. Such costs include but are not limited to: acquisition premium costs (i.e., amounts recorded in NARUC USOA Account 114 - Utility Plant Acquisition Adjustments or Account 116 - Other Utility Plant Adjustments and defined as the difference between the cost to the accounting utility of utility plant acquired and the original cost of such property, less the amounts credited to accumulated depreciation), including the return on those costs or the amortization thereof, transaction costs (defined as one-time costs required for items such as equity financing and

regulatory approvals), transition costs defined as one-time, temporary costs related to effecting the transaction that do not create a long lived or future benefit to ratepayers, severance costs related to termination of employees as a direct result of this transaction[1], or termination fees incurred in conjunction with the transaction. All costs related to the transaction shall be recorded in separate accounts specifically maintained to account for the transaction. The detailed journal entries recorded to reflect the transaction shall be filed with the Commission no later than thirteen months after the date of closing or prior to any rate increase application, whichever comes first.

Cost of Capital

3. The cost of capital as reflected in UWA's rates will not be adversely affected as a result of the transaction.

4. LEUC and UWA will not oppose, in either a regulatory proceeding or by judicial appeal of a Commission decision, the application of the principle that the determination of the cost of capital can be based only on the risks attendant to the regulated operations of UWA.

5. LEUC agrees that UWA's equity level will not fall below 40% of its total capitalization as a result of any dividend payments made to LEUC or any of its parent companies.

6. LEUC agrees the Accumulated Deferred Income Taxes (ADIT) amount, character, and all other terms reflected on the books of UWA immediately prior to the transaction shall be unchanged by the transaction with the exception of adjustments related to the splitting of Pension and Other Post-Employment

[1] Liberty Utilities notes that no terminations are expected as a result of this transaction.

Benefits (OPEB) accounts and funds and the reduction in plant related to any assets not purchased from United Water. ADIT will continue to be treated as a zero-cost source of capital.

Pension and Other Post-Employment Benefits

7. In calendar years 2013, 2014, and 2015, LEUC agrees to contribute up to $70,462 annually to its Pension Trust Fund and to contribute up to $902,721 annually to its OPEB Trust Fund. The maximum contributed in each year shall be the lower of $70,462 to its Pension Trust Fund and the amount allowed by the Employee Retirement Income Security Act (ERISA) or the maximum contribution allowed without initiating negative taxation consequences or penalties that would require the Pension Trust Fund to pay additional taxes or penalties as a result of the contribution. The maximum contributed in each year shall be the lower of $902,721 to its OPEB Trust Fund and the amount allowed by ERISA or the maximum contribution allowed without initiating negative taxation consequences or penalties that would require the OPEB Trust Fund to pay additional taxes or penalties as a result of the contribution. In the event that a contribution less than $70,462 is made to the Pension Trust Fund or a contribution less than $902,721 is made to the OPEB Trust in any of 2013, 2014, and 2015 due to ERISA or negative inter-trust taxation requirements, the balance of the funding shall be made at the earliest possible opportunity that does not violate ERISA requirements or have negative inter-trust taxation consequences.

In any rate case using a test year including any portion of calendar years 2013, 2014, or 2015, LEUC agrees to make a ratemaking adjustment to reflect

that the full contribution of $211,386 to its Pension Trust Fund and $2,708,163 to its OPEB Trust Fund have been made for determining the level of pension expense; OPEB expense; current, accrued, and other liabilities (CAOL); and any other applicable ratemaking treatment associated with pension and OPEB. Going forward, LEUC agrees to act prudently to properly fund its Pension and OPEB Trust Fund obligations in a timely and competent manner.

This adjustment will include the following:

- CAOL will decrease in the aggregate amount of $2,919,549;
- Associated ADIT will change resulting in an increase in the net amount of the ADIT liability;
- Capitalization will increase in aggregate by $2,919,549, less impacts of ADIT, if any; and
- Future levels of Pension and OPEB expense shall be calculated incorporating the $2,919,549 contribution.

Segregation of Assets

8. LEUC agrees that UWA will not comingle its assets with the assets of any other person or entity, except as allowed under the Commission's Affiliate Transaction Rules.

9. LEUC commits that UWA will conduct business as a separate legal entity and shall hold all of its assets in its own legal entity name.

10. LEUC commits that UWA will not grant or permit to exist any lien, encumbrance, claim, security interest, pledge, or other right in favor of any

person or entity in its assets, other than liens or encumbrances entered into in the ordinary course of business.

11. LEUC and UWA affirm that the present legal entity structure that separates the regulated business operations from those unregulated business operations shall be maintained unless express Commission approval is sought to alter any such structure. LEUC and UWA further agree that proper accounting procedures will be employed to protect against cross-subsidization of non-regulated businesses by UWA customers.

Books and Records

12. LEUC and UWA accounting records will be maintained in accordance with the NARUC Uniform System of Accounts as adopted by the Commission including the "NARUC Regulations to Govern the Preservation of Records of Electric, Gas and Water Utilities."

13. UWA commits it will maintain separate books and records, system of accounts, financial statements, and bank accounts.

14. LEUC, its affiliates, and UWA (Entities) agree to produce or deliver any or all accounting records and related documents requested by the Commission. Entities may, with Commission approval, provide verified copies of original records and documents. Entities further agree that the preferred method of production or delivery of records is by electronic access or electronic submission. If electronic access or electronic submission is not available or is deemed unsatisfactory by the Commission for its purposes, the Entities agree that the

requested records and related documents, or legible verified copies thereof, shall be physically produced and delivered to the Commission in a timely manner.

15. LEUC will maintain adequate records to support, demonstrate the reasonableness of, and enable the audit and examination of all centralized corporate costs that are allocated to or directly charged to UWA.

16. LEUC commits that Staff shall have access to the independent auditor's workpapers and reports of all entities who may allocate, assign, or direct charge costs to UWA.

Other

17. LEUC will adopt the individual plant-in-service, depreciation reserve, and contributions-in-aid-of-construction balances on UWA's books on the date of the sale. LEUC agrees to use the depreciation rates approved by the Arkansas Public Service Commission in Docket No. 09-130-U for all utility plant-in-service either on UWA's books or allocated to UWA until the next general rate case.

18. LEUC commits that in future rate case proceedings, LEUC and UWA will support its assurances provided in this document with appropriate analysis, testimony, and necessary journal entries fully clarifying and explaining how any such determinations were made.

19. LEUC and UWA agree to reaffirm and honor any prior commitments made by UWA to the Commission and to comply with any previously issued Commission orders applicable to UWA or its previous owners.

20. LEUC and UWA agree to maintain or improve the quality of service currently being provided by UWA.

21. LEUC commits it will file with the Commission an executed copy of the Affiliate Service Agreement within thirty (30) days of closing of the transaction.

22. LEUC agrees to provide Staff with copies of any customer notifications related to this transaction at least 72 hours prior to issuance for input from Staff regarding content of said notifications. The customer notification materials may include, but are not limited to, a press release upon closing, a letter to the customers welcoming them to Liberty Utilities, and a bill insert in the first bill.

C. FINANCING REQUEST

1. The application states that LEUC seeks authorization, pursuant to Ark. Code Ann. §§ 23-3-103 and 23-3-104, to enter into an inter-company promissory note for the borrowing of unsecured long-term debt. The capital to be secured through the debt proceeds will be used for normal operations of UWA and for any legal purposes provided by law. The issuance of the inter-company promissory note by UWA to LEUC will achieve the desired capital structure for UWA of 45% to 55% debt-to-equity. The Parties agree that UWA can enter into a promissory note with LEUC for up to a maximum amount of $20.0 million of long-term debt in order to achieve the desired capital structure.

D. COMPLETE AGREEMENT

1. Parties agree that this Agreement represents the entire agreement among or between them and that this Agreement resolves the issues in this Docket.

E. RIGHTS OF THE PARTIES

1. This Agreement is made upon the explicit understanding that it constitutes a negotiated settlement which is in the public interest. Nothing herein shall

constitute an admission of any claim, defense, rule or interpretation of law, allegation of fact, principle or method of ratemaking, or cost-of-service determination or rate design, or terms or conditions of service, or the application of any rule, or interpretation of law, that may underlie, or be perceived to underlie, this Agreement.

2. This Agreement is expressly contingent upon its approval by the Commission without modification. The various provisions of this Agreement are interdependent and inseverable. The Parties shall cooperate fully in seeking the Commission's acceptance and approval of this Agreement. The Parties shall not support any alternative proposal or settlement agreement while this Agreement is pending before the Commission.

3. Except as to matters specifically agreed to be done or to occur in the future, no party shall be precluded from taking any positions on the merits of any issue in any subsequent proceeding in any forum. This Agreement shall not be used or argued as establishing precedent for any methodology or rate treatment in any future proceeding. This Agreement does not alter prior regulatory commitments of UWA.

4. In the event that the Commission does not accept, adopt, and approve this Agreement in its entirety and without modification, the Agreement may be declared void and of no effect by any Party. In that event, however, the Parties agree that (1) no party shall be bound by any of the provisions or agreements herein contained; (2) the Parties shall be deemed to have reserved all their respective rights and remedies in this proceeding; and, (3) no Party shall

introduce this Agreement or any related writing, discussions, negotiations, or other communications of any type in any proceeding.

Respectfully submitted,

GENERAL STAFF OF THE ARKANSAS PUBLIC SERVICE COMMISSION

By: */s/ Cynthia L. Uhrynowycz*
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UNITED WATER ARKANSAS, INC., UNITED WATERWORKS INC., AND LIBERTY ENERGY UTILITIES CORP.

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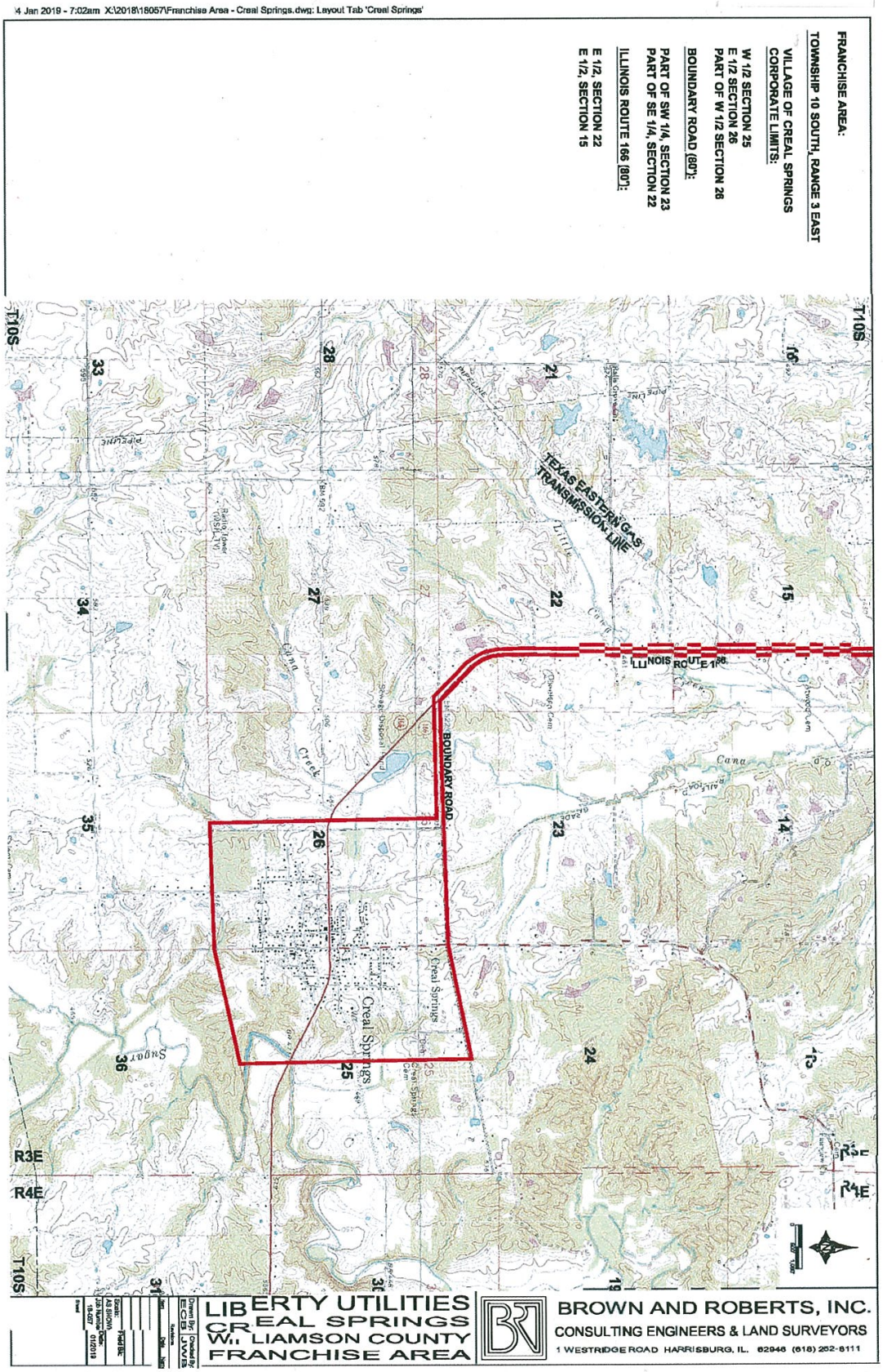
APPENDIX
19-0254



STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	:	
	:	
Application for Certificate of Public Convenience and Necessity to Provide Natural Gas Service to the City of Creal Springs and its Environs in Williamson County Illinois.	:	**19-0254**

ORDER

By the Commission:

I. PROCEDURAL HISTORY

On March 8, 2019, Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities ("Liberty Midstates" or the "Company") filed with the Illinois Commerce Commission ("Commission") an Application pursuant to Section 8-406 of the Public Utilities Act ("Act"), 220 ILCS 5/1-101 *et seq.,* to construct, own, operate and maintain a natural gas supply and distribution system and provide natural gas service in and to the City of Creal Springs ("Creal Springs" or the "City") and its environs in Williamson County, Illinois (collectively, the "Creal Springs Area"). The Company also requested approval of applicable rates for the Creal Springs Area, accounting entries related to the acquisition by the Company of natural gas supply and distribution facilities and related assets from the City (the "System"), a one-year grace period from certain financial penalties arising from safety violations occurring prior to the closing of that acquisition, and other necessary and useful authority.

Pursuant to notice given in accordance with the law and the rules and regulations of the Commission, an evidentiary hearing was held on June 26, 2019 before a duly authorized Administrative Law Judge ("ALJ") of the Commission at its offices in Springfield, Illinois. Appearances were entered by counsel for Liberty Midstates and by Commission Staff ("Staff"). Liberty Midstates presented the testimony of Michael D. Beatty, the Vice President of Gas and Water Operations for the Liberty Utilities Central Region, which includes the Company. Staff presented the testimony of Brett Seagle, a Gas Engineer in the Gas Section of the Energy Engineering Program of the Commission's Safety and Reliability Division, Janis Freetly, a Senior Analyst in the Finance Department of the Commission's Financial Analysis Division, Bonita A. Pearce, an Accountant in the Accounting Department of the Commission's Financial Analysis Division, and Christopher Boggs, a Rate Analyst in the Rates Department of the Commission's Financial Analysis Division. At the conclusion of the hearing, the record was marked "Heard and Taken." There were no contested issues in this proceeding and the parties agreed to file an

Agreed Draft Order. On July 25, 2019, the Company filed an Agreed Draft Order for the ALJ's consideration after it had been reviewed by Staff.

II. OVERVIEW OF PROCEEDING

Mr. Beatty testified that Liberty Midstates is a Missouri corporation. He stated the Company is engaged in the business of distributing and selling natural gas in Illinois, as well as in Iowa and Missouri, and is a public utility. Mr. Beatty indicated that the Company provides gas service to approximately 22,000 customers in Clay, Clinton, Effingham, Fayette, Logan, Macoupin, Marion, Massac, Midlothian, Montgomery, Saline, Sangamon and Williamson Counties, Illinois.

Creal Springs is a city in Williamson County, Illinois which currently owns the System, which serves approximately 160 active natural gas customers.

III. PROPOSED ACQUISITION AND BENEFITS

The City and Liberty Midstates entered into an Asset Purchase Agreement on July 9, 2018 which provides for the purchase of the System by the Company upon the satisfaction of certain conditions, including the Commission's approval of the sale. The Company requested a Certificate of Public Convenience and Necessity for the Creal Springs Area currently served by the System. The Company provided a more particular description of the Creal Springs Area, including a legal description and map, in an attachment to its Application.

Mr. Beatty testified that the City has been challenged by the responsibility of operating and maintaining a natural gas system with constrained budgets, particularly as safety standards and the overall complexity of operating a natural gas system increases. He testified that the City believes that Liberty Midstates, due to its expertise in natural gas operations and financial resources, would be better able to address the operations and maintenance of, and improvements to, the System. Mr. Beatty testified as to the Company's history of safe and reliable operations in Illinois and its efforts to maintain high customer satisfaction, as well as benefits that current System customers would receive by taking service from the Company, such as online bill payment, budget billing options and a regional call center.

Mr. Beatty also testified that the Company planned to make specific capital improvements to the System (the "System Improvements") in order to address certain operations, maintenance and safety issues, including issues identified by the Company in its due diligence investigation of the system and subsequent follow-up investigations. As an example, the Company discovered in its investigation that the City had not been odorizing its gas for more than two years. Recognizing this as a serious safety issue, the personnel conducting the due diligence investigation immediately corrected this problem, and the Company has continued to monitor the odorizer pursuant a mutual assistance agreement during the pendency of the acquisition and to replace the odorizer following the acquisition.

Mr. Beatty testified as to other issues identified in the Company's investigation, including leaks identified by a leak survey performed by the Company, a damaged and dated regulator station, and repairs to certain System assets. Mr. Beatty outlined the Company's current and anticipated corrective actions. Mr. Beatty also outlined additional

expected System Improvements, including an estimated $220,000 worth of capital improvements necessary to address and rectify issues identified by the Commission in approximately 45 Notice of Probable Violations issued by the Commission's Pipeline Safety Program to the City. The Company performed a cathodic protection survey that did not uncover critical issues but plans to conduct another survey following the closing.

In Docket No. 16-0038, the Commission previously approved the sale of the System to Ameren Illinois Company d/b/a Ameren Illinois ("Ameren Illinois"), which agreed to certain system improvements as well. Mr. Beatty testified that the Company includes in its proposed System Improvements all of the improvements agreed to be made by Ameren Illinois. This includes that the Company will (1) replace all existing gas meters in the System with compliant meters, (2) add pipeline markers, (3) conduct a (further) leak survey and repair all Grade 1 leaks immediately, (4) conduct a (further) cathodic protection survey and address issues by repairing within six months or replacing within one year, (5) locate emergency valves and exercise each valve, (6) locate all casings and inspect for adequate cathodic protection and proper isolation, (7) conduct odor intensity testing monthly, and (8) attempt to obtain records used by the City to show compliance with the minimum safety standards. Mr. Beatty testified that all of these items are included in the Company's proposed System Improvements, but that the System Improvements also include other actions the Company plans to take to correct the additional safety and reliability issues identified during the Company's investigation.

IV. CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

Section 8-406(b) of the Act requires the utility to demonstrate: (1) that the proposed construction is necessary to provide adequate, reliable, and efficient service to its customers and is the least-cost means of satisfying the service needs of its customers; (2) that the utility is capable of efficiently managing and supervising the construction process and has taken sufficient action to ensure adequate and efficient construction and supervision thereof; and (3) that the utility is capable of financing the proposed construction without significant adverse financial consequences for the utility or its customers. As discussed below, both the Company and Staff agree that Liberty Midstates has met these requirements in this case.

A. Necessity and Least Cost (Section 8-406(b)(1))

Mr. Beatty testified that the Company's acquisition of the System, the construction of the System Improvements, and the addition of the Creal Springs Area to the Company's service territory is necessary to provide adequate, reliable and efficient service to customers and is the least-cost means of satisfying the needs of natural gas customers in the Creal Springs Area. After reviewing the Company's supporting information and responses to Staff discovery requests, including financial analyses and supporting data, the results of the Company's investigations of the system, and the proposed System Improvements, Staff witness Brett Seagle found no reason to dispute this claim by the Company.

B. Capability to Effectively Manage and Supervise (Section 8-406(b)(2))

Mr. Beatty stated that the Company is capable of efficiently managing and supervising the acquisition of the System and the construction of the System

Improvements and has taken, and will continue to take, sufficient action to ensure adequate and efficient construction and supervision of construction.

Staff witness Seagle agreed that, based on the amount of work already performed by the Company through the mutual aid agreement and the proposed System Improvements, the Company has demonstrated that it is capable of efficiently managing and supervising the construction process. He noted that given the Company's other operations in Illinois, this type of project is well within the scope of its normal activities.

C. Capability to Finance (Section 8-406(b)(3))

Mr. Beatty stated that the Company is capable of financing the acquisition of the System and the construction of System Improvements without significant adverse financial consequences for the Company and its customers. Staff witness Janis Freetly reviewed the information contained in the Company's Application and testimony as well as in discovery. In particular, Ms. Freetly examined the Company's estimates of the direct costs associated with the acquisition, including the System Improvements. Ms. Freetly noted the Company's indication that it would not require any specific financing to support the acquisition and that funding would be generated from the Company's ordinary course of business. Given the size of the acquisition and System Improvements relative to the Company's budgeted capital expenditures, Ms. Freetly believes that the Company is capable of financing the proposed acquisition and additional investments without significant adverse financial consequences for the Company or its customers. Therefore, she recommended that the Commission find that the requirements of Section 8-406(b)(3) of the Act have been satisfied.

D. Commission Analysis and Conclusion

The Commission finds that the Company's proposal fulfills the requirements of Section 8-406(b) of the Act. The record demonstrates that (1) Liberty Midstates' purchase of the System, its construction of the System Improvements, and the addition of the Creal Springs Area to the Company's service territory are necessary to provide adequate, reliable and efficient service to customers and constitutes the least cost means of satisfying the service needs of customers in the Creal Springs Area, (2) Liberty Midstates is capable of efficiently managing and supervising the construction process and has taken sufficient action to ensure adequate and efficient construction and supervision thereof, and (3) Liberty Midstates is capable of financing the proposed construction without significant adverse financial consequences for the utility or its customers. Accordingly, the Commission approves the proposed transaction, the construction of the System Improvements, and the addition of the Creal Springs Area to the Company's service territory in accordance with Section 8-406 of the Act, and grants the Company's request for a Certificate of Public Convenience and Necessity to construct, own, operate and maintain a natural gas supply and distribution system and provide natural gas service in and to the Creal Springs Area.

V. OTHER ISSUES

A. Rates

The Company proposed that customers in the Creal Springs Area, including those served by the System, be subject to the Company's tariff rates, rules and regulations on

file from time to time in accordance with applicable law. Such rates, rules and regulations would remain in effect until any changes to the Company's tariffs and terms of service may be made in accordance with applicable law.

Mr. Beatty stated that he does not believe that the long-term cost of providing service to the Creal Springs Area would be substantially different than the Company's cost of providing service in its other, similar, service areas in Illinois. Mr. Beatty noted that the rates to customers in Creal Springs would increase as a result of this transaction. He noted that the primary benefit of the proposed transaction to the public and issuance of the Certificate of Public Convenience and Necessity to the Company arises from the provision of safe, efficient and reliable service to the Creal Springs Area, and that the Company's rates simply allow it to recover the cost of providing this service. Mr. Beatty stated that adoption of the Company's natural gas rates, rules and regulations for customers in the Creal Springs Area is appropriate and in the best interest of those customers.

Staff witness Christopher Boggs recommended that the Commission approve the Company's proposal regarding rates. He noted that although the rates would increase for Creal Springs customers, they will benefit from being able to have future large capital improvements spread among a larger number of customers when it becomes necessary to update infrastructure to provide safe and reliable natural gas service. Mr. Boggs also recommended that the Company provide draft tariff revisions. Mr. Beatty included the proposed revision in his rebuttal testimony.

Based on the record, the Commission concludes that the Company's proposal regarding rates is in the best interests of customers in the Creal Springs Area. Customers in the Creal Springs Area shall obtain service under the tariffs, rules, and regulations in effect at this time for the Company's customers generally, incorporating the tariff revisions proposed by the Company. Such tariffs, rates, rules and regulations will remain in effect until any changes to the Company's tariffs and terms of service may be made in accordance with applicable law.

B. Accounting Issues

1. Original Cost Determination

In Docket No. 16-0038, the Commission found that the net original cost of the System was $176,453 as of February 23, 2017. Using this as a starting point, the Company adjusted its proposed net original cost to $121,735 based on an updated January 31, 2019 Depreciation schedule provided by the City to the Company, as described by Staff witness Pearce. The Company proposed to record this amount based on journal entries provided in an attachment to its Application. Ms. Pearce recommended that the Commission accept $121,735 as the net original cost of the System. The Commission agrees and finds that the net original cost of the system is $121,735.

2. Acquisition Adjustment

Liberty Midstates outlined its proposed accounting treatment of the proposed transaction in its Application and requested that the Commission approve that treatment. Because the purchase price for the System exceeds its net original cost, the Company must record an acquisition adjustment. In this case, the Company proposed that the

acquisition adjustment be amortized in full during the first year following the acquisition to account 425 – Miscellaneous Amortization, which is a below-the-line operating expense account. Staff witness Pearce noted that since the acquisition adjustment will be written off or amortized below-the-line, the Company's proposed treatment has no effect on the ratepayers and is consistent with the Uniform System of Accounts for Gas Utilities. The Commission agrees and approves the Company's proposed treatment of the acquisition adjustment.

3. Accounting Entries

The Company's proposed accounting treatment included an attachment setting forth specific journal entries. Staff witness Pearce concluded that the proposed journal entries comply with Gas Plant Accounting Instruction 5 of the Uniform System of Accounts for Gas Utilities. Ms. Pearce identified additional specific journal entries to record (1) the amortization of the acquisition adjustment, (2) the organization costs for legal, engineering and surveying expenses incidental to this acquisition, and (3) the amortization of the organization costs. The Company agreed to adopt these entries.

Ms. Pearce further recommended that the Commission order the Company to file the final accounting entries for the transaction on the Commission's e-Docket system in this docket, including the journal entry to write off the acquisition adjustment, within sixty days of closing the transaction, with a copy to the Commission's Accounting Department at ICC.AccountingMgr@illinois.gov. If the transaction has not occurred within six months of the Final Order in this proceeding, Ms. Pearce recommended that the Company file status reports at six-month intervals until the journal entries are filed as ordered. The Company likewise agreed with this recommendation.

The Commission approves both the Company's and Staff's proposed journal entries as well as Ms. Pearce's recommendation regarding filing of the journal entries following the closing.

C. Grace Period

The Company requested that the Commission grant it a one-year grace period from any financial penalty associated with any enforcement action by its Natural Gas Pipeline Safety Division with respect to any violations of pipeline safety rules and requirements. The Company stated that this grace period would apply only to violations that originated with the City or its representatives prior to the closing of the proposed transaction. Given the state of the System and the issues identified with it, Mr. Beatty testified that it would be fair to allocate the grace period, and that the Company believes that after one year it would be in a position to fully understand and address any issues that it discovers.

Staff witness Seagle stated his opinion that if a safety violation, stemming from actions by the City, is discovered within the first year of the Company's operation of the System, the Company can reasonably claim that it had no previous knowledge of the safety violation. Therefore, he finds no reason to dispute the Company's request. Mr. Seagle did state that after the closing, if the Pipeline Safety Program finds Liberty Midstates in violation of any particular part of 49 CFR 191, 192, or 199, then the Commission's Pipeline Safety Program could assess a fine against the Company for

violation of those sections. In other words, he said, the one-year grace period does not preclude the Company from being found in violation of those provisions if the Company itself is found to be responsible for the violation. The Company agreed with Mr. Seagle on this point.

The Commission finds that a one-year period starting with the closing of the proposed acquisition in which fines associated with Pipeline Safety violations, originating from the actions of the City prior to the proposed acquisition, will not be imposed on the Company is reasonable and should be approved. As Mr. Seagle notes, this does not preclude fines based on violations by Liberty Midstates itself of 49 CFR 191, 192 or 199.

D. Reporting Obligation

The Company agreed that the Vice President of Gas Operations for Liberty Utilities Central Region would appear before the Commission on an annual basis after a final order is issued in this case to discuss the progress of the acquisition and its integration into Company operations. The Commission determines that such a report should be made, together with any other information the Company believes pertinent.

VI. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having considered the record herein, is of the opinion and finds that:

(1) Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities is a corporation engaged, among other things, in the distribution of natural gas to the public in portions of the State of Illinois and is a public utility within the meaning of the Public Utilities Act;

(2) the Commission has jurisdiction over Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities and the subject matter in this proceeding;

(3) the statements of fact and conclusions of law set forth in the prefatory portion of this Order are supported by the record and hereby adopted as findings of fact and conclusions of law;

(4) issuance of a Certificate of Public Convenience and Necessity for the City of Creal Springs and its environs to the Company will promote the public convenience and necessity thereto, and the Company has shown that the requirements of Section 8-406(b) have been met;

(5) the public convenience and necessity require that a certificate be issued, effective upon the transfer of the System to Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities, and Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities shall operate and maintain a natural gas system for the area legally described in Appendix A;

(6) the Asset Purchase Agreement between Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities and the City of Creal Springs shall be approved;

(7) the customers in the Creal Springs Area should obtain service under the Company's tariff, rates, rules, and regulations in effect at that time for its

customers generally together with the tariff revisions proposed herein, such tariff, rates, rules and regulations to remain in effect until any changes to the Company's tariffs and terms of service may be made in accordance with applicable law;

(8) the net original cost of the System is $121,735;

(9) the accounting treatment as proposed by the Company and Staff for the proposed transactions, including the journal entries proposed by the Company in Attachment D to the Application and the journal entries proposed by Staff in Staff Exhibit 3.01, is reasonable and shall be approved;

(10) Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities shall file the final accounting entries for the transaction as a filing on the Commission's e-Docket system with a copy to ICC.AccountingMgr@illinois.gov within sixty days of the transaction date;

(11) if the transaction has not occurred within six months of the date of this Order, Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities shall file status reports at six month intervals until the journal entries are filed on the Commission's e-Docket system with a copy to ICC.AccountingMgr@illinois.gov;

(12) there should be a one-year grace period during which fines associated with Pipeline Safety violations, originating from the actions of the City prior to the proposed acquisition, will not be imposed upon Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities;

(13) the Vice President of Gas Operations for Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities Central Region should appear annually before the Commission to discuss the progress of the acquisition and its integration into Company operations, together with such other information as the Company believes pertinent;

(14) the Company's request for all other necessary and useful relief and authority under the Public Utilities Act to allow the Company to construct, own, operate and maintain a natural gas supply and distribution system and provide natural gas service in the Creal Springs Area should be granted; and

(15) all motions, petitions, objections or other matters in this proceeding that remain unresolved should be resolved consistent with the conclusions contained herein.

IT IS THEREFORE ORDERED that pursuant to Section 8-406 a Certificate of Public Convenience and Necessity is hereby issued to Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities, such Certificate reading as follows:

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

IT IS HEREBY CERTIFIED that Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities is granted a Certificate of Public Convenience and Necessity for the construction, operation and maintenance of a public utility gas distribution system in the area of Creal Springs, Williamson County, as shown on the map attached to this Order as an Appendix.

IT IS FURTHER ORDERED that the Asset Purchase Agreement between Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities and the City of Creal Springs is approved.

IT IS FURTHER ORDERED that the customers in the Creal Springs Area should obtain service under the Company's tariff, rates, rules, and regulations in effect at that time for its customers generally, together with the tariff revisions proposed herein, such tariff, rates, rules and regulations to remain in effect until any changes to Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities' tariffs and terms of service may be made in accordance with applicable law.

IT IS FURTHER ORDERED that the accounting treatment as proposed by Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities and Commission Staff, including the journal entries proposed by Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities in Attachment D to the Application and the journal entries proposed by Commission Staff in Staff Exhibit 3.01, is reasonable and shall be approved.

IT IS FURTHER ORDERED that Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities shall file the final accounting entries for the transaction as a filing on the Commission's e-Docket system with a copy to ICC.AccountingMgr@illinois.gov within sixty days of the transaction date.

IT IS FURTHER ORDERED that if the proposed transaction has not occurred within six months of the date of this Order, Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities shall file status reports at six month intervals until the journal entries are filed on the Commission's e-Docket system with a copy to ICC.AccountingMgr@illinois.gov.

IT IS FURTHER ORDERED that there should be a one-year grace period during which fines associated with Pipeline Safety violations, originating from the actions of the City of Creal Springs prior to the proposed acquisition, will not be imposed upon Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities.

IT IS FURTHER ORDERED that the Vice President of Gas Operations for Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities Central Region should appear annually before the Commission to discuss the progress of the acquisition and its integration into Company operations, together with such other information as the Company believes pertinent.

IT IS FURTHER ORDERED that Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities is hereby granted all other necessary and useful relief and authority under the Public Utilities Act to allow the Company to construct, own, operate and

maintain a natural gas supply and distribution system and provide natural gas service in the Creal Springs Area.

IT IS FURTHER ORDERED that all motions, petitions, objections or other matters in this proceeding that remain unresolved should be resolved consistent with the conclusions contained herein.

IT IS FURTHER ORDERED that pursuant to Section 10-113(a) of the Public Utilities Act and 83 Ill. Adm. Code 200.880, any application for rehearing shall be filed within 30 days after service of the Order on the party.

IT IS FURTHER ORDERED that subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880; this Order is final; it is not subject to the Administrative Review Law.

By Order of the Commission this 21st day of August, 2019.

(SIGNED) CARRIE ZALEWSKI

Chairman

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	:	
Application for Certificate of Public Convenience and Necessity to Provide Natural Gas Service to the Village of Tamms and its Environs in Alexander and Union Counties, Illinois.	:	**20-0487**

ORDER

By the Commission:

I. PROCEDURAL HISTORY

On May 28, 2020, Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities ("Liberty Midstates" or the "Company") filed with the Illinois Commerce Commission ("Commission") an Application pursuant to Section 8-406 of the Public Utilities Act ("Act"), 220 ILCS 5/1-101 *et seq.,* to construct, own, operate, and maintain a natural gas supply and distribution system and provide natural gas service in and to the Village of Tamms ("Tamms" or the "Village") and its environs in Alexander and Union Counties, Illinois. The Company also requested approval of applicable rates for the Tamms Area, accounting entries related to the acquisition by the Company of natural gas supply and distribution facilities and related assets from the Village (the "System"), a one-year grace period from certain financial penalties arising from safety violations occurring prior to the closing of that acquisition, and other necessary and useful authority.

Pursuant to notice given in accordance with the law and the rules and regulations of the Commission, an evidentiary hearing was held on September 9, 2020, before a duly authorized Administrative Law Judge ("ALJ") of the Commission. Appearances were entered by counsel for Liberty Midstates and by counsel for Commission Staff ("Staff"). Liberty Midstates presented the testimony of Michael D. Beatty, the Vice President of Gas and Water Operations for the Liberty Utilities Central Region. Staff presented the testimony of Brett Seagle, a Gas Engineer in the Gas Section of the Energy Engineering Program of the Commission's Safety and Reliability Division; Janis Freetly, a Senior Financial Analyst in the Finance Department of the Commission's Financial Analysis Division; Steven R. Knepler, a Supervisor in the Accounting Department of the Commission's Financial Analysis Division; and Cheri Harden, a Rate Analyst in the Rates Department of the Commission's Financial Analysis Division. At the conclusion of the hearing, the record was marked "Heard and Taken." There were no contested issues in this proceeding and the parties agreed to file an Agreed Draft Order. On October 9, 2020,

the Company filed an Agreed Draft Order for the ALJ's consideration after it had been reviewed by Staff.

II. OVERVIEW OF PROCEEDING

Mr. Beatty testified that Liberty Midstates is a Missouri corporation. He stated the Company is engaged in the business of distributing and selling natural gas in Illinois, as well as in Iowa and Missouri, and is a public utility as defined by the Act. Mr. Beatty indicated that the Company provides gas service to approximately 21,200 customers in Adams, Champaign, Christian, Clay, Clinton, Douglas, Edgar, Effingham, Fayette, Fulton, Logan, Macon, Macoupin, Marion, Massac, Montgomery, Morgan, Moultrie, Peoria, Piatt, Pike, Saline, Sangamon, Scott, Shelby, Tazewell, Vermilion, and Williamson counties.

The Village of Tamms, which owns the system, is a village in Alexander County, Illinois. The Tamms distribution system, which serves approximately 260 active natural gas customers, is in Alexander and Union Counties, Illinois.

III. PROPOSED ACQUISITION AND BENEFITS

The Village and Liberty Midstates entered into an Asset Purchase Agreement on December 19, 2019, which provides for the purchase of the System by the Company upon the satisfaction of certain conditions, including the Commission's approval of the sale. The Company requested a Certificate of Public Convenience and Necessity for the area (the "Tamms Area") currently served by the System. The Company provided a more particular description of the Tamms Area, including a legal description and map, in an attachment to its Application.

Mr. Beatty testified that the Village believes that Liberty Midstates, due to its expertise in natural gas operations and financial resources, would be better able to address the operations and maintenance of, and improvements to, the System. Mr. Beatty testified as to the Company's history of safe and reliable operations in Illinois and its efforts to maintain high customer satisfaction, as well as benefits that current System customers would receive by taking service from the Company, such as online bill payment, budget billing options, and a regional call center. Mr. Beatty also mentioned that customers will be able to take advantage of Liberty Midstates' more favorable main extension and service line extension policies.

Mr. Beatty also testified that the Company planned to make specific capital improvements to the System (the "System Improvements") in order to address certain operations, maintenance and safety issues identified by the Company, including issues associated with the System's current use of polyvinyl chloride pipe ("PVC"). Mr. Beatty stated that in addition to replacing the two inch or smaller PVC gas mains (and adding tracer wire and caution tape) the Company planned to retire and/or replace 300 three quarter inch active, inactive and idle service lines, service tees and risers, anodes, valves, and boxes. In addition, he stated the Company plans to update town border station regulators, reliefs, heaters, and remove valves as necessary. Mr. Beatty stated his opinion that the System Improvements are necessary from a safety and reliability perspective.

Mr. Beatty noted that the Commission's Pipeline Safety Program issued notices of probable violation with respect to four new plastic pipe services installed in the System

by persons who had not been operator qualified. Mr. Beatty testified that, based on discussions with Staff, the Company will replace these four services within ninety days of the closing of the transaction, using operator qualified personnel. Mr. Beatty stated that the Company's preliminary estimate of the cost of the System Improvements was $1,550,000, of which $1,470,000 relates to the PVC main and services replacement project. In addition, the Company plans to replace all of the analog meters in the System with automatic meter reading meters and associated meter loops, at an estimated cost of $80,000. Mr. Beatty emphasized that the estimates in his testimony were preliminary and will vary based on the Company's experience once it begins to operate the System.

IV. CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

Section 8-406(b) of the Act requires the utility to demonstrate: (1) that the proposed construction is necessary to provide adequate, reliable, and efficient service to its customers and is the least-cost means of satisfying the service needs of its customers; (2) that the utility is capable of efficiently managing and supervising the construction process and has taken sufficient action to ensure adequate and efficient construction and supervision thereof; and (3) that the utility is capable of financing the proposed construction without significant adverse financial consequences for the utility or its customers. As discussed below, both the Company and Staff agree that Liberty Midstates has met these requirements in this case.

A. Necessity and Least Cost (Section 8-406(b)(1))

Mr. Beatty testified that the Company's acquisition of the System, the construction of the System Improvements, and the addition of the Tamms Area to the Company's service territory is necessary to provide adequate, reliable, and efficient service to customers and is the least-cost means of satisfying the needs of natural gas customers in the Tamms Area. After reviewing the Company's supporting information and responses to Staff discovery requests, including financial analyses and supporting data, the results of the Company's investigations of the system, and the proposed System Improvements, Staff witness Seagle testified that the Company demonstrated that it met this standard.

B. Capability to Effectively Manage and Supervise (Section 8-406(b)(2))

Mr. Beatty stated that the Company is capable of efficiently managing and supervising the acquisition of the System and the construction of the System Improvements and has taken, and will continue to take, sufficient action to ensure adequate and efficient construction and supervision of construction.

Mr. Seagle agreed that, based on the proposed System Improvements and the Company's track record with acquiring old natural gas distribution systems and making improvements in other cases, the Company has demonstrated that it is capable of efficiently managing and supervising the construction process.

C. Capability to Finance (Section 8-406(b)(3))

Mr. Beatty stated that the Company is capable of financing the acquisition of the System and the construction of System Improvements without significant adverse financial consequences for the Company and its customers. Staff witness Freetly reviewed the information contained in the Company's Application and testimony as well

as in discovery. In particular, Ms. Freetly examined the Company's estimates of the direct costs associated with the acquisition, including the System Improvements. Ms. Freetly noted the Company's intent to finance the acquisition and System improvements with internally generated funds supported by ongoing short-term and long-term debt and equity financing as needed from its parent company. Ms. Freetly compared the size of the acquisition and System Improvements relative to the Company's size and budgeted capital expenditures. Based on her analysis, Ms. Freetly judges that the Company is capable of financing the proposed acquisition and additional investments without significant adverse financial consequences for the Company or its customers. Therefore, she recommended that the Commission find that the requirements of Section 8-406(b)(3) of the Act have been satisfied.

D. Commission Analysis and Conclusion

The Commission finds that the Company's proposal fulfills the requirements of Section 8-406(b) of the Act. The record demonstrates that: (1) Liberty Midstates' purchase of the System, its construction of the System Improvements, and the addition of the Tamms Area to the Company's service territory are necessary to provide adequate, reliable, and efficient service to customers and constitutes the least cost means of satisfying the service needs of customers in the Tamms Area; (2) Liberty Midstates is capable of efficiently managing and supervising the construction process and has taken sufficient action to ensure adequate and efficient construction and supervision thereof; and (3) Liberty Midstates is capable of financing the proposed construction without significant adverse financial consequences for the utility or its customers. Accordingly, the Commission approves the proposed transaction, the construction of the System Improvements, and the addition of the Tamms Area to the Company's service territory in accordance with Section 8-406 of the Act, and grants the Company's request for a Certificate of Public Convenience and Necessity to construct, own, operate, and maintain a natural gas supply and distribution system and provide natural gas service in and to the Tamms Area.

V. OTHER ISSUES

A. Rates

The Company proposed that customers in the Tamms Area, including those served by the System, be subject to the Company's tariff rates, rules, and regulations on file with the Commission. Such rates, rules, and regulations would remain in effect until any changes to the Company's tariffs and terms of service may be made in accordance with applicable law.

Mr. Beatty stated that he does not believe that the long-term cost of providing service to the Tamms Area would be substantially different than the Company's cost of providing service in its other, similar service areas in Illinois. Mr. Beatty noted that the rates to customers in Tamms would increase as a result of this transaction. He noted that the primary benefit of the proposed transaction to the public and issuance of the Certificate of Public Convenience and Necessity to the Company arises from the provision of safe, efficient, and reliable service to the Tamms Area, and that the Company's rates simply allow it to recover the cost of providing this service. Mr. Beatty stated that adoption

of the Company's natural gas rates, rules, and regulations for customers in the Tamms Area is appropriate and in the best interest of those customers.

Staff witness Harden did not object to the Company's proposal regarding rates. She noted that although the rates would increase for Tamms customers, they will have more customer service options and could benefit from the Company's tariff policies despite the 25% increase in rates.

The Company also proposed to amend its tariff to specifically name Tamms as among the municipalities served by the Company, which are listed in the Territory section of its tariff. Ms. Harden recommended that if the Commission approves the requested certificate, it should order the Company to file the necessary compliance tariff within ten calendar days of the closing of the acquisition, with an effective date of not less than five business days after the date of filing.

Based on the record, the Commission concludes that the Company's proposal regarding rates is in the best interests of customers in the Tamms Area. Customers in the Tamms Area shall obtain service under the tariffs, rules, and regulations in effect at this time for the Company's customers generally, incorporating the tariff revisions proposed by the Company. Such tariffs, rates, rules, and regulations will remain in effect until any changes to the Company's tariffs and terms of service may be made in accordance with applicable law. In addition, the Commission adopts Ms. Harden's recommendation regarding the filing of a compliance tariff.

B. Accounting Issues

1. Original Cost Determination

Mr. Beatty explained that the Company determined original cost by applying the Handy-Whitman Index of Public Utility Construction Costs to the plant assets being purchased to estimate the original cost of the System and the related accumulated depreciation. Mr. Beatty pointed out that these indexes are widely used by regulatory bodies, operating utilities, valuation engineers, and insurance companies. Based on that methodology, the Company proposed a net original cost of $299,084. Staff witness Knepler agreed that the use of the Handy-Whitman Index value is an accepted practice for estimating the reproduction cost at a date certain. Mr. Knepler recommended that the Commission accept $299,804 as the net original cost of the System.

The Commission agrees and finds that the net original cost of the system is $299,804.

2. Acquisition Adjustment

Liberty Midstates outlined its proposed accounting treatment of the proposed transaction in its Application and requested that the Commission approve that treatment. Because the purchase price for the System exceeds its net original cost, the Company must record an acquisition adjustment. In this case, the Company proposed that the acquisition adjustment be amortized in full during the first year following the acquisition to account 425 – Miscellaneous Amortization, which is a below-the-line operating expense account. Mr. Knepler noted that since the acquisition adjustment will be written off or amortized below-the-line, the Company's proposed treatment has no effect on the ratepayers and is consistent with the Uniform System of Accounts for Gas Utilities.

The Commission agrees and approves the Company's proposed treatment of the acquisition adjustment.

3. Accounting Entries

The Company's proposed accounting treatment included an attachment setting forth specific journal entries. Staff witness Knepler concluded that the proposed journal entries comply with Gas Plant Accounting Instruction 5 of the Uniform System of Accounts for Gas Utilities.

Mr. Knepler further recommended that the Commission order the Company to file the final accounting entries for the transaction on the Commission's e-Docket system in this docket within sixty days of closing the transaction, with a copy to the Commission's Accounting Department at ICC.AccountingMgr@illinois.gov. If the transaction has not occurred within six months of the Final Order in this proceeding, Mr. Knepler recommended that the Company file status reports at six-month intervals until the journal entries are filed as ordered.

The Commission approves the Company's proposed journal entries as well as Mr. Knepler's recommendation regarding filing of the journal entries following the closing.

C. Grace Period

The Company requested that the Commission grant it a one-year grace period from any financial penalty associated with any enforcement action by its Natural Gas Pipeline Safety Division with respect to any violations of pipeline safety rules and requirements. The Company stated that this grace period would apply only to violations that originated with the Village or its representatives prior to the closing of the proposed transaction. Mr. Beatty testified that it would be fair to allocate the grace period, and that the Company believes that after one year it would be in a position to fully understand and address any issues that it discovers.

Staff witness Seagle stated his opinion that if a safety violation, stemming from actions by the Village, is discovered within the first year of the Company's operation of the System, the Company can reasonably claim that it had no previous knowledge of the safety violation. Therefore, he finds no reason to dispute the Company's request. Mr. Seagle did state that after the closing, if the Pipeline Safety Program finds Liberty Midstates in violation of any particular part of 49 CFR 191, 192, or 199, then the Commission's Pipeline Safety Program could assess a fine against the Company for violation of those sections. In other words, he said, the one-year grace period does not preclude the Company from being found in violation of those provisions if the Company itself is found to be responsible for the violation.

The Commission finds that a one-year period starting with the closing of the proposed acquisition in which fines associated with Pipeline Safety violations, originating from the actions of the Village prior to the proposed acquisition, will not be imposed on the Company is reasonable and should be approved. As Mr. Seagle notes, this does not preclude fines based on violations by Liberty Midstates itself of 49 CFR 191, 192 or 199.

D. Reporting Obligation

The Company agreed that the Vice President of Gas Operations for Liberty Utilities Central Region would appear before the Commission on an annual basis after a final order is issued in this case to discuss the progress of the acquisition and its integration into Company operations. The Commission determines that such a report should be made, together with any other information the Company believes pertinent.

VI. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having considered the record herein, is of the opinion and finds that:

(1) Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities is a corporation engaged, among other things, in the distribution of natural gas to the public in portions of the State of Illinois and is a public utility within the meaning of the Public Utilities Act;

(2) the Commission has jurisdiction over Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities and the subject matter in this proceeding;

(3) the statements of fact and conclusions of law set forth in the prefatory portion of this Order are supported by the record and hereby adopted as findings of fact and conclusions of law;

(4) issuance of a Certificate of Public Convenience and Necessity for the Village of Tamms and its environs to the Company will promote the public convenience and necessity thereto, and the Company has shown that the requirements of Section 8-406(b) have been met;

(5) the public convenience and necessity require that a certificate be issued, effective upon the transfer of the System to Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities, and Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities shall operate and maintain a natural gas system for the area legally described in Attachment A to the Application;

(6) the Asset Purchase Agreement between Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities and the Village of Tamms shall be approved;

(7) the customers in the Tamms Area should obtain service under the Company's tariff, rates, rules, and regulations in effect at that time for its customers generally together with the tariff revisions proposed herein, such tariff, rates, rules and regulations to remain in effect until any changes to the Company's tariffs and terms of service may be made in accordance with applicable law;

(8) the Company shall file its compliance tariff within ten calendar days of the closing of the acquisition, with an effective date of not less than five business days after the date of filing;

(9) the net original cost of the System is $299,084;

(10) the accounting treatment as proposed by the Company for the proposed transactions, including the journal entries proposed by the Company in Attachment D to the Application, is reasonable and shall be approved;

(11) Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities shall file the final accounting entries for the transaction as a filing on the Commission's e-Docket system with a copy to ICC.AccountingMgr@illinois.gov within sixty days of the transaction date;

(12) if the transaction has not occurred within six months of the date of this Order, Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities shall file status reports at six month intervals until the journal entries are filed on the Commission's e-Docket system with a copy to ICC.AccountingMgr@illinois.gov;

(13) there should be a one-year grace period during which fines associated with Pipeline Safety violations, originating from the actions of the Village prior to the proposed acquisition, will not be imposed upon Liberty Midstates;

(14) the Vice President of Gas Operations for Liberty Utilities Central Region should appear annually before the Commission to discuss the progress of the acquisition and its integration into Company operations, together with such other information as the Company believes pertinent;

(15) the Company's request for all other necessary and useful relief and authority under the Public Utilities Act to allow the Company to construct, own, operate, and maintain a natural gas supply and distribution system and provide natural gas service in the Tamms Area should be granted; and

(16) all motions, petitions, objections, or other matters in this proceeding that remain unresolved should be resolved consistent with the conclusions contained herein.

IT IS THEREFORE ORDERED that pursuant to Section 8-406 a Certificate of Public Convenience and Necessity is hereby issued to Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities, such Certificate reading as follows:

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

IT IS HEREBY CERTIFIED that Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities is granted a Certificate of Public Convenience and Necessity for the construction, operation and maintenance of a public utility gas distribution system in the area of Tamms, Alexander and Union Counties, as shown on the map attached to this Order as an Appendix.

IT IS FURTHER ORDERED that the Asset Purchase Agreement between Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities and the Village of Tamms is approved.

IT IS FURTHER ORDERED that the customers in the Tamms Area should obtain service under the Company's tariff, rates, rules, and regulations in effect at that time for

its customers generally, together with the tariff revisions proposed herein, such tariff, rates, rules, and regulations to remain in effect until any changes to Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities' tariffs and terms of service may be made in accordance with applicable law.

IT IS FURTHER ORDERED that the Company file its compliance tariff within ten calendar days of the closing of the acquisition, with an effective date of not less than five business days after the date of filing.

IT IS FURTHER ORDERED that the accounting treatment as proposed by Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities, including the journal entries proposed by Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities in Attachment D to the Application, is reasonable and shall be approved.

IT IS FURTHER ORDERED that Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities shall file the final accounting entries for the transaction as a filing on the Commission's e-Docket system with a copy to ICC.AccountingMgr@illinois.gov within sixty days of the transaction date.

IT IS FURTHER ORDERED that if the proposed transaction has not occurred within six months of the date of this Order, Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities shall file status reports at six month intervals until the journal entries are filed on the Commission's e-Docket system with a copy to ICC.AccountingMgr@illinois.gov.

IT IS FURTHER ORDERED that there should be a one-year grace period during which fines associated with Pipeline Safety violations, originating from the actions of the Village of Tamms prior to the proposed acquisition, will not be imposed upon Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities.

IT IS FURTHER ORDERED that the Vice President of Gas Operations for Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities Central Region should appear annually before the Commission to discuss the progress of the acquisition and its integration into Company operations, together with such other information as the Company believes pertinent.

IT IS FURTHER ORDERED that Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities is hereby granted all other necessary and useful relief and authority under the Public Utilities Act to allow the Company to construct, own, operate, and maintain a natural gas supply and distribution system and provide natural gas service in the Tamms Area.

IT IS FURTHER ORDERED that all motions, petitions, objections or other matters in this proceeding that remain unresolved should be resolved consistent with the conclusions contained herein.

IT IS FURTHER ORDERED that pursuant to Section 10-113(a) of the Public Utilities Act and 83 Ill. Adm. Code 200.880, any application for rehearing shall be filed within 30 days after service of the Order on the party.

IT IS FURTHER ORDERED that subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880; this Order is final; it is not subject to the Administrative Review Law.

By Order of the Commission this 18th day of November, 2020.

(SIGNED) CARRIE ZALEWSKI

Chairman

Appendix
Docket No. 20-0487

FRANCHISE AREA:

TOWNSHIP 13 SOUTH, RANGE 2 WEST

E ½ OF SECTION 12
E ½ OF SECTION 13
E ½ OF SECTION 24
E ½ OF SECTION 25

TOWNSHIP 13 SOUTH, RANGE 1 WEST

W ½ OF SECTION 7
W ½ OF SECTION 18
W ½ OF SECTION 19
SECTION 30
SECTION 31

TOWNSHIP 14 SOUTH, RANGE 1 WEST

SECTION 6
SECTION 7
SECTION 18
SECTION 19
SECTION 30
SECTION 31 LYING WEST OF MILL CREEK

TOWNSHIP 14 SOUTH, RANGE 2 WEST

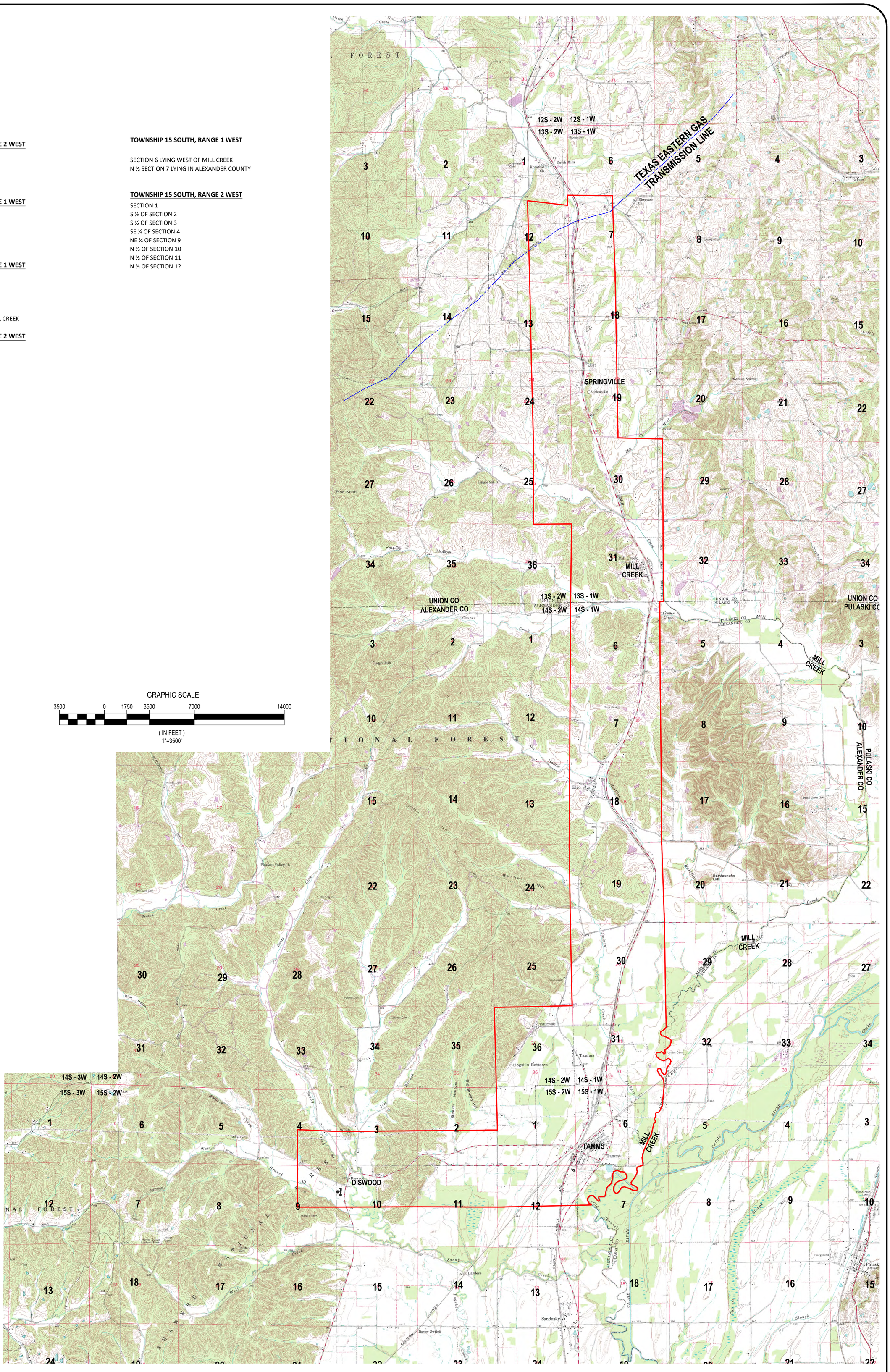
SECTION 36

TOWNSHIP 15 SOUTH, RANGE 1 WEST

SECTION 6 LYING WEST OF MILL CREEK
N ½ SECTION 7 LYING IN ALEXANDER COUNTY

TOWNSHIP 15 SOUTH, RANGE 2 WEST

SECTION 1
S ½ OF SECTION 2
S ½ OF SECTION 3
SE ¼ OF SECTION 4
NE ¼ OF SECTION 9
N ½ OF SECTION 10
N ½ OF SECTION 11
N ½ OF SECTION 12



Requested By:	Drafted by:	K FIELD
	Project Manager:	K FIELD
	Date:	05/05/2020
	Reviewed by:	B.J.A.
JERRY HACKWORTH OF LIBERTY UTILITIES	Scale:	1"=3500'
	Job Number:	2020-029
	Sheet:	1 OF 1

Drawing Status
☐ Preliminary Drawing
■ Final Drawing

This Professional Service Conforms To The Current Illinois Minimum Standards of Practice Applicable To Boundary Surveys.

Revisions

#	Date	Note

LIBERTY UTILITIES

TAMMS
UNION & ALEXANDER COUNTY
FRANCHISE AREA

Path: S:\2020\ALEXANDER\2020-029 LIBERTY UTILITIES\DELIVERABLES\DWG\2020-029 REVISED.DWG

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N W E S

11-0559
Appendix A

Required Conditions of Approval in Docket No. 11-0559

Each of the conditions enumerated below has been approved in the Order in this docket to which this Appendix A is attached. Implementation of each condition shall be consistent with the rationale for such condition, as explained in the Order. Where any specific details of implementation are set forth in the Order, implementation shall include such details.

1. Liberty shall file a semi-annual compliance report on the Commission's e-Docket system in this proceeding with a copy to the Manager of the Commission's Accounting Department, reporting on Liberty's progress toward satisfying each condition the Commission imposed on Liberty in this case beginning six months after the closing of the proposed reorganization and continuing until (1) two years thereafter or (2) Liberty petitions the Commission and receives Commission approval to cease filing the required reports, whichever comes first.

2. The President of Liberty Energy Midstates shall appear before the Commission each year on an ongoing basis to report on Liberty's progress toward and continuing compliance with the Commission's Final Order in this case, until such time as Liberty is no longer required to file the semi-annual reports set forth in condition 1.

3. Liberty Energy Midstates shall submit a report to the Commission on e-Docket with a copy to the Manager of the Commission's Accounting Department by March 31, 2013 that provides the following:

    a. A comparison of Liberty Energy Midstates' 2012 projected budget for the Illinois utility operations (filed as JA Ex. 5.3 and ICC Staff Ex. 9.0 Attachment A) to the actual costs incurred by Liberty Energy Midstates in operating the Illinois utility during 2012, with an explanation for each cost variation +/-15%; and

    b. A comparison of the 2013 projected budget for the Illinois utility operations compared to the actual 2012 costs incurred by Liberty Energy Midstates in operating the Illinois utility during 2012, with an explanation for each cost variation +/- 15%; and

    c. A conclusion as to whether the acquisition of the utility operations of Atmos in Illinois by Liberty Energy Midstates resulted in an adverse rate impact. (Section 7-204(b)(7))

4. The items identified in condition 3 above will also be reported by the President of Liberty Energy Midstates during the annual appearance before the Commission as described in condition 2 above.

5. All savings resulting from the proposed reorganization shall be flowed through to the costs associated with the regulated intrastate operations for consideration in setting rates by the Commission (Section 7-204(c)(i)).

6. Any costs incurred in accomplishing the proposed reorganization, including severance costs for any employees removed as part of the reorganization, in this or any future proceeding shall not be recoverable through Illinois jurisdictional regulated rates. (Section 7-204(c)(ii)).

7. There is no presumption for or against recoverability of costs attributed or related to the reorganization. The recoverability of any such costs, which may include costs of obtaining continuing services or investments to replace Atmos information technology and other infrastructure, should be determined by the Commission in a future rate case.

8. Liberty Energy Midstates shall file before the closing of the proposed reorganization (1) a letter from a credit rating agency confirming that the proposed long-term debt issuance will be rated at least BBB-/Baa3 and (2) a certification from Liberty Utilities' CEO or CFO that it received no oral or written statements from any credit rating agencies indicating that the proposed debt issuance will be rated lower. (Section 7-204(b)(4))

9. For the next rate proceeding for Liberty Energy Midstates, the pre-tax cost of capital will be set using no higher than the lower of (1) the pre-tax cost of capital that Liberty Energy Midstates would have had if (a) its debt to equity ratio was the same as Atmos' equity ratio as of September 30, 2011 (including short-term debt), and (b) the cost of its debt were the same as the cost of debt held by Atmos on September 30, 2011, and (2) the pre-tax cost of capital based on the actual capital structure of Liberty Energy Midstates. The FERC Form 2 Annual Report for the year ended December 31, 2011 will be used as the basis for the purpose of calculating the cost of debt for Atmos. (Section 7-204(b)(7))

10. Liberty Energy Midstates will file a compliance report with a copy to the Manager of the Commission's Finance Department following the proposed reorganization that describes Liberty Energy Midstates' post-acquisition capital structure and identifies capital structure adjustments that result from the proposed reorganization. (Section 6-103)

11. In the event that the compliance report shows that the capitalization exceeds book value, Liberty Energy Midstates shall file a petition seeking Commission approval of the fair value study and the resulting capital structure for Liberty Energy Midstates pursuant to Section 6-103 of the Act.

12. Liberty Energy Midstates shall provide the Manager of Accounting of the ICC with a template of all allocation percentages used to charge Midstates pursuant to

each applicable ASA. The template shall be provided within 60 days of closing the proposed transaction.

13. The template set forth in condition 12 shall be updated annually, with a copy provided to the Manager of Accounting no later than March 31.

14. Liberty Energy Midstates is prohibited from purchasing or selling gas supply from an affiliated entity following the closing of the proposed transaction unless approval is petitioned for and granted by the Commission or unless such approval is not required under applicable law.

15. Section V of the CAM shall not apply to Liberty Energy Midstates in Illinois, unless Liberty Energy Midstates seeks Commission approval to receive specific services from identified Service Companies.

16. As a regulatory matter, Liberty Energy Midstates shall be liable for all outstanding over-recovered purchased gas adjustment charges, and shall be entitled to all outstanding under-recovered purchased gas adjustment charges, related to open dockets for reconciliation periods ending prior to closing of the proposed transaction.

17. Liberty Energy Midstates shall file the final accounting entries (with the corrections noted herein), including the actual amounts recorded by Midstates within 60 calendar days following the closing of the proposed transaction with the Chief Clerk of the Commission with a copy of the filing to the Manager of the Accounting Department of the Commission.

18. Liberty Energy Midstates shall file the executed copy of the Asset Purchase Agreement and the executed ASA with the Chief Clerk of the Illinois Commerce Commission with a copy to the Manager of the Accounting Department of the Commission within fifteen (15) calendar days of the receipt of all regulatory approvals required for the proposed transaction to take effect. If the proposed transaction has not been consummated within 60 calendar days of the date of the Order in this proceeding, Liberty Energy Midstates shall file a status report with the Chief Clerk with a copy to the Manager of Accounting, and further status reports every 90 calendar days until the executed copy of the final purchase agreement has been filed.

19. Liberty Energy Midstates shall be liable to reimburse the Commission for any reasonable costs and expenses associated with an audit or inspection of books and records maintained outside Illinois.

20. Liberty Energy Midstates, following approval of the reorganization, shall address all issues identified during the plan and procedure review and subsequently conveyed via the NOA letter by the Pipeline Safety Program. Revised plans and

procedures shall be provided to the PSP by the response date identified in the NOA letter and address all issues identified by that letter. (Section 7-204(b)(5))

21. Atmos shall file an ICC form 21 for the period beginning January 1, 2012 and ending on the date of closing of the Asset Purchase Agreement.

22. Liberty Energy Midstates shall file an ICC form 21 for the period beginning on the date of closing of the Asset Purchase Agreement and ending on December 31, 2012. The filing shall also include a simple consolidation of this form with Atmos' form 21.

11-0559
Appendix B

Calculation of Section 6-108 Security Issuance Fees

Illinois Net Gas Plant

1010 - Gas Plant in Service	50,584,416
1080 - Accum Prov for Depreciation	(22,285,403)
Illinois Net Gas Plant	28,299,012

Consolidated Net Gas Plant

1010 - Gas Plant in Service	169,537,746
1080 - Accum Prov for Depreciation	(61,068,150)
Total Net Gas Plant	108,469,596

Allocation Factor

Illinois Net Gas Plant divided by Total Net Gas Plant	0.2609

ICC Equity Fee

Equity Issuance	62,000,000
Allocation Factor	0.2609
Illinois portion of Equity (Total Midstates Equity X Allocation Factor)	16,175,396.85
ICC Equity Fee (Illinois Portion / 100 X .12)	19,410.48

ICC Debt Fee

Private Placement Debt	55,000,000
Allocation Factor	0.2609
Illinois portion of Debt (Total Midstates Debt X Allocation Factor)	14,349,142.36
ICC Debt Fee (Illinois Portion / 100 X .24)	34,437.94

Total ICC Debt and Equity Fee

ICC Debt Fee + ICC Equity Fee	53,848.42

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Atmos Energy Corporation and Liberty Energy (Midstates) Corp.	:	
	:	**11-0559**
Application for Approval of Proposed Reorganization and Other Relief.	:	

ORDER

DATED: June 27, 2012

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STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Atmos Energy Corporation and Liberty Energy (Midstates) Corp.	:	
	:	**11-0559**
Application for Approval of Proposed Reorganization and Other Relief.	:	

ORDER

By the Commission:

I. PROCEDURAL BACKGROUND

On August 1, 2011, Atmos Energy Corporation (“Atmos”) and Liberty Energy (Midstates) Corp, (“Liberty”) (collectively, “Joint Applicants”) filed an Application (“Application”) with the Illinois Commerce Commission ("Commission") seeking approval under the Public Utilities Act (“Act”) (220 ILCS 5/101 et seq.) of the purchase by Liberty of Atmos’ Illinois natural gas utility operations and other relief.

In their Application, the Joint Applicants indicated that the reorganization would meet the requirements of Section 7-204(b)(1) through 7-204(b)(7) and 7-204(c) of the Act and submitted testimony from both Atmos and Liberty witnesses. Staff of the Illinois Commerce Commission ("Staff") participated in this docket. No petitions to intervene were filed in this proceeding. On January 31, 2012, an evidentiary hearing was held at the Commission's offices at 527 E. Capitol, Springfield, Illinois.

To reflect the issues which were resolved by the parties, Staff and Joints Applicants entered into a stipulation, “Agreed Stipulation Between Joint Applicants and Staff,” (“Stipulation”) which is demonstrative of some of the issues and conditions which Staff and Joint Applicants have resolved. Following the evidentiary hearing, the parties filed Initial and Reply Briefs. On April 13, 2012, the ALJ marked the record “Heard and Taken”. A Proposed Order was served on the parties. Briefs on Exceptions were filed by Staff and the Joint Applicants. The Joint Applicants filed a Reply Brief on Exceptions, while Staff declined to file a Reply Brief on Exceptions.

II. INTRODUCTION

A. Proposed Reorganization

On or about May 12, 2011, Atmos and Liberty entered into an Asset Purchase Agreement, which Agreement provides for the purchase by Liberty of Atmos’ natural gas utility operations in Illinois, Iowa and Missouri. The parties note that in Illinois, Atmos provides natural gas distribution service to approximately 24,000 customers.

Liberty notes that its ultimate parent, Algonquin Power and Utilities Corp. ("Algonquin"), is a publicly traded corporation that owns and operates an approximately US$1.1 billion portfolio of renewable power electric generation and utility operations across North America. The Joint Applicants suggest that as an experienced utility owner, Algonquin has developed a record of strong customer service, delivering safe and reliable power, water, and wastewater services to its customers.

The Joint Applicants argue that some of the benefits to this transaction include Algonquin's emphasis on local management and operation, which includes that functions related to customer service, human resources or that are regulator facing should be performed in the service territory, as opposed to central operations. The Joint Applicants state this will translate in to an immediate increase in desirable jobs being repatriated to Illinois. Liberty is committed to reinvesting capital in Illinois to preserve Liberty's regulatory assets and to extend the availability of natural gas in Illinois. Adding local personnel will create quality jobs in Illinois and enhance customer experiences, including by staffing customer walk-in centers. Liberty suggests that Algonquin's local emphasis will also increase the extent to which rates are based on costs incurred primarily at the local level and readily identifiable with the services provided. Moreover, Liberty anticipates the potential for a close working relationship with the Commission following the closing of the proposed transaction.

B. The Applicants and Related Parties

Atmos is a corporation duly organized and existing under the laws of the State of Texas and the Commonwealth of Virginia with its principal offices located in Dallas, Texas; and is a public utility within the meaning of the Act. It is engaged in the business of distributing and selling natural gas in Illinois as well as in the States of Georgia, Tennessee, Virginia, Missouri, Mississippi, Iowa, Kansas, Texas, Louisiana, Colorado and Kentucky. Atmos provides natural gas in Illinois to approximately 24,000 customers located in six operating areas—Virden, Vandalia, Harrisburg, Metropolis, Salem and St. Elmo.

Liberty's ultimate parent, Algonquin, is a Canadian corporation whose stock is traded on the Toronto Stock Exchange. It has two business units: (a) a power generation unit that includes forty-five renewable power generating facilities and twelve high-efficiency thermal generating facilities located in six U.S. states and Canada, and (b) a utility services unit that owns and operates twenty regulated utilities located in five states that provide retail water, sewer and electric utility service.

Algonquin acquired its first regulated utility operations in 2001 and since then has acquired an additional nineteen different water, waste water and electric utilities serving a total of approximately 125,000 customers in the United States—approximately 47,000 electric utility customers and approximately 75,000 water customers.

As discussed, Liberty is an indirect subsidiary of Algonquin, and it will become a public utility within the meaning of the Act upon the closing of the Purchase Agreement. The Joint Applicants note that Algonquin conducts its regulated utility operations through subsidiaries. Algonquin's regulated utilities businesses are organized under its wholly owned subsidiary Liberty Utilities (Canada) Corp. ("LUC"), a Canadian corporation, which owns Liberty Utilities Co. ("Liberty Utilities"), a Delaware corporation, which in turn owns Liberty Energy Utilities Company ("Liberty Energy"), which through subsidiaries currently provides electrical utility services to approximately 47,000 customers. Liberty Energy is the immediate parent of Liberty. Liberty Utilities also owns Liberty Water Co., a Delaware corporation that provides, through operating subsidiaries, regulated water utility services to more than 75,000 customers with a portfolio of nineteen water treatment facilities, at the time the Application was filed. None of these entities are currently public utilities in Illinois.

C. The Proposed Transaction

The Purchase Agreement provides for the transfer of Atmos' Illinois, Iowa and Missouri natural gas distribution utility operations to Liberty. The Joint Applicants note that the purchase price of the assets is approximately $124 million, subject to adjustment as set forth in the Purchase Agreement. The Joint Applicants suggest that the purchase price is reasonable and is the result of arms' length negotiations. Liberty notes that it is not assuming any existing indebtedness under the Purchase Agreement.

As set forth in the Purchase Agreement, included in the assets to be transferred are all applicable governmental permits that may legally be transferred to Liberty. Accordingly, subject to Commission approval, the Joint Applicants state that Atmos plans to transfer all of the Certificates of Public Convenience and Necessity ("Certificates") it holds in Illinois to Liberty pursuant to Sections 7-203 and 8-406 of the Act. The Applicants request authority for this transfer.

Following the consummation of the transactions contemplated by the Purchase Agreement, Liberty Energy (Midstates) will provide service to all of the utility customers Atmos currently provides service to in Illinois. The Applicants request approval for Atmos to permanently abandon the provision of natural gas service in all areas served by Atmos as of the closing of the Purchase Agreement.

The Joint Applicants state that Liberty requests that the Commission determine that its proposed capitalization complies with section 6-103, and requests approval of these equity and debt issuances pursuant to section 6-102. Liberty indicates that pursuant to the requested financing, it will pay fees under section 6-108 based on the amounts authorized by the Commission (with the proportion attributable to Illinois based on the net gas plant allocated to Illinois divided by Liberty's total net utility plant). Liberty requests that the Commission determine that its proposed capitalization complies with section 6-103. Liberty believes that allowing it flexibility to adapt its borrowings to market conditions in place nearer in time to the closing will improve its ability to obtain the most reasonable terms for the debt. Therefore Liberty requests that the Commission allow

Liberty the authority to issue the debt in amounts up to those to be requested in later filings or testimony on terms consistent with those indicated to the Commission herein and in later filings or testimony. Liberty asserts it would ensure that the debt complies with any conditions set forth by the Commission in such an approval.

D. Relief Requested

The Joint Applicants request the following findings and approvals from the Commission:

1. approval under Sections 7-204 and 7-204A of the Act to engage in the proposed reorganization, through which Liberty will acquire the natural gas operations of Atmos;

2. approval under Section 7-102 of the Act to the extent required;

3. approval under Section 6-103 of the Act of Liberty's initial capitalization;

4. approval of the issuance of equity and long term secured debt pursuant to Section 6-102 of the Act;

5. the Commission's authorization pursuant to Section 7-101 of the Act for the entry by Liberty into four separate Affiliated Services Agreements ("ASA"), and the Commission's authorization for Atmos to terminate its existing ASA without the requirement to provide notice to the Commission or obtain any other approval;

6. approval under Sections 7-203 and 8-406 of the Act to transfer to Liberty all of the Certificates of Public Convenience and Necessity held by Atmos or its predecessors;

7. the Commission's authorization for Atmos to abandon the provision of natural gas distribution in Illinois pursuant to Section 8-508;

8. approval under Section 5-106 of the Act to maintain books and records outside of Illinois;

9. the Commission exercise its authority under Section 9-201 to waive the 45 day notice requirement for filing of tariffs; and

10. all other approvals and authority that may be granted by the Commission under applicable law that may be required, necessary or useful in connection with sale by Atmos and the purchase by Liberty, and the transactions contemplated by the Purchase

Agreement or the provisions and purposes thereof or described in the record.

III. RESOLVED ISSUES

A. Section 7-203

Section 7-203 of the Act requires that "No franchise, license, permit or right to own, operate, manage or control any public utility shall be assigned, transferred or leased, nor shall any contract or agreement with reference to or affecting any such franchise, license, permit or right be valid or of any force or effect whatsoever, unless such assignment, lease, contract, or agreement shall have been approved by the Commission. Such permission shall not be construed to revive or validate any lapsed or invalid franchise, license, permit or right, or to enlarge or add to the powers and privileges contained in the grant of any franchise, license, permit or right, or to waive any forfeiture."

Staff witness Brett Seagle recommends that the Commission approve the Joint Applicants' request for authority to transfer all applicable obligations from Atmos to Liberty at the close of the proposed transaction. Mr. Seagle based his recommendation on his review of information contained in Section 5.9 of the Purchase Agreement. Section 5.9 of the Purchase Agreement, Schedule 5.9(a) contains a listing of Atmos' environmental permits and obligations, all municipal and county franchises, supply contracts, maintenance and labor agreements, and any other relevant agreements that Atmos will transfer to Liberty at the closing of the proposed transaction. Joint Applicant Exhibit 10.1 contains a complete listing of the Certificates of Public Convenience and Necessity Atmos intends to transfer to Liberty at the close of the proposed transaction.

The Commission finds that the evidence in the record supports Commission approval pursuant to Section 7-203 of the transfer of all of Atmos' Illinois certificates of public convenience and necessity to Liberty upon closing of the proposed reorganization.

B. Section 7-204(b)(1)

Subsection 7-204(b)(1) of the Act requires the Joint Applicants to demonstrate that "the proposed reorganization will not diminish the utility's ability to provide adequate, reliable, efficient, safe and least-cost public utility service." (220 ILCS 5/7-204(b)(1)).

Staff witness Seagle recommends that the Commission find that the proposed reorganization will not diminish the Joint Applicants' ability to provide adequate, reliable, efficient, safe and least-cost public utility service. Mr. Seagle testified that subject to certain conditions to which the Joint Applicants and Staff have agreed in the stipulation, specifically the Commission's imposing the conditions recommended by Staff witness Richard Bridal on the topic of operation and maintenance budgets and capital

expenditure budgets, he recommends that the Commission find that the reorganization will not diminish Liberty's ability to provide adequate, reliable, safe, and least-cost service.

The Commission finds that the Joint Applicants' have accepted the conditions proposed by Mr. Bridal, with minor modifications that have been agreed to by both Staff and the Joint Applicants in the Stipulation. Based on the evidence of record and in light of the Joint Applicants' acceptance of the conditions proposed by Staff, the Commission finds that the requirements of Section 7-204(b)(1) have been satisfied.

C. Section 7-204(b)(4)

Section 7-204(b)(4) of the Act requires that "the proposed reorganization will not significantly impair the utility's ability to raise necessary capital on reasonable terms or to maintain a reasonable capital structure." (220 ILCS 5/7-204(b)(4))

Joint Applicants state that following the proposed reorganization, all equity funding will be raised by Algonquin, the ultimate parent company of Liberty. Joint Applicants note that Algonquin is a publicly-traded Canadian corporation with a reasonably strong capital structure comprising approximately 50% debt and 50% equity as of June 30, 2011. Further, Joint Applicants state the $124 million purchase price for Atmos is only about 12% of Algonquin's $1 billion in total assets, and note that Algonquin was able to issue 15.1 million shares of common stock and raise over $85 million in equity in October 2011. From those facts, Joint Applicants claim that Staff witness Janis Freetly concluded that Algonquin has sufficient access to the equity markets to raise necessary equity capital on behalf of Liberty.

Staff alleges that Ms. Freetly indicates that the ability of Liberty to issue sufficient debt capital through private placement on reasonable terms was not established, and while on its face, the financial forecast provided by Liberty in response to Staff Data Request JF-4.01 indicates adequate financial strength to obtain debt financing, Liberty's response did not include a sufficiently detailed description of forecast assumptions. Further, Staff states Liberty Utilities has no historical financial statements, therefore the reasonableness of that forecast cannot be assessed. Finally, Liberty has no history of raising debt capital. Given that, Ms. Freetly and the Joint Applicants agreed on two conditions that would demonstrate whether Liberty Utilities can raise the necessary debt. (Stipulation, Attachment A, p. 2) Before the closing of the proposed reorganization, Staff indicates Liberty must file with the Chief Clerk (1) a letter from at least one credit rating agency stating its intention to assign a credit rating of BBB (low), BBB- or Baa3 or higher to the long-term debt to be issued by Liberty and loaned to Liberty through an intercompany note as described on Joint Applicants Ex. 6.3 ; and (2) a certified statement either from the chief executive officer or chief financial officer of Liberty that certifies that the Company received no oral or written statements from any credit rating agency stating an intention to assign the proposed debt issuance a credit rating below investment grade. The letter and certification would indicate that Liberty can issue the proposed debt referenced above at reasonable cost.

Further, in her rebuttal testimony, Ms. Freetly proposed that Liberty file a copy of a revolving credit facility with a principal amount of at least $60 million as evidence that Liberty Utilities will be able to provide Liberty with funds for working capital purposes. On January 19, 2012, Liberty Utilities entered into an agreement for an $80 million senior unsecured revolving credit facility. In accordance with Ms. Freetly's recommendation, the Company filed a copy of the revolving credit facility entered into by Liberty Utilities. The effectuation of this agreement provides confidence that Liberty will have sufficient liquidity to meet its short-term obligations.

Staff states that Liberty must request approval of an intercompany agreement to incur debt under this facility pursuant to Section 7-101(c) of the Act, which applies to transactions between the utility and its affiliated interest. In addition, approval under Section 6-102 is required if the term is longer than 12 months after the date of the issuance.

The Joint Applicants and Staff through a Stipulation have agreed to these conditions with certain modifications. Under the Stipulated conditions, Liberty shall file prior to the closing of the proposed reorganization (1) a letter from a credit rating agency confirming that the proposed long-term debt is rated at BBB-/Baa3 or higher and (2) a certification from Liberty's CEO or CFO that it received no oral or written statements from any credit rating agencies that the proposed debt issuance will be rated lower.

Staff witness Freetly also proposed that the Commission condition its finding by requiring a revolving credit facility with a principal amount of at least $60 million. Joint Applicant's witness Peter Eichler testified that Liberty Utilities entered into an agreement for an $80 million senior unsecured revolving credit facility. The revolving credit agreement was submitted as Joint Applicant Exhibit 9.3. Joint Applicants believe that Ms. Freetly's proposed condition has been satisfied by the filing of the revolving credit agreement. Liberty further indicates it will seek Commission approval of this revolving credit agreement and intercompany loan document in a separate docket.

Based on the evidence in the record, and in light of the Joint Applicants' acceptance of the conditions proposed by Staff, the Commission finds that the proposed reorganization satisfies the criteria of subsection 7-204(b)(4) of the Act.

D. Section 7-204(b)(5)

Section 7-204(b)(5) of the Act requires that the Commission must find, in order to approve a proposed reorganization, that, among other things, "the utility will remain subject to all applicable laws, regulations, rules, decisions and policies governing the regulation of Illinois public utilities." (220 ILCS 5/7-204(b)(5))

Staff witness Darin Burk testified regarding the Joint Applicant's obligations to comply with Federal pipeline safety standards codified under 49 CFR Sections 191, 192, 193 and 199 and adopted by the Commission in 83 Ill. Adm. Code 590, the Illinois

Pipeline Safety Act, and the Public Utilities Act. Liberty provided limited information and documentation to Mr. Burk regarding its plans to comply with the identified portions of the CFR, the Pipeline Safety Act and the Public Utilities Act. Mr. Burk indicated that he had assigned a Senior Pipeline Safety Analyst to review the material provided by Liberty.

Mr. Burk further indicated that, following completion of that review, he will send a Notice of Amendment ("NOA") to Liberty listing each item that needs to be addressed. Liberty will be advised in the NOA by what date they should respond outlining the steps they will take to address the issues identified in the NOA. Mr. Burk recommended that the Commission should order Liberty, upon approval of the reorganization, to address all issues identified in the NOA sent following review of their safety plans and procedures and to complete its response by the date provided in the NOA. Joint Applicant witness Eichler indicated that Liberty will address all issues identified during the plan and procedure review and subsequently conveyed via the NOA letter from the Commission's Pipeline Safety Program.

The following condition has been agreed to by Joint Applicants and Staff:

> Liberty, following approval of the reorganization, shall address all issues identified during the plan and procedure review and subsequently conveyed via the NOA letter by the Pipeline Safety Program ("PSP"). Revised plans and procedures shall be provided to the PSP by the response date identified in the NOA letter and address all issues identified by that letter. (Stipulation, Attachment A, p. 3)

Staff indicates that as it does not believe the Joint Applicants have satisfied all of the requirements of Section 7-204(b)(5), therefore Section 7-204(b)(5) is also addressed in the Contested Issues section of this Order.

E. Section 7-204(b)(6)

Section 7-204(b)(6) of the Act states that "the proposed reorganization is not likely to have a significant adverse effect on competition in those markets over which the Commission has jurisdiction."

Staff witness David Rearden concluded that the Commission should find that the proposed organization is not likely to have an adverse effect on competition in those markets over which the Commission has jurisdiction. Staff notes that the relevant market that the Commission has jurisdiction over is the retail transportation market, and that the Commission does not regulate the rates offered by competitive providers, but does approve the utility's tariffs that govern transportation service. The Commission also has jurisdiction to prevent some market abuses, and Staff opines that ratepayers are better protected when the retail market is more competitive. Staff notes that Atmos does not have transportation tariffs; therefore, the reorganization cannot have an

adverse effect on the competition in markets over which the Commission has jurisdiction.

The Commission agrees with Staff, and finds that the proposed reorganization is not likely to have a significant adverse effect on competition in the markets over which the Commission has jurisdiction.

F. Section 7-204(b)(7)

Section 7-204(b)(7) states, "[i]n reviewing any proposed reorganization, the Commission must find that the proposed reorganization is not likely to result in any adverse rate impacts on retail customers." (220 ILCS 5/7-204(b)(7))

Since the cost of capital is a component of a utility's rates, and the cost of capital could increase with financial risk, then an increase in financial risk could increase a utility's rates. Following the reorganization, the utility's capital structure will contain a higher proportion of common equity than Atmos Energy's capital structure. Although the Company indicates that they are not seeking approval of this proposed capital structure for ratemaking purposes, Staff indicates the Commission must consider whether the proposed capital structure, in conjunction with other components of the revenue requirement, is likely to result in any adverse rate impacts.

In order to avoid adverse rate impacts, Ms. Freetly recommended a condition, to which the Joint Applicants agreed, that essentially caps the common equity ratio for ratemaking purposes. This condition requires that in the next rate proceeding, the pre-tax cost of capital for Liberty will be set using no higher than the lower of (1) the pre-tax cost of capital that would have had if (a) its debt to equity ratio was the same as Atmos' equity ratio as of September 30, 2011 (including short-term debt), and (b) the cost of its debt were the same as the cost of debt held by Atmos on September 30, 2011; and (2) the pre-tax cost of capital based on the actual capital structure of Liberty. Staff asserts that imposing this condition provides assurance that the Company's capital structure will not contribute to any adverse rate impact resulting from the proposed reorganization.

Staff witness Bridal made two recommendations in rebuttal testimony with respect to approval to the proposed transaction under Section 7-204(b)(7), which the Joint Applicants have accepted:

1) Liberty shall submit a report to the Commission on e-Docket with a copy to the Manager of the Commission's Accounting Department by March 31, 2013 that provides the following:

    a. A comparison of Liberty's 2012 projected budget for the Illinois utility operations (Joint Applicants Ex. 5.3 and ICC Staff Ex. 9.0 Attachment A) to the actual costs incurred by Liberty in operating the Illinois utility during 2012, with an explanation for each cost variation +/-15%; and

b. A comparison of the 2013 projected budget for the Illinois utility operations compared to the actual 2012 costs incurred by Liberty in operating the Illinois utility during 2012, with an explanation for each cost variation +/- 15%; and

c. A conclusion as to whether the acquisition of the utility operations of Atmos in Illinois by Liberty resulted in an adverse rate impact.

2) The items identified in Section 1.a.-1.c. above will also be reported by the President of Liberty during the annual appearance before the Commission which is referenced by Staff witness Seagle .

With the conditions above, Staff believes the proposed transaction meets the requirements of Section 7-204(b)(7).

The Commission finds that, with the agreed conditions, the proposed reorganization meets the requirements of Section 7-204(b)(7).

G. Section 7-204(c)

Section 7-204(c) of the Act requires the Commission to make certain findings regarding savings resulting from the proposed reorganization, and costs incurred in accomplishing the proposed reorganization. Specifically, Section 7-204(c) of the Act states:

> The Commission shall not approve a reorganization without ruling on: (i) the allocation of any savings resulting from the proposed reorganization; and (ii) whether the companies should be allowed to recover any costs incurred in accomplishing the proposed reorganization and, if so, the amount of costs eligible for recovery and how the costs will be allocated. (220 ILCS 5/7-204(c), Emphasis added)

As such, if the Commission should approve the proposed reorganization, it must make two separate findings under Section 7-204(c).

The Commission notes that the first required finding is determining how any savings resulting from the proposed reorganization should be allocated among the operating utility, its holding company, its affiliates, its stockholders, and its ratepayers. Staff's recommendation is that all savings resulting from the proposed reorganization be flowed through to the costs associated with regulated intrastate operations for consideration in setting rates by the Commission. The Joint Applicants have accepted Staff's recommendation.

The second required finding is two-fold: (a) determining whether the Joint Applicants should be allowed to recover any costs incurred in accomplishing the proposed reorganization; and (b) if so, determining what amount of cost is eligible for recovery and how those costs should be allocated among the operating utility, its holding company, its affiliates, its stockholders, and its ratepayers. Staff's recommendation is that no costs incurred in accomplishing the proposed reorganization should be recovered from Illinois-jurisdictional ratepayers. Because Staff recommends zero cost be recovered, there is no need for a Commission finding on the allocation of recoverable cost. Staff's recommendations include two points of clarification: (1) "Costs incurred in accomplishing the proposed reorganization" include severance costs for any employees removed as part of the reorganization; and (2) Staff's recommendation carries no presumption of recoverability of costs attributed or related to the reorganization. The recoverability of any such costs, which may include costs of obtaining continuing services or investments to replace Atmos infrastructure, should be determined by the Commission in a future rate case. The Joint Applicants have accepted Staff's recommendation and clarifications.

In summary, in the event that the Commission should approve the proposed reorganization, Staff recommends, and the Joint Applicants agree, the Commission should also make the following rulings:

1) All savings resulting from the proposed reorganization shall be flowed through to the costs associated with the regulated intrastate operations for consideration in setting rates by the Commission (Section 7-204(c)(i) of the Act); and

2) Any costs incurred in accomplishing the proposed reorganization in this or any future proceeding shall not be recoverable through Illinois jurisdictional regulated rates (Section 7-204(c)(ii) of the Act).

Based on the entirety of the evidence in the record, the Commission finds that Staff witness Bridal's two recommended rulings should be adopted. The recommendations by Staff witness Bridal reasonably provide that any allocation of savings should be flowed through directly to ratepayers and prohibit the recovery of costs incurred in accomplishing the reorganization, including severance costs. The Commission agrees that potential recovery of costs attributed or related to the reorganization should be determined in a future rate proceeding.

H. Section 6-102

The Joint Applicants have requested approval under Section 6-102 for approval to issue equity and long term debt to finance the proposed reorganization. Liberty estimates that it will issue a maximum of $67 million of its common stock to its parent, Liberty Energy in respect to its equity capitalization. Since the proposed common stock issuance is to an affiliate, Joint Applicants note that Commission approval is needed under Section 7-101. Liberty notes that its long term debt will be issued by Liberty

Utilities through a private placement of unsecured notes that are passed through to Liberty in the form of an intercompany loan, and that approval of this intercompany loan is also required under Section 7-101. Liberty estimates it would borrow a maximum of $55 million in long term debt in respect of its initial debt capitalization. Liberty states that it provided a summary of the key terms of the proposed debt issuance in Exhibit 6.3, while noting that final details such as interest rate and maturity will not be in place until immediately prior to closing.

Liberty notes that it has agreed to pay fees on the issuance of the equity and debt pursuant to Section 6-108 for the proportion attributable to Illinois (determined by the net gas plant allocated to Illinois divided by Liberty' total net utility plant). That proportion is approximately 26% and the calculation for the allocation percentage is set forth in Exhibit 9.5. Based on a maximum authorization of $55 million in long term debt and $67 million in equity authorized by this Order, Liberty asserts it shall pay fees equal to $53,848.42 as calculated in Appendix B.

Liberty did not initially request approval for its revolving credit facility because the credit facility was not initially expected to have a term greater than 12 months; however the revolving credit facility entered into by Liberty Utilities has a term in excess of 12 months. Liberty and Staff have agreed that approval for the revolving credit facility should be addressed in a separate docket.

Based on the evidence in the record, the Commission concludes that the requested financing is necessary to effectuate the proposed reorganization and that it is in the public interest. Accordingly, the Commission finds that Liberty is authorized to issue the equity and long term debt described above to finance the proposed reorganization. In accordance with Section 6-101, Liberty shall place an Illinois Commerce Commission identification number on the face of the equity and long term debt for proper and easy identification. Liberty shall pay fees under Section 6-108 after it becomes aware of the final amounts of equity and debt to be issued. The Commission also approves the arrangements that Liberty has identified with Liberty Utilities to effectuate these financing activities under Section 7-101 of the Act as we find them to be in the public interest.

I. Section 9-201

Liberty is requesting authority to adopt the tariffs of Atmos immediately upon closing and requests that the Commission exercise its authority to waive the 45-day notice requirement for the filing of tariffs to assist with an orderly post-acquisition transition. Rather than Liberty replicating the tariffs of Atmos and identifying them as tariffs of Liberty, the Joint Applicants request the Commission waive the refiling of the tariffs and consent to the instantaneous transfer of their identity as Liberty' tariffs, at the moment the transaction is effective. Mr. Eichler noted that the Commission has previously allowed tariffs to be adopted without filing new tariffs in Docket No. 00-0261, Interstate Power Company's joint application for approval of merger and reorganization.

The Commission notes however, that Section 9-102 of the Act requires every public utility to file with the Commission schedules showing all rates, charges, classifications, rules and regulations relating to any product, commodity or service provided by the utility. It appears from the relief that the Joint Applicants are requesting, that Liberty would be operating as a public utility in the State of Illinois, without effective tariffs in its name on file with the Commission. A review of Docket No. 00-0261 finds that the Commission, in that proceeding, authorized Interstate Power Company to file new tariffs, identical to the previous tariffs in effect prior to the reorganization, while granting a waiver of the 45-day notice requirement of Section 9-201 of the Act.

The Commission, therefore, shall require the Liberty to file contemporaneously with the consummation of the reorganization, new tariffs identical to those currently in effect for Atmos, reflecting however the change to Liberty in each tariff. The Commission does, however, exercise its authority to waive the 45-day notice requirement for these tariffs to go into effect, and finds that they should be effective upon filing.

J. Other

Staff witness Seagle made two recommendations for conditions with respect to Commission approval of the proposed transaction, which the Joint Applicants have accepted. Staff notes that these conditions are similar to the conditions that the Commission enacted in the recently approved AGL/Nicor reorganization, (Order, December 7, 2011, Docket No. 11-0046, Appendix A, Conditions 27 and 34):

1) Liberty shall file a semi-annual compliance report on the Commission's e-Docket system in this proceeding with a copy to the Manager of the Commission's Accounting Department, reporting on Liberty's progress toward satisfying each condition the Commission imposed on Liberty in this case beginning six months after the closing of the proposed reorganization and continuing until (1) for two years thereafter or (2) Liberty petitions the Commission and receives Commission approval to cease filing the required reports, whichever comes first.

2) The President of Liberty shall appear before the Commission each year on an ongoing basis to report on Liberty's progress toward and continuing compliance with the Commission's Final Order in this case, until such time as Liberty is no longer required to file the semi-annual reports set forth in condition 1 above.

Staff also indicates that pursuant to Section 6-103 of the Act, in any reorganization, the Commission shall authorize the amount of capitalization of a public utility formed by a reorganization, which shall not exceed the fair market value of the property involved. (220 ILCS 5/6-103) Liberty plans to record the acquisition at book value and does not intend to seek recovery of goodwill or an acquisition premium, which

will be paid for by and recorded on the books of Liberty. Liberty agreed to file a compliance report with a copy to the Manager of the Commission's Finance Department following the proposed reorganization that describes Liberty's post acquisition capital structure and identifies the capital structure adjustments that result from the proposed reorganization. In the event that the capitalization exceeds book value, Liberty is required to file a petition seeking Commission approval of the fair value study and the resulting capital structure for Liberty pursuant to Section 6-103 of the Act.

K. 83 Ill. Adm. Code 505

Staff also recommends that the Commission find that the Joint Applicants' proposed accounting of the transaction as adjusted by Staff witness Bonita Pearce is in compliance with 83 Ill. Adm. Code 505, the Uniform System of Accounts for Gas Utilities Operating in Illinois, if the Commission imposes the following conditions, as set forth below:

1) Liberty shall accept the corrections to its preliminary journal entries as described in the rebuttal testimony of Staff witness Pearce (ICC Staff Exhibit 10.0, pp. 3 – 4, lines 64 – 76); and,

2) Liberty shall file the final accounting entries (with the corrections noted herein), including the actual amounts recorded by Liberty within 60 calendar days following the closing of the proposed transaction with the Chief Clerk of the Commission, with a copy of the filing to the Manager of the Accounting Department of the Commission.

The Joint Applicants have agreed to these conditions.

Additionally, Section 5-106 of the Act specifically requires that:

> Each public utility shall have an office in one of the cities, villages or incorporated towns in this State in which its property or some part thereof is located and shall keep in said office all such books, accounts, papers, records and memoranda as shall be ordered by the Commission to be kept within the State. The address of such office shall be filed with the Commission. No books, accounts, papers, records or memoranda ordered by the Commission to be kept within the State shall be at any time removed from the State, except upon such conditions as may be prescribed by the Commission.
>
> Each public utility shall be liable for, and upon proper invoice from the Commission shall promptly reimburse the Commission for, the reasonable costs and expenses associated with the audit or inspection of any books, accounts, papers, records and memoranda kept outside the State. (220 ILCS 5/5-106)

Liberty has requested approval to maintain books and records outside of Illinois and has agreed to be liable to reimburse the Commission for any reasonable costs and expenses associated with an audit or inspection of information maintained outside Illinois. Liberty indicated its financial and accounting records will be maintained in Missouri and that the files will be maintained on the Company's electronic database so that digital copies of all books and records will be available in Illinois and at the Commission's request hard copies will be made available in Illinois as well. The Applicants state that certain original source paper documents may be more efficiently maintained in locations other than Illinois. Staff does not object to the Commission granting Liberty permission to keep its books and records outside of the State of Illinois.

With regard to ICC Form 21, the Joint Applicants propose that it file two copies of ICC form 21for 2012. Joint Applicants recommended that the Commission order:

1) Atmos shall file an ICC form 21 for the period beginning January 1, 2012 and ending on the date of closing of the Asset Purchase Agreement.

2) Liberty shall file an ICC form 21 for the period beginning on the date of closing of the Asset Purchase Agreement and ending on December 31, 2012. The filing shall also include a simple consolidation of this form with Atmos' form 21.

Staff has indicated that it agrees with this proposal.

IV. CONTESTED ISSUES

It appears to the Commission that the contested issues in this docket are centered on Liberty's proposed Affiliated Service Agreements ("ASA") and Cost Allocation Manual ("CAM"). The parties appear to be in general agreement that the ASAs are necessary, and Liberty has adopted most of Staff's recommendations for changes to them. However, there remain a handful of changes recommended by Ms. Pearce that Joint Applicants allege are unduly burdensome, unsupported by the record, and not consistent with Illinois law.

A. Section 7-204(b)(2)

Section 7-204(b)(2) of the Act requires that the Commission must find that "the proposed reorganization will not result in the unjustified subsidization of non-utility activities by the utility or its customers."

1. Joint Applicants

Joint Applicants assert that no party has suggested that the transaction as a whole does not meet this requirement, and claim that Algonquin's corporate structure separates its regulated utilities and nonregulated businesses under separate

subsidiaries, providing clear separation at the corporate level, while its operating philosophy keeps costs incurred, where reasonable, at the local level. With respect to Section 7-204(b)(2), the more detailed analysis has principally focused on Liberty's ASAs and CAM.

Liberty notes that it initially submitted an ASA as Joint Applicant Exhibit F to the Application as well as a Cost Allocation Manual as Joint Applicant Exhibit I. The initial ASA was substantially in the form of the Atmos' current ASA that had previously been approved by the Commission in Docket 04-0405. Based on discussions with Staff, Joint Applicants note the initial ASA was completely rewritten with revised ASAs submitted to Staff on multiple occasions. Pursuant to recommendations by Staff that a separate affiliate agreement be in place for each entity providing services, Liberty created separate affiliate agreements for each of the four entities that will provide services to it. The four entities that will provide services to Liberty are Algonquin, LUC, Liberty Utilities, and Liberty Energy Utilities (New Hampshire) Corp ("Liberty NH"). Joint Applicants state that the latest versions of the ASAs and CAM were filed with the surrebuttal testimony of Mr. Eichler as Joint Applicant Exhibits 9.6 through 9.10.

Joint Applicants allege that the ASAs and CAM set forth all of the services to be provided under the ASAs and require costs to be allocated in a manner that is transparent, fair, and reasonable. Joint Applicants aver that the evidentiary record fully supports the required finding under Section 7-204(b)(2), noting that Mr. Eichler testified that Illinois ratepayers are fully protected from cross-subsidization because any covered transaction that involves Liberty is required to be conducted in accordance with the ASAs and CAM.

The Joint Applicants argue that the ASAs and CAM provide that Liberty will receive services from affiliated interests at the cost incurred by those affiliated interests to provide such services, and where services are provided to multiple entities, the ASAs and CAM set forth clear allocation procedures. As set forth in the CAM, Joint Applicants state that the founding principal of the Cost Allocation Manual is to "a) directly charge as much as possible to the entity that procures any specific service, and b) to ensure that inappropriate subsidization of unregulated activities by regulated activities and vice versa does not occur."

Joint Applicants opine that the services to be provided to Liberty and the manner in which those costs will be allocated are clearly set forth in the ASAs, and because Liberty's rates cannot include any of the charges under the ASAs until the Commission approves their inclusion in a rate case, Joint Applicants aver that the Commission can generally be assured that no unjust subsidization may occur. However, Joint Applicants note that there are also many checks and balances in the ASAs to both ensure that all charges under the ASAs are fair and reasonable and to ensure that the Commission will be able to exercise all necessary regulatory oversight, even prior to analysis in a rate case.

Liberty notes it has voluntarily agreed to several safeguards suggested by Staff witnesses with respect to its ASAs, including agreeing to an annual internal audit for each of the ASAs, which exceeds the biennial audit requirement imposed by Commission rules; agreeing to provide a template of all allocation percentages used to charge Liberty pursuant to each of the ASAs, which will be updated annually; and preparing a billing report summarizing the monthly charges to Liberty under each of the ASAs, which will also be filed annually pursuant to each ASA. Additionally, Liberty states that it will be conducting a full study of the cost of services provided under all the ASAs on a triennial basis. Joint Applicants argue that these safeguards provide the Commission with detailed reports and information to ensure that Liberty is in compliance with the terms of its proposed ASAs and in particular that no unjustified subsidization of nonutility activities occurs. In addition, Mr. Eichler testified that Section 2.2 of the ASAs requires each providing company to charge all recipients, regardless of whether they are a party to the ASA, according to the CAM, thereby ensuring that costs are allocated among recipient companies in the same manner.

Joint Applicants indicate that the conditions proposed by Staff, in addition to what has been agreed to, in order for the Commission to make the required findings under Section 7-204(b)(2), are as follows:

1) The Company be required to modify the ASA and CAM consistent with the proposed revisions as set forth in Attachments A through F of Staff witness Pearce's rebuttal testimony.

2) Each service provider be required to provide the Manager of Accounting of the ICC with a template of all allocation percentages used to charge Liberty pursuant to each applicable ASA. The template shall be provided within 60 days of closing the proposed transaction and shall be updated annually, with a copy provided to the Manager of Accounting no later than March 31.

3) Each service provider be required to perform an annual, rather than biennial audit that includes certain specific tests of costs allocated to Liberty pursuant to the applicable ASA.

4) Each service provider is required to conduct a full study of the cost of services provided under the applicable ASA on a triennial basis. A full study shall be required periodically to ensure that Liberty will be charged appropriately for the services it receives, with no over- or under-charging.

5) Each service provider be required to file annually by May 1 a billing report on the ICC’s e-Docket system in Docket No. 11-0559 with a copy to the ICC’s Accounting Department Manager and to the Office of the Chief Clerk of the ICC. The billing report shall

summarize the monthly charges to Liberty from its affiliated service companies under each applicable ASA.

6) Liberty, its affiliate LUC, and all of its affiliated service companies, such as Liberty Energy Utilities (New Hampshire) Corp. are prohibited from purchasing gas supply from an affiliated entity following the closing of the proposed transaction unless approval is petitioned for and granted by the Commission.

a. Condition 1: ASA and CAM

Joint Applicants allege that Staff witness Pearce has not set forth any rationale or explanation of the changes in the markups of the ASAs attached to her rebuttal testimony. Ms. Pearce flatly recommended that the Commission require changes to the ASAs, or additional ASAs, without indicating the purpose of any change, or in what way the changes would relate to the statutory provisions she cited.

Joint Applicants assert that because there is no testimony that ties any particular change to any statutory provision, the Joint Applicants (and the Commission) cannot know if Ms. Pearce believes the individual changes relate to Section 7-204(b)(2), or to some other issue (or how they relate to either). Moreover, the Joint Applicants suggest the Commission cannot know the reason why it is being asked to order changes to the proposed ASAs and CAM, based on the arguments of Staff. Joint Applicants assert that neither Section 7-101 (nor any other Section of the Act) specifically requires the suggested changes and there are no Commission rules or policies that require these changes or conditions. Where there is no legal requirement for recommendations and no evidence to support them, Joint Applicants suggest the Commission would have no basis for imposing them.

The Joint Applicants state they have made numerous changes in response to Staff requests and have in fact reflected nearly all of the changes requested by Ms. Pearce. The Joint Applicants claim to have ensured the ASAs prevent any cross-subsidization as required by Section 7-204(b)(2).

The Joint Applicants assert it has complied with condition 1 with the exception of three instances as described below.

a. That Liberty require its affiliates, LUC and Algonquin Power Company, to enter into an ASA between each other that is subject to Commission approval.

In her rebuttal testimony, Ms. Pearce recommended that the Commission require Liberty to modify the ASA and CAM consistent with the proposed revisions attached to her testimony. However, the Joint Applicants note that one of the attachments did not involve Liberty, but was rather between LUC (an indirect parent corporation of Liberty) and Algonquin Power Company ("APCo") (a sister company that is also owned by

Algonquin). To be clear, Liberty did not propose such an agreement, nor does one exist. It is unclear to the Joint Applicants how Liberty can modify an agreement that does not exist and to which it is not a party.

Joint Applicants argue that Staff has presented no evidence on its rationale for requiring such an agreement; and that Staff has simply made a declarative statement that these changes to the ASAs should be accepted. Liberty understands that Section 7-101 requires approval of transactions between it and affiliated interests. However, Joint Applicants opine that transactions between LUC and APCo are not subject to Section 7-101. Moreover, any charges to the public utility in Illinois from affiliated interests will be charged pursuant to the four draft ASAs filed by Liberty, which require cost-based charges and all necessary safeguards. Should APCo provide a service to LUC, which cost is allocated to Liberty, Liberty will be required to prove the cost was prudently incurred, which would include at a minimum providing invoices and other source documentation, just as it would with a third party vendor that provides services to LUC and whose costs are allocated to Liberty. Therefore, Joint Applicants aver there can be no unjust subsidization as a result of the relationships between LUC and APCo.

Joint Applicants opine that Staff has not identified any benefit from requiring an ASA between LUC and APCo, nor has it identified any harm that could occur from the absence of this agreement. Joint Applicants state there is no indication of what sort of transactions might be covered by such an agreement. Joint Applicants assert that the record contains no basis for requiring an agreement between these companies, and the Commission should decline to impose a requirement that LUC and APCo enter into an Agreement that is subject to Commission approval.

Joint Applicants assert that there is no justification, nor does the Act contemplate that the Commission would approve affiliate services agreements between entities that are not Illinois public utilities. Joint Applicants assert that Section 7-101, on its face, applies to transactions with a public utility rather than transactions among non-utility affiliates. Joint Applicants indicate that the Commission has previously declined to approve a proposed Services Agreement between two non-utility affiliates stating that its jurisdiction over affiliated interests is limited to their transactions with a public utility.

Liberty notes that it is seeking Commission authorization for all of the covered transactions that it plans to conduct or may plan to conduct with affiliated interests though the approval of the ASAs. Liberty acknowledges that it needs approval for transactions it conducts with affiliates or else they are of no effect in Illinois. Liberty avers it has not sought approval of Ms. Pearce's proposed ASA between LUC and APCo because Liberty is not a party to that ASA and will not receive or pay for services under that ASA. Liberty is seeking approval of an ASA with LUC, as it will receive and pay for services from LUC. Joint Applicants suggest that the ASA between Liberty and LUC contains all the safeguards mentioned elsewhere that apply to every one of the ASAs. Joint Applicants also suggest that any charges that Liberty bears for services performed for it by LUC are subject to all of the safeguards in the ASA—full support for any charges, whether directly or indirectly incurred, must be provided. Joint Applicants

assert that there should be no ASA between APCo and LUC subject to Commission approval.

b. That Liberty modify the ASAs to require Liberty to include as parties a list of additional receiving companies to the ASAs.

Joint Applicants assert the ASAs proposed by Liberty are between Liberty, (which will be, upon the closing of the proposed transaction, the Illinois public utility) and the affiliated interests that will provide certain specified services to Liberty. Joint Applicants suggest these ASAs are intended to cover all services that will be provided by an affiliated interest to the Illinois public utility. Joint Applicants indicate that Staff witness Pearce proposed changes to the ASAs that would include as parties numerous other companies that are not Illinois public utilities and that are not providing services to Liberty. Joint Applicants disagree with the inclusion of these parties, indicating that Section 7-101 does not contemplate approval of affiliate transactions that do not involve a public utility. Joint Applicants assert that Liberty is not requesting approval of these transactions, because it is not a party to them. Mr. Eichler testified that the proposed ASAs differ from certain other shared services agreements that have been approved by the Commission because Liberty's ASAs are not multidirectional. In other words, Liberty will only receive services and not provide them. Liberty understands that if it were to provide services to the various affiliates that Ms. Pearce listed on what was Schedule III to her markups of the ASAs, it would need to obtain Commission approval for those transactions (or provide them subject to an exception to Section 7-101), however Liberty has no plans to do so, therefore no such approval is required.

Joint Applicants argue Ms. Pearce did not indicate any rationale for the portion of her markup that would require Liberty to add these additional receiving companies to the ASAs. If it is merely for informational purposes, Liberty has stated that it is not opposed to informing the Commission of what entities receive similar services from companies that provide shared services to Liberty. Joint Applicants propose that this information be provided on annual basis in connection with the agreed provision of templates of allocation percentages. Liberty notes it has presented an example of the information it would provide in Joint Applicant Exhibit 9.10.

Joint Applicants urge the Commission to reject the proposal of Staff witness Pearce that the Commission require a list of other receiving companies under the CAM to be included as an exhibit to the ASA, and updated whenever the identities of receiving companies change. The Joint Applicants indicate they have presented detailed testimony on why rejecting this requirement will not result in unjustified subsidization of non-utilities activities and does not reduce the ability of the Commission to identify the costs properly included for ratemaking purposes. Mr. Eichler testified that Illinois customers are completely protected from cross subsidization because any covered transaction that involves Liberty will be required to be conducted in accordance with the ASAs and the CAM. Joint Applicants assert that the allocation methods and safeguards contained in the ASAs and CAM apply to every covered transaction pursuant to which an Illinois customer will bear a cost. Joint Applicants assert further,

that the reporting, auditing, and other obligations in the ASAs and the Commission's own powers, are more than sufficient to ensure that the Commission has the information it needs to determine that the ASAs are being complied with and that all cost allocations are made in accordance with the Commission's requirements, without requiring continual modifications to the ASAs to reflect changes in the Algonquin companies' corporate structure. Mr. Eichler testified that Section 2.2 of the ASAs makes clear that the affiliated interest providing services to Liberty is required to use the same methodology, as set forth in the CAM, to allocate costs to other affiliates, so there is no danger that different affiliates may be subject to a different cost allocation methodology.

Joint Applicants urge the Commission to reject Staff's proposed condition that the Commission require Liberty to include as parties to the ASAs entities that are not receiving services from it or providing services to it, nor to continually update a list of affiliates that are also receiving services from other affiliates. Joint Applicants state that Liberty does not object to being required to include as an informational matter, a yearly report of its affiliates that receive shared services from entities with which Liberty has an ASA.

c. That Liberty be required to modify the CAM attached to the ASAs to remove Section V.

Joint Applicants note that the markups of the ASAs and CAM proposed by Ms. Pearce in her rebuttal testimony had stricken Section V of the CAM. Joint Applicants assert that Ms. Pearce has not set forth any rationale for striking Section V, but simply declared that the markups should be required and this was part of her markup. Joint Applicants state that it may not be necessary to get into too much detail regarding Section V of the CAM, because Liberty does not intend to receive any services under that section. Joint Applicants indicate that Liberty has proposed a condition that has the same effect in Illinois as if the provision had been removed. Liberty proposes the following condition:

> Section V of the CAM shall not apply to Liberty in Illinois unless Liberty seeks Commission approval to receive specific services from identified Service Companies.

Joint Applicants assert that Staff witness Pearce did not indicate any specific objection to Section V of the CAM. Joint Applicants note that Section V permits LUC's regulated utilities to obtain services from a service company as defined in the CAM, and sets forth the manner in which charges for those services would be allocated. Mr. Eichler testified that the Joint Applicants' cannot just simply remove Section V of the CAM because although Liberty will not receive services under Section V, other utilities in jurisdictions outside of Illinois receive services under this provision.

Joint Applicants submit that although there was no indication of a reason to object to the CAM's inclusion of Section V, by eliminating its effect in Illinois the question can be rendered moot, without causing difficulties in other jurisdictions. Joint

Applicants assert that if no amounts are charged to Liberty under Section V of the CAM, it can have no effect on any subsidization or the ability to identify that costs are properly included for ratemaking purposes.

b. Condition 2: Cost Allocation Template

In response to Ms. Pearce's proposed condition, Liberty has agreed to provide an annual detailed cost allocation template. Liberty provided a sample of what the template would look like in Joint Applicant Exhibit 9.11. Ms. Pearce initially testified that she was uncertain based on the sample provided in Joint Applicant Exhibit 9.11 that 100% of all of the costs under all of the ASAs would be included in the templates. Ms. Pearce later agreed that Liberty has acknowledged that the actual annual template will need to include allocation percentages for all provider companies. The Joint Applicants believe that this fully satisfied Ms. Pearce's proposed Condition 2 on this point.

c. Condition 3: Audit Requirement

In response to Ms. Pearce's proposed condition, the Joint Applicants have agreed to conduct an annual internal audit and included this requirement in each of the ASAs attached to Mr. Eichler's surrebuttal testimony. Ms. Pearce testified that because Liberty's change to her proposed annual internal audit requirement shifted the burden to the utility instead of the providing company she was not clear whether Liberty's requirement called for a single report or an individual report for each ASA. Ms. Pearce made a clarification during cross examination that an annual internal audit of the charges under each ASA would satisfy her concerns. Section 7 of Schedule II to each of the draft ASAs proposed by Liberty requires an internal audit of the charges covered by that specific ASA, thereby satisfying her clarified concerns. Section 7-101(2) provides in pertinent part that prior to requesting "reports from the affiliated interest, the Commission shall first seek to obtain the information that would be included in such accounts, records, or reports from the public utility."

The Joint Applicants believe Condition 3 proposed by Ms. Pearce has been satisfied.

d. Condition 4: Triennial Cost Study

In response to Ms. Pearce's recommendation, Liberty agreed to conduct a triennial cost study and included this requirement in each of the ASAs attached to Mr. Eichler's surrebuttal testimony. Ms. Pearce initially testified that she had concerns with Liberty changing the burden to the utility instead of the provider. As discussed above, placing the burden on Liberty is consistent with Section 7-101(2). In cross-examination, Ms Pearce clarified that her concerns would be met if Liberty agreed to provide a cost study for the charges under each of the ASAs. Section 8 of Schedule II to each of the draft ASAs proposed by Liberty requires a cost study with respect to the charges under that ASA, thereby satisfying her clarified concern. The Joint Applicants believe that this satisfies Ms. Pearce's proposed Condition 4.

e. Condition 5: Billing Report

In response to Ms. Pearce's recommendation, the Joint Applicants have agreed to file an annual billing report summarizing the monthly charges to Liberty from the provider companies and included this requirement in each of the ASAs attached to Mr. Eichler's surrebuttal testimony. Ms. Pearce again discussed concerns that this requirement was on the utility level. However, as discussed above, this is consistent with Section 7-101(2). Ms. Pearce clarified during cross examination that if Liberty agreed to provide a billing report with respect to the charges under each of the ASAs, that would satisfy her concerns. Section 9 of Schedule II to each of the draft ASAs proposed by Liberty requires a billing report with respect to the charges under that ASA, thereby satisfying her clarified concern. The Joint Applicants believe Condition 5 proposed by Ms. Pearce has been met.

f. Condition 6: Gas Supply Purchases

The Joint Applicants submit they have also satisfied Condition 6 relating to gas supply purchases. Ms. Pearce testified during cross examination that her concern that Liberty not be allowed to purchase gas from an affiliated entity was satisfied by the inclusion of the following proposed condition in Joint Applicant Exhibit 9.1:

> Liberty is prohibited from purchasing gas supply from an affiliated entity following the closing of the proposed transaction unless approval is petitioned for and granted by the Commission or unless such approval is not required under applicable law.

The Joint Applicants opine that they have shown that there will be no unjust subsidization as a result of this transaction. Joint Applicants assert that in addition to structural separation, all covered transactions between Liberty and its affiliated interests are subject to a closely monitored, transparent ASA that operates to ensure that charges and allocations are made reasonably and in accordance with all legal requirements.

Liberty has agreed to nearly all of the recommendations proposed by Ms. Pearce with respect to the ASAs and CAM, having agreed to Conditions 2 through 6 with certain modifications, and having agreed to nearly all of the changes proposed by Ms. Pearce to the ASAs and CAM themselves with respect to Condition 1. Joint Applicants suggest that the protections incorporated into the ASAs and CAM go beyond the general rules and regulations that the Commission has imposed on utilities through rulemaking or general requirement, to safeguard the public interest in this regard. Liberty opines that it has been responsive to all of Ms. Pearce's stated concerns, and any remaining changes that were included in markups have no support in the record. Joint Applicants note the Commission can be comfortable finding that there will be no unjust subsidization as required under Section 7-204(b)(2).

Joint Applicants note that Staff's initial brief is concerned about potential cross-subsidization that could occur due to charges from APCo being indirectly allocated to Liberty through LUC. However, Joint Applicant assert that when Mr. Eichler was questioned whether there would ever be a situation where APCo provided services to another affiliate and allocated charges to that affiliate, and then some of those charges got allocated down to Liberty, Mr. Eichler said "I can't think of a situation where that would occur, no." Mr. Eichler went on to explain that assuming, however unlikely, that APCo provided a service to Algonquin, which then allocated costs to Liberty, the ASA between Liberty and Algonquin would protect the Illinois ratepayer from any cross-subsidization. Joint Applicants aver that the ASA would require Liberty to support any costs back to the genesis of the charge.

Joint Applicants allege the recordkeeping requirements of Section 2.1 of the ASAs require documentation going all the way back to the original source of costs, including invoices. Mr. Eichler testified to the backup records that Liberty maintains for all allocations and in particular that these records have been sufficient to satisfy any information request it has received from regulators. Joint Applicants indicated that Liberty has the ability to challenge allocated costs originating from APCo under any ASA. Joint Applicants also assert that other "Safeguard Conditions," meaning the conditions agreed to by the Joint applicants relating to the annual internal audit, billing report, cost allocation percentage template, triennial cost study and prohibition on purchasing gas from affiliates, are in place, which ensures the Commission has adequate access to information to prevent cross-subsidization. Joint Applicants state that any costs incurred under the ASAs must be shown to have been prudently incurred and will not be charged to any customer unless and until the Commission sees fit to approve the recovery of those costs in a rate case. Joint Applicants aver that these protections prevent unjustified subsidization without requiring an ASA between LUC and APCo, and also provide the Commission with sufficient information to determine the costs appropriately included for ratemaking purposes. Joint Applicants believe that Staff witness Pearce has never explained why she believes these ASA protections are not sufficient to protect Illinois ratepayers.

Joint Applicants indicate that Staff's assertion that Liberty is asking the Commission to "approve transactions by an unidentified Service Company" under Section V of the CAM has no support in the record. According to the Joint Applicants, Staff's Initial Brief completely ignores that the Joint Applicants have proposed a condition that Section V of the CAM shall not apply to Liberty in Illinois. Because Liberty's proposed condition does not permit it to receive services under Section V of the CAM, Staff's argument is moot.

Additionally, Joint Applicants aver that Staff's argument is based on a flawed premise, noting that the CAM has not been independently submitted for approval. Joint Applicants assert that the CAM is an attachment to specific ASAs and as such describes how costs will be allocated under those specific ASAs, and is not a stand-alone document that would authorize transaction not provided for under the ASA. Joint Applicants allege there can be no harm to the public interest or risk of cross-

subsidization by not specifically identifying the CAM service companies, because Liberty cannot be charged under Section V of the CAM.

Joint Applicants opine that beside the practical reasons for not requiring Liberty to make changes to a section of the CAM that will have no effect in Illinois, there is simply no evidence in the record to support Staff's argument. Joint Applicants allege Staff witness Pearce did not testify as to anything regarding Section V of the CAM (other than attaching a markup that deletes Section V), therefore Staff's position on the issue is without record support.

Joint Applicants also complain that Staff has chosen to wait until its Initial Brief to argue that Section V of Liberty's CAM is not in the public interest. The Commission has previously rejected the argument of a party that has failed to present any evidence and it should do so here. While Liberty has, in fact, identified the entities that are Service Companies today, there is no purpose to be served by limiting transactions under the CAM that do not affect Illinois. Because of the Joint Applicants' proposed condition, Section V has no effect in Illinois and the hypothetical effects mentioned, with no record support, in Staff's brief are not valid.

While Staff asserts that each ASA should identify all parties to the agreement, Joint Applicants assert the ASAs do identify all parties to them, with the only receiving party under the ASAs being Liberty. The only providing parties are Algonquin, LUC, Liberty Utilities Co. and Liberty Utilities (New Hampshire) Corp., each of which is the subject of a separate ASA with Liberty. These are the only transactions that the Commission is being asked to approve, not transactions between non-Illinois utilities and other non-Illinois affiliates. Joint Applicants suggest that Staff's requirement, that all parties be identified, has been satisfied. Staff's statement in its initial brief that it is not clear which entities are receiving services under the ASA besides Liberty is incorrect (and again lacks citation to any record evidence). Joint Applicants assert the ASAs are very clear and list the parties by name in the preamble.

The Joint Applicants argue they have addressed Staff's desire to know what other entities may be receiving a particular service, and Liberty has agreed to provide the identity of other entities receiving services for which cost allocations are made as part of its yearly allocation percentage report that shows the calculation used to allocate costs under each ASA to Liberty. As demonstrated on the sample Algonquin yearly allocation percentage report, submitted as Joint Applicants Exhibit 9.11, this report will show all of the entities that received services and contain all of the information necessary to ensure costs were allocated pursuant to the CAM. As stated in Mr. Eichler's surrebuttal testimony, Joint Applicants note Liberty has committed to providing a yearly allocation percentage report for each entity providing services to Liberty, i.e., Algonquin, LUC, Liberty Utilities Co., and Liberty Energy Utilities (New Hampshire) Corp.

Moreover, the Joint Applicants have demonstrated that rejecting Staff's recommendation will not result in cross subsidization or diminish the ability of the

Commission to identify the costs properly included for ratemaking purposes. The affiliated interests that provide services to Liberty pursuant to the ASAs are required to use the same methodology, as set forth in the CAM, to allocate costs to other affiliates, thereby ensuring that costs are allocated among recipient companies in the same manner. Additionally, Liberty has adopted Safeguard Conditions to prevent any cross subsidization and ensure costs can be properly identified for ratemaking purposes. Liberty asserts it has already incorporated most of the cost allocation principles proposed by Staff, albeit in different locations than proposed by Staff

Likewise, Staff proposed the following cost allocation principles be added to the CAM, but Liberty has moved portions of them to the ASA:

> Costs shall be charged to a party using either a direct charge or an allocation. Any cost allocation methodology for the assignment of corporate and affiliate costs will comply with the following principles:
>
> 1) For administrative services rendered to a rate-regulated subsidiary of LUC or each cost category subject to allocation to rate-regulated subsidiaries by LUC, LUC must be able to demonstrate that such service or cost category is reasonable for the rate-regulated subsidiary for the performance of its regulated operations, is not duplicative of administrative services already performed within the rate-regulated subsidiary, and is reasonable and prudent.
>
> 2) LUC will have in place positive time reporting systems adequate to support the allocation and assignment of costs of executives and other relevant personnel to receiving parties.
>
> 3) Parties must maintain records sufficient to specifically identify costs subject to allocation, particularly with respect to their origin. In addition, the records must be adequately supported in a manner sufficient to justify recovery of the costs in rates of rate-regulated receiving parties to this agreement to ensure that costs which would have been denied recovery in rates had such costs been directly incurred by the regulated operation are appropriately identified and segregated in the books of the regulated operation.

Specifically, Liberty has moved principle 1) to Schedule II of the ASAs and incorporated the concept of principle 3) into Section 2.1 of the ASAs. Staff has presented no evidence why any of these principles should be in the ASAs instead of the CAM (and vice versa). In fact it appears to the Joint Applicants that Staff does not understand that they are incorporated—Staff states (with no citation) that “it is not apparent that these principles are reflected in Liberty's proposed ASA and CAM, as they should be.” A simple look at the documents shows that they are. For that matter, Staff has presented no evidence or legal support as to why any of the cost allocation principles should be included at all. Staff witness Pearce simply made a declarative

statement that the proposed language should be adopted. Joint Applicants assert there is no basis in the record for requiring Liberty to place the principles in a particular location, noting any of them are binding in either the ASA or CAM, or to even to include them at all.

Staff witness Pearce proposed certain conditions to the ASAs that Joint Applicants were under the impression they had adopted. However, Staff's initial brief suggests the requirements for these conditions have not been met. Joint Applicants suggest this confusion is a consequence of Staff failing to develop a sufficient evidentiary record that clearly describes the requirements and rationale of each condition she proposed. A declarative statement that a condition is required does not provide any guidance to the Joint Applicants (or the Commission) on the requirements of a condition, particularly where there are no statutory provisions or rules mandating imposition of the condition. As a result, the Joint Applicants argue they have in good faith adopted conditions proposed by Staff, only to find out that Staff does not view a condition to be met due to a previously undisclosed reason. Despite these difficulties, the Joint Applicants believe they have met all of Staff's requirements related to safeguards.

Joint Applicants note that Liberty has agreed to conduct an annual internal audit and included this requirement in each of the ASAs, and while Staff noted a concern that the requirement is on the utility level, Joint Applicants allege Staff has not presented evidence that it will be unable to obtain sufficient records or reports from Liberty. Under the Commission's own biennial internal audit requirement, Rule 506 places the burden on the public utility. Ms. Pearce made a clarification during cross examination that an annual internal audit of the charges under each ASA would satisfy her concerns about the requirement being placed on the utility level. Joint Applicants assert Section 7 of Schedule II to each of the draft ASAs proposed by Liberty requires an internal audit of the charges covered by that specific ASA, thereby satisfying Staff's clarified concerns. The Joint Applicants believe they fulfilled Staff's recommendation for an annual internal audit based on the clarification of Ms. Pearce and statutory authority.

In response to Ms. Pearce's recommendation regarding billing reports, the Joint Applicants have agreed to file an annual billing report summarizing the monthly charges to Liberty from the provider companies and included this requirement in each of the ASAs. Joint Applicants note that Ms. Pearce discussed concerns that this requirement was on the utility level, but did not present evidence that the information could not be provided by Liberty. Joint Applicants indicate that placing the requirement on the utility level is consistent with Section 7-101(2). Ms. Pearce clarified during cross examination that if Liberty agreed to provide a billing report with respect to the charges under each of the ASAs, that would satisfy her concerns about the requirement being placed on the utility level. Joint Applicants state that Section 9 of Schedule II to each of the draft ASAs proposed by Liberty requires a billing report with respect to the charges under that ASA, thereby satisfying her clarified concern. Based on statutory authority and the clarifications of Ms. Pearce, the Joint Applicants believe this condition has been met.

Joint Applicants note that Liberty agreed to conduct a triennial cost study and included this requirement in each of the ASAs attached to Mr. Eichler's surrebuttal testimony. Ms. Pearce initially testified that she had concerns with Liberty changing the burden to the utility instead of the provider, but has not presented evidence that Liberty will be unable to provide the study. As discussed above, placing the burden on Liberty is consistent with Section 7-101(2). In cross-examination, Ms Pearce clarified that her concerns about the requirement being placed on the utility level would be met if Liberty agreed to provide a cost study for the charges under each of the ASAs. Section 8 of Schedule II to each of the draft ASAs proposed by Liberty requires a cost study with respect to the charges under that ASA. Accordingly, the Joint Applicants believe they have satisfied the requirement that the ASAs provide a cost study based on statutory authority and by meeting Staff's clarification.

In response to Ms. Pearce's proposed condition regarding a cost allocation percentage template, Liberty has agreed to provide an annual detailed cost allocation percentage template. Ms. Pearce testified that she was uncertain based on the sample provided in Joint Applicant Exhibit 9.11 that 100% of all of the costs under all of the ASAs would be included in the templates. Ms. Pearce later agreed that Liberty has acknowledged that the actual annual cost allocation percentage template will need to include allocation percentages for all provider companies. Liberty confirms that all costs allocated to Liberty under each ASA will be included in the ASA reports, and the reports will show how these costs were spread amongst all the other affiliates as well. Accordingly, the Joint Applicants believe they have satisfied Staff's condition requiring an annual allocation percentage template.

It is uncontested that Joint Applicants' proposed condition prohibits Liberty from purchasing gas from an affiliate without Commission approval or exemption under applicable law. Liberty also notes it has not requested approval to purchase gas from any affiliates. Therefore, the Joint Applicants' proposed condition prohibits purchase of gas from affiliates to the extent not allowed by Section 7-101. It is not clear to the Joint Applicants what Staff's remaining concerns about cross-subsidization are. Staff witness Pearce's rebuttal testimony offers no guidance because it merely listed a proposed condition with no rationale provided. Staff imputes a concern of cross-subsidization in its Initial Brief but that concern was not actually expressed in the testimony with respect to this requirement. Similarly, Ms. Pearce gave no indication of any concerns with the Joint Applicants' proposed condition during cross examination. She agreed that this condition would satisfy her concerns on this point.

Joint Applicants contend that Staff's Initial Brief contradicts Ms. Pearce's testimony, indicating in the brief that Liberty had not adopted the condition exactly as described by Ms. Pearce in her rebuttal testimony. This is true, but Ms. Pearce was aware of this when she testified on cross-examination that the proposed condition was acceptable. Joint Applicants are unclear as to the reason for this disagreement; however believe it may be that Staff believes that Commission jurisdiction should extend to non-Illinois utilities' purchases of gas. To the extent that this addresses Staff's concerns, Liberty is willing to extend the prohibition to state that neither Liberty, LUC nor

Liberty Energy (New Hampshire) will purchase gas from an affiliated interest of Liberty to serve Illinois customers without Commission approval or unless such approval is not required under applicable law.

While Staff is also suggesting an additional Section 7-101 petition be required, Joint Applicants argue it is not necessary, and there is also no record basis for requiring an additional Section 7-101 petition to consider the effectiveness of the ASAs approved in this proceeding. Joint Applicants complain that Staff argues in its Initial Brief for the first time that its proposed additional Section 7-101 petition is necessary to prevent cross-subsidization under Section 7-204(b)(2), however the Joint Applicants note there is no record evidence that ties the additional Section 7-101 petition to Section 7-204(b)(2) of the Act. Although Staff witness Pearce has testified that an additional 7-101 proceeding should be required under Section 7-204(b)(3), there is no explanation as to how such a proceeding would actually meet the requirements of Section 7-204(b)(3).

Joint Applicants argue that the suggestion that another Section 7-101 petition be required, whether under Section 7-204(b)(2) or Section 7-204(b)(3), or Section 7-101, is not supported by the law, nor has Staff demonstrated any basis for the Commission to implement the requirement. Section 7-101 does not require an additional proceeding, and contemplates approving agreements on a prospective basis. Joint Applicants aver that Staff has not presented any precedent of the Commission ever conditioning approval of an ASA with the requirement that a utility come in for an additional 7-101 hearing to evaluate the effectiveness of an agreement.

While Staff suggests this second petition is necessary because Liberty has not accepted Staff's proposed revisions to the ASAs and CAM and Liberty has not accepted Staff's Safeguard Conditions or all of Staff's proposed revisions to the ASAs and CAM, Joint Applicants assert the revisions are inconsistent with the Act, have no record support, and are not necessary to allow the Commission to approve the transaction or the ASAs and CAM. Accordingly, these revisions are not a basis to require an additional 7-101 petition.

2. Staff

Staff indicates that it is unable to recommend that the Commission make the finding pursuant to Section 7-204(b)(2) based on the Joint Applicants' proposal and, therefore, recommends the Commission deny approval of the proposed reorganization. Staff suggests that the reason that Algonquin seeks to acquire the utility operations of Atmos is to subsidize the unregulated operations held by Algonquin, including APCo. Staff has identified what changes it recommends to be made in the ASAs and CAM and offered the revised ASAs and CAM in its rebuttal testimony. Staff asserts that Liberty did not adopt those changes and instead offered new revised ASAs and CAM in its surrebuttal testimony. Staff indicates that if the intent of acquiring the regulated gas utility operations of Atmos was not to subsidize the unregulated operations of APCo, Liberty should have adopted the ASAs and CAM offered by Staff.

Staff recommends that in the event the Commission does approve the reorganization, the Commission should impose certain conditions to ensure that the proposed reorganization will not result in the unjustified subsidization of non-utility activities by the utility or its customers, as required by Section 7-204(b((2) of the Act. Staff believes that the Joint Applicants did not accept all of Staff's proposed conditions, and suggests that many of the suggested conditions are relevant to more than one finding that the Commission would need to make in order to approve the proposed reorganization. The discussion of each of Staff's proposed conditions will follow the presentation of the various findings that the Commission is required to make.

> Condition 1) Liberty will accept the proposed revisions to the Affiliated Service Agreements ("ASA") and Cost Allocation Manual ("CAM") as set forth in ICC Staff Exhibit 10.0, Attachments A through F.

According to the surrebuttal testimony of Mr. Eichler, some of Staff's revisions to the ASA and CAM were accepted, but not all. Additionally, Staff notes the revised ASAs included with Mr. Eichler's surrebuttal testimony did not start with Staff's proposed documents from ICC Staff Exhibit 10.0, Attachments A through F, and reflect Liberty's changes in blackline. Because Liberty failed to provide blackline versions of its latest proposed ASAs and CAM, and because some of Staff's proposed revisions were accepted by Liberty but reflected in a different section of the ASA or CAM, Staff complains it was difficult to identify and describe all the differences between Staff's proposed versions and those provided by Liberty in surrebuttal testimony. Therefore, Staff suggests it is limited to discussing the more significant differences between the ASAs proposed by Staff in its rebuttal testimony, and the ASAs proposed by the Joint Applicants.

Staff states that the most significant of Staff's revisions that Liberty did not accept include the following:

a) There should be an ASA for the services provided by APCo;

b) The CAM should clearly identify the "Service Companies";

c) Each ASA should identify all parties to the agreement;

d) The principles of cost allocation should be incorporated into the ASAs; and

e) The principles of cost allocation should also be incorporated into the CAM.

Staff asserts that a separate ASA is necessary for each entity that provides services to affiliates that result in charges being billed to Liberty. Staff notes the surrebuttal testimony of Mr. Eichler did not include a proposed ASA between APCo and

LUC, as proposed by Staff. Staff notes that APCo is a holding company as defined by FERC, and is the parent company for the unregulated operations of Algonquin.

Staff notes that the proposed CAM states:

> "From time to time, APCo may provide Engineering and Technical Labor to Liberty Utilities. These charges plus an allocation for corporate overheads such as rent, materials, supplies, etc. are capitalized and directly charged to the relevant utility."

Staff avers that charges plus an allocation for corporate overheads would be directly charged to the "relevant utility" which would include the regulated operations of Liberty. Thus, Staff asserts that charges from the unregulated operations of APCo would be billed to the Illinois regulated operations of Liberty without safeguards to insure that Liberty did not subsidize the unregulated operations of APCo. In addition, Staff notes the CAM does not state how the allocation for corporate overheads would be derived. By including this language in the CAM, Liberty is asking the Commission to approve transactions between the unregulated operations and the regulated operations without providing any indication as to how those charges would be determined or under what conditions those services would be provided. Without an ASA that sets forth the parameters of the transactions that would be approved by the Commission, Staff opines that the Commission is unable to safeguard the public interest as required by Section 7-101(3) of the Act.

Staff states that during cross-examination of Liberty witness Eichler, he was asked if the CAM provides that APCo may provide engineering and technical labor to LUC and he agreed that it does. Mr. Eichler was also asked if that section of the CAM states "These charges plus an allocation for corporate overhead such as rent, materials, supplies, etc. are capitalized and directly charged to the relevant utility" and he answered yes. Staff states Mr. Eichler was also asked if the Joint Applicants had sought approval for an ASA for charges from APCo to LUC and he affirmed they had not, because those are two Canadian companies that are non-utilities. When Mr. Eichler was asked to confirm if that is the reason the Joint Applicants did not request approval of an ASA for these transactions, he indicates that as well as being Canadian companies, neither of those is a public utility, so for that reason, Joint Applicants didn't believe that approval is required.

In addition, Staff states the surrebuttal testimony of Mr. Eichler did not include an ASA for the provision of services by LUC to Algonquin and APCo, noting that LUC is the parent of Liberty Utilities which indirectly owns Liberty. Moreover, through the CAM, Staff suggests LUC provides many services to Liberty, which Staff states Mr. Eichler confirmed during cross examination.

Staff indicates Liberty's proposed CAM states that LUC provides informational technology and some human resource services to APCo and Algonquin and directly charges costs for these services to APCo and Algonquin. However, when Mr. Eichler

was asked during cross-examination if Liberty provided an ASA that seeks approval for charges from LUC to the ultimate parent Algonquin and its affiliates, he answered, “No. Again, that was deemed non-utility and we did not seek approvals for that”.

Staff witness Pearce expressed concerns that the ASAs provided by Liberty would not be sufficient to protect Illinois ratepayers from potential cross-subsidization that could occur because of the organization of some affiliates, whereby services and their related costs might be charged by one of the affiliates to another affiliate who would then allocate those costs to the Illinois utility, and those costs would not be covered by an ASA or readily identified at the utility level.

Staff opines that the proposed CAM also refers to services by a generic "Service Company" that has not been identified within the CAM and for which Liberty has not submitted an ASA setting forth the method of cost allocations or the manner in which costs will be charged to the entities receiving service. By the inclusion of the following statement in the CAM, Staff suggests Liberty is requesting that the Commission approve future transactions without allowing the Commission to put appropriate safeguards to protect the public interest as required by Section 7-101 of the Act in place:

> Some of LUC’s regulated utilities may receive services such as: billing and customer service; operations and engineering; environment, health and safety, and security; finance information technology; regulatory; legal; and administrative services, e.g., rent, insurance, and office services, from a Service Company.

In response to questions under cross examination of Mr. Eichler, Liberty filed Exhibit 12.0, attached to its Initial Brief as Attachment C, which identified the Service Companies referred to in the CAM. However, Staff argues the information in this document has not been incorporated into the CAM or any of the applicable ASAs. Further, Staff notes the identification of a generic “Service Company” in the CAM is not limited by the filed Exhibit 12.0, so unless the generic “Service Company” is identified in the CAM, Staff argues the Commission is being asked to approve transactions by an unidentified Service Company.

Staff asserts that each ASA should identify all parties to the agreement, and that those parties should be listed on a Schedule of each ASA. Staff states that Liberty did not incorporate Staff’s proposal that all parties to the agreement be identified in each of the ASAs; therefore, it is not clear to Staff which entities are receiving services, other than Liberty, under each ASA. Staff indicates that having all parties that receive services from the entity providing services listed in the ASA is Staff’s remedy to identifying all affiliates who could receive services from the providing entity under each respective ASA. Absent a list in the ASA or something comparable, Staff argues that the Commission will not know what other affiliates besides Liberty are receiving services from each entity, making it impossible to prevent cross-subsidization.

Staff notes that LUC provides services to entities other than Liberty, but that provision of services is not considered in the ASA for LUC as proposed by Liberty. By the inclusion of this statement in the CAM that these services may be provided, Liberty is requesting the Commission's approval of the transactions for which the Commission knows nothing about how the costs would be allocated to the unregulated entities receiving services. Staff contends the Commission cannot safeguard the public interest as required by Section 7-204 of the Act to insure that the unregulated operations do not subsidize the regulated operations without those transactions also being considered in the ASA.

Staff argues further that the principles of cost allocation should be incorporated into the ASAs, noting that the following language that sets forth the principles of cost allocation found in Section B. of the Illinois Rider should be incorporated into the ASAs, as exemplified in ICC Staff Exhibit 10.0, Attachments A and C through F:

> B. The following bases for charges shall apply to transactions entered into pursuant to the ASA:
>
> i. Costs charged and allocated pursuant to the ASA shall include direct labor, direct materials, direct purchased services associated with the related asset or services, and overhead amounts.
>
> ii. Tariffed rates or other pricing mechanisms established by rate setting authorities shall be used to provide all regulated services.
>
> iii. Services not covered by (ii) shall be charged by the providing party to the receiving party at fully distributed cost.
>
> iv. For facilities and administrative services rendered to a rate-regulated subsidiary of the Service Company, parties shall charge for services on the following basis:
>
> Services provided to a rate-regulated subsidiary of Service Company by another party shall be charged by the providing party to the receiving party at:
>
> (1) the prevailing price for which the service is provided for sale to the general public by the providing party (i.e., the price charged to non-affiliates if such transactions with non-affiliates constitute a substantial portion of the providing party's total revenues from such transactions) or, if no such prevailing price exists,
>
> (2) an amount not to exceed the fully distributed cost (determined as provided in the CAM) incurred by the providing party in providing such service to the receiving party.

Staff opines that this language sets forth the basis for affiliate charges, as necessary to prevent cross-subsidization between regulated and unregulated utilities, as well as cross-subsidization between regulated utilities. Staff indicates it is not apparent that these principles are reflected in the proposed ASAs and CAM, as they should be. In order for there to be no cross subsidization, all services provided by the entity must be subject to the same cost allocation principles, not just the Illinois regulated utility operations.

Staff suggests that the language below that sets forth the principles of cost allocation should also be incorporated into the CAM as reflected in Staff's proposed revisions to Sections III through V of the CAM. Staff Exhibit 10.0, Attachment B, Section III, items 2 and 3 contain principles for cost allocation to support identification of cost origin and support for the allocation method, as well as identification to prevent recovery of allocated costs that would not be recoverable in rates if they were directly charged to the entity. Staff states that in order for there to be no cross-subsidization, all costs charged by the entity providing the services must be subject to the same cost allocation principles, and not just apply to the Illinois regulated utility operations. Staff notes the language below is only adapted for LUC and would need to be adapted for each service provider.

> Costs shall be charged to a party using either a direct charge or an allocation. Any cost allocation methodology for the assignment of corporate and affiliate costs will comply with the following principles:
>
> 1) For administrative services rendered to a rate-regulated subsidiary of LUC or each cost category subject to allocation to rate-regulated subsidiaries by LUC, LUC must be able to demonstrate that such service or cost category is reasonable for the rate-regulated subsidiary for the performance of its regulated operations, is not duplicative of administrative services already performed within the rate-regulated subsidiary, and is reasonable and prudent.
>
> 2) LUC will have in place positive time reporting systems adequate to support the allocation and assignment of costs of executives and other relevant personnel to receiving parties.
>
> 3) Parties must maintain records sufficient to specifically identify costs subject to allocation, particularly with respect to their origin. In addition, the records must be adequately supported in a manner sufficient to justify recovery of the costs in rates of rate-regulated receiving parties to this agreement to ensure that costs which would have been denied recovery in rates had such costs been directly incurred by the regulated operation are appropriately identified and segregated in the books of the regulated operation.

> Condition 2) Each service provider must provide the Manager of Accounting of the ICC with a template of all allocation percentages used to charge costs to Liberty pursuant to each applicable ASA. Specifically, each template should account for 100% of each cost category being allocated, including the respective percentages allocated to other affiliates, as well as Liberty. The template should be provided within 60 days of closing the proposed transaction and should be updated annually, with a copy provided to the Manager of Accounting no later than March 31.

It appears to Staff that the Joint Applicants accepted Staff's proposed condition, provided that the obligation would be on the utility, not the entity providing services to Liberty. Staff indicates it is unsure whether Liberty' proposal to provide a template of all the allocation percentages used to charge Liberty pursuant to each of the ASAs is satisfactory, with Staff expressing the concern that Staff would want to see for each service provider the costs that are being allocated to the utility, and how those were spread amongst all the other affiliates as well. Staff also expressed a desire to see how all the costs were being allocated, that they would comprise the portion that was flowing down to the regulated utility, not just the calculation of the percentage that went to the utility. In response to questioning, Staff witness Pearce indicated that she would want to know that 100 percent of all the costs and how they are being charged to all the affiliates according to all the ASA would be included on the templates, and based on her review of Joint Applicants Exhibit 9.11, she indicated that it was not clear to her that this is the case.

> Condition 3) Each service provider must perform an annual internal audit of compliance with the ASA that includes tests of costs allocated to Liberty pursuant to the applicable ASA, including compliance with the processes outlined in the ASA and including a review of the allocation factors and the calculation of each to verify that they are updated and calculated in accordance with the respective ASA., as stated in the Illinois Rider attached to the ASA.

According to the surrebuttal testimony of Mr. Peter Eichler, Liberty accepted Staff's proposed condition, provided that the obligation would be on the utility, not the entity providing services to Liberty. During cross-examination, Staff witness Pearce was referred to Joint Applicants Exhibit 9.7, the Illinois Rider, and in particular to paragraph 7 thereof, which requires an internal audit of the charges covered by the ASA during the preceding calendar year to be provided to the Manager of the Accounting Department of the Commission no later that July 1 of each calendar year. Staff witness Pearce indicated concerns that the annual internal audit would need to be conducted by the entity that provided the services, not the utility that received the service. In that way, the charges being allocated down to the utility could be audited. Ms. Pearce further indicated that the annual internal audit should be performed on the charges under each of the ASAs.

> Condition 4) Each service provider must conduct a full study of the cost of services provided under the applicable ASA on a triennial basis. Staff claims that a full study is necessary periodically to ensure that Liberty will be charged appropriately for the services it receives, with no over- or under-charging. The cost of services study shall be provided to the Accounting Department Manager no later than July 1 of the year following the initial three-year period, according to provisions of the Illinois Rider attached to the ASA.

According to the surrebuttal testimony of Mr. Peter Eichler, Liberty accepted Staff's proposed condition, provided that the obligation would be on the utility, not the entity providing services to Liberty. During cross-examination, Staff witness Pearce was asked if that would satisfy her concerns on the point of triennial cost studies. Staff states Ms. Pearce clarified that the obligation should rest with the entity providing the services, to ensure that the allocators are reasonable for the portion that's going to the Illinois utility. Upon further questioning, Staff notes Ms. Pearce agreed that a cost study for the charges under each of the ASAs would address her concerns.

> Condition 5) Each service provider must file annually by May 1 a billing report on the ICC's e-Docket system in Docket No. 11-0559 with a copy to the Commission's Accounting Department Manager and to the Office of the Chief Clerk of the Commission, and the billing report should summarize the monthly charges billed to Liberty and each of the affiliated companies by each service provider under the applicable ASA.

Staff notes that according to the surrebuttal testimony of Mr. Peter Eichler, Liberty accepted Staff's proposed condition, provided that the obligation would be on the utility, not the entity providing services to Liberty. During cross-examination, Staff witness Pearce was asked if that would satisfy her recommendation that the utility provide a billing report to the Commission. She clarified that the obligation should rest with the entity providing the services, to ensure that the allocators are reasonable for the portion that's going to the Illinois utility. Upon further questioning, she agreed that a billing report with respect to the charges under each of the ASAs would address her concerns.

> Condition 6) The Commission enter as a condition of approval of the reorganization that neither Liberty nor its affiliate LUC nor any of its affiliated service companies, such as Liberty Energy Utilities (New Hampshire) Corp. ("Liberty New Hampshire") may purchase gas supply from an affiliated entity following the closing of the proposed transaction without petitioning the Commission for authority.

According to the surrebuttal testimony of Mr. Peter Eichler, Liberty agreed that it is prohibited from purchasing gas supply from an affiliated entity following closing of the proposed transaction, unless such approval is not required under applicable law. During cross-examination, Staff witness Pearce was asked if that condition would

satisfy her concerns that Liberty not be allowed to procure gas supply from an affiliated entity without approval and she indicated it would.

However, Staff states that its proposed condition would also prohibit affiliates of Liberty, including LUC and Liberty New Hampshire from purchasing gas supply from an affiliated entity, therefore Staff believes its concerns regarding potential cross-subsidization through gas purchases from an affiliate of Liberty has not been fully addressed by Liberty's condition. Staff indicates that further confusion as to Liberty's response to this condition results from the Joint Applicants indicating in Exhibit 9.2 which indicates that this provision was "Accepted with clarification that the condition applies to the extent prohibited by applicable law." Based on the fact that Liberty did not accept Staff's proposed condition, as referenced in the rebuttal testimony of Staff witness Pearce, it is Staff's view that this condition has not been accepted.

> Condition 7) That the Commission direct that Algonquin and its affiliates should be required to submit a petition under Section 7-101 of the Act for the Commission to consider the effectiveness of the ASAs approved in this proceeding prior to filing any request for an increase in rates, but in any case no later than September 30 of the year following the first full calendar year subsequent to closing the proposed transaction. Staff states the petition should indicate the costs recovered from Liberty for each accumulated calendar year through each ASA, and the allocated common costs from each service provider should be supported by exemplar allocation percentages for each service provided and must include all allocation percentages to the various entities to account for 100% of the allocated costs. The direct charges to the various affiliates billed by each service company should also be included. After reviewing the results, the Commission may consider modifications to the ASAs.

Staff notes that Liberty does not accept this condition, because in Liberty's view, such a requirement would be unduly burdensome, particularly where the Commission retains all of its oversight powers over Liberty and where additional reporting and other conditions provide the Commission with additional access to information regarding the costs incurred by Liberty.

Staff supports this condition because Liberty did not accept Staff's proposed revisions to the CAM and ASAs, and because Liberty did not accept Staff's conditions regarding the internal audit; annual billing report; cost allocation template; and triennial cost of service study. Instead, Staff notes, Liberty modified Staff's proposed conditions to place the obligation on the utility, not on the affiliated entity providing the services pursuant to the respective ASA.

Staff believes this condition is necessary, mainly because Liberty did not accept all of Staff's proposed conditions to preclude potential cross-subsidization, especially Staff's proposed revisions to the CAM and ASA set forth in ICC Staff Exhibit 10.0, Attachments A through F. Staff argues the ultimate parent of Liberty, Algonquin, has an

organization structure which includes various levels of service providers and affiliates who may provide services for which Liberty ultimately is charged, either directly or indirectly. Staff notes the CAM and ASAs proposed in Staff Exhibit 10.0, Attachments A through F, may not include all the necessary provisions to preclude potential cross-subsidization. As Staff witness Pearce indicated during cross-examination, her intent with this recommendation is to allow the Commission to consider the effectiveness of the ASAs approved in this proceeding prior to the filing of a request for an increase in rates. Ms. Pearce acknowledged that even though there might be an approved ASA in place, the Commission is not obligated to allow recovery of any charges for ratemaking purposes, but this condition would provide an opportunity to assess if everything that's approved in this proceeding effectively protects the Illinois ratepayers.

B. Section 7-204(b)(3)

Section 7-204(b)(3) of the Act requires that the Commission must find that "the costs and facilities are fairly and reasonably allocated between utility and non-utility activities in such a manner that the Commission may identify those costs and facilities which are properly included by the utility for ratemaking purposes."

1. Joint Applicants

Joint Applicants suggest that the evidence in the record demonstrates that the requirements of 7-204(b)(3) have been met. Joint Applicants indicate that Liberty is focused on providing utility services; non-utility services are generally provided by separate subsidiaries, which provides for a clear separation at a basic corporate level. Additionally, Joint Applicants suggest that the emphasis on local presence that Liberty is proposing results in improved regulatory transparency. Joint Applicants claim that local emphasis increases the extent to which rates are based on costs incurred primarily at the local level and therefore these costs are more readily identifiable with the services provided. Lastly, Joint Applicants state that in accordance with Illinois law, transactions between the utility and the non-utility affiliated interests are subject to considerable regulatory oversight and statutory requirements. Liberty states it has demonstrated its ability to meet those requirements by proposing ASAs that not only comply with all applicable rules, but also include numerous mechanisms beyond those required by the Commission or the Act, to ensure transparency and fairness.

In addition to the Commission's existing requirements on utilities generally, Joint Applicants note Liberty has included requirements for an annual internal audit, monthly billing summaries, templates of costs and triennial cost studies. Joint Applicants aver these mechanisms provide the Commission with a wealth of information even in advance of any ratemaking proceeding. Additionally, Joint Applicants state Section 2.1 of the ASAs details significant recordkeeping requirements taken from language proposed by Ms. Pearce. Joint Applicants note that Section 2.1 requires records to be maintained for each department and division of the Provider Company in order to accumulate all costs of doing business and to determine the cost of service. Joint Applicants suggest these costs include wages and salaries of employees and related

expenses such as insurance, taxes, pensions, and other employee welfare expenses, rent, light, heat, telephone, supplies, and other housekeeping costs. Joint Applicants note that Mr. Eichler testified that in the other jurisdictions where Algonquin's subsidiaries operate it has been able to respond to all requests for information regarding affiliate transactions. Joint Applicants opine that Mr. Eichler testified to the level of detailed information found in Algonquin's records related to cost allocations, including the date of a transaction, a description of the transaction, the amount, and invoices.

Joint Applicants note that the Commission must approve any allocations before they have an effect on rates in the context of a rate case, where Liberty will have the responsibility to prove that its costs were prudently incurred and reasonably allocated before recovering them.

Joint Applicants note that Staff has recommended that the Commission make the required Section 7-204(b)(3) finding provided that the following conditions are imposed:

1) The Company is required to modify the ASA and CAM consistent with Staffs proposed revisions as set forth in Attachments A through F.

2) Liberty is required to provide the Manager of Accounting of the ICC with a template of all allocation percentages used to charge Liberty pursuant to the ASA. The template shall be provided within 60 days of closing the proposed transaction and shall be updated annually, with a copy provided to the Manager of Accounting no later than March 31.

3) Each service provider is required to perform an annual, rather than biennial audit that includes certain specific tests of costs allocated to Liberty pursuant to the applicable ASA.

4) Each service provider is required to conduct a full study of the cost of services provided under the applicable ASA on a triennial basis. A full study is required periodically to ensure that Liberty will be charged appropriately for the services it receives, with no over- or under-charging.

5) Each service provider is required to file annually by May 1 a billing report on the ICC's e-Docket system in Docket No. 11-0559 with a copy to the ICC's Accounting Department Manager and to the Office of the Chief Clerk of the ICC. The billing report shall summarize the monthly charges to Liberty from its affiliated service companies under each applicable ASA.

6) Algonquin and its affiliates are required to submit a petition under Section 7-101 of the Act for the Commission to consider the

> effectiveness of the ASAs approved in this proceeding prior to filing any request for an increase in rates, but in any case no later than September 30 of the year following the first full calendar year subsequent to closing the proposed transaction. The petition shall indicate the costs recovered from Liberty for each accumulated calendar year through each ASA. The allocated common costs shall be supported by exemplar allocation percentages for each service provided and must include all allocation percentages to account for 100% of the allocated costs; the direct charges to the various affiliates billed by each service company shall also be included. After reviewing the results, the Commission may consider modifications to the ASAs.

With the exception of condition 6, Liberty opines that the conditions proposed by Staff are the same as the conditions proposed by Staff with respect to Section 7-204(b)(2). To briefly recap the Joint Applicants' position on these conditions, the Joint Applicants have agreed to most of changes suggested by Ms. Pearce in condition 1. The Joint Applicants believe they have satisfied condition 2 regarding a cost allocation template, condition 3 regarding an audit, condition 4 regarding a cost study, and condition 5 regarding a billing report.

The Joint Applicants disagree with condition 6, and also continue to disagree with certain changes recommended in condition 1.

Joint Applicants argue that Staff has not set forth any rationale or explanation of the changes in the markups of the ASA and CAM, so there is no clear indication that they are actually tied to Section 7-204(b)(3), or in what way they may relate to Section 7-204(b)(3). Furthermore, Joint Applicants aver that there is no indication how any of the provisions in the ASAs proposed by Liberty would affect Section 7-204(b)(3), or even whether any individual change does affect that Section. As was the case with Section 7-204(b)(2), the Joint Applicants have addressed the concerns Ms. Pearce stated in her testimony and more importantly have ensured that the ASAs and CAM comply with Section 7-204(b)(3) by providing transparency on how costs will be allocated.

Joint Applicants note that Staff proposed a requirement without stating any basis for the Commission to implement the requirement, by recommending that the Commission order Algonquin and its affiliates to submit a petition under Section 7-101 to consider the effectiveness of the ASAs approved in this proceeding.

The Joint Applicants note they are seeking approval of the ASAs under Section 7-101 in this proceeding, and have amply demonstrated that this approval is warranted. As indicated, these ASAs and the associated conditions include numerous safeguards and oversight mechanisms that go beyond the requirements that the Commission and Illinois law imposes on public utilities generally. Joint Applicants aver that these safeguards provide the Commission with the necessary information to evaluate the

effectiveness of the ASAs, particularly where the Commission retains all oversight powers over Liberty. Joint Applicants suggest that even Staff witness Pearce acknowledged that the Commission has many other mechanisms in place to modify or revoke an ineffective ASA. Given all of these controls, informational requirements, and mechanisms, Joint Applicants argue it is wasteful to require a second proceeding to evaluate an agreement that has already been approved.

Moreover, Joint Applicants argue that Section 7-101 applies to proceedings to approve an agreement on a prospective basis, and does not contemplate multiple approvals of the same agreement, nor does it contain standards for a post-agreement review of transactions under approved agreements. Joint Applicants suggest this would be an altogether new type of proceeding under an inapplicable statute.

Joint Applicants assert that Staff has presented no evidence describing why this condition should be imposed or what potential harm could occur it if were rejected. Additionally, Joint Applicants note that Staff witness Pearce was unable to identify another instance where such a condition has been imposed. With no evidence to support a need for this new proceeding, and no statutory basis for its conduct, Joint Applicants suggest the Commission should not include this requirement. This is particularly true where, as here, the utility has voluntarily exceeded the Commission's requirements to ensure its ability to evaluate the effectiveness of the ASAs.

The Joint Applicants submit that they have shown that costs and facilities are fairly and reasonably allocated between the utility and non-utility activities in such a manner that the Commission may identify those costs and facilities which are properly included by the utility for ratemaking purposes, as required by Section 7-204(b)(3). In addition to structural separation and philosophy of local control, all covered transactions between Liberty and its affiliated interests are subject to a closely monitored, transparent ASA that operates to ensure that charges and allocations are made reasonably and in accordance with all legal requirements.

In addition, Joint Applicants suggest it has agreed to nearly all of the recommendations proposed by Ms. Pearce with respect to the ASAs and CAM, having agreed to conditions 2) through 5) on this point with certain modifications, and having agreed to nearly all of the changes proposed by Ms. Pearce to the ASAs and CAM themselves with respect to condition 1). Joint Applicants opine that the protections incorporated into the ASAs and CAM go beyond the general rules and regulations that the Commission has imposed on utilities through rulemaking or general requirement, to safeguard the public interest in this regard. Liberty has been responsive to all of Ms. Pearce's stated concerns, and her remaining recommendations included in markups, as well as the requirement for a new Section 7-101 proceeding, have no support in the record or law.

Joint Applicants complain that Staff's initial brief presents no evidence regarding the requirements of Section 7-204(b)(3) other than a statement that it cannot make the required finding. While Staff refers to its discussion regarding Section 7-204(b)(2), it's

Initial Brief makes no mention of how that discussion relates to the standards of Section 7-204(b)(3), if at all. Joint Applicants, however, have presented a wealth of information demonstrating that "costs and facilities are fairly and reasonably allocated between the utility and non-utility activities in such a manner that the Commission may identify those costs and facilities which are properly included by the utility for ratemaking purposes."

Joint Applicants argue that Liberty has a clear separation on the corporate level from non-utilities, which operate out of separate subsidiaries, noting that Liberty's focus on local emphasis increases the extent to which rates are based on costs incurred primarily at the local level and therefore these costs are more readily identifiable with the services provided. In addition to the Commission's existing requirements on utilities generally, Joint Applicants suggest it has also included the "Safeguard Conditions" described earlier. Joint Applicants note the ASAs and CAM contain detailed requirements for cost allocation, as well as record-keeping and reporting that allow for easy identification and separation of costs. Joint Applicants suggest all of these provide the Commission with an abundance of information for a rate proceeding. Joint Applicants opine that Mr. Eichler testified to the level of detailed information found in Algonquin's records related to cost allocations, including the date of a transaction, a description of the transaction, the amount, and invoices, and state that nothing in Staff's initial brief addresses any alleged failures by the Joint Applicants to meet the Section 7-204(b)(3) requirements.

2. Staff

Staff indicates it is unable to recommend the Commission make the finding pursuant to Section 7-204(b)(3) based on the Joint Applicants' proposal and, therefore, recommends the Commission deny approval of the proposed reorganization. In the event the Commission does approve the reorganization, Staff recommends that the Commission impose certain conditions as set forth earlier in order to make this finding.

Staff reasserts its earlier arguments in support of its position of Section 7-204(b)(3).

C. Section 7-204(b)(5)

Section 7-204(b)(5) of the Act requires the Commission must find that "the utility will remain subject to all applicable laws, regulations, rules, decisions and policies governing the regulation of Illinois public utilities."

1. Joint Applicants

Joint Applicants suggest that the application and testimony make clear that upon the closing of the proposed transaction, Liberty will remain subject to all applicable laws, regulations, rules, decisions and policies governing the regulation of Illinois public utilities. Joint Applicants argue that no party has disputed that, and note that Ms. Pearce indicated that she had not identified any such laws that would be inapplicable to

Liberty, and that she had no reason to believe that it would not be subject to all of those laws. Accordingly, the Joint Applicants argue they have fully satisfied the requirements of Section 7-204(b)(5). Joint Applicants suggest that Staff witness Pearce's recommendations under Section 7-204(b)(5) are based on a fundamental misunderstanding of the statute and the Commission's prior authority and should not be given any weight.

Joint Applicants state that Ms. Pearce testified that her recommendation regarding Section 7-204(b)(5) was based on an interpretation that the Commission's finding must consider whether Liberty will be able to comply with all applicable laws, regulations, rules, decisions, and policies governing the regulation of Illinois public utilities. Based on this interpretation, the Joint Applicants note that Ms. Pearce recommended the Commission make the required finding under Section 7-204(b)(5) if the following conditions were imposed:

1) The Company is required to modify the ASA and CAM consistent with my proposed revisions as set forth in Attachments A through F.

2) Liberty is required to provide the Manager of Accounting of the ICC with a template of all allocation percentages used to charge Liberty pursuant to the ASA. The template shall be provided within 60 days of closing the proposed transaction and shall be updated annually, with a copy provided to the Manager of Accounting no later than March 31.

3) Each service provider is required to perform an annual, rather than biennial audit that includes certain specific tests of costs allocated to Liberty pursuant to the applicable ASA.

4) Each service provider is required to conduct a full study of the cost of services provided under the applicable ASA on a triennial basis. A full study is required periodically to ensure that Liberty will be charged appropriately for the services it receives, with no over- or under-charging.

5) Each service provider is required to file annually by May 1 a billing report on the ICC's e-Docket system in Docket No. 11-0559 with a copy to the ICC's Accounting Department Manager and to the Office of the Chief Clerk of the ICC. The billing report shall summarize the monthly charges to Liberty from its affiliated service companies under each applicable ASA.

6) Atmos Energy Corporation shall remain liable for all outstanding over-recovered purchased gas adjustment charges related to open dockets for reconciliation periods ending prior to closing of the proposed transaction.

7) Liberty, its affiliate LUC, and all of its affiliated service companies, such as Liberty Energy Utilities (New Hampshire) Corp. are prohibited from purchasing gas supply from an affiliated entity following the closing of the proposed transaction unless approval is petitioned for and granted by the Commission.

8) Liberty shall file the executed copy of the Asset Purchase Agreement and the executed ASA with the Chief Clerk of the Illinois Commerce Commission with a copy to the Manager of the Accounting Department of the Commission within fifteen (15) calendar days of the receipt of all regulatory approvals required for the proposed transaction to take effect. If the proposed transaction has not been consummated within 60 calendar days of the date of the Order in this proceeding, I further recommend that a status report be required to be filed with the Chief Clerk with a copy to the Manager of Accounting, and further status reports every 90 calendar days until the executed copy of the final purchase agreement has been filed.

Joint Applicants note that many of the conditions proposed by Ms. Pearce overlap with her proposed recommendations in Sections 7-204(b)(2) and (3). As previously discussed, the Joint Applicants have agreed to nearly all (but not all) of the changes suggested by Ms. Pearce in her markups in condition 1. As indicated above, the Joint Applicants believe that the requirements of conditions 2 (cost allocation template), 3 (annual audit), 4 (triennial cost study), 5 (billing report), and 7 (prohibition on gas supply purchases) have been satisfied. The Joint Applicants have also agreed to condition 6 with minor modifications that have been agreed to by both Staff and the Joint Applicants, and have agreed to condition 8 as set forth by Ms. Pearce

The Joint Applicants note that they proposed modifications to Condition 6, suggesting the following language:

> [a]s a regulatory matter, Liberty shall be liable for all outstanding over-recovered purchased gas adjustment charges, and shall be entitled to all outstanding under-recovered purchased gas adjustment charges, related to open dockets for reconciliation periods ending prior to closing of the proposed transaction.

Joint Applicants state that Staff witness Pearce testified that her concerns about purchased gas adjustment charges were satisfied by the Joint Applicants' proposed modifications to condition 6.

The Joint Applicants do not agree with certain parts of condition 1) relating to modifications to the ASAs and CAM, and note that the Joint Applicant's earlier arguments with respect to those modifications are applicable to this issue as well. In

addition, Joint Applicants assert that Staff's interpretation of the standard required by Section 7-204(b)(5) is legally incorrect, and claim Staff did not actually raise any issue of noncompliance. Therefore, Joint Applicants suggest Ms. Pearce's recommendations as to Section 7-204(b)(5) should not be adopted.

Joint Applicants aver that Staff's interpretation of Section 7-204(b)(5) is not supported by either the plain meaning of the statute or prior Commission precedent. Staff's interpretation of Section 7-204(b)(5) as requiring a finding on whether a utility will be able to comply with applicable laws and rules is one that the Commission has previously declined to adopt. Joint Applicants note that in Docket No. 98-0555, In re SBC Communications, Inc. et. al., the Commission rejected Staff's argument that a pattern of non-compliance would amount to a failure to meet the requirements of Section 7-204(b)(5). Instead, the Commission found "that other sections of section 7-204 grant the Commission authority to ensure that public utilities are fully compliant with its directives."

In construing a statute, Joint Applicants note that courts generally find that the surest and most reliable indicator of legislative intent is the statutory language itself, which is to be given its plain and ordinary meaning. By its plain language, Joint Applicants opine that Section 7-204(b)(5) only requires that all applicable laws, regulations, rules, decisions and polices governing the regulations of Illinois public utilities remain applicable to Liberty following the reorganization. Joint Applicants note that the Commission has interpreted Section 7-204(b)(5) consistent with the plain meaning of the statute and in particular as requiring the Commission to "ensure that the proposed reorganization does not inappropriately shelter or otherwise remove a utility's activities from regulatory scrutiny by this Commission (e.g., by somehow shifting regulated functions to an unregulated affiliate)." Joint Applicants state that all parties to this case have agreed that Liberty will remain subject to the jurisdiction of the Commission and to all laws, regulations, rules, decisions, and policies to the same extent after the reorganization as before the reorganization. Joint Applicants aver that as in Docket No. 98-0555, other statutory provisions provide the Commission with authority to ensure compliance, and the Commission should not deviate from the plain meaning of Section 7-204(b)(5), or the approach it has applied in previous proceedings.

Joint Applicants also argue that in addition to applying an incorrect legal standard, Staff has also not raised the issue of noncompliance. Joint Applicants note that Staff has presented no evidence of any law that Liberty will be unable to comply with. In addition, the recommendations of each Staff witness assume that if the Commission ordered a condition or requirement that it would be complied with. Although the parties are in disagreement regarding whether the Commission should adopt a subset of those recommendations in this order, there is no indication or allegation that Liberty will fail to comply with whatever conditions the Commission adopts.

Section 7-204(b)(5) sets forth a straightforward standard that requires the Commission to find that "the utility will remain subject to all applicable laws, regulations,

rules, decisions, and policies governing the regulation of Illinois public utilities." No party has disputed that Liberty will remain subject to these laws, and even Ms. Pearce indicated that she had not identified any such laws that would be inapplicable to Liberty, and that she had no reason to believe that it would not be subject to all of those laws. Accordingly, the Joint Applicants have fully satisfied the requirements of Section 7-204(b)(5).

2. Staff

Staff indicates that it is unable to recommend the Commission make the finding pursuant to Section 7-204(b)(5) based on the Joint Applicants proposal and therefore recommends the Commission deny approval of the proposed reorganization. In the event the Commission does approve the reorganization, Staff recommends that the Commission impose certain conditions as set forth below in order to make this finding.

Staff reasserts its earlier mentioned conditions, as well as the following:

1) Liberty will remain liable for all outstanding over-recovered purchased gas adjustment charges related to open dockets for reconciliation periods ending prior to closing of the proposed transaction;

2) Liberty must file the executed copy of the Asset Purchase Agreement and the executed ASA with the Chief Clerk of the Illinois Commerce Commission with a copy to the Manager of the Accounting Department of the Commission within fifteen (15) calendar days of the receipt of all regulatory approvals required for the proposed transaction to take effect. If the proposed transaction has not been consummated within 60 calendar days of the date of the Order in this proceeding, a status report should be filed with the Chief Clerk with a copy to the Manager of Accounting, and further status reports every 90 calendar days until the executed copy of the final purchase agreement has been filed.

Staff notes that the Joint Applicants proposed a modification to Condition 1) above noting that Liberty, instead of Atmos, will be responsible as a regulatory matter for outstanding charges under prior dockets. Staff accepts this modification as a necessary practical matter, understanding that if the proposed transaction is approved, Liberty will assume the customer billing function and would, therefore, be the party in position to issue any refunds related to prior overcharges or to collect amounts due related to outstanding charges under prior dockets.

Staff states that it agrees that the Joint Applicants accepted Condition 2) in the surrebuttal testimony of Mr. Peter Eichler.

D. Section 7-101

Section 7-101 of the Act sets forth the Commission's jurisdiction over transactions with affiliated interests. In accordance with Section 7-101 the Joint Applicants proposed ASA and CAM must be adequate to safeguard the public interest.

1. Joint Applicants

Joint Applicants state that the essential standard of approval under Section 7-101 of the Act, which governs certain transactions between affiliated interests, is that the agreement must be in the public interest. To uphold that standard, the Joint Applicants note the Commission may disapprove the agreement or "condition [its] approval in such a manner as it may deem necessary to safeguard the public interest." Joint Applicants submit the evidence in the record supports a finding that the ASAs are in the public interest.

Joint Applicants state that the ASAs and CAM provide that Liberty will receive services from affiliated interests at the cost incurred by those affiliated interests to provide such services, noting that whenever possible, the agreements provide for direct charges to the entity that procures a service. Joint Applicants note that Mr. Eichler testified that the services subject to the ASAs replace services currently provided by Atmos through an affiliated agreement and that the ASAs are necessary to the provision of reliable and cost efficient gas. Joint Applicants suggest the parties appear to be in agreement that the ASAs are necessary for the provision of utility service, and with the general approach of the ASAs and CAM and no party has seriously disputed whether they are in the public interest.

Joint Applicants assert that the ASA include many checks and balances to both ensure that all charges under the ASAs are fair and reasonable, and to ensure that the Commission will be able to exercise all necessary regulatory oversight. For example, Joint Applicants note that Liberty has agreed to an annual internal audit, which Joint Applicants suggest exceeds the biennial audit requirement imposed by Commission rules. Joint Applicants state Liberty has also agreed to provide a template of all allocation percentages used to charge Liberty pursuant to the ASAs, which will be updated annually. Joint Applicants note Liberty has also agreed to provide a billing report summarizing the monthly charges to Liberty, which will also be filed annually pursuant to each ASA. Additionally, Liberty will be conducting a full study of the cost of services provided under the ASAs on a triennial basis. Joint Applicants submit that all of these safeguards provide the Commission with detailed reports and information to ensure that Liberty is in compliance with the terms of its proposed ASAs.

The Joint Applicants note that Staff witness Pearce recommended the Commission find the proposed ASAs and CAM meet the requirements of Section 7-101 if the following conditions are imposed by the Commission:

1) The Company is required to modify the ASA and CAM consistent with my proposed revisions as set forth in Attachments A through F.

2) Liberty is required to provide the Manager of Accounting of the ICC with a template of all allocation percentages used to charge Liberty pursuant to the ASA. The template shall be provided within 60 days of closing the proposed transaction and shall be updated annually, with a copy provided to the Manager of Accounting no later than March 31.

3) Each service provider is required to perform an annual, rather than biennial audit that includes certain specific tests of costs allocated to Liberty pursuant to the applicable ASA.

4) Each service provider is required to conduct a full study of the cost of services provided under the applicable ASA on a triennial basis. A full study is required periodically to ensure that Liberty will be charged appropriately for the services it receives, with no over- or under-charging.

5) Each service provider is required to file annually by May 1 a billing report on the ICC's e-Docket system in Docket No. 11-0559 with a copy to the ICC's Accounting Department Manager and to the Office of the Chief Clerk of the ICC. The billing report shall summarize the monthly charges to Liberty from its affiliated service companies under each applicable ASA.

6) Atmos Energy Corporation shall remain liable for all outstanding over-recovered purchased gas adjustment charges related to open dockets for reconciliation periods ending prior to closing of the proposed transaction.

7) Liberty, its affiliate LUC, and all of its affiliated service companies, such as Liberty Energy Utilities (New Hampshire) Corp. are prohibited from purchasing gas supply from an affiliated entity following the closing of the proposed transaction unless approval is petitioned for and granted by the Commission.

8) Liberty shall file the executed copy of the Asset Purchase Agreement and the executed ASA with the Chief Clerk of the Illinois Commerce Commission with a copy to the Manager of the Accounting Department of the Commission within fifteen (15) calendar days of the receipt of all regulatory approvals required for the proposed transaction to take effect. If the proposed transaction has not been consummated within 60 calendar days of the date of the Order in this proceeding, I further recommend that a status

report be required to be filed with the Chief Clerk with a copy to the Manager of Accounting, and further status reports every 90 calendar days until the executed copy of the final purchase agreement has been filed.

9) The new utility shall be liable to reimburse the Commission for any reasonable costs and expenses associated with an audit or inspection of books and records maintained outside Illinois.

10) Liberty shall file the final accounting entries (with the corrections noted herein), including the actual amounts recorded by Liberty within 60 calendar days following the closing of the proposed transaction with the Chief Clerk of the Commission with a copy of the filing to the Manager of the Accounting Department of the Commission.

As previously discussed, the Joint Applicants have agreed to most of changes suggested by Ms. Pearce in condition 1. The Joint Applicants believe they have fully satisfied conditions 2 (cost template), 3 (annual audit), 4 (triennial cost study), 5 (billing report), 6 (PGA clause liability), and 7 (gas supply purchases from affiliates) as set forth above. Conditions 8 through 10 have been accepted by the Joint Applicants in testimony.

With the clarifications noted in this section, the Joint Applicants believe the issues in this section are resolved except for certain parts of condition 1) relating to changes to the ASAs and CAM. Joint Applicants opine that Staff has not identified in the record any specific concerns relating to Section 7-101 and has instead listed a set of conditions that Ms. Pearce declares should be required without providing any analysis of how they relate to the statute, or identifying any benefits from accepting the recommendations. The Joint Applicants' analysis under Section 7-101 is substantially similar to that of Section 7-204 and therefore its arguments are incorporated by reference.

Joint Applicants state that it modified the ASAs in accordance with Ms. Pearce's requests to separate what had been a single ASA into four ASAs, one for each of the affiliated interests that will provide services to Liberty. By separating out the Agreements, Joint Applicants aver that the identity of the entity providing services to Liberty is clear, and state Liberty is not providing services to any entity under any of the ASAs. Joint Applicants indicate that each ASA sets forth a detailed listing of the services covered by the ASA in Section 1.2, and believe that this fully satisfies Ms. Pearce's concerns on this point.

In regard to Staff's requirement that Liberty be a signer of the ASA, Joint Applicants state that Liberty will be a signer to the ASAs in the latest draft filed by the Joint Applicants, which it believes Staff witness Pearce acknowledged. Accordingly, the Joint Applicants do not believe this requirement remains at issue.

Joint Applicants note Ms. Pearce also made a recommendation regarding language in Schedule II to the ASAs setting forth the scope of the agreement. The Joint Applicants note that the language proposed by Ms. Pearce has been adopted, with a slight modification, such that it states that each agreement "shall be limited in their application to transactions that affect Liberty costs subject to the regulatory oversight of the Illinois Commerce Commission ("ICC") and shall remain in effect until otherwise ordered by the ICC." Joint Applicants indicate that Ms. Pearce testified that this satisfied her concern expressed in her testimony.

In response to Staff's request that there by a separate agreement for each entity that provides services, Joint Applicants aver that there have been filed separate agreements for each of the entities that provide services to it, these being Algonquin, LUC, Liberty Utilities Co., and Liberty NH. As previously discussed in other sections, an agreement between APCo and LUC was not filed. Setting aside the issue of Ms. Pearce's inclusion in her markups of an agreement between APCo and LUC, the Joint Applicants believe the issue of separating each of the ASAs involving Liberty has been addressed as requested by Staff witness Pearce.

In regard to Staff's request for annual internal audits of charges covered by the ASAs during the preceding calendar year, Joint Applicants note Liberty has agreed to an annual internal audit.

Joint Applicants complain that Staff has not presented evidence that the proposed ASAs and CAM are not in the public interest, as required by Section 7-101, but rather has simply declared that Ms. Pearce's changes and conditions should be accepted without delving into any rationale. Joint Applicants opine that this unsupported statement does not rebut the Joint Applicants' showing that Liberty proposed ASAs and CAM are in the public interest, noting that Mr. Eichler testified that the services subject to the ASAs replace services currently provided by Atmos through an affiliated agreement, and that the ASAs are necessary to the provision of reliable and cost efficient natural gas. In addition to direct charging whenever possible, Joint Applicants note there are included many checks and balances in the ASAs to both ensure that all charges under the ASAs are fair and reasonable and to ensure that the Commission will be able to exercise all necessary regulatory oversight.

Joint Applicants state that these checks and balances include an annual internal audit, a template of all cost allocation percentages used to charge Liberty pursuant to the ASAs, a billing report summarizing the monthly charges to Liberty, and a full study of the cost of services provided under the ASAs on a triennial basis. Joint Applicants suggest that all of these "Safeguard Conditions" provide the Commission with detailed reports and information to ensure that Liberty is in compliance with the terms of its proposed ASAs.

Joint Applicants also note that in Staff's Initial Brief, Staff does not bother to indicate how most of the conditions proposed by Ms. Pearce relate to Section 7-101; the

discussion merely references the other portions of Staff's Initial Brief. However, Joint Applicants opine that the portions of the brief cited relate to Section 7-204(b)(2), rather than the public interest standard applicable to Section 7-101. Joint Applicants argue that the only reference tying Staff's conditions to Section 7-101 that Joint Applicants were able to find in the record is a general statement made by Ms. Pearce that the public interest is protected if there are adequate safeguards to satisfy the requirements of Section 7-204. Joint Applicants opine that the totality of the evidence shows that they have satisfied the requirements of Section 7-204, and accordingly, the Joint Applicants recommend that the Commission find that the proposed ASAs and CAM are in the public interest and should be approved under Section 7-101.

2. Staff

Staff states that Ms. Pearce expressed concerns related to Liberty's proposed ASA and CAM, and she therefore recommended the Commission make this finding subject to certain conditions, should the Commission approve the reorganization. Staff notes that these conditions are essentially the same for each of the contested issues.

Staff states that Section 7-101 of the Act sets forth the Commission's jurisdiction over transactions with affiliated interests, and note that in accordance with Section 7-101 Liberty's proposed ASA and CAM must be adequate to safeguard the public interest. Staff notes that the Commission, in its recent Order approving the Nicor/AGL reorganization, stated the following:

> Our analyses, above, regarding subsidization and cost allocation, is also applicable here in the broader context of the public interest. Subsidization of a non-utility affiliate is not in the interests of the general public, the involved utility or the utility's customers. Fair and reasonable cost allocation among utility and non-utility activities, to facilitate proper ratemaking, serves those interests.
>
> (Order, Docket No. 11-0046, December 7, 2011, p. 56)

The Joint Applicants argue that the evidence supports a finding that the ASAs are in the public interest, however, Staff witness Pearce has expressed concerns related to Liberty's proposed ASA and CAM. In connection with the findings pursuant to Sections 7-204(b) (2),(3) and (5) and to ensure proposed ASA and CAM are adequate to safeguard the public interest, Staff recommends the Commission impose the following condition, in the event the proposed transaction is approved:

> Algonquin and its affiliates shall be required to submit a petition under Section 7-101 of the Act for the Commission to consider the effectiveness of the ASAs approved in this proceeding prior to filing any request for an increase in rates, but in any case no later than September 30 of the year following the first full calendar year subsequent to closing the proposed transaction. The petition shall indicate the costs recovered from Liberty

> for each accumulated calendar year through each ASA. The allocated common costs from each service provider shall be supported by exemplar allocation percentages for each service provided and must include all allocation percentages to the various entities to account for 100% of the allocated costs. The direct charges to the various affiliates billed by each service company shall also be included. After reviewing the results, the Commission may consider modifications to the ASAs.

Staff notes that the Joint Applicants have indicated they do not accept this condition for the following reasons:

a) The ASAs and CAM proposed by the Joint Applicants contain numerous safeguards and oversight mechanisms that go beyond the requirements imposed on public utilities generally;

b) These safeguards provide the Commission with the necessary information to evaluate the effectiveness of the ASAs, particularly where the Commission retains all oversight powers over Liberty;

c) Section 7-101 applies to proceedings to approve an agreement on a prospective basis; it does not contemplate multiple approvals of the same agreement, nor does it contain standards for a post-agreement review of transactions under approved agreements; and,

d) The Joint Applicants contend this would be an altogether new type of proceeding under an inapplicable statute.

Staff strongly disagrees with the Joint Applicants for the following reasons.

First, Staff states it is not aware that Section 7-101 precludes a Commission review of existing ASAs. In fact, Staff notes the Commission has found otherwise in its recent Order that approved the Section 7-204 reorganization of Northern Illinois Gas and AGL, where the Commission held that:

> Subsection 7-204A(b) gives the Commission discretionary power to review any such contract or arrangement "in the same manner as it may review any other public utility and its affiliated interest." In our view, this latter clause invokes, inter alia, the powers residing in Section 7-101 (quoted above), including the broad power to safeguard the public interest.
>
> Further, our administrative regulations declare that "[t]ransactions between a gas utility and its affiliated interests shall not be allowed to subsidize the affiliated interests."[4] This provision applies to the OA, and any dealings pursuant to its terms and conditions, whether or not there is a pending reorganization request.

> With particular regard to reorganization requests, inter-affiliate contract approval is not specifically addressed by statute. However, subsection 7-204(f) provides that "[i]n approving any proposed reorganization pursuant to this Section, the Commission may impose such terms, conditions or requirements as, in its judgment, are necessary to protect the interests of the public utility and its customers."[5] Subsection 7-204(f) does not exempt any component of utility operations from its purview. The Commission therefore concludes that the power to impose merger conditions extends to a utility's inter-affiliate agreements, such as the OA here, and to utility conduct under the terms of those agreements [6].

(Order, Docket No. 11-0046, December 7, 2011, p. 44)

Staff notes the Commission frequently reviews affiliate agreements that are proposed by long-established utilities operating in Illinois. For example, Staff states the recent Commission rate order for North Shore Gas Company and The Peoples Gas Light and Coke Company, Docket Nos. 11-0280 and 11-0281 (consol.), entered January 10, 2012 concluded the following:

> The Commission agrees with Staff and finds that the Utilities have not properly interacted with their affiliates as evidenced by our conclusions in the above related sections. Staff's proposal for further Commission investigation of the Utilities' interactions with their affiliates is warranted and in the public interest. We believe the investigation is necessary to prevent ratepayers from continuing to subsidize the affiliates. . . . Thus, the Utilities are required within 90 days of the Order in this case to file a petition and testimony demonstrating that the Utilities' affiliate interactions are in compliance with the STA and the Master AIA. Additionally, the petition and testimony must address any jurisdictional issues with the Master AIA agreement pending in Wisconsin. Finally this petition and testimony must provide full cost justification for the repair rates charged to ratepayers as well.

(Order, Docket Nos. 11-0280 and 11-0281 (consol.), January 10, 2012, p. 98)

Staff indicates that another example is the Commission rate order for Northern Illinois Gas Company d/b/a Nicor Gas Company for Docket No. 08-0363 entered March 25, 2009 that included the following Finding:

> (14) Nicor shall file a petition with 120 days of the date of a final Order in this proceeding seeking either re-approval of its current Operating Agreement or approval of a new affiliated interest transaction agreement; this petition shall address the criteria expressed by Staff, as is set forth in section XIV(C) herein; and it shall be supported by verified testimony;

(Order, Docket No. 08-0363, March 25, 2009, pp. 183-184)

Specifically, Staff notes that Section 7-101(3) states in part:

> If it be found by the Commission, after investigation and a hearing, that any such contract or arrangement is not in the public interest, the Commission may disapprove such contract or arrangement. Every contract or arrangement not consented to or excepted by the Commission as provided for in this Section is void.
>
> (220 ILCS 5/7-101(3)

Because Section 7-101 provides for Commission disapproval of contracts or arrangements that are not in the public interest, Staff believes it stands to reason that the law does not preclude a review of existing affiliate agreements for the very purpose of determining whether they function according to the public interest. Additionally, Staff suggests that the aforementioned 'safeguards in the ASAs and CAM that provide the Commission with the necessary information to evaluate the effectiveness of the ASAs' would serve little purpose if it became apparent that the ASAs were not effective and the Commission were not allowed to revisit the existing affiliate agreements.

Finally, Staff suggests that the ASAs and CAM that were proposed in ICC Staff Exhibit 10.0, Attachments A through F, may not include all the necessary provisions to preclude potential cross-subsidization. Moreover, Staff states that the ultimate parent of Liberty, Algonquin, has an organizational structure which includes various levels of service providers and affiliates who may provide services for which Liberty ultimately is charged, either directly or indirectly. As Staff witness Pearce indicated during cross-examination, her intent with this recommendation is to allow the Commission to consider the effectiveness of the ASAs approved in this proceeding prior to the filing of a request for an increase in rates. Ms. Pearce acknowledged that even though there might be an approved ASA in place, the Commission is not obligated to allow recovery of any charges for ratemaking purposes, but this condition would provide an opportunity to assess whether everything that has been approved in this proceeding effectively protects Illinois ratepayers. However, Staff believes that the Joint Applicants appear to view the approval process somewhat backwards from Staff, as evidenced in the following assertion in the Joint Applicants Initial Brief:

> Because (Liberty's) rates cannot include any of the charges under the ASAs until the Commission approves their inclusion in a rate case, the Commission can generally be assured that no unjust subsidization may occur.

Staff notes that the primary objective of ASA approval is to prevent cross-subsidization from occurring; evaluation of resultant costs for rate recovery is secondary. Accordingly, Staff strongly supports this condition if the proposed transaction is approved.

E. Commission Analysis and Conclusion

The Commission will first note that it has chosen to address the contested issues in this matter in a single conclusion, in part because the parties have indicated that the recommendations for each of the contested issues are for the most part the same, and the parties have in fact referenced earlier portions of their Briefs throughout their arguments.

From the Commission's review of the arguments, it appears that Staff is recommending that the Commission not grant authority for the proposed reorganization, while Liberty believes it has shown that the proposed reorganization has satisfied the statutory requirement, that it is in the best interest of the public that the reorganization should be granted.

The Commission notes that in addition to the conditions that Liberty has agreed to, it appears that Staff is requesting, should the Commission grant the reorganization, that additional conditions be imposed on the reorganization, in order to satisfy Section 7-204(b)(2), Section 7-204(b)(3), Section 7-204(b)(5) and/or Section 7-101of the Act. The Commission will address each of these proposed conditions; however the Commission will not attempt to re-state each of the party's arguments on each issue, but will generally rely on the stated positions as laid out elsewhere in this Order.

> Condition 1: The Company is required to modify the ASA and CAM consistent with the proposed revisions as set forth in Attachments A through F of Staff witness Pearce's rebuttal testimony.

It appears to the Commission that based on the Briefs and the arguments of the parties, that the Joint Applicants believe that they have satisfied this condition, except for three subsets of this condition. These include Staff's request that Liberty require two of its affiliates, LUC and APCo to enter into an ASA between the two of them that is subject to Commission approval; that Liberty modify the ASAs to include as parties a list of additional receiving companies to the ASAs; and that Liberty be required to modify the CAM to remove Section V.

The Joint Applicants object to each of these conditions, noting that neither LUC nor APCo is an Illinois utility, and in fact neither is a public utility. Joint Applicants question how it can modify an agreement that does not exist, and to which it is not even a party. Liberty also complains that Staff has presented no rationale or evidence for requiring such an agreement, nor has it identified any benefit that will occur from having an ASA between LUC and APCo.

Joint Applicants also complain that Staff is proposing to include in the ASAs numerous other companies that are not Illinois public utilities, and which in fact are not providing services to Liberty. Joint Applicants argue that they have shown that rejecting this requirement will not result in any unjustified subsidization of non-utility activities,

and that it will not reduce the Commission's ability to identify the costs properly included for ratemaking purposes.

Joint Applicants note that Section V permits LUC's regulated utilities to obtain services from a service company as defined in the CAM, and sets forth the manner in which charges for those services would be allocated. Joint Applicants complain that they cannot simply remove Section V of the CAM, because although Liberty will not receive services under Section V, other utilities in jurisdictions outside of Illinois receive services under this provision.

Staff expresses concern that the ASAs provided by Liberty might not be sufficient to protect Illinois ratepayers from potential cross-subsidization that could occur because of the organization of some affiliates, and that certain charges could be allocated to the Illinois utility, which costs would not be covered by an ASA or readily identified at the utility level.

Staff suggests further that language on this issue of cost allocation needs to be incorporated into the ASAs and the CAM, arguing that the suggested language would set forth the basis for affiliate charges, and would aid in preventing cross-subsidization between companies.

The Commission is satisfied, based on the totality of the evidence presented by the parties, that it is not necessary for approval in this proceeding to require the Joint Applicants to provide an ASA between APCo and LUC. The Commission notes that it appears from the evidence presented that Liberty will have sufficient ASAs with its affiliated interests, which, combined with the suggested cost allocation language, will be satisfactory to minimize the risk of cross-subsidization, which language it appears the Joint Applicants have accepted.

The Commission also notes that the Joint Applicants propose that rather than include in the ASAs a list of additional receiving companies, that this information be provided on an annual basis in connection with the agreed provision of templates of allocation percentages. The Commission declines to adopt Staff's recommendation, noting that all parties to the ASAs need not be identified. The Commission, instead, prefers to rely on the annual template of allocation percentages to stay apprised of parties to the ASAs.

The Commission notes that it appears that Section V of the CAM permits LUC's regulated utilities to obtain services from a service company, as defined in the CAM and sets forth the manner in which charges for those services would be allocated. Joint Applicants suggest that although Liberty will not receive services under Section V, other utilities in jurisdictions outside of Illinois receive services under this provision, therefore this section should remain. Joint Applicants, therefore, suggested that additional language be included, to the effect that Section V of the CAM would not apply to Liberty in Illinois unless Liberty seeks Commission approval to receive specific services from identified service companies. That language is adopted and set forth in Condition 15 of

Appendix A to this Order. The Commission is satisfied, based on the arguments presented, that with the addition of the Joint Applicants suggested language, that the relief sought by Staff is essentially achieved, and that the modified Section V of the CAM should remain as part of the CAM.

> Condition 2: Each service provider is required to provide the Manager of Accounting of the ICC with a template of all allocation percentages used to charge Liberty pursuant to each applicable ASA. The template shall be provided within 60 days of closing the proposed transaction and shall be updated annually, with a copy provided to the Manager of Accounting no later than March 31.

Joint Applicants state Liberty has agreed to provide an annual detailed cost allocation template, noting that it provided a sample of what the template would look like. Liberty acknowledges that the actual annual template would need to include allocation percentages for all provider companies, and suggest that they have satisfied Staff's proposed condition. Staff notes that it appears the Joint Applicants accepted the suggested language on cost allocation, provided that the obligation would be on the utility, not the entity providing services to Liberty. Staff also expresses concern with how all the costs are being allocated, not just the calculation of the percentage that went to the Illinois utility.

The Commission is satisfied with the agreement expressed by the Joint Applicants to the condition, and will incorporate it into the Order. The Commission agrees with the Joint Applicants however, that the obligation contained in this condition suggested by Staff should properly be on the Illinois utility, Liberty, rather than on the entity providing service to Liberty.

> Condition 3: Each service provider is required to perform an annual, rather than biennial audit that includes certain specific tests of costs allocated to Liberty pursuant to each applicable ASA, each annual audit to be provided to the Manager of the Accounting Department of the Commission no later than July 1 of each calendar year.

The Commission notes that the Joint Applicants have agreed to conduct an annual internal audit, and note it has been included in each ASA. Although Staff indicated it was initially unclear whether 100% of all costs under the ASAs would be included in the templates, it appears to the Commission that Staff has acknowledged that the actual annual template will need to include actual allocation percentages for all provider companies, which it appears Liberty has agreed to. Staff however suggests that Liberty has accepted this condition with the understanding that the obligation would be on Liberty, and not on the entities providing services to Liberty. Staff suggests that the audit needs to be conducted by the entity providing the services, that way the charges being allocated down to the utility could be audited.

As the Commission understands this issue, Liberty considers this issue settled, if it performs the annual internal audits and reports the results to the Commission annually, while Staff suggests that the internal audit should be performed by each entity providing services to Liberty under the ASAs. The Commission is satisfied with the annual internal audit condition being imposed on Liberty, with the understanding that it will perform a separate audit for each entity providing services, and to provide the results of that audit as suggested by Staff.

> Condition 4: Each service provider is required to conduct a full study of the cost of services provided under the applicable ASA on a triennial basis. A full study shall be required periodically to ensure that Liberty will be charged appropriately for the services it receives, with no over- or under-charging.

Joint Applicants note that Liberty has agreed to perform a triennial cost study, and this condition is included in each ASA executed for this proceeding. Joint Applicants note that Staff initially indicated it had concern with Liberty changing the burden of the audit to Liberty, rather than the provider of services. Liberty states that Staff indicated it would be satisfied if Liberty provided a cost study for the charges under each of the ASAs. Liberty indicates it agrees with that condition, and considers this matter settled.

Staff however indicates that during cross-examination, Ms. Pearce clarified that the obligation should rest with the entity providing the services, to ensure that the allocators are reasonable for the charges to the Illinois utility. Staff notes Ms. Pearce then agreed that a cost study for the charges under each of the ASAs would address her concerns.

The Commission considers, based on the statements of the parties, and the conditions previously imposed, that the Joint Applicant's suggestion is satisfactory. The Commission understands that this condition will require Liberty to conduct a full study of the cost of services provided under each ASA on a triennial basis, with the understanding that the triennial study will address the charges under each of the ASAs.

> Condition 5: Each service provider is required to file annually by May 1 a billing report on the ICC's e-Docket system in Docket No. 11-0559 with a copy to the ICC's Accounting Department Manager and to the Office of the Chief Clerk of the ICC. The billing report shall summarize the monthly charges to Liberty from its affiliated service companies under each applicable ASA.

Liberty notes that it has agreed to file an annual billing report summarizing the monthly charges from the provider companies, and have included this requirement in each of the ASAs in this docket. Liberty indicates that while Ms. Pearce initially expressed concern this was on the utility level, she indicated during cross-examination that if Liberty agreed to provide a billing report with respect to the charges under each of

the ASAs, this would satisfy her concerns; therefore the Joint Applicants consider this condition met. It appears to the Commission that Staff is in agreement on this condition; therefore it will be included in the Order in this proceeding.

> Condition 6: Liberty shall be liable for all outstanding over-recovered purchased gas adjustment charges, and shall be entitled to all outstanding under-recovered purchased gas adjustment charges, related to open dockets for reconciliation periods ending prior to closing of the proposed transaction.

It does not appear to the Commission that there is any dispute between the parties that the above condition is appropriate if the reorganization is approved, therefore the Commission will include this condition in the Order in this docket.

> Condition 7: Liberty, its affiliate LUC, and all of its affiliated service companies, such as Liberty Energy Utilities (New Hampshire) Corp. are prohibited from purchasing gas supply from an affiliated entity following the closing of the proposed transaction unless approval is petitioned for and granted by the Commission.

Joint Applicants suggest that this condition be modified so that Liberty is prohibited from purchasing gas supply from an affiliated entity unless Commission approval is granted or unless such approval is not required under applicable law. The Joint Applicants suggest that this will prevent any unjust subsidization, and note that all transactions with affiliated interests are subject also to the ASAs.

Staff however argues that Liberty's proposal would not alleviate Staff's concerns regarding potential cross-subsidization; therefore Staff suggests that its conditions should be adopted.

Based on the Commission's review of the evidence, it appears that the language suggested by Liberty is more appropriate in this matter. The Commission, however believes that the additional condition of prohibiting either the purchase or sale of gas by Liberty to an affiliate is appropriate without prior Commission approval, and necessary to protect against cross-subsidization. In regard to Staff's suggestion, the Commission finds it is not clear that it has the power, or if it did that it should exercise that power, to ban the sale of natural gas supply between affiliated, non-Illinois companies, some of whom are not even public utilities. The Commission is satisfied that the condition imposed is sufficient to protect Illinois ratepayers from potential harm.

> Condition 8: Liberty shall file the executed copy of the Asset Purchase Agreement and the executed ASA with the Chief Clerk of the Illinois Commerce Commission with a copy to the Manager of the Accounting Department of the Commission within fifteen (15) calendar days of the receipt of all regulatory approvals required for the proposed transaction to take effect. If the proposed transaction has not been consummated within

60 calendar days of the date of the Order in this proceeding, I further recommend that a status report be required to be filed with the Chief Clerk with a copy to the Manager of Accounting, and further status reports every 90 calendar days until the executed copy of the final purchase agreement has been filed.

Condition 9: The new utility shall be liable to reimburse the Commission for any reasonable costs and expenses associated with an audit or inspection of books and records maintained outside Illinois.

Condition 10: Liberty shall file the final accounting entries (with the corrections noted herein), including the actual amounts recorded by Liberty within 60 calendar days following the closing of the proposed transaction with the Chief Clerk of the Commission with a copy of the filing to the Manager of the Accounting Department of the Commission.

It appears to the Commission that the parties are in agreement as to the appropriateness of each of these conditions, therefore each will made a condition of the proposed reorganization, and incorporated into the Order in this proceeding.

Condition 11: Algonquin Power & Utilities Corp. and its affiliates should be required to submit a petition under Section 7-101 of the Act for the Commission to consider the effectiveness of the ASAs approved in this proceeding prior to filing any request for an increase in rates, but in any case no later than September 30 of the year following the first full calendar year subsequent to closing the proposed transaction. The petition should indicate the costs recovered from Liberty for each accumulated calendar year through each ASA. The allocated common costs from each service provider should be supported by exemplar allocation percentages for each service provided and must include all allocation percentages to the various entities to account for 100% of the allocated costs. The direct charges to the various affiliates billed by each service company should also be included. After reviewing the results, the Commission may consider modifications to the ASAs.

Staff notes the Commission frequently reviews affiliate agreements that are proposed by long-established utilities operating in Illinois, and notes several proceedings where the Commission has in fact required review of affiliate agreements. Staff indicates it does not believe that Section 7-101 precludes a Commission review of existing ASAs, and in fact notes the Commission has found otherwise in its recent Order that approved the Section 7-204 reorganization of Northern Illinois Gas and AGL, Docket No. 11-0046.

Because Section 7-101 provides for Commission disapproval of contracts or arrangements that are not in the public interest, Staff believes it stands to reason that the law does not preclude a review of existing affiliate agreements for the very purpose

of determining whether they function according to the public interest. Additionally, Staff suggests that the safeguards in the ASAs and CAM that provide the Commission with the necessary information to evaluate the effectiveness of the ASAs, would serve little purpose if it became apparent that the ASAs were not effective and the Commission were not allowed to revisit the existing affiliate agreements.

The Commission notes that the Joint Applicants have indicated they do not accept this condition, claiming that the ASAs and CAM proposed by the Joint Applicants contain numerous safeguards and oversight mechanisms that go beyond the requirements imposed on public utilities generally; and that these safeguards should provide the necessary information to evaluate the effectiveness of the ASAs. The Joint Applicants also complain that Section 7-101 applies to proceedings to approve an agreement on a prospective basis; and it does not contemplate multiple approvals of the same agreement, nor does it contain standards for a post-agreement review of transactions under approved agreements. The Joint Applicants contend this would be an altogether new type of proceeding under an inapplicable statute, and that it has put in place sufficient checks and balances to comply with the Commission rules and regulations.

The Joint Applicants state that these checks and balances include an annual internal audit, a template of all cost allocation percentages used to charge Liberty pursuant to the ASAs, a billing report summarizing the monthly charges to Liberty, and a full study of the cost of services provided under the ASAs on a triennial basis. Joint Applicants claim all of these conditions provide the Commission with detailed reports and information to ensure that Liberty is in compliance with the terms of its proposed ASAs.

The Commission notes that Section 7-101 contemplates that the Commission approve designated affiliate transactions prior to their taking effect. The Commission does not believe that Section 7-101 creates a mechanism by which the Commission would examine a utility's affiliated interest transactions that occurred in the past. While the Commission agrees with Staff that continued oversight is necessary, particularly where transactions between utilities and their affiliates are involved, the Commission finds that there are already present the necessary mechanisms and controls to protect ratepayers. As indicated by the Joint Applicants, these transactions will be subject to considerable oversight and review on the basis of voluntary commitments by the utility, including reporting and audit requirements, cost study requirements, and other safeguards that go well beyond those required by Commission rules or the Act. Furthermore, the Commission notes that approval of the ASAs in this docket does not constitute approval for ratemaking purposes, and Liberty will need to justify these expenses, and any allocations, before making any recoveries from Illinois ratepayers.

Accordingly, the Commission declines to impose a requirement that Liberty file another petition under Section 7-101 to revisit the ASAs approved in this docket.

The Commission therefore finds, based on the totality of the evidence, the Stipulation of Conditions entered into by the parties, and the conditions on the reorganization imposed by this Order, that the proposed reorganization should be approved, and the parties granted permission to finalize their proposed transaction. The Commission believes that each statutory condition has been satisfied by the Joint Applicants as laid out in this Order, and that the conditions imposed by the Commission are sufficient to protect ratepayers affected by this transaction.

V. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having given due consideration to the entire record herein and being fully advised in the premises, is of the opinion and finds that:

(1) Atmos is a corporation duly organized and existing under the laws of the State of Texas and the Commonwealth of Virginia engaged in the business of distributing and selling natural gas in Illinois and as such is a public utility within the meaning of the Act;

(2) Liberty Energy (Midstates) is a Missouri corporation that will become a public utility with the meaning of the Act upon closing of the reorganization;

(3) the Commission has jurisdiction over the parties hereto and the subject matter herein;

(4) the recitals of fact set forth in the prefatory portion of this Order are supported by the record and are hereby adopted as findings of fact;

(5) an Appendix ("Appendix A") should be attached to this order and fully incorporated into this Order; it should contain the Required Conditions of Approval established by the Commission in this Order, which conditions for approval of the proposed reorganization and the other relief granted in this Order;

(6) pursuant to Section 7-204 of the Act, and subject to the conditions established in this order (enumerated in Appendix A), the Commission finds that:

a) the proposed reorganization will not diminish Liberty Energy (Midstates) ability to provide adequate, reliable, efficient, safe and least-cost public utility service;

b) the proposed reorganization will not result in the unjustified subsidization of non-utility activities by the utility or its customers;

c) costs and facilities are fairly and reasonably allocated between the utility and non-utility activities in such a manner that the Commission may identify those costs and facilities which are properly included by the utility for ratemaking purposes;

d) the proposed reorganization will not significantly impair the ability of Liberty Energy (Midstates) to raise capital on reasonable terms or to maintain a reasonable capital structure;

e) the utility will remain subject to all applicable laws, regulations, rules, decisions, and policies governing the regulation of Illinois public utilities;

f) the proposed reorganization is not likely to have a significant adverse effect on competition on those markets over which the Commission has jurisdiction; and

g) the proposed reorganization is not likely to result in any adverse rate impacts on retail markets;

(7) any savings resulting from the propose reorganization shall be flowed through to the costs associated with the regulated intrastate operations for consideration in setting rate by the Commission; and no costs incurred in accomplishing the proposed reorganization in this or any future proceeding shall be recoverable through Illinois jurisdictional regulated rates;

(8) there is no presumption for or against recoverability of costs attributed or related to the reorganization. The recoverability of any such costs, which may include costs of obtaining continuing services or investments to replace Atmos information technology and other infrastructure, should be determined by the Commission in a future rate case;

(9) following the closing of the reorganization, Atmos will cease to exist as a public utility in Illinois; the public convenience and necessity require the continued operation of the existing gas facilities currently owned and operated by Atmos in Illinois; therefore, it is appropriate to authorize the following:

(a) the discontinuance by Atmos of public utility service in Illinois, such discontinuance to be effective upon closing of the reorganization, pursuant to Section 8-508;

(b) the issuance of a certificate of public convenience and necessity to Liberty Energy (Midstates) pursuant to Section 8-406(a) of the Act, to be effective upon closing of the proposed reorganization;

(c) the issuance to Liberty Energy (Midstates) of certificates of public convenience and necessity that are identical to the certificates of public convenience and necessity previously issued by this Commission to Atmos pursuant to Section 7-203; such transfer to be effective at the time of closing of the proposed reorganization;

(d) a waiver pursuant to Section 9-201 of the Act of the 45-day notice requirement for the filing of tariffs by Liberty Energy (Midstates), upon the filing of tariffs identical to the tariffs in force for Atmos prior to the consummation of the reorganization, except for the identity of the utility, those tariffs filed to be effective upon filing;

(10) the proposed reorganization will not be inconsistent with Section 6-103 of the Act, insofar as that statute applies to the subject matter of this proceeding;

(11) a waiver pursuant to Section 5-106 of the Act is authorized, such waiver to be effective upon closing of the proposed reorganization;

(12) the evidence demonstrates that the proposed reorganization should reasonably be granted, and that the public will be convenienced thereby, in accordance with Section 7-102 of the Act;

(13) the four ASAs entered into evidence as Joint Applicant Exhibits 9.6 through 9.9 should be approved, and are in the public interest, in accordance with Section 7-101 of the Act;

(14) Liberty Energy (Midstates) should be authorized to issue up to $55,000,000 in long-term debt through intercompany loan, and up to $67,000,000 in common stock to its parent, pursuant to 6-102 of the Act; these issuances are in the public interest and should be approved in accordance with Section 7-101 of the Act;

(15) Liberty Energy (Midstates) shall pay fees in accordance with Section 6-108 of the Act on the issuances described in paragraph (14) at a rate of 24 cents per one hundred dollars of long term debt for the proportion attributable to Illinois, and at a rate of 12 cents per one hundred dollars of long term equity for the proportion attributable to Illinois, such fee calculated in accordance with Appendix B; these fees shall be paid to the Commission within thirty days of this order;

(16) in accordance with Section 6-101 of the Act, Liberty Energy (Midstates) should cause the following identification number to be place on the face of any long-term debt authorized pursuant to the Order in this proceeding: Ill. C.C. No. 6586; and shall cause the following identification number to be place on the face of any common stock issued pursuant to the Order in this proceeding: ILL. C.C. No. 6587.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the Joint Applicants' request to engage in the reorganization, through which the Illinois assets of Atmos Energy Corporation will be transferred by Atmos Energy Corporation to Liberty Energy (Midstates), is hereby approved, subject to the condition adopted in this Order, under Section 7-204, Section 7-204A and Section 7-102.

IT IS FURTHER ORDERED that any savings resulting from the reorganization shall be flowed through to the costs associated with the regulated intrastate operations for consideration in setting rates by the Commission ratepayers and any costs incurred in accomplishing the proposed reorganization, including severance costs for any employees removed as part of the reorganization, in this or any future proceeding shall not be recoverable through Illinois jurisdictional regulated rates.

IT IS FURTHER ORDERED that Liberty Energy (Midstates) capitalization is approved pursuant to Section 6-103.

IT IS FURTHER ORDERED that the four ASAs set forth in Joint Applicant Exhibits 9.6 through 9.9 are hereby approved under Section 7-101.

IT IS FURTHER ORDERED that Liberty Energy (Midstates) is authorized under Section 6-102 and 7-101 to issue $55,000,000 in long term debt through an intercompany loan and issue $67,000,000 of common stock.

IT IS FURTHER ORDERED that Liberty Energy (Midstates) shall pay fees in accordance with Section 6-108 of the Act on the issuances described in paragraph (14) at a rate of 24 cents per one hundred dollars of long term debt for the proportion attributable to Illinois, and at a rate of 12 cents per one hundred dollars of long term equity for the proportion attributable to Illinois, as set forth in Appendix B; these fees shall be paid to the Commission within thirty days of service of this Order.

IT IS FURTHER ORDERED that Liberty Energy (Midstates) shall cause the following identification number to be place on the face of any long-term debt authorized pursuant to the Order in this proceeding: Ill. C.C. No. 6586; and shall cause the following identification number to be place on the face of any common stock issued pursuant to the Order in this proceeding: Ill. C.C. No. 6587.

IT IS FURTHER ORDERED as follows:

(a) Atmos shall discontinue the provision of public utility service in Illinois, effective upon closing of the reorganization;

(b) Liberty Energy (Midstates) is granted a certificate of public convenience and necessity pursuant to Section 8-406(a) of the Act, to transact business, effective upon closing of the proposed reorganization;

(c) for its Illinois service territory, Liberty Energy (Midstates) is hereby issued certificates of public convenience and necessity identical to the certificates of public convenience and necessity that were issued to Atmos, effective at the time of closing of the proposed reorganization; and

(d) a waiver pursuant to Section 9-201 of the Act of the 45-day notice requirement for the filing of tariffs by Liberty Energy (Midstates), upon the filing of tariffs identical to the tariffs in force for Atmos Energy prior to the consummation of the reorganization, except for the identity of the utility, those tariffs filed to be effective upon filing;

IT IS FURTHER ORDERED that a waiver to maintain books and records outside of Illinois is hereby granted pursuant to Section 5-106 of the Act.

IT IS FURTHER ORDERED that all other approvals and authority that may be granted by the Commission under applicable law that may be required, necessary or useful in connection with the proposed reorganization and the transactions contemplated by the Purchase Agreement or the provisions and purposes thereof or described in the record is hereby granted.

IT IS FURTHER ORDERED that all motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that subject to the provisions of Section 10-113 of the Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By order of the Commission this 27th day of June, 2012.

(SIGNED) DOUGLAS P. SCOTT

Chairman

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	:	
	:	**15-0155**
Application for Certificate of Public Convenience and Necessity to Provide Natural Gas Service to the Village of Pittsburg and its Environs in Williamson County, Illinois	:	

ORDER

By the Commission:

I. INTRODUCTION

On February 27, 2015, Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities ("Liberty Midstates" or the "Company"), filed an application with the Illinois Commerce Commission (the "Commission") pursuant to Section 8-406 of the Public Utilities Act to construct, own, operate, and maintain a natural gas supply and distribution system and provide natural gas service in and to the Village of Pittsburg, Illinois and its environs. The Company also requested approval of applicable rates for the Pittsburg Area, accounting entries related to the acquisition by the Company of natural gas supply and distribution facilities and related assets from the Village of Pittsburg, and other necessary and useful authority.

Company witness Christopher Krygier and Commission Staff ("Staff") witnesses Brett Seagle, Rochelle Phipps, Mike Ostrander, and Philip Rukosuev testified in this proceeding. No parties intervened. An evidentiary hearing was held in this matter on July 16, 2015. At the conclusion of the hearing, the Record was marked "Heard and Taken."

II. BACKGROUND

A. Nature of the Parties

Liberty Midstates is a corporation organized and existing under the laws of the State of Missouri. Liberty Midstates provides natural gas in Illinois to approximately 22,000 customers in Massac, Saline, Macoupin, Logan, Sangamon, Montgomery, Midlothian, Fayette, Effingham, Marion, Clinton and Clay Counties and is a public utility within the meaning of the Public Utilities Act. Liberty Midstates also provides natural gas service in the States of Iowa and Missouri.

Pittsburg is a village in Williamson County, Illinois. The Village of Pittsburg owns a natural gas supply and distribution system (the “System”) that serves approximately 150 natural gas customers.

B. Proposed Transaction and Benefits

The Village of Pittsburg voted to approve the sale of the System to Liberty Midstates on September 15, 2014. Liberty Midstates and the Village of Pittsburg entered into an Asset Purchase Agreement on December 8, 2014.

The Company requested that the Commission grant it a Certificate of Public Convenience and Necessity to construct, own, operate and maintain a natural gas supply and distribution system and provide natural gas service in and to Pittsburg and its environs in Williamson County, Illinois (the “Pittsburg Area”). The Company provided a more particular description of the Pittsburg Area, including a legal description and map, in an attachment to its Application.

Liberty Midstates stated that it plans to make certain improvements to the System (“System Improvements”) that represent an extensive upgrade to the safety and reliability of the System. The System Improvements are expected to address, among other things, certain operations, maintenance and safety issues associated with the System’s current use of polyvinyl chloride pipe ("PVC"). The System Improvements include the construction of natural gas main and services using polyethylene ("PE") and steel pipe as well as improvements to the regulator station and odorization equipment. In addition to replacing the two inch through four inch PVC gas mains (and adding tracer wire and caution tape), Mr. Krygier testified that the Company plans over time to replace three quarter inch service lines, service tees and risers, anodes, valves and boxes, meters, meter loops and regulators. In addition, Mr. Krygier testified that the Company plans to replace odorizers, town border station regulators, reliefs, heaters and remove valves as necessary.

The Village of Pittsburg believes that Liberty Midstates would be better able to address the operations and maintenance of, and improvements to, the System due to Liberty Midstates’ expertise in natural gas operations and financial resources. Mr. Krygier testified that customers will benefit from Liberty Midstates’ enhanced customer service offerings including online bill payment, budget billing and a regional call center, none of which Pittsburg customers have today.

III. SECTION 8-406(b)

Section 8-406(b) of the Public Utilities Act requires the utility to demonstrate: (1) that the proposed construction is necessary to provide adequate, reliable, and efficient service to its customers and is the least-cost means of satisfying the service needs of its customers; (2) that the utility is capable of efficiently managing and supervising the construction process and has taken sufficient action to ensure adequate and efficient construction and supervision thereof; and (3) that the utility is capable of financing the

proposed construction without significant adverse financial consequences for the utility or its customers. As discussed below, both the Company and Staff agree that Liberty Midstates has met these requirements in this case.

A. Section 8-406(b)(1)

The Company stated that the acquisition of the System, the construction of the System Improvements, and the addition of the Pittsburg Area to the Company's service territory is necessary to provide adequate, reliable and efficient service to customers and is the least-cost means of satisfying the needs of natural gas customers in the Pittsburg Area.

1. Adequate, Reliable and Efficient Service

Staff witness Seagle testified that after reviewing the testimony of Mr. Krygier as well as Liberty Midstates' response to certain Staff data requests, he found no reason to dispute the Company's assertion that the construction of the proposed new gas pipeline facilities is necessary for it to provide adequate, reliable, and efficient service to its potential customers in the Pittsburg Area. Staff witness Seagle noted that the proposed construction is necessary for two reasons. First, Mr. Seagle noted that the glue used to make PVC pipe connections on the existing Pittsburg gas delivery system no longer meets the industry standard for connections of this type. Second, Mr. Seagle explained that the mechanical connection hardware for joining PVC pipe to PE pipe is in limited supply, making maintenance on a distribution system like the one in Pittsburg that contains both materials impractical. Staff witness Seagle testified that it is his opinion that the Company has demonstrated that the proposed construction is necessary to provide adequate, reliable and efficient service.

2. Least-cost means of satisfying service needs

Staff witness Seagle additionally testified that Liberty Midstates has demonstrated that it can provide natural gas service to the customers of the Pittsburg Area on a least-cost basis. Mr. Seagle stated that his determination was based on his review of a Present Value Revenue Requirement ("PVRR") calculation that compared an estimate of the present value of the Company's anticipated revenues from the addition of customers currently served by the Village of Pittsburg to an estimate of the present value of the Company's revenue requirement for serving the Pittsburg Area. Mr. Seagle noted that Staff places great reliance on PVRR analyses to conduct an economic study of utility options, especially in situations such as the Pittsburg acquisition. Mr. Seagle used the PVRR to compare the Company's anticipated revenues from the addition of the customers currently served by the Village of Pittsburg to the Company's expected costs to serve those same customers. His review of the PVRR calculation demonstrated that ratepayers would not subsidize the acquisition and System Improvements. Therefore, Mr. Seagle concluded the proposed transaction is in the best interest of Liberty Midstates existing customers. Mr. Seagle recommended that the Company conduct a PVRR analysis in any future acquisition.

Mr. Krygier testified that the Company performed the PVRR at Staff's request, to the extent it might be helpful to Staff and the Commission. However, he stated that the Company did not itself use the PVRR calculation in determining that the proposed acquisition would be in the public interest. Mr. Krygier stated that although Mr. Seagle and he differ regarding the value of the PVRR analysis in this instance, in any future acquisition involving the issuance of a certificate the Company understands that it will have to provide such analyses and evidence as may be necessary to satisfy its burden of proof that its proposal is necessary to provide adequate, reliable, and efficient service to its customers and is the least cost means of satisfying the service needs of its customers.

B. Section 8-406(b)(2)

The Company stated that it is capable of efficiently managing and supervising the acquisition of the System and the construction of the System Improvements and has taken, and will continue to take, sufficient action to ensure adequate and efficient construction and supervision of construction.

Staff witness Seagle agreed that the Company had demonstrated that it is capable of efficiently managing and supervising the construction process. Mr. Seagle based this determination on information provided by the Company. In particular, he mentioned evidence that this type of project, the replacement of PVC pipe, is well within the normal activities of Liberty Midstates, and that Liberty Midstates provides natural gas service in Illinois to approximately 22,000 customers in a safe and reliable manner. He also pointed out that Liberty Midstates' construction practices must comply with federal safety standards.

C. Section 8-406(b)(3)

The Company stated that it is capable of financing the acquisition of the System and the construction of System Improvements without significant adverse financial consequences for the Company and its customers.

Staff witness Phipps reviewed the information contained in the Company's application and testimony. In particular, Ms. Phipps examined the Company's estimates of the direct costs for the System Improvements. Ms. Phipps stated that the total cost of the proposed transaction is diminutive in relation to the Company's utility plant and operating revenue. Therefore, Ms. Phipps concluded that the Company is capable of financing the proposed construction without significant adverse consequences for the Company or its customers.

D. Commission Analysis and Conclusion

The Commission finds that the Company's proposal fulfills the requirements of Section 8-406(b) of the Public Utilities Act. The record demonstrates that (1) Liberty

Midstates' purchase of the System, its construction of the System Improvements, and the addition of the Pittsburg Area to the Company's service territory are necessary to provide adequate, reliable and efficient service to customers and constitutes the least cost means of satisfying the service needs of customers in the Pittsburg Area, (2) Liberty Midstates is capable of efficiently managing and supervising the construction process and has taken sufficient action to ensure adequate and efficient construction and supervision thereof, and (3) Liberty Midstates is capable of financing the proposed construction without significant adverse financial consequences for the utility or its customers. Accordingly, the Commission approves the proposed transaction, the construction of the System Improvements, and the addition of the Pittsburg Area to the Company's service territory in accordance with Section 8-406 of the Public Utilities Act, and grants the Company's request for a Certificate of Public Convenience and Necessity to construct, own, operate and maintain a natural gas supply and distribution system and provide natural gas service in and to the Pittsburg Area.

IV. OTHER ISSUES

A. Accounting Entries

Liberty Midstates outlined its proposed accounting treatment of the proposed transaction in its Application and requested that the Commission approve that treatment. The Company's proposed accounting treatment included an attachment setting forth specific journal entries. Staff witness Ostrander concluded that the proposed journal entries comply with Gas Plant Accounting Instruction 5 of the Uniform System of Accounts for Gas Utilities. Mr. Ostrander recommended that the Commission approve the proposed accounting entries and that the Company's attachment setting forth its proposed journal entries be included as an appendix to the Final Order in this proceeding.

Mr. Ostrander further recommended that the Commission order the Company to file the final accounting entries for the transaction, showing the actual dollar values of all involved accounts as a filing on the Commission's e-Docket system with a copy to the Commission's Accounting Department Manager within sixty (60) days of the transaction date. If the transaction has not occurred within six months of the Final Order in this proceeding, Mr. Ostrander recommended that the Company file status reports at six-month intervals until the journal entries are filed in accordance with his recommendation.

B. Rates

The Company proposed that customers in the Pittsburg Area, including those served by the System, be subject to the Company's tariff rates, rules and regulations on file from time to time in accordance with applicable law. The Company proposed that such customers would obtain service under the tariff rates, rules and regulations in effect at that time and applicable to Rate Zone 3. Mr. Krygier stated that at this time there is no difference in rates, rules and regulations applicable in the Company's rate zones. Such rates, rules and regulations would remain in effect until any changes to the Company's tariffs and terms of service may be made in accordance with applicable law.

Mr. Krygier stated that he does not believe that the long term cost of providing service to the Pittsburg Area would be substantially different than the Company's cost of providing service in its other, similar, service areas in Illinois. The Company stated that adoption of the Company's natural gas rates, rules and regulations for customers in the Pittsburg Area is appropriate and in the best interest of those customers.

Staff witness Rukosuev stated that Staff did not object to the Company's rate design proposal. He stated that it represents the most fair and balanced scenario at this time. Mr. Rukosuev stated that the proposed rates, rules, and regulations simply allow the Company to recover the cost of gas service to the Pittsburg Area, and that the adoption of the Company's natural gas rates, rules and regulations for customers in the Pittsburg Area is appropriate and in the best interest of those customers. He recommended that the Commission approve the Company's proposed rates, rules and regulations for the Pittsburg Area.

C. Ongoing Reporting

Mr. Krygier stated that the Company agreed to have its president appear before the Commission on an annual basis after a final order is issued in this case to discuss the progress of the acquisition and its integration into Company operations.

D. Commission Analysis and Conclusions

Based on the record, the Commission finds that Company's proposed journal entries as set forth in Appendix A to this Order are approved. The Commission agrees with Staff's recommendation that Liberty Midstates be required to file final accounting entries within sixty days of the close of the proposed transaction.

In addition, based on the record the Commission concludes that the Company's proposal regarding rates is in the best interests of customers in the Pittsburg Area. Customers in the Pittsburg Area shall obtain service under the tariffs, rules, and regulations in effect at this time for Rate Zone 3. Such tariffs, rates, rules and regulations will remain in effect until any changes to the Company's tariffs and terms of service may be made in accordance with applicable law.

Finally, the Commission determines that the Company's president should appear, on an annual basis after a final order is issued in this case, to discuss the progress of the acquisition and its integration into Company operations.

V. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having considered the entire record herein and being fully advised in the premises, is of the opinion and finds that:

(1) Liberty Midstates is a corporation engaged in the distribution of natural gas to the public in Illinois and, as such, is a public utility within the meaning of the Public Utilities Act;

(2) the Commission has jurisdiction over Liberty Midstates and of the subject matter in this proceeding;

(3) the statements of fact set forth in the prefatory portion of this Order are supported by the record and are hereby adopted as findings of fact;

(4) issuance of a Certificate of Public Convenience and Necessity for the Village of Pittsburg and its environs to the Company will promote the public convenience and is necessary thereto, and the requirements of Section 8-406(b) have been met;

(5) the Asset Purchase Agreement between Liberty Midstates and the Village of Pittsburg should be approved;

(6) Liberty Midstates' proposed accounting treatment for the proposed transaction, including the accounting journal entries set forth in Appendix A to this Order, is reasonable and should be approved;

(7) Liberty Midstates shall file the final accounting entries for the transaction, showing the actual dollar values of all involved accounts as a filing on the Commission's e-Docket system with a copy to the Commission's Accounting Department Manager within sixty (60) days of the transaction date and, if the transaction has not occurred within six months of the date hereof, Liberty Midstates shall file status reports at six month intervals until the journal entries are filed on the Commission's e-Docket system with a copy to the Commission's Accounting Department Manager;

(8) the customers in the Pittsburg Area should obtain service under the Company's tariff, rates, rules, and regulations in effect at that time for Rate Zone 3, such tariff, rates, rules and regulations to remain in effect until any changes to the Company's tariffs and terms of service may be made in accordance with applicable law;

(9) the president of the Company should appear annually before the Commission to discuss the progress of the acquisition and its integration into Company operations;

(10) the Company's request for all other necessary and useful relief and authority under the Public Utilities Act to allow the Company to construct, own, operate and maintain a natural gas supply and distribution system and provide natural gas service in the Pittsburg Area should be granted; and

(11) all motions, petitions, objections or other matters in this proceeding that remain unresolved should be resolved consistent with the conclusions contained herein.

IT IS THEREFORE ORDERED that pursuant to Section 8-406 a Certificate of Public Convenience and Necessity is hereby issued to Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities, such Certificate reading as follows:

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

IT IS HEREBY CERTIFIED that Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities is granted a Certificate of Public Convenience and Necessity for the construction, operation and maintenance of a public utility gas distribution system in area of Pittsburg, Williamson County, as shown on the map attached to this Order and identified as Appendix A attached hereto.

IT IS FURTHER ORDERED that the Asset Purchase Agreement between Liberty Midstates and the Village of Pittsburg is approved.

IT IS FURTHER ORDERED that Liberty Midstates' proposed accounting treatment for the proposed transaction, including the journal entries as set forth in Appendix B to this Order, is reasonable and are approved.

IT IS FURTHER ORDERED that Liberty Midstates shall file the final accounting entries for the transaction, showing the actual dollar values of all involved accounts as a filing on the Commission's e-Docket system with a copy to the Commission's Accounting Department Manager within sixty (60) days of the transaction date and, if the transaction has not occurred within six months of the Final Order in this proceeding, Liberty Midstates shall file status reports at six month intervals until the journal entries are filed on the Commission's e-Docket system with a copy to the Commission's Accounting Department Manager.

IT IS FURTHER ORDERED that the customers in the Pittsburg Area shall obtain service under the Company's tariff, rates, rules, and regulations in effect at that time for Rate Zone 3, such tariff, rates, rules and regulations to remain in effect until any changes to the Company's tariffs and terms of service may be made in accordance with applicable law.

IT IS FURTHER ORDERED that the president of the Company should appear annually before the Commission to discuss the progress of the acquisition and its integration into Company operations.

IT IS FURTHER ORDERED that the Company is hereby granted all other necessary and useful relief and authority under the Public Utilities Act to allow the

Company to construct, own, operate and maintain a natural gas supply and distribution system and provide natural gas service in the Pittsburg Area.

IT IS FURTHER ORDERED that all motions, petitions, objections or other matters in this proceeding that remain unresolved should be resolved consistent with the conclusions contained herein.

IT IS FURTHER ORDERED that, subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Illinois Administrative Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By order of the Commission this 28th day of July, 2015.

(SIGNED) BRIEN SHEAHAN

Chairman

15-0155
Appendix B

Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities
Attachment D
Village of Pittsburg Acquisition Accounting Entry

Entry 1 - To Record Utility Plant in Service			
Account	**Account Description**	**Dr**	**Cr**
8855-2-0400-10-1615-1020	Plant Purchased or Sold		$ 86,193
8855-2-0400-10-1615-3762	T&D-Mains-PLST	$ 56,126	
8855-2-0400-10-1615-3780	Measuring & regulating stn eqt-General	$ 2,500	
8855-2-0400-10-1615-3780	Measuring & regulating stn eqt-General	$ 7,255	
8855-2-0400-10-1615-3800	Services	$ 20,312	
	Total	$ 86,193	$ 86,193

Entry 2 - To Record Depreciation & Acquisition Adjustments			
Account	**Account Description**	**Dr**	**Cr**
8855-2-0400-10-1615-1020	Plant Purchased or Sold	$ 86,193	
8855-2-0400-10-1615-1140	Plant Acquisition Adjustments	$ 833	
8855-2-0400-10-1655-1080	Accum Prov for Depn of Gas Utility Plant-Mains		$ 56,126
8855-2-0400-10-1655-1080	Accum Prov for Depn of Gas Utility Plant-Meas & Reg		$ 2,500
8855-2-0400-10-1655-1080	Accum Prov for Depn of Gas Utility Plant-Meas & Reg		$ 1,088
8855-2-0400-10-1655-1080	Services		$ 20,312
8850-2-0400-10-1020-1310	Cash		$ 7,000
	Total	$ 87,026	$ 87,026

Entry 3 - To Write-Off Plant Acquisition Adjustments			
Account	**Account Description**	**Dr**	**Cr**
8855-2-0400-80-8641-4250	Miscellaneous Amortization	$ 833	
8855-2-0400-10-1615-1140	Plant Acquisition Adjustments		$ 833

15-0155
Appendix

FRANCHISE AREA:

TOWNSHIP 8 SOUTH, RANGE 3 EAST

E ½ SECTION 34
SECTION 35
W ½ SECTION 36
S ¼ SECTION 36

TOWNSHIP 8 SOUTH, RANGE 4 EAST

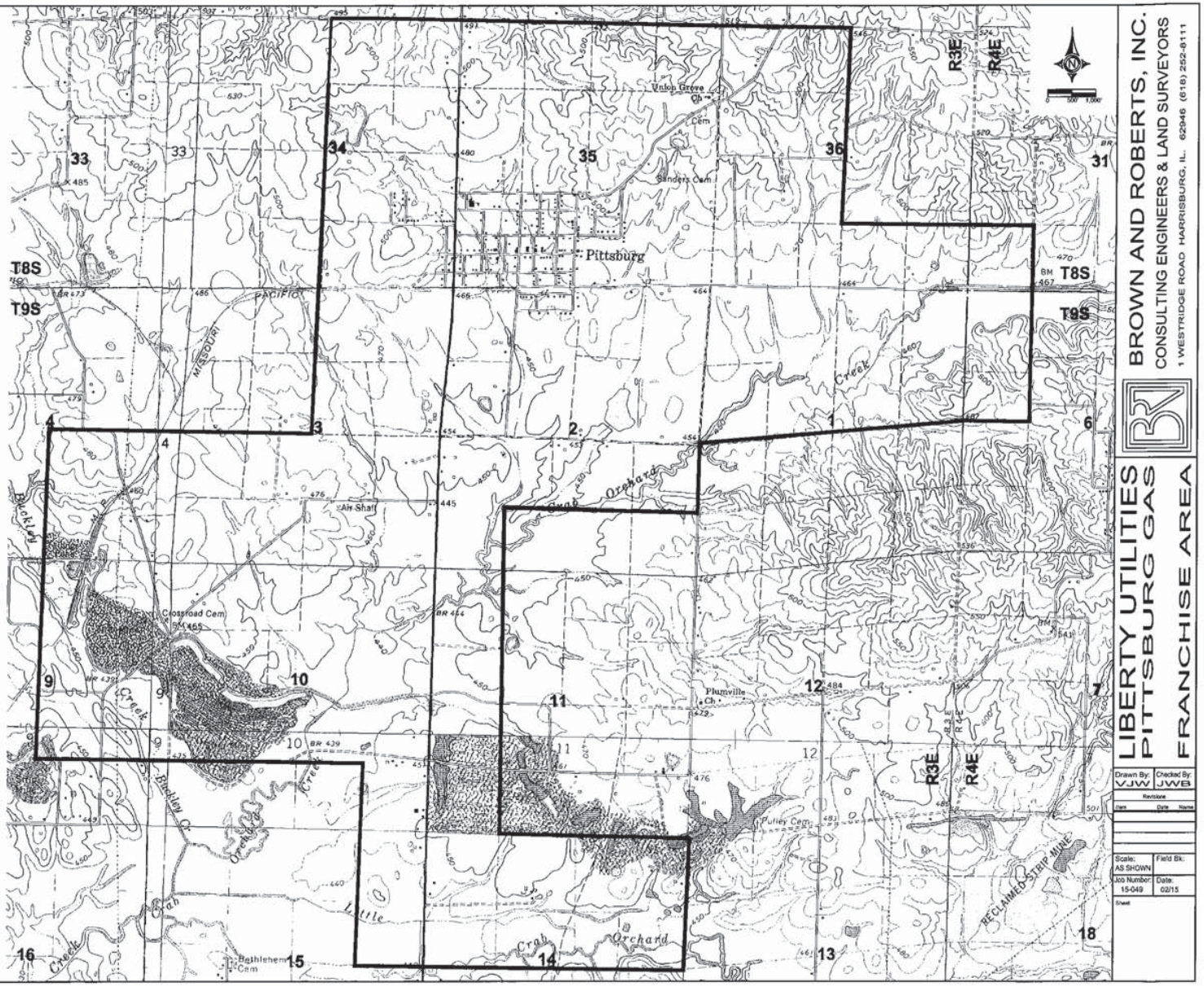
SW ¼ SW ¼ SECTION 31

TOWNSHIP 9 SOUTH, RANGE 3 EAST

N ½ SECTION 1
N ¾ SECTION 2
SW ¼ SW ¼ SECTION 2
E ½ SECTION 3
SW ¼ SECTION 3
SE ¼ SECTION 4
NE ¼ SECTION 9
N ½ SE ¼ SECTION 9
N ¾ SECTION 10
SE ¼ SE ¼ SECTION 10
W ¼ SECTION 11
N ½ SECTION 14
E ½ NE ¼ SECTION 15

TOWNSHIP 9 SOUTH, RANGE 4 EAST

W ½ NW ¼ SECTION 6



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LIBERTY UTILITIES
PITTSBURG GAS

FRANCHISE AREA

Drawn By: VJW | Checked By: JWB
Revisions
Item | Date | Name
Scale: AS SHOWN | Field Bk:
Job Number: 15-049 | Date: 02/15
Sheet

APPENDIX A
05 Feb 2015 - 9:17am X:\2015\15049\acd\Franchise Area - Pittsburg.dwg: Layout Tab 'Franchise Area'

STATE OF IOWA

DEPARTMENT OF COMMERCE

UTILITIES BOARD

IN RE: ATMOS ENERGY CORPORATION AND LIBERTY ENERGY (MIDSTATES) CORPORATION	DOCKET NO. SPU-2011-0008

ORDER NOT DISAPPROVING PROPOSAL FOR REORGANIZATION, GRANTING REQUEST TO DISCONTINUE SERVICE, AND REQUIRING REPORTS

(Issued November 14, 2011)

PROCEDURAL BACKGROUND

On August 15, 2011, Atmos Energy Corporation (Atmos) and Liberty Energy (Midstates) Corporation (Liberty Midstates) (collectively Joint Applicants) filed a joint proposal for reorganization pursuant to Iowa Code §§ 476.76 and 476.77 (2011). The application included a request for Board approval required in Iowa Code § 476.20(1) and 199 IAC 7.1(6) for Atmos to discontinue service to customers in Iowa. The filing is the result of an Asset Purchase Agreement entered into on May 12, 2011. Under the agreement, Liberty Midstates will acquire all of the natural gas assets of Atmos located in Iowa, Illinois, and Missouri. With the application, Joint Applicants filed supporting information that included the prepared direct testimony and exhibits of witnesses Mark A. Martin, Peter Eichler, Ian E. Robertson, and David J. Pasieka.

Included with the proposal for reorganization, Joint Applicants filed a request that the Board waive the review of its application as provided in Iowa Code

§ 476.77(4) or, in the alternative, expedite consideration of the reorganization proposal and not conduct a hearing.

On August 24, 2011, the Board issued an order docketing the proposal for reorganization and request for waiver. In the August 24, 2011, order, the Board established a date for intervention and a date for responding to the request for waiver or expedited consideration. On September 12, 2011, the Consumer Advocate Division of the Department of Justice (Consumer Advocate) filed a pleading stating that it had no objection to the proposed reorganization or the waiver request. No petitions to intervene were filed.

On September 26, 2011, Joint Applicants filed a pleading in which they provided responses to questions and requests for additional information from Board staff.

On October 3, 2011, the Board issued an order that denied the request for waiver, granted expedited consideration, and required additional information. In the order, the Board stated that it did not appear a hearing was necessary; however, the Board had not completed its review of the proposed reorganization. On October 10, 2011, Joint Applicants filed the information requested by the Board in the October 3, 2011, order.

Iowa Code § 476.77(2) provides that a proposal for reorganization shall be deemed to have been approved unless the Board disapproves the proposal within 90 days after its filing. The Board, for good cause shown, may extend the deadline for acting on an application for an additional period not to exceed 90 days. However, the

Board shall not disapprove a proposal for reorganization without providing for notice and opportunity for hearing. The notice of hearing shall be provided no later than 50 days after the proposal for reorganization has been filed. Iowa Code § 476.77(3) states that in the Board's review of the proposal for reorganization, the Board may consider the following five issues:

a. Whether the board will have reasonable access to books, records, documents, and other information relating to the public utility or any of its affiliates.

b. Whether the public utility's ability to attract capital on reasonable terms, including the maintenance of a reasonable capital structure, is impaired.

c. Whether the ability of the public utility to provide safe, reasonable, and adequate service is impaired.

d. Whether ratepayers are detrimentally affected.

e. Whether the public interest is detrimentally affected.

PROPOSAL FOR REORGANIZATION

The Asset Purchase Agreement states that the purchase price of the assets is approximately $124 million, subject to adjustment. Under the provisions of the proposal for reorganization, Atmos will sell and Liberty Midstates will purchase Atmos' Iowa assets. Following the reorganization, Atmos will no longer provide utility services in Iowa. Atmos currently provides natural gas service to approximately 4,000 customers in Southeast Iowa, primarily in the Keokuk and Montrose areas. The Iowa assets are only a small portion of the total Atmos utility assets, which are

located in Georgia, Tennessee, Virginia, Mississippi, Texas, Louisiana, Kentucky, Colorado, Illinois, Missouri, and Kansas. Atmos is also selling its Missouri and Illinois assets to Liberty Midstates.

According to Atmos witness Martin, Atmos had not been looking to sell its Iowa assets and had rejected prior offers from Algonquin Power & Utility Corporation (Algonquin) to purchase its assets. After exploring its potential ability for growth in Iowa, Atmos had determined that there were no viable options available and that it would maintain the status quo. Discussions between Algonquin and Atmos continued and Atmos realized that Algonquin and Atmos shared common corporate and operational values that would benefit Atmos' customer base and personnel. At that point, Atmos decided it would sell its Iowa assets to Algonquin. According to Martin, the sale to Algonquin is the only alternative Atmos considered.

Algonquin, the ultimate parent of Liberty Midstates, was organized in 1987, is incorporated under the laws of Canada and has its principal offices located in Ontario, Canada. Algonquin is publically traded on the Toronto Stock Exchange. Over 50 percent of Algonquin's revenues are generated through operations located in the United States, which include regulated and non-regulated companies. Algonquin acquired its first regulated utility operations in 2001. Since then it has acquired 19 additional electric and water and wastewater utilities serving a total of approximately 125,000 customers in the United States.

Algonquin conducts its regulated utility operations through subsidiaries. The regulated utilities are organized under the wholly-owned subsidiary Liberty Utilities

(Canada) Corp., a Canadian corporation, which owns Liberty Utilities Co. (Liberty Utilities), a Delaware corporation, which in turn owns Liberty Energy Utilities Company (Liberty Energy), which is the immediate parent of Liberty Midstates. Liberty Midstates is a Missouri corporation and was formed by Algonquin for the purpose of acquiring the Iowa, Missouri, and Illinois assets from Atmos. Liberty Utilities also owns Liberty Water Co., a Delaware corporation that provides water utility services to over 75,000 customers.

Under the proposal for reorganization, all applicable government permits that may be legally transferred from Atmos to Liberty Midstates will be transferred. This includes all of the certificates of public convenience and necessity in Iowa. After the purchase is completed, Liberty Midstates will provide service to approximately 4,000 former Atmos customers in Iowa, to approximately 24,000 former Atmos customers in Illinois, and to approximately 57,000 former Atmos customers in Missouri. The purchase agreement will terminate if the closing has not occurred on or before January 12, 2012. The agreement may be extended under certain circumstances.

In addition to review by the Board, the proposed reorganization must also be approved by the Illinois Commerce Commission and the Missouri Public Service Commission. The Joint Applicants stated that the following steps are necessary to complete the transfer of assets in Iowa from Atmos to Liberty Midstates if the Board does not disapprove the proposal for reorganization:

1. Approval of the transfer of all Board-issued certificates from Atmos to Liberty Midstates;

2. Approval of the abandonment of service by Atmos;

3. Granting Liberty Midstates authority to provide all services currently provided by Atmos in accordance with the rules, regulations, and terms and conditions of service currently applicable to Atmos;

4. Authorizing Liberty Midstates to adopt and provide service immediately pursuant to the Atmos tariffs approved by the Board; and

5. All other approvals and authority that may be necessary for Liberty Midstates to provide rate-regulated natural gas service to customers in Iowa.

STATUTORY ISSUES AND OTHER ISSUES

In reviewing the proposal for reorganization the Board considers the five issues set out in Iowa Code § 476.77(3) and other issues the Board considers relevant to this proposal for reorganization. Since Consumer Advocate raises no issues regarding the proposal for reorganization and there are no intervenors, the Board will discuss the information and testimony filed by Joint Applicants that applies to each issue considered below.

1. Whether the Board will have Reasonable Access to Books, Records, Documents, and Other Information Relating to the Public Utility or any of its Affiliates

A. Books and Records

The application and Liberty Midstates' witness Eichler state that it is anticipated that the books and records of Liberty Midstates will be maintained outside of Iowa; however, the Board will continue to have reasonable access to those books

and records, electronically or by other reasonable means. In the September 26, 2011, response, Joint Applicants state that the books and records of Liberty Midstates will be kept within its service territory, most likely in Missouri. Electronic records will be maintained in Canada but can be accessed remotely from anywhere. Pipeline safety and engineering records will be maintained in local offices within Iowa.

Board Discussion

Board rules at 199 IAC 18.2 and 18.3 require that all records of regulated public utilities be kept and made available for examination in Iowa unless otherwise authorized by the Board. Board rules at 199 IAC 32.4(2)"c" require that the application include information about the location of the books and records of the public utility after reorganization and their availability to the Board. Joint Applicants state that it is anticipated that the books and records of Liberty Midstates will be maintained outside of Iowa and that the Board will have reasonable access to these books and records electronically, or by other reasonable means.

Assurances made by the Joint Applicants in the September 26, 2011, compliance filing appear to resolve concerns about access to accounting and safety and engineering records. Based on those assertions, the Board finds that it will have adequate access to: (1) books and records kept in the regional office (probably in Missouri) or available electronically from Canada; and (2) safety and engineering records kept in the local office in Iowa.

B. Cost Allocations and Affiliate Transactions

Joint Applicants state that Liberty Midstates will allocate costs and facilities between utility and non-utility activities and among its utilities in a fair and reasonable manner, such that the Board may readily identify those costs and facilities which should properly be included in Liberty Midstates' Iowa rates. Algonquin and its subsidiaries operate as part of a shared services model under which certain services provided at the corporate level, either by Algonquin or Liberty Utilities, are charged to Algonquin affiliates based on either a direct charge or a defined cost allocation methodology. The majority of costs are based on direct charges because they reflect labor costs for a particular service.

Joint Applicants state that Algonquin's cost allocation methodology is based on several factors, including (1) earnings before interest, taxes, depreciation, and amortization (collectively known as EBITDA); (2) revenues; (3) plant-in-service; (4) employees; (5) square footage; and (6) expenses. Where one of these factors is the principal cost driver, it is used exclusively to allocate costs among Algonquin's current direct subsidiaries. When a single cost driver cannot be identified, EBITDA, revenues, plant-in service, and expenses are averaged to determine the proper cost allocation. Costs are then allocated to the direct subsidiaries and are then further allocated to their respective subsidiaries based on a weighted average of plant-in-service, customer count, labor costs, and other expenses.

Joint Applicants state there are certain costs for services performed by Liberty Utilities for its subsidiaries that must be charged to the appropriate entities. These

costs for services that are performed by Liberty Utilities mostly relate to labor, which generally can be directly charged. The majority of the costs and related services benefit Liberty Water and Liberty Energy and their subsidiaries. These costs are directly charged either to Liberty Water or Liberty Energy, as appropriate, and in turn, are allocated to each operating company based on a four-factor methodology that includes a weighted average of rate base, total customers, non-labor expenses, and labor. Where costs cannot be attributed either to Liberty Water or Liberty Energy, they are divided using the four-factor methodology described above. Non-labor costs are also allocated using the four-factor methodology. Joint Applicants state that the same allocation methodology will be applied to Liberty Midstates that is applied to all of the other Liberty Utilities subsidiaries, which means directly charging as much as possible, and using the cost allocation drivers where direct assignment is not possible.

Eichler provided the current Cost Allocation Manual (CAM) used by Algonquin subsidiaries as an exhibit. Eichler testifies that the CAM was completed in accordance and conformance with the "NARUC Guidelines for Cost Allocations and Affiliate Transactions." The founding principles of the CAM are to: (a) directly charge as much as possible to the entity that procures any specific service, and (b) to ensure that inappropriate subsidization of unregulated activities by regulated activities and vice versa does not occur.

Joint Applicants state in their September 26, 2011, compliance filing that Liberty Midstates will file a copy of its Cost Allocation Manual upon completion of the proposed reorganization and it will file annual updates thereafter.

Joint Applicants state that Liberty Midstates will be subject to and will abide by all applicable Iowa laws, regulations, rules, decisions, and policies governing the regulation of public utilities in Iowa, including without limitation those related to affiliate transactions.

Joint Applicants state that Liberty Midstates plans to employ individuals within its service region to provide services where it is reasonable to do so. Joint Applicants point out that some services are more reasonably provided on a regional, national, or international level and these transactions for services, such as executive management, treasury, corporate finance, legal and some information technology, human resources, and regulatory functions that are provided outside the local level, will be in accordance with applicable Iowa law, including the requirement that any such contracts be filed with the Board.

Joint Applicants state in the September 26, 2011, response that Liberty Midstates will file a copy of its CAM upon completion of the proposed reorganization and that it will file annual updates thereafter. The CAM provides the allocation methodology used by affiliates of Liberty Midstates to allocate costs to Liberty Midstates.

Board Discussion

While the CAM filed by the Joint Applicants does not specifically mention Liberty Midstates, it does describe the allocations to subsidiaries at the same level in the corporate hierarchy as Liberty Midstates. The founding principles of the manual appear to be consistent with 199 IAC 33.4(3) which states:

> *Time reporting.* Positive time reporting shall be used whenever possible. In situations where positive time reporting cannot be used, exception time reporting or study time reporting may be used. Nonproductive work time shall be allocated between utility and nonutility operations in proportion to the allocation of productive work time.

Atmos does not currently file a CAM with the Board because it does not reach the filing threshold in 199 IAC 33.2. Liberty Midstates has committed to filing a CAM when this proposed reorganization is consummated and annually thereafter. The provisions proposed for the CAM as described by Joint Applicants appear reasonable and Liberty Midstates' commitment to voluntarily comply with 199 IAC 33.5 will allow the Board to address any allocation issues that arise in the future.

Joint Applicants filed a CAM with their application. While the CAM does not specifically mention Liberty Midstates, it does describe the allocations to companies at the same level in the corporate hierarchy as Liberty Midstates. The founding principles of the CAM appear to be consistent with 199 IAC 33.4(3).

C. Location of Assets

Liberty Midstates states that it does not intend to remove any of the Iowa assets from the state of Iowa or from the Board’s jurisdiction. Based upon this

commitment, the Board should retain its jurisdiction over the assets that provide utility service to Iowa consumers and the Board expects Liberty Midstates to inform the Board if a change in this commitment is contemplated.

D. Compliance with Board Rules

Joint Applicants assert that Liberty Midstates will be subject to and will abide by all applicable Iowa laws, regulations, rules, decisions, and policies governing the regulation of public utilities in Iowa, including without limitation those related to affiliate transactions. Liberty Midstates' commitment assures the Board that Liberty Midstates understands that it operates as a rate-regulated public utility in Iowa under the Board's jurisdiction.

E. Accounting Policies

Joint Applicants state that Liberty Midstates will utilize Federal Energy Regulatory Commission (FERC) accounting standards, consistent with Atmos' current practice. Accounting at the parent level and for all its subsidiaries is performed in accordance with U.S. Generally Accepted Accounting Principles (GAAP). Joint Applicants state that Algonquin is compliant with the federal Sarbanes-Oxley Act.

The purchase agreement provides that "the sum of the Purchase Price and the Assumed Obligations will be allocated among the Purchased Assets on a basis consistent with section 1060 of [the Internal Revenue Code of 1986, as amended] and the Treasury Regulations thereunder." If the Joint Applicants are unable to

agree on an allocation once the final purchase price is determined, the allocation will be determined by an independent accounting firm and will be binding on the parties.

Board Discussion

Based upon the assertions of the Joint Applicants and the provisions in the purchase agreement with regard to the accounting policies that will be followed by Liberty Midstates, the Board finds that the accounting practices are substantially in compliance with Board rules.

2. Whether the Public Utility's Ability to Attract Capital on Reasonable Terms, Including the Maintenance of a Reasonable Capital Structure, Is Impaired

According to the information in the Asset Purchase Agreement, the estimated purchase price for Atmos' Iowa, Illinois, and Missouri assets is approximately $124 million. Joint Applicants state that Liberty Midstates will issue a minimum of $68 million of common stock to its immediate parent, Liberty Energy. Liberty Midstates will also issue approximately $56 million in long-term debt, in the form of privately placed secured notes. Joint Applicants state that these projections could change based on purchase price adjustments.

Joint Applicants state that after the reorganization, Liberty Midstates' ability to attract capital on reasonable terms or to maintain a reasonable capital structure will not be impaired. Liberty Midstates intends to have a proposed capital structure of 45 percent debt and 55 percent common equity. Joint Applicants state that these ratios are consistent with industry norms and past Board decisions. Joint Applicants state

that Liberty Midstates' intends to maintain a strong balance sheet and investment grade credit rating so that it will be able to obtain needed capital.

Joint Applicants state that Algonquin has a strong balance sheet and an excellent credit rating and it is able to access debt and equity capital when it is needed which can be used to meet the capital needs of Liberty Midstates. In addition, Algonquin has a relatively low level of debt and is able to access the capital markets as funds are needed. Joint Applicants state that Algonquin has a strong balance sheet that supports a bond rating from Standard & Poor's (S&P) of BBB-.

Algonquin witness Robertson testifies that: (1) Algonquin's common stock and debentures are traded on the Toronto Stock Exchange; (2) Algonquin is a registered private issuer with the U.S. Securities and Exchange Commission (SEC) compliant with all applicable SEC and Sarbanes-Oxley Act requirements; (3) all of Algonquin's financial statements are presented in accordance with U.S. GAAP; (4) a large number of analysts cover Algonquin's stock; and (5) Algonquin's ability to issue debt at favorable rates demonstrates the strength of its debt issuances. Joint Applicants state that after the announcement of the proposed transaction addressed in this docket, financial analysts have expressed support for the proposed reorganization in their reports.

Board Discussion

A review of the business and financial risks associated with the reorganization will help determine whether the reorganization will have a negative impact on the

utility's capital structure, costs, or availability of funds at reasonable rates. No intervenors filed an objection to this merger, and Consumer Advocate stated that it does not object to the reorganization.

Business Risk

Business risk is any risk unique to a type of business that increases the variability of earnings; for example, factors affecting business risk include a company's markets, management, regulatory environment, and competitiveness. Therefore, it is worthwhile to compare the business operations of the incumbent utility with the business operations of the acquiring company.

The acquiring company, Algonquin, is made up of: 1) Algonquin Power Co. that owns and operates renewable energy assets that include wind, hydroelectric, and thermal generation; and 2) Liberty Utilities that owns and operates a portfolio of North American utilities that provide electricity, natural gas, and water and wastewater services. Normally having a diversified portfolio lowers a company's business risk since it can help reduce the variability of earnings.

However, in its credit report for Algonquin dated February 14, 2011, S&P stated that the "complex and dispersed nature of the company's electricity generation portfolio, however, tempers the credit risk advantage typically associated with diversification." S&P went on to say that due to the complexity of this portfolio, it requires the knowledge of many technologies and different regulatory environments. Algonquin's portfolio of different assets can also limit operational efficiencies and "constrain effective management." Another risk noted by S&P includes the foreign

exchange rate risk since 60 percent of the revenues are generated in the U.S., while 40 percent come from Canada where Algonquin is headquartered. Eichler testifies that Algonquin had a net gain in years 2009 and 2010 because of the foreign exchange rate as shown in its 2010 Annual Report.

S&P also mentioned Algonquin's strengths, which are: (1) negligible competition with its business markets; (2) considerable portion of the revenue streams are regulated or contracted; and (3) the diversified businesses operate under long-term contracts which underpin stability.

Unlike Algonquin, Atmos is solely involved in the natural gas industry. Atmos distributes natural gas to customers over a 12-state region, has a natural gas pipeline and storage assets in Texas and has a subsidiary, Atmos Energy Holdings, involved in unregulated businesses. According to Moody's rating agency, Atmos has a conservative management approach and has lower risk due to its rate-regulated natural gas distribution utilities operating in relatively constructive regulatory regimes. S&P states that lack of competition and a large residential customer base help support Atmos' excellent business risk profile.

Based on the analysis of credit reports, it appears that Atmos has a stronger (less risky) business risk profile compared to Algonquin's. This is comparing the parent holding companies, which include all businesses. The newly-created subsidiary, Liberty Midstates, should exhibit business risk resembling that of Atmos since this subsidiary will consist of the assets once owned by Atmos in Iowa, Illinois, and Missouri. These assets should also (1) be a part of the lower risk rate-regulated

utility operations, (2) lack competition, and (3) have a larger residential customer base, which are some of the reasons for Atmos' excellent business risk profile. In addition, Liberty Midstates will be assigned its own credit rating which should reflect its business risks.

Financial Risk

Financial risk reflects the amount of fixed capital included within a capital structure. If there is too much debt, it increases the amount of financial risk and limits the financial flexibility of the company which also increases the costs of acquiring needed debt capital. It is Algonquin's position that the pro forma balance sheet for Liberty Midstates reflects 45 percent debt and 55 percent common equity, consistent with the industry and capital structures approved by the Board. According to Eichler, this capital structure will ensure access to the financial markets and should provide a separate credit rating of investment grade for Liberty Midstates. Eichler also states that due to Algonquin's investment grade credit rating and strong balance sheet, Algonquin can access debt and equity capital to meet Liberty Midstates' capital needs if necessary. Although the capital structure is provided in the proposed reorganization, the actual amount of debt and common equity and the terms on the debt issues are not available at this time. Liberty Midstates asserts that it needs the flexibility to issue the capital when it is needed. Liberty Midstates has committed to provide this information to the Board when it becomes available.

Based upon the above discussion, the Board finds that the proposed capital structure is reasonable and should not impair Liberty Midstates' ability to access the

capital markets at reasonable rates. A capital structure with more common equity than debt helps reduce the financial risk of a company. This is also in line with the capital structures of other utility companies that operate in Iowa and is similar to Atmos' current capital structure and Atmos appears to be a financially strong company. Atmos has a current credit rating of BBB+ by S&P and A- by Fitch Ratings. The credit rating assigned to a company reflects the quantitative and qualitative analysis of a company including financial risks and business risks and is a good indicator of a company's overall financial strength.

Algonquin's credit rating is investment grade as mentioned above; however not as strong as Atmos'. Algonquin's current rating is BBB-. Algonquin's California utility recently received a BBB investment grade credit rating, stronger than its parent. Even though Algonquin's credit rating is lower than Atmos', the proposed reorganization's impact on the financial position of the utility does not suggest that there needs to be an improvement to the utility's ability to attract capital.

Finally, analysts from Canada-based Canaccord Genuity made the following positive statements regarding the reorganization:

1) The company has been delivering on its stated goals, providing a greater level of confidence in management's ability to further the company's growth objections.
2) We are pleased to see the company extend its growth profile and expect earnings per share growth over the next couple of years will exceed the company's stated 5% annual earnings per share growth objective.

The Board considers the commitments made by Algonquin and Liberty Midstates reasonable as long as (1) Liberty Midstates will ultimately end up with a

capital structure resembling the proposed capital structure of 45 percent debt and 55 percent common equity; (2) the parent company plans for Liberty Midstates to maintain a strong balance sheet and investment grade status; and (3) Algonquin is willing and able to allocate capital to the subsidiary if needed. The Board also considers it important that Consumer Advocate did not object to the proposed reorganization.

3. Whether the Ability of the Public Utility to Provide Safe, Reasonable, and Adequate Service Is Impaired

A. Operational Structure and Management Team

Joint Applicants state that Algonquin and its operating subsidiaries have been in the regulated utility business for over a decade and have developed a record of strong customer service, delivering safe and reliable power and water and wastewater services to its customers. This experience, expertise, and strategy are evident in the successful history of acquisitions and subsequent reliable, cost effective and safe operation of a large number of utility businesses. Joint Applicants indicate that Liberty Midstates is open to making changes as the need for them becomes apparent; however, until the need for such changes has been identified, service will be provided on a basis that is consistent with the level that customers have become accustomed to under Atmos.

Joint Applicants state that a Regional President will have full-time responsibility for the day-to-day operations in Iowa and throughout the Liberty Midstates service area. Management in the areas of Energy Procurement; Government, Regulatory and Community Relations; Finance and Administration;

Human Resources; Customer Service and Business Development; Environment, Health, Safety, and Security; and Operations will report to the Regional President.

Joint Applicants state that the management team that will be directly responsible for the operation and management of Liberty Midstates at the regional level will be comprised of personnel who have experience performing similar functions for Atmos and the other acquired utilities, together with new hires such as the Regional President. In a few areas, functions will be supported by personnel at Liberty Utilities, but most functions will be the primary responsibility of individuals employed by Liberty Midstates.

Board Discussion

It appears that Algonquin has been operating regulated utilities successfully for over ten years and that the operational structure and management team planned for Liberty Midstates should contribute to the ability of Liberty Midstates to provide reasonable and adequate service to its Iowa customers.

B. Cost Benefit Analysis

Joint Applicants state that the benefits of the proposed reorganization are primarily service-oriented, both from a customer and operations perspective. Joint Applicants state that Liberty Midstates does not anticipate any cost increases resulting from the transaction and Liberty Midstates does not anticipate that there will be cost savings resulting from the transaction. According to Joint Applicants, Liberty Midstates is not aware of any reason why it would be more or less costly for it to operate the Atmos system than its current cost structure indicates.

Board Discussion

In accordance with 199 IAC 32.4(4)"a," Joint Applicants addressed the projected benefits and costs of the proposed reorganization and demonstrated that the proposed reorganization should not result in any additional costs or savings to Liberty Midstates. Based upon the intent of Liberty Midstates to continue to operate the public utility in Iowa in the same manner as the current operations under Atmos, it appears reasonable to assume that customers will not experience increased costs as a result of the proposed reorganization. Liberty Midstates did indicate that since Atmos had not filed a rate case in many years, the possibility of a general rate case filing in the future should be recognized.

C. Pipeline Safety Programs

In the application and testimony, Joint Applicants state that Liberty Midstates will abide by all applicable laws and Board rules after the sale is consummated. Eichler testifies that the sale will have no impact on the existing telecommunications network, field customer operations, customer contact operations, or the operational support system. Liberty Midstates intends to continue to operate the natural gas company consistent with Atmos' operation.

Pasieka testifies that Liberty Midstates possesses the managerial, technical, and financial capabilities and expertise to provide adequate, safe, and reliable natural gas service in Iowa. Pasieka points out that Algonquin has been operating regulated businesses for over a decade and has a strong record of delivering safe and reliable

service. Pasieka testifies that Liberty Midstates intends to leave field operations unchanged from current Atmos operations.

In the October 3, 2011, order, the Board requested information concerning how Liberty Midstates will comply with 49 CFR 192.615 and 199 IAC 19.8(4) that require procedures for responding to emergency calls. The Board asked for information regarding: (1) How Liberty Midstates plans to receive and respond to emergency natural gas calls on a 24-hour, seven-day-a-week, 365-day-a-year basis; (2) whether Liberty Midstates will be required to change existing Atmos emergency telephone numbers; and (3) if the numbers are required to be changed, what plans Liberty Midstates has to educate emergency responders and the general public about the new telephone numbers. The October 3, 2011, order also requested a timeline for sending notification of the new telephone numbers, if required, to emergency responders and the general public.

In the October 10, 2011, response, Joint Applicants state that during the first nine months after the transaction closes, Atmos will continue to answer customer phone calls, including emergency calls, pursuant to a Continuing Services Agreement (CSA) with Liberty Midstates. Calls will be handled by Atmos as they are currently. During this nine-month period, Liberty Midstates will be implementing its own call-handling and dispatch systems and will be hiring and training additional personnel in Missouri to perform these functions. Joint Applicants state that the requirements of 49 CFR 192.615 and 199 IAC 19.8(4) will be included in the Liberty Midstates training process. After the nine-month period, Liberty Midstates will have its own telephone

numbers. Liberty Midstates intends to answer calls during core hours by call handling staff and, after core hours, the calls will be handled by the Liberty Midstates' 24/7/365 dispatch operation. Joint Applicants indicate that discussions are underway between Liberty Midstates and Atmos on a telephone number strategy that will ensure a seamless transition of the call-handling function. Part of the strategy involves establishing the new telephone numbers well in advance of Liberty Midstates taking over the call handling. This will allow for proper communication of the new telephone numbers.

Board Discussion

It appears that Algonquin has been operating regulated utilities successfully for over ten years and the intent to continue Atmos' operations in Iowa shows that once the proposed reorganization is consummated, Liberty Midstates will be able to provide safe and reliable service to Iowa customers. The Board is satisfied that the procedures for handling emergency calls after the reorganization is executed described in the October 10, 2011, response provide a reasonable transition from Atmos to Liberty Midstates. The nine-month CSA should allow Liberty Midstates sufficient time to staff and establish a process for handling emergency calls. The Board will require Liberty Midstates to file in this docket the strategy for establishing new telephone numbers and communication to emergency responders and the general public once that strategy has been developed.

D. Pipeline Permits

In the application, Joint Applicants request the Board grant Liberty Midstates all of the necessary regulatory approvals and authority to operate a rate-regulated natural gas utility in Iowa. Joint Applicants did not specifically discuss the individual requirements of 199 IAC19.10 concerning sale or transfer of pipeline permits.

Board Discussion

Board rules in 199 IAC 10.19(1) require that a permit for a natural gas pipeline will not be sold without prior written approval of the Board. Under this rule, a petition for approval is required to be filed by the buyer and seller and is to include assurances that the buyer is authorized to transact business in the state of Iowa and is willing and able to construct, operate, and maintain the pipeline in accordance with the Board's pipeline safety rules. In addition, 199 IAC 10.19(2) requires that no transfer of a pipeline permit prior to completion of pipeline construction shall be effective until the person to whom the permit was issued files notice with the Board of the transfer. The notice shall include the date of the transfer and the name and address of the transferee. Finally, 199 IAC 10.19(3) provides that the reassignment of a pipeline permit as part of a corporate restructuring, with no change in pipeline operating personnel or procedures, is considered a transfer.

This rule requires that where a corporate restructuring will reassign the ownership of a pipeline permit, even where there will be no change in the operating personnel, notice to the Board of the transfer is required. The Board has considered the proposal for reorganization to be sufficient to meet the notice requirement in this

rule. Docket No. SPU-07-12, In re: Aquila Inc., d/b/a/ Aquila Networks, Black Hills Corporation, and Black Hills/Iowa Gas Utility Company, LLC., "Order Approving Settlement Agreement, Not Disapproving Proposal for Reorganization, Granting Request to Discontinue Service, and Requiring Reports." (8/31/07)

The Board finds that the requirements of 199 IAC 10.19 are satisfied by the proposed reorganization filing. The pipeline permits will be transferred from Atmos to Liberty Midstates once the sale has been completed. Liberty Midstates will be directed to inform the Board of the date of execution of the sale. The pipeline permits that will be transferred are Pipeline Permit Nos. P-0871, the Roquette Lateral, and P-0856, the Montrose/Keokuk Lateral.

4. Whether Ratepayers Are Detrimentally Affected

A. Rates and Tariff Provisions

Liberty Midstates indicates that the proposed reorganization will not impact the rates or terms and conditions of service for any of its customer segments. After the proposed reorganization, Liberty Midstates intends to provide natural gas distribution service to the Iowa public pursuant to the rates, rules, regulations, and terms and conditions of service that are currently in place with respect to Atmos' operations, subject to any changes hereafter made in accordance with applicable law, and to continue all services currently provided by Atmos, without interruption or change.

Rather than replicating the tariffs of Atmos and identifying them as tariffs of Liberty Midstates, the Joint Applicants request that the Board state that immediately upon the closing of the proposed reorganization, the current Atmos tariffs will become

the tariffs of Liberty Midstates. Liberty Midstates will not seek to include an acquisition premium in rates and does not intend to charge the transaction costs incurred in the acquisition to its customers.

Liberty Midstates notes that Atmos' last rate case occurred over ten years ago. Liberty Midstates states that any utility that has not filed a rate case for more than ten years is likely to need an increase in rates. If Liberty Midstates does file for an increase in rates, it would be based solely on the cost of service and not the result of this transaction.

Board Discussion

Liberty Midstates' commitment not to seek an acquisition premium or charge transaction costs to its customers helps shield Atmos customers from a potential rate increase as a result of the proposed transaction. Liberty Midstates' request that current Atmos tariffs become the tariffs of Liberty Midstates ensures that natural gas service continues under the rates, rules, and regulations presently on file with and approved by the Board. As Liberty Midstates requested, the Board order will state that, effective immediately upon closing of the proposed reorganization, the current Atmos tariffs become the tariffs of Liberty Midstates. Liberty Midstates will be required to make a tariff filing with a new cover sheet for the tariff book indicating that Liberty Midstates is the company providing service under the tariff.

B. Customer Service

Joint Applicants state that Liberty Midstates' customer service philosophy is guided by the following:

1. To provide high quality service at a reasonable cost in order to have satisfied customers.
2. To have local customer service representatives located where the customers are located, whenever possible.
3. Deliver information to customers in the manner and form they desire (i.e., paper, electronic, hours of operation, etc.).
4. Giving local management teams significant authority to determine how best to meet the needs of the customers.
5. Sharing knowledge, experience, and capabilities across the family of companies, while leaving decision-making affecting customers at the local level whenever possible.
6. Meeting local regulatory obligations will be more readily attainable with satisfied customers being served by people living in the same communities.

Joint Applicants state that, in addition to a central operations center structure, Liberty Midstates plans to have a number of walk-in customer service counters staffed by one or more members of the customer service group who will take customer calls or perform other customer service work. The service counters will also be available to address more localized issues, including providing assistance to customers who walk in and want to speak to someone in person to address customer service issues. Joint Applicants state that with today's technology customer service

representatives can be distributed across multiple locations without losing economies of scale.

Joint Applicants indicate that this approach has brought improvements in customer satisfaction in other jurisdictions. The improvement has been documented through an annual customer service survey conducted by an independent research firm. Joint Applicants state that customer feedback forms the backbone of efforts to ensure customer needs and expectations are continually being met. Management compensation is also linked to the customer satisfaction results. Joint Applicants state that Liberty Midstates intends to engage in a similar process in Iowa.

The company goal is to empower employees to resolve customer issues at the first point of contact whenever possible. This is encouraged internally through its "Liberty Heroes" program. This program recognizes employees who go "above and beyond the call of duty" for customers.

In the September 26, 2011, response, Joint Applicants indicate that Liberty Midstates plans to maintain the same Call Center hours of operation as Atmos. The Emergency Service (for example, reporting natural gas leaks or service outages) will continue to be available 24 hours per day, seven days per week after the proposed transaction. Atmos currently has one Iowa office located in Keokuk where customers interact with Atmos representatives. Liberty Midstates plans to keep the office open and expand the services offered to include bill payment and all inquiry types that are supported in the Call Center. Liberty Midstates has no plans at this time to open

similar additional offices. Liberty Midstates will maintain arrangements with third-party locations where customers currently pay bills.

Board Discussion

It appears that customer contact options and customer service quality under Liberty Midstates will be similar to that currently provided by Atmos. The Board has received no written complaints against Atmos since 2003. The Board has received calls each year regarding Atmos. The number of calls does not appear excessive, and the Keokuk office tends to resolve the matters quickly. Liberty Midstates customers will have the additional option of customer service interaction through the local Keokuk office. Based upon the continuation of the Atmos customer service operations and the additional in-person contact to be offered by Liberty Midstates, the Board finds that the transfer will not be detrimental to the quality of customer service in Iowa.

5. Whether the Public Interest Is Detrimentally Affected

Robertson testifies that the proposed reorganization will not be detrimental to the public interest since Algonquin and its operating subsidiaries have been in the business of operating regulated businesses for over a decade. These companies have been successfully serving 75,000 regulated water and wastewater customers and 50,000 electric distribution customers. Robertson testifies that Algonquin's business model emphasizes locally-employed personnel, local customer service, and the potential that Liberty Midstates will hire additional employees in Iowa.

Eichler testifies that Liberty Midstates intends to schedule regular meetings with the Board to provide updates on utility operations. Liberty Midstates wants to encourage an open exchange between the Board and management. Eichler testifies that Liberty Midstates will organize its Regulatory Affairs department along jurisdictional lines and keep authority and control at the local level. Liberty Midstates intends to have regular meetings with stakeholders, in addition to the meetings with the Board. Eichler also testifies that Liberty Midstates intends to stay in contact with customers and the community by locating the customer call center in Iowa and to maintain customer walk-in centers. Liberty Midstates also intends to conduct programs that teach customers about utility programs and conservation efforts. Finally, Eichler states that Liberty Midstates will maintain ongoing interactions with local officials and the business community to ensure it is meeting customer expectations and will also work closely with all functions across the organization to ensure Liberty Midstates is responding promptly to any concerns that are raised and to facilitate support for important state policies.

Eichler testifies that Liberty Midstates intends to ensure compliance with regulations by maintaining data bases with the required information. This will allow Liberty Midstates to provide the necessary relevant information to regulatory agencies. Eichler testifies that nothing in the proposed reorganization will diminish the regulatory oversight of the Board.

In the October 3, 2011, order, the Board requested information about Liberty Midstates' intentions with regard to retention of Atmos' employees. In the response,

Joint Applicants state that Atmos has five employees currently in Iowa and Liberty Midstates intends to offer employment to all of the current Atmos employees in Iowa. Joint Applicants also state that Liberty Midstates intends to replace any employees who do not accept employment and those employees will be located in Iowa. In addition, Liberty Midstates does not at this time have any plans to consolidate operations that would result in the transfer of employees to another jurisdiction.

Board Discussion

If Liberty Midstates keeps the commitments that it has made in the proposal for reorganization and its witnesses' testimony, then the public interest should not be detrimentally affected by the sale of Atmos' assets. Liberty Midstates has committed to retain Atmos' employees, maintain Atmos' operations procedures, maintain call center operations, and continue the Atmos activities to meet federal and Board safety requirements. Algonquin has a corporate philosophy that focuses on customer satisfaction. In addition, Liberty Midstates has emphasized that it will provide additional customer contact opportunities. Based on commitments made by Liberty Midstates that service will continue at the level now provided, the communities Atmos serves should see no change in service or other adverse effects from the proposed reorganization. Based upon these commitments, the Board finds that the sale of Atmos will not detrimentally affect the public interest and since the Iowa operations will be part of a smaller company serving only Iowa, Illinois, and Missouri, rather than the Atmos approach where the Iowa operations were a part of a very large multi-state company, the sale may have a beneficial effect on customer service.

6. Natural Gas Purchasing

Atmos currently purchases natural gas for its Iowa customers as part of the company's overall natural gas purchasing process. This process is established by Atmos' corporate management and includes all of Atmos' natural gas utilities. Since Iowa has such a small portion of the Atmos' overall operations, some special procedures have been developed for the Iowa natural gas purchased by Atmos. Atmos meets with Board staff each year to discuss and update its natural gas purchasing and hedging plan. Since the Asset Purchase Agreement will not be consummated until at least January 2012, natural gas for the winter heating season will already have either been contracted for or there will be hedging options in place.

In the September 26, 2011, response, Joint Applicants state that Atmos' current natural gas purchasing contracts will be assigned to, and assumed by, Liberty Midstates upon consummation of the proposed reorganization.

Board Discussion

The Board is satisfied with the procedures established for continuation of the purchasing of natural gas after the sale of the Iowa assets to Liberty Midstates. Once the sale is complete, the Board will have the opportunity to discuss with Liberty Midstates how that company intends to purchase natural gas for its Iowa operations.

IV. CONCLUSION

Iowa Code § 476.77(1) provides that a proposal for reorganization should be disapproved if the reorganization would be contrary to the interest of the public utility's ratepayers or the public interest. The discussion of the statutory issues

shows that Atmos' customers should see little or no difference in service or rates after the acquisition and that Liberty Midstates has committed to maintain Atmos business operations to ensure the system is safely maintained. Liberty Midstates appears to be a financially sound company and has committed to retaining Atmos employees and hiring additional employees where necessary. Based upon the discussion of the statutory and other issues above, the Board finds that the reorganization is not contrary to ratepayer interests and is not contrary to the public interest.

Based upon the review of the five factors from Iowa Code § 476.77(3) above and the other issues addressed in this memo, a contested case hearing is not necessary for the Board to issue a decision in this docket. The Board will not disapprove the proposal for reorganization and pursuant to the provisions of Iowa Code § 476.77(2) no hearing is required.

V. DISCONTINUANCE OF SERVICE

Joint Applicants request that Atmos be authorized to discontinue service to its current Iowa customers and to discontinue service as a public utility once the transactions contemplated by the Asset Purchase Agreement between Atmos and Liberty Midstates are consummated.

Pasieka testifies that Liberty Midstates does not intend to significantly alter field operations as a result of the proposed reorganization. Liberty Midstates intends to offer employment to current Atmos employees and these employees will continue to perform the same operations as they do for Atmos.

Board Discussion

The Board has reviewed the reorganization proposal and based upon that review considers the management of Liberty Midstates to be ready, willing, and able to provide utility service comparable to the service currently provided by Atmos. In addition, service by Atmos will no longer be necessary once the transaction contemplated in the Asset Purchase Agreement between Atmos and Liberty Midstates is consummated. The Board will require Atmos to notify the Board of the exact date that the responsibility for utility service is transferred.

VII. ORDERING CLAUSES

IT IS THEREFORE ORDERED:

1. The proposal for reorganization filed by Atmos Energy Corporation and Liberty Energy (Midstates) Corporation on August 15, 2011, is not disapproved.

2. Atmos Energy Corporation is granted permission to discontinue natural gas service in Iowa upon the completion of the acquisition by Liberty Energy (Midstates) Corporation. Atmos Energy Corporation shall file notice of the specific date service will be discontinued prior to discontinuance.

3. Immediately upon the closing of the proposed reorganization, the current Atmos Energy Corporation tariffs will become the tariffs of Liberty Energy (Midstates) Corporation. Immediately after closing, Liberty Energy (Midstates) shall make a tariff filing with a new cover sheet for the tariff book indicating that Liberty Energy (Midstates) Corporation is the company providing service under the tariff.

4. Liberty Energy (Midstates) Corporation shall file its strategy for implementing its emergency call process once that strategy is established. Liberty Energy (Midstates) Corporation shall notify the Board once it has assumed operation of the emergency call process.

5. Within ten days of the consummation of the sale, Liberty Energy (Midstates) Corporation shall notify the Board of the exact date the sale was executed so the pipeline permits described in this order are transferred.

6. Liberty Energy (Midstates) Corporation shall file its Cost Allocation Manual with the Board once the sale has been consummated.

7. Liberty Energy (Midstates) Corporation shall file the actual amount of debt and common equity and the terms on the debt issues after the sale has been consummated.

7. Joint Applicants shall file a copy of any decision issued by any other jurisdiction addressing the proposed reorganization within 20 days of the date of that decision. The filing shall include an analysis of whether a decision from another jurisdiction impacts the terms and conditions of the reorganization as reviewed by the Board.

UTILITIES BOARD

/s/ Elizabeth S. Jacobs

/s/ Darrell Hanson

ATTEST:

/s/ Joan Conrad
Executive Secretary

/s/ Swati A. Dandekar

Dated at Des Moines, Iowa, this 14th day of November 2011.

STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Joint Application of The Empire District Electric Company, Liberty Sub Corp. and Liberty Utilities (Central) Co. for Approval of an Agreement and Plan of Merger and for Other Related Relief	)))))	Docket No. 16-EPDE-410-ACQ

ORDER GRANTING JOINT MOTION TO APPROVE THE UNANIMOUS SETTLEMENT AGREEMENT AND APPROVAL OF THE JOINT APPLICATION

This matter comes before the State Corporation Commission of the State of Kansas ("Commission") for consideration and decision. Having reviewed the pleadings and record, the Commission finds and concludes:

Background:

1. On March 16, 2016, The Empire District Electric Company ("Empire"), Liberty Sub Corp. ("LSC") and Liberty Utilities (Central) Co. ("LU Central") (collectively referred to herein as "Joint Applicants") filed a Joint Application and supporting testimony pursuant to K.S.A. 66-101, *et seq*., and other applicable statutes and orders issued by the Commission, seeking Commission approval of the acquisition by LU Central of all of the common stock of Empire and for other related relief (the "Transaction").[1]

2. On March 21, 2016, the Citizens' Utility Ratepayer Board (CURB) filed a Petition to Intervene, which was granted by the Commission on May 10, 2016.

3. On August 9, 2016, the Commission issued an Order on Merger Standards reaffirming the merger standards stated by the Commission in previous dockets.[2]

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[1]Joint Application (March 16, 2016).
[2] Order on Merger Standards (Aug. 9, 2016) (citing *Application of Kansas City Power & Light Co.*, Consolidated Docket Nos. 172,745-U and 174,155-D (Nov. 14, 1991) and *Application of Western Resources, Inc., and Kansas City*

4. On August 24, 2016, Empire mailed to its customers Notice of Public Comment Period informing the customers of the proposed Transaction and telling customers they had the opportunity to submit comments regarding the proposed merger to the Commission through October 31, 2016.[3]

5. On September 7, 2016, the Joint Applicants, the Commission Staff ("Staff") and CURB (hereinafter the "Parties") filed a Joint Motion to Amend Procedural Schedule. The Parties informed the Commission they had reached an agreement in principle that would resolve all issues in this matter and therefore requested modification to the procedural schedule.[4]

6. On September 22, 2016, the Commission issued an Order Amending the Procedural Schedule. Pursuant to the new procedural schedule, the Parties filed a Joint Motion for Commission Approval of Unanimous Settlement Agreement (SA) on October 6, 2016.[5] All Parties filed testimony supporting approval of the SA.

7. On November 9, 2016, the Commission held an evidentiary hearing, in which Joint Applicants, Staff and CURB participated. Pursuant to the SA, the prefiled testimony, exhibits and appendices filed with the Joint Application was referred into the record.[6] The testimony received at the hearing on behalf of Staff, CURB and Joint Applicant's supported approval of the Transaction subject to the terms and conditions set forth in the SA ("Merger Conditions").

8. On November 30, 2016, Commission Staff filed a Motion to Amend Transcript and Correct Record. Staff asks that the portion of the Transcript containing Mr. Grady's testimony

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Power & Light Co., Docket No. 97-WSRE-676-MER (Sep. 28, 1999)).
[3] Affidavit of Mailing for The Empire District Electric Company (August 29, 2016).
[4] Joint Motion to Amend Procedural Schedule at 2 (Sep. 7, 2016).
[5] The Joint Motion for Commission Approval of Unanimous Settlement Agreement filed October 6, 2016 will hereinafter be referred to as the "Joint Motion" in general but specific provisions will be cited to the corresponding page number in the attached settlement agreement ("SA").
[6] Transcript at 5-6.

beginning at page 48, line 10 with the sentence starting with "But" and ending at page 48, line 17 at the conclusion "more in line"[7] be struck from the record. Staff states that Mr. Grady's testimony is inaccurate as stated and striking that portion would not add or detract from the substance of Mr. Grady's testimony.[8] No Party objected to the motion.[9]

9. In summary, the Joint Applicants request approval for LU Central to acquire all the capital stock of Empire through the transaction in which LSC, an entity owned by LU Central, merges into Empire, with Empire being the surviving entity. Because LU Central is owned by Liberty Utilities Co. (Liberty Utilities), which is an indirect subsidiary of Algonquin Power & Utilities Corp. (Algonquin), the result of the transaction would be that Empire is indirectly owned by Algonquin. The Parties, through the SA, have agreed upon certain terms and conditions upon which the Joint Application shall be subject subsequent to approval.

Jurisdiction:

10. The Commission has full power, authority and jurisdiction to supervise and control the electric public utilities doing business in Kansas and is empowered to do all things necessary and convenient for the exercise of such power, authority and jurisdiction.[10] All "incidental powers necessary to carry into effect" the provisions of the Kansas Public Utilities Act "are expressly granted to and conferred upon the commission."[11] Accordingly, the Commission applies a liberal construction to its grant of power, authority and jurisdiction.

11. No public utility shall transact business in the state of Kansas until it obtains a

[7] Motion to Amend Transcript and Correct Record at 2 (Nov. 30, 2016).
[8] *Id.*
[9] *Id.*
[10] K.S.A. 66-101, *et seq.*
[11] K.S.A. 66-101g.

certificate from the Commission that public convenience will be promoted by the transaction of said business.[12] Furthermore, no franchise or certificate of convenience and necessity granted to a public utility shall be assigned, transferred, or leased, nor shall any contract or agreement with reference to or affecting such certificate of convenience and necessity or right thereunder be valid or of any force or effect whatsoever, unless the assignment, transfer, lease, contract, or agreement shall have been approved by the Commission.[13] To that end, the Commission has adopted a set of Merger Standards to be applied in evaluation of such transactions. Those standards will be evaluated in the context of the Commission's five factor test outlined below.

12. The Commission must separately state findings of fact, conclusions of law, and policy reasons for its decision if it is an exercise of its discretion.[14] Any findings of fact must be based exclusively upon the evidence or record in the adjudicative proceeding and on matters officially noticed at the proceeding.[15] Agency action must be based upon evidence that is substantial when viewed in light of the record as a whole.[16]

13. The SA was presented to the Commission as a comprehensive settlement for the Joint Applicants' request for approval of the Transaction. The SA is considered a unanimous settlement agreement under K.A.R. 82-1-230a(a)(2). Pursuant to K.A.R. 82-1-230a(b), the Commission may approve, reject or modify a settlement agreement.

14. Kansas law favors compromising and settling disputes when the agreement is entered intelligently, and in good faith.[17]

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[12] K.S.A. 66-131.
[13] K.S.A. 66-136.
[14] K.S.A. 77-526(c).
[15] K.S.A. 77-526(d).
[16] K.S.A. 77-621(c)(7), (d).
[17] *Bright v. LSI Corp.*, 254 Kan. 853, 858 (1994).

15. The Commission evaluates the evidence in the record as a whole regarding the SA under the following factors:

- Has each party had an opportunity to be heard on its reasons for opposing the settlement?
- Is the agreement supported by substantial competent evidence in the record as a whole?
- Does the agreement conform to applicable law?
- Will the agreement result in just and reasonable rates?
- Are the results of the agreement in the public interest, including the interests of customers represented by any party not consenting to the agreement?[18]

16. The SA contains provisions which act as conditions upon the granting of authority to transact business. "Any condition imposed must be both lawful and reasonable."[19] "To be 'lawful' the condition must be within the statutory authority of the KCC and all statutory and procedural rules must be followed."[20] A condition is "reasonable" if based upon substantial, competent evidence.[21]

Findings and Conclusions:

17. Empire is subject to the Commission's power, authority, and jurisdiction pursuant to K.S.A. 66-101 because it is a public utility as defined in K.S.A. 66-104, which supplies electricity. The Joint Application comes under the Commission's review pursuant to K.S.A. 66-131and 66136 because Empire seeks to merge into LSC, which would cause Empire to be owned by LU Central, which in turn is owned by Liberty Utilities an indirect subsidiary of Algonquin. The Parties have

[18] Order Approving Contested Settlement Agreement at 5-6, *Application of Atmos Energy for Adjustment of its Natural Gas Rates in the State of Kansas*, Docket No. 08-ATMG-280-RTS (May 12, 2008).
[19] *Kansas Electric Power Coop., Inc. v. Kan. Corp. Comm'n.*, 235 Kan. 661, 665 (1984).
[20] *Id.*
[21] *Id.*

submitted a unanimous settlement agreement in accordance with K.A.R. 82-1-230a. The Commission therefore finds that it has the full authority and jurisdiction to consider the Joint Application and Joint Motion for Commission Approval of Unanimous Settlement Agreement.

18. The Commission reviews the SA under the five criteria identified for evaluating a settlement.

Each Party Has Had an Opportunity to Be Heard on its Reasons for Opposing the Settlement.

19. The SA is supported by all Parties and the record indicates that all Parties actively participated in all aspects of the docket. The Commission finds this factor is met.

The Agreement is Supported by Substantial Evidence in the Record as a Whole.

20. By submitting pre-filed testiony and testifying in support of the SA, the Parties are acknowledging that the record is sufficient to commit to compromise. Orders issued by the Commission are considered reasonable if they are based upon substantial competent evidence.[22] Applying the same standard to the SA that is applied to orders issued by the Commission, it is clear that the SA is based upon substantial competent evidence. The Commission's standard has been to review settlement agreements in light of the record as a whole. The proceedings established the scope and breadth of the record in this case as discussed above. To that end, the Commission finds that Staff's Motion to Amend Transcript and Correct Record shall be granted. The Commission finds that such a thorough record, and supplementary filings used to support the SA, establishes the

[22] *Cent. Kansas Power Co. v. State Corp. Comm'n*, 221 Kan. 505, 511 (1977).

substantial competent evidence necessary to support settlement. Therefore, the Commission finds that this factor is satisfied.

The Agreement Conforms to Applicable Law.

21. "An Order is 'lawful' if it is within the statutory authority of the Commission and if prescribed statutory and procedural rules are followed in making the Order."[23] The Agreement meets this test.

22. Under K.S.A. 66-131 and 66-136, it is the Commission's duty to evaluate the assignment or transfer of a certificate prior to the transaction of business pursuant to said certificate to determine if the granting of authority to transact business pursuant to such transaction is in the interest of the public convenience. In order to carry out that duty, the Commission has adopted a set of standards to follow.[24] The Merger Standards will be evaluated under the last of the five factors below.

23. In evaluating the conditions placed upon the Transaction through the SA, the Commission is guided by case law.[25] Conditions imposed on a certificate must be lawful and based upon substantial competent evidence.[26]

24. Because "the law favors the amicable settlement of disputes,"[27] it follows that if the Parties come to such a resolution, their resolution could seek to impose conditions upon the granting of a certificate. The granting of the authority to transact business via compromise between the

[23] *Central Kansas* Power,221 Kan. at 511.
[24] Order on Merger Standards (Aug. 9, 2016)
[25] *See* ¶ 16 *supra.*
[26] *Kansas Electric Power Coop.,* 235 Kan. at 665.
[27] *Int'l Motor Rebuilding Co. v. United Motor Exch., Inc.*, 193 Kan. 497, 499 (1964).

Parties is still subject to Commission approval. Therefore, it is well within the lawful authority and jurisdiction of the Commission to consider this SA.

25. The Parties and the Commission complied with all procedural rules within this docket. The Parties and the Commission complied with the procedural schedules, the issuance of orders and the disposition of preliminary matters in accordance with the Kansas Administrative Procedure Act, K.S.A. 77-501 *et seq*. The Commission may therefore find that the prescribed statutory and procedural rules for reviewing the SA and issuing this order have been followed. As stated above, the SA is also based upon substantial competent evidence in light of the record as a whole.

26. After reviewing the SA, considering the pre-filed testimony and exhibits and the testimony presented at the hearing, and in applying the Commission's test and standards for the evaluation for such Joint Application, the Commission concludes that the SA conforms to applicable law.

The Agreement Will Result in Just and Reasonable Rates.

27. Under the terms of the SA, Empire is required to maintain all existing rate tariffs.[28] Those rates were determined just and reasonable in Application of the Empire District Electric Company for Approval to Make Certain Changes in its Charges for Electric Service, Docket No. 11-EPDE-856-RTS (Dec. 21, 2011).[29] In future rate cases, the SA allows Staff and CURB to

[28] SA at 5-6.
[29] Order Approving Stipulation and Agreement (Dec. 21, 2011).

review and make recommendations with respect to any cost increases to Empire caused by the Transaction.[30] Therefore, the SA results in just and reasonable rates.

The Results of the Agreement are in the Public Interest.

28. Pursuant to K.S.A. 66-131 and 66-136, the Commission is statutorily bound to consider the public convenience and necessity, often referred to as the "public interest." To evaluate whether a merger or acquisition, requiring the transfer of a certificate of convenience, is in the public interest, the Commission adopted a list of factors to weigh and consider. The "factors are the beginning criteria to be used when evaluating a merger application, and are to be supplemented by any other considerations that are relevant given the circumstances existing at the time of the merger proposal."[31] The Commission therefore turns its attention to the Merger Standards:

(a) The effect of the transaction on consumers, including:

(i) The effect of the proposed transaction on the financial condition of the newly created entity as compared to the financial condition of the stand-alone entities if the transaction did not occur.

29. According to the testimony filed by the Parties, there are several elements in the SA that address Merger Standard (a)(i). There are several safeguards specific to protecting consumers from the effects of adverse changes in the merged entity's financial health.

30. Paragraph 35 of the SA limits Empire's parent companies from transferring equity capital out of Empire such that it would be left with less than a 40% equity ratio.[32] The intent is to

[30] SA at 9-10.
[31] Order on Merger Standards at 3.
[32] Direct Testimony and Testimony in Support of Unanimous Settlement Agreement Prepared by Adam H. Gatewood at

ensure that Empire has sufficient capital on hand to successfully operate, as it has in past decades.[33] After consummation of the transaction, the acquiring party is required to maintain capital ratios and financial resources consistent with Empire's current and past financial posture ensuring future generations can expect to be served by a utility that is financially capable.[34]

31. As discussed in the Joint Application, post-merger Empire will receive debt capital through Liberty Utilities.[35] The SA provides for LU Central, Liberty Utilities, and Algonquin to take action if a negative credit event occurs. The actions are focused on rectifying a loss of investment-grade debt rating or, at a minimum, protecting consumers from the added cost that comes with a lower bond rating.[36]

32. Quality of service is also addressed in the context of financial viability. Paragraph 60 explains that a degree of ring-fencing would be instituted at the Empire level to ensure that a sufficient amount of earnings produced at the Empire level remain at Empire and that capital is used to rectify any decline in quality of service.[37]

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9 (Oct. 6, 2016) [*hereinafter* Gatewood Test.].
[33] *Id.*
[34] *Id.* (Staff's states their position that parent companies of Kansas jurisdictional utilities will be held accountable for prudently financing their subsidiary that is providing service in Kansas, regardless of whether those parent companies are a Kansas certificated utility. This is very important, particularly when a financially sound and conservatively managed utility that has a proven record of attracting capital is going to become a subsidiary of a holding company. The local utility will no longer be able to obtain its own capital; it will be completely dependent on its parent company for capital. The new parent company has to understand that Kansas ratepayers expect the new parent company to provide the necessary capital to the utility.).
[35] Testimony of Peter Eichler in Support of the Unanimous Settlement Agreement at 7 (Oct. 6, 2016) [*hereinafter* Eichler Test.]
[36]Gatewood Test. at 11-12 ("The actions outlined in this paragraph are actions that Staff would likely take with any Kansas jurisdictional utility that loses its investment-grade rating. The loss of an investment grade rating is a major event that would increase the utility's cost to borrow money.").
[37] *Id.* at 12.

33. Finally, paragraphs 61 and 62 provide guidance for the Joint Applicants in holding earnings generated by Empire at the Empire level in the event Empire suffers from a reduction of credit worthiness.[38]

(a) The effect of the transaction on consumers, including:

(ii) Reasonableness of the purchase price, including whether the purchase price was reasonable in light of the savings that can be demonstrated from the merger and whether the purchase price is within a reasonable range.

34. In evaluating Merger Standard (a)(ii), Staff considered the following factors: 1) whether the purchase price is commensurate with other recent utility transactions according to commonly accepted measures of purchase price evaluation; and 2) whether the agreed-upon purchase price can be justified by the operational synergies or cost savings that can be demonstrated from the merger.[39] As to Staff's first factor under this standard, Staff concluded that the consideration agreed to be paid in this Transaction is consistent with the market valuations being commanded in other recent electric utility acquisitions.[40] However, regard Staff's second factor, Staff states that the purchase price agreed to be paid by Algonquin for Empire's stock could not be determined to be reasonable in light of the savings demonstrated by the Transaction.[41] This is because the Joint Application is clear in that Liberty Utilities did not expect to be able to create significant synergies or operating cost savings as a result of this Transaction.[42] Staff ultimately

[38] *Id.* at 12-13.
[39] Direct Testimony and Testimony in Support of Unanimous Settlement Agreement Prepare by Justin T. Grady at 7 (Oct. 6, 2016) [*hereinafter* Grady Test.]
[40] *Id.* at 8-10
[41] *Id.* at 11-12.
[42] *Id.*

concluded the purchase price itself was not unreasonable and that because the Merger Conditions result in quantified net benefit to ratepayers, the Transaction is in the public interest.[43]

(a) The effect of the transaction on consumers, including:

(iii) Whether ratepayer benefits resulting from the transaction can be quantified.

35. The primary source of quantifiable ratepayer benefits stem from the rate-making provisions set forth in the SA. They include:

- Joint Applicant's agreement to withdraw Empire's rate case currently pending before the Commission.[44]
- The Joint Applicant's agreement to not refile a general rate case until May 1, 2018.[45]
- The continuation of the Asbury Environmental Cost Rider ("AECR").[46]
- The agreement of the Parties to allow Empire to file a revision of the AECR rider to include the revenue requirement associated with the conversion of the Riverton 12 simple-cycle, natural gas-fired combustion turbine to a combine-cycle natural gas-fired combustion turbine and to change the name of the rider to the Ashbury Environmental and Riverton Rider (AERR).[47]

36. Staff attests to the quantifiable benefit for ratepayers resulting from the rate making provisions.[48] Staff calculated a positive net present value (NPV) customer benefit of $5.77 million associated with this Transaction, as modified by the Agreement, or $597 per Kansas customer.[49]

37. The SA also ensures that future return on equity capital determinations will view risks in the same scope as Empire does as a stand-alone provider of electric utility services.[50] The

[43] *Id.* at 16.
[44] SA at 5.
[45] *Id.*
[46] *Id.* at 6.
[47] *Id.* at 6-7.
[48] Grady Test. at 17-21.
[49] *Id.* at 21.

Joint Applicants have also accepted the burden of explaining their position on capitalization in their rate case application.[51] Finally, the SA insulates Empire ratepayers from negative consequences of goodwill impairment.[52]

(a) The effect of the transaction on consumers, including:

(iv) Whether there are operational synergies that justify payment of a premium in excess of book value.

38. Staff testified that there are not operational savings which justify the payment of the Acquisition Premium (AP) over book value.[53] However, the Parties agreed this factor was appropriately addressed through the SA terms addressing the quantified net benefits obtained for Empire's Kansas ratepayers through the rate moratorium and tariff provisions discussed above and the Joint Applicants' agreement not to seek recovery of the AP and transaction costs in rates.[54]

(a) The effect of the transaction on consumers, including:

(v) The effect of the proposed transaction on the existing competition.

39. David Pasieka, on behalf of Joint Applicants, testified that Liberty Utilities does not currently serve any Kansas customers or have any overlapping franchise territories with any of Empire's operations in other States, therefore, competition levels will be preserved.[55] Staff agrees.[56] In addition, the Federal Energy Regulatory Commission reviewed the issue of whether or not the Transaction would have an impact on competition by evaluating the potential impact on

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[50] SA at 8; *see* Gatewood Test. at 17-18 ("This protects consumers from any attempts to expand that scope to possibly include riskier business endeavors that Empire's new parent company may be involved in, such as the riskier power generation businesses that Algonquin also owns or will acquire in the future.").
[51] Gatewood Testimony, page 18 ("[A]s opposed to leaving the issue to be addressed in rebuttal testimony and, only then, if the issue is raised by a party.").
[52] SA at 18; Gatewood Test. at 19.
[53] Grady Test. at 21.
[54] *Id.* at 25-26.
[55] Direct Testimony of David Pasieka at 13 (Mar. 16, 2016) [*hereinafter* Pasieka Test.].
[56] Grady Test. at 27.

vertical and horizontal market power and did not find any negative impact on competition at the wholesale level.[57] The Commission is satisfied that factor (a) and all subparts together demonstrate that the Transaction will not negatively affect consumers.

(b) The effect of the transaction on the environment.

40. Mr. Pasieka testified that Algonquin's extensive experience in the deployment of renewable energy is a potential positive impact on the environment as a result of the Transaction.[58] Staff testified that given Liberty Utilities' business and acquisition model and stated intentions of purchasing a fully functioning stand-alone utility, the Transaction should be neutral to the environment.[59] The Commission concludes that the Transaction will not negatively impact the environment.

(c) Whether the proposed transaction will be beneficial on an overall basis to state and local economies and to communities in the area served by the resulting public utility operations in the state. Whether the proposed transaction will likely create labor dislocations that may be particularly harmful to local communities, or the state generally, and whether measures can be taken to mitigate the harm.

41. Staff testified that the "Transaction, as modified by the Agreement, should be beneficial to the State economy and local economies of southeast Kansas."[60] Staff testified, as discussed above, that the rate making provisions provide a NPV benefit of approximately $600 per Kansas customer over the next two years. "Because Empire's customers will not have to pay higher electric rates during this period, this is money these customers could potentially spend in the local

[57] *See* Order Authorizing Disposition of Jurisdiction Facilities, Docket No. EC16-88 (May 6, 2016).
[58] Pasieka Test. at 14.
[59] Grady Test. at 27-28.
[60] *Id.* at 28.

economy."[61] "Additionally, the period of rate stability afforded by this Transaction and the Agreement should help business planning and competitiveness in the communities in which Empire serves in southeast Kansas, which is positive for the economy."[62]

42. In addition, Liberty Utilities plans on keeping Empire's existing headquarters location in Joplin, Missouri and expanding the reach of this headquarters to include the operations of LU Central.[63] In an agreement between the Joint Applicants and the City of Joplin, Missouri, filed at the Missouri Public Service Commission on July 19, 2016, in Docket No. EM-2016-0213, Liberty Utilities has committed to keep its headquarters located in Joplin with at least 85% of the current administrative supervisory, executive, and management positions currently located there, for a period of 15 years.[64] Staff further testified that no involuntary terminations are planned or expected because of the Transaction.[65]

43. Based upon the above, the Commission concludes that the Transaction is beneficial to the State and local economies and will not create labor dislocations that are particularly harmful.

(d) Whether the proposed transaction will preserve the jurisdiction of the KCC and the capacity of the KCC to effectively regulate and audit public utility operations in this state.

44. The SA explicitly states that Algonquin and Liberty Utilities are each an "affiliated interest" and the transaction complies with K.S.A. 66-1401, 66-1402 and 66-1403.[66] "These

[61] *Id.*
[62] *Id.*
[63] Application at 7; Grady Test. at 29 ("Joplin, Missouri is located just six miles from the Kansas border.").
[64] Grady Test. at 29.
[65] *Id.* at 29 (citing Joint Applicants' testimony).
[66] SA at 8; *see* Grady Test. at 30.

statutes confer certain jurisdiction to the Commission regarding access to books and records, submission of contracts, review of affiliate transactions detail, etc."[67]

45. Empire will "continue to exist as a separate legal entity with the existing separations between regulated and non-regulated business operations, unless Commission approval is sought to alter any such structure."[68] Additionally, LU Central and Empire are committed to employ the proper accounting procedures amongst the various business entities.[69]

46. "Taken together, Staff contends that these provisions contained within the [SA] will enable the Commission and its Staff to effectively regulate and audit Empire's public utility operations, including the reasonableness of allocated corporate overhead costs and transactions between affiliates within the Algonquin and Liberty group of companies."[70] Based on Staff's evaluation of the Transaction, the Commission believes its jurisdiction is preserved and the Commission can continue to effectively regulate and audit the public utility.

(e) The effect of the transaction on affected public utility shareholders.

47. "Empire shareholders are receiving approximately $1.5 billion in cash in exchange for their investment."[71] "The consideration of $34 per share is approximately 50% over the

[67] SA at 8.
[68] Grady Test. at 31.
[69] *Id.* at 30-32 ("Liberty Utilities' existing cost allocation manual (CAM) . . . is based on the guidelines for cost allocation and affiliate transactions endorsed by the National Association of Regulatory Utilities Commissioners (NARUC), and that a revised CAM will be filed within six months of the close of the Transaction. The fact that the Liberty Utilities CAM expressly recognizes the NARUC cost allocation and affiliate transaction guidelines is an important feature that reduces the possibility of inappropriate cross subsidization. These guidelines represent a robust framework for how regulated utilities should allocate costs and price transactions with affiliates in order to reduce the likelihood of cross subsidization that is an ever-present risk when regulated entities are being allocated costs from affiliates across multiple lines of business or several jurisdictional boundaries. . . Paragraph 47 requires Empire to maintain separate books, records, financial statements, and bank accounts. Paragraphs 48 and 49 contain an agreement by Algonquin, Liberty Utilities, and Empire to maintain adequate records to support the reasonableness of, and enable the audit and examination of, all centralized corporate costs that are allocated or directly charged to Empire.").
[70] *Id.* at 32.
[71] *Id.*

unaffected share price of $22.65 on December 10, 2015."[72] Staff also states in considering this standard that if shareholders receive too much of a benefit that some of that value should be redirected to ratepayers.[73] Staff is convinced the rate moratorium provisions discussed above effectively meet that desire.[74] The Commission thus concludes that this Merger Standard is satisfied.

(f) Whether the transaction maximizes the use of Kansas energy resources.

48. Mr. Pasieka testified that Empire purchases energy from two wind farms in Kansas and that it will continue to purchase that energy in the future.[75] Mr. Pasieka also stated that Liberty Utilities will continue to seek ways to develop and invest in Kansas energy resources.[76] Staff stated that this standard cannot be fully evaluated at this time, however, Staff noted it does not disagree with Mr. Pasieka's statement.[77] Staff thus concluded that the Transaction is neutral with regard to this standard.[78] The Commission concludes the same.

(g) Whether the transaction will reduce the possibility of economic waste.

49. Staff stated that the Transaction meets this Merger Standard as it is likely to reduce the possibility of economic waste, because there are certain administrative costs that will obviously be avoided by combining Empire with the Liberty Utilities organization, such as public company auditing and filing fees, board of director fees, and other expenses which do not have to be duplicated.[79] Based upon Staff's review of this standard and the balancing of interests undertaken

[72] *Id.*
[73] *Id.* at 33.
[74] Grady Test. at 33.
[75] Pasieka Test. at 16.
[76] *Id.*
[77] Grady Test. at 34.
[78] *Id.*
[79] *Id.* at 35.

in each of the previous standards, the Commission concludes that the Transaction, subject to the provisions of the SA, reduces economic waste.

(h) What impact, if any, the transaction has on the public safety.

50. This particular merger standard does not appear to be addressed by any Party except for Staff in the context of reliable, quality service.[80] Staff states that due to its concerns on the AP over book value issue discussed above, "there is a risk that available capital (both human and economic) may be focused on servicing the Company's AP related to debt rather than maintaining its infrastructure and responding to customer inquiries."[81] Staff, however, concludes that the provisions of the SA dealing with the maintenance of quality of service and reporting requirements adequately address that concern.[82] The Commission therefore concludes that this standard has been met.

51. After evaluation of the Merger Standards the Commission concludes that the fifth factor is met and the transaction, subject to the Merger Conditions, is in the public interest.

Conclusion:

52. The Commission concludes that application of the five factors favors granting the Joint Motion to approve the SA. The Commission finds that the proposed Transaction, subject to the Merger Conditions contained in the SA, satisfies the Commission's merger standards and promotes the public interest. The Commission grants the Joint Motion, the Joint Application and approves the proposed Transaction, subject to the Merger Conditions contained in the SA.

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[80] Gile Test. at 7.
[81] *Id.* at 6.
[82] *Id.* at 7-11.

THEREFORE, THE COMMISSION ORDERS:

A. The Joint Motion for Commission Approval of Unanimous Settlement Agreement is granted resulting in approval of the Joint Application subject to the Merger Conditions contained in the Unanimous Settlement Agreement, which is attached hereto as Exhibit A and incorporated herein by reference.

B. Joint Applicants shall provide notice to the Commission within ten (10) days of the closing of the Transaction.

C. Staff's Motion to Amend Transcript and Correct Record is granted.

D. The parties have 15 days from the date of electronic service of this Order to petition for reconsideration.[83]

E. The Commission retains jurisdiction over the subject matter and the parties for entering such further orders as it deems necessary.

BY THE COMMISSION IT IS SO ORDERED.

Emler, Chairman; Albrecht, Commissioner; Apple, Commissioner.

Dated: DEC 2 2 2016.

Amy L. Green
Secretary to the Commission

EMAILED
DEC 2 2 2016

DLK/sc

[83] K.S.A. 66-118b; K.S.A. 77-529(a)(1).

EXHIBIT A

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Joint Application of The Empire District Electric Company, Liberty Sub Corp. and Liberty Utilities (Central) Co. for Approval of an Agreement and Plan of Merger and for Other Related Relief	)))))	Docket No. 16-EPDE-410-ACQ

UNANIMOUS SETTLEMENT AGREEMENT

Pursuant to K.A.R. 82-1-230a(1), The Empire District Electric Company ("Empire" or "EDE"), Liberty Utilities (Central) Co. ("LU Central"), and Liberty Sub Corp. ("LSC") (collectively, the "Joint Applicants"), Algonquin Power & Utilities Corp. ("Algonquin"), the Staff of the Kansas Corporation Commission ("Staff"), and the Citizens' Utility Ratepayers' Board "(CURB"), by and through their undersigned counsel, have reached the following Unanimous Settlement Agreement (the "Agreement") as a comprehensive settlement of all issues relevant to the Joint Application filed by the Joint Applicants.

I. DESCRIPTION OF THE PROCEEDINGS

1. Empire is a Kansas Corporation with its principal office and place of business at 602 South Joplin Avenue, Joplin, Missouri 64801. Empire is qualified to conduct business and is conducting business in Kansas as well as in the states of Missouri, Arkansas and Oklahoma. Empire is engaged generally in the business of generating, purchasing, transmitting, distributing and selling electric energy in portions of said states. Empire also provides water utility service in Missouri. Through a wholly owned subsidiary, The Empire District Gas Company, Empire provides natural gas utility service in Missouri. Empire's Kansas electric utility operations are subject to the jurisdiction of the Commission as provided by law.

2. LU Central is a Delaware Corporation and was formed for the purpose of acquiring

the capital stock of Empire as described herein. LU Central is a wholly owned subsidiary of Liberty Utilities Co. ("Liberty Utilities") and is an indirect subsidiary of Algonquin.

3. LSC is a Kansas corporation that is a wholly owned subsidiary of LU Central. LSC is a special purpose corporation formed for the sole purpose of merging with and into Empire as hereinafter described.

4. On March 16, 2016, the Joint Applicants filed an application with the Commission for approval of an agreement and plan of merger and for other relief. Under the agreement and plan of merger, LSC will be merged with and into Empire under the terms and provisions described in the Agreement, with Empire emerging as the surviving corporation. Immediately following the merger LSC will cease to exist. As a consequence of the merger, Algonquin will acquire, indirectly through its subsidiary LU Central all of the capital stock of Empire. Empire's outstanding debt and related obligations will remain with Empire.

5. On March 22, 2016, CURB filed its Petition to Intervene which was granted by the Commission.

6. On June 9, 2016, the Commission issued a procedural order in this proceeding. Pursuant to said Order, Staff and CURB were directed to file direct testimony on September 29, 2016. Joint Applicants were ordered to file rebuttal testimony on October 20, 2016. A technical hearing was scheduled for November 29 through December 1, 2016. Joint Applicants, Staff and CURB have filed a Joint Motion to Amend the Procedural Order to account for the fact that they have entered into an agreement.

7. Staff, CURB and the Joint Applicants have reached an agreement on all issues which have been raised in this proceeding.

8. Joint Applicants, Staff and CURB have agreed, that in accordance with the

acquisition and merger standards articulated by the Commission in the Kansas Power & Light Company, KCA Corporation and Kansas Gas & Electric Company merger, Docket No. 174,155-U, as modified in KCC Docket No. 97-WSRE-676-MER, which were reaffirmed by the Commission in its Order on Merger filed in this docket on August 9, 2016, and subject to the terms and conditions contained in the Agreement, the Joint Application filed in this proceeding and the authority requested therein should be approved and granted by the Commission. The terms and conditions on approval of the Joint Application are as set out in this Agreement.

II. TERMS OF THE SETTLEMENT

9. Subject to the conditions and reservations set forth herein, the signatories to this Agreement have evaluated the proposed transaction under the standards articulated by the Commission in the Kansas Power & Light Company, KCA Corporation and Kansas Gas & Electric Company acquisition proceeding, Docket No. 174,155-U, as modified in KCC Docket No. 97-WSRE-676-MER, which were reaffirmed by the Commission in its Order on Merger filed in this docket on August 9, 2016, and agree that, in accordance with those standards, adoption of this Agreement is in the public interest.

10. The signatories to this Agreement recommend to the Commission for approval of this Agreement; that the transaction more fully described in the Joint Application in this case be approved; and that the following conditions be ordered as part of that approval.

A. CONDITIONS ON APPROVAL OF THE JOINT APPLICATION OF MERGER

i. GENERAL PROVISIONS

11. LU Central and LSC will acquire all of the capital stock of EDE through a merger transaction ("Transaction"). At the close of the all-cash transaction, EDE will become a wholly owned subsidiary of LU Central.

12. As a subsidiary of LU Central, EDE's utility operations will continue to be regulated by each of the five regulatory commissions that currently regulate EDE, including the Commission.

13. Liberty Utilities will establish a "Central Region" which will be headquartered in Joplin, Missouri. This regional office will provide senior leadership to the current operations of EDE and Liberty Utilities' gas operations in Missouri, Illinois, and Iowa, and Liberty Utilities' water operations in Missouri, Arkansas, and Texas.

14. EDE will continue to operate as a jurisdictional public utility in Kansas, pursuant to EDE's existing Commission approved Certificate of Public Convenience and Necessity and Kansas law.

15. EDE will continue to utilize the rates, rules, regulations and other tariff provisions on file with and approved by the Commission, and will continue to provide service to its customers under those rates, rules and regulations, and other tariff provisions until such time as they may be modified by Commission action.

16. There will be no changes to the EDE service area as a result of the acquisition.

17. LU Central shall cause EDE and its subsidiaries to maintain and operate their respective businesses under the "Empire District" brand for a period of at least five (5) years following the closing of the merger, provided that such use may also include a "Liberty Utilities" company brand or similar co-branding designation.

18. Following the completion of the acquisition of the shares of EDE, all of EDE's assets utilized for the provision of electric, water and natural gas utility operations, as well as its fiber optic line of business will continue to be owned by EDE and these services will continue to be provided by EDE and its existing subsidiary companies (Empire District Industries, Inc. and Empire District Gas Company).

19. All the utilities within LU Central will continue to operate in the same manner as they do today.

20. LU Central has committed to retain all of EDE's management team and its workforce following closing of the Transaction. No involuntary reductions in EDE's current administrative, professional and field workforce and its existing management team are planned for or expected as a result of the Transaction.

21. LU Central will honor the terms and conditions of EDE's existing severance packages.

22. A regional board of directors will be established to provide guidance and counsel on local issues and enhanced customer service. All existing board members of EDE will be offered a position on the board.

23. EDE and certain of Liberty Utilities' existing utilities will be reorganized under LU Central, with Bradley Beecher, the current Chief Executive Officer ("CEO") of EDE assuming the role of the CEO of LU Central.

ii. RATEMAKING AND RELATED ISSUES

24. In exchange for Staff's agreement not to recommend in this proceeding, or any future EDE ratemaking proceeding, a sharing with ratepayers of the acquisition premium or gain on sale associated with the Transaction and the other provisions contained in this Agreement, the Joint Applicants, Staff and CURB (the "Parties"), agree that upon approval by the Commission of this Agreement EDE will withdraw its rate application currently pending before the Commission. In addition, the Parties agree that EDE shall not re-file to change its base rates prior to May 1, 2018, with new rates effective no sooner than January 1, 2019. This means the current base rates, which went into effect on January 1, 2012, will not change for a period of seven (7) years as a result of this

settlement (2012, 2013, 2014, 2015, 2016, 2017 and 2018). This general rate case moratorium does not preclude EDE from changing rates or tariffs to recover appropriate costs under Commission approved energy cost adjustment ("ECA"), annual cost adjustment ("ACA"), ad valorem tax surcharge ("AVTS") tariffs and the surcharge as set forth in Paragraphs 25 and 26 of this Agreement. Subject to the provision that base rates should remain fixed for the term of the moratorium set forth in this paragraph of this Agreement, EDE may make tariff filings to comply with new Commission rules or policies, including revenue neutral changes to rate design and EDE may propose methods to recover the cost of furnishing new voluntary services. Notwithstanding the above, in the event of changes in law or regulations, or the occurrence of events outside the control of EDE that result in a material adverse impact to EDE, EDE may file an application with the Commission proposing methods to address the impact of the events, including the possibility of changes in base rates. Staff and CURB shall have the right to contest the application, including whether the impact of the changes or event is material to EDE, and whether EDE's proposed remedy in the application is reasonable.

25. The Parties agree the current surcharge established in Docket 15-EPDE-233-TAR for the Asbury plant environmental upgrades shall continue with the modifications discussed in Paragraph 26 below until rates are set in the next base rate case.

26. Notwithstanding Paragraph 24 above, and in order to lessen the impact of any future rate increase on customers, the Parties agree that EDE will seek an Order from the Commission to amend the rider referenced in Paragraph 25 herein to include the Riverton 12 revenue requirement increase consisting of return on investment and depreciation expense associated with the Riverton 12 plant. This filing should be filed in Kansas as soon as possible following close of the Transaction. The Parties agree that they will not categorially oppose such a request as long as the

rider amendment is filed with the following conditions: 1) The revised rider should be referred to as the AERR (the Asbury Environmental and Riverton Rider; 2) The revised rider should update Gross Plant and Accumulated Depreciation associated with the AERR revenue requirement, to the most recent actual data possible; 3) The AERR will use the least cost capital structure determined by comparing the actual capital structure of EDE and the actual capital structure of any other entity which it receives financing from, (including but not limited to, the consolidated Algonquin capital structure); 4) The AERR will use a return on equity of 9.3%; and 5) The AERR will be implemented on an interim basis, subject to true-up and eventual refund or recovery in EDE's next base rate case. The Parties reserve their rights to challenge the reasonableness of any of the costs collected under the amended rider in EDE's next general rate case.

27. No costs of the proposed merger transaction will be borne by Kansas ratepayers directly, or indirectly, in any future LU Central or EDE ratemaking proceeding. Such costs include but are not limited to: (1) acquisition premium costs (i.e., amounts recorded in FERC USOA Account 114 - Utility Plant Acquisition Adjustments or Account 116 - Other Utility Plant Adjustments and defined as the difference between the cost to the accounting utility of utility plant acquired and the original cost of such property, less the amounts credited to accumulated depreciation), including the return on those costs or the amortization thereof, (2) transition costs defined as one-time, temporary costs related to effecting the Transaction that do not create a long lived or future benefit to ratepayers, severance costs related to termination of employees as a direct result of the Transaction, or termination fees incurred in conjunction with the Transaction, or (3) transaction costs, defined as one-time costs required for items such as equity financing and regulatory approvals, including but not limited to LU Central or EDE personnel costs incurred as a result of the Transaction. All costs related to the Transaction shall be recorded in separate accounts

specifically maintained to account for the Transaction. The detailed journal entries recorded to reflect the Transaction shall be filed with the Commission no later than six months after the date of closing of the Transaction.

28. Algonquin and Liberty Utilities each expressly recognize that each represents an "Affiliated Interest" under K.S.A. 66-1401, 66-1402, and 66-1403. These statutes confer certain jurisdiction to the Commission regarding access to books and records, submission of contracts, review of affiliate transactions detail, etc.

29. EDE's fuel and purchased power costs shall not be adversely impacted as a result of the Transaction.

30. Liberty Utilities already has in place a cost allocation manual that sets forth a cost allocation methodology to be used by all regulated utilities entities based largely on the guidelines established by the National Association of Regulatory Utility Commissioners ("NARUC"). Liberty Utilities will revise or modify its current cost allocation manual, as needed, to reflect the acquisition of EDE within six (6) months following the closing of the Transaction, and provide a copy to the Commission.

31. LU Central commits it will file with the Commission an executed copy of the Affiliate Service Agreement within thirty (30) days of closing of the Transaction, pursuant to K.S.A. 66-1402.

32. The return on equity capital (ROE) as reflected in EDE's rates will not be adversely affected as a result of the Transaction.

33. LU Central agrees the ROE shall be determined in future rate cases, consistent with applicable law, regulations and practices of the Commission.

34. LU Central and EDE will not oppose, in either a regulatory proceeding or by judicial

appeal of a Commission decision, the application of the principle that the determination of the ROE can be based only on the risks attendant to the regulated operations of EDE.

35. LU Central agrees that EDE's equity level will not fall below 40% of its total capitalization as a result of any dividend payments, equity repurchase, or other upstream cash payment made to LU Central or any of its parent companies.

36. For purposes of determining a fair and reasonable allowed rate of return for determining EDE's revenue requirement in future rate cases, LU Central agrees that if EDE's per books capital structure is different from that of the entity or entities in which EDE relies for its financing needs (debt or equity), EDE shall be required to provide evidence as to why EDE's per book capital structure, or the capital structure of the entity or entities in which EDE relies on for its financing needs is the least cost. Nothing herein restricts the ability of Staff or CURB to present a different recommendation than EDE regarding the least cost capital structure for purposes of determining a fair and reasonable allowed rate of return for determining EDE's revenue requirement.

37. LU Central agrees the accumulated deferred income taxes (ADIT) amount, character, and all other terms reflected on the books of EDE immediately prior to the Transaction shall be unchanged by the Transaction. Additionally, EDE will record on its books all deferred taxes related to income tax deductions or credits created by EDE's operations.

38. At the time of any EDE rate case filing within five years after the Transaction closes, EDE shall provide an analysis demonstrating that administrative and general (A&G) costs and general corporate overheads have not increased as a direct result of the Transaction. Nothing herein restricts the ability of Staff or CURB from independently reviewing this analysis and making a different recommendation than EDE on the issue of A&G or overhead costs (including but not

limited to the issue of future USD/CAD exchange rate fluctuations) occurring as a result of the Transaction.

39. LU Central commits that in future rate case proceedings, LU Central and EDE will support its assurances provided in this document with appropriate analysis, testimony, and necessary journal entries fully clarifying and explaining how any such determinations were made.

iii. SEGREGATION OF ASSETS

40. LU Central agrees that EDE will not comingle its assets with the assets of any other person or entity, except as allowed under the Commission's Affiliate Transaction Statutes.

41. LU Central commits that EDE will conduct business as a separate legal entity and shall hold all of its assets in its own legal entity name.

42. LU Central commits that EDE will not grant or permit to exist any lien, encumbrance, claim, security interest, pledge, or other right in favor of any person or entity in its assets, other than liens or encumbrances entered into in the ordinary course of business.

43. LU Central and EDE affirm that the present legal entity structure that separates the regulated business operations from those unregulated business operations shall be maintained unless express Commission approval is sought to alter any such structure. LU Central and EDE further agree that proper accounting procedures will be employed to protect against cross-subsidization of non-regulated businesses or regulated businesses in other jurisdictions by EDE's Kansas customers.

iv. ACCOUNTING STANDARDS

44. LU Central shall not permit any subsidiary to make any material change in financial accounting methods, principles or practices, except to the extent as may have been required by a change in applicable state or federal law or Generally Accepted Accounting Principles ("GAAP") or by any Governmental Entity (including the Securities and Exchange Commission ("SEC") or the

Public Company Accounting Oversight Board).

45. LU Central affirms there will be no material change in accounting for Kansas held assets of LU Central or EDE unless reviewed and approved by the Commission.

v. **BOOKS AND RECORDS**

46. LU Central and EDE accounting records will be maintained in accordance with the NARUC Uniform System of Accounts as adopted by the Commission including the "NARUC Regulations to Govern the Preservation of Records of Electric, Gas and Water Utilities."

47. EDE commits it will maintain separate books and records, system of accounts, financial statements, and bank accounts.

48. Algonquin, LU Central, its affiliates, and EDE (collectively the "Entities") agree to produce or deliver any or all accounting records and related documents requested by the Commission, Staff, or CURB. The Entities may, with Commission approval, provide verified copies of original records and documents. The Entities further agree that the preferred method of production or delivery of records is by electronic access or electronic submission. If electronic access or electronic submission is not available or is deemed unsatisfactory by the Commission for its purposes, the Entities agree that the requested records and related documents, or legible verified copies thereof, shall be physically produced and delivered to the Commission in a timely manner. Nothing in this condition shall be deemed a waiver of any of the Entities' right to seek protection of the information or to object, for purposes of submitting such information as evidence in any evidentiary proceeding, to the relevancy or use of such information by any party.

49. The Entities will maintain adequate records to support, demonstrate the reasonableness of, and enable the audit and examination of all centralized corporate costs that are allocated to or directly charged to EDE. Nothing in this condition shall be deemed a waiver of any

of the Entities' right to seek protection of the information or to object, for purposes of submitting such information as evidence in any evidentiary proceeding, to the relevancy or use of such information by any party.

vi. CUSTOMER SERVICE AND CUSTOMER NOTIFICATION

50. LU Central and EDE agree to maintain or improve EDE's current quality of service, consistent with the requirements of Commission rules. In addition, EDE agrees to the following quality of service parameters and penalties for non-compliance in the event of failure to maintain these parameters. Using the methodology established in the Annual Reliability Benchmarking Report of the Institute of Electronic and Electrical Engineers (IEEE), EDE's normalized[1] reliability statistics (SAIDI, SAIFI, CAIDI) for its Kansas operations (area 212) shall be calculated for years 2013 through 2015. EDE shall pay a refund to its Kansas customers for any year the Kansas Service area normalized annual statistics decrease in reliability below the 2013-2015 averages according to the following schedule:

a. 5%-10%: $35,000

b. 10%-15%: $70,000

c. >15%: $105,000

51. Subject to the extraordinary event provision contained in paragraph 52 below, EDE shall calculate the answered call rate (ratio of calls answered to calls received) for its normalized operations during the years 2013 through 2015. EDE shall pay a refund to its Kansas customers for any year its answered call rate normalized annual operation falls below 95% of the 2013-2015 average according to the following schedule:

a. 5% to 10%: $17,000

[1]Normalized shall be defined as excluding major event days as defined by IEEE. The occurrence of any major event shall be considered in evaluating customer service reporting metrics.

b. >10%: $34,000

52. The Parties recognize that there may be certain extraordinary events that occur from time to time, which (1) are beyond the control of the utility, such as an act of nature, and (2) may affect the utility's ability to meet the service standards agreed to in Paragraphs 50 and 51 of this Agreement and the attachment to this Agreement. Upon the occurrence of an extraordinary event as that term is further defined below, EDE shall document the event and its impact on EDE's call center or electric service performance as applicable. Should EDE's service performance become inferior to service standards of any of the performance indicators specified, EDE will have the opportunity to present evidence of an extraordinary event in its written report, attaching supporting documentation as previously described. For purposes of this Agreement, the term "extraordinary event" means an event beyond the control of the utility, which shall include acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightening, earthquakes, fires, storms, ice storms, floods, tornados, washouts, arrests and restraints of governments and people, acts, orders, laws or regulations of government authority, civil disturbances, explosions, breakage or accident to machinery or lines of pipe or electric supply lines, major events causing electric service interruptions of the magnitude defined by the Commission's Electric Reliability Requirements Rule 3 (n), other than those caused by the utility's negligence, the necessity for making repairs or alterations to machinery, equipment or lines of pipe, freezing lines of pipe or electric supply lines, which could not have been prevented by the utility's standard and custom industry practice, partial or entire failure of supply of natural gas or fuel which could not have been prevented by the utility's use of standard and custom industry practices, acts of independent and unaffiliated third parties which damage or interference with the kind herein enumerated or otherwise beyond the control of the utility, if, using standard and custom

industry practice, the utility could have avoided the extraordinary event, then the impact of such event will be considered in the measurement of the performance of the utility.

53. From the effective date of the closing of the Transaction and ending three years later there shall be no net reduction in the total number of the field/plant personnel serving the customers of Kansas.

54. Each of the penalty provisions detailed in Paragraphs 50 and 51 shall expire the later of three years from the date of the closing of the Transaction or three years from the date a violation has occurred.

55. Failure on the part of EDE to comply with reporting requirements listed in this Agreement could result in a show cause hearing and additional penalties under the provisions of K.S.A. 66-138.

56. EDE agrees to the reporting requirements contained in Appendix A to this Agreement.

vii. OTHER

57. LU Central and EDE agree to reaffirm and honor any prior commitments made by EDE to the Commission and to comply with any previously issued Commission orders applicable to EDE or its previous owners.

viii. FINANCING

58. Algonquin acknowledges that it is ultimately responsible for maintaining the financial integrity of EDE such that EDE is capable of meeting its statutory responsibility to provide sufficient and efficient service.

59. In the event EDE, and/or the affiliate on which it relies on for its debt financing ("Financing Affiliate"), should have its Corporate Credit Rating as determined by Standard & Poor's

("S&P") or Moody's[2] downgraded to below BBB- or Baa3, respectively, EDE commits to file:

a. Notice with the Commission within five (5) business days of such downgrade;

b. A pleading with the Commission within 60 days which shall include the following:

i. A plan identifying all reasonable steps, taking into account the costs, benefits and expected outcomes of such actions, that will be taken to restore and maintain a S&P BBB- or Moody's Baa3 or above credit rating, for EDE and/or the Financing Affiliate. If EDE's plan does not involve taking steps to restore and maintain an S&P BBB- or Moody's Baa3 or above credit ratings for either or both of these entities then EDE shall concisely state why the cost of such steps is not reasonable or necessary;

ii. Additionally, EDE shall specifically address the impact, or lack thereof, it believes the Corporate Credit Rating of below BBB- or Baa3 has had and will have on its capital costs;

iii. Documentation, including but not limited to, a cost of capital study showing how EDE will not pass along higher capital costs to its Kansas customers, directly or indirectly, due to the downgrade(s);

iv. File with the Commission, every 45 days thereafter until EDE, and/or the Financing Affiliate, have regained a Corporate Credit Rating of BBB- or Baa3 or above, a status report with respect to the implementation of steps to restore the Corporate Credit Rating to BBB- or Baa3 or above and a study that estimates the

[2]Nothing in this Agreement shall require EDE or any Financing Affiliate to maintain credit ratings with both S&P and Moody's.

increased cost of capital, if any, EDE has incurred due to a Corporate Credit Rating of below BBB- or Baa3;

60. If the Commission determines that EDE's, and/or the Financing Affiliate's, Corporate Credit Rating decline has caused its service to decline, EDE shall be required to file a report that demonstrates to the Commission that it can adequately safeguard capital produced and secured by its public utility assets. If EDE cannot sufficiently demonstrate this ability, then EDE shall execute reasonable steps to ensure EDE's S&P or Moody's Corporate Credit Ratings will be based on its own stand-alone credit quality. These steps may include consideration of restoring EDE's corporate financing functions and restricting the distribution of cash flows to its affiliates in the event that EDE has transferred these activities to an affiliate.

61. In the event EDE's affiliation with Algonquin and its companies should cause EDE's and/or the Financing Affiliate's Corporate Credit Rating to be downgraded to below BBB- or Baa3, EDE, or the Financing Affiliate, shall pursue additional legal and structural separation, if necessary, from the affiliate(s) causing the downgrade, to ensure EDE continues to have access to capital at the least cost. EDE shall not pay a dividend to, or repurchase outstanding equity from its upstream parent companies until there is sufficient evidence that EDE's Corporate Credit Rating has been restored to the rating EDE had before the event.

62. If EDE's S&P or Moody's Corporate Credit Rating declines, and/or the credit rating of the Financing Affiliate declines, EDE shall file with the Commission a comprehensive risk management plan that assures EDE's access to and cost of capital will not be further impaired. The plan shall include a non-consolidation opinion if required by S&P or Moody's.

63. EDE shall not seek an increase to the cost of capital as a result of this Transaction or EDE's ongoing affiliation with Algonquin and its affiliates other than EDE after the Transaction.

Any net increase in the cost of capital EDE seeks shall be supported by documentation that: (a) the increases are a result of factors not associated with the Transaction or the post Transaction operations of Algonquin or its non-EDE affiliates; (b) the increases are not a result of changes in business, market, economic or other conditions caused by the Transaction or the post Transaction operations of Algonquin or its non-EDE; and (c) the increases are not a result of changes in the risk profile of EDE caused by the Transaction or the post Transaction operations of Algonquin or its non-EDE affiliates. The provisions of this section are intended to recognize the Commission's authority to consider, in appropriate proceedings, whether this Transaction or the post Transaction operations of Algonquin or its non-EDE affiliates has resulted in capital cost increases for EDE. Nothing in this Agreement shall restrict the Commission from disallowing such capital cost increases from recovery in EDE's rates.

64. LU Central plans to use a reasonable and prudent investment grade capital structure. LU Central will be provided with appropriate amounts of debt and equity from Liberty Utilities to maintain such a capital structure. LU Central will, in turn, use the capital provided by Liberty Utilities to contribute the necessary capital to its utility subsidiaries including EDE. LU Central will provide the Commission with details on any debt and equity instruments associated with the Transaction, and provide copies of such instruments within 30 days of closing of the Transaction.

65. The Parties recognize that both the acquisition premium and the debt, equity, and other capital components used to finance the acquisition premium are recorded on the books of LU Central and are not recorded on the books of EDE, and therefore, are not reflected in the rate base or capital structure of EDE. The Parties acknowledge that no gain on sale shall be recorded on the books of Algonquin, Liberty Utilities, EDE or any of their subsidiaries or affiliates.

66. If Liberty Utilities or LU Central refinance any or all of EDE's existing debt, for

reasons other than to obtain a lower interest rate that provides demonstrated net benefits to EDE's customers over the period until the debt would have otherwise matured, ratepayers should be protected by allowing no remaining unamortized debt issuance costs and no losses on reacquired debt for such refinanced debt.

67. To the extent the goodwill arising from the Transaction which is assigned to LU Central becomes impaired and such impairment negatively effects EDE's cost of capital, all net costs associated with the decline in EDE's credit quality specifically attributed to the goodwill impairment, considering all other capital cost effects of the Transaction and the impairment, shall be excluded from the determination of EDE's rates.

68. For the first five years after closing of the Transaction, LU Central shall provide Staff and CURB, its annual goodwill impairment analysis in a format that includes spreadsheets in their original format with formulas and links to other spreadsheets intact and any printed materials within 30 days after it is performed. Thereafter, this analysis will be made available to Staff and CURB upon request.

69. Staff will retain a copy of Liberty Utilities' financial/valuation model. Staff will continue to protect the confidentiality of the information contained within that model.

ix. ACCESS TO RECORDS

70. EDE shall provide Staff and CURB with access, upon reasonable written notice during working hours and subject to appropriate confidentiality and discovery procedures, to all written information provided to common stock, bond or bond rating analysts which directly or indirectly pertains to EDE or any affiliate that exercises influence or control over EDE or has affiliate transactions with EDE. Such information includes, but is not limited to, common stock analyst's and bond rating analyst's reports. For purposes of this condition, "written" information

includes, but is not limited to, any written and printed material, audio and video tapes, computer disks, and electronically stored information. Nothing in this condition shall be deemed a waiver of any entity's right to seek protection of the information or to object, for purposes of submitting such information as evidence in any evidentiary proceeding, to the relevancy or use of such information by any party.

71. EDE agrees to make available to Staff and CURB, upon written notice during normal working hours and subject to appropriate confidentiality and discovery procedures, all books, records and employees as may be reasonably required to verify compliance with EDE's CAM and any conditions ordered by this Commission. EDE shall also provide Staff and CURB any other such information (including access to employees) relevant to the Commission's ratemaking, financing, safety, quality of service and other regulatory authority over EDE; provided that any entity producing records or personnel shall have the right to object on any basis under applicable law and Commission rules, excluding any objection that such records and personnel of affiliates; (a) are not within the possession or control of EDE or (b) are either not relevant or are not subject to, the Commission's jurisdiction and statutory authority by virtue of, or as a result of, the implementation of the proposed Transaction.

72. EDE shall provide Staff and CURB access to and copies of, if requested by Staff or CURB, the complete Liberty Utilities, LU Central and EDE Board of Directors' meeting minutes, including all agendas and related information distributed in advance of the meeting, presentations and handouts, provided that privileged information shall continue to be subject to protection from disclosure and EDE shall continue to have the right to object to the provision of such information on relevancy grounds.

B. MISCELLANEOUS PROVISIONS

73. Except as specifically set forth herein, there shall be nothing about the Transaction that alters the applicability of previous Commission orders in other dockets, policies, rules and applicable statutes.

74. To the extent not already provided through discovery, executed copies of all agreements identified in the Joint Application, including confidential copies of all schedules to those agreements, shall be provided to the Commission within thirty (30) days following the completion of the Transaction.

75. Except for provided in this Agreement otherwise, nothing in this Agreement shall preclude Staff, CURB or the Commission from reviewing the appropriateness of any cost of service item in any future rate case filed by EDE.

76. Liberty Utilities and LU Central shall provide upon request and with appropriate notice, all information needed to verify compliance with these conditions and any other information relevant to the Commission's ratemaking, financing, safety, quality of service and other regulatory authority over EDE.

77. The terms and conditions of the Agreement reached herein shall only go into effect upon the closing of the Transaction, which is the subject of the Joint Application filed in this docket. In the event that the Transaction does not close, then the terms of this Agreement among the Parties are void ab initio. The terms and conditions shall remain in effect either as stated in this Agreement, or if not stated herein, until such time as the Commission may order otherwise in a general rate case or other proceeding brought for that purpose.

78. The terms and conditions of the Agreement reached herein are interdependent. In the event that the Commission does not approve and adopt the terms and conditions of this Agreement in total, the Agreement shall be voidable and no party hereto shall be bound, prejudiced,

or in any way affected by any of the agreements or provisions hereof. Further, in such event, the Agreement shall be considered privileged and not admissible in evidence or made a part of the record in any proceeding.

79. If the Commission accepts the Agreement in its entirety and incorporates the same into its final Order in this docket, the Parties intend to be bound by its terms and the Commission's Order incorporating its terms as to all issues addressed herein, and will not appeal the Commission's Order.

80. Algonquin, on behalf of itself, its successors, assignees, and its subsidiaries, and in consideration of the signatories' support of the proposed acquisition embodied in this document, agrees that it will uphold the conditions agreed to by EDE and LU Central in this Agreement.

WHEREFORE, on behalf of their respective clients, the undersigned attorneys respectfully request that the Commission approve this Unanimous Settlement Agreement in its entirety and that the Commission issue an order in this matter approving the Joint Application subject to the conditions contained in the Unanimous Settlement Agreement.

Dated this 6th day of October, 2016.

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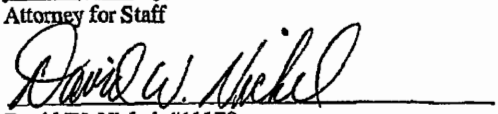

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Appendix A
Reporting Requirements

REPORTING REQUIREMENTS (Based on 02-GIME-365-GIE Docket)

I. Electric Reliability Requirements

1. Definitions and General Obligations are found in Kansas Docket No. 02-GIME-365-GIE January 16, 2004 Order.

2. Record-keeping and data retention for outages.

(a) EDE shall maintain an accurate record of each interruptions of service that affects one or more customers. Each record shall contain at least the following information:
  (1) Outage report number or work order number;
  (2) The locations where the outage occurred;
  (3) Identification of the substation involved;
  (4) Identifications of the circuits involved;
  (5) The date and time the outage occurred;
  (6) That date and the time service was restored;
  (7) The duration of the outage;
  (8) The number of customers interrupted by the outage;
  (9) The outage cause;
  (10) The interrupting device that make the interruption;

(b) For interruptions where customers are not simultaneously restored, an electric utility shall keep records that document the step restoration operations.

(c) For major events where an electric utility cannot obtain accurate data, the electric utility shall make reasonable estimates.

(d) The information shall be used to compute the summaries in the reliability reports in Section 3, and shall be provided to the Commission in the electronic format prescribed by the Commission upon request. EDE shall retain the detailed records associated with this provision for a minimum of five years.

3. Annual reporting on electric service reliability. EDE shall provide and annual reliability performance report to the Commission by May 1 of each year for the previous calendar year for the utility's Baxter Springs, Kansas service area ("Area 212").

(a) Annual Report of Baxter Springs service area: The annual report shall provide an overall assessment of the reliability performance, including:
  (1) An assessment of the service area-wide SAIFI, SAIDI and CAIDI performances for the previous calendar year for the Baxter Springs, Kansas service territory, pursuant to Paragraph (3)(b);
  (2) A presentation of the service area-wide SAIFI, SAIDI and CAIDI performance for the previous 5 calendar years with trend analysis and assessment for this period, to the extent that such data are available;
  (3) An assessment of utility service area wide reliability, and;
  (4) For each worst performing circuit in Subparagraph (3)(b)(4) that also qualified as a worst performing circuit for the previous year, an assessment of performance and planned improvements, excluding Major Event Days, as defined by IEEE 1366.

(b) Annual Report of Baxter Springs service area Kansas Circuit Performance:

The annual report shall include the following performance data presented for each Kansas circuit:

(1) Annual actual reliability data including:
   (A) Average monthly customers;
   (B) Total customer interruptions, subject to limitations in Paragraph (c) and including interruptions during major events;
   (C) Total customer interruption minutes, subject to limitations in Paragraph (c) and including interruptions during major events;
   (D) Actual SAIDI in minutes, calculated from data furnished in Paragraphs (A) and (C);
   (E) Actual SAIFI in interruptions, calculated from data furnished in Paragraphs (A) and (B);
   and
   (F) Actual CAIDI in minutes, calculated from data furnished in Paragraphs (B) and (C);

(2) Annual normalized reliability data, including;
   (A) Average monthly customers;
   (B) Total customer interruptions, subject to limitations in Paragraph (c) and including interruptions during major events;
   (C) Total customer interruption minutes, subject to limitations in Paragraph (c) and including interruptions during major events;
   (D) Normalized SAIDI in minutes, calculated from data furnished in Paragraphs (A) and (C);
   (E) Normalized SAIFI in interruptions, calculated from data furnished in Paragraphs (A) and (B); and
   (F) Normalized CAIDI in minutes, calculated from data furnished in Paragraphs (B) and (C);

(3) An action report for each major event as defined by IEEE 1366.

(4) A list and categorization of actual interruption statistics by root cause, including;
   (A) Total customer interruptions corresponding to each root cause category; and
   (B) Total customer interruption minutes corresponding to each root cause category.

(5) EDE shall establish and maintain a program for identifying and analyzing its worst performing circuits during the course of each calendar year. This program shall include:
   (A) An analysis of the top five percent (5%) worst performing circuits used to serve the customers in area 212, the circuits shall be identified and ranked using SAIFI values, adjusted to exclude all major events as defined by the IEEE 1366;
   (B) Circuit SAIFI value;
   (C) Circuit SAIDI value;
   (D) Indication of whether the circuit qualified as a worst performing circuit for the previous calendar year;
   (E) Associated substations supplying the power to the circuit;
   (F) Number of customers served by the circuit;

(G) Customer interruptions;
(H) Customer interruption duration in minutes;
(I) Circuit CAIDI value.

(c) Interruptions shall not be included in the presentations of data or calculation of the reliability indices when caused by an intentional interruption pursuant to an interruptible service or tariff or contract, or by authorized disconnections due to nonpayment of a bill, failure to improper operations of customer equipment, tampering with customer service equipment, customer denial of utility access to service equipment, hazardous conditions, violation of a tariff or service contract, the request of the customer or a law enforcement or governmental authority, or other lawfully authorized disconnection or interruption.

II. Customer Service Metrics Reporting

1. Customer call center data shall be reported to the Commission on an annual basis. This data shall include:

(d) Call center Agent averages and totals per shift;
(e) Calls received;
(f) Calls answered; and
(g) Calls abandoned.

III. Field/Plant personnel shall be defined as follows:

Manager of Line Operations
Journeyman Electrician
Electrician Foreman
Meter Reader 1st Class
Journeyman Meter Tester
Line Foreman
Journeyman Lineman - M&S Truck
Clerk-Storekeeper 1st Class
Line Foreman
Line Foreman
Journeyman Lineman
Journeyman Lineman
Journeyman Lineman
Line Foreman
Construction Designer
Journeyman Lineman
Lineman 2nd Class
Journeyman Lineman
Lineman 3rd Class
Senior Operator/Technician
Senior Operator/Technician
Results Manager - Riverton
Construction Designer - Assoc
Journeyman Lineman - M&S Truck
Meter Reader 1st Class
Journeyman Lineman - M&S Truck
Senior Operator/Technician
Senior Operator/Technician
Manager of Operations-Riverton
Senior Operator/Technician
Plant Manager - Riverton
Senior Operator/Technician
Admin Asst - Riverton - Sr
Site Supervisor - Riverton
Senior Operator/Technician
Senior Operator/Technician
Energy Supply Training Manager
Senior Operator/Technician
Senior Operator/Technician
Senior Operator/Technician
Associate Operator/Technician
Associate Operator/Technician
Senior Operator/Technician
Local Projects Mgr-Riv-Assoc

Maintenance Manager-Riverton
Senior Operator/Technician
Local Projects Manager - Riv

CERTIFICATE OF SERVICE

16-EPDE-410-ACQ

I, the undersigned, certify that the true copy of the attached Order has been served to the following parties by means of Electronic Service on DEC 22 2016.

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CERTIFICATE OF SERVICE

16-EPDE-410-ACQ

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/S/ DeeAnn Shupe
DeeAnn Shupe

EMAILED

DEC 22 2016

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of the Joint Application of Atmos Energy Corporation and Liberty Energy (Midstates) Corp. for Authority to Sell Certain Missouri Assets To Liberty Energy (Midstates) Corp. and, in Connection Therewith, Certain Other Related Transactions.	)))))	**Case No. GM-2012-0037**

UNANIMOUS STIPULATION AND AGREEMENT

COME NOW Atmos Energy Corporation ("Atmos" or "Company") and Liberty Energy (Midstates) Corp. ("Liberty-Midstates")(collectively "Joint Applicants"), the Commission Staff ("Staff"), the Office of the Public Counsel ("Public Counsel" or "OPC"), and IBEW Local No. 1439 ("IBEW")(collectively "Signatories") by and through their undersigned counsel and, pursuant to Missouri Public Service Commission ("Commission") Rule 4 CSR 240-2.115, respectfully request that the Commission approve the following Stipulation And Agreement (hereinafter referred to as the "Stipulation" or "Stipulation and Agreement") recognizing that such approval is conditioned upon Liberty-Midstates filing with the Commission evidence of the necessary FERC approval to transport gas to Rich Hill and Hume prior to closing. In support thereof, the Signatories state the following:

BACKGROUND

1. On August 1, 2011, the Joint Applicants filed their Joint Application with the Commission under Section 393.190.1, RSMo 2000 as currently supplemented; Section 393.200, RSMo.; 4 CSR 240-3.210; 4 CSR 240-3.220; and 4 CSR 240-4.020(2), requesting an order from the Commission approving the sale of certain Atmos property to Liberty-Midstates and certain

related transactions (the "Transaction").[1] Atmos and Liberty-Midstates also filed the testimony of Ian E. Robertson, David Pasieka, Peter Eichler, and Mark Martin in support of the Joint Application on August 1, 2011.

2. On August 2, 2011, the Commission issued its Order Directing Notice and Setting Date For Submission Of Intervention Requests which set August 22, 2011 as the date for any intervention requests to be filed. On August 24, 2011, IBEW Local 1439 ("IBEW") filed for intervention. On September 12, 2011, the Commission issued its Order Granting Intervention and Setting Prehearing Conference which granted the intervention of IBEW and scheduled a prehearing conference for September 22, 2011.

3. The Signatories appeared at the prehearing conference on September 22, 2011. Thereafter, on September 29, 2011, the Staff filed, on behalf of the Signatories, a proposed procedural schedule for this case, which was adopted by the Commission by its Order issued on September 29, 2011. Pursuant to the procedural schedule, the Joint Applicants, Staff, Public Counsel, and IBEW participated in a Technical Conference on October 12, 2011. Thereafter, on November 18, 2011, the Staff, Public Counsel and IBEW provided to the Joint Applicants their proposed conditions for recommending approval of the proposed transaction.

4. Having engaged in discovery, the Signatories met for a settlement conference on December 1-2, and December 5-6, 2011, for discussion of the proposed conditions and possible settlement of the case. As a result of those discussions, the Signatories have now reached a Unanimous Stipulation And Agreement, which they recommend to the Commission as

[1] As stated in the Joint Application, Liberty-Midstates proposes to purchase substantially all of the assets of Atmos used to provide natural gas and transportation service in the States of Missouri, Illinois, and Iowa, as specifically described in the Asset Purchase Agreement dated May 12, 2011 ("Agreement") under the terms and provisions further described in the Agreement, including its certificates of convenience and necessity.

reasonable and not detrimental to the public interest. This Stipulation resolves all remaining issues in this proceeding as set forth below.

APPROVAL OF THE TRANSACTION

5. Accordingly, the Signatories agree that:

I. General

The Commission should issue its Order:

(1) finding that the transaction described in the Asset Purchase Agreement ("Agreement") attached to the Joint Application is not detrimental to the public interest;

(2) authorizing Atmos to sell and Liberty-Midstates to acquire the assets of Atmos identified in the application, and including the issuance of new certificates of convenience and necessity for the service areas currently served by Atmos;

(3) authorizing the Joint Applicants to enter into, execute and perform in accordance with the terms described in the Agreement and to take any and all other actions which may be reasonably necessary and incidental to the performance of the acquisition;

(4) authorizing Liberty-Midstates to maintain its books and records outside of Missouri, pursuant to 4 CSR 240-10.010;

(5) authorizing Atmos to abandon the provision of natural gas distribution in Missouri upon the closing of the transaction;

(6) if necessary, granting the Joint Applicants' Motion for Waiver of Commission Rule 4 CSR 240-4.020(2), to the extent it may otherwise be required;

(7) granting such other relief as is appropriate under the circumstances to accomplish the purposes of the Agreement and the Joint Application and to consummate related transactions in accordance with the Agreement.

II. CONDITIONS

A. The Signatories recommend that the Commission approve the proposed sale of the assets of Atmos to Liberty-Midstates, subject to the following conditions:

1. Rate Moratorium:

Liberty-Midstates shall not file a general rate case for non-gas costs prior to December 31, 2013, unless there is the occurrence of a significant, unusual event that has a major impact on any of its Missouri service territories. Major impact is defined as loss of 20% of infrastructure or customers from events such as (i) terrorist activity or an act of God; (ii) a significant change (20%) in federal or state tax laws; or (iii) a significant change in federal or state utility or environmental laws or regulations. Liberty-Midstates will be permitted to file ISRS requests which conform to Missouri statutes, throughout the term of the general rate case moratorium. The other Signatories agree they will not file an earnings complaint against Liberty-Midstates during the same period.

2. Rate Base Offset:

Liberty-Midstates shall include a rate base offset of $16.34 million on its books and records on the effective date of close of this Transaction. Liberty-Midstates shall amortize this rate base offset over a period of ten years commencing on the effective date of close. For clarification, the outstanding balance of such rate base offset shall serve to reduce rate base for rate making purposes in the context of future rate proceedings, which will effectively credit customers with a return on such rate base offset through lower rates and charges in future periods.

3. Acquisition Costs and Premium:

a. Liberty-Midstates shall not ever seek to include or recover any amount of acquisition costs including all transaction costs, which as used herein refers to costs relating to gaining regulatory approval, development of transaction documents, investment banking costs, costs related to raising equity incurred prior to closing of the Transaction, communication costs regarding the

ownership change with customers and employees, the cost of name changes on facilities, vehicles, sign and lettherhead, and any amount of acquisition premium associated with this transaction in any future proceeding.

b. The Signatories agree that transition costs and capital expenditures can be booked on the Liberty-Midstates books to be considered in rate cases for review of the appropriateness, reasonableness and prudence of these costs and expenditures to determine if they should be recoverable in rates. Liberty-Midstates shall have the burden of proving to the Commission in Liberty-Midstates' next general rate proceeding that recovering any such transition costs and related capital expenditures in rates is just and reasonable.

c. If the Joint Applicants agree that any services are required subsequent to the termination of the continuing services agreements (CSA), such services shall be provided pursuant to terms determined in good faith, arms-length negotiations between the Joint Applicants. Should the Joint Applicants determine that a service is best provided by a third party, Atmos commits to use its best efforts to assist Liberty Midstates in identifying and selecting such a third party.

d. Liberty-Midstates shall record and separately identify all transition and transaction costs that are incurred as a result of this transaction by CSA service, by month incurred, and by FERC account for the review of Staff and OPC at the time of filing of its next general rate case.

e. Atmos and Liberty-Midstates agree that transition costs that are a part of this transaction carry no guarantee of recovery and may be challenged in a subsequent rate case.

4. Environmental:

Liberty-Midstates shall not ever seek recovery in rates for any environmental costs related to the clean-up of the Hannibal Manufactured Gas Plant site, unless such costs are related to new claims that were not known to Atmos or Liberty-Midstates at the time of closing of the Transaction.

5. Injuries and Damages and Workers' Compensation Claims:

Liberty-Midstates shall not ever seek recovery in rates for any injuries and damages and any Workers' Compensation claims for incidents that occurred prior to the date of closing of this Transaction in any future proceeding.

6. Prepaid Pension Asset Balance

Liberty-Midstates shall not ever seek recovery in rates for any amount of prepaid pension asset balance that currently exists for Atmos-Missouri in any future proceeding. In addition, the Signatories acknowledge that the manner that pensions and OPEBS have been handled in the past for Atmos is not necessarily indicative of how these two items will be dealt with in rates after the sale.

7. Affiliate Transactions and Cost Allocation Manual (CAM)

a. Liberty-Midstates shall comply with the Commission's Affiliated Transaction and Marketing Affiliate Transaction Rules, 4 CSR 240-40.015 and -40.016. This agreement relating to affiliate transactions rule annual reporting requirements shall not waive any part of the record keeping requirements of Liberty-Midstates or its parent, or any of its affiliates as required by the Affiliate Transaction and Marketing Affiliate Transactions Rules. Liberty-Midstates shall provide Staff and OPC full access to records of affiliated entities in accordance with the Affiliate Transaction and Marketing Affiliate Transaction Rules.

b. As required by 4 CSR 240-40.015(4)(B), Liberty-Midstates shall provide to the Staff and OPC on, or before, March 15 of the succeeding year:

1) A full and complete list of all affiliate entities as defined by the rule;

2) A full and complete list of all goods and services provided to or received from affiliated entities;

3) A full and complete list of all contracts entered with affiliated entities;

4) A full and complete list of all affiliate transactions undertaken with affiliated entities without a written contract together with a brief explanation of why there was no contract;

5) The amount of all affiliate transactions, by affiliated entity and account charged by the type of transaction and amount with monthly totals; and

6) The basis used (e.g., fair market price, FDC, etc.) to record each type of affiliate transaction.

c. Upon request of Staff and/or OPC, Liberty-Midstates shall provide a list of each intercompany accounts receivable transaction between Liberty-Midstates and its parent or any other affiliate, with details including: the date, each account, the amount of each transaction, and the general ledger description of each transaction. If a general ledger description requires additional explanation, copies of this information shall be made available to the Staff within twenty (20) days upon request.

d. Upon request of Staff and/or OPC, Liberty-Midstates shall provide the annual calculation of all allocation factors including: all components used in the development of each and every CAM allocation factor, and all source documents to support the basis used and to verify the price charged. This information shall be maintained by Liberty-Midstates and its affiliates in accordance with the affiliate transactions rules recordkeeping requirements and copies of such documentation shall be made available to the Staff and/or OPC within twenty (20) days upon request.

e. Liberty-Midstates shall submit its first CAM to the Commission within ten months after the Commission approves this Stipulation. This CAM shall, among other things, describe the methods used to allocate and share costs between affiliated entities including other jurisdictions and/or corporate divisions, and shall set forth cost allocation, market valuation and internal cost methods. No approval of Liberty-Midstates' CAM is granted as part of Case No. GM-2012-0037. Liberty-Midstates shall file to seek approval from the Commission for its CAM prior to, or as part of, its next general rate case proceeding.

f. On an on-going basis, Liberty-Midstates shall provide a complete copy of its CAM with its annual March 15th BAFT filing and highlight any changes to the CAM.

8. Adherence to Previous Commission Orders and Stipulations and Agreements

Liberty-Midstates shall comply with all requirements resulting from all Commission Approved stipulation and agreements and Commission Orders in all cases applicable to Atmos, which are still in force, from the effective date of the Commission's Order approving Atmos' acquisition of Greeley Gas Company in Case No. GM-94-6. To the extent any requirement in those prior stipulation and

agreements and orders conflicts with a provision of the Stipulation and Agreement, the Stipulation and Agreement shall govern. In addition, Liberty-Midstates shall comply with all Commission rules (including but not limited to the Commission's Cold Weather Rule, Gas Safety rules and Affiliate Transactions rules), reporting requirements and other practices, subject to existing waivers or variances authorized by the Commission for Atmos.

9. Tariffs

Atmos has Commission approved tariffs. Liberty-Midstates shall formally adopt in whole Atmos' tariffs verbatim upon the closing of the transaction. These tariffs shall remain in effect until changed by Order of the Commission or by operation of law.

10. Depreciation Related-Issues

a. For purposes of accruing depreciation expense, Liberty-Mid-States shall adopt the currently ordered depreciation rates for Atmos approved by the Commission in File No. GR-2006-0387 and attached as Schedule JAR-1 (Appendix 1);

b. Atmos shall transfer all plant and depreciation reserve records to Liberty-Midstates in compliance with the format set forth in Title 18: Conservation of Power and Water Resources, Part 201—Uniform System Of Accounts Prescribed For Natural Gas Companies Subject To The Provisions Of The Natural Gas Act (FERC USOA).

c. Liberty-Midstates shall prepare and maintain its books in accordance with the FERC Uniform System of Accounts (USOA).

d. Staff recognizes the Depreciation Study submitted by Atmos is sufficient for meeting the requirement of 4 CSR 240-3.275. The Signatories acknowledge that this study shall be deemed to meet Liberty-Midstates' requirement to perform a depreciation study within 5 years or 3 years prior to the next rate case.

e. The Signatories recommend the Commission order Atmos to record the entries determined in its Missouri depreciation study submitted on June 1, 2011, prior to the close of the Transaction.

f. Liberty-Midstates shall submit the following information in accordance with 4 CSR 240-3.275 Submission Requirements for Gas Utility Depreciation Studies.

1) FERC USOA requires the following information shall be recorded as part of a Continuing plant inventory record (CPR).

2) FERC USOA CPR Rule 8. *Continuing plant inventory record* means company plant records for retirement units and mass property that provide, as either a single record, or in separate records readily obtainable by references made in a single record, the following information:

A. For each retirement unit:

(1) The name or description of the unit, or both;
(2) The location of the unit;
(3) The date the unit was placed in service;
(4) The cost of the unit as set forth in Plant Instructions 2 and 3 of this part; and
(5) The plant control account to which the cost of the units is charged;

and

B. For each category of mass property:

(1) A general description of the property and quantity;
(2) The quantity placed in service by vintage year;
(3) The average cost as set forth in Plant Instructions 2 and 3 of this part; and
(4) The plant control account to which the costs are charged.

11. Credit Issues

a. Liberty-Midstates shall take necessary steps to ensure that Liberty-Midstates is not consolidated with Algonquin Power Co. ("APCo") and/or Algonquin Power & Utilities Corp. ("APUC)" in the event of bankruptcy.

b. Liberty-Midstates shall take the necessary steps to ensure that the entity on

which Liberty-Midstates relies on for debt financing has and maintains an investment grade credit rating.

c. At the date of execution of the Stipulation and Agreement, Liberty Midstates represents that Liberty Utilities' current and proposed assets contemplated under the J.P. Morgan Credit Agreement dated as of January 18, 2012 (the "Liberty Utilities Credit Revolver") support the ability to increase the credit facility capacity if so needed. Liberty-Midstates represents that Liberty Utilities Co. will not provide APUC or APCo access to any credit facility Liberty Utilities Co. may enter into for the benefit of Liberty-Midstates.

12. Financing Authorization

The Signatories are not agreeing that any Commission financing approval is to be granted in this case. Liberty-Midstates has represented that it can finance this transaction in a manner that does not require Commission approval.

13. Service Quality Conditions

a. Liberty-Midstates shall provide to the Staff the same monthly service quality reporting provided to the Staff by Atmos as agreed to in stipulations approved by the Commission in Case Nos. GM-2000-312 and GR-2006-0387. Such reporting shall include the following Call Center metrics: the Number of Calls Offered, the Average Speed of Answer (ASA), the Abandoned Call Rate (ACR) and Number of Call Center Staff, segregated into permanent and temporary and/or contract call center staff.

b. Liberty-Midstates shall, at such time it begins to offer Virtual Hold or Virtual Hold–type Call Center technology, notify the Staff and the OPC and shall incorporate such metrics in its monthly call center reporting.

c. On a monthly basis, Liberty-Midstates shall provide Staff and OPC the number of bills relying on usage estimates instead of actual meter readings and the number of bills consecutively estimated. Liberty-Midstates shall also state the number of months the bills have been estimated. Liberty-Midstates shall provide updated lists to the Staff and OPC of all of its Missouri pay stations and Missouri business offices. Liberty-Midstates shall provide lists to the Staff and the OPC whenever its pay stations and business offices change, but in any event shall provide this information annually.

d. Liberty-Midstates shall provide the Staff and the OPC a current

organizational chart, including the positions and names of employees that have customer service responsibilities. In the event structural changes are made to Liberty-Midstates' organization, Liberty-Midstates shall provide updated organizational charts to the Staff and OPC within 30 days of such changes.

e. Prior to closing of the Transaction, Liberty-Midstates shall provide the Staff and OPC a sample customer bill for the first billing period that includes all information required by Commission Rules, 4 CSR 240-13 (Chapter 13).

f. Customer bills shall continue to include the "Bill Check-Off Program," as identified in item 13 of the Unanimous Stipulation and Agreement approved by the Missouri Public Service Commission in Case File No. GR-2010-0192. This program permits a customer to make a voluntary contribution to help other customers pay their bills and includes a shareholder match of customer contributions.

g. Liberty-Midstates shall provide the Staff and the OPC all customer notifications sent to its Missouri customers describing the sale of the Atmos gas properties to Liberty-Midstates including new Liberty-Midstates contact information including but not limited to: emergency phone numbers, non-emergency phone numbers, Web-site addresses, and business office locations that will permit customer walk-in traffic and other changes.

14. Continuing Services Agreement (CSA)

a. Atmos shall make all of the services outlined in the draft CSA schedules filed with the Staff on November 14, 2011 (attached as Appendix 2 to this Stipulation) available to Liberty-Midstates for nine (9) months following the close of the transaction. Atmos and Liberty-Midstates represent that the CSA schedules submitted to the Staff on November 14, 2011, comprise all services necessary to continue and maintain the operations at pre-transactions levels.

b. Atmos and Liberty-Midstates shall provide the Staff and OPC final CSA schedules upon closing of this transaction.

c. Atmos and Liberty-Midstates represent that the goal of transition services is 1) to provide for a seamless transition of all operating functions from Atmos to Liberty-Midstates and 2) to ensure that all operating functions are

performing at pre-transaction levels prior to the termination of remaining transition services. Not less than 30 days prior to the termination of any CSA, Liberty-Midstates shall notify the Staff and OPC and, if requested, coordinate a technical conference with the Staff and OPC to describe how the transition service will be provided.

d. Liberty-Midstates shall provide to the Staff and OPC, at least every 90 days after close of the transaction until completion of all CSA services, a transition status report of the progress being made towards the assumption by Liberty-Midstates of all transition services that are being provided to Liberty-Midstates. Liberty-Midstates shall provide advance notice to the Staff and the OPC of all changes to transition plans and/or CSAs, including but not limited to those that impact customer service quality and gas supply. Copies of any and all amendments or other changes to the transition plans/CSAs shall be provided with the Liberty-Midstates transition status reports. Liberty-Midstates shall file these status reports in EFIS, under the case number GM-2012-0037.

e. During the first 12 months following closing of the transaction, the Chief Executive Officer of Algonquin Power & Utilities Corp., the President of Liberty Utilities and a representative of Atmos shall accompany the President of Liberty-Midstates to attend quarterly meetings with Staff and OPC to provide status reports on the progress of the transaction and transition plans.

f. Atmos and Liberty-Midstates shall participate throughout the transition period in conference calls with the Staff and OPC to discuss transition status and progress.

g. Atmos and Liberty-Midstates shall notify Staff and OPC immediately if a CSA is determined to be required beyond the nine (9) month transition period after date of close.

    1) Atmos and Liberty-Midstates management shall be present for an on-the-record presentation before the Commission to be scheduled in early November 2012. Liberty-Midstates shall present witnesses to provide live testimony and be prepared to discuss the status of the transition and any problem areas and to offer action plans to ensure completion of a seamless transition without disruption to ratepayers. Liberty-Midstates witnesses shall be available for questions from the Signatories regarding the progress of the transition involving the matters contained in this Stipulation. After the closing of this Transaction, the Staff shall

file a pleading on behalf of the Signatories proposing a date for the on-the-record presentation.

2) The Joint Applicants have represented to Staff and OPC that they anticipate the CSAs will only be needed for a period of 9 months from the date of closing.

15. Gas Supply and Hedging Plans

a. For the first two years after a Commission order approving the Transaction, Liberty-Midstates shall present to Staff twice annually, during the Spring and Fall, its gas supply and hedging plans for the upcoming winter. The Spring presentation shall occur no later than May 15th of each year and the Fall updated presentation shall occur no later than September 15th of each year. Thereafter, Liberty-Midstates shall present to Staff its gas supply and hedging plans no later than May 15th of each year. The Liberty-Midstates gas supply and hedging plans presentation shall include gas supply plans for normal, colder and warmer weather, storage plans, and hedging plans including strategies and control policies, and implementation (timing, types, etc.) of hedges. The Liberty-Midstates gas supply and hedging plans shall contain at least as much detail as the former Atmos plans and include a planning time horizon beyond one year.

b. Atmos shall not delay normal gas supply planning and hedging related to the operation of these properties because of the proposed sale of these properties.

c. Liberty-Midstates shall develop a plan to increase vendor participation in bid responses to gas-supply Requests for Proposals (RFPs).

d. In its Spring gas supply and hedging plans presentation, Liberty-Midstates shall discuss its actions to improve gas procurement policies and procedures to consider innovative techniques to acquire reliable and reasonable-cost gas supply for each of its service areas. For example, Liberty-Midstates shall discuss its plans to increase vendor participation in bid responses to Requests for Proposals.

e. Prior to direct assumption of gas procurement responsibility by Liberty-Midstates following termination of the CSA related to the provision of such services by Atmos, Liberty-Midstates shall have in its possession and shall be operating, an in-house gas procurement invoicing, gas procurement data

base, and operations system (SCADA, telemetry, etc.) with customer functionality similar to Atmos' systems.

f. Atmos shall transfer to Liberty-Midstates copies of all records and documents related to PGA/ACA cases. Liberty-Midstates shall not assert its inability to obtain Atmos' records and/or its inability to have access to Atmos personnel as a defense against potential adjustments in PGA/ACA cases. Atmos shall provide Liberty-Midstates all testimony, work papers, records, data, materials and other information related to Missouri service area cost of service studies and Missouri service area class cost of service studies performed by Atmos in GR-2006-0387 and GR-2010-0192.

g. Within 90 days after closing of the transaction, and annually no later than May 15th thereafter, for the first two years of ownership, Liberty-Midstates shall submit to the Staff and OPC a comprehensive peak day demand study. After 2 years of operation, comprehensive peak day demand studies shall be performed no less frequently than every 3 years. Liberty-Midstates shall file these peak day demand studies in EFIS, under case number GM-2012-0037.

    1) Liberty-Midstates's comprehensive peak day demand study shall be conducted for each Missouri natural gas service area, estimating projected peak day (coldest day) requirements for the next five years and the capacity available to meet such requirements.

    2) If Liberty-Midstates revises the transportation or storage capacity from that identified in the peak day demand study, Liberty-Midstates shall prepare an addendum to the peak day demand study within 6-months of making such changes, explaining the changes and the rationale for the changes, and provide the addendum to Staff and OPC. Revisions requiring an addendum include changes to any of the transportation and storage contracts (delivery or receipt points, quantities, terms, etc.). Liberty-Midstates shall file these addendums, in EFIS, under case number GM-2012-0037.

    3) Copies of any and all transportation contracts, including storage, contracts shall be provided to Staff, no later than 90 days after the effective date of the revised contract(s). Liberty-Midstates shall file these contracts in EFIS, under case number GM-2012-0037.

h. Liberty-Midstates shall not seek recovery in Missouri rates for transportation charges resulting from the Gas Transportation Agreement between Atmos

and Liberty-Midstates dated February 2012, by which Atmos delivers natural gas to Liberty-Midstates at or near the Missouri/Kansas border until the effective date of rates in Liberty-Midstates' next general rate case. Recovery of transportation rate charges shall be limited for a period of eight (8) years after the effective date of recovery of these charges to no more than $0.075MMBtu on a usage basis. Liberty-Midstates shall file a compliance tariff incorporating the provisions of this paragraph (15.h) within 30 days of the effective date of approval of this Stipulation and Agreement.

i. Atmos and Liberty-Midstates shall ensure that reliability and transportation priority for western Missouri (WEMO) customers shall be equivalent to Kansas residential service.

16. FERC Approvals

a. Atmos and Liberty-Midstates shall not close the sale of the Missouri Atmos properties until Liberty-Midstates receives Section 7(f) authority from FERC and Atmos receives a limited jurisdiction blanket certificate from FERC to provide transportation service.

b. The Signatories agree that the Commission's order approving the Stipulation and Agreement should be conditioned upon Liberty-Midstates filing with the Commission evidence of the necessary FERC approval to transport gas to Rich Hill and Hume prior to closing.

c. Nothing in this Stipulation and Agreement prevents the Commission from pursuing its interests in FERC cases CP 12-41, CP 12-42, and CP 12-53.

17. Gas Safety

a. Liberty-Midstates shall comply fully with all of the Commission's pipeline safety regulations and, prior to operating the system, must meet the following requirements and have the following programs or plans in place and fully operational, subject to existing waivers or variances authorized for Atmos:

Field personnel shall be Operator Qualification tested;
Field personnel shall be drug tested as required by CSR 240-40.080;
Field personnel shall be trained in Missouri's specific gas safety rules;
Leak calls shall be responded to immediately;
Operations and Maintenance Plan;
Emergency Plan;

Operator Qualification Plan;
Anti-Drug and Alcohol Misuse Plan;
Damage Prevention Program;
Public Awareness Program;
Integrity Management Program for Transmission Pipelines;
Integrity Management Program for Distribution Pipelines; and,
Membership in Missouri One Call Systems, Inc
Control Room Management Program

b. In addition to an Operator Qualification Plan, Liberty-Midstates shall have qualified personnel in place to operate the natural gas system. In addition to having an Anti-Drug and Alcohol Plan, Liberty-Midstates shall conduct pre-employment testing of new personnel, and conduct random testing as required by Commission rules.

c. Liberty-Midstates shall have a process to receive and respond to emergency, leak and odor calls, at any time (24 hours a day, 7 days a week, 365 days a year). Joint Applicants shall have a transition plan in place for transferring to Liberty-Midstates personnel the Liberty-Midstates customers that call Atmos' telephone numbers. Liberty-Midstates shall have personnel in place to receive, dispatch and respond to emergency, leak and odor calls as required by the Commission (within one hour for inside odor call and within two hours for outside odor calls). If Liberty-Midstates changes the emergency telephone number used by the public, Liberty-Midstates shall widely advertise that number so the public is aware of the 24-hour emergency telephone number to be called in an emergency.

d. Liberty-Midstates shall establish a plan to replace signage at regulator stations, above ground piping, road crossings and other locations. In addition to establishing a Control Room Management Program, Liberty-Midstates shall establish a gas control function for supervisory control and data acquisition (SCADA) systems for remotely controlling and monitoring remote-controlled valves and system pressures.

18. <u>IBEW Conditions</u>

a. All individual Cash Balance (pension) accounts will be fully funded at the time of the closing of the sale.

b. Liberty-Midstates will accept and conform to all terms and conditions contained in the current collective bargaining agreement between Atmos and

IBEW Local 1439 and will extend said collective bargaining agreement for one year beyond the current expiration date (2012), subject to a negotiated wage/benefit increase.

19. Miscellaneous Conditions

a. Prior to Liberty-Midstates filing its first general rate proceeding related to the acquired Atmos properties, Liberty-Midstates will not request Commission authorization to alter or be relieved of any of the terms or conditions contained in past stipulations or Commission orders that were applicable to Atmos just prior to the acquisition.

b. Atmos will provide Liberty-Midstates all testimony, work papers, records, data, materials and other information in Atmos' possession related to Missouri service area cost of service studies and Missouri service area class cost of service studies performed by Atmos' predecessors.

c. Atmos will provide Liberty-Midstates all testimony, work papers, records, data, materials and other information related to Missouri service area cost of service studies and Missouri service area class cost of service studies performed by Atmos in GR-2006-0387 and GR-2010-0192.

d. If in its first general rate proceeding related to the acquired Atmos properties, Liberty-Midstates proposes to alter the existing rate districts, alter the existing rate classifications or to apply rate increases to customer classes within a rate district in a manner other than as an equal percentage increase to all customer classes and all rate elements, Liberty-Midstates will prepare and submit to Staff and OPC a class cost of service study together with detailed work papers for each district and each customer class. The class cost of service study work papers will be provided in electronic format to Staff and Public Counsel at the time of Liberty-Midstates' direct testimony filing.

e. Until March 31, 2014, Liberty-Midstates shall not assess reconnection charges, delinquent payment charges, or foregone delivery charge fees (see Tariff Sheet No. 21) resulting from any system conversion related error(s). To effectuate this term, the Signatories request that the Commission grant Liberty-Midstates a temporary waiver from applying these tariff-authorized charges. Until March 31, 2014, Liberty-Midstates also agrees not to disconnect customers whenever the reason for the disconnection is the result of any system conversion related error(s).

20. No Detriment

The Signatories agree that the intent of the Stipulation is to avoid detrimental impacts to customers, and that this Stipulation should be interpreted accordingly.

III. GENERAL PROVISIONS

(1) This Stipulation has resulted from negotiations among the Signatories and the terms hereof are interdependent. In the event the Commission does not adopt this Stipulation in total, then this Stipulation shall be void and no Signatory shall be bound by any of the agreements or provisions hereof. The stipulations herein are specific to the resolution of this proceeding, and all stipulations are made without prejudice to the rights of the Signatories to take other positions in other proceedings except as otherwise provided herein. The Signatories agree that, unless this Stipulation becomes effective as provided herein, any and all discussions related hereto shall be privileged and shall not be subject to discovery, admissible in evidence, or in any way used, described or discussed in any proceeding other than during any Stipulation presentation scheduled by the Commission in this proceeding and in the November 2012 on-the-record presentation.

(2) This Stipulation is being entered into for the purpose of disposing of all issues in this case. The Signatories represent that the terms of this Stipulation constitute a fair and reasonable resolution of the issues addressed herein, in a manner which is not detrimental to the public interest. Except as otherwise addressed herein, none of the Signatories to this Stipulation shall be deemed to have approved, accepted, agreed, consented or acquiesced to any accounting principle, ratemaking principle or cost of service determination underlying, or supposed to underlie any of the issues provided for herein.

(3) The Signatories further understand and agree that the provisions of this

Stipulation relate only to the specific matters referred to in the Stipulation, and no Signatory or person waives any claim or right which it otherwise may have with respect to any matter not expressly provided for in this Stipulation. The Signatories further reserve the right to withdraw their support for the settlement in the event that the Commission modifies the Stipulation in a manner which is adverse to the Signatory, and further, the Signatories reserve the right to contest any such Commission order modifying the settlement in a manner which is adverse to the Signatory contesting such Commission order.

(4) The non-utility Signatory Parties enter into this Stipulation in reliance upon information provided to them by the Joint Applicants and this Stipulation is explicitly predicated upon the truth of representations made by the Joint Applicants.

(5) In the event the Commission accepts the specific terms of this Stipulation without modification, the Signatories waive, with respect to the issues resolved herein: their respective rights pursuant to Section 536.070(2), RSMo 2000 to call, examine and cross-examine witnesses; their respective rights to present oral argument or written briefs pursuant to Section 536.080.1, RSMo 2000; their respective rights to the reading of the transcript by the Commission pursuant to Section 536.080.2, RSMo 2000; their respective rights to seek rehearing pursuant to Section 386.500, RSMo 2000; and their respective rights to judicial review pursuant to Section 386.510, RSMo 2000. Furthermore, in the event the Commission accepts the specific terms of this Stipulation without modification, the Signatories agree that the prefiled testimony of all witnesses who have prefiled testimony in this case shall be included in the record of this proceeding without the necessity of such witnesses taking the stand.

(6) The Staff shall, within 14 days of the filing of this Stipulation and Agreement, file

suggestions or a memorandum in support of this Stipulation. Each of the other Signatories shall be served with a copy of any such suggestions or memorandum and shall be entitled to submit to the Commission, within five (5) business days of receipt of Staff's suggestions or memorandum, responsive suggestions or a responsive memorandum which shall also be served on all Signatories. The contents of any memorandum provided by any Signatory are its own and are not acquiesced in or otherwise adopted by the other Signatories to this Stipulation.

(7) The Staff shall also have the right to provide, at any agenda meeting at which this Stipulation is noticed to be considered by the Commission, whatever oral explanation the Commission requests, provided that the Staff shall, to the extent reasonably practicable, promptly provide other Signatories with advance notice of when the Staff shall respond to the Commission's request for such explanation once such explanation is requested from Staff. Staff's oral explanation shall be subject to public disclosure, except to the extent it refers to matters that are privileged or previously designated confidential by any signatory.

(8) Except as otherwise addressed in this Stipulation, Commission approval of the sale of assets of Atmos to Liberty-Midstates, and for the Joint Applicants to execute and perform in accordance with the terms of the Agreement, does not in any way, limit, form a basis for determination, or constitute a defense against any Signatory proposing, or the Commission ordering, the disallowance and/or imputation of account balances, expenses, revenues and/or other ratemaking findings, regarding Atmos or Liberty-Midstates in a future rate proceeding

(9) To assist the Commission in its review of this Stipulation, the Signatories also request that the Commission advise them of any additional information that the Commission may desire from the Signatories relating to the matters addressed in this Stipulation, including any

procedures for furnishing such information to the Commission.

WHEREFORE, the Signatories unanimously recommend that Atmos' sale of its Missouri properties to Liberty-Midstates is reasonable and not detrimental to the public interest and respectfully request that the Commission approve this Stipulation And Agreement subject to the conditions contained herein, including that the Joint Applicants obtain the necessary FERC approvals to transport gas to Rich Hill and Hume.

Respectfully submitted,

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STATE OF MISSOURI
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held at its office in Jefferson City on the 4th day of April, 2018.

In the Matter of Liberty Utilities (Missouri Water) LLC and Ozark International, Inc., Concerning an Agreement to Acquire the Assets of Bilyeu Ridge Water Company, LLC Midland Water Company, Inc., Moore Bend Water Utility, LLC, Riverfork Water Company, Taney County Water, LLC, And Valley Woods Utility	)))))))	**File No. WM-2018-0023**

ORDER APPROVING STIPULATION AND AGREEMENT AND GRANTING CERTIFICATES OF CONVENIENCE AND NECESSITY

Issue Date: April 4, 2018 Effective Date: April 14, 2018

On September 14, 2017, Liberty Utilities (Missouri Water) LLC and Ozark International, Inc. filed a joint application with the Commission seeking authority for Liberty to purchase the franchise and operating assets of each of the following wholly-owned Ozark subsidiaries: Bilyeu Ridge Water Company, LLC; Midland Water Company, Inc.; Moore Bend Water Utility, LLC; Riverfork Water Company, LLC; Taney County Water, LLC; and Valley Woods Utility (the Ozark subsidiaries are collectively referred to as the "Ozark Utilities"). All of the companies to be acquired operate water systems. Valley Woods Utility also operates a sewer system.

The Commission issued notice of the joint application and set a deadline for intervention requests. The Missouri Department of Natural Resources applied to intervene and that request was granted.

The Commission's Staff filed its Recommendation and Memorandum regarding the joint application on January 5, 2018. Staff recommended the joint application be granted,

subject to certain conditions. However, Staff recommended Liberty Utilities not be allowed to proceed with its proposal to consolidate the tariffed rules, regulations and rate schedules of the six Ozark Utilities into a single consolidated tariff.

Liberty Utilities and Ozark did not object to the conditions proposed by Staff, but did disagree with Staff's recommendation to deny consolidation of the tariffs of the subsidiaries. Because of the disagreement, the Commission set this matter for an evidentiary hearing to be held on March 22. On March 16, all parties filed a unanimous stipulation and agreement indicating their acceptance of all aspects of Staff's Recommendation, including the conditions proposed by Staff. By the terms of Staff's recommendation, which were incorporated into the stipulation and agreement, Liberty Utilities will adopt all rates, rules, and regulations in each of the Ozark Utilities' existing tariffs.

After reviewing the stipulation and agreement, the Commission independently finds and concludes that the stipulation and agreement is a reasonable resolution of the issues addressed by the stipulation and agreement and that such stipulation and agreement should be approved. Because of the unanimous agreement of the parties, this order will be made effective in ten days.

THE COMMISSION ORDERS THAT:

1. The Unanimous Stipulation and Agreement filed on March 16, 2018, is approved as a resolution of all issues. The signatory parties are ordered to comply with the terms of the stipulation and agreement. A copy of the stipulation and agreement is attached to this order.

2. Ozark is authorized to sell and transfer the regulated utility assets and its subsidiaries' certificates of convenience and necessity to Liberty Utilities, and Liberty Utilities is authorized to provide service in the Ozark service areas as requested.

3. To the extent any acquisition premium that may result from the purchase of Ozark's regulated utility assets by Liberty Utilities exists, any related acquisition adjustment shall be excluded from rate recovery in any future rate case.

4. Consistent with Staff's recommendation to adopt all rates, rules, and regulations in each of the Ozark Utilities' existing tariffs, Liberty Utilities is authorized to apply each of the Ozark Utilities' existing rates and rules on an interim basis immediately after closing on the assets, until an adoption notice tariff sheet becomes effective.

5. Liberty Utilities shall submit an adoption notice tariff sheet for the existing tariffs within ten days after closing on the assets and as a thirty-day tariff filing for the existing Ozark Utilities' tariffs.

6. The Ozark Utilities' existing depreciation and CIAC amortization rates for water utility plant accounts are approved to apply to their respective service areas' assets.

7. If closing on the water system assets does not take place within thirty days following the effective date of this order, Liberty Utilities or Ozark, or both, shall submit a status report within five days after this thirty day period regarding the status of closing, and shall submit additional status reports within five days after each additional thirty day period, until closing takes place, or until Liberty Utilities or Ozark determines that the transfer of the assets will not occur.

8. If Liberty Utilities or Ozark determines that a transfer of the assets will not occur, Liberty Utilities shall notify the Commission of such determination no later than the

date of the next status report, as addressed in ordered paragraph 7, after that determination is made.

9. Liberty Utilities shall, within ninety days after the effective date of this order authorizing the transfer of assets, correct its books and records to reflect the adjusted plant, depreciation reserve and Contributions in Aid of Construction balances reflected in Staff's Accounting Schedules.

10. Liberty Utilities shall develop and implement, with the review and assistance of Staff, comprehensive allocation procedures to allocate costs and investments between regulated and non-regulated operations and between the various regulated entities of Liberty Utilities' corporate parent consistent with the utility's current practices.

11. Liberty Utilities shall, upon closing of the sale, take physical possession of, and maintain pursuant to regulation, any and all books and records of each Ozark entity being acquired, including, but not limited to, all financial records, plant and depreciation reserve records, invoices, purchase orders and purchase agreements, all customer billing records and customer deposit records, all payroll and employee information, etc.

12. Liberty Utilities shall develop a comprehensive time reporting system specifically designed to identify time spent and cost incurred by its personnel on each of the Ozark Utilities and other Liberty Utilities entities. This time reporting shall be developed in time for use in Liberty Utilities' next rate cases.

13. Liberty Utilities shall, within ten days after closing on the assets, provide an example of its actual communication with customers of each of the Ozark Utilities regarding Liberty Utilities' acquisition and operations of the Ozark Utilities' water system assets, and how customers may reach Liberty Utilities regarding water matters.

14. Liberty Utilities shall include the Ozark Utilities' customers in its established monthly reporting to the Customer Experience Department (CXD) staff. Such reporting has previously been ordered by the Commission and is provided by both The Empire District Electric Company and Liberty Utilities. Liberty Utilities shall include metrics for the Ozark Utilities customers in whichever individual company customer service system – either The Empire District Electric Company or Liberty Utilities – may be serving the Ozark Utilities' customers. Such reporting shall include, but is not limited to, such metrics as: a) call center staffing; b) calls offered; c) average speed of answer; d) abandoned call rate; e) number of estimated bills; f) number of consecutive estimated bills; and g) calls answered by Integrative/Interactive Voice Response Unit. Liberty Utilities shall also include the Ozark Utilities' metrics in all future service quality reporting that may be provided to Staff by Liberty Utilities or The Empire District Electric Company, or both, which can be aggregated with service quality data reported to Staff for all affiliated companies.

15. Liberty Utilities shall distribute to Ozark Utilities' customers before the first billing from Liberty Utilities an informational brochure detailing the rights and responsibilities of the utility and its customers regarding its water and sewer service, consistent with the requirements of Commission Rule 4 CSR 240-13.040(3)(A-L).

16. Liberty Utilities shall provide to the CXD staff a sample of ten billing statements from each of the first three months of bills issued to the Ozark Utilities' customers within thirty days of such billing.

17. The Commission makes no finding that would preclude it from considering the ratemaking treatment to be afforded any matters pertaining to Liberty Utilities, including

expenditures related to the Ozark Utilities' certificated service areas and capacity adjustments, in any later proceeding.

18. This order shall be effective on April 14, 2018.

19. This file shall be closed on April 15, 2018.

BY THE COMMISSION

Morris L. Woodruff
Secretary

Hall, Chm., Kenney, Rupp, Coleman, and Silvey, CC., concur.

Woodruff, Chief Regulatory Law Judge

STATE OF MISSOURI
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held at its office in Jefferson City on the 10th day of July, 2019.

In the Matter of the Application of Liberty Utilities (Missouri Water) LLC and Franklin County Water Company Inc. for Liberty Utilities to Acquire Certain Water Assets of Franklin County Water	))))	**File No.: WA-2019-0036**

ORDER APPROVING TRANSFER OF ASSETS AND GRANTING CERTIFICATE OF CONVENIENCE AND NECESSITY

Issue Date: July 10, 2019 Effective Date: August 9, 2019

On March 13, 2019, Liberty Utilities (Missouri Water) LLC d/b/a Liberty Utilities (hereinafter, "Liberty Utilities") filed an *Application for Authority to Transfer Utility Assets and Certificated Area of Franklin County* ("Application") with the Missouri Public Service Commission ("Commission") seeking an order authorizing Liberty Utilities to acquire the franchise and operating assets of Franklin County Water Company, Inc. ("Franklin County"), including its Certificate of Convenience and Necessity ("CCN"). With the transfer, Liberty Utilities would acquire all customers served by Franklin County, substantially all operating assets used to serve those customers, and all CCNs issued by the Commission.

The Franklin County water distribution assets are located in rural Franklin County, Missouri, near the City of St. Clair, Missouri, and serve approximately 189 single-family residential customers in an area known as "Lake Saint Clair." Liberty Utilities and Franklin County have entered into an Asset Purchase Agreement ("Agreement") providing for the

sale of the assets, property and real estate used in and comprising Franklin County's water distribution system, all as set out in the Agreement.

On March 19, 2019, the Commission issued its *Order Directing Notice and Order Directing Filing.* No applications to intervene were filed. Staff filed a *Report and Recommendation* ("Staff's Recommendation") on June 10, 2019, recommending that the Commission approve Franklin County's sale and transfer of utility assets and CCN to Liberty Utilities subject to conditions. Staff, however, did not support the consolidation of rates described in the Application. Liberty Utilities filed no objection to Staff's Recommendation. Staff recommends that the Commission do the following:

1. Authorize Franklin County to sell and transfer utility assets to Liberty Utilities and transfer the CCN currently held by Franklin County to Liberty Utilities upon closing on any of the respective systems;
2. Retain the existing Franklin County rates of $5.70 customer charge and $2.61 commodity charge;
3. Upon closing on the Franklin County water system, authorize Franklin County to cease providing service, and authorize Liberty Utilities to begin providing service;
4. Require Liberty Utilities to submit tariff sheets *prior* to closing on Franklin County assets, to include existing Franklin County water rates, a service area map, and service area written description, to be included in its EFIS water tariff P.S.C. MO No. 14, all applicable specifically to water service in its Franklin County service area;

5. Require Liberty Utilities to create and keep financial books and records for plant-in-service, revenues, and operating expenses (including invoices) in accordance with the NARUC Uniform System of Accounts;

6. Require Liberty Utilities, going forward, to keep and make available for audit and review all invoices and documents pertaining to the capital costs of constructing and installing the water and sewer utility assets;

7. Approve depreciation rates for water and sewer utility plant accounts as described in Attachment 1 of Staff's "Memorandum" attached to its Recommendation;

8. Make no finding that would preclude the Commission from considering the ratemaking treatment to be afforded any matters in any later proceeding;

9. Require Liberty Utilities to provide to the Customer Experience Department Staff an example of its actual communication with the Franklin County customers regarding its acquisition and operations of the Franklin County water system assets, and how customers may reach Liberty Utilities regarding water matters, within ten (10) days after closing on the assets;

10. Require Liberty Utilities to include the Franklin County customers in its established monthly reporting to the Customer Experience Department Staff. Such reporting has been previously ordered by the Commission's Order Approving Application in WO-2011-0350 and is currently provided by Liberty Utilities. Such reporting includes, but is not limited to, such metrics as: 1) Calls Offered, 2) Call Center staffing, 3) Average Speed of Answer, 4) Abandoned Call Rate, 5) Number of Estimated Bills, 6) Number of

Consecutive Estimated Bills, and 7) calls answered by IVR (Integrative/Interactive Voice Response Unit);

11. Require Liberty Utilities to distribute an informational brochure detailing the rights and responsibilities of the utility and its customers regarding its water service to the Franklin County customers prior to the first billing from Liberty Utilities, consistent with the requirements of Commission Rule 4 CSR 240-13.040(3)(A-K); and

12. Require Liberty Utilities to provide to the Customer Experience Department Staff a sample of (10) billing statements from each of the first three months of bills issued to Franklin County customers within thirty (30) days of such billing.

Liberty Utilities filed no comments opposing Staff's Recommendation.

Liberty Utilities is a water corporation under Missouri law,[1] subject to the regulation, supervision and control of the Commission with regard to providing water service to the public. The Commission has jurisdiction to rule on the Application because Missouri law requires that "[n]o. . .water corporation. . .shall merge or consolidate such works or system, or franchises, or any part thereof, with any other corporation, person or public utility, without having first secured from the commission an order authorizing it so to do."[2] The Commission will deny the application only if approval would be detrimental to the public interest.[3]

[1] Section 386.020(59), RSMO 2016
[2] Section 393.190.1, RSMO 2016.
[3] *State ex rel. City of St. Louis v. Public Service Comm'n of Missouri,* 73 S.W.2d 393, 400 (Mo. 1934).

Liberty Utilities now serves approximately 3,300 water customers in Missouri. Liberty Utilities' greater size and its ability to gain access to the financial resources necessary to maintain or improve service will benefit customers currently served by the much smaller Franklin County. Once the proposed sale and transfer is approved, those customers currently being served by Franklin County will receive their water service from Liberty Utilities.

Based upon the information provided in the Application and upon the verified Recommendation and Memorandum of Staff, the Commission finds that the proposed transfer of assets set forth in the Agreement and subject to Staff's proposed conditions is not detrimental to the public interest. The Commission finds, however, that Liberty Utilities' request for a rate increase for Franklin County customers as a part of the acquisition is not reasonable. The Commission finds that the existing Franklin County rates of a $5.70 customer charge and a $2.61 commodity charge are just and reasonable.

With these rates and subject to the conditions recommended by Staff, the Commission finds that the *Application* should be approved, with the exception that the request to transfer Franklin County's certificate of convenience and necessity to Liberty Utilities cannot be granted. The Application requests transfer of Franklin County's CCN to Liberty Utilities, and the Staff has acceded to that request. A CCN, like a driver's license, is based upon the licensee's personal qualifications and is non-assignable. The Commission, however, will *sua sponte* consider whether to grant Liberty Utilities a CCN for the Franklin County service area.

The Commission may grant a water corporation a CCN to operate after determining that the construction and operation are either "necessary or convenient for

the public service."[4] The Commission applies the five "Tartan Criteria" established in *In the Matter of Tartan Energy Company, et al.,* 3 Mo. PSC 3d 173, 177 (1994) when deciding whether to grant a new CCN. The criteria are: (1) there must be a need for the service; (2) the applicant must be qualified to provide the proposed service; (3) the applicant must have the financial ability to provide the service; (4) the applicant's proposal must be economically feasible; and (5) the service must promote the public interest. For all of the reasons that the Commission finds for authorizing the transfer of the water operation assets to Liberty Utilities and stated above, the Commission finds that the factors for granting a certificate of convenience and necessity to Liberty Utilities have been satisfied. The Commission will grant Liberty Utilities a certificate of convenience and necessity for the Franklin County service area.

The COMMISSION ORDERS THAT:

1. Subject to the conditions recommended by the Commission Staff which are delineated in the body of this Order, the *Application of Liberty Utilities (Missouri Water) LLC d/b/a Liberty Utilities* is granted, except as stated in the next paragraph;

2. Liberty Utilities shall retain the existing Franklin County rates of a $5.70 customer charge and a $2.61 commodity charge. That part of the *Application* requesting the transfer of Franklin County's CCN to Liberty Utilities is denied, and Liberty Utilities is granted a CCN as stated below;

3. Franklin County is authorized to sell and transfer to Liberty Utilities and Liberty Utilities is authorized to acquire the water system located in Franklin County,

[4] Section 393.170.3, RSMO.

Missouri, described in the *Application* and the Asset Purchase Agreement entered into between those parties;

4. Liberty Utilities is granted a Certificate of Convenience and Necessity to provide water service within the Franklin County service area as more particularly described in the *Application*, subject to the conditions and requirements contained in Staff's *Recommendation* and set out above, effective upon the date of closing of the purchase transaction;

5. Liberty Utilities and Franklin County are authorized to do and perform, or cause to be done and performed, all such acts and things, as well as make, execute and deliver any and all documents as may be necessary, advisable and proper to the end that the intent and purposes of the approved transaction may be fully effectuated;

6. In issuing this order, the Commission is making no ratemaking determination regarding any potential future regulatory oversight;

7. This order shall become effective on August 9, 2019

BY THE COMMISSION

Morris L. Woodruff
Secretary

Silvey, Chm., Kenney, Hall, Rupp, and Coleman, CC., concur.

Graham, Regulatory Law Judge

STATE OF MISSOURI
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held by telephone and internet audio conference on the 17th day of June, 2020.

In the Matter of the Application of Liberty Utilities (Missouri Water), LLC d/b/a Liberty Utilities to Acquire the Water and Sewer Franchises and Assets of Lakeland Heights Water Company, Oakbrier Water Company, R.D. Sewer Company LLC, and Whispering Hills Water System	)))))))	**File No. WM-2020-0174**

ORDER GRANTING TRANSFER OF ASSETS AND GRANTING CERTIFICATES OF CONVENIENCE AND NECESSITY

Issue Date: June 17, 2020 Effective Date: July 17, 2020

On February 6, 2020, Liberty Utilities (Missouri Water) LLC d/b/a Liberty Utilities (Liberty Water) filed an application with the Missouri Public Service Commission requesting that the Commission approve its acquisition of the water and sewer franchises and assets of Lakeland Heights Water Company (Lakeland Heights), Oakbrier Water Company (Oakbrier), R.D. Sewer Company LLC (R.D. Sewer), and Whispering Hills Water System (Whispering Hills)(collectively the Selling Utilities). Liberty Water also requested the transfer of the related certificates of convenience and necessity (CCNs).

The Commission issued notice of the application and set a deadline for the filing of applications to intervene, but no applications were received. The Commission ordered its Staff (Staff) to file a recommendation. Staff filed a recommendation on June 4, 2020, recommending approval of the transfer of assets and CCNs subject to conditions. No other responses were received. No responses or objections to Staff's recommendation were filed.

No party requested a hearing and the requirement for a hearing is met when the opportunity for a hearing has been provided.[1] Thus, the Commission will rule on the application.

Liberty Water provides water service to over 7,000 customers and sewer service to more than 400 customers in several service areas throughout Missouri. Liberty Water is a certificated water corporation and a sewer corporation, subject to the Commission's jurisdiction.[2]

Lakeland Heights provides water service to approximately 101 single-family residential customers in the Lakeland Heights subdivision, located in the Rockwood Point area of the City of Wappapello, Wayne County, Missouri. Lakeland Heights is a certificated water corporation, subject to the Commission's jurisdiction.[3] Liberty Water's proposed improvements for Lakeland Heights appear to be consistent with the results of Staff's document review and observations at the time of Staff's inspection.

Oakbrier provides water service to approximately 78 single-family residential customers in the Oakbrier subdivision located in Butler County, Missouri. Oakbrier is a certificated water corporation, subject to the Commission's jurisdiction.[4] Liberty Water's proposed improvements for Oakbrier appear to be consistent with the results of Staff's document review and observations at the time of Staff's inspection.

R.D. Sewer provides sewer service to approximately 176 single-family residential customers in a subdivision near the city of Dexter in Stoddard County, Missouri. R.D. Sewer is a certificated sewer corporation, subject to the Commission's jurisdiction.[5] Liberty Water's

[1] *State ex rel. Rex Deffenderfer Ent., Inc. v. Public Serv. Comm'n*, 776 S.W.2d 494, 496 (Mo. App., W.D. 1989).
[2] Section 386.020(49), (59), RSMo 2016.
[3] Section 386.020(59), RSMo 2016; CCN granted in Case No. 17928 (1973).
[4] Section 386.020(59), RSMo 2016; CCN granted in WA-88-128.
[5] Section 386.020(49), RSMo 2016; CCN granted in SO-2008-0289.

proposed improvements for R.D. Sewer appear to be consistent with the results of Staff's document review and observations at the time of Staff's inspection.

Whispering Hills provides water service to approximately 50 single-family residential customers in the Whispering Hills subdivision located in Wayne County, Missouri. Whispering Hills is a water corporation, subject to the Commission's jurisdiction.[6] Liberty Water's proposed improvements for Whispering Hills appear to be consistent with the results of Staff's document review and observations at the time of Staff's inspection.

As regulated utilities, the Selling Utilities must obtain the Commission's authorization before selling or transferring their assets.[7] In evaluating the proposed acquisition, the Commission can only disapprove the transaction if it is detrimental to the public interest.[8]

Liberty Water has acquired several small existing water and sewer systems, and, as a subsidiary of Algonquin Power & Utilities Corporation, is affiliated with other companies that undertake some of the tasks associated with utility service, such as customer billing, and technical resources. Liberty Water has demonstrated managerial capacity in the operation of its current system. Liberty Water has access to capital through its upstream affiliates. Staff's position is that Liberty Water has the technical, managerial, and financial capacities to acquire and operate the Selling Utilities. The Commission finds that allowing Liberty Water to acquire the assets of the Selling Utilities is not detrimental to the public interest.

The purchase price for the Selling Utilities is above the net book value of the assets to be acquired. It has been Staff's position in prior cases that utility rates for acquired properties should be based upon the remaining net book value associated with the original cost of utility plant at the time when the plant was first devoted to public use; rate base should not reflect the amount of any acquisition adjustment, either above or below net book value.

[6] Section 386.020(59), RSMo 2016; CCN granted in WM-2009-0436.
[7] Section 393.190, RSMo 2016.
[8] *State ex rel. City of St. Louis v. Public Service Com'n of Missouri*, 73 S.W.2d 393, 400 (Mo banc 1934).

Liberty Water has not requested an acquisition adjustment in this matter. Liberty Water has the financial capacity to purchase and operate the Selling Utility's systems at the agreed to purchase price.

The Selling Utilities currently maintain a business office in Bernie, Missouri, that is used by many customers to pay their bills or conduct business with the Selling Utilities. Liberty Water will not maintain a local office in the area, but will establish a third-party payment center at a location yet-to-be-determined. Liberty Water's current customer service representatives will be available to take and process customer inquiries pertaining to billing and/or service issues, make necessary bill adjustments, enter into payment plans within company guidelines, interact with Staff in working with customer complaints, and manage new customer accounts and the closing of customer accounts.

Liberty Water proposed adopting the Selling Utilities' existing rates, and applying Liberty Water's existing tariff rules. There are sufficient differences in the rules and regulations between the two sets of tariffs that Staff recommends Liberty Water adopt the currently effective tariffs of the Selling Utilities, and work towards a consolidation at its next rate proceeding. Liberty Water did not object to this recommendation.

Staff recommends using the depreciation rates ordered in each of the Selling Utilities' most recent general rate cases: WR-2012-0266 for Lakeland Heights; WR-2012-0267 for Oakbrier; SR-2012-0263 for R.D. Sewer; and WM-2009-0436 for Whispering Hills. These rates will be reviewed during the pendency of Liberty Water's next rate case involving these systems. Liberty Water did not object to this recommendation.

The Commission may grant a water or sewer corporation a certificate of convenience and necessity to operate after determining that the construction and operation are either

"necessary or convenient for the public service."[9] The Commission articulated the specific criteria to be used when evaluating applications for utility CCNs in the case *In Re Intercon Gas, Inc.*, 30 Mo P.S.C. (N.S.) 554, 561 (1991). The *Intercon* case combined the standards used in several similar certificate cases, and set forth the following criteria: (1) there must be a need for the service; (2) the applicant must be qualified to provide the proposed service; (3) the applicant must have the financial ability to provide the service; (4) the applicant's proposal must be economically feasible; and (5) the service must promote the public interest.[10] These criteria are known as the Tartan Factors.[11]

There is a need for the service because as the customers of the Selling Utilities are already receiving service and will continue to need that service with the improvements Liberty Water proposes. Liberty Water is qualified to provide the service based on its current provisions of water and sewer service throughout its Missouri service areas. Liberty Water has demonstrated its financial ability by making appropriate investment in its current operations. The proposed transaction is economically feasible as no rate change is requested. The proposal promotes the public interest as demonstrated by positive findings in in the first four Tartan Factors.

The Commission finds that Liberty Water possesses adequate technical, managerial, and financial capacity to operate the water and sewer systems it wishes to purchase from the Selling Utilities. The Commission concludes that the factors for granting a CCN to Liberty Water have been satisfied and that it is in the public interest for Liberty Water to provide water and sewer service to the service areas currently served by the Selling Utilities. The

[9] Section 393.170.3, RSMo 2016.
[10] The factors have also been referred to as the "Tartan Factors" or the "Tartan Energy Criteria." See Report and Order, *In re Application of Tartan Energy Company, L.C., d/b/a Southern Missouri Gas Company, for a Certificate of Convenience and Necessity*, Case No. GA-94-127, 3 Mo. P.S.C. 3d 173 (September 16, 1994), 1994 WL 762882, *3 (Mo. P.S.C.).
[11] *In re Tartan Energy Company*, 3 Mo.P.S.C. 173, 177 (1994).

Commission will authorize the transfer of assets and grant Liberty Water the certificates of convenience and necessity to provide water and sewer service within the proposed service areas, subject to the conditions in Staff's memorandum.

Liberty Water also seeks a waiver of the Commission's 60-day notice requirement of Commission rule 20 CSR 4240-4.017(1)(D). Liberty Water certifies that it has had no communication with the office of the Commission regarding any substantive issue likely to be in this case during the preceding 150 days.

THE COMMISSION ORDERS THAT:

1. Liberty Water's request for waiver from the 60-day notice requirement of Commission rule 20 CSR 4240-4.017(1)(D) is granted.

2. The Selling Utilities are authorized to sell and transfer to Liberty Water the assets identified in the application.

3. Liberty Water is granted Certificates of Convenience and Necessity to install, acquire, build, construct, own, operate, control, manage and maintain water and sewer systems in the areas currently served by the Selling Utilities.

4. Upon closing of the asset transfer, the Selling Utilities are authorized to cease providing service, and Liberty Water is authorized to begin providing service.

5. Liberty Water shall adopt the currently effective tariffs of the Selling Utilities, and work towards a consolidation at its next rate proceeding.

6. Liberty water shall use the depreciation rates as recommended in Staff's Memorandum.

7. The transactions are subject to the following conditions as put forth in Staff's June 4, 2020, Memorandum:

> A. Liberty Water shall submit an adoption notice <u>prior to closing on the assets</u>, to adopt the existing Lakeland Heights, Oakbrier, and Whispering Hills tariffs (emphasis original);

B. Liberty Water shall create and keep financial books and records for plant-in-service, revenues, and operating expenses (including invoices) in accordance with the NARUC Uniform System of Accounts;

C. Liberty Water shall provide training to its call center personnel regarding rates and rules applicable to the customers acquired from the Selling Utilities, prior to the customers receiving notification of the pending acquisition;

D. Liberty Water shall establish a third party local payment center and notify Staff of the location and associated payment fees within fifteen (15) days after closing on the assets;

E. Liberty Water shall distribute to the newly acquired customers, prior to the first billing from Liberty Water, an informational brochure detailing the rights and responsibilities of the utility and its customers regarding its utility service, consistent with the requirements of Chapter 13 of the Commission rules, as well as notification regarding changes to the billing cycle, bill format, and payment options within fifteen (15) days of closing on the assets;

F. Liberty Water shall provide to the Customer Experience Department (CXD) Staff a sample of its actual communication with its newly acquired customers regarding its acquisition and operations of the utility assets, and how customers may reach Liberty Water, within fifteen (15) days after closing on the assets;

G. Liberty Water shall provide to the CXD Staff a sample of five (5) billing statements for each acquired company from the first month's billing within thirty (30) days after closing on the assets;

H. Liberty Water shall include the customers acquired from the Selling Utilities in its established monthly reporting to the CXD Staff on customer service and billing issues, on an ongoing basis, after closing on the assets;

I. Liberty Water shall file notice in this case once the Staff recommendations regarding staff training, payment center, informational brochure, communications, and billing are completed.

8. The Commission makes no finding that would preclude the Commission from considering the ratemaking treatment to be afforded any matters in any later proceeding.

9. This order shall become effective on July 17, 2020.

BY THE COMMISSION

Morris L. Woodruff
Secretary

Silvey, Chm., Kenney, Rupp, Coleman, and Holsman CC., concur.

Hatcher, Regulatory Law Judge.

STATE OF MISSOURI
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held at its office in Jefferson City on the 18th day of March, 2020.

In the Matter of Liberty Utilities (Missouri Water), LLC's Application for a Certificate of Convenience and Necessity Authorizing it to Construct, Install, Own, Operate, Maintain, Control, and Manage a Sewer System in Cape Girardeau County, Missouri	))))))	**File No. SA-2020-0067**

ORDER GRANTING CERTIFICATE OF CONVENIENCE AND NECESSITY

Issue Date: March 18, 2020 Effective Date: April 17, 2020

On November 25, 2019, Liberty Utilities (Missouri Water), LLC (Liberty Water) filed an application with the Missouri Public Service Commission requesting a Certificate of Convenience and Necessity (CCN) to install, own, acquire, construct, operate, control, manage, and maintain a sewer system in Cape Girardeau County, Missouri.

The Commission issued notice and set a deadline for intervention requests, but received none. On March 2, 2020, the Commission's Staff filed its recommendation to approve Liberty Water's request for a CCN, with specified conditions.

Liberty Water is a "water corporation," a "sewer corporation," and "public utility" as those terms are defined in Section 386.020, RSMo, and is subject to the jurisdiction of the Commission.

The CCN would allow Liberty Water to acquire sewer utility assets in Savers Farm, a new development with five phases to be completed by the end of 2020. Phases one through three are completed. The system is currently owned and operated by the

system's developer, Cape Land & Development, LLC (Cape Land), an entity not currently subject to the Commission's jurisdiction.

Cape Land operates a recirculating sand filter system providing sewer service to approximately 110 residential customers in the subdivision. Construction of the wastewater treatment facility began in 2016 and was completed in 2017. The facility is comprised of a parallel tank system with a 50,000-gallon septic tank and a 25,000-gallon recirculating tank in each of the parallel paths, followed by four sand filter beds and ultraviolet light disinfection. Two of the four sand filter beds are currently in use to treat the flow from approximately 110 completed homes.

Staff's calculations for projected plant-in-service of $688,941 and depreciation reserve balances of $71,093, as of December 31, 2019, yield an estimated rate base of $617,848. Based on its review of the Savers Farm information in this proceeding, the purchase price being paid by Liberty Water may be below the Net Book Value (NBV) of the Savers Farm assets.

If the Commission approves this CCN and Liberty acquires the sewer system, then Staff expects an updated rate base level for this system will be established when Liberty Water files its next rate case. The Savers Farm wastewater system was designed and constructed to serve approximately twice the number of residential customers currently being served. Staff states that it may propose, in a future rate proceeding, a capacity adjustment to certain wastewater system components. Such a capacity adjustment, if applied, would reduce the plant balance level and depreciation expense to be included in rate calculations.

Savers Farm homeowners currently pay no fees for the sewer service provided by the subdivision developer. Liberty Water proposes the existing rates, rules, and

regulations currently applicable to certain named service areas found in MO PSC No. 15 Sheet No. 4.1 be applied to Savers Farm. The monthly flat rate for a single-family residence would be $46.21. Staff states that a Commission's decision regarding rate base level in this case is not necessary, and Staff is not recommending any change to the rates charged by Liberty in the applicable existing tariff to be applied to Savers Farm. Members of the homeowners association were given notification of a proposed transfer of the system to Liberty at an annual homeowner's association meeting on December 19, 2019. Liberty informed Staff that the homeowners were very receptive to the proposal.

Ten days have passed since Staff filed its recommendation and no party has objected to Liberty Water's application or Staff's recommendation. No party has requested an evidentiary hearing.[1]Thus, the Commission will rule upon the application.

The Commission may grant a sewer corporation a CCN to operate after determining that the construction and operation are either "necessary or convenient for the public service."[2] The Commission articulated criteria to be used when evaluating applications for utility certificates of convenience and necessity in the case *In Re Intercon Gas, Inc.*, 30 Mo P.S.C. (N.S.) 554, 561 (1991). The *Intercon* case combined the standards used in several similar certificate cases, and set forth the following criteria: (1) there must be a need for the service; (2) the applicant must be qualified to provide the proposed service; (3) the applicant must have the financial ability to provide the service; (4) the applicant's proposal must be economically feasible; and (5) the service must

[1] *State ex rel. Rex Deffenderfer Ent., Inc. v. Public Serv. Comm'n*, 776 S.W.2d 494, 496 (Mo. App., W.D. 1989).
[2] Section 393.170.3, RSMo.

promote the public interest.[3] These criteria are known as the Tartan Factors.[4]

There is a need for the service since the customers in Savers Farm already receive sewer service and more homes will be built that require service. Liberty Water is qualified to provide the service as it is currently providing water and sewer services to approximately 3,000 customers throughout its Missouri service areas. Liberty Water has the financial ability to provide the service and no financing approval is being requested. The proposal is economically feasible because the system is relatively new and has already been constructed. The proposal promotes the public interest as demonstrated by positive findings in in the first four Tartan Factors.

Staff evaluates applications involving existing sewer systems utilizing technical, managerial, and financial criteria. Staff states "Liberty has demonstrated over many years that it has adequate resources to operate utility systems that it owns, to acquire new systems, to undertake construction of new systems and expansions of existing systems, to plan and undertake scheduled capital improvements, and timely respond and resolve emergency issues when such situations arise." Staff's review found that Liberty Water meets the requisite technical, managerial, and financial criteria.

Based on the application and Staff's recommendations, the Commission concludes that the factors for granting a CCN to Liberty Water have been satisfied and that it is in the public's interest for Liberty Water to provide sewer service to Savers Farm in Cape Girardeau County. The Commission finds that Liberty Water possesses adequate

[3] The factors have also been referred to as the "Tartan Factors" or the "Tartan Energy Criteria." See Report and Order, *In re Application of Tartan Energy Company, L.C., d/b/a Southern Missouri Gas Company, for a Certificate of Convenience and Necessity*, Case No. GA-94-127, 3 Mo. P.S.C. 3d 173 (September 16, 1994).

[4] *In re Tartan Energy Company*, 3 Mo.P.S.C. 173, 177 (1994).

technical, managerial, and financial capacity to operate the sewer system. Further, Commission finds that the flat fee of $46.21 for sewer service is just and reasonable. Therefore, the Commission will grant Liberty Water's requested CCN, subject to the conditions described by Staff's recommendation.

THE COMMISSION ORDERS THAT:

1. Liberty Utilities (Missouri Water), LLC is granted a certificate of convenience and necessity to provide sewer service to the property described in the map and legal description provided in its application, subject to the conditions and requirements contained in Staff's Recommendation, including the filing of tariffs, as set out below:

A. Liberty Water's monthly residential flat rate of $46.21 shall apply to Savers Farm;

B. Liberty Water shall submit new and revised tariff sheets, to become effective before closing on the assets, that include:

   a. Cover (Sheet No. Title Page)
   b. Index (Sheet No. 1)
   c. Sewer rates (Sheet No. 4.1)
   d. Service area map (Sheet No. 2.4)
   e. Service area written description (Sheet No. 3.4)

   as applicable to sewer service in its Savers Farm service area, to be included in its EFIS sewer tariff P.S.C. MO No. 15;

C. Liberty Water shall notify the Commission of closing on the assets within five (5) days after such closing;

D. If closing on the sewer system assets does not take place within thirty (30) days following the effective date of the Commission's order approving such, Liberty Water shall submit a status report within five (5) days after this thirty (30) day period regarding the status of closing, and additional status reports within five (5) days after each additional thirty (30) day period, until closing takes place, or until Liberty determines that the transfer of the assets will not occur;

E. If Liberty Water determines that a transfer of the assets will not occur, Liberty Water shall notify the Commission of such no later than the date of the next status report, as addressed above, after such determination is made, and

Liberty Water shall submit tariff sheets as appropriate and necessary that would cancel service area maps, descriptions, rates and rules applicable to the Savers Farm service area in its sewer tariff;

F. Liberty Water shall keep its financial books and records for plant-in-service and operating expenses as related to the Savers Farm operations in accordance with the NARUC Uniform System of Accounts;

G. Liberty Water shall provide detailed plant records that includes for each plant asset a detailed description and original plant costs with supporting detailed invoices and identified by USOA account numbers in its next rate case for Savers Farm Sewer System;

H. Liberty Water shall adopt for the Savers Farm sewer assets the depreciation rates ordered for Cape Rock Village in Liberty's last rate case, Case No. WR-2018-0170;

I. Liberty Water shall obtain from Cape Land, prior to or at closing, all available plant-in- service related records and documents, including but not limited to all plant-in-service original cost documentation, along with depreciation reserve balances, documentation of contribution–in-aid-of construction transactions, and any capital recovery transactions;

J. The Commission makes no finding that would preclude it from considering the ratemaking treatment to be afforded any matters pertaining to the granting of the CCN to Liberty Water, including expenditures related to the certificated service area, in any later proceeding;

K. Liberty Water shall provide training to its call center personnel regarding rates and rules applicable to the Savers Farm customers;

L. Liberty Water shall include the Savers Farm customers in its established monthly reporting to the Customer Experience Department Staff on customer service and billing issues, on an ongoing basis, after closing on the assets;

M. Liberty Water shall distribute to the Savers Farm customers an informational brochure detailing the rights and responsibilities of the utility and its customers regarding its sewer service, consistent with the requirements of Commission Rule 20 CSR 4240-13, within thirty (30) days of closing on the assets;

N. Liberty Water shall provide to the Customer Experience Department Staff an example of its actual communication with the Savers Farm customers regarding its acquisition and operations of the sewer system assets, and how customers may reach Liberty Water, within ten (10) days after closing on the assets;

O. Liberty Water shall provide to the Customer Experience Department Staff a sample of ten (10) billing statements from the first month's billing within thirty (30) days after closing on the assets; and,

P. Liberty Water shall file notice in this case outlining completion of the above-recommended training, customer communications, and notifications within ten (10) days after such communications and notifications.

2. This order shall become effective on April 17, 2020.

BY THE COMMISSION

Morris L. Woodruff
Secretary

Silvey, Chm., Kenney, Rupp, Coleman, and
Holsman CC., concur.

Clark, Senior Regulatory Law Judge

STATE OF MISSOURI
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held by telephone/internet audio conference on the 8th day of April, 2020.

In the Matter of the Joint Application of Liberty Utilities (Missouri Water), LLC d/b/a Liberty Utilities and The Empire District Electric Company for Authority for Liberty Utilities (Missouri Water), LLC d/b/a Liberty Utilities to Acquire the Water Franchises and Assets of The Empire District Electric Company	)))))))	**File No. WM-2020-0156**

ORDER APPROVING TRANSFER OF ASSETS AND GRANTING CERTIFICATE OF CONVENIENCE AND NECESSITY

Issue Date: April 8, 2020 Effective Date: May 8, 2020

On December 27, 2019, Liberty Utilities (Missouri Water) LLC d/b/a Liberty Utilities (hereinafter Liberty Water) and The Empire District Electric Company (hereinafter Empire)[1] filed a joint application asking the Commission to approve a sale and transfer of water utility assets between the applicants whereby Empire will sell and transfer Empire's water utility assets, including all contracts, agreements, franchises, and certificates of convenience and necessity (CCNs), to Liberty Water.

On December 27, 2019,[2] the Commission issued its Order Directing Notice, Setting Intervention Date, and Directing Staff to File a Recommendation. No applications to intervene were filed. Staff filed a recommendation on March 27, recommending the Commission approve Empire's sale and transfer of water utility assets and CCNs to

[1] Hereinafter, collectively, the applicants.
[2] All date references hereafter will be to 2020, unless otherwise indicated.

Liberty Water subject to conditions. Staff, however, did not support Liberty Water's adoption of its own rules and regulations from P.S.C. MO No. 14 for the transferred Empire water customers.[3] Staff stated there were sufficient differences in the rules and regulations between the two sets of tariffs that Liberty Water should adopt Empire's currently effective tariff and work towards a consolidation in the course of Liberty Water's next rate proceeding.[4]

Staff recommended the Commission do the following:

1. Authorize Empire to transfer utility assets and its current CCNs to Liberty Water;

2. Authorize Liberty Water to apply Empire's existing rates and rules on an interim basis immediately after closing on the assets, to apply to the Empire service area until an adoption notice tariff sheet becomes effective;

3. Require Empire to submit an adoption notice tariff sheet for the existing tariffs within 10 days after closing on the assets and as a 30-day tariff filing, for the existing Empire tariff;

4. Approve Empire's existing depreciation rates for water utility plant accounts to apply to the Empire service area assets;

5. If closing on the water system assets does not take place within 30 days following the effective date of the Commission's order approving such, require Liberty Water and/or Empire to submit a status report within 5 days after this 30-day period regarding the status of closing, and additional status reports within 5 days after each additional 30-day period,

[3] Staff Report, Case File Memorandum, p. 2.
[4] Staff Report, Case File Memorandum, p. 2.

until closing takes place, or until either Liberty Water or Empire determines that the transfer of the assets will not occur; and

6. Make no finding that would preclude the Commission from considering the ratemaking treatment to be afforded any matters pertaining to the acquisition at any later proceeding.

FINDINGS

Findings of Fact

Liberty Water is a Missouri limited liability company with its principal office located in Joplin, Missouri. It provides water and sewer service to customers in its Missouri service areas, as certificated by the Commission, serving approximately 3,000 water and/or sewer system customers in McDonald, Stone, Taney and Christian Counties in southwest Missouri; in Franklin and Jefferson Counties in eastern Missouri; and in Cape Girardeau County in southeast Missouri. Empire is a Kansas corporation with its principal office and place of business in Joplin, Missouri. Empire is qualified to conduct business and is conducting business in Missouri, as well as in the states of Arkansas, Kansas, and Oklahoma. The affected water assets are in Aurora, Verona, and Marionville, Lawrence County, Missouri, where Empire currently serves approximately 4,400 drinking water customers.[5]

Both applicants are subsidiaries of Liberty Utilities Co., a Delaware Corporation, which is a subsidiary of Algonquin Power & Utilities Corp (APUC).[6] The Commission authorized the merger of Liberty Utilities Co. and Empire on October 7, 2016, whereby

[5] Staff Report, Case File Memorandum, p. 1.
[6] Joint Application, paragraph 14.

Liberty Utilities Co. acquired all of Empire's common stock.[7] Customer service for each utility has been merged into one call center.[8] Billing for Empire and Liberty Water customers is accomplished utilizing the same system.[9] Empire's website is already rebranded "Liberty Utilities Empire District." There will be no foreseeable operational changes to either entity as a result of the asset transfer.[10] Therefore, while this matter is a transfer of assets between two subsidiaries of Liberty Utilities Co., from a customer perspective it is primarily a restructuring.[11] The transfer will cause no change to or disruption of utility operation, and the primary difference that some ratepayers will experience is a change in the name of their utility provider.[12]

Conclusions of Law and Decision

The Commission has jurisdiction to rule on the application because Missouri law requires that "[n]o gas corporation, electrical corporation, water corporation or sewer corporation shall hereafter sell. . .its. . .works or system. . .without having first secured from the commission an order authorizing it so to do."[13] The Commission may deny the application only if approval would be detrimental to the public interest.[14]

Based upon the information provided in the verified joint application and upon the verified recommendation and memorandum of Staff, the Commission finds that the proposed transfer of assets is not detrimental to the public interest. The Commission

[7] Staff Report, Case File Memorandum, p. 1.
[8] Staff Report, Case File Memorandum, p. 1.
[9] Staff Report, Case File Memorandum, p. 1.
[10] Staff Report, Case File Memorandum, p. 2.
[11] Staff Report, Case File Memorandum, p. 1.
[12] Staff Report, Case File Memorandum, p. 4.
[13] Section 393.190.1, RSMo.
[14] *State ex rel. City of St. Louis v. Public Service Comm'n of Missouri*, 73 S.W.2d 393, 400 (Mo. 1934).

finds, however, that the applicant's proposal that Liberty Water adopt its existing rules and regulations from P.S.C. MO No. 14 for the transferred Empire water customers should not be granted. The Commission finds there are sufficient differences in the rules and regulations between the two sets of tariffs such that Liberty Water should adopt Empire's currently effective tariff and work towards a consolidation in the course of Liberty Water's next rate proceeding.

The joint application includes a request for authorization to transfer Empire's CCNs to Liberty Water. It expressly states no CCN is sought. The water assets in question and the customers served by the water system are located in Lawrence County, Missouri. Neither the joint application nor Staff's recommendation indicates Liberty Water currently has a CCN for the Lawrence County area. Such a deficiency cannot be cured by transferring Empire's CCNs to Liberty Water. Among other requirements for receiving a CCN, the CCN applicant must be qualified to provide the proposed service and have the financial ability to do so.[15] Empire's CCNs were based in part upon Empire's meeting those criteria. Those qualifications are personal and not transferrable. In order to operate the water system and serve the Lawrence County customers, Liberty Water must have its own CCN for that area. On its own motion, the Commission will consider whether Liberty Water may be granted a CCN.

The Commission may grant a water and sewer corporation a CCN to operate after determining that the construction and operation are either "necessary or convenient for the public service."[16] The Commission articulated the specific criteria to be used when

[15] *In re Intercon Gas, Inc.*, 30 Mo. P.S.C. (N.S.), 561 (1991).
[16] Section 393.170.3, RSMO.

evaluating applications for utility CCNs in the case *In re Intercon Gas, Inc*., 30 Mo. P.S.C. (N.S.), 561 (1991). *Intercon* combined the standards used in several similar certificate cases and set forth the following criteria: (1) there must be a need for the service; (2) the applicant must be qualified to provide the proposed service; (3) the applicant must have the financial ability to provide the service; (4) the applicant's proposal must be economically feasible; and (5) the service must promote the public interest.[17]

The Empire water assets and system in question currently serve approximately 4,400 drinking water customers in Aurora, Marionville, and Verona in southwest Missouri.[18] Empire needed and currently has a CCN to serve these customers. Criteria one and five are satisfied: There is a need for the service, and the service promotes the public interest.

Liberty Water serves approximately 3,000 water and/or sewer system customers in McDonald, Stone, Taney and Christian Counties in the southwest; in Franklin and Jefferson Counties in the east; and in Cape Girardeau County in the southeast.[19] The records of the Department of Natural Resources reveal no violations for the Liberty Water or Empire water system that would indicate operational compliance challenges,[20] and the Commission concludes that given Liberty Utilities Co. is the parent company for the joint applicants, the technical and managerial standards will continue to be met after the utility asset transfer. Criterion two is satisfied: The applicant is qualified to provide the service.

[17] The factors have been referred to as the "Tartan Factors" or the "Tartan Energy Criteria." See Report and Ord, *In re Application of Tartan Energy Company, L.C., d/b/a Southern Missouri Gas Company, for a Certificate of Convenience and Necessity*, Case No. GA-94-127, 3 Mo. P.S.C. 3d 173 (September 16, 1994), 1994 WL 762882, *3 (Mo. P.SW.C.).
[18] Staff Recommendation, Memorandum, p. 1.
[19] Staff Recommendation, Memorandum, p. 1.
[20] Staff Recommendation, Memorandum, p. 2.

Liberty Water and Empire are both subsidiaries of Liberty Utilities Co., which is a subsidiary of APUC, and the Commission authorized the merger of Liberty Utilities Co. and Empire on October 7, 2016. Liberty Water, as a subsidiary of APUC, will continue to have access to sufficient financial capacity. Criterion three is satisfied: The applicant has the financial ability to provide the service.[21] With respect to the physical delivery of water to customers, the system is operating now. The asset transfer will require no operational changes and no physical plant or personnel changes or additions.[22] Criterion four is satisfied: Nothing about a simple asset transfer with nothing added or subtracted renders Liberty Water's continued operation of a currently operating system economically unfeasible. All CCN requirements being satisfied, the Commission finds Liberty Water's operation of the water assets which are the subject of the joint application is "necessary or convenient for the public service."[23]

The Commission makes no finding that will preclude the Commission from considering the ratemaking treatment to be afforded any matters pertaining to the granting of the joint application to any later proceeding.

The joint applicants have filed no objections to Staff's recommendation. No party requested an evidentiary hearing in this matter, so the Commission may grant the application's request based upon the verified joint application and Staff's verified recommendation.[24] Based upon its review of the joint application and Staff's

[21] Staff Recommendation, Memorandum, p. 1. Thus, with the satisfaction of criteria two and three, the "technical, managerial, and financial capacity" standards originally developed by the United States Environmental Protection Agency are met. See Staff Report Case File Memorandum, p. 2
[22] Staff Recommendation, Memorandum, p. 2.
[23] Section 393.170.3, RSMO.
[24] See *State ex rel. Rex Deffenderfer Enterprises, Inc. v. Public Service Commission*, 776 S.W.2d 494, 496 (Mo. App. 1989).

recommendation, the Commission will grant the application except as stated herein and will grant Liberty Water a certificate of convenience and necessity.

THE COMMISSION ORDERS THAT:

1. The joint application for Liberty Water to acquire Empire's water and assets is granted, except as stated in the next paragraphs.

2. That part of the joint application[25] proposing to adopt Liberty Water's existing tariff rules and regulations for the customers within Empire's existing service area is denied.

3. Empire is authorized to sell and transfer to Liberty Water and Liberty Water is authorized to acquire the water utility assets located in Lawrence County, Missouri, described in the joint application.

4. Liberty Water and Empire are authorized to do and perform, or cause to be done and performed, all such acts and things, as well as make, execute and deliver any and all documents as may be necessary, advisable and proper to the end that the intent and purposes of the approved transaction may be fully effectuated.

5. Liberty Water shall apply Empire's existing water tariff rules and rates to the Empire service area on an interim basis immediately after closing on the assets to apply to the Empire service area until an adoption notice tariff sheet becomes effective.

6. Liberty Water shall submit an adoption notice tariff sheet for the existing tariffs within ten days after closing on the assets, as a 30-day tariff filing for the existing Empire tariff.

[25] Joint Application, paragraph 9.

7. Empire's existing depreciation rates for water utility plant accounts are approved to apply to the acquired Empire service area assets.

8. If closing on the water system assets does not take place within thirty days following the effective date of this order, Liberty Water and Empire shall submit a status report within five days after the thirty-day period regarding the status of closing. They shall file additional status reports within five days after each additional thirty-day period until closing takes place, or until either Liberty Water or Empire determines that the transfer of the assets will not occur.

9. Liberty Water is granted a new CCN to provide water service in the Lawrence County, Missouri, service area now served by Empire with the assets and water system which is the subject of this order, with Liberty Water to begin providing such service upon closing on the assets.

10. This order shall become effective on May 8, 2020.

11. This file may be closed on May 9, 2020.

BY THE COMMISSION

Morris L. Woodruff
Secretary

Silvey, Chm., Kenney, Rupp, Coleman, and
Holsman CC., concur.

Graham, Regulatory Law Judge

STATE OF MISSOURI
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held at its office in Jefferson City on the 7th day of September, 2016.

In the Matter of The Empire District Electric Company, Liberty Utilities (Central) Co. and Liberty Sub Corp. Concerning an Agreement and Plan of Merger and Certain Related Transactions	))))	**File No. EM-2016-0213**

ORDER APPROVING STIPULATIONS AND AGREEMENTS AND AUTHORIZING MERGER TRANSACTION

Issue Date: September 7, 2016 Effective Date: October 7, 2016

On March 16, 2016, The Empire District Electric Company ("Empire"), Liberty Utilities (Central) Co. ("LU Central") and Liberty Sub Corp. (collectively, "Applicants") filed a joint application asking the Commission to approve a transaction under an Agreement and Plan of Merger in which Liberty Sub Corp. will be merged with and into Empire with Empire as the surviving corporation. As a consequence of the merger, LU Central would acquire all of the common stock of Empire.

Stipulations and Agreements

The Applicants filed separate non-unanimous stipulations and agreements with each of the following parties:

- The City of Joplin, Empire District Retired Members & Spouses Association LLC, Laborer's International Union of North America, and International Brotherhood of Electrical Workers Locals 1464 and 1474 on July 19, 2016 (collectively, "Intervenor Agreements");

- The Office of the Public Counsel, filed on August 23, 2016, which also includes as Appendix A the stipulation and agreement with Staff filed on August 4, 2016 (collectively, "OPC Agreement");
- The Empire District Electric SERP Retirees, filed on August 23, 2016 ("EDESR Agreement");
- Missouri Department of Economic Development-Division of Energy and Renew Missouri, filed on August 24, 2016 ("DE/Renew Missouri Agreement"), which amends a previously filed stipulation and agreement by those parties; and
- International Brotherhood of Electrical Workers Locals 1464 and 1474, filed on August 26, 2016 ("IBEW Agreement"), which amends the stipulation and agreement between those parties previously filed on July 19, 2016.

The Commission approved the Intervenor Agreements on August 10, 2016. The Commission conducted an on-the-record proceeding regarding the OPC Agreement, EDESR Agreement, DE/Renew Missouri Agreement and IBEW Agreement (collectively, "Pending Agreements") on August 30, 2016. At that proceeding, the Commission questioned the parties about the terms of the Pending Agreements and gathered additional information about the merger transaction and the conditions set forth in the Pending Agreements. The Pending Agreements constitute a settlement of the respective parties' issues relevant to the application filed by the Applicants in this matter. The Pending Agreements all describe conditions to the merger transaction proposed in the Applicants' application, which is subject to Commission approval.

The Pending Agreements are non-unanimous in that they were not signed by all parties. However, Commission Rule 4 CSR 240-2.115(2) provides that other parties have

seven days in which to object to a non-unanimous stipulation and agreement. If no party files a timely objection to a stipulation and agreement, the Commission may treat it as a unanimous stipulation and agreement. More than seven days have passed since the Pending Agreements were filed, and no party has objected. Therefore, the Commission will treat the Pending Agreements as unanimous stipulations and agreements. After reviewing the Pending Agreements, the Commission independently finds and concludes that the Pending Agreements are a reasonable resolution of the issues addressed by the Pending Agreements and that such Pending Agreements should be approved. The Commission will also grant the motion to modify the Commission's order issued on August 10, 2016, which approved the stipulation and agreement between the Applicants and IBEW Locals 1464 and 1474.

Merger Transaction

Empire is an "electrical corporation", a "gas corporation", a "water corporation", and a "public utility," as defined in Sections 386.020(15), (18), (59), and (43), respectively, and is subject to the jurisdiction, supervision, and control of the Commission under Chapters 386 and 393 of the Missouri Revised Statutes. Empire must by law obtain the authorization of the Commission before consummating the transaction in accordance with the Agreement and Plan of Merger.[1] In evaluating the proposed merger transaction, the Commission must determine if the merger is "not detrimental to the public".[2] The Commission has stated in prior cases that it "may not withhold its approval of the proposed transaction unless the Applicants fail in their burden to demonstrate that the transaction is

[1] Section 393.190.1, RSMo 2000.

[2] *State ex rel. City of St. Louis v. Public Service Commission of Missouri*, 335 Mo. 448, 460, 73 S.W.2d 393, 400 (1934).

not detrimental to the public interest, and detriment is determined by performing a balancing test where attendant benefits are weighed against direct or indirect effects of the transaction that would diminish the provision of safe or adequate of service or that would tend to make rates less just or less reasonable."[3]

After reviewing the Applicants' joint application, the testimony filed in this case, and the reasonable conditions imposed on the merger transaction by the Intervenor Agreements and Pending Agreements, the Commission independently finds and concludes that the merger transaction contemplated by the Agreement and Plan of Merger is not detrimental to the public and should be authorized.

THE COMMISSION ORDERS THAT:

1. The *Stipulation and Agreement* between the Applicants and the Office of the Public Counsel filed on August 23, 2016, including the stipulation and agreement between the Applicants and Staff filed on August 4, 2016 and incorporated therein as Appendix A, is approved as a resolution of the issues addressed in that stipulation and agreement. The signatory parties are ordered to comply with the terms of the stipulation and agreement. A copy of the stipulation and agreement is attached to this order as Attachment A and incorporated herein.

2. The *Stipulation and Agreement as to EDESR* filed on August 23, 2016, is approved as a resolution of the issues addressed in that stipulation and agreement. The

[3] *In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Aquila, Inc., for Approval of the Merger of Aquila, Inc., with a Subsidiary of Great Plains Energy Incorporated and for Other Related Relief,* Report and Order, Case No. EM-2007-0374, p. 229-232, citing *In the Matter of the Application of Union Electric Company, d/b/a AmerenUE, for an Order Authorizing the Sale, Transfer and Assignment of Certain Assets, Real Estate, Leased Property, Easements and Contractual Agreements to Central Illinois Public Service Company, d/b/a AmerenCIPS, and, in Connection Therewith, Certain Other Related Transactions*, Case No. EO-2004-0108.

signatory parties are ordered to comply with the terms of the stipulation and agreement. A copy of the stipulation and agreement is attached to this order as Attachment B and incorporated herein.

3. The *Amended Stipulation and Agreement as to Division of Energy and Renew Missouri* filed on August 24, 2016, is approved as a resolution of the issues addressed in that stipulation and agreement. The signatory parties are ordered to comply with the terms of the stipulation and agreement. A copy of the stipulation and agreement is attached to this order as Attachment C and incorporated herein.

4. The *Amended Stipulation and Agreement as to IBEW 1464 and IBEW 1474* filed on August 26, 2016, is approved as a resolution of the issues addressed in that stipulation and agreement. The signatory parties are ordered to comply with the terms of the stipulation and agreement. A copy of the stipulation and agreement is attached to this order as Attachment D and incorporated herein.

5. The Applicants and International Brotherhood of Electrical Workers Locals 1464 and 1474's *Motion to Modify Order Approving Stipulations and Agreements* is granted. The Commission's *Order Approving Stipulations and Agreements* issued on August 10, 2016 is modified to replace the *Stipulation and Agreement as to IBEW 1464 and IBEW 1474* filed July 19, 2016 with the *Amended Stipulation and Agreement as to IBEW 1464 and IBEW 1474* approved in Ordered Paragraph 4 above as Attachment D.

6. The Applicants are authorized to consummate the transaction described in their joint application in accordance with the terms and conditions of the Agreement and Plan of Merger and all other transaction-related instruments, and to take any and all other

actions as may be reasonably necessary and incidental to the performance of the transaction.

7. LU Central and Liberty Sub Corp. are authorized to acquire all of the stock of Empire pursuant to the terms of the Agreement and Plan of Merger.

8. Empire is authorized to merge with Liberty Sub Corp. with Empire being the surviving corporation, as more particularly described in the Agreement and Plan of Merger.

9. This order shall become effective on October 7, 2016.

BY THE COMMISSION

Morris L. Woodruff
Secretary

Hall, Chm., Stoll, Kenney,
Rupp, and Coleman, CC., concur.

Bushmann, Senior Regulatory Law Judge

STATE OF MISSOURI
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held at its office in Jefferson City on the 7th day of September, 2016.

In the Matter of The Empire District Electric Company, Liberty Utilities (Central) Co. and Liberty Sub Corp. Concerning an Agreement and Plan of Merger and Certain Related Transactions	))))	**File No. EM-2016-0213**

ORDER APPROVING STIPULATIONS AND AGREEMENTS AND AUTHORIZING MERGER TRANSACTION

Issue Date: September 7, 2016 Effective Date: October 7, 2016

On March 16, 2016, The Empire District Electric Company ("Empire"), Liberty Utilities (Central) Co. ("LU Central") and Liberty Sub Corp. (collectively, "Applicants") filed a joint application asking the Commission to approve a transaction under an Agreement and Plan of Merger in which Liberty Sub Corp. will be merged with and into Empire with Empire as the surviving corporation. As a consequence of the merger, LU Central would acquire all of the common stock of Empire.

Stipulations and Agreements

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- The Office of the Public Counsel, filed on August 23, 2016, which also includes as Appendix A the stipulation and agreement with Staff filed on August 4, 2016 (collectively, "OPC Agreement");
- The Empire District Electric SERP Retirees, filed on August 23, 2016 ("EDESR Agreement");
- Missouri Department of Economic Development-Division of Energy and Renew Missouri, filed on August 24, 2016 ("DE/Renew Missouri Agreement"), which amends a previously filed stipulation and agreement by those parties; and
- International Brotherhood of Electrical Workers Locals 1464 and 1474, filed on August 26, 2016 ("IBEW Agreement"), which amends the stipulation and agreement between those parties previously filed on July 19, 2016.

The Commission approved the Intervenor Agreements on August 10, 2016. The Commission conducted an on-the-record proceeding regarding the OPC Agreement, EDESR Agreement, DE/Renew Missouri Agreement and IBEW Agreement (collectively, "Pending Agreements") on August 30, 2016. At that proceeding, the Commission questioned the parties about the terms of the Pending Agreements and gathered additional information about the merger transaction and the conditions set forth in the Pending Agreements. The Pending Agreements constitute a settlement of the respective parties' issues relevant to the application filed by the Applicants in this matter. The Pending Agreements all describe conditions to the merger transaction proposed in the Applicants' application, which is subject to Commission approval.

The Pending Agreements are non-unanimous in that they were not signed by all parties. However, Commission Rule 4 CSR 240-2.115(2) provides that other parties have

seven days in which to object to a non-unanimous stipulation and agreement. If no party files a timely objection to a stipulation and agreement, the Commission may treat it as a unanimous stipulation and agreement. More than seven days have passed since the Pending Agreements were filed, and no party has objected. Therefore, the Commission will treat the Pending Agreements as unanimous stipulations and agreements. After reviewing the Pending Agreements, the Commission independently finds and concludes that the Pending Agreements are a reasonable resolution of the issues addressed by the Pending Agreements and that such Pending Agreements should be approved. The Commission will also grant the motion to modify the Commission's order issued on August 10, 2016, which approved the stipulation and agreement between the Applicants and IBEW Locals 1464 and 1474.

Merger Transaction

Empire is an "electrical corporation", a "gas corporation", a "water corporation", and a "public utility," as defined in Sections 386.020(15), (18), (59), and (43), respectively, and is subject to the jurisdiction, supervision, and control of the Commission under Chapters 386 and 393 of the Missouri Revised Statutes. Empire must by law obtain the authorization of the Commission before consummating the transaction in accordance with the Agreement and Plan of Merger.[1] In evaluating the proposed merger transaction, the Commission must determine if the merger is "not detrimental to the public".[2] The Commission has stated in prior cases that it "may not withhold its approval of the proposed transaction unless the Applicants fail in their burden to demonstrate that the transaction is

[1] Section 393.190.1, RSMo 2000.

[2] *State ex rel. City of St. Louis v. Public Service Commission of Missouri*, 335 Mo. 448, 460, 73 S.W.2d 393, 400 (1934).

not detrimental to the public interest, and detriment is determined by performing a balancing test where attendant benefits are weighed against direct or indirect effects of the transaction that would diminish the provision of safe or adequate of service or that would tend to make rates less just or less reasonable."[3]

After reviewing the Applicants' joint application, the testimony filed in this case, and the reasonable conditions imposed on the merger transaction by the Intervenor Agreements and Pending Agreements, the Commission independently finds and concludes that the merger transaction contemplated by the Agreement and Plan of Merger is not detrimental to the public and should be authorized.

THE COMMISSION ORDERS THAT:

1. The *Stipulation and Agreement* between the Applicants and the Office of the Public Counsel filed on August 23, 2016, including the stipulation and agreement between the Applicants and Staff filed on August 4, 2016 and incorporated therein as Appendix A, is approved as a resolution of the issues addressed in that stipulation and agreement. The signatory parties are ordered to comply with the terms of the stipulation and agreement. A copy of the stipulation and agreement is attached to this order as Attachment A and incorporated herein.

2. The *Stipulation and Agreement as to EDESR* filed on August 23, 2016, is approved as a resolution of the issues addressed in that stipulation and agreement. The

[3] *In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Aquila, Inc., for Approval of the Merger of Aquila, Inc., with a Subsidiary of Great Plains Energy Incorporated and for Other Related Relief,* Report and Order, Case No. EM-2007-0374, p. 229-232, citing *In the Matter of the Application of Union Electric Company, d/b/a AmerenUE, for an Order Authorizing the Sale, Transfer and Assignment of Certain Assets, Real Estate, Leased Property, Easements and Contractual Agreements to Central Illinois Public Service Company, d/b/a AmerenCIPS, and, in Connection Therewith, Certain Other Related Transactions*, Case No. EO-2004-0108.

signatory parties are ordered to comply with the terms of the stipulation and agreement. A copy of the stipulation and agreement is attached to this order as Attachment B and incorporated herein.

3. The *Amended Stipulation and Agreement as to Division of Energy and Renew Missouri* filed on August 24, 2016, is approved as a resolution of the issues addressed in that stipulation and agreement. The signatory parties are ordered to comply with the terms of the stipulation and agreement. A copy of the stipulation and agreement is attached to this order as Attachment C and incorporated herein.

4. The *Amended Stipulation and Agreement as to IBEW 1464 and IBEW 1474* filed on August 26, 2016, is approved as a resolution of the issues addressed in that stipulation and agreement. The signatory parties are ordered to comply with the terms of the stipulation and agreement. A copy of the stipulation and agreement is attached to this order as Attachment D and incorporated herein.

5. The Applicants and International Brotherhood of Electrical Workers Locals 1464 and 1474's *Motion to Modify Order Approving Stipulations and Agreements* is granted. The Commission's *Order Approving Stipulations and Agreements* issued on August 10, 2016 is modified to replace the *Stipulation and Agreement as to IBEW 1464 and IBEW 1474* filed July 19, 2016 with the *Amended Stipulation and Agreement as to IBEW 1464 and IBEW 1474* approved in Ordered Paragraph 4 above as Attachment D.

6. The Applicants are authorized to consummate the transaction described in their joint application in accordance with the terms and conditions of the Agreement and Plan of Merger and all other transaction-related instruments, and to take any and all other

actions as may be reasonably necessary and incidental to the performance of the transaction.

7. LU Central and Liberty Sub Corp. are authorized to acquire all of the stock of Empire pursuant to the terms of the Agreement and Plan of Merger.

8. Empire is authorized to merge with Liberty Sub Corp. with Empire being the surviving corporation, as more particularly described in the Agreement and Plan of Merger.

9. This order shall become effective on October 7, 2016.

BY THE COMMISSION

Morris L. Woodruff
Secretary

Hall, Chm., Stoll, Kenney,
Rupp, and Coleman, CC., concur.

Bushmann, Senior Regulatory Law Judge

NON-PROPRIETARY
_____ DENOTES HC

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company, Liberty Utilities (Central) Co. and Liberty Sub Corp. Concerning an Agreement and Plan of Merger and Certain Related Transactions.	))))	Case No. EM-2016-0213

STIPULATION AND AGREEMENT

COME NOW The Empire District Electric Company ("Empire"), Liberty Utilities (Central) Co. ("LU Central"), and Liberty Sub Corp. (sometimes collectively hereinafter "Joint Applicants"), and Algonquin Power & Utilities Corp., and the Office of the Public Counsel ("OPC"), by and through their undersigned counsel and, pursuant to Missouri Public Service Commission ("Commission") Rule 4 CSR 240-2.115, request that the Commission approve this agreement as a comprehensive settlement of all issues relevant to the Joint Application filed by Empire, LU Central and Liberty Sub Corp. In support thereof, the signatories hereto agree as follows:

BACKGROUND

On March 16, 2016, Joint Applicants filed a Joint Application with the Commission under §393.190 RSMo., 2000, requesting an order from the Commission authorizing them to perform in accordance with the terms of an Agreement and Plan of Merger dated February 9, 2016 (the "Agreement") pursuant to which LU Central and Liberty Sub Corp. will acquire all of the stock of Empire (the "Transaction").

The Signatories have met to discuss resolution of this matter on a number of occasions. As a result, the Signatories have now reached a Stipulation and Agreement ("Stipulation") set forth below which they recommend to the Commission, subject to the conditions and representations contained in the Stipulation.

The Signatories hereto recommend that the Commission approve the proposed Transaction subject to the following conditions (and subject to any other unopposed and approved stipulations in this case):

STAFF STIPULATION AND AGREEMENT

1. The Stipulation and Agreement between the Joint Applicants and the Staff of the Commission filed on August 4, 2016, and attached hereto as Appendix A, is hereby incorporated by reference as if more fully set forth herein.

RATEPAYER PROTECTIONS

2. In the first rate case after Empire implements a new customer information system and/or billing system, Empire will support the costs of the new system by submitting a "business case," with its application. The business case will, among other things, (1) demonstrate Empire's need for a new system and the impact of the merger on this need, (2) demonstrate Empire's analysis resulting in the selection of the new system implemented, (3) describe and quantify the costs associated with the selected system, and (4) describe the impact on rates of the cost of the new and the retiring systems, including the treatment of any remaining undepreciated balances and changes to the useful lives of the systems.

3. The Joint Applicants will ensure that the merger will be rate-neutral for Empire's customers. In ensuring that the transaction is rate-neutral, the Joint Applicants commit that there will be no establishment of regulatory assets as part of the merger, unless approved by the Public Service Commission.

CORPORATE GOVERNANCE AND RING-FENCING

4. Empire shall not assume liability for the debts issued by Algonquin, Liberty Utilities, or any of their subsidiaries or affiliates.

5. Empire shall maintain corporate officers who have a fiduciary duty to Empire.

6. Empire shall maintain separate books and records, and make them available for review by Staff and OPC.

7. Should it be deemed necessary for Staff or OPC employees to travel to locations outside of the State of Missouri to examine any records deemed relevant to the subject matter at hand Empire shall bear all reasonable expense incurred by the employees, provided, however, that before any such expense shall be incurred by Staff or OPC, Empire shall be given reasonable notice to produce the records requested for inspection and examination at the office of the Commission at Jefferson City, Missouri, the offices of its local counsel, Empire's offices in Joplin, Missouri, or at such other point in Missouri, as may be mutually agreed, in which case Empire shall make available at that place, at that time, a person(s) who is acquainted with the records.

8. Empire shall maintain its own board of directors with a majority of non-management, independent directors.

9. Empire shall not pay a dividend if its equity to total capitalization ratio, based on a 12-month rolling average, falls below 40%, or if payment of dividends would cause Empire's equity to total capitalization ratio to fall below that threshold.

EMPLOYMENT IN THE STATE OF MISSOURI

10. In its first general rate case after the close of the Transaction, Empire shall provide testimony discussing the employment metrics related to the number of full time

employees and the average turnover rate along with any material changes to those metrics since the close of the Transaction.

CHARITABLE CONTRIBUTIONS AND COMMUNITY SUPPORT

11. During the five-year period following the closing of the Transaction, Empire shall maintain, at a minimum, on a total company basis, an annual level of charitable contributions and traditional local community support of approximately **_____ _____**.

AFFILIATE TRANSACTION AND COST ALLOCATION MATTERS

12. Shared services costs shall be directly charged to the extent practicable. In its next base rate proceeding in Missouri, Empire shall file testimony addressing shared services charges and the bases for such charges. Empire's testimony shall also explain any changes in allocation procedures since its last base rate proceeding.

13. Empire shall provide copies to Staff and OPC of the portions of any external audit reports performed for Algonquin and Liberty Utilities Co.'s shared services pertaining directly or indirectly to determinations of direct billings and cost allocations to Empire. Such material shall be provided no later than thirty (30) days after the final report is completed.

14. Within Empire's next general electric rate case, Empire will provide upon request a list of proceedings, if any, where Liberty Utilities Co.'s cost allocation practices have been audited in any other jurisdictions. Empire shall further make any such audit reports available to the Commission, its Staff, and the OPC upon request.

15. Applicants will notify the Commission Staff and the OPC within thirty days anytime there 1.) is an addition or deletion of an affiliated entity that provides services to, or receives services from, Empire; 2.) an addition or deletion of an unregulated service provided by

Empire ; or 3.) an addition or deletion of a regulated service by Empire for which a tariff has not been approved.

16. Either the Staff or the OPC can request an independent attestation engagement of the CAM related to non-regulated affiliates and activities. If approved by the Commission, the costs of any independent attestation engagement related to the CAM shall be shared by the regulated and non-regulated operations consistent with the allocation of similar costs.

TAX INDEMNITY

17. Empire's parent company will indemnify Empire for any federal or local income tax liability in excess of Empire's standalone liability for any period in which Empire is included in a consolidated income tax filing.

RATE CASE MORATORIUM

18. The Joint Applicants agree to refrain from filing a rate case until at least one full year of financial and operational information is available following the close of the Transaction.

CORPORATE SOCIAL RESPONSIBILITY

19. No later than thirty days after the closing of the Transaction, Empire will fund an account in the amount of $1,500,000 to be available to the following Community Action Agencies:

Ozarks Area Community Action Corporation (OACAC)
Economic Security Corporation of the Southwest Area (ESC)
West Central Missouri Community Action Agency (WCMCAA)

It is expressly acknowledged that said funds are not operating costs of the utility but will be appropriately recorded as a transaction cost, and not recovered in rates. The funds will be prioritized towards the creation of an additional position(s) within the Community Action

Agency structure to better enable the utilization of weatherization dollars or such other appropriate use as deemed effective by the agencies.

$500,000 will be allocated to each agency with the express purpose of the creation of an additional position(s) to enable further low-income weatherization deployment at a recommended spend level of $50,000 per year over a ten-year period. Any excess funds can be allocated in the following categories at the agencies' discretion:

- Weatherization training and certification of agency personnel
- Discretionary funds for health and hazard for on-site units (that may or may not otherwise be passed over)
- Outreach efforts
- Utility weatherization account
- Hardship fund for on-bill payments

Each agency is required to provide documentation to the Company to verify how expenditures were occurred.

Community action agencies are required to file annual report with the Company on how funds were expended. Empire will file a condensed report of each of the three agencies individual annual reports with the Commission Staff, OPC and the Division of Energy (DE) as to how annual funds were expended.

Any additional information is left to the Agencies discretion (e.g., estimated additional homes weatherized as a result of the expenditures).

20. Empire shall investigate the feasibility of a bill payment extension for residential and small commercial accounts to be prolonged from twenty-one days to thirty-one days before the 0.5% for residential and 5% for commercial penalty begins. The results of the study shall be presented to OPC and Staff within 6 months following the Transaction. The results of the study

shall be used to inform recommendations on payment term extensions in the context of Empire's next rate case.

21. For existing (as of the date of the approved stipulation) bad debt and arrearage related to customers who received benefits through a low income program will be matched by the Company (below the line) dollar (customer) for dollar (Company) assuming that the customer account remains current for a period of at least 12 months after reconnection. This program shall be in place for a period of 18 months from the Transaction.

- The Company will record any and all action taken on the customer-side to pay the amount towards the reduction of said bad debt/arrearages and file a comprehensive report of actions to date in future rate cases.

22. Empire will commit to having a link on their front homepage signaling clearly for ratepayers with a "Trouble Paying Your Bill" signage. Said link will contain information on the Company's delinquency policy, including fees, timelines, cut-off practices, Community Action Agency other 3rd party contacts (e.g., Salvation Army, United Way, etc…), LIHEAP, LIWAP, and additional Company specific programs (e.g., EASE, etc…). Said link will also contain contact information for prospective at-risk ratepayers and information regarding paragraph 21 above.

23. Empire commits to an annual meeting with each of the local Community Action Agencies in-person for the next five years in Joplin, Missouri at Empire's headquarters with extended invitations to (at least) the Commission Staff, OPC, and the Division of Energy to discuss progress to date Strengths, Weaknesses, Opportunities, and Threats to Empire's low-income population.

DIVISION OF ENERGY OVERSIGHT OF WEATHERIZATION FUNDS

24. Empire and The Empire District Gas Company agree to provide DE an annual payment totaling up to 5% of the agreed to weatherization funds for a pilot program concerning the administration and monitoring of the funds (not to exceed an annual cap of $12,500) to the extent DE is utilized for the management of those funds. Said funds, will be provided for a period of five years and be considered below the line and not recovered in future rates. Nothing in this paragraph will affect Staff's and OPC's ability to oppose funding for DE in future cases whether for Empire or any other utility. DE shall work with the OPC, Staff, and Empire to develop reporting standards for its administration and monitoring activities to be presented at the annual meetings with each local Community Action Agency.

GENERAL PROVISIONS

A. This Stipulation has resulted from negotiations among the Signatories and the terms hereof are interdependent. In the event the Commission does not adopt this Stipulation in total, then this Stipulation shall be void and no Signatory shall be bound by any of the agreements or provisions hereof. The stipulations herein are specific to the resolution of this proceeding, and all stipulations are made without prejudice to the rights of the Signatories to take other positions in other proceedings except as otherwise provided herein. The Signatories agree that any and all discussions related hereto shall be privileged and shall not be subject to discovery, admissible in evidence, or in any way used, described or discussed.

B. This Stipulation is being entered into for the purpose of disposing of all issues in this case. The Signatories represent that the terms of this Stipulation constitute a fair and reasonable resolution of the issues addressed herein, in a manner which is not detrimental to the public interest. Except as otherwise addressed herein, none of the Signatories to this Stipulation shall be deemed to have approved, accepted, agreed, consented or acquiesced to any accounting

principle, ratemaking principle or cost of service determination underlying, or supposed to underlie any of the issues provided for herein.

C. The Signatories further understand and agree that the provisions of this Stipulation relate only to the specific matters referred to in the Stipulation, and no Signatory or person waives any claim or right which it otherwise may have with respect to any matter not expressly provided for in this Stipulation. The Signatories further reserve the right to withdraw their support for the settlement in the event that the Commission modifies the Stipulation in a manner which is adverse to the Signatory, and further, the Signatories reserve the right to contest any such Commission order modifying the settlement in a manner which is adverse to the Signatory contesting such Commission order. The Signatories agree that the details of this Stipulation have no precedential value in any future proceeding not related to enforcement of this agreement.

D. The non-utility Signatory Parties enter into this Stipulation in reliance upon information provided to them by the Joint Applicants and this Stipulation is explicitly predicated upon the truth of representations made by the Joint Applicants.

E. In the event the Commission accepts the specific terms of this Stipulation without modification, the Signatories waive, with respect to the issues resolved herein: their respective rights pursuant to Section 536.070(2), RSMo 2000 to call, examine and cross-examine witnesses; their respective rights to present oral argument or written briefs pursuant to Section 536.080.1, RSMo 2000; their respective rights to the reading of the transcript by the Commission pursuant to Section 536.080.2, RSMo 2000; their respective rights to seek rehearing pursuant to Section 386.500, RSMo 2000; and their respective rights to judicial review pursuant to Section 386.510, RSMo 2000. Furthermore, in the event the Commission accepts the specific terms of this

Stipulation without modification, the Signatories agree that the pre-filed testimony of all witnesses who have pre-filed testimony in this case shall be included in the record of this proceeding without the necessity of such witnesses taking the stand.

F. Staff shall have the right to provide, at any agenda meeting at which this Stipulation is noticed to be considered by the Commission, whatever oral explanation the Commission requests, provided that Staff shall, to the extent reasonably practicable, promptly provide other Signatories with advance notice of when Staff shall respond to the Commission's request for such explanation once such explanation is requested from Staff. Staff's oral explanation shall be subject to public disclosure, except to the extent it refers to matters that are privileged or previously designated confidential by any Signatory.

G. Except as otherwise addressed in this Stipulation, Commission approval of the acquisition by LU Central and Liberty Sub Corp. of the stock of Empire, and for the Joint Applicants to execute and perform in accordance with the terms of the Agreement, does not in any way, limit, form a basis for determination, or constitute a defense against any Signatory proposing, or the Commission ordering, the disallowance and/or imputation of account balances, expenses, revenues and/or other ratemaking findings, regarding Empire's operations in a future rate proceeding.

H. To assist the Commission in its review of this Stipulation, the Signatories also request that the Commission advise them of any additional information that the Commission may desire from the Signatories relating to the matters addressed in this Stipulation, including any procedures for furnishing such information to the Commission.

WHEREFORE, the Signatories hereto recommend that the acquisition by LU Central and Liberty Sub Corp. of the stock of Empire as contemplated by the Agreement and Plan of Merger is reasonable and not detrimental to the public interest and respectfully request that the Commission approve this Stipulation and Agreement subject to the conditions contained herein.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned certifies that a true and correct copy of the foregoing document was sent via U.S. Mail, postage prepaid, hand-delivery, electronic filing system, or electronically, this 23rd day of August, 2016, to the following:

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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company, Liberty Utilities (Central) Co. and Liberty Sub Corp. Concerning an Agreement and Plan of Merger and Certain Related Transactions.	))))	Case No. EM-2016-0213

STIPULATION AND AGREEMENT

COME NOW The Empire District Electric Company ("Empire"), Liberty Utilities (Central) Co. ("LU Central"), and Liberty Sub Corp. (sometimes collectively hereinafter "Joint Applicants"), and Algonquin Power & Utilities Corp., and the Staff of the Missouri Public Service Commission ("Staff"), by and through their undersigned counsel and, pursuant to Missouri Public Service Commission ("Commission") rule 4 CSR 240-2.115, request that the Commission approve this agreement as a comprehensive settlement of all issues relevant to the Joint Application filed by Empire, LU Central and Liberty Sub Corp. In support thereof, the signatories hereto agree as follows:

BACKGROUND

On March 16, 2016, Joint Applicants filed a Joint Application with the Commission under §393.190 RSMo., 2000, requesting an order from the Commission authorizing them to perform in accordance with the terms of an Agreement and Plan of Merger dated February 9, 2016 (the "Agreement") pursuant to which LU Central and Liberty Sub Corp. will acquire all of the stock of Empire (the "Transaction").

The Signatories have met to discuss resolution of this matter on a number of occasions. As a result, the Signatories have now reached a Stipulation and Agreement ("Stipulation") set forth below which they recommend to the Commission, subject to the conditions and representations contained in the Stipulation.

The Signatories hereto recommend that the Commission approve the proposed Transaction subject to the following conditions (and subject to the unopposed stipulations filed on July 19, 2016, and any unopposed stipulations that may be filed in this case in the future):

A. FINANCING CONDITIONS

The following Financing Conditions shall remain in effect until such time as the Commission may order otherwise in a general rate case or other proceeding brought for that purpose:

1. In the event The Empire District Electric Company ("Empire"), and/or the affiliate on which it relies on for its debt financing ("Financing Affiliate"), should have its Standard & Poor's ("S&P") Corporate Credit Rating downgraded to below BBB- , Empire commits to file:

a. Notice with the Commission within five (5) business days of such downgrade;

b. A pleading with the Commission within 60 days which shall include the following:

i. A plan identifying all reasonable steps, taking into account the costs, benefits and expected outcomes of such actions, that will be taken to restore and maintain a S&P BBB- or above credit rating for Empire and/or the Financing Affiliate. If Empire's plan does not involve taking steps to restore and maintain an S&P BBB- or above credit rating for either or both of these entities then Empire shall concisely state why the cost of such steps is not reasonable or necessary;

ii. Additionally, Empire shall specifically address the impact, or lack thereof, it believes the S&P Corporate Credit Rating of below BBB- has had and will have on its capital costs;

iii. Documentation, including but not limited to, a cost of capital study showing how Empire will not pass along higher capital costs to its Missouri customers, directly or indirectly, due to the downgrade(s);

iv. File with the Commission, every 45 days thereafter until Empire, and/or the Financing Affiliate, have regained an S&P Corporate Credit Rating of BBB- or above, a status report with respect to the implementation of steps to restore the Corporate Credit Ratings to BBB- or above and a study that estimates the increased cost of capital, if any, Empire has incurred due to S&P Corporate Credit Ratings of below BBB-;

v. If the Commission determines that Empire's, and/or the Financing Affiliate's, Corporate Credit Rating decline has caused its service to decline, Empire shall be required to file a report that demonstrates to the Commission that it can adequately safeguard capital produced and secured by its public utility assets. If Empire cannot sufficiently demonstrate this ability, then Empire shall execute reasonable steps to ensure Empire's S&P Corporate Credit Rating will be based on its own stand-alone credit quality. These steps may include consideration of restoring Empire's corporate financing functions and restricting the distribution of cash flows to its affiliates in the event that Empire has transferred these activities to an affiliate.

2. In the event Empire's affiliation with Algonquin Power & Utilities Corp. and its companies should cause Empire's and/or the Financing Affiliate's S&P Corporate Credit Rating to be downgraded to below BBB-, Empire, or the Financing Affiliate, shall pursue additional legal and structural separation, if necessary, from the affiliate(s) causing the downgrade, to

ensure Empire continues to have access to capital at the least cost. Empire shall not pay a dividend to its upstream parent companies until there is sufficient evidence that Empire's S&P Corporate Credit Rating has been restored to the rating Empire had before the event.

3. If Empire's S&P Corporate Credit Rating declines, and/or the credit rating of the Financing Affiliate declines, Empire shall file with the Commission a comprehensive risk management plan that assures Empire's access to and cost of capital will not be further impaired. The plan shall include a non-consolidation opinion if required by S&P.

4. Empire shall not seek an increase to the cost of capital as a result of this Transaction or Empire's ongoing affiliation with Algonquin Power & Utilities Corp. and its affiliates other than Empire after the Transaction. Any net increase in the cost of capital Empire seeks shall be supported by documentation that: (a) the increases are a result of factors not associated with the Transaction or the post Transaction operations of Algonquin Power & Utilities Corp. or its non-Empire affiliates; (b) the increases are not a result of changes in business, market, economic or other conditions caused by the Transaction or the post Transaction operations of Algonquin Power & Utilities Corp. or its non-Empire affiliates; and (c) the increases are not a result of changes in the risk profile of Empire caused by the Transaction or the post Transaction operations of Algonquin Power & Utilities Corp. or its non-Empire affiliates. The provisions of this section are intended to recognize the Commission's authority to consider, in appropriate proceedings, whether this Transaction or the post Transaction operations of Algonquin Power & Utilities Corp. or its non-Empire affiliates has resulted in capital cost increases for Empire. Nothing in this agreement shall restrict the Commission from disallowing such capital cost increases from recovery in Empire's rates.

5. If Empire's per books capital structure is different from that of the entity or

entities in which Empire relies for its financing needs, Empire shall be required to provide evidence in subsequent rate cases as to why Empire's per book capital structure is the most economical for purposes of determining a fair and reasonable allowed rate of return for purposes of determining Empire's revenue requirement.

6. The Joint Applicants will not obtain Empire financing services from an affiliate, unless such services comply with Missouri's Affiliate Transaction Rules.

7. To the extent the goodwill arising from the Transaction which is assigned to LU Central becomes impaired and such impairment negatively effects Empire's cost of capital, all net costs associated with the decline in Empire's credit quality specifically attributed to the goodwill impairment, considering all other capital cost effects of the Transaction and the impairment, shall be excluded from the determination of its rates.

8. For the first five years after closing of the Transaction, LU Central shall provide Staff and OPC, its annual goodwill impairment analysis in a format that includes spreadsheets in their original format with formulas and links to other spreadsheets intact and any printed materials within 30 days after it is performed. Thereafter, this analysis will be made available to Staff and OPC upon request.

9. Staff will retain a copy of Liberty Utilities' financial/valuation model. Staff will continue to protect the confidentiality of the information contained within that model.

B. <u>DEPRECIATION CONDITIONS</u>

1. Electric Assets

a. For purposes of accruing depreciation expense, Empire shall use the ordered depreciation rates for Empire that are awaiting approval by the Commission in Case No. ER-2016-0023, and those depreciation rates attached hereto that were attached

to the Stipulation and Agreement in that case as Schedule JAR(DEP)-r2. Depreciation rates resulting from Case No. ER-2016-0023 are to remain in effect until they are changed in a subsequent rate proceeding.

b. Empire shall continue to book all plant and depreciation reserve records in compliance with the format set forth in Title 18: Conservation of Power and Water Resources, Part 101—Uniform System Of Accounts Prescribed For Public Utilities and Licensees Subject To The Provisions Of The Federal Power Act (FERC USOA).

c. Empire will continue to prepare and maintain its books in accordance with the FERC Uniform System of Accounts (USOA).

d. Empire shall submit the following information in accordance with 4 CSR 240-3.175 - Submission Requirements for Electric Utility Depreciation Studies.

i. FERC USOA requires the following information to be recorded as part of a Continuing Plant Inventory Record (CPR).

ii. FERC USOA CPR Rule 8. Continuing plant inventory record means company plant records for retirement units and mass property that provide, as either a single record, or in separate records readily obtainable by references made in a single record, the following information:

1. For each retirement unit:

a. The name or description of the unit, or both;

b. The location of the unit;

c. The date the unit was placed in service;

d. The cost of the unit as set forth in Plant Instructions 2 and 3 of this part; and

e. The plant control account to which the cost of the units is charged; and

2. For each category of mass property:

a. A General description of the property and quantity;

b. The quantity placed in service by vintage year;

c. The average cost as set forth in Plant Instructions 2 and 3 of this part; and

d. The plant control account to which the costs are charged.

2. Gas Assets

a. For purposes of accruing depreciation expense, Empire shall ensure that The Empire District Gas Company ("EDG") uses the currently ordered depreciation rates for EDG approved by the Commission in File No. GR-2009-0434, and attached as Schedule JAR(DEP)-r3 until changed in a subsequent rate proceeding.

b. Empire shall ensure that EDG continues to book all plant and depreciation reserve records in compliance with the format set forth in Title 18: Conservation of Power and Water Resources, Part 201—Uniform System Of Accounts Prescribed For Natural Gas Companies Subject To The Provisions Of The Natural Gas Act (FERC USOA).

c. Empire shall ensure that EDG prepares and maintains its books in accordance with the FERC Uniform System of Accounts (USOA).

d. Empire shall ensure that EDG submits the following information in accordance with 4 CSR 240-3.275 Submission Requirements for Gas Utility Depreciation Studies.

i. FERC USOA requires the following information shall be recorded as part of a Continuing Plant Inventory Record (CPR).

ii. FERC USOA CPR Rule 8. Continuing plant inventory record means company plant records for retirement units and mass property that provide, as either a single record, or in separate records readily obtainable by references made in a single record, the following information:

1. For each retirement unit:

a. The name or description of the unit, or both;

b. The location of the unit

c. The date the unit was placed in service;

d. The cost of the unit as set forth in Plant Instructions 2 and 3 of this part; and

e. The plant control account to which the cost of the units is charged; and

2. For each category of mass property:

a. A general description of the property and quantity;

b. The quantity placed in service by vintage year;

c. The average cost as set forth in Plant Instructions 2 and 3 of this part; and

d. The plant control account to which the costs are charged.

3. Water Assets: Empire shall continue to utilize the depreciation rates ordered in Case No. WR-2012-0300, attached hereto as Schedule JAR(DEP)-r4, and those depreciation

rates shall remain in effect until they are changed in a subsequent rate proceeding.

C. DEFERRED TAXES CONDITIONS

1. Empire will record on its books all deferred taxes related to income tax deductions or credits created by Empire's operations.

D. RATEMAKING/ACCOUNTING CONDITIONS

1. Goodwill associated with the premium over book value of the assets paid for the shares of Empire stock (referred to for purposes of this stipulation as "Acquisition Premium") will be maintained on the books of LU Central. The amount of any acquisition premium paid for Empire shall not be recovered in retail rates. Nothing herein shall preclude any party to this Agreement from taking a position in any future ratemaking proceedings involving Empire regarding the ratemaking measures and adjustments necessary to ensure no impact from the acquisition premium on rates. Empire will not seek direct or indirect recovery or recognition of any acquisition premium through any purported acquisition savings "sharing" adjustment (or similar adjustment) in future rate cases.

2. Transaction costs include, but are not limited to, those costs relating to obtaining regulatory approvals, development of transaction documents, investment banking costs, costs related to raising equity incurred prior to the close of the Transaction, payments to employees who invoke severance payment agreements, and communication costs regarding the ownership change with customers and employees. Empire will not seek either direct or indirect rate recovery or recognition of any transaction costs through any purported acquisition savings "sharing" adjustment (or similar adjustment) in any future rate cases.

3. Transition costs are those costs incurred to integrate Empire under the ownership of LU Central and includes integration planning and execution, and "costs to achieve."

Transition costs include capital and non-capital costs. Non-capital transition costs can be ongoing costs or one- time costs. Non-capital transition costs can be deferred on the books of LU Central or Empire to be considered for recovery in future Empire rate cases. If subsequent rate recovery is sought, Empire will have the burden of proving that the recoveries of any transition costs are just and reasonable and the costs provide benefits to its customers.

E. AFFILIATE TRANSACTIONS AND COST ALLOCATION MANUAL (CAM) CONDITIONS

1. Empire is to be operated after the purchase in compliance with the affiliate transaction rule, or will obtain any necessary variances from the MoPSC's affiliate transaction rule as defined in 4 CSR 240-20-015(10) and 4 CSR 240-40-015(10).

2. Algonquin Power & Utilities Corp. and its subsidiaries will commit that all information related to an affiliate transaction consistent with 4 CSR 240-20.015(5)(A)(1)-(2) and 4 CSR 240-40.015(5)(A)(1)-(2) charged to Empire will be treated in the same manner as if that information is under the control of Empire, and

3. Empire will provide no preferential service, information, or treatment to an affiliated entity over another party at any other time, consistent with 4 CSR 240-20.015(2) and 4 CSR 240-40.015(2).

F. CUSTOMER SERVICE CONDITIONS

1. Empire and Liberty will strive to meet or exceed the customer service and operational levels currently provided to their customers.

2. Empire and Liberty will meet with Staff Consumer and Management Analysis personnel on a periodic basis (such as quarterly) or, as Staff deems necessary, after the close of the Transaction to review contact center and other service quality performance. Staff and/or

OPC may request additional periodic meetings with Empire and Liberty personnel to address customer service operating procedures and the level of service being provided to Missouri customers.

3. Empire and Liberty shall notify Staff of any material operational changes concerning customer contact centers, or other customer service functions, occurring within 24 months of the close of the Transaction. Material operational changes include, but are not limited to: Empire and/or Liberty employing call deferral technologies such as Virtual Hold or Call Back In Queue, outsourcing call center or other service quality processes, such as meter reading, substantial changes in billing processes, and the utilization of services or management agreements to perform any of the customer service functions currently performed by any of the previously noted three companies. Empire and Liberty agree to begin reporting the utilization of call deferral technologies if and when they are implemented. Such reports shall include 1) the number of calls offered call deferral technology, and 2) the number of calls accepting call deferral technology.

4. Within thirty (30) days after closing the Transaction, Empire and LU Central shall provide Staff and OPC a current organizational chart, illustrating the positions and names of employees that have customer service responsibilities. In the event structural changes are made to Empire's organization, updated organizational charts shall be provided to Staff and OPC within 30 days of such changes.

5. Empire and Liberty agree to not make available, sell or transfer customer information to affiliated or unaffiliated entities without prior informed consent of the Missouri customer, other than as necessary to provide services to and in support of their regulated operations.

6. In evaluating billing systems for future use, the Joint Applicants shall consider the ability of any billing system to maintain or improve cumulative frequency distribution of bills ending in each block in each billing cycle and the quality of existing load research and metering data.

7. The Joint Applicants agree that Empire's load research sample will take into account both the summer and winter usage of the customers in each customer class before Empire's next subsequent rate case.

G. ACCESS TO RECORDS CONDITIONS

1. Empire shall provide Staff and OPC with access, upon reasonable written notice during working hours and subject to appropriate confidentiality and discovery procedures, to all written information provided to common stock, bond or bond rating analysts which directly or indirectly pertains to Empire or any affiliate that exercises influence or control over Empire or has affiliate transactions with Empire. Such information includes, but is not limited to, common stock analyst's and bond rating analyst's reports. For purposes of this condition, "written" information includes, but is not limited to, any written and printed material, audio and video tapes, computer disks, and electronically stored information. Nothing in this condition shall be deemed a waiver of any entity's right to seek protection of the information or to object, for purposes of submitting such information as evidence in any evidentiary proceeding, to the relevancy or use of such information by any party.

2. Empire agrees to make available to Staff and OPC, upon written notice during normal working hours and subject to appropriate confidentiality and discovery procedures, all books, records and employees as may be reasonably required to verify compliance with Empire's CAM and any conditions ordered by this Commission. Empire shall also provide Staff and OPC

any other such information (including access to employees) relevant to the Commission's ratemaking, financing, safety, quality of service and other regulatory authority over Empire; provided that any entity producing records or personnel shall have the right to object on any basis under applicable law and Commission rules, excluding any objection that such records and personnel of affiliates; (a) are not within the possession or control of Empire or (b) are either not relevant or are not subject to, the Commission's jurisdiction and statutory authority by virtue of, or as a result of, the implementation of the proposed Transaction.

3. Empire shall provide Staff and OPC access to and copies of, if requested by Staff or OPC, the complete Liberty Utilities Co, LU Central and Empire Board of Directors' meeting minutes, including all agendas and related information distributed in advance of the meeting, presentations and handouts, provided that privileged information shall continue to be subject to protection from disclosure and Empire shall continue to have the right to object to the provision of such information on relevancy grounds.

4. Empire will maintain records supporting its affiliated transactions for at least five years.

5. Should it be deemed necessary for Staff employees to travel to locations outside of the State of Missouri to examine any records deemed relevant to the subject matter at hand Empire shall bear all reasonable expense incurred by the employees, provided, however, that before any such expense shall be incurred by Staff, Empire shall be given reasonable notice to produce the records requested for inspection and examination at the office of the Commission at Jefferson City, Missouri or at Empire's offices in Joplin, Missouri, or at such other point in Missouri, as may be mutually agreed, in which case Empire shall make available at that place, at that time, a person(s) who is acquainted with the records.

H. ENERGY EFFICIENCY CONDITIONS:

Upon the close of the Transaction, Empire shall comply with any Commission order in ER -2016-0023 regarding Demand Side Management programs**.**

I. NATURAL GAS PROCUREMENT PRACTICES:

1. LU Central shall prepare a cost benefit analysis prior to any decision to materially change any existing gas procurement practices of EDG to a LU Central gas procurement approach. This should include, but not be limited to, an evaluation of EDG's existing supplier availability, hedging methods, gas volume accounting systems, transportation balancing systems, PGA and ACA recordkeeping and other existing EDG gas procurement practices as contrasted to changing a materially different gas procurement practice.

2. Prior to the effective date of the closing of the Transaction, Empire will provide Staff with evidence that no assignment of transportation and storage contracts with EDG interstate pipeline suppliers will be required due to the merger, or that acceptance of such assignment has been obtained. Further, Empire will provide evidence that no transfer of existing gas hedges for Empire or EDG will be required as a result of the merger, or that acceptance of such transfer has been obtained.

J. PARENT COMPANY CONDITION:

1. Algonquin Power & Utilities Corp., on behalf of itself, its successors, assignees, and its subsidiaries, and in consideration of the signatories' support of the proposed acquisition embodied in this document, agrees that it will uphold the conditions agreed to by Empire and LU Central in this Stipulation.

GENERAL PROVISIONS

A. This Stipulation has resulted from negotiations among the Signatories and the terms hereof are interdependent. In the event the Commission does not adopt this Stipulation in total, then this Stipulation shall be void and no Signatory shall be bound by any of the agreements or provisions hereof. The stipulations herein are specific to the resolution of this proceeding, and all stipulations are made without prejudice to the rights of the Signatories to take other positions in other proceedings except as otherwise provided herein. The Signatories agree that any and all discussions related hereto shall be privileged and shall not be subject to discovery, admissible in evidence, or in any way used, described or discussed.

B. This Stipulation is being entered into for the purpose of disposing of all issues in this case. The Signatories represent that the terms of this Stipulation constitute a fair and reasonable resolution of the issues addressed herein, in a manner which is not detrimental to the public interest. Except as otherwise addressed herein, none of the Signatories to this Stipulation shall be deemed to have approved, accepted, agreed, consented or acquiesced to any accounting principle, ratemaking principle or cost of service determination underlying, or supposed to underlie any of the issues provided for herein.

C. The Signatories further understand and agree that the provisions of this Stipulation relate only to the specific matters referred to in the Stipulation, and no Signatory or person waives any claim or right which it otherwise may have with respect to any matter not expressly provided for in this Stipulation. The Signatories further reserve the right to withdraw their support for the settlement in the event that the Commission modifies the Stipulation in a manner which is adverse to the Signatory, and further, the Signatories reserve the right to contest any such Commission order modifying the settlement in a manner which is adverse to the

Signatory contesting such Commission order. The Signatories agree that the details of this Stipulation have no precedential value in any future proceeding not related to enforcement of this agreement.

D. The non-utility Signatory Parties enter into this Stipulation in reliance upon information provided to them by the Joint Applicants and this Stipulation is explicitly predicated upon the truth of representations made by the Joint Applicants.

E. In the event the Commission accepts the specific terms of this Stipulation without modification, the Signatories waive, with respect to the issues resolved herein: their respective rights pursuant to Section 536.070(2), RSMo 2000 to call, examine and cross-examine witnesses; their respective rights to present oral argument or written briefs pursuant to Section 536.080.1, RSMo 2000; their respective rights to the reading of the transcript by the Commission pursuant to Section 536.080.2, RSMo 2000; their respective rights to seek rehearing pursuant to Section 386.500, RSMo 2000; and their respective rights to judicial review pursuant to Section 386.510, RSMo 2000. Furthermore, in the event the Commission accepts the specific terms of this Stipulation without modification, the Signatories agree that the pre-filed testimony of all witnesses who have pre-filed testimony in this case shall be included in the record of this proceeding without the necessity of such witnesses taking the stand.

F. Staff shall have the right to provide, at any agenda meeting at which this Stipulation is noticed to be considered by the Commission, whatever oral explanation the Commission requests, provided that Staff shall, to the extent reasonably practicable, promptly provide other Signatories with advance notice of when Staff shall respond to the Commission's request for such explanation once such explanation is requested from Staff. Staff's oral

explanation shall be subject to public disclosure, except to the extent it refers to matters that are privileged or previously designated confidential by any Signatory.

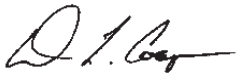
G. Except as otherwise addressed in this Stipulation, Commission approval of the acquisition by LU Central and Liberty Sub Corp. of the stock of Empire, and for the Joint Applicants to execute and perform in accordance with the terms of the Agreement, does not in any way, limit, form a basis for determination, or constitute a defense against any Signatory proposing, or the Commission ordering, the disallowance and/or imputation of account balances, expenses, revenues and/or other ratemaking findings, regarding Empire's operations in a future rate proceeding.

H. To assist the Commission in its review of this Stipulation, the Signatories also request that the Commission advise them of any additional information that the Commission may desire from the Signatories relating to the matters addressed in this Stipulation, including any procedures for furnishing such information to the Commission.

WHEREFORE, the Signatories hereto recommend that the acquisition by LU Central and Liberty Sub Corp. of the stock of Empire as contemplated by the Agreement and Plan of Merger is reasonable and not detrimental to the public interest and respectfully request that the

Commission approve this Stipulation and Agreement subject to the conditions contained herein.

Respectfully submitted,



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CERTIFICATE OF SERVICE

The undersigned certifies that a true and correct copy of the foregoing document was sent via U.S. Mail, postage prepaid, hand-delivery, electronic filing system, or electronically, this 4th day of August, 2016, to the following:

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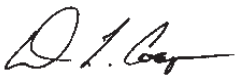

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Empire District Electric Company,	)	
Liberty Utilities (Central) Co. and Liberty Sub Corp.	)	Case No. EM-2016-0213
Concerning an Agreement and Plan of Merger and	)	
Certain Related Transactions.	)	

STIPULATION AND AGREEMENT AS TO EDESR

COME NOW The Empire District Electric Company ("Empire"), Liberty Utilities (Central) Co. ("LU Central"), and Liberty Sub Corp. (sometimes collectively hereinafter "Joint Applicants"), and The Empire District Electric SERP Retirees ("EDESR"), by and through their undersigned counsel and, pursuant to Missouri Public Service Commission ("Commission") rule 4 CSR 240-2.115, request that the Commission approve this agreement as a settlement of the EDESR's issues related to the Joint Application filed by the Joint Applicants. In support thereof, the signatories hereto state the following:

The Signatories hereto agree as follows:

The Signatories hereto recommend that the Commission approve the proposed transaction ("Transaction") subject to the following condition:

Supplemental Executive Retirement Plan ("SERP")

Empire will, within one year after the Transaction closes, cause to be performed an actuarial analysis with the intention of determining whether a SERP funded via a Rabbi trust according to the SERP plan is less expensive to ratepayers than benefits paid from Empire's general funds for the life of the plan (the "Study"). The current SERP recipients shall be included in the development of all assumptions and allowed review and analysis of the Study. If the Study concludes the annual costs and expenses of funds contributed by Empire using a

Rabbi trust (including contributions to the trust) to provide benefits are essentially the same or less than the costs and expenses to ratepayers of providing the alternate of SERP benefits from Empire's general funds, Empire will discuss the results of the Study with Staff and OPC, and to the extent neither party oppose the rate recovery of the Rabbi trust in place of the SERP funded from general funds, Empire will fund a Rabbi trust according to the plan. Any trust documents shall be subject to review by the SERP recipients' counsel.

General Provisions

A. This Stipulation has resulted from negotiations among the Signatories and the terms hereof are interdependent. In the event the Commission does not adopt this Stipulation in total, then this Stipulation shall be void and no Signatory shall be bound by any of the agreements or provisions hereof. The stipulations herein are specific to the resolution of this proceeding, and all stipulations are made without prejudice to the rights of the Signatories to take other positions in other proceedings except as otherwise provided herein. The Signatories agree that any and all discussions related hereto shall be privileged and shall not be subject to discovery, admissible in evidence, or in any way used, described or discussed.

B. This Stipulation is being entered into for the purpose of disposing of The EDESR's issues in this case. The Signatories represent that the terms of this Stipulation constitute a fair and reasonable resolution of the issues addressed herein, in a manner which is not detrimental to the public interest. Except as otherwise addressed herein, none of the Signatories to this Stipulation shall be deemed to have approved, accepted, agreed, consented or acquiesced to any

accounting principle, ratemaking principle or cost of service determination underlying, or supposed to underlie any of the issues provided for herein.

C. The Signatories further understand and agree that the provisions of this Stipulation relate only to the specific matters referred to in the Stipulation, and no Signatory or person waives any claim or right which it otherwise may have with respect to any matter not expressly provided for in this Stipulation. The Signatories further reserve the right to withdraw their support for the settlement in the event that the Commission modifies the Stipulation in a manner which is adverse to the Signatory, and further, the Signatories reserve the right to contest any such Commission order modifying the settlement in a manner which is adverse to the Signatory contesting such Commission order. The Signatories agree that the details of this Stipulation have no precedential value in any future proceeding not related to enforcement of this agreement.

D. The non-utility Signatory Parties enter into this Stipulation in reliance upon information provided to them by the Joint Applicants and this Stipulation is explicitly predicated upon the truth of representations made by the Joint Applicants.

E. In the event the Commission accepts the specific terms of this Stipulation without modification, the Signatories waive, with respect to the issues resolved herein: their respective rights pursuant to Section 536.070(2), RSMo 2000 to call, examine and cross-examine witnesses; their respective rights to present oral argument or written briefs pursuant to Section 536.080.1, RSMo 2000; their respective rights to the reading of the transcript by the Commission pursuant to

Section 536.080.2, RSMo 2000; their respective rights to seek rehearing pursuant to Section 386.500, RSMo 2000; and their respective rights to judicial review pursuant to Section 386.510, RSMo 2000. Furthermore, in the event the Commission accepts the specific terms of this Stipulation without modification, the Signatories agree that the pre-filed testimony of all witnesses who have pre-filed testimony in this case shall be included in the record of this proceeding without the necessity of such witnesses taking the stand.

F. Except as otherwise addressed in this Stipulation, Commission approval of the acquisition by LU Central and Liberty Sub Corp. of the stock of Empire, and for the Joint Applicants to execute and perform in accordance with the terms of the Agreement, does not in any way, limit, form a basis for determination, or constitute a defense against any Signatory proposing, or the Commission ordering, the disallowance and/or imputation of account balances, expenses, revenues and/or other ratemaking findings, regarding Empire's operations in a future rate proceeding.

G. To assist the Commission in its review of this Stipulation, the Signatories also request that the Commission advise them of any additional information that the Commission may desire from the Signatories relating to the matters addressed in this Stipulation, including any procedures for furnishing such information to the Commission.

WHEREFORE, the Signatories hereto recommend that the acquisition by LU Central and Liberty Sub Corp. of the stock of Empire as contemplated by the Agreement and Plan of

Merger is reasonable and not detrimental to the public interest and respectfully request that the Commission approve this Stipulation and Agreement subject to the conditions contained herein.

By: _____

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Attorney for The Empire District Electric SERP Retirees

CERTIFICATE OF SERVICE

The undersigned certifies that a true and correct copy of the foregoing document was sent via U.S. Mail, postage prepaid, hand-delivery, electronic filing system, or electronically, this 23rd day of August, 2016, to the following:

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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Empire District Electric Company, Liberty Utilities (Central) Co. and Liberty Sub Corp. Concerning an Agreement and Plan of Merger and Certain Related Transactions.	))))	Case No. EM-2016-0213

AMENDED STIPULATION AND AGREEMENT
AS TO DIVISION OF ENERGY AND RENEW MISSOURI

COME NOW The Empire District Electric Company ("Empire"), Liberty Utilities (Central) Co. ("LU Central"), and Liberty Sub Corp. (sometimes collectively hereinafter "Joint Applicants"), and the Missouri Division of Energy ("DE") and Earth Island Institute d/b/a Renew Missouri ("Renew Missouri"), by and through their undersigned counsel and, pursuant to Missouri Public Service Commission ("Commission") rule 4 CSR 240-2.115, request that the Commission approve this agreement as a settlement of DE and Renew Missouri's issues relevant to the Joint Application filed by Empire, LU Central and Liberty Sub Corp.

The Signatories hereto agree as follows:

The Signatories hereto recommend that the Commission approve the proposed Transaction subject to the following conditions:

(1) **Demand-side management ("DSM") programs.** Empire will work with DE, the Staff of the Commission ("Staff"), the Office of the Public Counsel ("OPC") and other parties through the existing DSM Advisory Group to review and consider the viability of adopting additional energy efficiency programs for its customers. Within one year of the Commission's finding of substantial compliance of the Empire Integrated Resource Plan that follows Commission approval of a Statewide Technical Reference Manual (TRM), Empire will develop and submit an application for approval of a portfolio of DSM programs under the Missouri Energy Efficiency

Investment Act (MEEIA), so long as any such portfolio is a part of Empire's adopted preferred resource plan in its Integrated Resource Plan, or has been analyzed through the integration process required by 4 CSR 240-22.060, and the portfolio and any DSIM submitted in the application is fully compliant with the MEEIA statute and applicable regulations.

(2) **Combined Heat and Power ("CHP").** Within one year of the completion of the merger transaction, Empire will assist DE and the US DOE Midwest CHP Technical Assistance Partnership ("CHP TAP") in completing an outreach effort for screening potential CHP customers within The Empire District Gas Company's ("EDG," a wholly owned subsidiary of Empire) service territory in Missouri. The screening tool to be provided by the CHP TAP is a survey to help determine if CHP is a good fit for the customers from a financial and technical perspective. Target sectors will include public, commercial, institutional and industrial facilities with consistent gas consumption throughout the year, indicative of consistent thermal load requirements. Example customers that may generally fit this profile include hospitals, large residential facilities such as nursing homes and correctional facilities, universities, and food manufacturers. Those surveyed customers with favorable evaluations will be encouraged to take the next step of contacting the CHP TAP for follow-up technical assistance services, which could include a more detailed CHP feasibility study. Detailed process/roles are as follows:

(i) Empire will utilize its knowledge of the EDG service territory and customers to develop a list of customers in the target sectors territory–wide, with outreach occurring beyond the form of a bill insert. Empire will review the types of customers and number of customers of each type in the target sectors with the EDG Demand Side Management

Advisory Group ("DSMAG"). The DSMAG will be able to provide feedback regarding the types and number of customer's identified, as well as how to optimize outreach efforts.

(ii) CHP TAP/DE will provide Empire with an educational packet explaining CHP and a tailored CHP Screening Survey tool, to include explanation of the use that will be made of the customer data.

(iii) Empire will email or mail and personally follow up by phone with customers to encourage completion of the survey, and, if requested, will assist customers with obtaining past billing information.

(iv) Interested customers will complete the CHP Screening Survey tool and email or mail them to CHP TAP.

(v) CHP TAP will score the surveys and share the results with surveyed customers, and offer those who "scored well" a follow-up conversation to discuss next steps and other available CHP TAP services, which could include a more detailed CHP feasibility study.

(vi) CHP TAP will provide Empire with a survey report, with information aggregated to a level that does not disclose customer-specific information.

(vii) Empire will share the report with interested stakeholders, including Staff, the Office of the Public Counsel and DE.

(viii) If Empire determines that the requirements of this provision cannot be reasonably completed without additional CHP TAP assistance, Empire will ensure CHP TAP has complied with all statutes and Commission

rules regarding the handling of confidential information prior to releasing any customer specific information to CHP TAP.

(3) Any recovery of third party or non-reoccurring costs associated with the Combined Heat and Power survey will not exceed five-thousand dollars ($5,000).

(4) Microgrid Industrial Consortium. Within six (6) months following the completion of the Transaction and the publication of best practices recommendations for microgrid interconnection by the Missouri University of Science and Technology's Microgrid Industrial Consortium, Empire will meet with DE to consider a microgrid interconnection strategy consistent with the best practices recommendations of the Microgrid Industrial Consortium.

(5) Empire will review and consider the viability of offering a community solar or solar subscription program that provides its customers with the option of purchasing blocks of electricity generated from solar installations constructed and/or owned by Empire within the state of Missouri. Empire will solicit input and feedback on proposals and will work with Staff, OPC, DE, Renew Missouri, and other interested stakeholders to design a successful customer solar program, with the goal of submitting a formal proposal to the Commission within one year of the completion of the Transaction.

General Provisions

A. This Stipulation has resulted from negotiations among the Signatories and the terms hereof are interdependent. In the event the Commission does not adopt this Stipulation in total, then this Stipulation shall be void and no Signatory shall be bound by any of the agreements or provisions hereof. The stipulations herein are specific to the resolution of this proceeding, and all stipulations are made without

prejudice to the rights of the Signatories to take other positions in other proceedings except as otherwise provided herein. The Signatories agree that any and all discussions related hereto shall be privileged and shall not be subject to discovery, admissible in evidence, or in any way used, described or discussed.

B. This Stipulation is being entered into for the purpose of disposing of DE and Renew Missouri's issues in this case. The Signatories represent that the terms of this Stipulation constitute a fair and reasonable resolution of the issues addressed herein, in a manner which is not detrimental to the public interest. Except as otherwise addressed herein, none of the Signatories to this Stipulation shall be deemed to have approved, accepted, agreed, consented or acquiesced to any accounting principle, ratemaking principle or cost of service determination underlying, or supposed to underlie any of the issues provided for herein.

C. The Signatories further understand and agree that the provisions of this Stipulation relate only to the specific matters referred to in the Stipulation, and no Signatory or person waives any claim or right which it otherwise may have with respect to any matter not expressly provided for in this Stipulation. The Signatories further reserve the right to withdraw their support for the settlement in the event that the Commission modifies the Stipulation in a manner which is adverse to the Signatory, and further, the Signatories reserve the right to contest any such Commission order modifying the settlement in a manner which is adverse to the Signatory contesting such Commission order. The Signatories agree that the details of this Stipulation have no precedential value in any future proceeding not related to enforcement of this agreement.

D. The non-utility Signatory Parties enter into this Stipulation in reliance upon information provided to them by the Joint Applicants and this Stipulation is explicitly predicated upon the truth of representations made by the Joint Applicants.

E. In the event the Commission accepts the specific terms of this Stipulation without modification, the Signatories waive, with respect to the issues resolved herein: their respective rights pursuant to Section 536.070(2), RSMo 2000 to call, examine and cross-examine witnesses; their respective rights to present oral argument or written briefs pursuant to Section 536.080.1, RSMo 2000; their respective rights to the reading of the transcript by the Commission pursuant to Section 536.080.2, RSMo 2000; their respective rights to seek rehearing pursuant to Section 386.500, RSMo 2000; and their respective rights to judicial review pursuant to Section 386.510, RSMo 2000. Furthermore, in the event the Commission accepts the specific terms of this Stipulation without modification, the Signatories agree that the pre-filed testimony of all witnesses who have pre-filed testimony in this case shall be included in the record of this proceeding without the necessity of such witnesses taking the stand.

F. Except as otherwise addressed in this Stipulation, Commission approval of the acquisition by LU Central and Liberty Sub Corp. of the stock of Empire, and for the Joint Applicants to execute and perform in accordance with the terms of the Agreement, does not in any way, limit, form a basis for determination, or constitute a defense against any Signatory proposing, or the Commission ordering, the disallowance and/or imputation of account balances, expenses,

revenues and/or other ratemaking findings, regarding Empire's operations in a future rate proceeding.

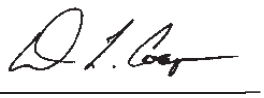
G. To assist the Commission in its review of this Stipulation, the Signatories also request that the Commission advise them of any additional information that the Commission may desire from the Signatories relating to the matters addressed in this Stipulation, including any procedures for furnishing such information to the Commission.

WHEREFORE, the Signatories hereto recommend that the acquisition by LU Central and Liberty Sub Corp. of the stock of Empire as contemplated by the Agreement and Plan of Merger is reasonable and not detrimental to the public interest and respectfully request that the Commission approve this Amended Stipulation and Agreement subject to the conditions

contained herein.

Respectfully submitted,

BRYDON, SWEARENGEN & ENGLAND P.C.

By: 

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CERTIFICATE OF SERVICE

The undersigned certifies that a true and correct copy of the foregoing document was sent via electronic mail, this 23rd day of August, 2016, to the following:

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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Empire District Electric Company, Liberty Utilities (Central) Co. and Liberty Sub Corp. Concerning an Agreement and Plan of Merger and Certain Related Transactions.	))))	Case No. EM-2016-0213

AMENDED STIPULATION AND AGREEMENT
AS TO IBEW 1464 AND IBEW 1474
AND MOTION TO MODIFY
ORDER APPROVING STIPULATIONS AND AGREEMENTS

COME NOW The Empire District Electric Company ("Empire"), Liberty Utilities (Central) Co. ("LU Central"), and Liberty Sub Corp. (sometimes collectively hereinafter "Joint Applicants"), and the International Brotherhood of Electrical Workers ("IBEW") Local 1464 and IBEW Local 1474, by and through their undersigned counsel and, pursuant to Missouri Public Service Commission ("Commission") rule 4 CSR 240-2.115, request that the Commission amend its Order Approving Stipulations and Agreements dated August 10, 2016 to approve this amended agreement as a comprehensive settlement of IBEW 1464 and IBEW 1474's issues relevant to the Joint Application filed by Empire, LU Central and Liberty Sub Corp.

1. On July 19, 2016, the Signatories executed and filed a Stipulation and Agreement As To IBEW 1464 and IBEW 1474, for the purpose of addressing issues raised by IBEW Locals 1464 and 1474.

2. The Commission issued an Order Approving Stipulations and Agreements on August 10, 2016, which, among other things, approved the Stipulation and Agreement As To IBEW 1464 and IBEW 1474.

3. Since that time, the Signatories have determined that certain revisions to the Stipulation and Agreement As To IBEW 1464 and IBEW 1474 would better describe and define the Signatories' intent. Accordingly, the Signatories are providing this Amended Stipulation and

Agreement As To IBEW 1464 and IBEW 1474, and request that the Commission issue an order modifying its Order Approving Stipulations and Agreements dated August 10, 2016 to approve this Amended Stipulation in place of the Stipulation and Agreement As To IBEW 1464 and IBEW 1474 filed July 19, 2016.

The Signatories hereto agree and amend their prior Stipulation and Agreement in its entirety and hereto recommend that the Commission approve the proposed Transaction subject to the following conditions:

(1) There will be no layoff of any current bargaining unit members from either IBEW Local 1464 or 1474 as a result of the Transaction.

(2) Joint Applicants will fully comply with, and not cause any material amendment to, or termination of, the Empire District Electric Company Employees' Retirement Plan, prior to such time as the Retirement Plan may be addressed in the next collective bargaining agreements. Notwithstanding this agreement, Joint Applicants will continue until completed the double Pay Credits provisions of the Cash-Balance formula (commonly referred to as the "catch-up" provisions). Further, nothing in this paragraph prohibits Joint Applicants from making administrative changes to the Employees' Retirement Plan.

(3) All Empire employees formerly employed by Aquila Energy will continue to be covered under their current retirement benefit plan.

(4) For a period of ten years from the Transaction, the Joint Applicants will continue to abide by all agreements currently in force related to employee healthcare for bargaining unit members from IBEW Local 1464 and 1474 and will not change retiree healthcare benefits (defined as plan design and cost share) during the ten years from the Transaction for those bargaining unit members that retire during that ten year period, unless there is an application of

or amendment to the Affordable Care Act, that would impair the ability of Empire to provide the benefit or that substantially increases the cost to Empire of providing such benefits.

General Provisions

A. This Stipulation has resulted from negotiations among the Signatories and the terms hereof are interdependent. In the event the Commission does not adopt this Stipulation in total, then this Stipulation shall be void and no Signatory shall be bound by any of the agreements or provisions hereof. The stipulations herein are specific to the resolution of this proceeding, and all stipulations are made without prejudice to the rights of the Signatories to take other positions in other proceedings except as otherwise provided herein. The Signatories agree that any and all discussions related hereto shall be privileged and shall not be subject to discovery, admissible in evidence, or in any way used, described or discussed.

B. This Stipulation is being entered into for the purpose of disposing of IBEW 1464 and IBEW 1474's issues in this case. The Signatories represent that the terms of this Stipulation constitute a fair and reasonable resolution of the issues addressed herein, in a manner which is not detrimental to the public interest. Except as otherwise addressed herein, none of the Signatories to this Stipulation shall be deemed to have approved, accepted, agreed, consented or acquiesced to any accounting principle, ratemaking principle or cost of service determination underlying, or supposed to underlie any of the issues provided for herein.

C. The Signatories further understand and agree that the provisions of this Stipulation relate only to the specific matters referred to in the Stipulation, and no Signatory or person waives any claim or right which it otherwise may have with

respect to any matter not expressly provided for in this Stipulation. The Signatories further reserve the right to withdraw their support for the settlement in the event that the Commission modifies the Stipulation in a manner which is adverse to the Signatory, and further, the Signatories reserve the right to contest any such Commission order modifying the settlement in a manner which is adverse to the Signatory contesting such Commission order. The Signatories agree that the details of this Stipulation have no precedential value in any future proceeding not related to enforcement of this agreement.

D. The non-utility Signatory Parties enter into this Stipulation in reliance upon information provided to them by the Joint Applicants and this Stipulation is explicitly predicated upon the truth of representations made by the Joint Applicants.

E. In the event the Commission accepts the specific terms of this Stipulation without modification, the Signatories waive, with respect to the issues resolved herein: their respective rights pursuant to Section 536.070(2), RSMo 2000 to call, examine and cross-examine witnesses; their respective rights to present oral argument or written briefs pursuant to Section 536.080.1, RSMo 2000; their respective rights to the reading of the transcript by the Commission pursuant to Section 536.080.2, RSMo 2000; their respective rights to seek rehearing pursuant to Section 386.500, RSMo 2000; and their respective rights to judicial review pursuant to Section 386.510, RSMo 2000. Furthermore, in the event the Commission accepts the specific terms of this Stipulation without modification, the Signatories agree that the pre-filed testimony of all witnesses who have pre-

filed testimony in this case shall be included in the record of this proceeding without the necessity of such witnesses taking the stand.

F. Except as otherwise addressed in this Stipulation, Commission approval of the acquisition by LU Central and Liberty Sub Corp. of the stock of Empire, and for the Joint Applicants to execute and perform in accordance with the terms of the Agreement, does not in any way, limit, form a basis for determination, or constitute a defense against any Signatory proposing, or the Commission ordering, the disallowance and/or imputation of account balances, expenses, revenues and/or other ratemaking findings, regarding Empire's operations in a future rate proceeding.

G. To assist the Commission in its review of this Stipulation, the Signatories also request that the Commission advise them of any additional information that the Commission may desire from the Signatories relating to the matters addressed in this Stipulation, including any procedures for furnishing such information to the Commission.

WHEREFORE, the Signatories hereto recommend that the acquisition by LU Central and Liberty Sub Corp. of the stock of Empire as contemplated by the Agreement and Plan of Merger is reasonable and not detrimental to the public interest and respectfully request that the

Commission modify it Order Approving Stipulations and Agreements dated August 10, 2016 to approve this Amended Stipulation and Agreement As To IBEW 1464 and IBEW 1474 in place of the Stipulation and Agreement As To IBEW 1464 and IBEW 1474 filed July 19, 2016.

Respectfully submitted,

BRYDON, SWEARENGEN & ENGLAND P.C.

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CERTIFICATE OF SERVICE

The undersigned certifies that a true and correct copy of the foregoing document was sent via electronic mail, this 26th day of August, 2016, to the following:

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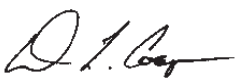

STATE OF MISSOURI

OFFICE OF THE PUBLIC SERVICE COMMISSION

I have compared the preceding copy with the original on file in this office and I do hereby certify the same to be a true copy therefrom and the whole thereof.

WITNESS my hand and seal of the Public Service Commission, at Jefferson City, Missouri, this 7th day of September 2016.

Morris L. Woodruff
Secretary

MOPSC Digitally signed by MOPSC
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Date: 2016.09.07 13:57:21 -05'00'

MISSOURI PUBLIC SERVICE COMMISSION

September 7, 2016

File/Case No. EM-2016-0213

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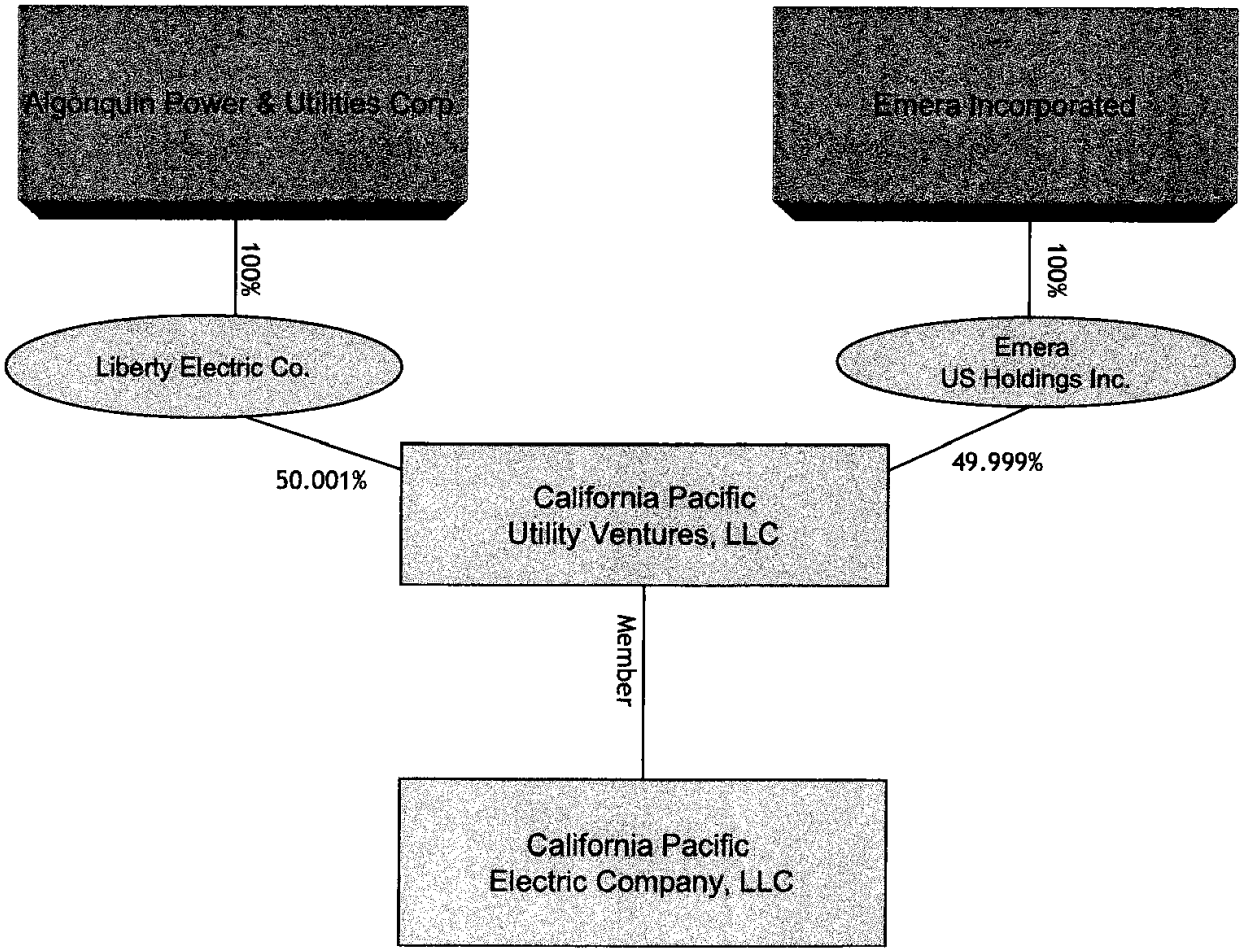
Enclosed find a certified copy of an Order or Notice issued in the above-referenced matter(s).

Sincerely,

Morris L. Woodruff
Secretary

Recipients listed above with a valid e-mail address will receive electronic service. Recipients without a valid e-mail address will receive paper service.

CalPeco Ownership Structure



(END OF APPENDIX 2)

APPENDIX 3

Regulatory Commitments

1. Separateness.

(a) The California Utility[1] shall be held in a separate legal subsidiary (CalPeco) with no other operations. The only other California business activity currently undertaken by Algonquin Power & Utilities Corp. ("Algonquin") and/or by Emera Incorporated ("Emera") and/or their respective affiliates is a non-utility cogeneration power plant in the Fresno area ("Sanger Cogeneration"), which is owned and operated by Algonquin. Sanger Cogeneration sells power only at wholesale. It owns no electric distribution or transmission lines and it serves no retail electric customers. Sanger Cogeneration shall have no ownership or other interest in CalPeco. There shall be no overlapping of employees or responsibilities between the operations of Sanger Cogeneration and CalPeco.

(b) Although each of Algonquin and Emera is an experienced owner/operator of regulated utilities and actively involved in developing and operating electric generating assets, including renewable generation sources, neither Algonquin nor Emera owns utility assets in the State of California subject to public utility regulation. In the event that either Algonquin or Emera were to acquire any other regulated utility in addition to CalPeco:

1. The assets of such other public utility would be held in a legal entity separate from CalPeco;

2. Algonquin or Emera, as the case may be, would segregate the capitalization, financing, and working cash for such other utility and CalPeco in totally separate money pools;

3. There would be no cross ownership or other interests between such other utility and CalPeco; and

4. The operations of such other utility and CalPeco would be totally discrete.

(c) CalPeco will not provide financing or guarantees for, extend credit to, or pledge utility assets in support of either Algonquin or Emera or any of their respective affiliates. Algonquin and Emera each shall finance and fund their respective other business activities independently of CalPeco. The assets of CalPeco shall be used solely and exclusively for the purpose of providing electric distribution services to its customers and securing any debt financing obtained by CalPeco.

[1] Capitalized terms used in the Regulatory Commitments and not otherwise defined in the Regulatory Commitments have the meanings ascribed to such terms in the Joint Application.

(d) To the extent that Algonquin or Emera shall finance its non-utility or any business activities other than CalPeco's provision of public utility service, any such financing shall provide the financing parties no recourse to CalPeco's assets.

(e) CalPeco shall not alter the "ring fencing" provisions set forth in sections 1(a)-1(d) above without first requesting and obtaining approval from the Commission to make any such change.

(f) CalPeco shall not transfer any physical assets used to provide services to its customers to either Algonquin or Emera or any of their respective affiliates without first obtaining the necessary approvals from the Commission and shall in no event request approval to transfer any physical assets if such transfer would impair CalPeco's ability to fulfill its public utility obligations to serve, or to operate in a prudent and efficient manner**.**

(g) Emera and Algonquin will provide sufficient initial equity to fund fifty percent (50%) of the purchase price for CalPeco. CalPeco shall seek to obtain the balance of the required capital necessary for the purchase price through stand-alone debt issued by CalPeco. Algonquin and Emera are prepared to make this initial equity investment and invest any additional equity in CalPeco based on their understanding that the Commission shall grant CalPeco timely recovery in rates (i) for the reasonable expenses it will make or undertake, respectively, to provide electric service; and (ii) for CalPeco to earn a reasonable return of and on CalPeco's investment in rate base. On this basis Emera and Algonquin are committed to ensure that CalPeco maintains sufficient funds to operate and has sufficient capital available for necessary capital investments. CalPeco, Algonquin and Emera acknowledge that dividends or similar distributions by CalPeco may be restricted as necessary to maintain minimum equity levels that are reasonable in relation to any equity ratio requirements.

(h) CalPeco shall hold all of its assets in its own name, and will maintain adequate capital and number of employees in light of its business purposes. CalPeco shall maintain the current level of employees for a period of at least three (3) years.

2. Books and Records.

(a) CalPeco shall maintain separate books and records, systems of accounts, financial statements and bank accounts and shall in all events maintain its books and records in full compliance with Commission, and to the extent applicable, FERC, rules and regulations. All financial books and records of CalPeco will be kept in the California operations office, and, together with any records of any Emera and/or Algonquin affiliate that are relevant to CalPeco (wherever held), will be made available for review by the Commission upon request. Algonquin and Emera will make available to the Commission upon request its books and records and the books and records of any of their respective affiliates that allocate overhead or have operational or financial dealings with CalPeco, including any Algonquin or Emera affiliate that is a recipient of any funds (including dividends

or similar distributions) from CalPeco. Algonquin, Emera and CalPeco have reviewed the Commission's regulations and decisions on affiliate transactions and commit to comply fully with such rules and regulations.

(b) Neither Algonquin nor Emera nor any of their respective affiliates conducts any other business within the geographic proximity of the California Utility. Accordingly, Algonquin and Emera (and their respective affiliates) do not anticipate that CalPeco and either Algonquin and/or Emera (and/or their respective affiliates) will be providing any operations-related services to one another. It is, however, contemplated that Algonquin or Emera (or their respective affiliates) may provide management, administrative, and regulatory services to CalPeco with respect to the California Utility. In the event that Algonquin and/or Emera (and/or or their respective affiliates) provide services to CalPeco or CalPeco provides services to Algonquin and/or Emera (and/or their respective affiliates), CalPeco will develop and file with the Commission such shared services agreements and such agreements will comply with applicable affiliate rules and regulations of the Commission.

3. Operating Commitments.

(a) Credit extended by Algonquin or Emera, jointly or individually, to CalPeco will be at rates and upon terms no less advantageous than those otherwise available to CalPeco from unaffiliated third parties for similar transactions.

(b) CalPeco will conduct business in the same or similar manner as it has under Sierra's ownership concerning functions such as power delivery, contracting and management, system operation and maintenance activities, safety and service reliability, customer service functions, and billing operations. With respect to regulatory relations, CalPeco will maintain a manager level representative (having such authority as may be required by the Commission) physically present in an office located within the California Utility's service territory with primary responsibility for maintaining Sierra's positive relationships with, and responding to requests for information from, the Commission and other regulatory agencies. CalPeco will also engage competent and respected area consultants such as the Davis Wright Tremaine law firm to provide CalPeco with San Francisco-based support and presence with respect to the maintenance of such positive relationship.

(c) For an initial period extending through the filing of the next general rate case for the California Utility, CalPeco will maintain and accept all tariffs of the California Utility existing at the Closing or approved by the Commission in response to filings made by Sierra prior to the Closing and as requested to be modified in this proceeding with respect to (i) the reallocation of certain amounts of revenue recovery from general rate to ECAC rate recovery and (ii) the ECAC tariff as explained and requested at pages 30-37 of the Joint Application (but shall not be required to accept a reduction or roll-back in such rates pursuant to the

Required Regulatory Approvals).[2] In this § 854(a) proceeding, CalPeco is requesting no increase in rates or in the total revenue requirement; on the day after Closing, rates for the customers of the California Utility shall remain at the same rate levels as the day prior to Closing and the total revenue requirement shall remain the same.

(d) CalPeco shall provide service to its customers in compliance with all rules, regulations and decisions issued by the Commission. Among other matters, CalPeco will not change any rate or any other terms and conditions of service for its customers without first having obtained the necessary Commission approvals and CalPeco shall comply with all existing statutes and Commission regulations regarding affiliated interest transactions.

(e) CalPeco agrees to maintain the existing low-income programs as part of the pending request under § 854(a) to acquire the California Utility. CalPeco shall operate within the existing rate case cycles now in effect for Sierra, including for general rates and ECAC rates.

(f) CalPeco and Sierra have entered into a settlement agreement with the Plumas-Sierra Rural Electric Cooperative ("PSREC"), City of Loyalton, City of Portola, Sierra County and Plumas County ("PSREC Settlement"). The PSREC Settlement is Exhibit Q to Exhibit 1 to the proceeding. The PSREC Settlement obligates Sierra and CalPeco to make certain payments to PSREC at specified times and subject to certain conditions. Among these is a payment of $250,000 to be made to PSREC within fifteen days of Closing. Under the terms of the PSREC Settlement, in the event that the Commission were to ultimately approve CalPeco making an $1 million investment in the Herlong Transmission Project (as defined in the PSREC Settlement) and to authorize CalPeco to recover rates on this investment, PSREC has agreed that it will credit the $250,000 payment as an advance payment against CalPeco's $1 million investment. CalPeco and Sierra commit that if CalPeco never requests authority to make an investment in the PSREC Herlong Transmission Project or if CalPeco requests Commission authorization to invest in the Herlong Transmission Project and the Commission rejects such request in its entirety, that CalPeco and Sierra will retain 100% of the cost responsibility for the $250,000 payment to PSREC (i.e., customers will be held harmless).

(g) CalPeco shall adopt, maintain and strive to improve the high quality of service standards that Sierra presently provides its customers.

[2] References to "Joint Application" herein are to the Joint Application of Sierra Pacific Power Company (U903E) and California Pacific Electric Company, LLC for Transfer of Control and Additional Requests Relating to Proposed Transaction filed with the Commission on October 16, 2009, as updated and supplemented by Joint Applicants' letters to Administrative Law Judge Vieth dated April 7, 2010, June 11, 2010, and June 16, 2010.

(h) Algonquin shall own at least fifty percent (50%) of CalPeco for a minimum period of ten (10) years.

(i) CalPeco has requested that the Commission approve that either Algonquin or Emera be allowed to transfer to the other all or any portion of its ownership interest in CalPeco and without the need for any additional approval by the Commission ("Internal Transfer Approval"). The Internal Transfer Approval is described at page 70 and 71 of the Joint Application. In the event that the Commission were to grant the request for the Internal Transfer Approval, Emera and Algonquin will also commit to the following additional terms and conditions:

1. Any reduction in the dollar amount of Emera's direct investment in CalPeco will be made up by an increase in a corresponding dollar amount of Emera's investment in Algonquin;

2. Emera shall maintain its investment in Algonquin for a minimum period of three (3) years;

3. Should Emera use the Internal Transfer Approval process to sell down all or any portion of its direct ownership in CalPeco, Emera nonetheless through its ownership in Algonquin would continue to be active in the oversight of CalPeco in a manner designed to enable CalPeco to continue to realize the benefits of Emera's financial and operating strengths and resources and in developing renewable projects; and

4. Regardless of the authority that the Commission grants with respect to the Internal Transfer Approval with respect to changes of ownership interests in CalPeco between Algonquin and Emera, in no event shall Algonquin reduce for a minimum period of ten (10) years its ownership interest in CalPeco below the fifty percent (50%) interest committed to in Section 3(h) above.

4. Employees and Management Team.

(a) CalPeco intends to the extent practicable to retain the same experienced operations team that has been responsible for operations of the California Utility under Sierra's ownership. Any additional management team members which need to be recruited by CalPeco shall be experienced in electric utility operations.

(b) CalPeco intends to maintain a local headquarters within the California Utility's service territory, including maintaining a local management and customer service headquarters at a location within such service territory.

(c) CalPeco intends to offer each of Sierra's current administration and operations employees located within the service territory employment with CalPeco at the same locations with responsibilities and remuneration consistent with each of their existing roles. Accordingly, CalPeco shall make no material changes in the nature of the employment roles of the California Utility fulfilled by individuals

located within the service territory and intends, to the extent practical, to recruit within the California Utility service territory any additional operations staff necessary to replace functions currently performed by staff of Sierra located in Nevada. CalPeco will recognize the service and seniority of the former employees of Sierra who accept CalPeco's offer of employment for all non-pension purposes including vacation, sick pay benefits and for non-pension post retirement benefits such as retiree health benefits.

5. Premium and Cost Synergies.

(a) CalPeco agrees that its rate recovery shall be calculated based on the regulatory value of the California Utility, as depreciated by Sierra, and totally independent of the purchase price to acquire the California Utility. CalPeco shall in no event seek to recover the excess of the purchase price over the regulatory book value of the utility assets (i.e., "premium") in rates. Any premium which CalPeco shall pay shall not be recorded in the accounts of CalPeco utilized in the establishment of rates and tariffs for the California Utility.

(b) The cost levels CalPeco shall use to request rates in future general rate cases shall be based on the actual recorded cost levels of CalPeco and will incorporate any cost savings synergies arising in comparison to the baseline costs established in Sierra's 2008 rate case with respect to the California Utility.

(c) CalPeco shall not seek to recover from ratepayers the "transaction costs" (e.g. investment banking and legal fees, and perimeter metering costs) associated with its acquisition of the California Utility. CalPeco recognizes that its incurrence of any such "transaction costs" is not related to the provision of electric service to the ratepayers of the California Utility and thus these costs are necessarily to be borne exclusively by its owners.

6. California Regulatory Programs.

(a) Subject to the exemptions which are to be sought pursuant to the Required Regulatory Approvals as set out in the Power Purchase Agreement, CalPeco shall reaffirm Sierra's commitment to comply fully with the California RPS standards, the Commission's GHG Emissions Performance Standard, and the compliance requirements for operators of generating units imposed by the Commission's General Order 167.

(END OF APPENDIX 3)

APPENDIX 4

Excerpt from Joint Application of Joint Applicants' Analysis of FERC "Seven Factor Test" Demonstrating that Distribution Capacity Agreement is Subject to This Commission's Jurisdiction

Because (i) CalPeco will be providing Sierra capacity from the CalPeco distribution facilities for purposes of allowing Sierra to serve its retail customers in Nevada; (ii) Sierra will retain title to the power as it flows through the CalPeco facilities; and (iii) Sierra will be the load-serving distribution utility making the ultimate retail sales, CalPeco's provision of such distribution capacity service is "local distribution" service, appropriately subject to jurisdiction by this Commission. Under current law, while the FERC has exclusive jurisdiction over unbundled retail transmission service in interstate commerce, unbundled local distribution service is within the exclusive jurisdiction of the Commission.

Joint Applicants accordingly request that the Commission: (i) determine that all distribution facilities that will be transferred to CalPeco are properly considered to be "local distribution" facilities under the exclusive jurisdiction of the Commission, (ii) retain regulatory jurisdiction over such facilities after the Closing and assert jurisdiction over the Distribution Capacity Agreement and the transactions contemplated thereby, and (iii) authorize CalPeco to provide such distribution capacity services to Sierra based on the rates and other terms set forth in the agreement.[1]

Background of Jurisdictional Issues

Section 201 of the Federal Power Act[2] establishes exclusive federal jurisdiction for FERC to regulate the transmission of electricity in interstate commerce. Importantly, FERC's jurisdiction over interstate transmission does not extend to the regulation of local distribution services. The distinction between "FERC-jurisdictional transmission" facilities and "State-PUC local distribution" facilities has at times raised an issue as to whether particular facilities are subject to FERC or state regulatory jurisdiction.

[1] CalPeco will be advising the FERC that the Joint Applicants have requested the Commission to assert jurisdiction over the Distribution Capacity Agreement.

[2] 16 U.S.C. § 824(b).

Traditionally, all retail sales of electricity were "bundled" with the delivery service for such sales, requiring the customer to pay an integrated charge that recovered the costs of both power procurement and delivery. FERC traditionally has not attempted to assert jurisdiction over the transmission or distribution component of any retail sales that are "bundled" with delivery of the electricity.

In Order No. 888, FERC required the "unbundling" of wholesale sales of electricity from the transmission service associated with those wholesale sales. FERC accordingly obligated transmission owners to offer a separate transmission service with specific requirements, including, the establishment of separate rates for transmission service and the offering of transmission service according to a standardized OATT.

Some states also began requiring that transmission and distribution providers, who previously sold a bundled retail product, to also "unbundle" the retail sale of power from the delivery component. The transmission service of these now unbundled transactions had previously been regulated by the states as part of a bundled retail product.

In Order No. 888, FERC held that such "transmission" service to such "unbundled" state retail customers would be subject to FERC's exclusive jurisdiction. FERC then had to determine the point at which the distribution facilities transitioned from providing interstate FERC-regulated transmission service to providing state-regulated "local distribution" service. In Order No. 888, FERC identified seven factors that it would consider in assessing whether the service CalPeco will provide under the Distribution Capacity Agreement constitutes service by "transmission" facilities or "local distribution" facilities.

FERC's Seven Factor Test

The seven factors FERC will consider on a case-by-case basis to determine whether particular facilities are local distribution facilities include: (i) local distribution facilities are normally in close proximity to retail customers; (ii) local distribution facilities are primarily radial in character; (iii) power flows into local distribution systems; it rarely, if ever, flows out; (iv) when power enters a local distribution system, it is not reconsigned or transported on to some other market; (v) power entering a local distribution system is consumed in a comparatively restricted geographical area; (vi) meters are based at the transmission/local

distribution interface to measure flows into the local distribution system; and (vii) local distribution systems will be of reduced voltage.[3]

FERC acknowledges that the application of its seven factors is necessarily judgmental, and that not all seven factors have to be satisfied for the facilities to be considered distribution. Importantly, FERC has adopted a policy to accord deference to a state's determination that particular facilities are "local distribution" facilities and are to be subject to the state's regulatory jurisdiction:[4]

> Based on concerns raised by state commissions ...., we have further determined that it is appropriate to provide deference to state commission recommendations regarding certain transmission/local distribution matters that arise when retail wheeling occurs...
>
> * * *
>
> We believe that [this] Commission should take advantage of state regulatory authorities' knowledge and expertise concerning the facilities of the utilities that they regulate.
>
> * * *
>
> Moreover, we recognize that in some cases [this] Commission's seven technical factors may not be fully dispositive and that states may find other technical factors that may be relevant. We will consider jurisdictional recommendations by states that take into account other technical factors that the state believes are appropriate in light of historical uses of particular facilities...
>
> * * *
>
> If the utility's classifications and/or cost allocations are supported by the state regulatory authorities and are consistent with the principles established in the Final Rule [this] Commission will defer to such classifications and/or cost allocations. In order to give such deference, we expect state regulators to specifically evaluate the seven indicators and any other relevant facts and to make recommendations consistent with the essential elements of the Rule.[5]

[3] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,771.

[4] *Id.*, at 31,783.

[5] *Id.*, at 31,783-84.

Thus, Joint Applicants request that this Commission exercise its "knowledge and expertise" concerning the distribution facilities to be used in the Distribution Capacity Agreement, apply FERC's seven factor test, determine that all CalPeco facilities are local distribution facilities, and assert its jurisdiction over the facilities and the Distribution Capacity Agreement.

Application of the Seven Factor Test Demonstrates that Facilities to be Employed in the Distribution Capacity Agreement Should Remain Subject to this Commission's Jurisdiction

Factor 1 - Local distribution facilities are normally in close proximity to retail customers. Sierra's California retail customers are concentrated in the South Lake Tahoe and North Lake Tahoe areas, with smaller clusters of customers in Portola, Loyalton, Truckee, Markleville, and Coleville/Walker. Virtually all of these customers are served by distribution facilities that are within 15 miles of these communities. Distribution facilities in the other areas are located even closer to the customers.

Factor 2 - Local distribution facilities are primarily radial in character. Absent an emergency situation in the Incline Village area, the California Utility distribution facilities are exclusively radial in nature. Power flows over the lines in only one direction, *i.e.*, toward the retail customers where it is consumed, and there is no generation in the area except for the 12 MW Kings Beach Generation Facility. South Lake Tahoe is served by radial lines from Sierra's distribution system in Carson City, Nevada. Sierra's transmission system in Truckee, California serves the North Lake Tahoe area. The remaining areas are also served by radial lines from the Sierra system.

Factor 3 - Power flows into local distribution systems; it rarely, if ever, flows out. Almost all of the power that will flow into CalPeco's system will be consumed by customers within the CalPeco service territory.[6] The only material exception will be the power that Sierra will inject into CalPeco's system for purposes of serving Sierra's retail customers in Stateline, Incline Village and Verdi in accordance with the Distribution Capacity Agreement. CalPeco's

[6] As previously explained, CalPeco and Sierra have also executed the Borderline Customer Agreement for purposes of enabling both Parties to serve customers in their respective service territories and in proximity to the state border with existing facilities. Additionally, Sierra has been selling PG&E a small amount of wholesale power (just over 2 MW) in the Echo Summit, California area for purposes of enabling PG&E to serve its retail load in that area.

estimated total winter peak load of 120 MW is significantly larger than the estimated coincident peak load of approximately 23 MW that will flow to Sierra's Nevada customers in Incline Village, Stateline and Verdi.[7]

Factor 4 - When power enters a local distribution system, it is not reconsigned or transported on to some other market. The only distribution capacity that CalPeco will make available to a third party will be reflected in the Distribution Capacity Agreement and for the specific and limited purpose of enabling Sierra to most cost-effectively serve portions of its retail load in Stateline, Incline Village and Verdi. None of this power will flow into any market other than the isolated areas of Sierra's Nevada service territory referenced in Factor 3 above.

Factor 5 - Power entering a local distribution system is consumed in a comparatively restricted geographical area. The rationale given for Factor 1 applies equally to this factor.

Factor 6 - Meters are based at the transmission/local distribution interface to measure flows into the local distribution system. Perimeter metering will be installed and maintained to measure all flows into and out of CalPeco's distribution system.

Factor 7 - Local distribution systems will be of reduced voltage. Among the distribution assets that Sierra will be convey to CalPeco are 1400 miles of 12.5 kV, 14.4 kV, and 25.9 kV distribution circuits, 75 miles of 60kV distribution lines, and 19 miles of 120 kV distribution lines. The 120 kV and 60 kV lines connect CalPeco's distribution substations to Sierra's transmission and distribution systems. Two of the 120 kV lines connect CalPeco's South Lake Tahoe area with the Sierra distribution system at the Nevada/California state boundary, and the other 120 kV line connects the CalPeco North Lake Tahoe system to the Sierra transmission system at Truckee, California. There are also 60 kV lines in the North Lake Tahoe and South Lake Tahoe systems, and 14.4 kV distribution circuits will serve as interconnection points between the CalPeco and Sierra systems at Incline Village, Stateline, and Verdi.

There is no single definition of the physical or engineering characteristics of a "reduced voltage" distribution line. FERC has approved lines as high as 138 kV as local distribution

[7] A small amount of power is expected to flow from the Kings Beach Generation Facility into western Incline Village on those occasions when Kings Beach is operated to provide reliability backup service to the north Lake Tahoe area in the event of a transmission or distribution outage. Under the Borderline Customer Agreement, power will flow from the CalPeco distribution system across the state line to Sierra's system to serve only three Nevada customers; the amount of power that moves across the state line is *de minimis*.

based on their function. Significantly, in one instance, FERC relied upon the determination of this Commission that the particular 138 kV facilities are local distribution facilities.[8] More recently, FERC also approved 115 kV lines as local distribution.[9]

The limited nature of three 120 kV lines to be transferred to CalPeco and the circumstances of their use, combined with the fact that the remaining lines are at a voltage of 60kV or below, should be considered to satisfy the seventh of FERC's factors. However, even if not all of the transferred lines are technically considered to be "reduced voltage," that result should not outweigh the six other factors clearly supporting the conclusion that the facilities are local distribution facilities that are properly subject to this Commission's jurisdiction.

[8] *Pacific Gas and Electric Company, et al.*, 77 FERC ¶ 61,077 at 61,325 (1996).

[9] *Puget Sound Energy, Inc.*, 110 FERC ¶ 61,229 at 61,856 (2005).

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 20-03 October 13, 2020

Petition of Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty Utilities for approval by the Department of Public Utilities, pursuant to G.L. c. 164, § 96, of the acquisition of Blackstone Gas Company.

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I. INTRODUCTION

On January 15, 2020, Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty Utilities ("Liberty Utilities" or "Company"), pursuant to G.L. c. 164, § 96 ("Section 96"), submitted a petition ("Petition") to the Department of Public Utilities ("Department") for approval of the acquisition of the operations, gas-system assets, and customer base of Blackstone Gas Company ("Blackstone Gas"). As part of the filing, Liberty Utilities requested that the Department, in approving the subject transaction, confirm that the franchise rights and obligations currently held by Blackstone Gas shall be held by Liberty Utilities and that no separate authorization is required under G.L. c. 164, § 21 ("Section 21"). The Department docketed this matter as D.P.U. 20-03.

II. PROCEDURAL HISTORY

On January 23, 2020, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a notice of intervention in this matter pursuant to G.L. c. 12, § 11E(a). On January 30, 2020, the Low-Income Weatherization and Fuel Assistance Program Network ("Network") filed a petition to intervene in this proceeding as a full party, which the Department granted on February 4, 2020. On February 12, 2020, the Department of Energy Resources ("DOER") filed a petition to intervene as a full party, which the Department granted on February 21, 2020. Pursuant to notice duly issued, the Department conducted a public hearing and procedural conference on March 4, 2020.

In support of Liberty Utilities' filing, the Company sponsored the testimony of James M. Sweeney, President, East Region business group, Liberty Utilities Co., and

Vincent P. Duffy, the Company's Director of Regulatory Affairs. The Attorney General sponsored the testimony of Timothy Newhard, financial analyst with the Attorney General's Office of Ratepayer Advocacy.

On July 15, 2020, the Company, Attorney General, and Network ("Settling Parties") submitted the following documents: (1) a Joint Motion for Approval of Settlement ("Joint Motion"); (2) the associated Settlement Agreement; and (3) an Explanatory Statement.[1] In the Joint Motion, the Settling Parties request that the Department find that (1) the terms of the Settlement Agreement are reasonable and (2) implementation of the terms of the Settlement Agreement will result in an overall net benefit to customers of both Blackstone Gas and Liberty Utilities (Joint Motion at 2). As explained in further detail below, by its terms, the Settlement Agreement is deemed withdrawn, unless the Department approves the entire Settlement Agreement by October 15, 2020. No comments were filed relative to the proposed Settlement Agreement. The record consists of approximately 190 exhibits.[2]

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1 The Department required that any settlement be accompanied by an explanatory statement to facilitate review that included a procedural history, a section-by-Section summary of the settlement, the issues underlying the settlement and the major implications of the settlement, whether any of the issues raise policy implications, whether other pending proceedings may be affected, whether the settlement involves issues of first impression, if there is any change in treatment from a previously decided issue, and any other materials needed to evaluate the settlement. D.P.U. 20-03, Hearing Officer Memorandum (May 29, 2020).

2 The Department, on its own motion, moves the following documents into the evidentiary record: (1) the Company's direct testimony and attachments supporting its initial filing; (2) the Company's responses to nine sets of information requests; (3) the Attorney General's direct testimony and supporting attachments; (4) the Attorney General's responses to one set of information requests; (5) the Joint Motion, Settlement Agreement and Explanatory Statement; and (6) and the Settling Parties'

III. DESCRIPTION OF THE PROPOSED TRANSACTION

A. The Companies

Liberty Utilities, which consists of the former New England Gas Company assets, is a local natural gas distribution company subject to the Department's jurisdiction under G.L. c. 164 (Exh. LU-JMS-1, at 6). The Company is a wholly owned subsidiary of Liberty Utilities Co., which in turn is an indirect subsidiary of Algonquin Power and Utilities Corp. ("APUC") (Exh. LU-JMS-1, at 6). Liberty Utilities provides natural gas distribution service to approximately 56,500 customers in six communities located in the southeastern portion of Massachusetts, including Fall River, North Attleboro, Plainville, Swansea, Somerset, and Westport (Exh. LU-JMS-1, at 6-7). The Company's customer base consists of a mix of residential, commercial, and industrial customers (Exh. LU-JMS-1, at 7).

Blackstone Gas also is a local natural gas distribution company subject to the Department's jurisdiction under G.L. c. 164 (Exh. LU-JMS-1, at 6). Blackstone Gas serves approximately 1,900 customers in the towns of Blackstone, Bellingham, and Wrentham (Exh. LU-JMS-1, at 6). Blackstone Gas is a sole proprietorship organized as a Massachusetts corporation, and its issued and outstanding shares of stock are owned by a single stockholder, who also is the president of Blackstone Gas (Exh. LU-JMS-1, at 6).

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responses to two sets of information requests regarding the proposed Settlement Agreement. Further, the Department notes that no party requested an evidentiary hearing, and we find that the evidentiary record in this docket provides an adequate basis to address the issues raised in the Settlement Agreement without the need for an adjudicatory hearing.

Blackstone Gas' customer base includes residential heating and non-heating customers and small, low-load commercial customers (Exh. LU-JMS-1, at 6).

B. The Proposed Acquisition

Pursuant to an Agreement and Plan of Merger dated October 31, 2019, Liberty Utilities will acquire the operations, gas-system assets, and customer base of Blackstone Gas through the purchase of the issued and outstanding common stock held by Blackstone Gas' sole shareholder[3] for a price of $5,500,000, plus closing adjustments[4] (Exhs. LU-JMS-1, at 7; LU-JMS-2, at 15, 19-22, 115; DPU 2-2). Upon closing of the proposed transaction,[5] the Blackstone Gas corporate entity will merge with and into Liberty Utilities, and the separate corporate existence of Blackstone Gas will cease to exist (Exh. LU-JMS-1, at 7, 17). Further, upon closing, Liberty Utilities will continue as the surviving corporation, with the operations, assets, and customers of Blackstone Gas consolidated into that of Liberty Utilities (Exh. LU-JMS-1, at 7, 17).

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3 Specifically, Liberty Utilities will acquire 418 shares of common stock, at a par value of $25.00 per share (Exh. LU-JMS-1, at 7).

4 The closing adjustments relate to the actual amount of working capital at closing, which will either increase or decrease the final acquisition price (Exhs. LU-JMS-1, at 7; DPU 2-2).

5 The Company anticipated closing the acquisition within 30 days of approval by the Department and Liberty Utilities' regional board of directors (Exh. DPU 3-6). The Company states that as a Delaware corporation, it is not required to obtain shareholder approval of the proposed acquisition (Exhs. LU-JMS-1, at 19; DPU 1-10).

Regarding Blackstone Gas customers post-acquisition, nearly all will take service under the same rate schedules and terms of service as all other Liberty Utilities customers,[6] with a limited exception applying to a subset of low-use customers on the Blackstone Gas system who will continue to be assessed the current Blackstone Gas customer charge (Exh. LU-VPD-1, at 12-13). Blackstone Gas' operations employees will become employees within the Liberty Utilities organization (Exh. LU-JMS-1, at 17-18). Finally, as part of its filing, Liberty Utilities proposed to treat Blackstone Gas' assets as a $5,500,000 addition to Liberty Utilities' plant in service, to be rolled into rate base in the Company's next base distribution rate case (Exhs. LU-JMS-1, at 16; LU-VPD-1, at 14-15).

IV. DESCRIPTION OF THE PROPOSED SETTLEMENT AGREEMENT

A. Introduction

According to the Settlement Agreement, the Settling Parties agree that the Company's proposed acquisition of Blackstone Gas, as submitted to the Department for approval, is

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[6] Liberty Utilities and Blackstone Gas have similar residential rate classes, consisting of the following: Rate R-1, non-heating; Rate R-2, low-income non-heating; Rate R-3, heating; and Rate R-4, low-income heating (Exh. LU-VPD-1, at 6-7). Thus, Blackstone Gas residential customers will be assigned to Liberty Utilities' rate classes based on the corresponding Liberty Utilities tariff definitions (Exh. LU-VPD-1, at 6-7). Further, Blackstone Gas' single commercial and industrial ("C&I") rate class (Rate G-1) and its School Rate Schedule (Rate S-1), will be assigned to a Liberty Utilities rate class using a volume data set for the calendar year 2018 (Exh. LU-VPD-1, at 7). Thus, Blackstone Gas' C&I customers will be assigned to Liberty Utilities' rate classes as follows: Rate G-41, low volume low load factor; Rate G-42, medium volume low load factor; Rate G-51, low volume high load factor; and Rate G-52, medium volume high low factor (Exh. LU-VPD-1, at 7). The S-1 customers will be assigned to Liberty Utilities' rate class G-42 (Exh. LU-VPD-1, at 7).

consistent with the public interest as required by Section 96 (Settlement Agreement, § 2.1.1). Further, the Settling Parties agree that upon closing of the transaction to acquire Blackstone Gas, Liberty Utilities will continue to be subject to the same obligations that were respectively held by each of those companies prior to the acquisition, and that further action, pursuant to Section 21, is not required to consummate the proposed transaction (Settlement Agreement, § 2.1.1).

B. Organizational Structure

The Settlement Agreement provides that the proposed acquisition will result in no changes to Liberty Utilities' organizational structure (Settlement Agreement, § 1.5). The Settling Parties agree that seven of the nine current employees of Blackstone Gas are operations employees who will become employees within the Liberty Utilities organization (Settlement Agreement, § 1.5). The two individuals who will not join Liberty Utilities are management employees who elected to withdraw upon closing (Settlement Agreement, § 1.5).

C. Transfer of Blackstone Gas Customers to Liberty Utilities' Rate Classes

The Settlement Agreement provides that upon its approval, Liberty Utilities shall be authorized to transfer Blackstone Gas customers into comparable and equivalent customer rate classes established under existing, currently effective Liberty Utilities rate tariffs as early as possible, with three exceptions (Settlement Agreement, § 2.2.1). First, the Company will maintain the current existing separate Gas Adjustment Factors ("GAFs") for the existing customers of Blackstone Gas and Liberty Utilities until the Department has an opportunity to

review and approve the consolidation of the GAFs in a separate future proceeding (Settlement Agreement, § 2.2.2).

Second, the Gas System Enhancement Plan ("GSEP") costs for Liberty Utilities customers shall not be recoverable from any current Blackstone Gas customer through Liberty Utilities' GSEP factor for a period of at least ten years from the date of the subject acquisition closing, and after that, only upon Department approval in a base distribution rate proceeding filed pursuant to G.L. c. 164, § 94 ("Section 94") (Settlement Agreement, § 2.2.3). Third, of the 1,911 Blackstone Gas customers that will become customers of Liberty Utilities, approximately 140 low-use customers would experience a rate increase under the Company's rate tariffs at the current customer charge associated with the respective tariffs (Settlement Agreement, § 2.2.4). Thus, the Settlement Agreement provides that, to mitigate the impact on these affected customers, the Company will hold the customer charge at the current Blackstone Gas level for the low-use customers transferring to Liberty Utilities rate classes R-1, G-41, and G-51 (Settlement Agreement, § 2.2.4).[7] The Settlement Agreement further provides that this arrangement will remain in place until the Company's next base distribution rate case (Settlement Agreement, § 2.2.6).

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[7] The Settlement Agreement provides that upon its approval, the Company will submit a compliance filing, including tariffs applicable to customers in rate classes R-1, G-41, and G-51 that will indicate that these customers will be billed as Liberty Utilities customers for all rate components other than the customer charge (Settlement Agreement, § 2.2.6).

The Settlement Agreement also provides that Blackstone Gas customers taking service on two low-income rate classes (i.e., rate classes R-2 and R-4), will receive the benefit of an increase in the low-income discount rate once those customers are transitioned onto the Liberty Utilities rate schedules (Settlement Agreement, § 2.2.5).[8]

D. Distribution Rate Freeze

The Settlement Agreement provides that upon its approval, Liberty Utilities shall not seek a base distribution rate increase pursuant to Section 94 to become effective before November 1, 2022 (Settlement Agreement, § 2.3.1).[9] Further, the Settlement Agreement provides that upon closing of the subject acquisition, Blackstone Gas shall cease to exist and shall be ineligible to request future base rate changes except as a consolidated part of any Liberty Utilities base distribution rate proceeding (Settlement Agreement, § 2.3.1).

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[8] The Settlement Agreement notes that as of March 31, 2020, there were 116 Blackstone Gas low-income customers, and that rate class R-2 received a 14-percent low-income discount, while rate class R-4 received a 15.8-percent discount (Settlement Agreement, § 2.2.5). The Settlement Agreement further notes that Liberty Utilities' low-income discount rate is 25 percent (Settlement Agreement, § 2.2.5).

[9] Pursuant to the Settlement Agreement, the creation of any new reconciling rate recovery factor shall be deemed a base distribution rate increase and, therefore, may not become effective before November 1, 2022, unless mandated by statute (Settlement Agreement, § 2.3.2). The Settlement Agreement provides that this rate freeze provision is not intended to apply to any reconciling rate recovery factor in existence as of the effective date of the Settlement Agreement (Settlement Agreement, § 2.3.2). Further, the Settlement Agreement provides that this provision shall not preclude Liberty Utilities from implementing ratemaking mechanisms approved by the Department for all Massachusetts investor-owned local distribution gas companies to address impacts of the COVID-19 pandemic (Settlement Agreement, § 2.3.2).

E. Cost Reductions

The Settlement Agreement provides that Liberty Utilities customers should experience economic benefits from the proposed transaction resulting from an overall expansion of the customer base, thus spreading the Company's cost of service over a greater number of customers, which, all else equal, will serve to mitigate cost pressures going forward (Settlement Agreement, § 1.6). Further, pursuant to the Settlement Agreement, the Company asserts that it will achieve operating cost reductions for labor and labor-related costs, as well as the elimination of outside vendor costs estimated at $475,000, annually (Settlement Agreement, § 2.4.3).

F. Ratemaking Considerations

The Settlement Agreement provides that, at the time of Liberty Utilities' next base distribution rate proceeding, the Company shall be authorized to submit a unified cost of service for the consolidated customer base of Liberty Utilities and Blackstone Gas customers (Settlement Agreement, § 2.4.1).[10] Further, pursuant to the Settlement Agreement, Liberty Utilities shall be eligible to incorporate Blackstone Gas' original, historical-cost plant-in-service and other routine rate base components existing on its books of account at the end of the test year, into the respective books of account for Liberty Utilities for ratemaking

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10 Pursuant to the Settlement Agreement, at the time of Liberty Utilities' next base distribution rate proceeding, Blackstone Gas customers will be fully integrated into the Company's system and all rate mechanisms encompassed within its tariffs will be applicable to Blackstone Gas customers as part of the Liberty Utilities' customer base, with the exception of the GSEP-related costs noted above (Settlement Agreement, § 2.4.1).

purposes (Settlement Agreement, § 2.4.2). The Settlement Agreement notes that Liberty Utilities has accepted this rate base computation in accordance with Department ratemaking practice, although it differs from the recovery of rate base indicated in the Agreement and Plan of Merger dated October 31, 2019 (Settlement Agreement, § 2.4.2 & n.1).

In addition, at the time of Liberty Utilities' next base distribution rate proceeding, the Settlement Agreement provides that the Company shall be eligible to include an expense line item of $252,719 in the unified cost of service, representing the recovery of acquisition-related costs (Settlement Agreement, § 2.4.4).[11] Further, pursuant to the Settlement Agreement, the Company shall be eligible to propose to recover acquisition-related integration costs upon a showing that actual operating and maintenance cost reductions were equal to or greater than the sum of (a) $252,719, and (b) the amount of the amortization of the acquisition-related integration costs over a ten-year period on a straight-line basis (Settlement Agreement, § 2.4.5). The Settlement Agreement also provides that the Company shall not be eligible to recover transaction costs, which the Settlement Agreement states are the costs incurred to enter into the Agreement and Plan of Merger and obtain Department approval of the transaction (Settlement Agreement, § 2.4.5).

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[11] According to the Settlement Agreement, this expense item shall be included in base rates and recovered by Liberty Utilities as a revenue requirement component in the total amount of $252,719 over a 30-year period, starting with the implementation of new base rates approved by the Department in the future base distribution rate proceeding (Settlement Agreement, § 2.4.4).

G. Energy Efficiency

The Settlement Agreement provides that Liberty Utilities will assume responsibility from Boston Gas Company d/b/a National Grid ("National Grid") for providing gas energy efficiency services to Blackstone Gas customers at an administratively feasible date after closing (Settlement Agreement, § 2.5.1).[12] According to the Settlement Agreement, Liberty Utilities will transfer Blackstone Gas customers to the Company's existing energy efficiency tracking system; will develop and conduct a mailing to all Blackstone Gas customers introducing Liberty Utilities and marketing the energy efficiency rebates and all program offers; will update content and components on MassSave.com; and will take steps to tailor offerings to Blackstone Gas customers to the extent possible (Settlement Agreement, § 2.5.1).

H. Other Settlement Terms

The Settlement Agreement states that (1) it shall not constitute an admission by any party that any allegation or contention in this proceeding is true or false; (2) it establishes no principles and, except as to those issues resolved by approval of this Settlement Agreement, shall not foreclose any party from making any contention in any future proceedings; and (3) the entry of an Order by the Department approving the Settlement Agreement shall not in any respect constitute a determination by the Department as to the merits of any other issue raised in this proceeding, except as specified in the Settlement Agreement to accomplish the

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12 Under a service agreement approved by the Department, effective January 1, 2016, National Grid provides gas energy efficiency services to Blackstone Gas customers (Exh. LU-JMS-1, at 28). Blackstone Gas Company, Boston Gas Company, Colonial Gas Company, D.P.U. 15-79 (2015).

customer benefit intended by this Settlement Agreement (Settlement Agreement, §§ 3.1, 3.2). The Settlement Agreement provides that the Settling Parties agree that the content of settlement negotiations, including work papers and documents produced in connection with the Settlement Agreement, is confidential (Settlement Agreement, § 3.3). The Settlement Agreement also states that all offers of settlement are without prejudice to the position of any party or participant presenting such offer or participating in such discussion and that the content of settlement negotiations are not to be used in any manner with these or other proceedings involving the parties to this Settlement Agreement (Settlement Agreement, § 3.3).

The Settlement Agreement provides that its provisions are not severable and that the Settlement Agreement is conditioned on approval in full by the Department, as well as the provision of accurate and truthful information by the Company during the settlement negotiation process (Settlement Agreement, § 3.4). Further, the Settlement Agreement provides that if it is not approved by the Department in its entirety by October 15, 2020, the Settlement Agreement filing shall be deemed to be withdrawn and shall not constitute a part of the record in any proceeding or used for any other purpose (Settlement Agreement, § 3.5).

The Settlement Agreement provides that, from time to time during the term of the Settlement Agreement, the Attorney General may request in writing that the Company respond to informal information requests pursuant to G.L. c. 12, § 11E(c) regarding any matter related to the Settlement Agreement, the filing or subsequent compliance filings and rates, charges or tariffs, and that the Company shall answer these information requests in a

reasonably prompt manner, not to exceed 21 calendar days from issuance (Settlement Agreement, § 3.6). Further, according to the Settlement Agreement, nothing in the Settlement Agreement shall be construed to limit the Attorney General's right to petition the Department for a review of the Company under G.L. c. 164, § 93 or otherwise under law or regulation, for a review of the Company for any reason (Settlement Agreement, § 3.7).

The Settlement Agreement also provides that settlement of this proceeding does not establish any precedent or principles of law for use or application in any other proceeding before the Department, any court of law, administrative agency, or any other adjudicatory body (Settlement Agreement, § 3.7). Finally, the Settlement Agreement provides that it shall be governed by Massachusetts law and not the law of some other state; that it shall be effective upon approval by the Department, regardless of any pending appeals or motions for reconsideration, clarification, or recalculation; and that the obligations imposed in each article shall expire on that date stated therein, if any (Settlement Agreement, § 3.8).

V. STANDARDS OF REVIEW

A. Section 96

Section 96 sets forth the Department's authority to review and approve mergers, consolidations, sales and acquisitions, and changes of control of electric, gas, water companies, and holding companies of electric or gas companies. As a condition for approval, the Department must find that the proposed transaction is "consistent with the public interest." Section 96(b), (c). For purposes of demonstrating that a Section 96 transaction is consistent with the public interest, a petitioner must show "net benefits."

NSTAR/Northeast Utilities Merger, D.P.U. 10-170, Interlocutory Order on Standard of Review at 21 (March 10, 2011). Accordingly, petitioners must demonstrate that the benefits of a consolidation, merger, sale or acquisition, or change of control outweigh the costs. D.P.U. 10-170, Interlocutory Order on Standard of Review at 21-22, 26-27 (March 10, 2011). To determine whether petitioners have satisfactorily met this burden, the Department will consider any special factors surrounding an individual proposal. D.P.U. 10-170, Interlocutory Order on Standard of Review at 26-27 (March 10, 2011).

Historically, the Department held that various factors may be considered in determining whether a Section 96 transaction is consistent with the public interest. Traditionally, the Department considered the following factors: (1) effect on rates; (2) effect on the quality of service; (3) resulting net savings; (4) effect on competition; (5) financial integrity of the post-merger entity; (6) fairness of the distribution of resulting benefits between shareholders and ratepayers; (7) societal costs; (8) effect on economic development; and (9) alternatives to the merger or acquisition. Guidelines and Standards for Mergers and Acquisitions, D.P.U. 93-167-A at 7-9 (1994) ("Mergers and Acquisitions"). In 2008, the Legislature has amended Section 96(b), (c) to require the Department to consider, at a minimum, the following four factors: (1) potential rate changes, if any; (2) long-term strategies that will assure a reliable, cost-effective energy delivery system; (3) any anticipated interruptions in service; and (4) other factors that may negatively impact customer service.[13]

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[13] In 2012, the Legislature reorganized Section 96, adding new provisions and incorporating these four factors into Sections 96(b), (c). St. 2012, c. 209, § 21.

The second statutory factor, regarding long-term strategies, is the only factor not previously included in the nine factors outlined in Mergers and Acquisitions at 7-9.[14] The Department continues also to consider the traditional factors, but has held that this list of factors is illustrative and not "exhaustive," and the Department may consider other factors, or a subset of these factors, when evaluating a Section 96 proposal. Eastern Utilities Associates/New England Electric System Merger, D.T.E. 99-47, at 17-18 (2000); BEC Energy/Commonwealth Energy System Merger, D.T.E. 99-19, at 11-12 (1999); Eastern Enterprises/Colonial Gas Company Merger, D.T.E. 98-128, at 6 (1999). No one factor is controlling.

The Department's determination as to whether a proposed transaction meets the requirements of Section 96 must rest on a record that quantifies costs and benefits, to the extent such quantification can be made. D.T.E. 99-47, at 17-18. The Department also may undertake a more qualitative analysis of those aspects that are hard to measure. D.P.U. 10-170, Interlocutory Order on Standard of Review at 27 (March 10, 2011); Mergers and Acquisitions at 7-9. A Section 96 petition cannot rest on generalities, but must instead demonstrate benefits that outweigh the costs, including the cost of any acquisition premium sought. D.P.U. 10-170, Interlocutory Order on Standard of Review at 21-22, 27 (March 10,

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[14] The remaining statutory factors correspond to factors in Mergers and Acquisitions at 7-9. Specifically, the first factor in Section 96 is subsumed by the first factor in Mergers and Acquisitions, the effect of the proposed transaction on rates. The third and fourth factors delineated in Section 96 correspond to the second factor in Mergers and Acquisitions, the effect on the quality of service.

2011); D.T.E. 99-47, at 18; D.T.E. 99-19, at 12; D.T.E. 98-128, at 7; Bay State Gas Company/NIPSCO Acquisition Company Merger, D.T.E. 98-31, at 11 (1998); Eastern Enterprises/Essex Gas Company Merger, D.T.E. 98-27, at 10 (1998); Mergers and Acquisitions at 7-9.[15]

B. Settlements

In assessing the reasonableness of an offer of settlement, the Department reviews all available information to ensure that the settlement is consistent with Department precedent and the public interest. Fall River Gas Company, D.P.U. 96-60 (1996); Essex County Gas Company, D.P.U. 96-70 (1996); Boston Edison Company, D.P.U. 92-130-D, at 5 (1996); Bay State Gas Company, D.P.U. 95-104, at 14-15 (1995); Boston Edison Company, D.P.U. 88-28/88-48/89-100, at 9 (1989). A settlement among the parties does not relieve the Department of its statutory obligation to conclude its investigation with a finding that a just and reasonable outcome will result. D.P.U. 95-104, at 15; D.P.U. 88-28/88-48/89-100, at 9.

VI. ANALYSIS AND FINDINGS

A. Introduction

The Department fully supports the use of settlement negotiations as a means through which a company can satisfy its obligation to provide safe, reliable, least-cost utility service

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[15] An acquisition premium, or goodwill, is generally defined as representing the difference between the purchase price paid by a utility to acquire plant that previously had been placed into service by another entity and the net depreciated cost of the acquired plant to the previous owner. Mergers and Acquisitions at 9.

to ratepayers. See Integrated Resource Planning, D.P.U. 94-162, at 18 (1995). In considering the proposed acquisition, as recast in the proposed Settlement Agreement, and in light of the standard of review above, the Department's analysis will focus on the following factors: (1) potential rate changes at the time of the transaction, if any; (2) long-term strategies that will assure a reliable, cost-effective gas delivery system; (3) any anticipated interruptions in service, other factors that may negatively impact customer service, and any effects on the quality of service; (4) resulting net savings of the proposed acquisition; (5) fairness of the distribution of resulting benefits between shareholders and ratepayers; (6) societal costs and effect on economic development; and (7) the financial integrity of the post-acquisition entities.

B. Specific Acquisition Issues

1. Potential Rates Changes

In considering whether a proposed acquisition is consistent with the public interest, the Department must consider "potential rate changes, if any." Section 96(b), (c). The Settlement Agreement contains several provisions that will impact rates.

First, Blackstone Gas customers will be transferred into comparable and equivalent customer rate classes established under existing, currently effective Liberty Utilities rate tariffs, with three exceptions (Settlement Agreement, §§ 2.2.1, § 2.2.5). These exceptions are that (1) separate GAFs will remain in place for existing Blackstone Gas and Liberty Utilities customers until the Department has an opportunity to review and approve the

consolidation of the GAFs in a separate future proceeding;[16] (2) Liberty Utilities will not recover GSEP-related costs from existing Blackstone Gas customers through a GSEP factor for a period of at least ten years from the date of the subject acquisition closing, and after that, the GSEP factor would apply to Blackstone customers only upon Department approval in a base distribution rate proceeding filed pursuant to Section 94; and (3) the Company will hold the customer charge at the current Blackstone Gas level for the low-use customers transferring to Liberty Utilities rate classes R-1, G-41 and G-51 (Settlement Agreement, §§ 2.2.2, 2.2.3, 2.2.4).

The Department finds that the transfer of Blackstone Gas customers into comparable and equivalent Liberty Utilities customer rate classes, subject to the exceptions set forth above, will result in a base distribution rate decrease for all Blackstone Gas customers in all rate classes (Exhs. LU-JMS-1, at 25, 29; LU-VPD-1, at 9-14; LU-VPD-3; LU-VPD-4; DPU 4-4; DPU 4-5; AG 1-29, Att.). Further, although Blackstone Gas customers' existing GAF will remain in place and those customers will not bear any of Liberty Utilities' GSEP costs for some time, Liberty Utilities customers nevertheless likely will benefit from additional revenues and an overall expansion of the customer base, thus spreading the

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16 Liberty Utilities states that separate GAFs are appropriate because the Company and Blackstone Gas are each served by a different interstate natural gas pipeline (Liberty Utilities is served by Algonquin Gas Transmission, LLC and Blackstone Gas is served by Tennessee Gas Pipeline, LLC) with separate delivery points, and they have separate forecast and supply plans approved by the Department (Exh. DPU 2-21). Liberty Utilities states that over time it will assess whether there is value for customers in consolidating the GAFs (Exh. DPU 2-21).

Company's cost of service over a greater number of customers (Exhs. LU-JMS-1, at 22; LU-VPD-1, at 9, 14; LU-VPD-5; DPU 3-2). Additionally, to the extent that reconciliation factors operating outside of base rates are charged to Blackstone Gas customers under Liberty Utilities' rate tariffs, those factors will be reduced for all existing Liberty Utilities customers (Exhs. DPU 3-2; DPU 3-3).

Second, the Settlement Agreement provides for a base distribution rate freeze applicable to all existing Blackstone Gas and Liberty Utilities customers, during which the Company cannot seek a base distribution rate increase pursuant to Section 94 to become effective before November 1, 2022 (Settlement Agreement, § 2.3.1). In the absence of a base distribution rate freeze, we cannot know today the precise timing of any filing by Liberty Utilities for a base distribution rate increase, whether the Department would grant any rate increase, and if so, the amount of any such increase.[17] Thus, the savings associated with the proposed rate freeze cannot be determined with any level of precision. It stands to reason, however, that ratepayers will benefit from the certainty of no increases in base rates until November 1, 2022, at the earliest, when compared to the possibility of a base distribution rate increase occurring during that time period. See UIL Holdings Corporation

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17 The Company's last base distribution rate increase was granted in 2016 as part of a settlement. Liberty Utilities (New England Natural Gas Company) Corp., D.P.U. 15-75 (2015). Pursuant to Section 94, the Company may file for a general increase in rates and is required to submit rate schedules in intervals no longer than ten years. In its initial filing, prior to submission of the proposed Settlement Agreement, the Company noted that it expected to file a base distribution rate proceeding within the next five years (Exh. LU-JMS-1, at 15).

and Iberdrola USA, Inc., D.P.U. 15-26, at 20 (2015); New England Gas Company, D.P.U. 13-07-A at 42 (2013); D.T.E. 98-31, at 16 & n.22.[18]

Third, the Settlement Agreement contains additional provisions designed to produce no adverse changes in rates at the time of closing. Specifically, the Settlement Agreement provides that the Company shall not be eligible to recover any transaction costs associated with the proposed acquisition (Settlement Agreement, § 2.4.5). Further, and as discussed in more detail in Section VI.B.4 below, the Settlement Agreement postpones the recovery of certain acquisition costs and the potential recovery of certain acquisition-related integration costs until the Company's next base distribution rate proceeding. In addition, the Settlement Agreement does not provide for the recovery of goodwill (Exh. DPU-SP 2-1).[19] The

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[18] The Department notes that consistent with other rate freezes approved by the Department, the base rate freeze here applies only to base distribution rates. See, e.g., Fitchburg Gas and Electric Light Company (Electric Division), D.P.U. 19-130, at 8, 15-16 (April 17, 2020); Fitchburg Electric Light Company (Gas Division), D.P.U. 19-131, at 6, 14-15 (February 28, 2020); NSTAR/Northeast Utilities Merger, D.P.U. 10-170-B at 40 (2012); Fall River Gas Company/Southern Union Company Merger, D.T.E. 00-25, at 4 (2000); North Attleboro Gas Company/Providence Energy Company/Southern Union Company, D.T.E. 00-26, at 4 (2000); D.T.E. 99-47, at 4; D.T.E. 99-19, at 13; D.T.E. 98-128, at 8; D.T.E. 98-31, at 12; D.T.E. 98-27, at 10. Thus, there are reconciling components of ratepayers' bills that will not remain fixed at their current charge during the rate freeze period. Because these reconciling mechanisms recover costs on a dollar-for-dollar basis, they will increase or decrease from one year to the next.

[19] In a business combination transaction such a this, the difference between the purchase price paid by a utility to acquire plant that previously had been placed into service and the net depreciated cost of the acquired plant to the previous owner is treated as an acquisition premium and recorded as goodwill. Mergers and Acquisitions at 9.

Department finds that these provisions ensure that, at the time of closing, any potential rate changes will benefit Blackstone Gas and Liberty Utilities customers.

2. Long-Term Strategies

In considering whether a proposed acquisition is consistent with the public interest, the Department must consider "long-term strategies that will assure a reliable, cost effective energy delivery system." Section 96(b), (c). In this regard, the Department has noted that activities and commitments that advance clean energy development and address climate change are important components of this Section 96 factor. NSTAR/Northeast Utilities Merger, D.P.U. 10-170-B at 76-77 (2012).

Neither the Settlement Agreement nor the record supporting the proposed acquisition directly address clean energy development or climate change. Rather, the Company emphasizes its positive service quality record and maintains that its strong financial profile and operating expertise will ensure consistent and adequate capital investments necessary to ensure the safe and reliable performance of the Blackstone Gas system (Exh. LU-JMS-1, at 27-28, 35). Further, the Company points to anticipated improvements in energy-efficiency offerings to Blackstone Gas customers (Exhs. LU-JMS-1, at 35; DPU 1-18). In this regard, the Settlement Agreement states that Liberty Utilities will assume responsibility from National Grid for providing gas energy efficiency services to Blackstone Gas customers (Settlement Agreement, § 2.5.1). The Company states that it will develop a mutually agreed-upon plan and timeline in collaboration with National Grid to ensure a seamless transition of providing gas energy efficiency services to Blackstone Gas customers

(Exh. AG 1-19). Liberty Utilities states that this change in administration will allow the Company to provide Blackstone Gas customers with robust integrated energy efficiency offerings that are tailored more specifically to their needs (Exhs. LU-JMS-1, at 28, 35; AG 1-19; Settlement Agreement, § 2.5.1).

During the course of this proceeding, Liberty Utilities noted that preliminary discussions with National Grid personnel had taken place, but that the Company had not yet formulated a plan and timeline to transfer responsibility for providing gas energy efficiency services to Blackstone Gas customers because "it is dependent upon the approval and timing of this transaction" (Exhs. DPU 1-13; AG 1-19). The Settlement Agreement provides no definitive plan or timeline, but simply notes that Liberty Utilities would assume responsibility for providing such services "at an administratively feasible date after closing" (Settlement Agreement, § 2.5.1). The Department finds that it is reasonable and appropriate for the Company to assume responsibility for providing gas energy efficiency services to Blackstone Gas customers. We expect the Company to finalize a plan to transfer responsibility from National Grid as expeditiously as possible following the close of the acquisition, so that the Company is able to incorporate Blackstone Gas customers into its upcoming three-year energy efficiency plan for the 2022-2024 term (Exh. DPU 3-5).

Based on the above considerations, the Department finds that the Company has sufficiently demonstrated that it is committed to long-term strategies that will ensure a reliable, cost effective energy delivery system for Blackstone Gas customers.

3. Customer Service/Service Quality

In determining whether the Settlement Agreement is consistent with the public interest, the Department must consider "anticipated interruptions in service," as well as "other factors that may negatively impact customer service." Section 96(b), (c). The Department also may consider any effects on the quality of service. Mergers and Acquisitions at 7-8. The Department recognizes the importance of maintaining service quality standards, especially when an acquisition results in a merger of companies and such merger (and the resultant economies of scale realized to achieve cost savings) could result in service quality degradation. Boston Gas Company/Essex Gas Company, D.P.U. 09-139, at 23 (2000); D.T.E. 98-27, at 33 n.27.

Liberty Utilities intends to take a number of steps to address customer service/service quality and to promote public safety, including the following: (1) upgrading its SCADA program to connect to the Blackstone Gas distribution system;[20] (2) transferring Blackstone Gas customers to the Company's information and billing system;[21] (3) providing Blackstone

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[20] SCADA refers to a supervisory control and data acquisition computer and telemetry system that provides for the operation, control, and optimization of a gas company's distribution system. Liberty Utilities estimates that it will take approximately four months to integrate the Blackstone Gas distribution system into the Company's SCADA system (Exh. DPU 1-12).

[21] Liberty Utilities states that it intends to have Blackstone Gas' existing office staff continue to handle customer calls and in-person customer interactions with Blackstone Gas customers until those customers are converted to the Company's systems (Exh. AG 1-28). Liberty Utilities expects to have Blackstone Gas customers transferred to the Company's information and billing system within 60 days of the closing on the acquisition (Exh. DPU 1-15).

Gas customers with a broader range of customer service options and integrated energy efficiency offerings; (4) exposing Blackstone Gas employees to technology-based safety enhancements and a robust and regimented safety culture; and (5) organizing community-based events and fostering working relationships with local emergency response personnel (Exhs. LU-JMS-1, at 19-20, 28-29; DPU 1-11; DPU 1-14; DPU 3-7; DPU 6-2; AG 1-19; AG 1-21; AG 1-25; AG 1-26; AG 1-28). The Department recognizes that both Liberty Utilities and Blackstone Gas have positive service quality track records, and we expect that Liberty Utilities will take all steps necessary to ensure that customers will continue to experience a high level of service reliability post-acquisition (Exh. LU-JMS-1, at 27).

Further, we note that in Blackstone Gas' most recent long-range forecast and supply plan ("F&SP"), the Department expressed concerns regarding Blackstone Gas' supply planning and lack of contingency plan in the event of a service disruption. Blackstone Gas Company, D.P.U. 18-154, at 13, 16-17 (2019). Liberty Utilities states that it is actively engaged in addressing the Department's concerns by planning to construct the necessary appurtenances located at the existing Tennessee take station to allow for supplemental gas deliveries (Exh. DPU 3-7). We expect Liberty Utilities to continue to address these concerns and to take all appropriate measures as necessary to ensure the safe, reliable, and least-cost delivery of natural gas to Blackstone Gas customers without disruption. In its next F&SP filing, the Company must report on all of its efforts to address our concerns as outlined in D.P.U. 18-154.

Based on the Company's commitments and representations, the Department finds that the proposed acquisition should be seamless to Blackstone Gas customers from a customer service/service quality standpoint. We conclude that there should be no anticipated service interruptions associated with the transaction, and no other factors that may negatively impact customer service or quality of service.

4. Net Savings

One of the factors that the Department may consider in evaluating a proposed acquisition is resulting net savings. Mergers and Acquisitions at 7-8. In reviewing estimated net savings, the Department's review "must be based on whether the figures proposed by the Petitioners are reasonable estimates." D.P.U. 10-170-B at 57; D.T.E. 99-47, at 47, 50. Projections of future events can be judged in terms of whether they are substantiated by past experience and supported by logical reasoning founded on sound theory. D.P.U. 10-170-B at 57; D.P.U. 09-139, at 19-20; National Grid/KeySpan Corporation, D.P.U. 07-30, at 27 (2010); D.T.E. 99-47, at 50. Further, there is no requirement that projected net savings be demonstrated with a high degree of certainty, and the Department's net benefits standard does not require that net savings be substantial or sizeable. Eversource Energy and Macquarie Utilities, Inc., D.P.U. 17-115, at 28 (2017), citing D.P.U. 10-170, Interlocutory Order on Standard of Review at 27 (March 10, 2011).

In this case, Liberty Utilities did not conduct a net benefits study[22] (Exhs. LU-JMS-1, at 30; DPU 2-14; DPU 2-18; AG 1-1). Nevertheless, the evidentiary record and proposed Settlement Agreement provide sufficient support to enable us to evaluate this issue. In particular, the Settlement Agreement and record provide that the proposed acquisition will result in annual payroll and benefits cost savings associated with the reduction of the Blackstone Gas workforce (i.e., the transfer to the Liberty Utilities organization of only seven of the nine Blackstone Gas employees),[23] and the elimination of accounting, legal, and consultant costs (Settlement Agreement, §§ 1.5, 2.4.3 & Appendix 1; Exhs. LU-JMS-1, at 17-18, 29-30; DPU 2-14). While the Settlement Agreement estimates these annual savings at $475,000, a breakdown of the savings appended to the Settlement Agreement totals $471,217 (Settlement Agreement, § 2.4.3 & Appendix 1). The overall annual cost reduction is based on recent expense amounts associated with each category of cost (Settlement Agreement, Appendix 1). Therefore, we find that annual savings of $471,271 is substantiated by past experience and supported by logical reasoning.

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22 Liberty Utilities explained that it did not perform a cost study because (1) rate benefits will occur upon closing rather than being associated with future cost reductions; and (2) it was not feasible for the Company to assess Blackstone Gas' operations for the purpose of creating cost estimates for the integration of operations on a post-closing basis (Exhs. DPU 2-18; AG 1-1). Further, the Company stated that a cost study would be cost prohibitive given Blackstone Gas' relatively small operations and its lack of financial and operating systems (Exh. DPU 2-18).

23 The Company states that it will not need to hire additional employees beyond the seven operational employees transferring from Blackstone Gas (Exh. DPU 2-17).

Liberty Utilities also anticipates that the proposed acquisition will provide opportunities for additional efficiencies and operating cost savings over time as the Company and Blackstone Gas are integrated, which will benefit customers in the future through a cost of service that is lower than what it otherwise would be in the absence of the acquisition (Exhs. LU-JMS-1, at 30; DPU 1-16; DPU 2-14; AG 1-1). Further, the Company states that the proposed acquisition is expected to (1) mitigate future cost increases for Blackstone Gas customers in areas such as capital investment, as the Company has better access to capital; (2) provide the opportunity to implement purchasing and procurement strategies that could not be implemented by a sole proprietorship on a stand-alone basis; and (3) potentially reduce gas costs and yield operations and maintenance savings to offset cost increases that a smaller company like Blackstone Gas would consistently face (Exh. LU-JMS-1, at 30). While the Department recognizes the potential for these future savings, any such savings are speculative at this time and not included in net savings. Nevertheless, the Department expects the Company to aggressively pursue these and any other potential opportunities for additional efficiencies and operating cost savings over time, as they will benefit customers through a lower cost of service (Exhs. LU-JMS-1, at 30; DPU 2-14; AG 1-1).

In determining whether the proposed acquisition will result in net savings, the Department also considers costs associated with the transaction. Boston Gas Company/Colonial Gas Company, D.P.U. 19-69, at 11 (2019); D.P.U. 13-07-A at 80-82.

The Settlement Agreement expressly prohibits recovery of transaction costs[24] (Settlement Agreement, § 2.4.5). The Settlement Agreement provides that the Company, as part of its next base distribution rate proceeding, shall be eligible to include an expense line item of $252,719 in the unified cost of service (Settlement Agreement, § 2.4.4). This amount was negotiated by the Settling Parties and represents the annual recovery of a regulatory asset[25] in the amount of $2,557,877 (Exhs. DPU-SP 1-1; DPU-SP 1-2 & Atts.; DPU-SP 2-1). In turn, the regulatory asset represents the differential between the purchase price of $5,500,000 and the historical net book value reported in Blackstone Gas' 2019 Annual Return and to be included in rate base of $2,942,123 (Exhs. DPU-SP 1-1; DPU-SP 1-2 & Atts.). The Settling Parties note that acquisition costs that could not be quantified at the time of settlement, and that are expected to exist as of the closing date in excess of the regulatory asset, will be recorded to goodwill, but that no recovery for goodwill is provided for under the Settlement Agreement (Exhs. DPU-SP 1-1; DPU-SP 2-1). Further, in the Company's next base distribution rate proceeding, neither the regulatory asset balance nor the goodwill balance as

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24 Liberty Utilities anticipates only a modest level of transaction costs in the form of legal fees to develop and negotiate the purchase agreement and to obtain regulatory approval, and, notwithstanding the terms of the Settlement Agreement, the Company does not intend to seek recovery of any such transaction costs from customers (Exhs. DPU 1-2; DPU 2-14; DPU 2-15; DPU 7-1; AG 1-24).

25 A regulatory asset is an incurred cost for which a regulatory agency, such as the Department, allows a regulated company to record a deferral to be considered for recovery in the future. Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 10-54, at 318 n.235 (2010); NSTAR Pension, D.T.E. 03-47-A at 3 n.2 (2003).

of the test year-end in that proceeding will be included in rate base[26] (Exh. DPU-SP 1-1, at 2; see also Settlement Agreement, § 2.4.2 & n.1). In this instance, the Department finds the Settling Parties' proposed treatment of acquisition-related costs, including the creation of a regulatory asset, to be appropriate.

As noted above, the Company also expects to incur acquisition-related integration costs associated with upgrading the SCADA equipment to connect to the Blackstone Gas distribution system and transferring Blackstone Gas customers to Liberty Utilities' energy efficiency tracking system and information and billing system[27] (Exhs. DPU 2-16; DPU 3-4; DPU 6-1; DPU 6-2; DPU 7-1; DPU 7-2). The proposed Settlement Agreement provides, however, that Liberty Utilities shall be eligible to propose recovery of these acquisition-related integration costs only if the Company can demonstrate that actual operating and maintenance cost reductions were achieved of equal or greater amount than the sum of (a) $252,719, and (b) the amount of the amortization of the acquisition-related integration costs over a ten-year period on a straight-line basis (Settlement Agreement,

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26 The Settling Parties' agreement as to the treatment of the $5,500,000 purchase price and the establishment of a regulatory asset differs from the Company's proposal in its initial filing. There, the Company proposed to treat Blackstone Gas' assets as a $5,500,000 addition to Liberty Utilities' plant in service, to be rolled into rate base in the Company's next base distribution rate case (Exhs. LU-JMS-1, at 16; LU-VPD-1, at 14-15).

27 The Company estimates that the upgrade of the SCADA equipment will cost approximately $320,000, and the changes associated with transferring Blackstone Gas customers to Liberty Utilities' energy efficiency programs will cost approximately $44,800 to $49,800 (Exhs. DPU 2-16; DPU 3-4).

§ 2.4.5). Thus, the Settlement Agreement ensures that acquisition-related integration costs are recoverable only upon a showing of sufficient savings to offset the recovery of these costs through rates.

The Department finds that the Settling Parties have made a fair and reasonable demonstration of the costs and savings that would result from the proposed acquisition. The labor and labor-related cost reductions and the elimination of outside vendor costs are expected to be greater than the acquisition-related costs associated with the regulatory asset. Further, we find that acquisition-related integration costs are recoverable only upon a showing of sufficient savings to offset the recovery of these costs. Based on these considerations, we conclude that the proposed acquisition will result in net savings to ratepayers.

5. Distribution of Resulting Benefits

One of the factors the Department may consider in determining whether a proposed acquisition is consistent with the public interest is whether the acquisition's resulting benefits are fairly distributed between the shareholders and ratepayers. D.T.E. 98-128, at 85; Mergers and Acquisitions at 9. The proposed acquisition, as recast in the Settlement Agreement, provides customers with rate-related savings and benefits, including an immediate base distribution rate reduction for all Blackstone Gas customers, a rate freeze for all customers, the elimination of certain operating costs, the potential for additional efficiencies and operating cost savings over time, and a greater distribution of costs through the expansion of Liberty Utilities' customer base (Settlement Agreement, §§ 2.2.2, 2.2.3,

2.2.4, 2.3.1, 2.4.3, 2.4.5, Appendix 1; Exhs. LU-JMS-1, at 22, 25, 29-30; LU-VPD-1, at 9-14; LU-VPD-3; LU-VPD-4; LU-VPD-5; DPU 1-16; DPU 2-14; DPU 3-2; DPU 4-4; DPU 4-5; AG 1-1; AG 1-29, Att.). Further, the Company will not seek transaction costs related to the proposed acquisition, and the proposed Settlement Agreement does not provide for the recovery of goodwill (Settlement Agreement § 2.4.5; Exh. DPU-SP 2-1). To the extent that the Company seeks acquisition-related integration costs, it must demonstrate savings in excess of the costs (Settlement Agreement, § 2.4.5). Liberty Utilities will benefit from the proposed acquisition in the form of its regulated rate of return on utility operations, which will include the Blackstone Gas assets and customer additions. Based on these considerations, we conclude that the benefits of this transaction are fairly distributed between ratepayers and shareholders.

6. Societal Costs and Effect on Economic Development

Two factors that the Department may consider in determining whether a proposed acquisition is consistent with the public interest are resulting societal costs and any impact on economic development. Mergers and Acquisitions at 8. The Department's analysis of the societal costs and effect on economic development resulting from approval of a proposed transaction focuses on the public benefits and costs, and specifically looks at the impact on employment. Sheffield Water Company, D.P.U. 16-37, at 34 (2016); Plymouth Water Company, D.P.U. 13-130, at 25-26 (2013); Bay State Gas Company/Unitil Corporation, D.P.U. 08-43-A at 52 (2008). The Department has held that proponents of mergers and acquisitions must demonstrate that they have a plan for minimizing the effect of job

displacement on employees. D.P.U. 16-37, at 34; D.P.U. 13-130, at 26; D.P.U. 10-170-B at 98; D.P.U. 09-139, at 25; D.P.U. 08-43-A at 52; D.T.E. 98-27, at 44.

As noted above, the Settlement Agreement provides that the proposed acquisition will result in no changes to Liberty Utilities' organizational structure (Settlement Agreement, § 1.5). Further, seven of the nine current employees of Blackstone Gas are operations employees who will become employees within the Liberty Utilities organization (Settlement Agreement, § 1.5; Exh. LU-JMS-1, at 17-18). The remaining two individuals are management employees who elected to withdraw upon closing[28] (Settlement Agreement, § 1.5). The Company states that the seven Blackstone Gas employees will receive the benefits associated with joining a larger organization, including enhanced industry and safety training and greater opportunity for interaction with peers and industry professionals (Exh. LU-JMS-1, at 28-29). Based on these considerations, the Department finds there will be positive societal and economic impacts if the proposed acquisition is approved.

7. Financial Integrity of the Post-Acquisition Entity

One of the factors that the Department may consider in determining whether a proposed acquisition is consistent with the public interest is the financial integrity of the post-acquisition entity. D.P.U. 10-170-B, at 103; D.T.E. 98-128, at 83; D.T.E. 98-31, at 48; Mergers and Acquisitions at 8. This evaluation of financial integrity must take into

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28 In the absence of any planned changes to employee levels, facilities, and operations resulting from the proposed acquisition, the Department will not require a personnel displacement mitigation plan.

consideration both that of the company being acquired and the acquiring company itself. D.P.U. 10-170-B at 104-105; D.T.E. 98-31, at 48-49; see Community Utilities/Resort Supply, D.P.U. 16380, at 2-5 (1970) (merger rejected because Department found financial viability of both the acquiring company and the to-be-acquired company to be in question).

As noted above, the Company is a wholly owned subsidiary of Liberty Utilities Co., which in turn is an indirect subsidiary of APUC (Exh. LU-JMS-1, at 6). Thus, as a result of the proposed acquisition, Blackstone Gas will move from a sole proprietorship to part of a larger, publicly traded company that operates as a diversified generation, transmission and distribution utility with $10 billion of total assets (Exh. LU-JMS-1, at 31). Therefore, the proposed acquisition should provide greater access to capital markets to finance capital investments for Blackstone Gas when compared to its position as a sole proprietorship on a stand-alone basis (Exh. LU-JMS-1 at 32). Further, the proposed acquisition will have a positive impact to Liberty Utilities' customer base, thereby strengthening the Company's financial integrity by virtue of the revenues generated by the $2.9 million rate base addition (Exhs. DPU-SP 1-1; DPU-SP 1-2). In addition, the proposed acquisition will have a positive financial impact in terms of regulatory transparency and ratemaking, as the Blackstone Gas assets will be subject to the same financial accounting practices applied to the Company's current rates (Exhs. LU-JMS-1, at 32; DPU 1-17). Based on these considerations, the Department finds that the proposed acquisition would not negatively affect the financial integrity of Blackstone Gas or Liberty Utilities and would actually provide ratepayers with a net benefit.

8. Conclusion

The Department has investigated the proposed acquisition and examined the Settlement Agreement, which recast the proposed acquisition by providing additional ratepayer benefits. Based on our evaluation of the proposed acquisition and the Settlement Agreement, in light of the requirements of Section 96 and in balancing the applicable factors, the Department finds that the proposed acquisition in concert with the Settlement Agreement provides net benefits to ratepayers. Therefore, the Department finds that the proposed acquisition is consistent with the public interest and that the Settlement Agreement results in a just and reasonable outcome. Accordingly, the Department approves the proposed acquisition as set forth in the Settlement Agreement and approves the Settlement Agreement.[29]

VII. CONFIRMATION OF FRANCHISE RIGHTS

A. Introduction

As noted above, as part of the initial filing in this proceeding, Liberty Utilities requested that the Department, in approving the subject transaction, confirm that the franchise rights and obligations currently held by Blackstone Gas shall be held by Liberty Utilities and that no separate authorization is required under Section 21[30] (Petition, ¶ 17).

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[29] This Order whereby the Department approves the Settlement Agreement, which is an agreement among the Settling Parties, is intended to be, and shall be construed to be, a final Order issued pursuant to G.L. c. 25, § 5, and does not operate to make the Department a party to the Settlement Agreement, and does not form, and may not be construed to form, a contract binding the Department. D.P.U. 15-26, at 30.

[30] According to the Company, Blackstone Gas has a franchise right to provide service in three communities: Bellingham; Blackstone; and Millville (Exh. DPU 1-19).

Pursuant to the Settlement Agreement, the Settling Parties agree that upon closing of the transaction to acquire Blackstone Gas, Liberty Utilities will continue to be subject to the same obligations that were respectively held by each of those companies prior to the acquisition; and that further action, pursuant to Section 21, is not required to consummate the proposed transaction (Settlement Agreement, § 2.1.1).

B. Analysis and Findings

The operative statute limiting the transfer of utility franchises is found in Section 21, which states: "A corporation subject to this chapter shall not, except as otherwise expressly provided, transfer its franchise, lease its works or contract with any person, association or corporation to carry on its works, without the authority of the general court." The Department has determined that corporate mergers and acquisitions properly approved pursuant to Section 96 do not require separate legislative approval under Section 21 for the transfer of franchise rights since the General Court itself authorized the Department to approve Section 96 transactions. D.P.U. 10-170-B at 106-107; D.P.U. 09-139, at 33; D.T.E. 99-47, at 65; D.T.E. 98-27, at 75-76.

Section 96 provides that companies subject to Chapter 164 "may sell and convey all or substantially all of their properties to another of such companies." In the instant case, Blackstone Gas will convey substantially all of its property (i.e., its operations, gas-system assets, and customer base) to Liberty Utilities (Exhs. LU-JMS-1, at 7, 17; LU-JMS-2, at 15, 19-22, 115). Upon closing of the proposed transaction, Liberty Utilities will continue as the surviving corporation, with the operations, gas-system assets, and customers of Blackstone

Gas consolidated into that of Liberty Utilities (Exh. LU-JMS-1, at 7, 17). Section 96 expressly provides for the type of asset sale contemplated by the proposed transaction, so long as the transaction satisfies the public interest test. D.P.U. 13-07-B at 11-18; D.P.U. 13-07-A at 128.

As noted above, the Department has long held that an action properly approved by the Department under Section 96 would not require separate authorization from the Legislature for the transfer of franchise rights. D.P.U. 13-07-B at 11-18; D.P.U. 13-07-A at 128-129. As set forth in Section VI.B above, the proposed sale of Blackstone Gas' assets satisfies the Section 96 public interest standard. Based on these considerations, we conclude that separate legislative approval of the transfer of Blackstone Gas' franchise to Liberty Utilities is not required.

Accordingly, the Department finds that upon the consummation of the sale of Blackstone Gas' assets, Liberty Utilities shall have all the rights, powers, privileges, franchises, properties, real, personal, or mixed, and immunities held by Blackstone Gas as are necessary to engage in all the activities of a gas company in all the cities and towns in which Blackstone Gas was engaged in immediately prior to the sale of its assets; and that further action pursuant to Section 21 is not required to consummate the sale of Blackstone Gas' assets to Liberty Utilities.[31]

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[31] Blackstone Gas is directed to file a 2020 Annual Return for the period of January 1, 2020, through the date of closing on the acquisition.

VIII. ORDER

Accordingly, after due notice, hearing, and consideration, it is:

ORDERED: That pursuant to G.L. c. 164, § 96, and subject to the terms and conditions in this Order and the Settlement Agreement dated July 15, 2020, entered into and filed by Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty Utilities, the Attorney General of the Commonwealth of Massachusetts, and the Low-Income Weatherization and Fuel Assistance Program Network, it is hereby determined that the acquisition of Blackstone Gas Company by Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty Utilities is consistent with the public interest and is hereby APPROVED; and it is

FURTHER ORDERED: That the Settlement Agreement dated July 15, 2020, entered into and filed by Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty Utilities, the Attorney General of the Commonwealth of Massachusetts, and the Low-Income Weatherization and Fuel Assistance Program Network produces a just and reasonable outcome and is hereby APPROVED; and it is

FURTHER ORDERED: That upon consummation of the change of control approved herein, Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty Utilities, shall have all rights, powers and privileges, franchises, properties, real, personal, or mixed, and immunities held by Blackstone Gas Company as are necessary to engage in all the activities of a gas company in all the cities and towns in which Blackstone Gas Company was

engaged immediately prior to the acquisition; and that further action pursuant to G.L. c. 164, § 21 is not required to consummate the acquisition; and it is

FURTHER ORDERED: That a copy of the journal entries, or a schedule summarizing such entries, recording the effects of the acquisition shall be filed with the Department upon consummation of the acquisition; and it is

FURTHER ORDERED: That upon consummation of the change of control approved herein, Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty Utilities shall submit a compliance filing, including tariffs consistent with the terms of the Settlement Agreement; and it is

FURTHER ORDERED: That Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty Utilities, the Attorney General of the Commonwealth of Massachusetts, and the Low-Income Weatherization and Fuel Assistance Program Network shall comply with all directives contained in this Order.

By Order of the Department,

/s/

Matthew H. Nelson, Chair

/s/

Robert E. Hayden, Commissioner

/s/

Cecile M. Fraser, Commissioner

An appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part. Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. G.L. c. 25, § 5.

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 13-07-A December 13, 2013

Joint Petition of New England Gas Company, Plaza Massachusetts Acquisition, Inc., The Laclede Group, Inc., and Liberty Utilities Co. pursuant to G.L. c. 164, § 96, for Approval of the Sale of the Assets of New England Gas Company.

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I. INTRODUCTION AND PROCEDURAL HISTORY

On January 24, 2013, New England Gas Company ("NEGC" or "Company"), a division of Southern Union Company ("Southern Union"); Plaza Massachusetts Acquisition, Inc. ("PMA"); and The Laclede Group, Inc. ("LG"), pursuant to G.L. c. 164, § 96 ("§ 96"), submitted a joint petition to the Department of Public Utilities ("Department") for approval of the sale of NEGC's assets by Southern Union to PMA, a subsidiary of LG ("Joint Petition"). The Department docketed this matter as D.P.U. 13-07. On January 29, 2013, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a notice of intervention pursuant to G.L. c. 12, § 11E(a).

On February 19, 2013, an amended and restated joint petition ("Amended Joint Petition") was submitted to the Department to include as a party to the transaction Liberty Utilities Co. ("LUC") (together with NEGC, PMA, and LG as "Joint Petitioners"). Pursuant to the Amended Joint Petition, which is described in more detail below, NEGC's assets ultimately would be sold to PMA, which would be owned and controlled by LUC and not LG.

On February 20, 2013, the Department accorded intervenor status to the Department of Energy Resources ("DOER"). On March 12, 2013, the Department accorded intervenor status to the Conservation Law Foundation ("CLF").

Pursuant to notice duly issued, the Department conducted a public hearing and a procedural conference on March 14, 2013.[1] The Department held evidentiary hearings on June 25-27, 2013. In support of the Amended Joint Petition, the following witnesses provided

[1] On March 13, 2013, the Department received written comments from William Flanagan, the mayor of Fall River, Massachusetts, supporting the proposed transaction.

testimony: (1) Robert J. Hack, chief operating officer of NEGC; (2) Steven L. Lindsey, executive vice president and chief operating officer for distribution operations for LG; (3) Peter Eichler, director of regulatory strategy for Liberty Utilities (Canada) Corp.; (4) Janet M. Simpson, consultant, Dively and Associates, PLLC; (5) James M. Sweeney, senior director and general manager, NEGC; (6) Derek Tomka, director of environmental projects, NEGC; and (7) Mark Christopher Darrell, senior vice president, general counsel, chief compliance officer, The Laclede Group.[2] The Attorney General sponsored the testimony of the following witnesses: (1) James Connelly, consultant; (2) Donald M. Bishop, senior consultant, Snavely King Majoros & Associates, Inc.; (3) Michael J. Majoros, Jr., president, Snavely King Majoros & Associates, Inc.; and (4) Alvaro E. Pereira, managing consultant, La Capra Associates, Inc. DOER sponsored the testimony of Paul J. Hibbard, vice president, Analysis Group, Inc.

The Attorney General, DOER, and CLF submitted initial briefs on July 15, 2013. The Joint Petitioners submitted their initial brief on July 25, 2013. The Attorney General, DOER, and CLF submitted reply briefs on August 1, 2013. The Joint Petitioners submitted a reply brief on August 8, 2013.

On August 5, 2013, the Hearing Officer issued a memorandum that directed further process regarding several issues raised by the Joint Petitioners in their initial brief. See New England Gas Company, D.P.U. 13-07, Hearing Officer Memorandum (August 5, 2013) ("Hearing Officer Memorandum"). The Attorney General appealed the Hearing Officer Memorandum, and the Commission denied the appeal on August 15, 2013. New England Gas

[2] Messrs Hack and Lindsey also provided testimony in support of the initial joint petition.

Company, D.P.U. 13-07, Order on Attorney General's Appeal of Hearing Officer Memorandum (August 15, 2013). Pursuant to the additional process established by the Department, the Joint Petitioners responded to additional information requests and additional evidentiary hearings were held on August 21, 2013, and September 10, 2013. At the August 21, 2013 evidentiary hearing, the Joint Petitioners sponsored the testimony of Mr. Hack and Mr. Eichler. At the September 10, 2013 evidentiary hearing, the Attorney General presented Mr. Connolly and Mr. Pereira. The Joint Petitioners and the Attorney General filed supplemental initial briefs and reply briefs on September 20, 2013 and September 27, 2013, respectively. The record of the entire proceeding consists of approximately 625 exhibits and responses to 33 record requests.[3]

II. SUMMARY OF FINDINGS

In this Order, the Department approves the proposed sale of NEGC's assets to PMA, as we find that it is consistent with the public interest. As discussed in detail below, we reviewed the proposed transaction in light of a number of acquisition-related factors, and considered the various arguments of the parties. We find that the transaction will result in a variety of benefits to NEGC ratepayers that would not be available in the absence of the proposed transaction. These benefits include: (i) a 24-month base rate freeze; (ii) annual savings of at least $546,000 in the first year after the closing of the proposed transaction, an amount that is projected to increase over time; (iii) a rate base offset and targeted infrastructure recovery factor ("TIRF")

[3] The exhibits in this proceeding include prefiled direct testimony of witnesses; prefiled rebuttal testimony of witnesses; attachments, schedules, workpapers and/or exhibits to the foregoing prefiled testimony; responses to information requests and any attachments; confidential responses to information requests and any attachments; revised or supplemental versions of the foregoing exhibits; and documents offered at the evidentiary hearings.

credit that will be applied to offset any future rate impacts associated with the proposed transaction; (iv) improvements in customer service functions, specifically the relocation of the customer service center to Massachusetts; (v) an increase in TIRF-related main replacement and a corresponding reduction in greenhouse gas ("GHG") emissions; (vi) job creation in Massachusetts that is likely to have a positive economic impact on the communities in and around Bristol County; and (vii) ownership and operation of the renamed NEGC by a financially viable company that is focused on and committed to the gas distribution business.

In order to ensure that the benefits associated with the transaction are realized, the Department also finds that several ratepayer protections must be implemented as conditions to approval of the proposed transaction. First, we find that the proposed base rate freeze, rate base offset and TIRF credit must be applied prospectively from the date of this Order.

Second, we will hold the renamed NEGC to the cost savings representations made in this proceeding, and we direct the renamed NEGC and LUC to explore any and all additional measures that provide the opportunity to maximize efficiencies, minimize costs and pass resulting savings on to customers. Thus, the renamed NEGC shall track all such savings and present the results as part of the initial filing in its next base rate case, at which time the Department will fully examine (i) each of the areas of expected savings identified in Section VI.B.4 below and the level of the savings achieved by the renamed NEGC; and (ii) the renamed NEGC's efforts to achieve savings in other areas of operations.

Third, post-closing, the renamed NEGC will increase its TIRF-related main replacement activity to at least eight miles of main per year. Further, at the time of its next base rate case, the renamed NEGC shall provide the Department with an evaluation of the feasibility of accelerating

the TIRF-related main replacement rate beyond eight miles per year. In the meantime, the Department will continue to monitor the renamed NEGC's TIRF-related performance in annual TIRF filings and, consistent with the Department's decision in New England Gas Company, D.P.U. 10-114, at 64-65 (2011), evaluate whether the utility's performance benefits public safety, service reliability, and the environment.

Finally, within 30 days of LUC's assuming operational control of the renamed NEGC, the renamed NEGC and LUC shall file with the Department a report providing details and a timeline for the performance of energy audits at the renamed NEGC's three facilities (see n.32 below) and a plan for exploring the incorporation of compressed natural gas ("CNG") vehicles into its fleet. The energy audits, in particular, will be conducted as expeditiously as possible following LUC's assumption of operational control over the renamed NEGC and prior to the filing of the renamed NEGC's next base rate case. The renamed NEGC shall submit to the Department within 60 days of the completion of each audit a comprehensive written plan and timeline for implementing those cost-effective strategies that are recommended by each audit. In the meantime, the renamed NEGC and LUC also shall explore additional meaningful initiatives to reduce GHG gas emissions, advance clean energy development and address climate change. The renamed NEGC shall include the results of these efforts as part of its initial filing in its next base rate case.

The instant proceeding presented a variety of ancillary issues, both procedural and substantive, that we address in this Order. In short, we find that none of these issues warrant the rejection of the transaction or require any further action by the Department prior to approval of the transaction.

III. BACKGROUND

NEGC is a Massachusetts gas distribution company that provides natural gas distribution service to approximately 54,000 residential and commercial and industrial ("C&I") customers in the communities of: (1) Fall River, Somerset, Swansea, and Westport ("Fall River service area"); and (2) North Attleboro and Plainville ("North Attleboro service area") (see Exh. NEGC-2 (Supp.) at 2).[4] NEGC currently is operated as a division of Southern Union, which is a natural gas company incorporated in Delaware and headquartered in Houston, Texas (Amended Joint Petition at 2, ¶ 2; Exh. NEGC-2 (Supp.) at 2; DPU-1-50(I)(a) at 2 (Pre-Acquisition)). At the time of the filings in this case, Southern Union also owned and operated Missouri Gas Energy ("MGE"), a natural gas company that serves approximately 500,000 customers throughout western Missouri (see Exh. NEGC-2, at 4).

LG is a Missouri corporation and public utility holding company engaged in the retail distribution and sale of natural gas (Amended Joint Petition at 2, ¶ 3). LG's primary subsidiary is the Laclede Gas Company ("Laclede Gas"), which is a natural gas distribution utility serving approximately 631,000 customers in the city of St. Louis and ten other counties in eastern Missouri (Exh. NEGC-2, at 4). PMA is a Delaware corporation and wholly-owned subsidiary of LG (Amended Joint Petition at 2, ¶ 3; Exh. DPU-1-3, Att.).

LUC is a Delaware corporation and an indirect subsidiary of Liberty Utilities (Canada) Corp., which owns 26 regulated utilities, including natural gas distribution companies, and serves

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[4] The two service areas represent the service territories of the former Fall River Gas Company and the former North Attleboro Gas Company, respectively. Both companies merged with, and became operating divisions of, Southern Union in 2000. See Southern Union/North Attleboro Company, D.T.E. 00-26, at 24, 26 (2000); Southern Union/Fall River Gas Company, D.T.E. 00-25, at 25, 27 (2000).

approximately 350,000 customers across eight states in the United States (Exhs. NEGC-4, at 3; DPU-1-50 (vii) at 2 (Pre-Acquisition)). LUC's ultimate parent company is Algonquin Power & Utilities Corp. ("APUC"), which is incorporated under the laws of Canada, with a principal place of business in Oakville, Ontario, Canada (Exh. NEGC-4, at 3; DPU-1-50 (vii) at 2 (Pre-Acquisition)).

IV. DESCRIPTION OF THE PROPOSED TRANSACTION

Pursuant to a purchase and sale agreement ("P&S") dated December 14, 2012, Southern Union agreed to sell the assets of NEGC to PMA, a subsidiary of LG, for the sum of $60,000,000, subject to certain adjustments, including the assumption of approximately $20,000,000 in long-term debt associated with NEGC's operations, but currently held by Southern Union (see Exhs. NEGC-1, at 6, 20-22, § 2.2, 23, § 3.1; NEGC-2, at 3-4; see also Joint Petition at 5, ¶ 8). Following the purchase of the NEGC assets by PMA, LG intended to rename PMA "New England Gas Company" and operate the wholly owned subsidiary as a gas company under G.L. c. 164 and subject to the Department's jurisdiction (Joint Petition at 5, ¶ 9).

The nature of the transaction changed in February 2013. On February 11, 2013, LG and PMA entered into a stock purchase agreement with APUC, on behalf of LUC ("PMA Agreement") (Exhs. NEGC-3 (Supp.) at 2; DPU-1-5, Att.). The PMA Agreement provides that, immediately prior to the sale of NEGC's assets, all of the issued and outstanding shares of PMA will be acquired by LUC, so that LUC will become the parent company of PMA (Amended Joint Petition at 1-2; Exhs. NEGC-3 (Supp.) at 2; DPU-1-2; DPU-1-5, Article 1, §1.2). In exchange for the right to purchase PMA's stock, LUC will pay LG the sum of $11,000,000, and LUC will pay Southern Union the sum of $3,000,000 (Exhs. JP-Rebuttal-3, at 5; DPU-1-5, Att. at 1;

DPU-3-3, Att. at 1; AG-5-37; Tr. 1, at 66, 68-69, 100, 103; Tr. 2, at 196-197, 218, 222). Following the purchase of the NEGC assets by PMA, LUC (and not LG) by virtue of its ownership of PMA will own and control NEGC (Amended Joint Petition at 2; see also NEGC-3 (Supp.) at 2). LUC intends to rename PMA "Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty Utilities" and operate it as a gas company under G.L. c. 164 and subject to the Department's jurisdiction (Amended Joint Petition at 5, ¶ 9; see also, Exh. DPU-1-4; RR-DPU-16; RR-DPU-16 (Amended)). The Joint Petitioners state that the aggregate purchase price for the NEGC assets is $60,000,000 in cash, subject to certain adjustments, including the assumption of various liabilities at closing (Amended Joint Petition at 5, ¶ 8; Exhs. NEGC-1, at 20-22, § 2.2, 23, § 3.1; NEGC-2, at 4; Tr. 1, at 19).[5]

Pursuant to § 2.3 of the P&S, Southern Union will retain certain liabilities that will not pass to PMA (Exh. NEGC-1, at 22, § 2.3). Among these liabilities are "retained regulatory liabilities," which is defined in the P&S as "all Regulatory Liabilities of the [Southern Union] or its Affiliates arising out of or relating to the complaint of the Attorney General of Massachusetts v. NEGC, D.P.U. 09-GAF-P6 and D.P.U. 11-54, whether arising out of or related to the period before or after Closing" (Exh. NEGC-1, at 18, § 1.1).[6]

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[5] In a separate transaction, Southern Union agreed to sell the assets of MGE to Laclede Gas, subject to customary closing conditions and regulatory approvals, including the approval of the Missouri Public Service Commission (Amended Joint Petition at 8, ¶ 16). The Joint Petitioners do not seek Department approval of the MGE sale as part of the instant filing (see Amended Joint Petition at 8, ¶ 16). The sale of MGE to Laclede was finalized on September 1, 2013. See e.g., http://finance.yahoo.com/news/energy-transfer-completes-sale-missouri-173000026.html.

[6] A more complete discussion of Southern Union's retained regulatory liabilities and the issues presented in D.P.U. 09-GAF-P6 and D.P.U. 11-54 is provided below in Section VI.D.

The Joint Petitioners also submit that due to applicable purchase accounting standards, PMA's acquisition of NEGC's assets will prevent the continued recovery of unrecognized prior-period pension and post-retirement benefits other than pension ("PBOP") service gains and losses, absent an accounting ruling from the Department establishing a regulatory asset (Amended Joint Petition at 7, ¶ 13). As such, in order to maintain the continued recovery of these employee-related costs, the Joint Petitioners seek a ruling from the Department allowing the reclassification of NEGC's pre-acquisition accumulated other comprehensive income ("AOCI") balance to a post-acquisition regulatory asset on the renamed NEGC's balance sheet (Amended Joint Petition at 7, ¶ 13). According to the Joint Petitioners, the regulatory asset would be amortized for recovery through the pension expense factor ("PEF"), such that the total expense recoverable from customers would be equal to the sum of pension and PBOP expense recoverable from customers absent the proposed sale of NEGC's assets (Amended Joint Petition at 7, ¶ 13).

The Joint Petitioners further state that approval of the proposed transaction[7] under § 96 obviates the need for separate approval under G.L. c. 164, § 21 ("§ 21") for the transfer of the NEGC franchises (Amended Joint Petition at 7, ¶ 14, citing Eastern-Essex Acquisition, D.T.E. 98-27, at 75-76 (1999)). As such, the Joint Petitioners submit that it is necessary and appropriate for the Department, in approving the proposed transaction, to confirm that all of the franchise rights and obligations currently held by NEGC shall continue to be held by PMA after the sale and no separate authorization is required under § 21 (Amended Joint Petition at 7-8,

[7] References to the "proposed transaction" shall mean to the sale of NEGC's assets by Southern Union to PMA, as described above and in the Amended Joint Petition.

¶ 14, citing NSTAR/Northeast Utilities, D.P.U. 10-170-B at 106-107 (2012); D.T.E. 98-27, at 75-76).

Finally, the Joint Petitioners state that if the Department deems it necessary to deny the sale of NEGC's assets to LUC (by virtue of LUC's acquisition of PMA), then LG should be authorized to complete the transaction in accordance with the terms of the P&S (Amended Joint Petition at 8, ¶ 15). According to the Joint Petitioners, PMA is contractually obligated to acquire NEGC's assets even if the acquisition of PMA by LUC is delayed or does not take place (Amended Joint Petition at 8, ¶ 15).

V. STANDARD OF REVIEW

Section 96 sets forth the Department's authority to review and approve mergers, consolidations, and acquisitions and, as a condition for approval, requires the Department to find that the proposed transaction is "consistent with the public interest." Section 96 is the lineal descendent of St. 1908, c. 529, § 2, and these core words of the standard, "consistent with the public interest," date from that century-old enactment. In the past, the Department has construed the § 96 standard of consistency with the public interest as requiring a balancing of the costs and benefits attendant on any proposed merger or acquisition, stating that the core of the consistency standard is "avoidance of harm to the public." Boston Edison Company, D.P.U. 850, at 5-8 (1983). Thus, the Department has historically interpreted the merger standard as a "no net harm" test, meaning that a proposed merger or acquisition is allowed to go forward upon a finding by the Department that the public interest would be at least as well served by approval of a proposal as by its denial. Eastern Edison-Massachusetts Electric Merger, D.T.E. 99-47, at 16 (2000); BECo/ComEnergy Acquisition, D.T.E. 99-19, at 10 (1999); Eastern/Colonial Acquisition,

D.T.E. 98-128, at 5 (1999); NIPSCO/Bay State Acquisition, D.T.E. 98-31, at 9 (1998); Eastern/Essex Acquisition, D.T.E. 98-27, at 8; D.P.U. 850, at 5-8.

In NSTAR/Northeast Utilities, D.P.U. 10-170 (2012), the Department modified the § 96 standard from a "no net harm" test to a "net benefits" test. D.P.U. 10-170, Interlocutory Order on Standard of Review at 21 (March 10, 2011). Accordingly, to satisfy the statutory requirement that a transaction is "consistent with the public interest," petitioners must demonstrate that the benefits of a consolidation, merger, or acquisition outweigh the costs. D.P.U. 10-170, Interlocutory Order on Standard of Review at 21-22, 27. To determine whether petitioners have satisfactorily met this burden, the Department continues to consider the special factors surrounding an individual proposal. D.P.U. 10-170, Interlocutory Order on Standard of Review at 26-27.

The Department has held that various factors may be considered in determining whether a proposed merger or acquisition is consistent with the public interest pursuant to § 96. Traditionally, the Department has considered the following factors: (1) effect on rates; (2) effect on the quality of service; (3) resulting net savings; (4) effect on competition; (5) financial integrity of the post-merger entity; (6) fairness of the distribution of resulting benefits between shareholders and ratepayers; (7) societal costs; (8) effect on economic development; and (9) alternatives to the merger or acquisition. Guidelines and Standards for Mergers and Acquisitions, D.P.U. 93-167-A at 7-9 (1994) ("Mergers and Acquisitions"). The Department has held that this list of factors is illustrative and not "exhaustive," and the Department may consider other factors, or a subset of these factors, when evaluating a § 96 proposal. D.T.E. 99-47, at 17-18; D.T.E. 99-19, at 11-12; D.T.E. 98-128, at 6. No one factor is controlling.

As amended in 2008, § 96 expressly requires the Department to consider, at a minimum, the following four factors: (1) proposed rate changes, if any; (2) long-term strategies that will assure a reliable, cost-effective energy delivery system; (3) any anticipated interruptions in service; and (4) other factors that may negatively impact customer service. The second factor, regarding long-term strategies, is the only one not previously addressed in the so-called "nine-factor test" established in Mergers and Acquisitions.[8]

Although § 96 mandates that the Department consider the specific factors enunciated in the statute, the Department is not foreclosed from considering the nine factors, or a subset of those factors, established in Mergers and Acquisitions. Furthermore, depending upon the nature of the transaction, in determining whether the transaction is consistent with the public interest, the Department may consider additional factors not delineated in the statute or established in Mergers and Acquisitions. D.T.E. 99-47, at 17-18; D.T.E. 99-19, at 11-12; D.T.E. 98-128, at 6.

The Department's determination as to whether the merger or acquisition meets the requirements of § 96 must rest on a record that quantifies costs and benefits, to the extent such quantification can be made. The Department also may undertake a more qualitative analysis of those aspects that are hard to measure. D.P.U. 10-170, Interlocutory Order on Standard of Review at 27; Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company/Canal Electric Company, D.T.E. 06-40, at 16-17 (2006); D.T.E. 99-47, at 18; Mergers and Acquisitions, at 7. A § 96 petition that expects to avoid an adverse result cannot

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[8] The remaining statutory factors correspond to factors established in Mergers and Acquisitions. Specifically, the first factor in § 96 is subsumed by the first factor established in Mergers and Acquisitions, the effect of the proposed transaction on rates. The third and fourth factors delineated in § 96 correspond to the second factor established in Mergers and Acquisitions, the effect on the quality of service.

rest on generalities, but must instead demonstrate benefits that outweigh the costs, including the cost of any acquisition premium sought. D.P.U. 10-170, Interlocutory Order on Standard of Review at 21-22, 27; D.T.E. 99-47, at 18; D.T.E. 99-19, at 12; D.T.E. 98-128, at 7; D.T.E. 98-31, at 11; D.T.E. 98-27, at 10; Mergers and Acquisitions, at 7.

VI. ANALYSIS AND FINDINGS

A. Supplemental Process

1. Introduction

As noted above in Section I, on August 5, 2013, the Hearing Officer issued a memorandum providing for additional process relative to several issues (referred to as "commitments") raised by the Joint Petitioners in their initial brief. The Hearing Officer Memorandum limited the scope of the supplemental process to inquiry regarding seven of the ten commitments that required additional investigation in order to develop a complete evidentiary record. Hearing Officer Memorandum at Att. 1. The Hearing Officer Memorandum permitted one round of no more than 30 information requests to be propounded upon the Joint Petitioners. Hearing Officer Memorandum at 1. Further, a one-day evidentiary hearing was scheduled in order to afford an opportunity for the parties and Department to cross-examine the Joint Petitioners' witnesses. Hearing Officer Memorandum at 2. Finally, the Hearing Officer Memorandum permitted the filing of simultaneous briefs to address the issues raised during the supplemental discovery and hearing phases. Hearing Officer Memorandum at 2.

On August 10, 2013, the Attorney General filed an appeal to the Commission of the Hearing Officer Memorandum ("Attorney General Appeal"). On August 13, 2013, the Joint Petitioners filed a reply to the Attorney General Appeal ("Joint Petitioner Reply").

On August 15, 2013, the Department issued an Order that (i) upheld the Hearing Officer's decision regarding the propriety of the supplemental process; (ii) allowed the Attorney General to call witnesses to provide testimony regarding the commitments subject to further inquiry; and (iii) rejected as completely baseless the Attorney General's contention that the Hearing Officer engaged in an ex parte conversation with the Company's counsel in scheduling the supplemental process. New England Gas Company, D.P.U. 13-07, Order on Attorney General's Appeal of Hearing Officer Memorandum at 9-10, 11-12 (August 15, 2013) ("August 15 Order").

Despite the August 15 Order, the Attorney General continued to question the propriety of the supplemental process at a subsequent evidentiary hearing and in her supplemental initial brief, raising many of the same claims that were disposed of in the Department's August 15 Order. In deciding the issues presented in our August 15 Order, we fully considered G.L. c. 30A, Department precedent, and the Department's procedural rules. However, given the Attorney General's persistence in this regard, we will address in this final Order several issues regarding the supplemental process.[9]

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[9] As noted above, in our August 15 Order, we rejected as completely baseless the Attorney General's contention that the Hearing Officer engaged in an ex parte conversation with the Company's counsel in scheduling the supplemental process. D.P.U. 13-07, Order on Attorney General's Appeal of Hearing Officer Memorandum at 11-12. The supplemental process was already established by the Hearing Officer prior to any communication with counsel. D.P.U. 13-07, Order on Attorney General's Appeal of Hearing Officer Memorandum at 11. Further, the subsequent communication between the Hearing Officer and counsel was procedural in nature, as it related to the scheduling of the supplemental evidentiary hearing. D.P.U. 13-07, Order on Attorney General's Appeal of Hearing Officer Memorandum at 11-12. Therefore, the communication is exempt from our ex parte regulations. Although the Attorney General continues to question the propriety of this communication (see Attorney General Supplemental Brief at 2), we find

2. Positions of the Parties

a. Attorney General

The Attorney General argues that there is no reasoned consistency between controlling Department precedent and the Department's decision to hold supplemental proceedings on matters raised by the Joint Petitioners for the first time on brief (Attorney General Supplemental Brief at 8). She contends that a party to a Department proceeding has a right under G.L. c. 30A to expect that once a proceeding is under way, the Department will not arbitrarily change the decisional rules unless accompanied by a statement of reasons for the change, including a determination of each issue of fact or law necessary to support that change of precedent (Attorney General Supplemental Brief at 8-9, citing Boston Gas Company v. Department of Public Utilities, 367 Mass. 92, 104 (1975)). According to the Attorney General, the Department's actions in instituting on its own motion the supplemental proceeding directly contravenes 40 years of fundamental appellate principle and Department precedent (Attorney General Supplemental Brief at 9-11, citing Boston Gas Company, 367 Mass. at 104; Boston Gas Company, D.T.E. 03-40-A at 472 (2004); Boston Gas Company, D.P.U. 88-67 (Phase II) at 6-7 (1989).

Further, the Attorney General contends that the Joint Petitioners' inclusion of new proposals on brief violates not only Department case law precedent but directly contravenes the Department's procedural rules (Attorney General Supplemental Brief at 11, citing 220 C.M.R. § 1.11(8)). The Attorney General asserts that rather than rejecting the Joint Petitioners' efforts to introduce new proposals and striking the "offending material," the Department

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her redundant assertions to be unsubstantiated, without merit, and unworthy of further discussion.

arbitrarily and capriciously treated the Joint Petitioners' violation of Department procedural regulations as the Department's own motion, which did not require good cause to reopen the proceeding to consider the novel material (Attorney General Supplemental Brief at 11, 13). According to the Attorney General, the Department's actions resulted in "grave disadvantage" and prejudice to the intervenors (Attorney General Supplemental Brief at 11-13, citing Tr. 4, at 398-400; Tr. 5, at 479).

The Attorney General requests that the Department address and correct the procedural error by striking the materials offered by the Joint Petitioners in their initial brief (Attorney General Supplemental Brief at 12). Further, the Attorney General argues that such remedy is necessary, and that otherwise future petitioners may have an incentive to withhold certain aspects of their case when filing a § 96 petition (Attorney General Supplemental Brief at 12). According to the Attorney General, if the Department approves the sale of NEGC on the basis of the "novel material" improperly introduced on brief and upon evidence introduced in the supplemental proceeding, such a decision would substantially prejudice the rights of the Attorney General and the other intervenors, would be made upon unlawful procedure, and would be arbitrary and capricious and an abuse of discretion (Attorney General Supplemental Brief at 13, citing G.L. c. 30A, § 14(7)(d) and (f)).

b. Joint Petitioners

The Joint Petitioners reject the Attorney General's arguments and assert that the Department has not changed any decisional rule or contravened any fundamental appellate principle, and that such claims by the Attorney General are simply indicative of her "belabored effort" to create a procedural deficiency that does not exist (Joint Petitioner Supplemental Reply

Brief at 16). In particular, the Joint Petitioners argue that the doctrine of reasoned consistency is not applicable to the Department's decision to conduct a supplemental process and does not preclude the Department from making a decision that departs from prior precedent (Joint Petitioner Supplemental Brief at 16-17, citing Boston Gas Company, 367 Mass. at 105).

Further, the Joint Petitioners note that the instant case is only the second proceeding that the Department has litigated under its new "net benefits" standard under § 96 and there are no set guidelines that would either direct or constrain how this case should be conducted from a procedural standpoint (Joint Petitioner Supplemental Reply Brief at 17). In this regard, the Joint Petitioners submit that if a settlement is not possible, then the discovery, hearing and briefing phases become the only vehicle for the Joint Petitioners to receive a clear indication of the intervenors' positions and to attempt to address specific concerns of interested parties (Joint Petitioner Supplemental Reply Brief at 17). Thus, the Joint Petitioners assert that it is unreasonable for the Department to establish case precedent that prohibits parties to an adjudicatory proceeding from agreeing to issues argued by other parties or presenting information regarding the implementation of those agreed upon matters (Joint Petitioner Supplemental Reply Brief at 17).

Moreover, according to the Joint Petitioners, a settlement between the Attorney General's office and the Joint Petitioners would have presented the same result in terms of a need for supplemental process (Joint Petitioner Supplemental Reply Brief at 17-18 & n.9, citing D.P.U. 10-170-B). The Joint Petitioners contend that the interests of administrative efficiency are distinctly contravened when there is no process by which agreement among the parties may be examined and, therefore, the Department's decision to conduct a supplemental

process in this case is both warranted and appropriate (Joint Petitioner Supplemental Reply Brief at 18).

The Joint Petitioners also take issue with the Attorney General's assertion that the commitments were improperly raised on brief (Joint Petitioner Supplemental Reply Brief at 18-19). The Joint Petitioners argue that the commitments are neither novel matters, nor issues contested by the other parties, but rather a direct response to conditions to approval recommended by the Attorney General and financial concessions consistent with and on the basis of evidence developed through the proceeding (Joint Petitioner Supplemental Reply Brief at 19). Similarly, the Joint Petitioners contend that good cause existed to support the supplemental process because the Attorney General recommended that the Department take the action of imposing a customer rate credit to offset negative impacts that could result from the sale of NEGC and allow for the conveyance of net benefits available through the transaction once the potential negative impact was neutralized (Joint Petitioner Supplemental Reply Brief at 19-21). Thus, the Joint Petitioners assert that the Department has satisfied the interests of both due process and administrative efficiency in conducting the supplemental process, particularly given that the facts developed in the supplemental proceeding were also necessary to implement the Attorney General's conditions, regardless of the Joint Petitioners' subsequent agreement to make financial concessions (Joint Petitioner Supplemental Reply Brief at 19).

3. Analysis and Findings

In their initial brief, the Joint Petitioners offered ten commitments as proposed conditions to a Department approval of the sale of NEGC (Joint Petitioner Initial Brief at 11-14).[10] It is not atypical in certain cases, particularly a base rate case under § 94 or a proceeding under § 96, for a petitioner to seek specific relief and then agree to some modification of the relief sought as the evidentiary record is developed. Based on the record, it is clear that the commitments offered by the Joint Petitioners, though not contained in the original joint petition or Amended Joint Petition, are consistent with and based on the evidence developed through the course of this proceeding.

Nearly all of the commitments were subject to varying degrees of investigation prior to the establishment of the supplemental process. Specifically, the concept of a base rate freeze (commitment 1) was raised during discovery and discussed at the evidentiary hearings (see Exh. DPU-7-12; Tr. 1, at 123-125, 175-178; Tr. 2, at 250-252; Tr. 3, at 349-351; RR-DPU-11). Further, the Joint Petitioners' proposed rate base offset to the renamed NEGC's revenue requirement (commitments 2, 4) and their proposed annual targeted infrastructure recovery factor ("TIRF") credit (commitment 3) are designed to address any future rate impacts that may occur at the time of NEGC's next annual TIRF filing or base rate case (see Exhs. DPU-8-3; DPU-8-4 & Att.; AG-14-1). These three commitments (commitments 2, 3 and 4) also implicate the issue of any rate impacts resulting from the loss of accumulated

[10] A more complete discussion of several of the commitments follows in the various subsections of Section VI below.

deferred income taxes ("ADIT"),[11] and whether ratepayers should be held harmless from any loss of ADIT if the sale is approved. The loss of ADIT issue was raised at various stages in this proceeding (see, e.g., Exhs. AG-MJM-1, at 7-8, 12-13, 17; AG-AEP-1, at 13-14; AG-MJM-Surrebuttal-1, at 4, 5-6; AG-AEP-Surrebuttal-1, at 8-12; AG-9-13; AG-9-13 (Supp.); Tr. 1, at 65, 75, 118-121, 125-126; Tr. 2, at 269-282, 293-294, 304-309; RR-DPU-9 & Att.; RR-AG-3; RR-AG-3(A)-(F); RR-AG-4; RR-AG-5 & Att.)).

Similarly, the net book value of NEGC's assets (commitment 5) and any potential gain on the sale of those assets were discussed throughout the proceeding (see, e.g., Exhs. AG-MJM-1, at 6-7, 17; AG-9-12; Tr. 1, at 66-67, 99-104; Tr. 2, at 264-265; RR-DPU-5).[12] Further, the issue of transaction costs (commitment 6) was explored in discovery and at the evidentiary hearings (see, Exhs. DPU-1-22; DPU-1-25, Att.; DPU-4-11; Tr. 1, at 41-42, 59, 83). In addition, inquiry was made as to whether LUC would sell or "flip" NEGC (commitment 7) following the purchase of its assets, if approved (see Exh. DPU-1-39 at 1-2; Tr. 1, at 145-146; RR-DPU-12). The issue of an energy audit at NEGC's three service facilities (commitment 8) also was addressed during evidentiary hearings (Tr. 2, at 252-253). Moreover, the acceleration of NEGC's current TIRF-related main replacement activity (commitment 9) was

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[11] As explained in Section VI.B.1.b.ii below, the accrual of ADIT results from the mismatch between the amount of depreciation expense that can be deducted for income tax purposes and the amount that the Department allows to be collected from customers in rates. See Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 33 (2001); Essex County Gas Company, D.P.U. 87-59, at 27 (1987). In its simplest form, for ratemaking purposes, ADIT serves as credit to rate base and acts to lower rate base. In the instant case, upon closing of the proposed transaction, the renamed NEGC's ADIT balance will be set to zero (Exhs. AG-9-13; AG-9-13 (Supp.); Tr. 2, at 273-274).

[12] In any event, under the Uniform System of Accounts for Gas Companies, utilities are prohibited from revaluing plant accounts for ratemaking purposes. See 220 C.M.R. § 50.00, Gas Plant Instruction 2.

explored in discovery and at the evidentiary hearings (see, e.g., Exhs. DOER-1, at 7 & Atts. PJH-2, PJH-3; DPU-1-26; DPU-1-40; DPU-1-43; DPU-2-10; DPU-2-13; DPU-7-6; DPU-7-8; AG-3-8; DOER-1-8; DOER-2-5 & Atts.; Tr. 1, at 52-54, 128, 137; Tr. 2, at 286; Tr. 3, at 322-323). Finally, the issue of a performance bond to cover Southern Union's potential exposure to an adverse decision from the Department in dockets D.P.U. 09-GAF-P6 and D.P.U. 11-54 (commitment 10) was the subject of considerable inquiry (see, e.g., Exhs. JP-Rebuttal-2, at 7-9; DPU-3-4; DPU-4-12; DPU-7-1; DPU-7-2; DPU-7-3; AG-3-2; AG-3-3; AG-3-4; AG-3-5; Tr. 1, at 61-62, 115-116).

Although the commitments were offered to bolster the Joint Petitioners' assertion that the sale of NEGC's assets resulted in net benefits to customers, there is no evidence to suggest that the Joint Petitioners strategically withheld the commitments in an effort to assess the viability of their filings without them. As such, we reject the Attorney General's assertion that striking the commitments is necessary to prevent future petitioners from withholding aspects of their case when filing a § 96 petition. Moreover, as set forth in various subsections of Section VI.B below, and summarized in Sections II and VI.B.10, we find that on balance several of the commitments provide tangible benefits to ratepayers. Therefore, it would be unreasonable to deprive ratepayers of these benefits on the basis of a perceived procedural deficiency, particularly when the supplemental process established by the Department was fair and afforded the parties an opportunity to fully investigate the commitments.

In this regard, we confirm our previous finding that it was appropriate to reopen the hearings in this matter to allow additional investigation into, and develop a more complete

evidentiary record regarding, several of the commitments.[13] See D.P.U. 13-07, Order on Attorney General's Appeal of Hearing Officer Memorandum at 9, 12. Further, we confirm our finding that it was reasonable to allow limited discovery on the subject commitments in order to streamline the subsequent evidentiary hearings. See D.P.U. 13-07, Order on Attorney General's Appeal of Hearing Officer Memorandum at 9-10. In addition, we confirm our finding that it was appropriate to allow the parties an opportunity to present arguments on brief regarding the subject commitments. See D.P.U. 13-07, Order on Attorney General's Appeal of Hearing Officer Memorandum at 12. While the supplementary process directed by the Hearing Officer and upheld by the Commission following the Attorney General's appeal may not be routine, the Department's regulations do not prohibit it. In fact, pursuant to 220 C.M.R. § 1.11(8), the Department "may, at any time prior to the rendering of a decision, reopen [a] hearing on its own motion." There is no express requirement of good cause associated with the Department's actions, and we find no reason to imply such standard based on the plain language of the regulation. We find that the actions taken by the Hearing Officer were reasonable under the circumstances.

We also find no basis for the Attorney General's contentions that she was disadvantaged or prejudiced by the investigation of the particular commitments subject to the supplemental process. First, as noted above, the commitments subject to further inquiry are neither novel issues, nor are they overly complex. As shown by the extensive citation to the record indicated

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[13] Specifically, the Department established the supplemental process to address commitments 1-5, 7 and 8. The evidentiary record as to the remaining commitments already had been developed during the initial discovery and evidentiary phases of this case.

above, during the course of the proceeding, the parties were aware of the issues contained in the commitments. Further, the Attorney General in particular has extensive experience in litigating cases involving rate freezes, revenue requirement offsets, cost of service credits and matters similar to those raised in the commitments subject to supplemental process. Thus, the extension of the supplemental process was not prejudicial to any party.

Second, the Attorney General was afforded a full and fair opportunity to further investigate and comment on the subject commitments. Specifically, the Attorney General was allowed to, and did, issue information requests regarding the subject commitments.[14] Further, at the supplemental evidentiary hearings, the Attorney General cross-examined the Joint Petitioners' witnesses. She also was permitted to call her own witnesses, introduce evidence, and submit rebuttal evidence regarding the subject commitments.[15] Finally, the Attorney General was permitted to, and did file, a supplemental brief and a supplemental reply brief in order to fully argue her position regarding the commitments subject to the supplemental process. Based on these considerations and the circumstances presented in this case, it is simply unreasonable to suggest that permitting the Joint Petitioners' to present their commitments as a basis for approval of the sale of NEGC results in any disadvantage or prejudice to the Attorney

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14 The Attorney General was permitted to issue up to 30 information requests, yet she issued only eleven (see Attorney General's Fourteenth Set of Document and Information Requests, August 12, 2013).

15 The Attorney General chose to call two witnesses, one of whom provided little or no evidence, but simply testified regarding the alleged procedural improprieties committed by the Department (see generally Tr. 5, at 475-519).

General or any party.[16] In contrast, not permitting the supplemental process would have deprived ratepayers of the Department's consideration of tangible benefits associated with the proposed transaction.

For all of these reasons, we conclude that the establishment of the supplemental process was a valid exercise of the Department's authority, that the process afforded to the parties was fair and did not disadvantage or prejudice the parties, and that it is reasonable and appropriate to consider the commitments offered by the Joint Petitioners in evaluating whether the proposed sale of NEGC's assets satisfies the net benefit standard of § 96.[17]

B. Specific Acquisition-Related Factors

1. Effect on Rates

a. Introduction

In considering whether the proposed sale of NEGC's assets is consistent with the public interest, the Department must consider "proposed rate changes, if any." The Joint Petitioners propose no changes in rates charged to NEGC customers and neither plan nor contemplate to change the tariff rates or services as part of the proposed transaction (Exhs. NEGC-2 (Supp.) at 7; NEGC-4, at 13; DPU-1-6; DPU-1-7). Rather, the Joint Petitioners offer as a condition of approval of the proposed transaction three rate-related commitments to which the renamed NEGC and LUC will be bound. First, the Joint Petitioners offer a base rate freeze that precludes

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16 The Attorney General objects to the Department ordering the supplementary process less than one month after the conclusion of evidentiary hearings. Yet in another recent merger case, the Attorney General advocated for the reopening of hearings more than two months after the record closed to explore evidence that arose in a different matter. See Boston Gas Company/Essex Gas Company, D.P.U. 09-139, at 4, 28-29 (2010).

17 The Department regulates in the public interest, and we find that inclusion of the supplemental process is a gain, not a loss, for the public interest.

the renamed NEGC from seeking a general increase in base distribution rates for a period of 24 months from the date of the closing of the proposed transaction (see Exh. DPU-8-1; Tr. 4, at 416, 430). The Joint Petitioners state that in the absence of the proposed rate freeze, the renamed NEGC would file a base rate case in the near future, though likely not until at least a year following LUC's ownership of the utility (Exhs. JP-Rebuttal-5, at 13-14; DPU-5-23; DPU-8-2; Tr. 1, at 51-52; Tr. 4, at 414).

Second, the Joint Petitioners propose that during any year in which a rate case is filed in the 16 years[18] following the closing of the transaction, a rate base offset will be applied as a deduction to base for the purposes of setting rates (Exhs. DPU-8-3; DPU-8-4 & Att.; Tr. 4, at 441-447). The Joint Petitioners proposed rate base offset is intended to hold the cost of service neutral to adverse accounting changes that could arise as a result of the proposed transaction, and the proposed rate base offset amounts track, roughly, the expected loss of ADIT over a 16-year period (Exhs. DPU-8-3; DPU-8-4 & Att.).[19] The filing of a base rate case is the

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[18] The Joint Petitioners determined that a 15-year rate base offset period was appropriate, but because the proposed base rate freeze would prevent the renamed NEGC from seeking a rate increase in the first year following the closing of the transaction, it was necessary to extend the rate base offset period to 16 years in order to capture a full 15 years of offset potential (Exh. DPU-8-5; Tr. 4, at 429-430).

[19] The Joint Petitioners state that because the proposed transaction is a sale of assets, any historical ADIT balance at the time of the closing of the transaction must be repaid to the Internal Revenue Service by the seller (Southern Union) and a new ADIT balance will begin to accumulate on the same assets by the buyer (LUC) (Exhs. AG-9-13; AG-9-13 (Supp.)). As such, immediately following the closing of the transaction, the amount of ADIT associated with NEGC's assets will be reset to zero on the renamed NEGC's books and the NEGC assets will immediately begin to accumulate a new ADIT balance (see Exhs. AG-9-13; AG-9-13 (Supp.); Tr. 2, at 273-274). As set forth in further detail below, the Attorney General argues that the loss of ADIT at the time of closing will result in harm to the renamed NEGC's ratepayers.

triggering mechanism for the rate base offset (Tr. 4, at 444). Thus, for example, if the renamed NEGC files a rate case in 2015, the rate base offset available for that year ($15,900,000) would reduce the renamed NEGC's overall rate base amount and the lower rate base amount would be used for setting rates (Exhs. DPU-8-3; DPU-8-4 & Att.; Tr. 4, at 441-447).[20] The rate base offset would remain in place until the renamed NEGC files its next base rate case, at which time the rate base offset for that particular year would be applied to the overall rate base amount (Tr. 4, at 443-444).

As part of their proposal, the Joint Petitioners calculated a net present value to customers of the rate base offset (Exh. DPU-8-4, Att.; Tr. 4, at 426-427). The calculation is based on certain assumptions concerning the discount rate, the return on rate base, the aforementioned 16-year amortization period, and a rate case frequency interval of five years (Exh. DPU-8-4, Att.; Tr. 4, at 427-430). The calculation results in a net present value of $10,428,787 in savings to customers over the 16-year period (Exh. DPU-8-4, Att.; Tr. 4, at 429). The Joint Petitioners performed a similar net present value calculation of ADIT, and this calculation yielded an amount of $10,379,262 (Exh. DPU-8-4, Att.; Tr. 4, at 429).

Third, the Joint Petitioners propose a rate base offset (referred to as a "TIRF credit") to be applied in each annual TIRF filing covering periods prior to the implementation of new base rates. The purpose of this proposal is to alleviate any rate impacts resulting from the renamed NEGC's annual TIRF filings (see Exh. DPU-8-9; Tr. 4, at 447). The Joint Petitioners offer the TIRF credit as a "stop gap measure" to cover the time period between the closing of the

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[20] NEGC includes a schedule setting forth the rate base offset amount for each year, from year one through year 16, that would apply to a base rate case filed in that year (see Exh. DPU-8-4, Att.; Joint Petitioner Brief at 12).

proposed transaction and the filing of the next rate case, at which time the aforementioned rate base offset would be applied (Tr. 4, at 447-449). The TIRF credit was determined by conducting a financial analysis using a net present value methodology (Exh. DPU-8-10).

The TIRF credit is applicable to each annual TIRF filing up until the time of the renamed NEGC's next base rate case (Exh. DPU-8-8; Tr. 4, at 449). At the time of the renamed NEGC's next base rate case, a rate base offset will be applied to the company's overall rate base amount, as discussed above. The TIRF-related capital additions for which an annual TIRF credit was applied during the "stop gap" period will be placed into base rates for purposes of the rate base offset application (Exh. DPU-8-9; Tr. 4, at 447-448). Since the TIRF-related capital additions roll into base rates, it would be duplicative to continue to provide an offset in future TIRF filings because an offset already would be accounted for in base rates (Exh. DPU-8-9; Tr. 4, at 448). Thus, the TIRF credit will be extinguished at the time of the next base rate case (Exh. DPU-8-9; Tr.4, at 448, 450).

As set forth in further detail below, the Attorney General argues, among other things, that: (1) the Joint Petitioners' rate-related commitments constitute a rate plan, which was not properly noticed under G.L. c. 164, § 94 ("§ 94"); (2) the 24-month term of the proposed rate freeze is insufficient; (3) the Joint Petitioners' commitment to establish a rate base offset applicable to both base rates and annual TIRF filings prior to the next rate case will not offset the harm to ratepayers caused by the loss of ADIT upon the closing of the transaction; and (4) the Joint Petitioners' have displayed a lack of candor in offering the rate-related proposals and not disclosing the loss of ADIT that would result from the allowance of the proposed transaction. We address these issues below.

b. Propriety of § 96 Approval of Joint Petitioners' Rate-Related Proposals

i. Positions of the Parties

(A) Attorney General

The Attorney General argues that the Department has failed to adequately issue notice of the Joint Petitioners' proposed rate plan and associated rate impacts (Attorney General Supplemental Brief at 3-4, 6). In this regard, the Attorney General contends that if the proposed sale of NEGC's assets is approved, rate increases will flow through the Company's TIRF mechanism from the loss of the ADIT credit (Attorney General Supplemental Brief at 4, citing Tr. 5, at 509, 522; M.D.P.U. No. 1001A-C, §§1.10(F) & (H)). Further, according to the Attorney General, the loss of the ADIT credit in base rates also would result in a rate increase through the application of normal Department ratemaking practices with the filing of the Company's next base rate case (Attorney General Supplemental Brief at 4, citing Exh. JP/JMS-Rebuttal-1, at 23-24; Tr. 5, at 509, 522). As such, the Attorney General asserts that, all else being equal, the loss of ADIT results in a general increase in rates and triggers the requirements of a § 94 investigation (Attorney General Supplemental Brief at 6).

Further, the Attorney General argues that the rate plan filed on brief by the Joint Petitioners sought to mitigate rate increases by offering a TIRF credit, which is effectively a modification to the TIRF formula itself since the current formula has no variable to apply such a credit (Attorney General Supplemental Brief at 6, citing M.D.P.U. No. 1001A-C, §§1.10(F), (H)). The Attorney General contends that modifications to rate formulas are prohibited outside of a § 94 proceeding (Attorney General Supplemental Brief at 6, citing Attorney General v. Department of Public Utilities, 453 Mass. 191 (2009)).

The Attorney General argues that the Notice of Filing, Public Hearing and Procedural Conference issued with respect to the original and amended joint petitions is silent as to the Joint Petitioner's rate plan (Attorney General Supplemental Brief at 4-5, 6). Similarly, the Attorney General contends that no new notice was issued when the Department determined to conduct the supplemental process to investigate several of the commitments offered by the Joint Petitioners in their initial brief (Attorney General Supplementary Brief at 5, 6). As such, the Attorney General claims that NEGC customers were not put on notice that their material interests in rates would be at stake in this proceeding (Attorney General Supplementary Brief at 5, 6). The Attorney General asserts that the Department has not cured this defect and, therefore, should re-notice this case under § 94 and restart the procedural process as a rate-related proceeding (Attorney General Supplementary Brief at 6-8).

Finally, the Attorney General argues that allowing a rate plan to be approved when there has been no public notice of a § 94 filing is not a precedent the Department should set (Attorney General Supplemental Brief at 8). According to the Attorney General, doing so would require the Attorney General and other parties to intervene in more, if not all, Department cases on the off-chance that a rate plan may be submitted in a docket noticed for an entirely different purpose (Attorney General Supplementary Brief at 8).

(B) Joint Petitioners

The Joint Petitioners assert that the Department has the authority in this proceeding to approve the three rate-related proposals set forth above (Joint Petitioner Reply Brief at 3; Joint Petitioner Supplemental Reply Brief at 4). The Joint Petitioners submit that there are no modifications of tariff mechanisms or rate requirements proposed in this case, nor is there a

proposal for a general increase in rates that would require the filing of a general rate case under § 94 (Joint Petitioner Reply Brief at 3-5, Joint Petitioner Supplemental Reply Brief at 4, 5-8, 10-11, citing; Attorney General v. Department of Public Utilities, 453 Mass. 191, 198-199 (2009); Attorney General v. Department of Telecommunications and Energy, 438 Mass. 256, 270 (2002); Boston Gas Company, D.P.U. 10-99 at 21-22 (2011)). The Joint Petitioners contend that as a matter of law, a proceeding under § 96 simply requires notice to customers and interested parties that the proposed transaction may have an effect on rates and may involve proposed rate changes (Joint Petitioner Supplemental Reply Brief at 5).

Further, the Joint Petitioners argue that where the Department has the authority to grant approval of a transaction under § 96 based on an evaluation of the effect on rates and proposed rate changes, it also has the authority within that § 96 proceeding to set reasonable rate-related conditions to remediate any rate-related impacts (Joint Petitioner Supplemental Reply Brief at 6-8, citing Attorney General v. Department of Telecommunications and Energy, 438 Mass. 256 (2002); Mello v. License Commission of Revere, 435 Mass. 532 (2001); Fragopoulos v. Rent Control Board of Cambridge, 408 Mass. 302 (1990); Goodwin v. Department of Public Utilities, 351 Mass. 25 (1966)). Thus, according to the Joint Petitioners, the Department is authorized in this proceeding to consider a range of rate impacts under the public interest standard established in § 96, including proposals that involve a rate freeze or the disposition of other rate-related matters (Joint Petitioner Supplemental Reply Brief at 8).

In addition, the Joint Petitioners assert that the Attorney General's characterization of the three proposals as a rate plan is misplaced and the rate proposals do not give rise to a § 94 proceeding (Joint Petitioner Supplemental Reply Brief at 8-9). The Joint Petitioners note that the

instant proceeding is unlike previous mergers approved by the Department, wherein petitioners requested the approval of a rate plan in order to recover merger-related costs or to establish rate recovery mechanisms (Joint Petitioner Supplemental Reply Brief at 8-9 & n.5, citing NSTAR/Northeast Utilities Merger, D.P.U. 10-170-B at 32 (2012); Eastern/Colonial Acquisition, D.T.E. 98-128 (1999); D.T.E. 98-27). Rather, the Joint Petitioners contend that their proposals are designed to maintain the ratemaking status quo for customers, while providing net benefits in the avoidance of a base-rate increase (Joint Petitioner Reply Brief at 4; Joint Petitioner Supplemental Reply Brief at 9).

The Joint Petitioners also reject any assertion that this proceeding should have been publicly noticed under § 94 because the loss of the ADIT credit directly resulting from the asset sale, all else being equal, would result in a general increases in TIRF rates automatically with the next TIRF filing (Joint Petitioner Supplemental Reply Brief at 10). The Joint Petitioners assert that Massachusetts law is clear that a "general increase in rates" is the condition precedent that triggers the statutory notice and hearing provisions of § 94, and in this case no such general increase in rates will take place and no automatic increase in the TIRF rate occurs as a result of the Department's approval of the proposed transaction (Joint Petitioner Supplemental Reply Brief at 10-12, citing 438 Mass. at 269). Rather, the Joint Petitioners note that any revenue requirement changes caused by the loss of ADIT would occur in the first annual TIRF filing made subsequent to the closing of the proposed transaction, and such filing would be subject to notice, review and approval under § 94 (Joint Petitioner Supplemental Reply Brief at 12).

In addition, the Joint Petitioners reject any notion that the proposed TIRF credit is a modification to the TIRF formula, which would be prohibited outside of a § 94 proceeding

(Joint Petitioner Supplemental Reply Brief at 12-13). The Joint Petitioners assert that the TIRF credit proposal would maintain the fixed TIRF formula set in the TIRF tariff, and there is no requested or necessary adjustment to the formula rate in order to implement the credit (Joint Petitioner Supplemental Reply Brief at 13). Further, the Joint Petitioners note that even if the Department were to incorporate into the TIRF tariff reference to the accounting change relating to the proposed TIRF credit, such action would be consistent with the current provisions of the tariff (Joint Petitioner Supplemental Reply Brief at 13, citing M.D.P.U. No. 1002C, § 1.17).[21] Thus, the Joint Petitioners assert that there is no deficiency in notice under § 96, and the Department is authorized to approve the proposed TIRF credit under § 96 given that the credit is specifically designed to maintain the status quo with respect to the fixed rate (Joint Petitioner Supplemental Reply Brief at 13-14).

Finally, the Joint Petitioners reject the notion that approving the rate-related proposals in this proceeding would lead the Attorney General to intervene in more, if not all, Department cases on the off-chance that a rate plan may be submitted in a docket noticed for an entirely different purpose (Joint Petitioner Supplemental Reply Brief at 14). The Joint Petitioners note that the Attorney General intervened in this proceeding and selected appropriate witnesses,

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[21] In particular, the Joint Petitioners point to the following language from M.D.P.U. No. 1002C, § 1.17:

> The Department may, where appropriate, on petition or on its own motion, grant an exception from the provisions of the applicable regulations and this rate schedule, upon such terms that it may determine to be in the public interest. At any time, the Department may require the Company to file, or the Company may file with the Department, an amended LDAF. Said filing must be submitted at least ten (10) days before the proposed effective date of the amended LDAF.

(Joint Petitioner Supplemental Reply Brief at 13).

despite the fact that the proceeding was not noticed under Section 94 (Joint Petitioner Supplemental Reply Brief at 14). Further, the Joint Petitioners contend that the Attorney General requested that the Department impose the subject rate-related proposals as a condition of approval of the proposed transaction (Joint Petitioner Supplemental Reply Brief at 14, citing Attorney General Brief at 2, 43, 45). In addition, the Joint Petitioners note that they are not suggesting that the Department impose rate-related requirements or "rate plans" on a broad basis outside of § 96 without notice under § 94 (Joint Petitioner Supplemental Reply Brief at 15). Rather, the Joint Petitioners assert that the legal analysis that applies in this case rests on the proposition that the Department's authority under § 96 explicitly involves the investigation of the effect on rates and proposed rate changes, which therefore serves as the basis for adequate and appropriate notice on rate-related matters arising from the proposed transaction (Joint Petitioner Supplemental Reply Brief at 15).

ii. Analysis and Findings

Section 96 expressly requires the Department to consider "proposed rate changes, if any." Thus, assessing a merger or acquisition pursuant to § 96 necessarily entails some reference to § 94 considerations. See D.P.U. 10-170-B at 32, citing Attorney General v. Department of Telecommunications and Energy, 438 Mass. 256, 264-265 (2002); D.T.E. 99-47, at 18-20; D.T.E. 99-19, at 7. Accordingly, where a merger or acquisition includes elements related to rates, we review the § 96 criteria applying a standard that combines §§ 96 and 94's kindred public interest requirements. See D.P.U. 10-170-B at 32, citing Attorney General v. Department of Telecommunications and Energy, 438 Mass. at 263-264; D.T.E. 99-47, at 19.

The Department has approved rate freezes in the context of a § 96 proceeding on a number of occasions in the past. See e.g., D.P.U. 10-170-B at 40 (44-month rate freeze); BEC/ComEnergy Merger, D.T.E. 99-19, at 24-25 (1999) (four-year rate freeze); Eastern-Colonial Acquisition, D.T.E. 98-128, at 105 (1999) (ten-year rate freeze); NISPCO-Bay State Acquisition, D.T.E. 98-31, at 16-17 (1998) (five-year rate freeze); D.T.E. 98-27, at 21 (ten-year rate freeze). Further, the Department has drawn a clear distinction between such cases and proceedings in which a general increase in base distribution rates is sought. See, e.g., D.T.E. 99-19, at 22 (approving a four-year rate freeze and finding that the joint petitioners there "are not proposing a general distribution rate increase; rather, they are proposing to freeze rates at a level that has been determined by the Department to be just and reasonable"); D.T.E. 98-128, at 17 (approving a ten-year rate freeze and finding that "[t]his proceeding is a request to approve a merger that incorporates a ten-year rate freeze; it is not a traditional general rate case").

In the instant case, the Joint Petitioners have not proposed any modifications of tariff mechanisms or rate requirements, nor have they proposed a general increase in rates (Exhs. NEGC-2 (Supp.) at 7; NEGC-4, at 13; DPU-1-6; DPU-1-7). In fact, the proposed rate freeze is intended to keep base rates at their current level for a period of 24 months from the date of the closing of the transaction.

Further, although the renamed NEGC's ADIT balance will be zeroed out at the closing of the transaction, there is no evidence that ratepayers will experience an immediate rate impact associated with the loss of ADIT at that time. As noted above in n.11, the accrual of ADIT results from the mismatch between the amount of depreciation expense that can be deducted for

income tax purposes and the amount that the Department allows to be collected from customers in rates. See Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 33 (2001); Essex County Gas Company, D.P.U. 87-59, at 27 (1987). In its simplest form, for ratemaking purposes, ADIT serves as credit to rate base and acts to lower rate base. In the instant case, upon closing of the proposed transaction, the renamed NEGC's ADIT balance will be set to zero (Exhs. AG-9-13; AG-9-13 (Supp.); Tr. 2, at 273-274). Thus, at the time that base rates are reset, ratepayers no longer will have the benefit of the previously deferred income taxes that had accumulated over time and the renamed NEGC's rate base will reflect a lower ADIT credit. Thus, without any adjustment, rates will be set on a higher rate base amount. It is important to note, however, that such rate impacts resulting from the loss of ADIT will not surface immediately after closing of the proposed transaction.[22] Rather, the loss of ADIT will not become an issue for purposes of setting rates until the time of the renamed NEGC's next TIRF filing or base rate filing. As noted in Section VI.B.1.d.ii below, in response to both types of filings the Department will conduct a full investigation pursuant to § 94, at which time the Department will examine the rate impacts associated with the loss of ADIT and determine whether any adjustments, beyond those already proposed by the rate base offset and TIRF credit, are warranted.[23]

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[22] As stated above, the Joint Petitioners do not propose any changes in base rates with the closing of the proposed transaction (Exhs. NEGC-2 (Supp.) at 7; NEGC-4, at 13; DPU-1-6; DPU-1-7).

[23] Such investigation will include a public hearing and associated process necessary for a full investigation. The Attorney General will have an opportunity to intervene in those proceedings pursuant to G.L. c. 12, § 11E(a).

Finally, we are not persuaded by the Attorney General's argument that the proposed TIRF credit results in a modification of NEGC's TIRF tariff that is impermissible outside of a base rate proceeding. The TIRF credit proposal would maintain the formula rate set in the TIRF tariff and no adjustment to the formula rate is necessary to implement the credit.

Based on these considerations, we find that approval of the proposed transaction and the rate-related commitments offered by the Joint Petitioners will not have an immediate rate impact on ratepayers, and no "general increase in rates" would occur at the time of approval. Further, we find that the requirements of § 94 are not triggered by any other rate-related aspect of the proposed transaction. The instant case is a request for approval of a purchase and sale of assets; it is not a general rate case. Accordingly, we find that it is not necessary to re-notice this case under § 94 and review the rate-related issues pursuant to the requirements of that statute. See D.P.U. 10-170-B at 32 n.33, citing Fitchburg Gas and Electric Light Company v. Department of Telecommunications and Energy, 440 Mass. 625 (2004); Attorney General v. Department of Telecommunications and Energy, 438 Mass. at 270; Boston Gas Company, D.P.U. 10-99, at 21-22 (2011).

c. Proposed Rate Freeze

i. Positions of the Parties

(A) Attorney General

The Attorney General argues that the length of proposed rate freeze is too short to capture projected operational savings (Attorney General Reply Brief at 6). In particular, the Attorney General notes that the major component of the Joint Petitioners' reduced cost of service savings is replacing the current billing system with the Cogsdale billing system (Attorney General Brief

at 6). The Attorney General contends, however, that because savings associated with the implementation of the system likely will not be realized until 2016, and the test year for the first post-rate freeze rate case will most likely be 2014 or 2015, customers will bear the costs of the new billing system without experiencing any associated savings (Attorney General Reply Brief at 6-7, citing Exh. JP-Rebuttal-5A at 1). Thus, customers will pay more, not less, in rates post-transaction (Attorney General Reply Brief at 7). The Attorney General submits that in order to ensure that ratepayers experience post-transaction savings rather than increased costs in the next rate case, the rate freeze period should be five years, the same length of time that the Joint Petitioners expect to achieve permanent operating-cost savings (Attorney General Reply Brief at 7).

The Attorney General also argues that the Department developed its policy of customer benefits flowing from rate freezes at a time when base distribution rates contained more elements of the cost of service than they do now (Attorney General Supplemental Brief at 14, citing Tr. 5, at 528, 532-533; D.T.E. 99-19 (1999)). According to the Attorney General, capital tracking mechanism like the TIRF, and formula tariffs for expenses such as bad debt, low-income discounts, and pensions result in significant customer bill adjustments outside of base rates (Attorney General Supplemental Brief at 14). The Attorney General asserts that the Joint Petitioners' proposed rate plan does not propose to freeze the reconciling mechanisms, and does not prohibit the Company from filing a request for new mechanisms during the freeze (Attorney General Supplemental Brief at 14).

Further, the Attorney General argues that the Joint Petitioners provide no analysis to support their claimed $4,000,000 savings per year from the rate freeze, and the Attorney General

dismisses the figure as mere speculation and unsupported by sufficient evidence (Attorney General Supplemental Brief at 15, citing Tr. 5, at 529-530; Boston Gas Company v. Department of Telecommunications and Energy, 436 Mass. 233 (2002); Attorney General Supplemental Reply Brief at 2-3).

Finally, the Attorney General contends that the P&S contains a loophole regarding the closing date of the proposed transaction and the commencement of the rate freeze (Attorney General Supplemental Reply Brief at 3-5). According to the Attorney General, the language of the P&S can be interpreted to permit the closing date to be backdated to sometime in the past and, given that the rate freeze is tied to the closing date, customers could see less than 24 months of a base rate freeze (Attorney General Supplemental Reply Brief at 4).

(B) Joint Petitioners

The Joint Petitioners contend that the proposed rate freeze will create tangible benefits for customers and will create a strong incentive for the Company to further manage and reduce its costs during the 24-month rate-freeze period (Joint Petitioner Brief at 17). In particular, the Joint Petitioners assert that ratepayers will experience savings through the avoidance of a base rate filing during the proposed rate freeze period (Joint Petitioner Supplemental Brief at 4-6). According to the Joint Petitioners, although there are many variables that could affect the computation of the revenue deficiency presented in a future base rate filing, based on NEGC's two most recent rate cases, the cost savings associated with the avoidance of a rate filing are estimated to be in the range of $4,000,000 per year, for a total estimated savings of $8,000,000 under the Joint Petitioners' rate freeze proposal (Joint Petitioner Supplemental Brief at 5-6, citing Exh. DPU-8-2; RR-DPU 11; Tr. 4, at 451-452). The Joint Petitioners submit that the

benefits of the rate freeze are not reduced or eliminated by an estimation of savings, nor should the continuing operating of reconciling mechanisms diminish the benefits associated with a two-year freeze of rates (Joint Petitioner Supplemental Reply Brief at 23-24).

Further, the Joint Petitioners submit that the two-year term of the rate freeze is appropriate, as it would expire in late 2015, nearly five years since the last base rate increase approved by the Department (Joint Petitioner Reply Brief at 8). According to the Joint Petitioners, the imposition of a rate freeze for a period extending beyond 2015 is too long for a company of NEGC's size and would create a risk of financial detriment for LUC (Joint Petitioner Reply Brief at 8).

ii. Analysis and Findings

The Attorney General raises several issues with the proposed rate freeze. First, the Attorney General submits that in order to ensure that ratepayers experience post-transaction savings rather than increased costs in the next rate case, the rate freeze period should be five years, the same length of time that the Joint Petitioner expect to achieve permanent operating cost savings (Attorney General Reply Brief at 7). While the Attorney General raises a legitimate point regarding the importance of capturing operational savings during the rate freeze period, as set forth in Section VI.B.4.c below, we find that the proposed transaction will result in net savings to ratepayers.

Moreover, we are mindful of the fact that the Company's current base rates were established in March 2011, more than two years ago. See New England Gas Company, D.P.U. 10-114 (2011). A base rate freeze of an additional five years, as recommended by the Attorney General, would effectively freeze NEGC's current base rates until at least 2019, some

eight years after the Company's last increase.[24] In this regard, we acknowledge the concerns of the Joint Petitioners that such a length of time may pose an unreasonable financial detriment to a relatively small company that serves only 54,000 customers. This restriction on management's ability to seek a rate increase ultimately could have negative consequences for ratepayers. Thus, in this instance we are not persuaded that the interests of customers are best served by the Attorney General's recommended five-year base rate freeze.[25]

Along these lines, the Attorney General next asserts that the Joint Petitioners do not propose to freeze reconciling mechanisms, and that the renamed NEGC is not prohibited from filing a request for new mechanisms during the proposed rate freeze period (Attorney General Supplemental Brief at 14). Consistent with other rate freezes approved by the Department, the proposed rate freeze applies only to base distribution rates. See, e.g., D.P.U. 10-170-B at 40; Southern Union/North Attleboro Company, D.T.E. 00-26, at 4 (2000); Southern Union/Fall River Gas Company, D.T.E. 00-25, at 4 (2000); D.T.E. 99-47, at 4; D.T.E. 99-19, at 13; D.T.E. 98-128, at 8; D.T.E. 98-31, at 12; D.T.E. 98-27, at 10. Thus, there are components of ratepayers' bills that will not remain fixed at their current charge during the proposed rate freeze period. For instance, the rate freeze does not apply to rate fluctuations associated with NEGC's decoupling mechanism or its TIRF tariff (see Exh. DPU-14-5; Tr. 4, at 416-417). Additional

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[24] Given the date of this Order, the subsequent closing of the transaction, and the prospective commencement of the base rate freeze, a five-year base rate freeze would be in effect beginning sometime in 2014 and ending sometime in 2019. In light of the ten-month suspension period applicable to base rate filings, we recognize that under a five-year freeze the renamed NEGC could file for new base rates sometime in 2018 and request that the rates go into effect at the end of the base rate freeze period in 2019.

[25] In making this finding, we do not reach the issue of whether § 96 provides authority for the Department to impose a rate freeze that extends beyond the term offered or agreed upon by a petitioner.

components of ratepayers' bills that will not remain fixed during the proposed 24-month rate freeze period include a pension adjustment factor, residential assistance adjustment factor ("RAAF"), an energy efficiency reconciliation factor, and the Attorney General consultant expense factor. Because these reconciling mechanisms recover costs on a dollar-for-dollar basis, they will increase or decrease from one year to the next. However, freezing the reconciling mechanisms, as the Attorney General seems to suggest, would not necessarily provide an economic benefit to ratepayers because the balances would only be deferred for recovery at a later date.

Next, the Attorney General rejects as speculative the Joint Petitioners' claimed $4,000,000 savings per year from the proposed rate freeze (Attorney General Supplemental Brief at 15; Attorney General Supplemental Reply Brief at 2-3). The Joint Petitioners concede that calculation of savings associated with the avoidance of a rate case is not possible without an unreasonable level of speculation on a range of operating cost categories (Exh. DPU-8-2; Tr. 4, at 414-415; RR-DPU-11). Nevertheless, the Joint Petitioners state that if a forward-looking revenue deficiency were in the same range as historically experienced by the Company in its last two rate cases, the cost savings associated with an avoided rate case would be in the range of up to $4,000,000 million per year for the proposed two-year rate freeze period, recognizing that the approved revenue requirement may not reflect the revenue deficiency as filed (Exh. DPU-8-2; RR-DPU-11; Tr. 4, at 451-452).[26]

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[26] In NEGC's last base rate case, the Company requested a base distribution rate increase of $6,166,020, and the Department approved a base distribution rate increase of $5,072,686. See D.P.U. 10-114, at 1, 389. In the base rate case prior to that case, the Company sought a base distribution rate increase of $5,598,982, and the Department approved a base distribution rate increase of $3,675,666, which subsequently was amended to

The Department cannot know today the amount of the rate increase that the renamed NEGC would request, whether the Department would grant any rate increase, and if so, how large any such increase would be if the proposed rate freeze were not implemented. Thus, on this point, we agree that the two-year savings associated with the avoidance of such a rate case is speculative and cannot be precisely quantified. However, although the savings cannot be determined with any level of precision, it stands to reason that ratepayers would benefit from the certainty of no increases in base rates for a 24-month period of time when compared to the possibility of a base rate increase occurring during that time frame. See D.T.E. 98-31, at 16 & n.22 (declining to accept the petitioners' estimated savings of $31 million resulting from a five-year rate freeze, but finding the "rate freeze most likely would allow ratepayers to avoid some level of rate increase over the five-year period"). Thus, we conclude that the proposed base rate freeze would result in a benefit to ratepayers and, therefore, we accept the implementation of a 24-month base rate freeze.

Finally, the Attorney General contends that the P&S contains a loophole regarding the closing date of the proposed transaction and the commencement of the rate freeze (Attorney General Supplemental Reply Brief at 3-5). There is no evidence to suggest that the Joint Petitioners intend to manipulate the closing date to deprive customers of the full 24 months of stable base rates. Nevertheless, our approval of this rate-related proposal is conditioned upon the ratepayers of the renamed NEGC receiving a base rate freeze of 24 months in duration that commences subsequent to the date of this Order and no earlier than the date upon which LUC

$3,966,366. See New England Gas Company, Order on Motion for Recalculation and Motion to Extend the Judicial Appeal Period, D.P.U. 08-35, at 11 (June 22, 2009); New England Gas Company, D.P.U. 08-35, at 263, 274 (2009).

assumes operational control of NEGC. Within seven days of its occurrence, LUC shall provide to the Department written notice of the date upon which it assumes control of the renamed NEGC.

d. Proposed Rate Base Offset and TIRF Credit

i. Positions of the Parties

(A) Attorney General

As noted above, the Attorney General argues that if the proposed sale of NEGC's assets is approved, rate increases will flow through the Company's TIRF mechanism from the loss of the ADIT credit (Attorney General Supplemental Brief at 4, citing Tr. 5, at 509, 522; M.D.P.U. No. 1001A-C, §§1.10(F) & (H)). Further, the Attorney General contends that the loss of the ADIT credit in base rates also would result in a rate increase through the application of normal Department ratemaking practices with the filing of the Company's next base rate case (Attorney General Supplemental Brief at 4, citing Exh. JP/JMS-Rebuttal-1, at 23-24; Tr. 5, at 509, 522).

According to the Attorney General, there is no analysis in the record that demonstrates that the loss of the ADIT credits are offset completely by the Joint Petitioners' proposed rate base offset and TIRF credit (Attorney General Reply Brief at 7; Attorney General Supplemental Brief at 15). In fact, according to the Attorney General, it is disputable as to whether the rate base offset contains a "loophole" that would allow the successor to NEGC to file for a rate increase prior to the expiration of the rate freeze period and, based on the timing of the filing, avoid the application of the proposed rate base offset (Attorney General Supplemental Brief

at 14-15, citing Exhs. AG-14-4; AG-3; Tr. 5, at 523-529).[27] Further, the Attorney General contends that the Joint Petitioners seem to disclaim the notion that the rate base offset and TIRF credit are designed to hold customers harmless from the loss of the ADIT credit (Attorney General Supplemental Brief at 16, citing Exh. AG-14-1; Tr. 5, at 526-527). As such, the Attorney General asserts that it is speculative to maintain that rates would not go up under the proposed rate plan (Attorney General Supplemental Brief at 16).

The Attorney General also argues that in addition to the loophole inherent in the proposed rate base offset, any potential value to customers of the offset depends on the timing of rate case filings (Attorney General Supplemental Reply Brief at 5, citing Tr. 5, at 426-431). In this regard, the Attorney General notes that the Joint Petitioners' net present value analysis for the rate case offset is based on a five-year interval between rate cases, but more frequent rate cases will reduce the value of the rate base offset to a figure that is less than the value of the loss of the ADIT benefits under traditional ratemaking (Attorney General Supplemental Reply Brief at 6, citing Tr. 4, at 431). For instance, the Attorney General asserts that filing a rate case every two years would reduce the net present value of the proposed offset from $10,428,787 to $9,261,218 (Attorney General Supplemental Reply Brief at 6, citing Tr. 4, at 431, 440). The Attorney General argues that despite the loss of value associated with more frequent rate cases, the Joint Petitioners are unwilling to commit to a five-year interval between rate case filings

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[27] The Joint Petitioners provided a trajectory of the potential rate base offset amounts available over a 16-year period (see Exh. DPU-8-4, Att.; Joint Petitioner Brief at 12). The Attorney General questions the notation of "N/A" that corresponds to the offset associated with the year 2013, and argues that the renamed NEGC could file for new rates, select 2013 as the test year and then claim that the offset is "Not Applicable" to the setting of the rates in that case (Attorney General Supplemental Brief at 14-15, citing Exh. AG-3; Tr. 5, at 523-529).

(Attorney General Supplemental Reply Brief at 6, citing Tr. 4, at 431, 440). Moreover, the Attorney General submits that without the proposed transaction, if NEGC filed for a rate case with a 2012 test year, customers would see a higher level of ADIT credit than is currently represented in rates, and the Joint Petitioners' net present value analysis does not adequately account for this lost benefit under a status quo alternative (Attorney General Supplemental Reply Brief at 6, citing Exh. AG-4-1(A); Tr. 4, at 421-423).

Regarding the proposed TIRF credit, the Attorney General argues that a separate loophole exists as well (Attorney General Supplemental Reply Brief at 7). According to the Attorney General, the application of the TIRF credit expressly starts in calendar year 2014, but the closing date of the proposed transaction could be adjusted back prior to the filing date for the annual 2013 TIRF adjustment (Attorney General Supplemental Reply Brief at 7). Thus, the Attorney General contends that the ADIT would be zeroed out at the closing of the transaction, there would be no corresponding TIRF credit available for 2013, and TIRF rates will increase for all customers (Attorney General Supplemental Reply Brief at 7). The Attorney General notes that this possibility could occur in conjunction with the rate base offset loophole described above to deprive customers of both a rate base offset and a TIRF credit (Attorney General Supplemental Reply Brief at 7).

Finally, notwithstanding the above arguments, the Attorney General asserts that even if the proposed rate plan is revenue neutral, it is still a rate plan and would need to be filed and publicly noticed under § 94 (Attorney General Supplemental Brief at 16, citing D.T.E. 99-19).

(B) Joint Petitioners

The Joint Petitioners argue that the proposed rate base offset and TIRF credit will hold the cost of service neutral to adverse accounting changes and thereby hold harmless customers of NEGC from any negative ratemaking impacts associated with the proposed transaction in future rate proceedings (Joint Petitioner Brief at 17-18; Joint Petitioner Supplemental Brief at 6, citing Exh. JP-Rebuttal-5). Further, the Joint Petitioners submit that these proposals yield tangible benefits to customers. For instance, the Joint Petitioners submit that on a net present value basis, the rate base offset provides customers a credit of approximately $10.4 million over a 16-year period (Joint Petitioner Supplemental Brief at 6, citing Exhs. DPU-8-3; DPU-8-4, Att.; RR-DPU-21; Tr. 4, at 445-447). According to the Joint Petitioners, the rate base offset proposal is properly calculated to provide for a net present value that is greater than the loss related to the resetting of ADIT in future rates, with a base rate case proceeding serving as the triggering mechanism for a change in the rate base offset calculation (Joint Petitioner Supplemental Brief at 7, citing Exh. DPU-8-4; Tr. 4, at 441-442, 444; Joint Petitioner Supplemental Reply Brief at 21-23). In addition, the Joint Petitioners reject the Attorney General's notion that a loophole exists that could deprive ratepayers of the rate base offset (Joint Petitioner Supplemental Reply Brief at 21). The Joint Petitioners contend that the Attorney General misunderstands the nature of Joint Petitioners' commitment and ignores testimony on the record that clearly establishes the intention to provide the rate base offset to customers (Joint Petitioner Supplemental Reply Brief at 21-22, citing Tr. 4, at 450, 463-464).

Regarding the TIRF credit, the Joint Petitioners argue that this proposal, in conjunction with the other rate-related commitments, would provide for all benefits of the proposed

transaction to inure to customers and in aggregate would be greater than that which would otherwise be present under the proposed transaction (Joint Petitioner Supplemental Brief at 8-9, citing Tr. 4, at 448; Exh. DPU-8-10). The Joint Petitioners explain that once new rates are set in NEGC's next base rate case, no additional TIRF-related rate base credit will be included in the TIRF, because the rate base offset calculated in the annual TIRF credit will be inclusive of the TIRF amounts arising prior to the implementation of those new base rates, thereby resetting everything in the TIRF mechanism to zero as a result of the base rate case (Joint Petitioner Supplemental Brief at 9, citing Exhs. DPU-8-8; DPU-8-9; DPU-8-10; Tr. 4, at 449).

ii. Analysis and Findings

(A) Rate Base Offset

The Attorney General raises several issues with respect to the proposed rate base offset. First, the Attorney General argues that the rate base offset contains a loophole that could allow the renamed NEGC to file a rate case and avoid the application of the offset (Attorney General Supplemental Brief at 14-15, citing Exhs. AG-14-4; AG-3; Tr. 5, at 523-529). We disagree. The rate base offset is designed to take into consideration the proposed base rate freeze (Tr. 4, at 450-451). As such, the earliest that the renamed NEGC could file for new base rates would be sometime in 2015, at which time a rate base offset clearly would apply (Exh. DPU-8-4, Att.).[28] Further, we find assurance in the record that the renamed NEGC and LUC fully intend to provide

[28] The base rate freeze would be in effect for 24 months beginning sometime in 2014 and ending sometime in 2016. In light of the ten-month suspension period applicable to base rate filings, we recognize that the renamed NEGC could file for new base rates sometime in 2015 and request that the rates go into effect at the end of the base rate freeze period in 2016 (see n.24 above).

the rate base offset to customers regardless of the filing date of the next base rate case or the test year used for that rate case (see Exh. AG-14-4; Tr. 4, at 450-451, 463-464).

Next, the Attorney General questions whether the rate base offset holds customers harmless as a result of the loss of ADIT and, therefore, whether rates will increase as a result of the proposed transaction (Attorney General Supplemental Brief at 16). Along these lines, the Attorney General takes issue with Joint Petitioners' assumption of a five-year interval between rate cases, and she notes that more frequent rate cases will reduce the value of the rate base offset to a figure that is less than the value of the loss of the ADIT benefits under traditional ratemaking (Attorney General Supplemental Reply Brief at 6, citing Tr. 4, at 431).

The record shows that the net present value of savings associated with the rate base offset is higher than the net present value that would be associated with ADIT absent the proposed transaction (Exh. DPU-8-4, Att.; Tr. 4, at 429). This result, however, is based on several assumptions, including a five-year rate case filing interval based on the historical interval between NEGC's rate cases over the past 15 years (Tr. 4, at 443). The Company's three most recent base rate cases were filed in 2010, 2008, and 2007.[29] Therefore, it is arguable that something less than a five-year interval between rate case filings is more representative of NEGC's base rate case filing activity. However, in light of the proposed 24-month base rate freeze, the renamed NEGC's next base rate case will not be filed until at least 2015, approximately five years after the filing of its most recent base rate case. Further, we cannot know with precision the frequency of future base rate case filings beyond 2015. In light of these considerations, we find that the use of the five-year interval is not unreasonable. Moreover, as

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[29] See D.P.U. 10-114; D.P.U. 08-35; New England Gas Company, D.P.U. 07-46 (2007).

noted above in Section VI.B.1.b.ii, the loss of ADIT from the proposed transaction will not result in an immediate effect on rates, so ratepayers are not immediately exposed to a rate change upon the closing of the transaction. Further, the potential for customers to experience some future rate impact resulting from the loss of ADIT is but one factor that we balance against other considerations in evaluating the proposed transaction in its entirety. In this regard, we note that at the time of the renamed NEGC's next rate case, the Department will have the opportunity to revisit the relationship between the rate base offset and the loss of ADIT and, based on a full investigation into the renamed NEGC's cost of service, can determine whether additional ratemaking treatment is necessary.

After careful consideration of the issues presented regarding the proposed rate base offset, we approve the Joint Petitioners' proposed rate base offset. The rate base offset shall be applied to all base rate proceedings filed by the renamed NEGC in a 16-year period commencing from the date of this Order.

(B) TIRF Credit

The Attorney General argues that a separate loophole exists in the application of the TIRF credit that would allow the Joint Petitioners to backdate the closing of the transaction and deprive ratepayers of the benefits associated with the TIRF credit (Attorney General Supplemental Reply Brief at 7). We disagree. There is no evidence to suggest that the Joint Petitioners intend to manipulate the date of the closing to avoid the TIRF credit. Further, as a condition of approval of the proposed transaction we require prospective application of the three rate-related proposals.

After consideration of the arguments of the parties, and in light of our analysis above concerning the base rate freeze and rate base offset, we find that the TIRF credit is a reasonable means to protect ratepayers from any adverse rate effects that might occur at the time of the renamed NEGC's annual TIRF filings. At the time of the filing of the renamed NEGC's annual TIRF filings, the Department will have the opportunity to revisit the relationship between the TIRF credit and any impact of the loss of ADIT and can determine if any additional action is warranted.

As noted above, as a condition of approval of the rate freeze and rate base offset, the renamed NEGC must offer (i) a base rate freeze to customers that is 24 months in duration and commences subsequent to the date of this Order and no earlier than the date upon which LUC assumes operational control of NEGC and (ii) a rate base offset in all rate base filings for a 16-year period commencing after the date of this Order. The same prospective requirement applies to the TIRF credit; that is, our approval is conditioned upon the application of a TIRF credit in all annual TIRF filings that occur subsequent to the date of this Order.

e. Joint Petitioners' Purported Lack of Candor Regarding the Rate-Related Proposals

i. Positions of the Parties

(A) Attorney General

The Attorney General argues that the Joint Petitioners had every opportunity to present the proposed rate freeze, rate base offset and TIRF credit as part of their rebuttal testimony in response to issues raised by the Attorney General, but failed to do so (Attorney General Supplemental Reply Brief at 8). The Attorney General asserts that there was ample opportunity to include the rate plan at the outset of this proceeding so it could be fairly noticed and

deliberately examined, rather than attempt to "shoehorn" it into the record on brief (Attorney General Supplemental Reply Brief at 9). As such, the Attorney General submits that the dubious conduct of the Joint Petitioners should be considered in determining whether LUC's ownership of the NEGC assets is in the best interest of ratepayers (Attorney General Supplemental Reply Brief at 9).

The Attorney General also argues that the Department, as part of the § 96 public interest test, should take into consideration certain testimonial anomalies or irreconcilable mismatches between documentary and testimonial evidence concerning the potential rate changes generally affecting all ratepayers as a result of the loss of ADIT (Attorney General Supplemental Brief at 16). In short, the Attorney General claims that the record demonstrates that the Joint Petitioners knew of the potential rate impacts associated with the loss of ADIT and failed to disclose this information at various times during the course of this proceeding (Attorney General Supplemental Brief at 17, 18-22; Attorney General Supplemental Reply Brief at 8-9, citing Tr. 4, at 405-406; Tr. 5, at 503-510). The Attorney General asserts that she uncovered the issues concerning the loss of ADIT and, had she not asked about ADIT, the Joint Petitioners would not been inclined to disclose it on their own (Attorney General Supplemental Brief at 18). Further, the Attorney General claims that it is evident that the Joint Petitioners, in offering a rate plan to compensate for the loss of ADIT, concede that the proposed sale of assets is "freighted with adverse general effects on customer rates" (Attorney General Supplemental Brief at 17).

The Attorney General asserts that the Department must find that the public interest and the public trust would be ill-served by allowing the Amended Joint Petition and permitting the sale of NEGC's assets and transfer of its franchise to PMA (Attorney General Supplemental

Brief at 17, 24). Alternatively, the Attorney General recommends suspending the adjudication of the Amended Joint Petition so that the Department can investigate the various ADIT-related testimonial anomalies pursuant to G.L. c. 164, § 76 (Attorney General Supplemental Brief at 24).[30] According to the Attorney General, despite Southern Union's desire to exit the jurisdiction, the public interest would, for the interim, be better served by leaving NEGC as a Southern Union operating division until a suitable buyer, perhaps a utility already known to the Department, can be found (Attorney General Supplemental Brief at 17).

(B) Joint Petitioners

The Joint Petitioners argue that § 96 requires an examination of "proposed rate changes, if any," and not "potential rate changes," and all of the relevant testimonial exhibits support the point that no rate changes were proposed as part of the filing (Joint Petitioner Supplemental Reply Brief at 25). Further, the Joint Petitioners note that no rate changes would take effect as a result of the Department's approval of the proposed transaction, as no impact from ADIT would ever occur for customers until a filing to change TIRF rates or base rates was submitted to the Department, at which time the Department would investigate such rate changes (Joint Petitioner Supplemental Reply Brief at 25).

In addition, the Joint Petitioners argue that they set forth information regarding the loss of ADIT clearly and concisely in both discovery and rebuttal testimony without qualification (Joint Petitioner Supplemental Reply Brief at 26). In this regard, the Joint Petitioners assert that they offered no statement or testimony denying the fact that ADIT changes would occur, nor was

[30] Under G.L. c. 164, § 76, the Department has general supervisory authority over electric and gas companies.

there any "about face" on this issue in the proceeding (Joint Petitioner Supplemental Reply Brief at 26, citing Attorney General Supplemental Brief at 17).

Moreover, the Joint Petitioners contend, with respect to structuring their petitions, that there was no precedent in Massachusetts regarding the treatment of ADIT in mergers and acquisitions for ratemaking purposes (Joint Petitioner Supplemental Reply Brief at 26). However, the Joint Petitioners submit that they had to be mindful of Internal Revenue Service ("IRS") regulations that set strict requirements prohibiting ratemaking "normalization" of ADIT balances that are eliminated through accounting protocols (Joint Petitioner Supplemental Reply Brief at 26 & n.15). Further, the Joint Petitioners note that the Federal Energy Regulatory Commission has recognized repeatedly that an ADIT balance extinguished as a consequence of an asset sale is not offset in rates (Joint Petitioner Supplemental Reply Brief at 26-27).

Based on these considerations, the Joint Petitioners assert that the process for introduction of the ADIT issue is one on which reasonable minds may differ, with all perspectives focused on avoiding negative impacts for customers (Joint Petitioner Supplemental Reply Brief at 27). The Joint Petitioners note that this is particularly true where the rate base offset associated with the ADIT balance persists in base rates and provides a benefit to customers in the period between the closing of the transaction (and the zeroing out of ADIT) and the effective date of new rates approved in the next base rate case (Joint Petitioner Supplemental Reply Brief at 27).

ii. Analysis and Findings

The arguments raised by the Attorney General regarding the timing of the proposed rate freeze, rate base offset and TIRF credit, are unpersuasive. As explained above in Section

VI.A.3, there is no evidence to suggest that the Joint Petitioners strategically withheld these commitments in an effort to assess the viability of their Amended Joint Petition without them. Further, as we found in Section VI.A.3, the Attorney General was provided a full and fair opportunity to investigate these issues. As such, we reject the Attorney General's contention that the Joint Petitioners displayed dubious conduct that should be considered in the determination of whether LUC's ownership of the NEGC assets is in the best interest of ratepayers.

Similarly, we disagree with the Attorney General's recommendation that the proposed transaction should be suspended, or outright rejected, because of "various ADIT-related testimonial anomalies" (Attorney General Supplemental Brief at 17, 24). The Department expects that all utilities appearing before it will make full disclosure of all relevant information to the Department. See Bay State Gas Company, D.P.U. 09-30, at 174 (2009). Nevertheless, in this instance, we find that given the Joint Petitioners' concerns regarding the IRS's treatment of ADIT (see e.g., Exh. JP-Rebuttal-5, at 11-13; Tr. 1, at 125), it is not unreasonable that the Joint Petitioners did not initially propose an alternative ratemaking mechanism to address the loss of ADIT. Moreover, when the issue of the loss of ADIT was raised in these proceedings, the Joint Petitioners were forthcoming about the potential rate impact on customers (see, e.g., Exhs. JP/JMS-Rebuttal-1, at 22-25; DPU-8-4, Att.; Tr. 1, at 120; RR-AG-3). We conclude that there was no inappropriate intent on the part of the Joint Petitioners in failing to initiate the ADIT issue.

2. Long-Term Strategies that Will Assure a Reliable, Cost-Effective Energy Delivery System

a. Introduction

As noted above in Section V, § 96 expressly requires the Department to consider in evaluating the proposed sale of NEGC's assets the long-term strategies to assure a reliable, cost-effective energy delivery system. Further, as we noted in D.P.U. 10-170-B, at 76-77, activities and commitments that advance clean energy development and address climate change are important components of the § 96 factor regarding long-term strategies to provide a reliable, cost-effective energy delivery system. Thus, we consider the effect of the proposed transaction on clean energy development and climate change.

In addressing environmental objectives, the Joint Petitioners state that LUC is committed to increasing NEGC's current TIRF-related main replacement activity by one mile of main per year for a total of eight miles of main replaced (see Exh. AG-14-10; Tr. 4, at 407, 435-436, 454).[31] Further, the Joint Petitioners note that LUC has committed to the post-closing performance of an energy audit at the three service facilities occupied by NEGC,[32] and it agrees to explore the feasibility of implementing CNG vehicles in the future (see Exh. DPU-8-12; Tr. 2, at 256; Tr. 4, at 453-454, 460-461).

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31 NEGC's TIRF program includes the replacement of leak-prone natural gas mains. D.P.U. 10-114, at 33-37. Methane (CH4) is a greenhouse gas and it is the primary component of natural gas. See U.S. Environmental Protection Agency website: http://epa.gov/climatechange/ghgemissions/gases/ch4.html.

32 The Company currently operates three service facilities – 5th Street, Charles Street, and Anawan Street – all located in Fall River, Massachusetts (see Exh. DPU-8-12; RR-DOER-2)

b. Positions of the Parties

i. Attorney General

The Attorney General argues that neither NEGC's current replacement of gas mains (as contained in the Company's existing TIRF program) nor the accelerated and incremental replacement of mains (as currently proposed by the Joint Petitioners) should be viewed as a benefit of the proposed transaction (Attorney General Brief at 21). The Attorney General contends that NEGC's TIRF is a pre-existing program that is subject to modification only upon Department approval in the Company's next rate case (Attorney General Brief at 21-22, citing D.P.U. 10-114, at 76-77). The Attorney General notes that customers will receive incidental environmental benefits related to the TIRF program, regardless of whether the proposed sale of NEGC is approved (Attorney General Brief at 22). Thus, according to the Attorney General, the Joint Petitioners fail to demonstrate how the TIRF program makes the proposed asset sale beneficial to customers (Attorney General Brief at 21).

The Attorney General also argues that while it may be appropriate to examine incidental GHG emissions reductions that may accompany gas main replacement, such replacements are an ineffective means of reducing GHG emissions from a cost-benefit perspective (Attorney General Brief at 22, citing Exhs. AG-AEP-Surrebuttal-1, at 14-15; AG-2; Tr. 3, at 322; Attorney General Reply Brief at 8-9). In this regard, the Attorney General contends that an analysis submitted by DOER that purports to demonstrate the benefits of increased main replacement fails to properly take into account the costs associated with such activity (Attorney General Brief at 22). According to the Attorney General, when costs are factored into the analysis, it is clear that main replacement is not a cost-effective means of reducing GHG emissions, except in the most highly

unlikely scenarios (Attorney General Brief at 22, citing Tr. 3, at 322; Attorney General Reply Brief at 8).

Further, the Attorney General claims that DOER did not compare GHG reductions from the Company's current TIRF program to other methods of reducing GHG such as energy efficiency or renewable energy (Attorney General Reply Brief at 9, citing Tr. 3, at 336-338). Finally, the Attorney General asserts that DOER relies upon an improper calculation of lost and unaccounted for gas and, in any event, gas leakage is not an appropriate surrogate for GHG emissions collection data (Attorney General Brief at 22, citing Exhs. AG-AEP-Surrebuttal-1, at 15; DOER-1). The Attorney General argues that the results of the analysis conducted by DOER should not be understood as representing the full elimination of unaccounted for gas as calculated by NEGC for compliance with other Department directives (Attorney General Brief at 22-23, citing Exh. AG-AEP-Surrebuttal-1, at 15-16). Based on the foregoing, the Attorney General submits that DOER's analysis fails to advance the net benefits criteria under § 96 because it examines only claimed benefits without accounting for costs (Attorney General Reply Brief at 9).

ii. DOER

DOER argues that the Joint Petitioners have offered no evidence to demonstrate a specific commitment to reduce GHG emissions beyond NEGC's existing TIRF program or to mitigate NEGC's foreseeable climate impact (DOER Brief at 6, 11, 13-15, citing Exhs. DPU-7-6; DOER-2-5; Tr. 2, at 253-257; DOER Reply Brief at 1, 2). As such, DOER asserts that the Joint Petitioners have failed to provide public benefits that would serve the Commonwealth in its long-term strategies to assure reliable, cost-effective energy delivery

systems, or in reducing GHG emissions and climate change impact, and failed to meet the Department's net benefits standard under § 96 (DOER Brief at 3, 11-13, 15; DOER Reply Brief at 3).

DOER argues that a reduction of unaccounted for gas on NEGC's distribution system would be an appropriate means of providing a public benefit, and such could be achieved if the Company accelerated its replacement of TIRF-eligible mains by an additional three miles per year between 2013 and 2014 (DOER Brief at 3, 9, 10; DOER Reply Brief at 2). DOER believes that NEGC's actual and forecasted infrastructure replacement for 2009-2014 would generate benefits of $1,400,000 based on the reduction of 40,000 metric tons of CO_2e[33] emissions over the full asset life of the replacements (DOER Brief at 9-10, citing Exhs. DOER-1, at 10; DOER-1, Atts. PJH-2, PJH-3). Further, DOER asserts that an increase in main replacement activity by three miles over the next two years would provide an additional $186,000 in benefits over the forecasted amount (DOER Brief at 10, citing Exh. DOER-1, at 11). DOER contends that the Joint Petitioners are unwilling to dedicate sufficient resources to achieving this accelerated rate of main replacement (DOER Brief at 11, citing Exh. JP-Rebuttal-4, at 7-8, 9-10, 12; DOER Reply Brief at 2). Further, DOER submits that while the Attorney General and Joint Petitioners raise legitimate concerns regarding the cost-effectiveness of infrastructure replacement, these arguments fail to recognize the quantifiable benefits identified by DOER and the commodity costs passed on to ratepayers for gas leaks (DOER Reply Brief at 2, citing Exh. DOER-1, at 8).

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33 CO_2e refers to equivalent carbon dioxide, which is a measurement of the concentration of carbon dioxide (CO_2) that would cause the same level of radiative force as a given type and concentration of GHG, such as methane. See U.S. EPA website: http://www.epa.gov/climatechange/glossary.html.

DOER also notes that LUC's agreement to conduct an energy audit of NEGC's existing buildings falls short of providing any demonstrable reduction to GHG emissions (DOER Reply Brief at 2). Instead, DOER recommends an independent company-wide audit of NEGC's operations and energy use through all of its processes and facilities, and a specific commitment to measurable GHG reductions based on the results of the audit (DOER Reply Brief at 2). In fact, DOER notes that such an audit may identify more cost-effective means of reducing GHG emissions when compared to accelerated TIRF replacement activity (DOER Reply Brief at 2).

iii. CLF

CLF argues that the Joint Petitioners have offered four ways in which the proposed sale of NEGC's assets will result in net benefits vis-à-vis a reduction of GHG emissions: (1) through LUC's continuation of NEGC's current TIRF program and possibly conducting an additional mile of main replacement annually; (2) through the implementation of energy efficiency programs similar to those in which LUC participates in other states; (3) through LUC's parent company's "'environmentally focused mindset,'" as demonstrated by the fact that it is heavily involved in the production of renewable energy; and (4) through the planned energy audits of NEGC's buildings (CLF Brief at 6; CLF Reply Brief at 1-2). CLF argues that the Joint Petitioners' proposals fail to satisfy the § 96 net benefit standard (CLF Brief at 6; CLF Reply Brief at 1).

Regarding the first point, CLF argues that accelerated replacement of leak-prone infrastructure provides quantifiable benefits by reducing the risk of explosions; lowering operations and maintenance expense associated with monitoring and repairing leaks and by reducing the quantity of unaccounted for gas; and reducing the total quantity of methane emitted,

consistent with the goals and requirements of the GWSA (CLF Brief at 8, citing Exh. DOER-1, at 4-5). In this regard, CLF considers NEGC's current practice of replacing seven miles of leak-prone main per year as a baseline amount for purposes of determining whether any benefits arise from proposed sale of the Company's assets (CLF Brief at 8-9). As does DOER, CLF contends that if LUC increased the rate of main replacement beyond the baseline level to ten miles per year, quantifiable benefits would be realized in the form of reductions in costs, unaccounted for gas, and methane emissions (CLF Brief at 9, citing Exh. DOER-1, Att. PJH-2; DOER-2-5, Att. A; RR-DPU-19, Att. at 2; CLF Reply Brief at 2). Thus, CLF asserts that the replacement of leak-prone infrastructure is directly correlated with an increase in benefits (CLF Brief at 10).

Further, CLF argues that LUC has not shown a commitment to actual expansion of NEGC's current TIRF program, and has only gone so far as to consider adding one more mile of annual main replacement to the TIRF program (CLF Brief at 10-13, citing Exhs. DPU-2-10; AG-5-53; DOER-1-8; Tr. 1, at 52-53). As such, CLF asserts that the Department should set as a condition for approval of the proposed sale of NEGC's assets an acceleration of leak-prone main replacement of three additional miles per year (CLF Brief at 13; CLF Reply Brief at 2).

Regarding the second point above, CLF argues that the Joint Petitioners have failed to provide examples of specific energy efficiency programs that LUC will adopt if the proposed sale of NEGC's assets is approved, and instead have only discussed programs in other states in which LUC does business (CLF Brief at 13-14, citing Exh. DOER-3-4). CLF notes that while LUC's work with energy efficiency programs in other states is encouraging, such activity cannot

be used to demonstrate net benefits associated with the proposed sale of NEGC's assets (CLF Brief at 14).

Similarly, CLF argues that LUC's parent's involvement in the production of renewable energy, while admirable, is not relevant to the net benefits evaluation in this proceeding, particularly since the proposed asset sale involves a natural gas distribution company and not a generation company (CLF Brief at 14). Further, CLF acknowledges LUC's purported "green focus," but notes that there has been no quantification of any benefits associated with such an approach, and no specific commitments made by LUC to demonstrate this focus (CLF Brief at 14-15, citing Tr. 1, at 138-139; Tr. 2, at 255, 256-257).

Finally, CLF argues that NEGC has never conducted a company-wide audit of its energy usage, nor has it considered measures of energy conservation in its operations (CLF Brief at 15, citing Tr. 2, at 253). Further, CLF notes that LUC has not fully evaluated the operational changes that could be made for enhanced energy efficiency in this proposed asset sale (CLF Brief at 15-16, citing Tr. 2, at 255-257). CLF asserts that, as with any company, there are likely to be multiple opportunities for cost-effective reductions of GHG emissions related to NEGC's operations (CLF Brief at 16). Therefore, CLF recommends that the Department require LUC to do more than just audit NEGC's buildings and to condition any approval of the proposed sale of NEGC's assets on the requirement that LUC develop a comprehensive, company-wide plan to reduce GHG emissions from all aspects of NEGC's operations (CLF Brief at 16; CLF Reply Brief at 2).

iv. Joint Petitioners

The Joint Petitioners assert that the proposed sale of NEGC's assets will provide benefits in the form of incremental reductions in GHG emissions and increased energy efficiency, which further the long-term strategies for a reliable cost-effective energy delivery system (Joint Petitioner Brief at 30-31). In particular, the Joint Petitioners argue that as a result of the proposed sale: (1) NEGC's assets will be owned by a company whose ultimate parent is invested in environmentally friendly power generation, including 500 megawatts of wind generation; (2) LUC will increase NEGC's main replacement rate from seven miles to a minimum of eight miles of leak-prone pipe each calendar year until new base rates are set, thereby eliminating more gas leaks than the current TIRF program and reducing GHG emissions; (3) LUC will perform an energy audit of the Company's three service buildings as soon as practicable after the close of the transaction, and will consider the feasibility of implementing CNG vehicles in the future; (4) LUC will enhance the renamed NEGC's administration of energy efficiency programs through LUC's own substantial experience in similar programs; and (5) LUC will utilize the knowledge and experience of various local employees to develop and implement long-term strategies consistent with Massachusetts policies and requirements (Joint Petitioner Brief at 30-31, 59-61, citing Exhs. NEGC-4, at 19-20; DOER-2-5; DOER-2-5(A); Joint Petitioner Reply Brief at 15-16, citing Tr. 2, at 256; Joint Petitioner Supplemental Brief at 9, citing Exhs. DOER-2-5; DOER-2-5(A)).

Specifically regarding the TIRF program, the Joint Petitioners contend that NEGC has limited resources available to perform main replacement and simply does not have sufficient staffing of internal or external resources to allow for the safe and effective installation of three

additional miles of TIRF-eligible replacement annually, as suggested by DOER (Joint Petitioner Brief at 60, citing Exh. JP-Rebuttal-4, at 8-9). However, the Joint Petitioners state that the renamed NEGC will replace a minimum of eight miles of leak prone pipe each calendar year until new base rates are set (Joint Petitioner Supplemental Brief at 9, citing Exhs. DOER-2-5; DOER-2-5(A)). Further, the Joint Petitioners note that the renamed NEGC will complete this replacement rate even if total TIRF-eligible costs exceed the one percent revenue cap (Joint Petitioner Supplemental Brief at 9).

c. Analysis and Findings

There is no evidence on the record that the proposed transaction will adversely impact the renamed NEGC's ability to provide reliable and cost-effective gas delivery to its Massachusetts customers. In fact, we find that the renamed NEGC will benefit from LUC's retention of a number of senior management employees who are familiar to the Department and who have significant experience managing Massachusetts utilities, and are knowledgeable of Department regulations and operations (Exhs. NEGC-4, at 6-8, 14; DPU-1-26; Tr. 4, at 430-433; RR-AG-9).

In evaluating the long-term strategies to provide a reliable, cost-effective energy delivery system, the Department also examines the effect of the proposed transaction on GHG emissions and the activities and commitments that advance clean energy development and address climate change. The Joint Petitioners identify fugitive emissions as the greatest contributor to NEGC's baseline GHG emissions profile (Exh. DOER-2-5, at 2). As such, they focus on the replacement of leak-prone distribution mains and services as a means to maximize reduction of GHG emissions (Exhs. NEGC-4, at 19-20; DOER-2-5, at 2). The sustained replacement of leak-prone facilities is appropriate and desirable from a public policy perspective given the potential

benefits to public safety, service reliability, and the environment. See D.P.U. 10-114, at 56; Boston Gas Company/Essex Gas Company/Colonial Gas Company d/b/a National Grid, D.P.U. 10-55, at 121 (2010); D.P.U. 09-30, at 133-134. In particular, we find that the replacement of leak-prone pipe can result in environmental benefits through a reduction of lost and unaccounted for gas on a distribution system and ultimately a reduction in GHG emissions.

In this regard, LUC is committed to increasing NEGC's current TIRF-related main replacement activity by one mile of main per year for a total of eight miles of main replaced (see Exh. AG-14-10; Tr. 4, at 407, 435-436, 454). The Attorney General contends that NEGC's TIRF is a pre-existing program that is subject to modification only upon Department approval in the renamed NEGC's next rate case (Attorney General Brief at 21-22). Further, she asserts that customers will receive incidental environmental benefits related to the TIRF program, regardless of whether the proposed sale of NEGC is approved, thus she claims that the Joint Petitioners fail to demonstrate how the TIRF program makes the proposed asset sale beneficial to customers (Attorney General Brief at 21-22). DOER and CLF argue that LUC's TIRF-related main replacement commitment does not go far enough and they argue that public benefits associated with TIRF-related main replacement could only be achieved upon a main replacement rate of ten miles of main per year (DOER Brief at 3, 9, 10; DOER Reply Brief at 2; CLF Brief at 9-13; CLF Reply Brief at 2).

The Department approved NEGC's current TIRF in the Company's last base rate case. See D.P.U. 10-114, at 77. The TIRF was designed to support the Company's plan to replace approximately seven miles of mains per year over a 15-year period. D.P.U. 10-114, at 75-76. In approving the TIRF mechanism, the Department neither determined nor endorsed a specific

term, scope, pace, or approach for NEGC in maintaining and operating its distribution system. D.P.U. 10-114, at 76. The Department determined that NEGC is obligated to provide safe and reliable gas distribution service, and we would not substitute our judgment for utility management's job as to how best to meet and fulfill its service obligations to maintain and operate its system consistent with safety, reliability and other considerations. D.P.U. 10-114, at 76-77, citing Bay State Gas Company, D.T.E. 05-27, at 36-37, 39 (2005). Nevertheless, the Department concluded that during its review of the Company's annual TIRF filings, we would examine, among other things, the Company's performance relative to its proposed pace of leak-prone pipe replacement and project cost control. D.P.U. 10-114, at 64. The Department found that the TIRF mechanism would continue until the Company's next base rate case so long as NEGC demonstrated in its annual filings that its performance satisfies the underlying goals of providing benefit to public safety, service reliability, and the environment. D.P.U. 10-114, at 64-65. Since the establishment of the Company's TIRF, the Department has reviewed and approved one annual TIRF filing made by the Company, without modifying the TIRF mechanism. See New England Gas Company, D.P.U. 11-42 (2012).

In this case, LUC has voluntarily committed to increase the renamed NEGC's TIRF-related main replacement activity from seven to eight miles per year (see Exh. AG-14-10; Tr. 4, at 407, 435-436, 454). We find that this offer does not constitute a modification to the existing TIRF formula and is not inconsistent with our decision in D.P.U. 10-114 or any other provision of the TIRF tariff. See D.P.U. 10-114, at 66 (recognizing that a one percent revenue cap does not limit the level of TIRF-related investments in a given year and provides an incentive for NEGC at least to sustain, and potentially to increase, its current seven-mile per-year

pace of replacement of leak-prone mains in its distribution system, subject to the Company's discretion); M.D.P.U. No. 1002C § 1.10. Further, the record shows that using U.S. Environmental Protection Agency ("EPA") protocols on calculations and emission factors to quantify GHG emissions, replacing one more mile of leak-prone mains would result in reductions in CO_2e emissions, thereby yielding environmental and societal benefits to customers (see Exhs. DOER-1, Atts. PJH-2, PJH-3; DOER-2-5, Att. B).[34]

As noted above, DOER and CLF challenge the extent of LUC's commitment and argue that the TIRF-related main replacement activity should be increased by three miles of main per year for a total of ten miles. The analysis provided by DOER suggests that additional customer savings might be available if the renamed NEGC undertook this level of TIRF-related main replacement (see Exhs. DOER-1, Atts. PJH-2, PJH-3). However, an increase in the level of TIRF-related main replacement implicates other important factors, including the incremental costs associated with additional infrastructure replacement, the adequacy of infrastructure investment cost recovery between rate cases, and internal and external resource capabilities to manage the additional main replacement activities (see Exhs. JP-Rebuttal-4, at 8-11; AG-3-8; Tr. 1, at 53-54). The analysis performed by DOER does not adequately address these factors (see Exhs. DOER-1; DOER-1, Atts. PJH-2, PJH-3). Moreover, we find that the instant proceeding simply does not provide an appropriate forum for investigating and adjudicating all

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[34] The EPA relies on calculations and emissions factors rather than direct measurement to quantify GHG emissions, which raises a question with the precision of expected GHG reductions. However, it is clear that environmental and economic benefits will accrue from NEGC's replacement of an additional mile of leak-prone pipe. The Department notes that it is currently conducting a study to better understand the quantity of gas leaks in Massachusetts and the resulting CO2 emissions.

of these issues. Rather, we conclude that a base rate case is the proper venue for the Department to investigate these issues and to determine whether, in light of all relevant considerations, the renamed NEGC should accelerate the rate of TIRF-related main replacement beyond the level committed to by LUC.[35]

Based on these findings and considerations, the Department accepts LUC's commitment, and we direct the renamed NEGC to modify its TIRF program as necessary to support the replacement of a minimum of eight miles of eligible mains per year. Further, we direct the renamed NEGC to evaluate the feasibility of accelerating the TIRF-related main replacement rate beyond eight miles per year. The renamed NEGC shall provide the results of such evaluation at the time of the renamed NEGC's next base rate case.

Next, we evaluate the Joint Petitioners' activities and commitments that advance clean energy development and address climate change. In particular, LUC has committed to the post-closing performance of an energy audit at the three service facilities occupied by NEGC,[36] and agrees to explore the feasibility of implementing CNG vehicles in the future (see Exh. DPU-8-12; Tr. 2, at 256; Tr. 4, at 453-454, 460-461). Again, DOER and CLF criticize the Joint Petitioners' lack of a meaningful plan of action on these issues (see DOER Reply Brief at 2; CLF Brief at 13-14). We are mindful of the fact that the renamed NEGC is a relatively small gas distribution company. Further, it is reasonable to expect that LUC, as the new owner

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35 We note that in the one instance when the Department has modified a company's existing TIRF program to establish a main replacement threshold, we did so in the context of a base rate case. See Bay State Gas Company, D.P.U. 12-25, at 51-54 (2012).

36 The Company currently operates three service facilities – 5th Street, Charles Street, and Anawan Street – all located in Fall River, Massachusetts (see Exh. DPU-8-12; RR-DOER-2)

and operator of the renamed NEGC, may require some time to evaluate all possible initiatives that address these issues. Nevertheless, we stress that advancing clean energy development and addressing climate change are important public policy environmental objectives that we expect all electric and gas distribution companies operating in Massachusetts to recognize and pursue. We find that based on the circumstances of the instant case, the commitments of an energy audit at the three service facilities and the exploration of CNG vehicles are reasonable first steps toward addressing these objectives. We direct the renamed NEGC to submit within 30 days of LUC's assuming operational control of the renamed NEGC a report providing details and a timeline for the performance of the energy audits and the plan for exploring the incorporation of CNG vehicles into its fleet. We expect that the energy audits, in particular, will be conducted as expeditiously as possible following LUC's assumption of operational control over the renamed NEGC and prior to the filing of the renamed NEGC's next base rate case. The renamed NEGC shall submit to the Department within 60 days of the completion of each audit a comprehensive written plan and timeline for implementing those cost-effective strategies that are recommended by each audit. In the meantime, we direct the renamed NEGC to explore additional meaningful initiatives to reduce GHG gas emissions, advance clean energy development and address climate change. The renamed NEGC shall include the results of these efforts as part of its initial filing in its next base rate case.

3. Effect on Customer Service and Service Quality

a. Introduction

In analyzing the proposed transaction, and in accordance with the § 96 standard of review set forth above, the Department considers the potential impact of the sale of NEGC's assets on

quality of service, any anticipated interruptions of service, and any other factors that may adversely impact customer service. In general, the Joint Petitioners submit that as a result of the proposed transaction, customer service will improve based on LUC's "local utility approach," which includes repatriating the customer service functions to Massachusetts and hiring additional customer service employees (Exhs. NEGC-2 (Supp.) at 8; DPU-1-8; DPU-1-17; DPU-1-26, at 1). Further, the Joint Petitioners expect to retain all NEGC employees for at least a year after closing of the proposed transaction (Exhs. AG-3-9; AG-5-44; Tr. 4, at 430-433; RR-AG-9). The Joint Petitioners also expect no adverse impacts on service quality, no greater potential for service interruptions, and no negative service quality consequences resulting from the proposed transaction (Exh. NEGC-2 (Supp.) at 8).

b. Positions of the Parties

i. Attorney General

The Attorney General contends that NEGC's current walk-in services provide appropriate customer care and that the Company's customer satisfaction levels are exemplary (Attorney General Brief at 20, citing Exhs. AG-DMB at 9-10; AG-6-8; AG-8-15). Thus, according to the Attorney General it is unclear how LUC intends to improve in these areas and provide meaningful net benefits to customers (Attorney General Brief at 21).

Finally, the Attorney General argues that LUC's commitment to retain employees for one year after the closing of the transaction is a ploy to increase the Company's labor expense for what would be the test year of a future rate case once the rate freeze expires (Attorney General Supplemental Reply Brief at 8). The Attorney General contends that subsequent to that period, the Company would be free to terminate the employees and keep any savings for shareholders

(Attorney General Supplemental Reply Brief at 8). Further, the Attorney General notes that the Joint Petitioners have not promised to offset the costs of the twelve or more new hires with post-test year savings from transaction-related employee reductions (Attorney General Supplemental Reply Brief at 8). Thus, the Attorney General asserts that the Department should not consider the one-year promise of retaining staff as a net benefit for customers (Attorney General Supplemental Reply Brief at 8).

ii. Joint Petitioners

The Joint Petitioners argue that service provided to NEGC customers will improve post-transaction (Joint Petitioner Brief at 18). First, the Joint Petitioners assert that the local utility approach provided by LUC will include (i) an experienced local management team that will be empowered to deliver local, responsive, and caring customer service; (ii) the construction of local walk-in centers; and (iii) the addition of ten additional, locally hired, customer service representatives, a customer service supervisor, and a director of regulatory strategy (Joint Petitioner Brief at 18-19, 20, citing Exh. DPU-1-26; Tr. 1, at 90-92; Tr. 2, at 248-249; Joint Petitioner Supplemental Brief at 10). The Joint Petitioners submit that these changes will allow customers to complete transactions for utility services by speaking directly with employees who live in the communities served and who are engaged in local issues (Joint Petitioner Brief at 20). Further, according to the Joint Petitioners, this local approach allows for better monitoring, training, and operations of customer service functions (Joint Petitioner Brief at 18). For instance, the Joint Petitioners note that local management will be able to monitor, on a real-time basis, call volumes and customer walk-in traffic, allowing management to reallocate resources where needed to best serve customer needs (Joint Petitioner Brief at 20,

citing Exhs. DPU-2-21; AG-2-15. In addition, the Joint Petitioners note that LUC has committed that no terminations, involuntary severances, or induced retirements will result from the proposed transaction for at least a period of one year, thereby increasing the depth of what they consider to be an already experienced and local resource (Joint Petitioner Supplemental Brief at 10, citing RR-AG-9).

Second, the Joint Petitioners anticipate that service quality will be favorably affected by the adoption of "best practices" by subsidiary companies (Joint Petitioner Brief at 19, citing Exhs. NEGC-4, at 14-16; AG-2-4). The Joint Petitioners claim that customers should benefit from the exchange of ideas, methods and procedures and the implementation of system-wide best practices in the areas of operations and customer service (Joint Petitioner Brief at 19, citing Exhs. AG-2-4; AG-5-34; Tr. 1, at 90-92).

Third, the Joint Petitioners argue that the proposed transaction will not change the Department's authority to measure and monitor the quality of service provided by NEGC to its customers (Joint Petitioner Brief at 19). In this regard, the Joint Petitioners assert that they do not anticipate any negative service-quality impacts resulting from the proposed transaction (Joint Petitioner Brief at 19).

Fourth, the Joint Petitioners contend that the proposed transaction has a strong potential to increase the service quality for NEGC customers through improvements in the lost time accident rate measure and potential reductions in odor calls through increased infrastructure replacement (Joint Petitioner Brief at 19, citing Exhs. NEGC-4, at 14-16; DPU-1-8; AG-2-6; AG-8-2; Tr. 2, at 248-249). The Joint Petitioners argue that setting aside these improvements,

there is no evidence in the record to suggest that service quality will decrease as a result of the proposed transaction (Joint Petitioner Brief at 19).

c. Analysis and Findings

The Department recognizes the importance of maintaining service quality standards, especially when a change of ownership of a company (and any resulting economies of scale in an effort to achieve cost savings) could result in service quality degradation. See D.P.U. 10-170-B at 73; Boston Gas Company/Essex Gas Company, D.P.U. 09-139, at 23 (2010). Therefore, in analyzing the proposed transaction, and in accordance with the § 96 standard of review set forth above, the Department considers the potential impact of the proposed sale on quality of service, any anticipated interruptions of service, and any other factors that may adversely impact customer service.

Currently, calls to NEGC's customer service line are received and processed by ten customer service representatives and one call center supervisor working in – and presumably living in or around - Robinson, Pennsylvania, hundreds of miles from NEGC's service territory (Exhs. AG-1-3(g); AG-2-27; AG-4-14). LUC intends to change this structure and, within twelve to 18 months of closing of the proposed transaction, repatriate the customer service center to Massachusetts, where at least one new customer service center will be opened and staffed by ten locally hired customer service representatives and a locally hired customer service supervisor (Exhs. NEGC-4, at 9-10; DPU-1-8; DPU-1-17; DPU-1-26, at 1; DPU-2-6; DPU-2-16; AG-1-6; AG-1-3(f); AG-5-48; Tr. 1, at 37, 87-88, 144-145). Customer calls will be answered by customer-service representatives who live in or around NEGC's service territory and are familiar

with the characteristics of the service area and the utility-related issues facing NEGC customers (Exh. DPU-1-8).

The customer service center will double as a walk-in center (Tr. 1, at 37). Both of NEGC's predecessor organizations, Fall River Gas Company and North Attleboro Gas Company, had customer walk-in centers, which were closed years ago under Southern Union's ownership (Exhs. AG-2-30; AG-3-12). NEGC currently offers expanded hours only in its credit department, located at its Fall River headquarters, where customers can pay on overdue accounts, or receive information regarding making payments to a third-party pay station (Exhs. AG-2-30; AG-6-8; AG-8-15).[37] Under LUC's ownership, customers at a walk-in center will be able to interact personally with utility representatives and pay bills, request new service, have their questions answered, and receive information and assistance on various company programs (Exhs. DPU-1-8; DPU-1-17; DPU-1-26; AG-1-6; Tr. 1, at 37, 87-88).

In addition to these anticipated changes, LUC plans to offer employment to all of the Massachusetts-based employees of NEGC, and has committed that no terminations, involuntary severances, or induced retirements will result from the proposed transaction for at least a period of one year following the closing of the proposed transaction (Exhs. AG-3-9; AG-5-44; Tr. 1, at 148; Tr. 4, at 430-433; RR-AG-9). Further, LUC plans to support all existing and new personnel with a senior management team made up of employees who have significant experience managing Massachusetts utilities and familiarity with applicable regulations

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[37] Currently, NEGC customers may make bill payments at pay stations located in various retail establishments throughout the Company's service territory (Exhs. AG-3-11 & Att.; AG-8-18; AG-8-19; AG-8-20; AG-8-21 & Att.). LUC does not intend to reduce the number of pay stations (Exh. AG-8-22).

(Exhs. NEGC-4, at 6-8; DPU-1-26; Tr. 4, at 430-433; RR-AG-9). The effect of these changes is the creation of an autonomous, New England-based organization running the utility and dedicated to the needs of Massachusetts customers (Exhs. NEGC-4, at 6-8; DPU-1-26).[38]

The Attorney General argues that the Joint Petitioners' assurance of employee retention is a ploy to increase the renamed NEGC's labor expense for what would be the test year of a future rate case once the base rate freeze expires (Attorney General Supplemental Reply Brief at 8). The Attorney General contends that subsequent to that period, the Company would be free to terminate the employees and keep any savings for shareholders (Attorney General Supplemental Reply Brief at 8). We find such an assertion to be speculative and unsupported by any evidence on the record in this proceeding. Moreover, at the time of the renamed NEGC's next rate case, the Attorney General will have an opportunity to investigate and present evidence on any issues concerning the company's employee count and employee retention practices. Nevertheless, consistent with its public service obligation, the renamed NEGC is required to make employment decisions in the public interest.

Based on these findings and considerations, we conclude that the customer service-related changes described above should enable the renamed NEGC and LUC to provide a level of management focus, community commitment and local engagement that will enhance customer service capabilities for the benefit of NEGC ratepayers. However, we stress that such

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[38] In contrast, we note that Southern Union, the Texas-based current owner of NEGC's assets, is eager to depart the local gas distribution business. In announcing the sale of NEGC and MGE, Energy Transfer Partners, L.P. ("ETP"), a parent company of Southern Union (see n.45 below), stated that the sale of these assets is another important step in ETP's efforts to streamline and integrate its asset portfolio through the divestiture of non-core assets" (see ETP Press Release (September 3, 2013) at 1, available at www.energytransfer.com).

efforts will be of little consequence if the quality of service that the new and current employees provide deteriorates. In this regard, LUC submits that because the renamed NEGC will continue to be operated by highly qualified, local personnel who are familiar with the needs of the service area, no service interruptions are expected and emergency response efforts should be enhanced (Exhs. DPU-1-11; DPU-1-12). Further, LUC expects that the repatriation of the customer service function to Massachusetts will result in the continuation of NEGC's high level of performance in the emergency and non-emergency telephone response performance measures (Exhs. DPU-1-13; DPU-1-14). LUC also intends to maintain NEGC's service appointments and odor call response time performance measures, which in 2012 were 100 percent for both the Fall River and North Attleboro service areas (Exhs. DPU-1-15; DPU-1-18). Further, the Joint Petitioners note that NEGC's meter reading performance has experienced continued improvements, and that LUC will continue NEGC's goal of completing by 2015 the current seven-year automatic meter reading installation project (Exh. DPU-1-16). In addition, the Joint Petitioners do not expect LUC's ownership of NEGC's assets to have detrimental effect on the service quality measures of consumer division cases or billing adjustments, which are set on ten years of historical data (Exh. DPU-1-17). Moreover, LUC anticipates improvement in the lost time accident rate performance measure through implementation of LUC's training programs (Exhs. DPU-1-18; AG-2-6). Finally, LUC intends that NEGC's current service quality filing practices will continue to be made consistent with its service quality plan, as approved by the Department in Service Quality Plans for Local Gas Distribution Companies, D.P.U. 07-51 (2008), and in compliance with the procedures established by the Department (Exh. DPU-1-9).[39]

[39] The Department is currently reviewing its service quality standards in Service Quality

Based on the above considerations, we find that there should be no negative service quality effects resulting from the proposed transaction. We note that the performance benchmarks included in NEGC's current service quality plan will remain in place and apply to the renamed NEGC. These performance benchmarks provide strong incentives for the renamed NEGC to ensure that its ratepayers will be protected from service degradation following the proposed transaction. In this regard, the Department will continue to monitor the renamed NEGC's service quality performance pursuant to the established process for reviewing distribution companies' service quality performance in annual filings and future rate cases, in order to hold LUC to its representations regarding the renamed NEGC's service quality performance.

4. Resulting Net Savings

a. Introduction

As discussed above, one of the factors that the Department reviews when considering a proposed acquisition is projected net savings. Initially, the Joint Petitioners stated that significant net savings were not expected as a direct result of the proposed transaction (Exhs. NEGC-4, at 16; DPU-1-21; DPU-1-26; DPU-1-35; AG-9-15; Tr. 1, at 44-45). During the course of the proceedings, the Joint Petitioners identified savings opportunities related to eliminating the outsourcing of NEGC's billing arrangements, lowered debt costs, and transferring regulatory services in-house (Exhs. JP-Rebuttal-5, at 7-8; JP-Rebuttal-5A).

Standards for Electric Distribution Companies and Local Gas Distribution Companies, D.P.U. 12-120. The renamed NEGC will be subject to any additional or more stringent service quality standards that the Department may impose in that proceeding.

b. Positions of the Parties

i. Attorney General

The Attorney General argues that the timing and nature of the Joint Petitioners' net savings submissions is suspect, given that the Joint Petitioners initially claimed that no such savings or staff reductions were anticipated (Attorney General Brief at 16, 18, citing Exhs. NEGC-4, at 12; AG-2-16; AG-2-17; AG-9-15). Further, the Attorney General contends that the Joint Petitioners' savings quantifications are flawed, and even when adjusted for such concerns, there are no quantifiable net benefits (Attorney General Brief at 16, citing Exhs. AG-AEP Surrebuttal-1, at 8-14; AG-AEP Surrebuttal-3). In fact, the Attorney General asserts that, conservatively, customers can expect to incur several years of net costs even without consideration of the loss of ADIT benefits associated with the TIRF mechanism (Attorney General Brief at 16, citing AG-RR-3, at 2).

In particular, the Attorney General argues that nominal adjustments in staff of the type that make up anticipated savings from switching to in-house staff positions are not the type of savings that the Department could rely on to have any degree of permanence (Attorney General Brief at 16-17, citing Exh. AG-AEP Surrebuttal-3). Further, the Attorney General contends that there is no evidence that the costs associated with adding in-house personnel should be significantly different from the current costs of external personnel and, therefore, there is no evidence of net savings to customers (Attorney General Brief at 19, citing Exhs. JP-Rebuttal-5, at 25; Exh. AG-8-23). The Attorney General also argues that while costs associated with outside services received from affiliates, such as Southern Union, Energy Transfer, Inc. and MGE, and third-party vendors will remain flat after the closing of the proposed transaction, costs connected

with customer service center representatives will actually increase post-transaction (Attorney General Brief at 17-18, citing Exhs. AG-DMB, at 4-6, 7; DPU-AG-1-5). Thus, the Attorney General argues that the repatriation of the customer call center and walk-in center do not provide any financial savings or tangible benefits for customers (Attorney General Brief at 19).

ii. Joint Petitioners

The Joint Petitioners claim that customers will be the beneficiaries of up to $1,800,000 a year in annual operating cost reductions resulting from: (i) potential savings in costs of capital based on lower cost of debt used to finance the purchase of NEGC's assets ($774,000); (ii) lower cost of debt for future capital expenditures ($391,000); (iii) in-sourcing certain functions that are currently handled by outside vendors ($150,000); and (iv) investments in customer service billing infrastructure, specifically the introduction to NEGC of the Cogsdale billing system ($436,000) (Joint Petitioner Brief at 17, 20-22, citing Exhs. JP-Rebuttal-5, at 7-8; JP-Rebuttal-5A at 1, 6, 7; AG-8-24; Tr. 1, at 45-47, 49-50; Tr. 2, at 209-212; Joint Petitioner Supplemental Brief at 8).

According to the Joint Petitioners, LUC expects to achieve these permanent cost savings within five years of the closing of the proposed sale of NEGC's assets (Joint Petitioner Brief at 17, 20-21, 22, citing Exhs. JP-Rebuttal-5, at 7-8; JP-Rebuttal-5A at 1; Tr. 1, at 49-50). However, the Joint Petitioners note that savings from the proposed transaction begin to inure to the benefit of customers immediately, and when combined with the proposed rate base offset, are projected to total over $1,000,000 in the first year following the closing, and $1,100,000 in 2015 (Joint Petitioner Reply Brief at 8, citing Exhs. JP-Rebuttal-5; JP-Rebuttal-5A). The Joint

Petitioners argue that although savings associated with the Cogsdale billing system are not projected to start until 2016, those savings represent less than 20 percent of the total savings expected in 2016 (Joint Petitioner Reply Brief at 8-9). In fact, the Joint Petitioners note that 70 percent of the cost savings projected for 2016 will be achieved in 2014 (Joint Petitioner Reply Brief at 9). In sum, the Joint Petitioners submit that net operating annual savings ranging from $2,360,400 to $3,096,816 are conservatively estimated for the five year period immediately following the closing of the proposed transaction (Joint Petitioner Supplemental Reply Brief at 21, citing Exh. JP-Rebuttal-5A). According to the Joint Petitioners, these savings are in addition to a range of other benefits expected from the proposed transaction and are uncontroverted (Joint Petitioner Supplemental Reply Brief at 21).

Further, the Joint Petitioners submit that LUC will preserve the original cost value of the plant and will not make any adjustments to this value after the closing of the proposed transaction (Joint Petitioner Supplemental Brief at 8, citing Exh. DPU-8-11). According to the Joint Petitioners, the revenue requirement established in the next base rate proceeding, and subsequent proceedings, will lock into base rates operating-cost savings achieved through the end of the test year (Joint Petitioner Supplemental Brief at 8). The Joint Petitioners assert that these savings, coupled with the rate base offset discussed above, will ensure net benefits in the form of reduced operating costs that are captured in rates for the benefit of customers (Joint Petitioner Supplemental Brief at 8).

c. Analysis and Findings

i. Introduction

In reviewing a proposed acquisition, one of the factors the Department considers is the resulting net savings, if any. In this regard, the "Department's review… must be based on whether the figures proposed by the [p]etitioners are reasonable estimates." D.T.E. 99-47, at 47, 50. Projections of future events can be judged in terms of whether they are substantiated by past experience and supported by logical reasoning founded on sound theory. D.P.U. 09-139, at 19-20; National Grid/Keyspan Corporation, D.P.U. 07-30, at 27 (2010); D.T.E. 99-47, at 50.

ii. Costs and Savings

Our analysis of the net savings issue begins with an examination of the costs that the renamed NEGC will incur as a result of the proposed transaction. The Joint Petitioners do not intend to seek recovery of any transaction or transition costs, nor do they seek to recover an acquisition premium associated with the proposed transaction (Exhs. DPU-1-22; DPU-1-25, Att.; DPU-4-11; Tr. 1, at 41-42, 59, 83). However, the Joint Petitioners have identified several areas of acquisition-related costs that will be sought for recovery from ratepayers of the renamed NEGC.

The first category of costs relates to rebranding efforts necessary to replace current assets and operate the utility, such as replacing signs and decals with the renamed NEGC moniker (Exh. DPU-1-22; DPU-1-24; DPU-1-25, Att.; AG-9-16). The Joint Petitioners estimate these efforts will cost approximately $100,000 (Exhs. DPU-1-22; DPU-1-24; AG-9-16).

The second category of costs relates to capital expenditures concerning the deployment of LUC's information technology ("IT") systems, including the Cogsdale billing system, and IT

infrastructure, such as telephones and computers (Exhs. DPU-1-25, Att.; AG-9-16; Tr. 1, at 31-35; RR-DPU-1). In the normal course of business, LUC intends to transition the renamed NEGC to LUC's own standardized technology platform (Exh. AG-9-6). The Joint Petitioners estimate the cost of these capital expenditures to be $4,810,000 (Exh. AG-9-16; RR-DPU-1). Of this amount, approximately $3,200,000 is attributable to the Cogsdale billing system (Exhs. DPU-4-10; JP-Rebuttal-5A at 5; Tr. 1, at 46, 48, 56; RR-DPU-1).[40]

Next, the record shows that the renamed NEGC will incur annual operating expenses of approximately $27,000 related to IT maintenance and software renewals (Exh. AG-12-7; Tr. 1, at 34, 48-49). Further, the renamed NEGC will incur approximately $1,535,000 in direct and allocated charges from LUC's parent company, APUC, and other subsidiaries (see Exhs. DPU-1-27; DPU-7-10; Tr. 1, at 57, 107-107; RR-DPU-8).[41] These charges include payroll expenses, certain outside service fees, rents, travel expenses, and other corporate costs

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40 The Joint Petitioners note that $200,000 of the $3.2 million relates to NEGC's share of the purchase price of the Cogsdale billing system, which will be shared among the renamed NEGC and its affiliates EnergyNorth Natural Gas, Inc. and Granite State Electric Company (Exh. AG-12-6; Tr. 1, at 48, 56).

41 The Joint Petitioners note that after the acquisition, the renamed NEGC will receive gas supply services from LUC's gas procurement department, which is located in New Hampshire, and costs will be allocated pursuant to the APUC cost allocation manual (Exh. DPU-1-27). Further, on an as needed basis, the renamed NEGC may also seek support from LUC's New Hampshire management team, for which costs would be directly billed (Exh. DPU-1-27). In addition, the renamed NEGC will receive from APUC and Liberty Utilities (Canada) Corp., corporate management services similar to those provided by Southern Union (Exh. DPU-1-27). Finally, the employees of the renamed NEGC will be employed by Liberty Utilities Service Corp., an affiliate of the renamed NEGC (Exh. DPU-1-27). Accordingly, the renamed NEGC will receive services from Liberty Utilities Service Corp., and these costs will be allocated pursuant to the APUC cost allocation manual, which requires direct billing whenever possible (Exh. DPU-1-27).

(Tr. 1, at 57-58; RR-DPU-8). In addition, LUC expects to spend approximately $1,000,000 in salaries and benefits related to the retention of 14 new customer service and regulatory affairs employees (Exh. JP-Rebuttal-5A at 8).

Finally, the Joint Petitioners identified another area of potential costs relating to continuing services to be provided by MGE to operate the renamed NEGC until such time as LUC is capable of offering the services on a stand-alone basis (Exh. DPU-1-25, Att.). Under the current shared services arrangement with MGE, NEGC receives the following services: accounts payable, plant accounting, and gas supply (Exhs. DPU-1-27, at 1; AG-1-13, at 1; AG-6-10, at 1; AG-8-9). The annual cost of these services is approximately $300,000, and is included in NEGC's current rates (Exh. AG-8-9; Tr. 1, at 105). The Joint Petitioners note that MGE may continue to support NEGC for a period of time after the closing of the proposed transaction, but at the time of the evidentiary hearings in this case the need for, and duration and costs of, these continued services were not yet known (Exhs. NEGC-4, at 5; DPU-7-10; AG-2-1; AG-5-45; Tr. 1, at 59).

Several of the costs discussed above will be partially or completely offset by savings. In particular, the Cogsdale billing system will be implemented in two years and the renamed NEGC no longer will utilize its current third-party billing vender, Vertex, to which it pays an annual fee of $950,000 (Exh. JP-Rebuttal-5A at 5; Tr. 1, at 46, 48, 56; RR-DPU-1). The Cogsdale billing system will begin to provide immediate savings when compared to the Vertex option, and by the third year of operation the renamed NEGC is expected to experience annual savings of $436,000 over the current outsourced provider (see Exhs. JP-Rebuttal-5, at 7; JP-Rebuttal-5A at 1, 5; Tr. 1, at 45-46). The remaining amount of the $4,810,000 in IT capital costs not attributable to the

Cogsdale billing system totals $935,000 (RR-DPU-1). However, NEGC's current allocation of IT capital costs from Southern Union totals approximately $970,000 (RR-DPU-1). As such, the renamed NEGC is expected to experience some modest cost savings in this area.

As noted above, the renamed NEGC will incur approximately $1,535,000 in direct and allocated costs as a result of the proposed transaction (RR-DPU-8). However, the Company's current allocated share of similar expenses totals approximately $1,600,000 (RR-DPU-8). Therefore, the renamed NEGC is expected to experience cost savings in this area.

Further, while the renamed NEGC will see an increase in payroll and related expenses of about $550,000 as a result of the eleven new customer service hires, it no longer will pay $554,000 in annual expenses for the Robinson, Pennsylvania customer service center (Exhs. JP-Rebuttal-5, at 25; JP-Rebuttal-5A at 8; AG-1-3; Tr. 1, at 44, 55, 147-148). Thus, the renamed NEGC should experience nominal savings in this area.

Similarly, the costs associated with the three regulatory affairs employees that LUC intends to hire are approximately $459,000 (Exh. JP-Rebuttal-5A at 8). These employees will perform certain regulatory services, such as preparing day-to-day filings, which currently are outsourced and cost NEGC approximately $611,000 annually (Exhs. JP-Rebuttal-5A at 8; AG-3-14; AG-8-24; Tr. 1, at 44). Thus, the result of bringing these functions in-house is expected to be annual savings of approximately $152,000 (see Exhs. JP-Rebuttal-5, at 7-8; JP-Rebuttal-5A at 6).

In addition, the Joint Petitioners note that the associated cost of debt on future capital projects will be lower, because the renamed NEGC no longer will have a blended debt rate imputed (Exh. JP-Rebuttal-5, at 7). The record shows that savings associated with the cost of

debt will amount to approximately $91,000, but over the course of five years will rise to approximately $391,000 on an annual basis (Exhs. JP-Rebuttal-5, at 7; JP-Rebuttal-5A at 1, 3).

The Joint Petitioners also identify savings related to a lower cost of debt used to finance the proposed transaction (Exh. JP-Rebuttal-5, at 7). In particular, they calculated the annual savings in debt costs as follows: total debt of NEGC of $39,710,532, less the amount of debt assumed of $19,500,000 to arrive at an incremental debt amount of $20,210,532 (Exh. JP-Rebuttal-5A at 7). The Joint Petitioners then subtracted the rate of debt costs under LUC ownership of 3.5 percent from the rate of debt costs under Southern Union ownership of 7.33 percent to arrive at a cost of debt difference of 3.83 percent (Exh. JP-Rebuttal-5A at 7). The Joint Petitioners applied the cost of debt difference to the incremental debt amount to arrive at annual savings of $774,000 (Exh. JP-Rebuttal-5A at 7).

On this point, we find that the Joint Petitioners' calculation of savings is overstated. The record shows that the $19,500,000 in debt being assumed by LUC has an 8.24 percent cost, and when blended with the estimated 3.5 percent cost of the incremental debt, yields a weighted debt cost rate for the renamed NEGC of 5.83 percent (Tr. 2, at 204-207, 257-258). In turn, the cost of debt difference is 1.5 percent (7.33 – 5.83), not 3.83 percent claimed by the Joint Petitioners. Applying the debt difference to the incremental debt amount of $20,210,532, produces annual savings of $303,158.

Finally, the Joint Petitioners include in their analysis of savings potential downstream benefits associated with the hiring of 14 new employees and the reopening of the customer service center in Fall River (Exh. JP-Rebuttal-5A at 1, 8). The Joint Petitioners calculated the effect of this local employment using the U.S. Bureau of Economic Analysis' Regional

Input-Output Modeling System, which allows the calculation of the downstream job impact and the economic impact on the community of one incremental position (Exh. JP-Rebuttal-5, at 7-8). According to the Joint Petitioners, the direct effect earnings multiplier for an incremental utility position in Bristol County is $1.3312 for each incremental dollar of earning, and the direct effect employment multiplier for an incremental utility position in Bristol County is 1.883 (Exh. JP-Rebuttal-5, at 8). Using these figures, the Joint Petitioners calculated the impact on the local economy of 14 new employees as $1,343,181 downstream dollars being spent and 26 additional downstream jobs being created (Exh. JP-Rebuttal-5A at 8). While this information may be relevant to our analysis of the impact of the proposed transaction on economic development (see Section VI.B.7 below), we are not persuaded that the potential for downstream benefits results in direct savings to ratepayers of the renamed NEGC. As such, we do not consider the Joint Petitioners' calculation of these benefits in our evaluation of net savings.

iii. Conclusion

The Department has reviewed the potential costs and savings associated with the proposed transaction based on the record provided in this proceeding. We also have given careful consideration to the Attorney General's arguments and concerns.

We find that the proposed transaction will result in approximately $27,000 in recurring IT maintenance costs and approximately $100,000 in integration costs that we do not expect to be recurring. The record demonstrates that these costs will be offset by tangible savings. In particular, we expect the renamed NEGC to experience at least $546,000 in annual savings in the first year after the closing of the proposed transaction, comprised of $152,000 in savings related to moving in-house certain regulatory functions; $91,000 in savings related to the cost of debt on

future capital projects; and $303,158 in savings related to the lower cost of debt to finance the proposed transaction. The record shows that the level of savings is projected to increase over the next four years, particularly when the Cogsdale billing system becomes operational and the renamed NEGC ceases to utilize its current outsourced system (see Exh. JP-Rebuttal-5A at 1). We also expect that lower overall IT costs and lower direct and allocated operating costs will produce measureable savings for customers.

Based on these considerations, we conclude that the proposed transaction will result in net savings to ratepayers. However, we direct the renamed NEGC and LUC to explore any and all additional measures that provide the opportunity to maximize efficiencies, minimize costs and pass on resulting savings to customers (see Exh. AG-2-17; Tr. 1, at 42-43). The renamed NEGC shall track all such savings and present the results as part of the initial filing in its next base rate case, at which time the Department will fully examine (i) each of the areas of expected savings identified above and the level of the savings achieved by the renamed NEGC; and (ii) the renamed NEGC's efforts to achieve savings in other areas of operations.

5. Effect on Competition

a. Introduction

One of the factors that the Department considers in determining whether an acquisition is consistent with the public interest is the effect that the acquisition has on competition. According to the Joint Petitioners, NEGC has established processes to conduct business transactions with competitive suppliers serving customers on its distribution system, and such processes are consistent with the protocols of the Department and will remain so following the completion of the proposed transaction, subject to any modification by the Department

(Exh. NEGC-4, at 16). Thus, the Joint Petitioners assert that the sale of NEGC's assets raises no concerns of harm to competitors or adverse affects on competition (Joint Petitioner Brief at 22). No other party addressed this factor on brief.

b. Analysis and Findings

The Joint Petitioners have proposed no changes to NEGC's existing business practices with competitive suppliers serving customers on its distribution system (Exhs. NEGC-4, at 16; DPU-1-36). Thus, the Department finds that the proposed sale of NEGC's assets will not harm either wholesale or retail competition.

6. Financial Integrity of the Post-Acquisition Company

a. Introduction

The Department considers the financial integrity of the post-transaction entity as one of its nine factors for determining whether a proposed transaction is consistent with the public interest. According to the Joint Petitioners, LUC is targeting a capital structure for PMA upon closing of the proposed transaction with 48 percent debt and 52 percent equity (Exh. NEGC-4, at 17-18). The Joint Petitioners state that LUC, at the time of the renamed NEGC's next rate case, is committed to achieving a capital structure in the range of 45-50 percent for the total debt ratio for the purposes of setting rates (Exh. JP-Rebuttal-5, at 35). Further, the Joint Petitioners state that $19.5 million of debt will be assumed by PMA upon the closing of the transaction, and LUC expects to issue approximately $5.5 million in additional short-term debt to PMA (Exh. NEGC-4, at 18). LUC expects to convert that short-term debt to long-term debt at some point in the future, at which point PMA will seek authority from the Department to issue such long-term debt (Exh. NEGC-4, at 18).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that if the Department ultimately approves the proposed transaction, it should impose a condition requiring LUC to use a 45-50 percent total debt ratio for ratemaking purposes in the renamed NEGC's next base rate case (Attorney General Brief at 44). According to the Attorney General, because there are no plans as to when a rate case will be filed, this condition will keep the capital structure consistent pre- and post-transaction, thereby assuring that rates are not affected by the proposed transaction (Attorney General Brief at 44, citing Exh. AG-DMB at 12). Further, the Attorney General asserts that LUC's "commitment" to use a 45-50 percent debt ratio is insufficient and suspect; thus, this debt ratio should be imposed by the Department as a condition to approval of the proposed transaction (Attorney General Reply Brief at 3-4).

ii. Joint Petitioners

The Joint Petitioners assert that post-closing, the NEGC assets will continue to be owned and operated by a financially secure entity with favorable access to both the debt and equity markets (Joint Petitioner Brief at 23, citing Exhs. NEGC-4, at 17; DPU-1-37; Tr. 2, at 191-192). The Joint Petitioners note that LUC has an "investment grade" balance sheet (Standard and Poor's BBB- rating) with a modest debt level that targets a balanced 45-50 percent total debt ratio for each of its utilities (Joint Petitioner Brief at 23, 57). Thus, as noted above, while the Joint Petitioners state that LUC will target a capital structure consisting of 48 percent debt at the time of closing, they note that at the time of the renamed NEGC's next base rate case, LUC is

committed to achieving a capital structure in the range of 45-50 percent for the total debt ratio for setting rates (Joint Petitioner Reply Brief at 57, citing Exh. JP-Rebuttal-5, at 35).

Further, the Joint Petitioners contend that LUC is capable of obtaining debt financing at favorable rates, as demonstrated by recent debt issuances (Joint Petitioner Brief at 23).[42] The Joint Petitioners assert that LUC intends to maintain investment grade status for the utilities group to ensure ready access to debt on reasonable terms (Joint Petitioner Brief at 23). In addition, the Joint Petitioners submit that the renamed NEGC will have access to the equity markets through LUC's parent company, APUC (Joint Petitioner Brief at 23). According to the Joint Petitioners, the liquidity of APUC's shares is demonstrated by the large number of analysts who cover its stock and the support shown in the capital markets for its business strategy (Joint Petitioner Brief at 23).

Based on these considerations, the Joint Petitioners assert that the proposed transaction will produce an entity with a lower cost of debt than would be achievable if not for the new ownership (Joint Petitioner Brief at 24, citing Exh. DPU-5-5; Tr. 2, at 191-192).

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42 According to the Joint Petitioners, LUC's debt offerings in 2010, 2011, and 2012 were oversubscribed, notwithstanding current tight credit markets (Joint Petitioner Brief at 23, citing Exh. NEGC-4, at 17). Further, the Joint Petitioners assert that in 2012, LUC issued $225 million of debt at 4.38 percent with maturity of over ten years (Joint Petitioner Brief at 23). The Joint Petitioners note that this debt issuance obtained a BBB (flat) investment grade credit rating from Dominion Bond Rating Service (Joint Petitioner Brief at 23).

c. Analysis and Findings

We have reviewed NEGC's and LUC's financial and operating data, as represented in part by globally recognized credit agencies[43] ratings, Annual Reports to the Department, balance sheets, annual reports to shareholders, and separate and combined cash position(s) (Exhs. NEGC-4, at 17; DPU-2-8, Att. A; DPU-2-11; DPU-4-1, Att.; DPU-4-3; DPU-4-5; DPU-4-6; DPU-5-1; DPU-5-10; DPU-5-17; DPU-5-19; DPU-6-21; DPU-6-26, Atts.; AG-1-2 & Atts.; AG-2-18, Atts.). Based on this review, we find that both NEGC and LUC are viable companies, and NEGC's financial integrity is unlikely to be adversely affected by approval of the proposed asset sale. Moreover, the renamed NEGC's financial position may be enhanced by LUC's access to the debt and equity markets, as well as APUC's access to the capital markets (Exhs. NEGC-4, at 17; DPU-1-37; Tr. 2, at 191-192).

The Joint Petitioners note that by the time of the renamed NEGC's next base rate case, LUC is committed to achieving a capital structure in the range of 45-50 percent for the total debt ratio for setting rates (Exh. JP-Rebuttal-5, at 35). The Attorney General asserts that the Department should enforce this commitment at this stage and condition approval of the proposed transaction on LUC's use of a 45-50 percent total debt ratio in the next rate case (Attorney General Brief at 44). We find that it is prudent to examine issues concerning a company's capital structure, including a company's total debt ratio, in the context of a base rate case when all information relevant to setting rates is available for the Department's review and consideration. Therefore, we decline to impose the Attorney General's suggested condition.

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[43] The Joint Petitioners provided analyses by credit ratings agencies Dominion Bond Rating Service, Fitch Ratings, Standard & Poor's, and Moody's Investor Services (Exhs. DPU-2-11; AG-2-18, Atts.).

7. Societal Costs and Effect on Economic Development

a. Introduction

In evaluating the proposed transaction under § 96, the Department may consider the resulting societal costs and impact on economic development, if any. In this proceeding, the Joint Petitioners state that the proposed transaction produces benefits in both areas through LUC's emphasis on a renewed local focus with respect to operations and LUC's intention to add 14 incremental jobs in Massachusetts (Exhs. NEGC-4, at 6-8, 18-19; JP-Rebuttal-5, at 7; DPU-1-39; DPU-1-40; Tr. 1, at 90-92, 142-144; Tr. 2, at 248-249).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that while there may be some positive effect on economic development resulting from jobs moving to Fall River, the Joint Petitioners have failed to demonstrate societal benefits for the service area because the customer service jobs are being relocated and not newly created (Attorney General Brief at 20, citing Exh. AG-DMB-Surrebuttal-1, at 9; Attorney General Reply Brief at 9, citing Exh. AG-DMB-1, at 7). Further, the Attorney General contends that although jobs will be brought to Fall River, a matching job loss will be experienced in Pennsylvania where the proposed repatriated employees currently work (Attorney General Reply Brief at 9). In addition, the Attorney General claims that the three regulatory jobs proposed for relocation to Massachusetts would result in a loss of $850,155 to consulting firms that currently provide these services (Attorney General Reply Brief at 9). According to the Attorney General, when these losses are considered, the net effect "is a wash" and there are no societal benefits in the form of

downstream dollars or jobs (Attorney General Reply Brief at 9, citing Exh. AG-DMB-Surrebuttal-1, at 8).

ii. Joint Petitioners

The Joint Petitioners assert that the proposed transaction will result in a net benefit with respect to societal interests and economic development (Joint Petitioner Brief at 25, 27). In particular, the Joint Petitioners note that LUC has never sold a utility that it has purchased and is committed to owning and operating the renamed NEGC for a minimum of five years, thereby providing customers with a stable, financially secure owner (Joint Petitioner Brief at 27, citing Tr. 1, at 145-146; RR-DPU-12). Further, the Joint Petitioners claim that LUC is committed to a renewed local focus, including opening additional customer walk-in centers, assigning experienced local personnel to manage NEGC's assets, maintaining operational headquarters in Fall River, and continuing NEGC's record of charitable contributions and community support (Joint Petitioner Brief at 26-27, citing Exhs. NEGC-4, at 6-8, 18; DPU-1-39; Tr. 1, at 90-92, 142-144; Tr. 2, at 248-249).

The Joint Petitioners also contend the repatriation of 14 employees to Massachusetts will have a positive economic benefit in Bristol County and result in a total of $1,300,000 in downstream dollars spent and 26 additional downstream jobs created (Joint Petitioner Brief at 25-26, citing Exh. JP-Rebuttal-5A at 8). According to the Joint Petitioners, there is no evidence that the proposed transaction will result in jobs being lost in other states and, even assuming such evidence existed, it is irrelevant to the Department's determination of whether the sale of NEGC's assets produces net benefits to Massachusetts customers (Joint Petitioner Reply Brief at 10).

c. Analysis and Findings

The Department has held that proponents of mergers, consolidations, and acquisitions must demonstrate that they have a plan for minimizing the effect of job displacement on employees. D.T.E. 98-27, at 44. In the instant case, LUC plans to offer employment to all of the Massachusetts-based employees of NEGC, and has committed that no terminations, involuntary severances, or induced retirements from the proposed transaction will occur for at least one year following the closing of the proposed transaction (Exhs. DPU-1-40; AG-3-9; Tr. 1, at 148; Tr. 4, at 430-433; RR-AG-9). Thus, we find that the Joint Petitioners have demonstrated a plan for minimizing the effect of any job displacements on employees.

Further, LUC intends to add 14 incremental job positions, consisting of repatriated customer service employees and regulatory affairs employees, to Bristol County (Exhs. NEGC-4, at 9-10, 19; JP-Rebuttal-5, at 7; see also Sections VI.B.3 and VI.B.4 above). In addition, as noted above in Section VI.B.4.c, the added job positions are expected to result in a total of $1,300,000 in downstream dollars spent and 26 additional downstream jobs created (Exhs. JP-Rebuttal-5, at 7; JP-Rebuttal-5A at 8). These new jobs and downstream dollars spent are likely to have a positive economic effect on communities in and around Bristol County.

Regarding the Attorney General's arguments, the ten customer service representatives located in Pennsylvania will be supplanted by ten new locally hired customer service representatives working in Massachusetts. Thus, these are new job positions being added to Massachusetts. In evaluating societal costs, the primary focus of the Department's inquiry is potential job loss on employees of the utility or utilities subject to a merger or acquisition. See, e.g., D.T.E. 00-26, at 15; D.T.E. 00-25, at 16; D.T.E. 99-47, at 33; D.T.E. 98-128, at 86-87;

D.T.E. 98-31, at 50-5l. As stated above, there will be no such job loss, as current Massachusetts employees of NEGC will be offered jobs with the renamed NEGC and there will be no terminations, involuntary severances, or induced retirements from the proposed transaction for at least one year following the closing of the proposed transaction.[44]

8. Alternatives to the Acquisition

a. Introduction

The Joint Petitioners state that Southern Union's parent corporation, Energy Transfer,[45] owns and operates a diversified portfolio of energy assets in the natural gas, natural gas liquids, and propane sectors in the United States (Exh. NEGC-2, at 5-6). According to the Joint Petitioners, Energy Transfer's primary lines of business involve the gathering, treatment, transportation and storage of natural gas, natural gas liquids, propane and crude oil, on a wholesale basis (Exhs. NEGC-2, at 5-6; DPU-1-42). The MGE and NEGC operations are the only state-regulated retail utility operations existing within the Energy Transfer portfolio of

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44 In any event, we note that the current provider of customer service functions on behalf of NEGC is a company with 385 employees and ten other utility clients (Exh. AG-2-27). There is no evidence that the ten employees specifically assigned to NEGC will lose their jobs as opposed to simply being reassigned within the organization. Similarly, the outside consultants that provide regulatory assistance to NEGC include accounting and legal firms that are well known to the Department and provide work on behalf of other regulated utilities (see Exh. JP-Rebuttal-5A at 6-7). These consulting companies operate in a competitive environment and they can expect some level of churn rate, and there is no evidence that these firms will cease to provide services to Massachusetts utilities in the future.

45 The Joint Petitioners note that Southern Union is a wholly owned subsidiary of ETP Holdco Corporation, which is owned 60 percent by Energy Transfer Equity, L.P. and 40 percent by Energy Transfer Partners, L.P. (see Amended Joint Petition at 2, ¶ 2; Exhs. DPU-1-50(I)(a) (Pre-Acquisition) at 1-2, 4; DPU-1-50(I)(b)). The Joint Petitioners refer to "Energy Transfer" as the parent corporation of Southern Union. For ease of reference, and because the issue is not relevant to the disposition of this case, we shall do the same.

assets (Exh. DPU-1-42). The Joint Petitioners state that within the context of Energy Transfer's existing portfolio, the transactions involving the MGE and NEGC assets represent the continuation of Energy Transfer's efforts to streamline and integrate its asset portfolio through divestiture of non-core assets (Exh. DPU-1-42). As such, the sale of these assets was the only option considered (Exhs. NEGC-2, at 16-17; DPU-1-42).

The Joint Petitioners assert that the sale of the NEGC assets to LUC, rather than continued ownership by Southern Union, will be beneficial to NEGC's customers because NEGC will be owned and operated by a corporation in relatively close proximity to NEGC's operations that is exclusively focused on the local distribution business, community commitment and local engagement (Joint Petitioner Brief at 28-29). According to the Joint Petitioners, the level of net benefits achievable through the sale of NEGC's assets to LUC cannot be achieved in any way other than through the proposed transaction and, therefore, there is no better alternative to the proposed sale (Joint Petitioner Brief at 28, 29). No other party addressed this factor on brief.

b. Analysis and Findings

The proposed transaction is part of a plan by Energy Transfer, Southern Union's parent company, to streamline and integrate its asset portfolio through divestiture of non-core assets, which include gas distribution companies (Exh. DPU-1-42; see also n.38 above). Given that NEGC is held as a division of Southern Union, an asset sale is the only option available to effectuate the divestiture of the Company (See Amended Joint Petition at 2, ¶ 2; Exhs. NEGC-2 (Supp.) at 2; DPU-1-50(I)(a) at 2 (Pre-Acquisition); Tr. 2, at 201, 274, 276-277). Based on these

considerations, we find that it is reasonable that no other alternatives to the proposed sale of NEGC's assets were considered.

9. Distribution of Resulting Benefits Between Shareholders and Ratepayers

a. Introduction

The Joint Petitioners state that as a result of the rate freeze period, future rate base offsets, and other commitments made, the proposed transaction is projected to produce $1,800,000 in permanent, annual cost savings within five years of the closing date (Exhs. JP-Rebuttal-5, at 7-8; JP-Rebuttal-5A, at 1; Tr. 1, at 49). Further, the Joint Petitioners expect that the proposed transaction will create benefits such as increased local presence, decision-making, and operations; increased local employment; increased levels of customer service; and increased levels of sales and energy efficiency activity throughout the service territory (Exhs. NEGC-4, at 18; JP-Rebuttal-5, at 3-8; Tr. 1, at 122). The Joint Petitioners submit that the aforementioned benefits will inure to customers and will be incorporated into rates and service quality metrics over time, as appropriate (Exh. NEGC-4, at 18).

The Joint Petitioners also state that LUC expects to receive the benefits that are customarily afforded to shareholders by virtue of owning a utility and does not expect to recover any transaction costs as a result of the sale of NEGC's assets (Exh. NEGC-4, at 18).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that the lack of net savings as a result of the proposed transaction, coupled with the loss of ADIT, weigh against the increased earnings and gain on the sale of assets that shareholders will reap (Attorney General Brief at 17). As such, the Attorney

General asserts that the division of benefits between customers and shareholders is decidedly lopsided in the shareholders' favor (Attorney General Brief at 17).

ii. Joint Petitioners

The Joint Petitioners assert that, based on the above considerations, customers will experience benefits arising from operating cost savings (Joint Petitioner Brief at 24-25). Thus, the Joint Petitioners contend that there is a fair distribution of transaction benefits sufficient to satisfy the public interest (Joint Petitioner Brief at 25).

c. Analysis and Findings

We find that approval of the proposed transaction will provide customers with rate-related savings and benefits associated with the 24-month base rate freeze, rate base offset and TIRF credit. Customers also will experience operational net savings as a result of the transaction. We expect that LUC will benefit from potential earnings through its ownership and control of the renamed NEGC. LUC will not recover any transaction or transition costs, nor does it seek to recover an acquisition premium associated with the proposed transaction. Based on these considerations, we conclude that the benefits of this transaction are fairly distributed between ratepayers and shareholders.

10. Conclusion

Based on the findings and considerations in the foregoing sections, we conclude that approval of the proposed transaction will result in a variety of benefits to NEGC ratepayers that would not be available in the absence of the proposed transaction. These benefits include: (i) a 24-month base rate freeze; (ii) annual savings of at least $546,000 in the first year after the closing of the proposed transaction, an amount that is projected to increase over time; (iii) a rate

base offset and TIRF credit that will be applied to offset any future rate impacts associated with the proposed transaction; (iv) improvements in customer service functions, specifically the relocation of the customer service center to Massachusetts; (v) an increase in TIRF-related main replacement and a corresponding reduction in GHG emissions; (vi) job creation in Massachusetts that is likely to have a positive economic impact on the communities in and around Bristol County; and (vii) ownership and operation of the renamed NEGC by a financially viable company that is focused on and committed to the gas distribution business.

As noted in the various sections above, in order to ensure that the benefits associated with the proposed transaction are realized, the Department finds that several ratepayer protections must be implemented as conditions of approval of the proposed transaction. First, we find that the proposed base rate freeze, rate base offset and TIRF credit must be applied prospectively from the date of this Order.

Second, we will hold the renamed NEGC to the cost savings representations made in this proceeding, and we direct the renamed NEGC and LUC to explore any and all additional measures that provide the opportunity to maximize efficiencies, minimize costs and pass resulting savings on to customers (see Exh. AG-2-17; Tr. 1, at 42-43). Thus, the renamed NEGC shall track all such savings and present the results as part of the initial filing in its next base rate case, at which time the Department will fully examine (i) each of the areas of expected savings identified in Section VI.B.4 and the level of the savings achieved by the renamed NEGC; and (ii) the renamed NEGC's efforts to achieve savings in other areas of operations.

Third, post-closing, the renamed NEGC will increase its TIRF-related main replacement activity to at least eight miles of main per year. Further, at the time of its next base rate case, the

renamed NEGC shall provide the Department with an evaluation of the feasibility of accelerating the TIRF-related main replacement rate beyond eight miles per year. In the meantime, the Department will continue to monitor the renamed NEGC's TIRF-related performance in annual TIRF filings and, consistent with the Department's decision in D.P.U. 10-114, evaluate whether the utility's performance benefits public safety, service reliability, and the environment. D.P.U. 10-114, at 64-65.

Finally, within 30 days of LUC's assuming operational control of the renamed NEGC, the renamed NEGC and LUC shall file with the Department a report providing details and a timeline for the performance of energy audits at the renamed NEGC's three facilities and a plan for exploring the incorporation of CNG vehicles into its fleet. The energy audits, in particular, will be conducted as expeditiously as possible following LUC's assumption of operational control over the renamed NEGC and prior to the filing of the renamed NEGC's next base rate case. The renamed NEGC shall submit to the Department within 60 days of the completion of each audit a comprehensive written plan and timeline for implementing those cost-effective strategies that are recommended by each audit. In the meantime, the renamed NEGC and LUC also shall explore additional meaningful initiatives to reduce GHG gas emissions, advance clean energy development and address climate change. The renamed NEGC shall include the results of these efforts as part of its initial filing in its next base rate case.

Based on the foregoing findings and considerations, and having balanced all of the applicable factors above, and subject to the foregoing ratepayer protections, the Department finds that the benefits of the transaction outweigh the costs, and therefore, the proposed transaction results in net benefits to ratepayers. Accordingly, the Department concludes that the proposed

transaction is consistent with the public interest and that the sale of NEGC's assets is approved subject to the various provisions specified in this Order.

C. Gain on Sale of Assets

1. Introduction

In addition to the factors set forth above and the other issues discussed in this Order, we will examine in the following section whether there is a gain on the sale of NEGC's assets and whether it is necessary to flow through to NEGC ratepayers the appreciation on assets that they have supported in rates. As discussed below, the Joint Petitioners and the Attorney General disagree on these two issues.

2. Positions of the Parties

a. Attorney General

The Attorney General argues that there is considerable dispute on the record as to whether the proposed transaction will result in a gain on the sale of NEGC's assets (Attorney General Brief at 10, citing Tr. 2, at 195, 197, 220-222). However, the Attorney General submits that this issue can be reserved until the renamed NEGC's next rate case, where the issue should undergo a thorough vetting (Attorney General Brief at 11-12; Attorney General Reply Brief at 6). Thus, the Attorney General asserts that if the Department approves the proposed transaction, it should specifically reserve judgment on making any final determination about the disposition of the ratemaking consequences of the asset sale (Attorney General Brief at 12). In this regard, the Attorney General notes that Southern Union no longer will be subject to the Department's jurisdiction after the closing of the proposed transaction (Attorney General Brief at 12). Thus, according to the Attorney General, the Department, in order to appropriately

protect ratepayers vis-à-vis any gain, should condition the approval of the proposed transaction upon the an agreement between the Joint Petitioners to transfer exclusive operational control over the NEGC franchise and joint ownership of the franchise to PMA until such time as the Department adjudicates and enforces the ratemaking associated with the asset sale (Attorney General Brief at 12).

b. Joint Petitioners

The Joint Petitioners argue that there is no gain on the sale of assets and that the Attorney General has raised this issue only because the total price that LUC will pay to acquire the NEGC assets is higher than the valuation that LG attributed to the NEGC assets in the context of its bid for the combined operations of MGE and NEGC (Joint Petitioner Brief at 35; Joint Petitioner Reply Brief at 7). According to the Joint Petitioners, the fact that Southern Union may be willing to sell the NEGC assets at a price below net book value to LG (in the context of its sale of MGE to LG) does not mean that anything above that price is a gain on the sale of assets (Joint Petitioner Brief at 35-36, 41). Further, the Joint Petitioners argue that the Attorney General is confused as to what constitutes a gain on the sale of assets and the type of disposition of assets that triggers the analysis of gain (Joint Petitioner Brief at 39-41).

The Joint Petitioners also contend that the Attorney General's position is misplaced for two significant reasons (Joint Petitioner Brief at 36-38). First, the Joint Petitioners contend that there will be no capital gain or appreciation attributable to the sale of NEGC's assets (Joint Petitioner Brief at 37; see also Joint Petitioner Reply Brief at 7). In fact, the Joint Petitioners note that the fair market value of the NEGC assets, as determined by the total

purchase price that will be paid by LUC, is less than the net book value of the assets (Joint Petitioner Brief at 37, citing Exh. AG-9-8 (Supp.); RR-DPU-5).

Second, the Joint Petitioners assert that, unlike the property sales or transfers in past cases adjudicated by the Department, the NEGC assets will remain in the service of customers, under the operation and control of the utility (Joint Petitioner Brief at 37). The Joint Petitioners note that the adjustment made in a rate case to attribute a gain on the sale of assets to customers is made not to establish a representative level of expenses, but rather to flow through to ratepayers the appreciation on assets that they have supported in rates as reflected by a return of and/or on the investment (Joint Petitioner Brief at 37-38, citing Commonwealth Electric Company, D.P.U. 88-135/151, at 92 (1989)). However, the Joint Petitioners submit that in the instant case, there will be no appreciation in the assets as a result of the sale, and the NEGC assets will continue to be used and useful in providing service to the public and to be supported in rates (Joint Petitioner Brief at 38). The Joint Petitioners emphasize that the conveyance of NEGC assets in this case effects a "change in control" in relation to the utility assets, but it does not effect a divestiture by the utility of assets previously supported in rates, as was the scenario in cases cited by the Attorney General (Joint Petitioner Brief at 38-39, citing D.P.U. 88-67, at 79-80; Colonial Gas Company, D.P.U. 84-94, at 20-21 (1984); Eastern Edison Company, D.P.U. 837/968, at 37 (1982); Massachusetts Electric Company, D.P.U. 1133, at 34 (1982)).

The Joint Petitioners also reject the Attorney General's recommendation that the Department should specifically reserve judgment on any final determination about the disposition of the ratemaking consequences of the asset sale until the time of the renamed NEGC's next rate case (Joint Petitioner Brief at 41-42; Joint Petitioner Reply Brief at 7). The

Joint Petitioners argue that such treatment is not necessary or appropriate because all relevant issues are clear; specifically, the final purchase price and net book value will be determined on the date of closing, and rate base of the renamed NEGC will be based on net utility plant in service and will not change regardless of whether the NEGC assets are owned by LG, LUC or even Southern Union (Joint Petitioner Brief at 41-42, citing RR-DPU-5; RR-DPU-17; Joint Petitioner Reply Brief at 7).

Finally, the Joint Petitioners reject the Attorney General's recommendation that the Department condition the approval of the proposed transaction upon an agreement between the Joint Petitioners to transfer exclusive operational control over the NEGC franchise, as well as joint ownership–but not sole ownership—of the franchise to PMA until such time as the Department adjudicates and enforces the ratemaking associated with the asset sale (Joint Petitioner Brief at 42-43). The Joint Petitioners argue that the Department does not have the authority to change the structure of the proposed transaction, or separate operational control from ownership, or order joint ownership of NEGC's assets (Joint Petitioner Brief at 43).

3. Analysis and Findings

The Department's policy regarding a gain on the sale of assets is long-standing: if utility assets are recorded above the line, ratepayers support those assets through the inclusion of the assets in the company's rate base. Therefore, if the property is later sold by the utility, an adjustment is necessary to flow through to ratepayers the appreciation on assets that they have supported in rates reflected by a return on the investment. Barnstable Water Company, D.P.U. 93-223-B at 12-13 (1994); D.P.U. 88-135/151, at 92. This policy also applies to non-utility plant if such plant had been previously included in utility plant in service regardless

of the length of time the plant had been treated as plant in service. Western Massachusetts Electric Company, D.P.U. 88-250, at 38-39 (1989).

The Department's policy is premised upon the divestiture of an asset that was supported by customers in rates and that no longer will provide service to those ratepayers. See, e.g., D.P.U. 88-135/D.P.U. 88-151, at 86; D.P.U. 88-67, at 79-80; Colonial Gas Company, D.P.U. 84-94, at 20-21); D.P.U. 837/968, at 37. In the instant case, no portion of the ratepayers' investment in the form of used and useful assets will be removed from plant in service, or disposed of, or moved to non-utility accounts as a result of the proposed transaction. Rather, the proposed transaction is simply a transfer of ownership and operational control of NEGC's assets from Southern Union to LUC. Therefore, we find that the sale of NEGC's assets does not implicate the Department's ratemaking policy regarding a gain on the sale of assets.

Notwithstanding this conclusion, because the final purchase price will depend upon certain adjustments to be made at closing, we direct the Joint Petitioners to provide to the Department within 30 days of the closing the final purchase price and net book value of the renamed NEGC. Further, if the purchase price is less than the net book value of the acquired assets, we direct the renamed NEGC to record the difference to Account 217, Surplus Invested in Plant. See Boston Edison Company/Boston Gas Company, D.P.U. 17444, at 6-7 (1972); The Berkshire Gas Company/Greenfield Gas and Light Company, D.P.U. 12479 (1958); Pittsfield Coal Gas Company/The Berkshire Gas Company, D.P.U. 11018 (1954). If the purchase price exceeds the net book value of the acquired assets, the renamed NEGC shall book the difference to Account 303, Miscellaneous Intangible Plant. In any event, such amount shall not be included in rate base for ratemaking purposes. The Joint Petitioners shall file a copy of the

journal entries recording the effects of the acquisition with the Department upon consummation of the transaction.

D. Southern Union's Retained Regulatory Liabilities

1. Introduction

a. D.P.U. 09-GAF-P6 and D.P.U. 11-54

On July 31, 2009, NEGC submitted its 2008 environmental remediation adjustment clause ("RAC") filing to the Department.[46] Consistent with Department practice, this filing was investigated in the Company's 2009 gas adjustment factor ("GAF") and local distribution adjustment factor ("LDAF") proceedings, D.P.U. 09-GAF-P6. The Attorney General intervened pursuant to G.L. c. 12, § 11E and issued two sets of information requests related to the proposed environmental remediation adjustment charge ("ERAC") included in the Company's 2008 RAC filing. On October 30, 2009, the Department conditionally approved the Company's proposed LDAFs, which included the ERAC. New England Gas Company, D.P.U. 09-GAF-P6, Letter Order at 1 (October 30, 2009).[47]

On November 3, 2009, the Attorney General issued a third set of information requests related to the proposed ERAC, to which the Company responded on April 15, 2010. In the cover letter to its responses, the Company asserted that the legal billing invoices responsive to

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[46] Under its RAC, NEGC can seek recovery of environmental response costs for investigation, testing, remediation, litigation, and other liabilities related to manufactured gas plant sites, disposal sites, or other sites onto which material may have migrated as a result of the operating or decommissioning of Massachusetts gas manufacturing facilities. See M.D.P.U. No. 1002D, § 1.06 (effective February 1, 2012).

[47] The Department's conditional approval allowed the proposed LDAFs to go into effect on November 1, 2009, subject to reconciliation after investigation. D.P.U. 09-GAF-P6, Letter Order at 1 (October 30, 2009).

Information Request AG 3-23 were protected by attorney-client privilege and, therefore, only redacted copies of the invoices would be provided. D.P.U. 09-GAF-P6, Responses of New England Gas Company to the Attorney General's Third Set of Information Requests, Cover Letter at 1 (April 15, 2009).

On July 7, 2011, the Attorney General filed with the Department, pursuant to G.L. c. 164, § 93, a written complaint ("§ 93 Complaint") regarding the price of gas provided by NEGC. The Department docketed the matter as D.P.U. 11-54. The Attorney General requested that the Department review the environmental response costs that NEGC has recovered from ratepayers through the Company's LDAF (§ 93 Complaint at 8). In particular, the Attorney General requested that the Department investigate the prudence of legal fees related to environmental response costs that the Company has conditionally recovered since 2005 (§ 93 Complaint at 8). The Attorney General also asked the Department to determine whether the Company has properly differentiated, for purposes of cost recovery, legal fees associated with environmental response costs and legal fees associated with insurance and third-party litigation expenses (§ 93 Complaint at 8). In support of the § 93 Complaint, the Attorney General cited the legal invoices at issue in D.P.U. 09-GAF-P6 and withheld in response to Information Request AG-3-23 (§ 93 Complaint at 6-7 & nn.6, 7).

b. The P&S Agreement

As noted above in Section IV, pursuant to § 2.3 of the P&S, Southern Union will retain certain liabilities that will not pass to PMA upon closing of the transaction (Exh. NEGC-1, at 22, § 2.3). Among these liabilities are "retained regulatory liabilities," which is defined in the P&S as "all Regulatory Liabilities of the [Southern Union] or its Affiliates arising out of or relating to

the complaint of the Attorney General of Massachusetts v. NEGC, D.P.U. 09-GAF-P6 and D.P.U. 11-54, whether arising out of or related to the period before or after Closing" (Exh. NEGC-1, at 18, § 1.1).

The Joint Petitioners state that if the Department finds that NEGC or its successor is obligated to refund or return money to customers as a result of the § 93 Complaint, Southern Union will be contractually responsible for that liability (see Exh. JP-Rebuttal-2, at 4-5). Further, the Joint Petitioners state that after the closing of the proposed transaction in this case, the Department will retain full jurisdiction and authority over all of NEGC's rates (see Exh. JP-Rebuttal-2, at 5-6). Thus, the Joint Petitioners submit that to the extent that the Department orders an adjustment for any element encompassed in the "retained regulatory liabilities" section of the P&S, NEGC or its successor will be obligated to make an appropriate rate adjustment for the benefit of NEGC's customers, and Southern Union will be obligated to compensate the purchaser of the NEGC assets for such amounts (see Exh. JP-Rebuttal-2, at 5-6).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that Department approval of the Joint Petitioners' request to sever the retained regulatory liabilities at issue in D.P.U. 09-GAF-P6 and D.P.U. 11-54 from the sale of NEGC's assets would be contrary to the public interest as that standard is imposed by § 96, and, therefore, would violate Massachusetts law (Attorney General Brief at 27-30). Further, the Attorney General contends that such approval would threaten the continued viability of the ERAC mechanism established pursuant to the settlement in Manufactured Gas Plants, D.P.U. 89-161 (1990), adversely affect the Attorney General's ability to prosecute the § 93

Complaint, and might cause the Attorney General to oppose provisional allowance of the recovery of future costs through the ERAC mechanism[48] (Attorney General Brief at 40-42; Attorney General Reply Brief at 15, 17-21).

The Attorney General asserts that the Department should reject the Joint Petitioners' request to sever the retained regulatory liabilities and should not allow the proposed transaction as structured (Attorney General Brief at 27, 40 and 42). In the alternative, the Attorney General submits that if the Department approves the proposed transaction, it should impose certain conditions on the Joint Petitioners that they must accept by formal notification to the Department and the intervenors (Attorney General Brief at 27, 30). In particular, the Attorney General asserts that the Department should: (1) determine that responsibility for responding to the § 93 Complaint is not severable from the sale of NEGC's assets or the transfer of its franchise; (2) require a bond, surety, or escrow from Southern Union in an amount sufficient to make ratepayers whole with interest in the event of a finding in the § 93 Complaint that is adverse to the Company; (3) require an unconditional pledge or schedule commitment from Southern Union and from both the current and the potential owners of PMA to complete the proceedings in D.P.U. 09-GAF-P6 and D.P.U. 11-54 by December 31, 2013; and (4) require Southern Union to provide, at the time of notification that the Department's conditions are accepted, sufficient documentation that the bond, surety, or escrow requirement is satisfied and is agreeable to the other petitioners, the Attorney General and other intervenors (Attorney General Brief at 30-31).

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[48] In this regard, the Attorney General notes that protection of ratepayers' interests should not be placed in opposition to expeditious environmental clean up (Attorney General Brief at 42).

In addition, the Attorney General argues that if the Department were to approve the proposed sale of NEGC's assets and sanction transfer of the franchise to PMA, it must require that all business records of the NEGC franchise follow the assets sold and the franchise transferred (Attorney General Brief at 31; see Attorney General Reply Brief at 14). In particular, according to the Attorney General, there is no basis in statute or in case law for the Joint Petitioners' proposal to leave the legal billings records at issue in D.P.U. 09-GAF-P6 and D.P.U. 11-54 in the sole custody of Southern Union (Attorney General Brief at 31). The Attorney General claims that the retention of any franchise records by Southern Union is inconsistent with the requirements to preserve records of contract under 220 C.M.R. § 75.00 and would frustrate the Attorney General's attempts to obtain the records in the D.P.U. 09-GAF-P6 and D.P.U. 11-54 proceeding (Attorney General Brief at 33-35; 37-39; see Attorney General Reply Brief at 15). In this regard, the Attorney General asserts that the Department should take specific steps, as conditions of approval of the sale of NEGC's assets, to ensure that all franchise records are preserved and transferred to PMA upon the closing of the proposed sale (Attorney General Brief at 39-40; Attorney General Reply Brief at 15).[49]

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[49] In particular, the Attorney General argues that the Department should: (1) require that PMA designate a supervisory official responsible for taking custody of all records that NEGC and Southern Union are required to preserve in accordance with 220 C.M.R. § 75.00, including especially those relevant to D.P.U. 09-GAF-P6 and D.P.U. 11-54; (2) expressly apprise Southern Union, NEGC, PMA, LG, and LUC of their joint and several responsibility to preserve all records relevant to D.P.U. 09-GAF-P6 and D.P.U. 11-54 and ensure that these records pass, intact and in their entirety, into the custody of the supervisory official designated by PMA; (3) require, as regulatory pre-conditions to closing, that on the next day following the expiration of the appeal period under G.L. c. 25, § 5, the Joint Petitioners notify the Department and the Attorney General (with affidavits attested by all of the Joint Petitioners) of all arrangements made to satisfy the conditions for inventorying, preserving, and transferring of records sought in or relevant to D.P.U. 09-GAF-P6 and D.P.U. 11-54, which notification shall be subject

b. Joint Petitioners

The Joint Petitioners argue that the structure of the proposed transaction – that is, the sale of NEGC assets to LUC and the retention of certain regulatory liabilities by Southern Union – does not violate Massachusetts law (Joint Petitioner Brief at 47). According to the Joint Petitioners, LUC as the ultimate owner of the renamed NEGC would remain wholly subject to the Department's regulation in relation to the ERAC mechanism and the § 93 Complaint (Joint Petitioner Brief at 47, citing Exh. JP-Rebuttal-2, at 4-6; Tr. 1, at 115-116). The Joint Petitioners assert that there is no regulatory obligation or privilege that is being transferred to or retained by Southern Union, and that following the closing of the proposed transaction Southern Union will have a contractual obligation to reimburse LUC for any adverse decision rendered in relation to the § 93 Complaint (Joint Petitioner Brief at 47-48, citing Exh. JP-Rebuttal-2, at 4-6). Thus, the Joint Petitioners note that Southern Union is a necessary party to the § 93 Complaint as it is Southern Union's management that must account for the ERAC-related legal expenses incurred during the period of its ownership of NEGC (Joint Petitioner Brief at 48; Joint Petitioner Reply Brief at 12).

According to the Joint Petitioners, LUC simply will be "backstopped" by Southern Union's contractual obligation to pay LUC for any cost disallowance (Joint Petitioner Brief

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to hearing and testimony at the direction of the Department or upon the request of the Attorney General; and (4) require Southern Union to file with the Department an affidavit from its chief executive officer or president that Southern Union has performed a due-diligence search of corporate records for all records related to its law firms' billings for costs sought to be recovered through the ERAC and has caused the originals (as defined in 220 C.M.R. § 75.03(4)(c)) of all of these records to be deposited at NEGC's principal office in Massachusetts and safeguarded preparatory to their surrender as company records to PMA upon the closing of the transaction (Attorney General Brief at 39-40; see also Attorney General Reply Brief at 17).

at 48, citing Exh. JP-Rebuttal-2, at 6-7). The Joint Petitioners note that the backstopping function is further strengthened by Southern Union's commitment to execute a performance bond for the benefit of LUC, in the event the Department approves the sale of NEGC's assets (Joint Petitioner Brief at 48, citing JP-Rebuttal-2, at 7). Therefore, the Joint Petitioners assert that the contention that NEGC's regulatory obligations are being improperly transferred to Southern Union is erroneous and unsupported by law or fact (Joint Petitioner Brief at 48).

The Joint Petitioners also reject the Attorney General's notion that the Department, should it approve the proposed transaction, must condition it on specific considerations related to the § 93 Complaint (Joint Petitioner Brief at 48). The Joint Petitioners assert that they are not seeking to sever any responsibility related to the § 93 Complaint; Southern Union has already committed to a performance bond equal to the total amount of legal costs at issue; the performance bond is a routine financial instrument in the marketplace, which neither needs approval by the Attorney General and other parties, nor would be appropriate for review given that it fundamentally protects LUC's business interests; and the Department has complete and exclusive control over the schedule in D.P.U. 09-GAF-P6 and D.P.U. 11-54 (Joint Petitioner Brief at 48-50, citing Exh. JP-Rebuttal-2, at 7-8).

Further, the Joint Petitioners argue that the Department should reject the Attorney General's assertion regarding record retention, including her specific recommendations (Joint Petitioner Brief at 50; Joint Petitioner Reply Brief at 11-12). The Joint Petitioners submit that all utility records necessary to support regulated operations will be transferred to LUC, in accordance with Massachusetts law and with Southern Union's obligations under the P&S, subject to appropriate conditions and documentation to preserve the attorney/client privilege and

attorney work product immunity (Joint Petitioner Brief at 50; Joint Petitioner Reply Brief at 11-12). In addition, the Joint Petitioners claim that the contents of the "ERAC filings" will remain under the control of the entity regulated by the Department, but that Southern Union will retain a copy of these documents, including the relevant legal invoices, "as Southern Union is the entity that is defending against the Attorney General's complaints" (Joint Petitioner Brief at 50-51).

Finally, the Joint Petitioners argue that because Southern Union is responsible for any adverse judgment in the D.P.U. 09-GAF-P6 and D.P.U. 11-54 proceedings, Southern Union has an incentive to produce relevant documentation or risk an adverse judgment in those proceedings (Joint Petitioner Brief at 51; Joint Petitioner Reply Brief at 12). Thus, the Joint Petitioners assert that there is no action required by the Department in this proceeding, beyond accepting Southern Union's commitment to execute a performance bond, to protect the interests of customers in relation to the § 93 Complaint (Joint Petitioner Brief at 51; Joint Petitioner Reply Brief at 12). According to the Joint Petitioners, the physical location of the documentation during the proceeding is simply an irrelevant matter (Joint Petitioner Brief at 51).

3. Analysis and Findings

The P&S is structured so that Southern Union will retain certain regulatory liabilities related to matters at issue in D.P.U. 09-GAF-P6 and D.P.U. 11-54. The Attorney General has raised two primary issues with respect to the retained regulatory liabilities: (i) the continuing obligation of Southern Union to participate in the proceedings in D.P.U. 09-GAF-P6 and D.P.U. 11-54 following the conveyance of NEGC's assets to LUC; and (ii) the post-sale

retention by the former NEGC of billing records and other relevant franchise documents that may be at issue in D.P.U. 09-GAF-P6 and D.P.U. 11-54. We address each of these issues below.

Upon the consummation of the proposed transaction, the renamed NEGC will operate in Massachusetts, subject to Massachusetts law and under the Department's jurisdiction. It is this entity that will be directly responsible to Massachusetts ratepayers for any adverse judgment rendered in D.P.U. 09-GAF-P6 and D.P.U. 11-54. Thus, to the extent that the Department orders a refund of any amounts collected from ratepayers as a result of the conditional approval of the Company's ERAC, the Department will enforce its judgment against the renamed NEGC.

Although Southern Union no longer will operate a jurisdictional entity in Massachusetts following the sale of NEGC's assets (see Exh. AG-3-2), the record demonstrates that Southern Union intends to actively participate in the D.P.U. 09-GAF-P6 and D.P.U. 11-54 proceedings for the benefit of the renamed NEGC (Exhs. DPU-7-2; DPU-7-3).[50] It is in Southern Union's own best interest to do so, as it acknowledges that the P&S contractually obligates the company to pay any adverse judgment rendered against the renamed NEGC in those proceedings (see Exhs. NEGC-1, at 18, § 1.1; 22, § 2.3; DPU-3-4; DPU-4-12; DPU-7-1; DPU-7-2; DPU-7-3; AG-5-39).

The extent of participation in D.P.U. 09-GAF-P6 and D.P.U. 11-54 will be determined in those dockets. However, we expect that Southern Union will make available the appropriate

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50 Although Southern Union is not a party to this proceeding, its chief operating officer for distribution operations in Missouri and Massachusetts, Robert Hack, was a witness in this case and sponsored numerous discovery responses confirming Southern Union's obligations with respect to any retained regulatory liabilities and provided testimony regarding the same (see, e.g., Exhs. DPU-3-4; DPU-4-12; DPU-7-1; DPU-7-2; DPU-7-3; AG-5-39; Tr. 1, at 40; Tr. 4, at 436-439).

witnesses necessary for the litigation in D.P.U. 09-GAF-P6 and D.P.U. 11-54 to proceed expeditiously and fairly. Further, we expect that as part of the closing of the proposed transaction, and in accordance with Massachusetts law and the Department's regulations, Southern Union will transfer to LUC all of the documentation necessary to support the renamed NEGC's utility operations, including documentation necessary for a proper adjudication of the issues in D.P.U. 09-GAF-P6 and D.P.U. 11-54. Thus, we disagree with the Joint Petitioners that the physical location of documents is irrelevant. See G.L. c. 164, § 80.[51] LUC and the renamed NEGC are entitled to the physical possession of all relevant documentation. As already noted, should Southern Union frustrate the adjudication of the issues presented in the D.P.U. 09-GAF-P6 and D.P.U. 11-54, or in any way impair the renamed NEGC's ability to sufficiently litigate those proceedings, Southern Union risks an adverse judgment against the renamed NEGC and, in turn, Southern Union's own exposure to contractual liability to pay such judgment. In this regard, it is important to note that the renamed NEGC bears the burden of proving the propriety of the ERAC under investigation in D.P.U. 09-GAF-P6 and D.P.U. 11-54. See Metropolitan District Commission v. Department of Public Utilities, 352 Mass. 18, 25 (1967).

In the § 93 Complaint, the Attorney General alleges that the Company has passed onto ratepayers $18,542,480 in legal fees since 2005 (see New England Gas Company, D.P.U. 11-54, Complaint at 4, ¶ 11; 8, ¶ 23 (July 7, 2011). Southern Union has committed to a performance bond in the amount of $18,000,000, which it claims is more than sufficient to cover any adverse

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[51] G.L. c. 164, § 80 requires all gas companies to keep in their local Massachusetts offices "all books and papers required by law to be kept within the commonwealth, and also such books as may be required to show their receipts, expenditures, indebtedness and financial condition … ."

judgment against the renamed NEGC because not all of the legal fees associated with the § 93 Complaint could be deemed to be excessive (Exh. JP-Rebuttal-2, at 7; DPU-14-11; Tr. 1, at 115; Tr. 4, at 436-437). We make no findings in this Order with respect to the merits of the § 93 Complaint or specific matters at issue in D.P.U. 09-GAF-P6 and D.P.U. 11-54. However, given the amount that the Attorney General has identified as potentially disallowable, we find that a performance bond in the amount of $18,000,000 provides reasonable assurance that (i) Southern Union will continue to participate in D.P.U. 09-GAF-P6 and D.P.U. 11-54, and (ii) the relevant indemnification provisions of the P&S will be satisfied for the benefit of the renamed NEGC should there be findings adverse to the renamed NEGC in D.P.U. 09-GAF-P6 and D.P.U. 11-54 (see Exhs. NEGC-1, at 18, § 1.1; 22, § 2.3). We stress, however, that we do not view or intend for the performance bond to represent the renamed NEGC's maximum liability exposure in D.P.U. 09-GAF-P6 and D.P.U. 11-54. The performance bond operates as Southern Union's guaranty of its financial commitment under the P&S to pay to the renamed NEGC and/or LUC any adverse judgment in D.P.U. 09-GAF-P6 and D.P.U. 11-54. While the performance bond also may be some evidence of Southern Union's commitment to participate in those dockets, it does not measure or otherwise cap any disallowance amount determined in those proceedings. Should any adverse judgment in those proceedings exceed the amount of the performance bond, the renamed NEGC and/or LUC could exercise any independent rights to proceed against Southern Union for indemnification of any amounts in excess of $18,000,000.

Based on the foregoing, we find that it is prudent to condition the approval of the sale of NEGC's assets on Southern Union's obtaining a performance bond in the amount of $18,000,000 for the benefit of the renamed NEGC and/or LUC, with the understanding that the performance

bond will be used toward satisfying any judgment rendered against the renamed NEGC as a result of the proceedings in D.P.U. 09-GAF-P6 and D.P.U. 11-54. The Department directs the Joint Petitioners to submit proof of the performance bond within 30 days of the date of this Order. We conclude that it is unnecessary to condition our decision in the instant proceeding on additional assurances that Southern Union will continue to participate in the D.P.U. 09-GAF-P6 and D.P.U. 11-54 proceedings. Further, we decline to issue any additional specific directives regarding the transfer of documentation to the renamed NEGC.

E. Pension and Post-Retirement Benefits other than Pensions Regulatory Asset

1. Introduction

NEGC's annual expense amounts for pension and PBOP are recovered through the pension expense factor ("PEF") component of the pension adjustment mechanism ("PAM"). Currently, unrecognized gains and losses associated with NEGC's pension and PBOP obligations are recorded as accumulated other comprehensive income ("AOCI"), consistent with Financial Accounting Standards Board, Accounting Standards Codification (FASB ASC) 715-20, 715-30, and 715-60 (Exh. NEGC-2, at 8). Under these standards, unrecognized gains and losses are factored into the calculation of annual pension and PBOP expense recovered through the PEF, thereby working down the balance recorded in AOCI (Exh. NEGC-2, at 8).

In the context of the proposed sale of NEGC's assets, FASB ASC 805, Business Combinations, requires that the acquiring company recognize the value of pension assets or liabilities in an amount equal to the funded status of the plant as of the acquisition date (Exh. NEGC-2, at 8). As a result, any previously unrecognized prior service costs and actuarial gains or losses of the acquired company related to assumed pension and PBOP plans, including

amounts reflected in AOCI, must be eliminated for financial reporting purposes (Exh. NEGC-2, at 8-9).

The Joint Petitioners state that absent the creation of a regulatory asset, the AOCI balance related to pension and PBOP would have to be recorded as goodwill on the Company's balance sheet, which would make it ineligible for continued recovery through rates (Exh. NEGC-2, at 9). As part of the balance of goodwill, the pre-acquisition amounts of unrecognized prior period gains and losses and prior service costs would no longer be includable in the calculation of annual pension and PBOP expense (Exh. NEGC-2, at 8). Therefore, these amounts would never be recovered from ratepayers through the PAM (Exh. NEGC-2, at 9). As such, the Joint Petitioners request permission to reclassify the pre-acquisition AOCI balance to a post-acquisition regulatory asset on its balance sheet rather than stranding those amounts in goodwill (Exhs. NEGC-2, at 9-10; AG-6-15). None of the parties commented on the Joint Petitioners' request.

2. D.P.U. 12-68

On March 1, 2013, following the filing of the original petition and the Amended Joint Petition in this case, the Department issued its decision in New England Gas Company, D.P.U. 12-68 (2013). In that case, NEGC requested the creation of a similar regulatory asset as described above in order to continue to recover the AOCI balance associated with pension and PBOP expenses following the acquisition of Southern Union, of which NEGC is an operating division, by ETE on March 26, 2012. D.P.U. 12-68, at 1. The Department found as a result of Southern Union's acquisition by Energy Transfer, the Company would be obligated under FASB ASC 805 to zero out its AOCI balance and transfer the amount to goodwill. D.P.U. 12-68, at 10.

We determined that such a transaction would result in an impairment of goodwill represented by $23.9 million in pension obligations and $3.1 million in PBOP obligations that would remain unrecoverable. D.P.U. 12-68, at 10. We concluded that a $27 million write-off of pension and PBOP expenses (the unrecognized balance in AOCI) that would result from the transfer of this amount from AOCI to goodwill would have an adverse financial effect on NEGC and frustrate the Department's intent to permit the Company rate recovery of its legitimate pension and PBOP obligations. D.P.U. 12-68, at 10. Therefore, the Department permitted NEGC to establish a pension and PBOP regulatory asset ("PPRA") to amortize its pension and PBOP expenses for recovery through the PAM. D.P.U. 12-68, at 10-11.

In establishing the regulatory asset in D.P.U. 12-68, the Department also approved NEGC's proposed method of accounting for the AOCI balance associated with pension and PBOP expenses. D.P.U. 12-68, at 11-12. Specifically, we found that NEGC's actuary would annually determine the amount of pension and PBOP expense that would have been considered to be net periodic pension and PBOP expense if the pre-merger balance, net of any post-merger amortization, were still part of the AOCI balance rather than residing in a PPRA account. D.P.U. 12-68, at 4. Current year actual pension and PBOP expense then would be subtracted from the above amount. D.P.U. 12-68, at 4. Under this method (referred to as the "two asset method"), the resulting differential would be equal to the current year PPRA amortization. D.P.U. 12-68, at 4. The current year PPRA amortization would reduce the PPRA balance and would be recorded in the pension and PBOP accounts on the Company's books and would be added to the current year actual pension and PBOP expense for the PAM. D.P.U. 12-68, at 4. The proposed method would result in an amortization of the PPRA such that the expense

recoverable through the PAM would be equal to the sum of pension and PBOP expense that would have been recoverable had the reclassification of the AOCI balance attributable to FASB ASC 805 not occurred. D.P.U. 12-68, at 4-5.

3. Analysis and Findings

The Department's decision in D.P.U. 12-68 is controlling in the instant case. Accordingly, we find that the renamed NEGC shall establish a pension and PBOP regulatory asset in order to continue to recover the AOCI balance associated with pension and PBOP expenses following the acquisition of NEGC's assets. The renamed NEGC shall continue to use the two asset method to account for the AOCI balance associated with pension and PBOP expenses.

Currently, NEGC records the value in AOCI pertaining to pension and post-retirement benefits from information contained in year-end reports received from the Company's actuary (Exh. DPU-2-15). The balance as of December 31, 2012, totaled $4,808,336, and consisted of: (i) non-union pension AOCI of $2,925,251; (ii), union pension AOCI of $1,704,186, and (iii) post-retirement AOCI of $178,899 (Exhs. DPU-2-15, Att. (a) at II-6; DPU-2-15, Att. (b) at II-6; DPU-2-15, Att.(c) at II-6). Once the closing date of the proposed transaction has been finalized, the renamed NEGC's actuary will prepare updated actuary reports and compute the actual AOCI balance as of that date (Exh. DPU-2-15). Those reports will include the calculation of the AOCI balance as of that date which is the balance that will require reclassification to the regulatory asset account (Exh. DPU-2-15). The renamed NEGC shall provide this updated information to the Department once it has been determined.

F. Additional § 96 Approval

1. Introduction

As noted above in Section IV, immediately prior to the sale of NEGC's assets all of the issued and outstanding shares of PMA will be acquired by LUC, so that LUC will become the parent company of PMA (Amended Joint Petition at 1-2; Exhs. NEGC-3 (Supp.) at 2; DPU-1-2; DPU-1-5, Art. 1, §1.2). Following the purchase of the NEGC assets by PMA, LUC, by virtue of its ownership of PMA, will own and control NEGC (Amended Joint Petition at 2; see also Exh. NEGC-3 (Supp.) at 2). LUC will rename PMA and operate it as a gas company under G.L. c. 164 and subject to the Department's jurisdiction (Amended Joint Petition at 5, ¶ 9; see also, Exh. DPU-1-4; RR-DPU-16; RR-DPU-16 (Amended)).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that because of the "deliberate and manipulative manner" in which the proposed transaction has been "restructured, amended, and restated," the Department must render two separate judgments under the § 96 public interest test (Attorney General Brief at 25, citing Exh. AG-JC at 15-17; Attorney General Reply Brief at 11, 13). More specifically, the Attorney General contends that the PMA Agreement is the collateral agreement that allows LUC to purchase PMA and, with it, effectively to own PMA's contingent right to purchase NEGC's assets and become vested with the franchise (Attorney General Brief at 25). The Attorney General claims that whatever its probability, performance of the collateral agreement among LG, PMA, and LUC is not a foregone conclusion (Attorney General Brief at 25; Attorney General Reply Brief at 12-13). Thus, according to the Attorney General "the logic of decision"

requires the Department first to determine that LG has made the requisite showing that acquisition of NEGC's assets by the LG-owned shell, PMA, would satisfy the Department's net benefits test under § 96 (Attorney General Brief at 25). The Attorney General submits that any Department order would be inadequate if it failed to render a § 96 public interest judgment as to the fitness of both LG and LUC as potential sole owner and controller of PMA, and only if this first showing is made can the Department consider whether the PMA/LUC acquisition of NEGC's assets transaction also satisfies the public interest test (Attorney General Brief at 25; Attorney General Reply Brief at 12). In this regard, the Attorney General argues that the Joint Petitioners have failed to demonstrate that the first transaction satisfies the net benefits test (Attorney General Brief at 25-26).

b. Joint Petitioners

The Joint Petitioners reject the Attorney General's contention that the Department must render two separate judgments under the § 96 public interest test (Joint Petitioner Brief at 46; Joint Petitioner Reply Brief at 10). Further, the Joint Petitioners assert that the structure of the subject transaction is in no way dubious, but instead necessary to facilitate the transfer of the NEGC assets (Joint Petitioner Reply Brief at 10). The Joint Petitioners argue that only one determination from the Department under § 96 is necessary – that is, the approval of LUC's purchase of NEGC's assets (Joint Petitioner Brief at 46-47; Joint Petitioner Reply Brief at 11). According to the Joint Petitioners, the Department does not have any legal authority over the conveyance of PMA to LUC and, therefore, there is no legal basis or justification for the Department to approve that conveyance under § 96 (Joint Petitioner Brief at 47).

3. Analysis and Findings

PMA was incorporated in the state of Delaware on December 13, 2012 (Exh. DPU-1-3, Att.). All of the stock of PMA is currently owned by LG (Exh. DPU-1-5, Att. at 1; Tr. 1, at 68). Pursuant to the PMA Agreement, immediately prior to the closing on the sale of NEGC's assets, LG will sell all of the PMA stock to LUC (Amended Joint Petition at 1-2; Exhs. NEGC-3 (Supp.) at 2; DPU-1-2; DPU-1-5, Att. at 2, Art. 1, §1.2; Tr. 1, at 16; Tr. 2, at 228, 229). Thus, at no time will LG own the assets of NEGC, and the assets of NEGC will pass to PMA after PMA is acquired by LUC (Tr. 1, at 17, 20; Tr. 2, at 228). There has been no evidence to suggest that the transaction governed by the PMA Agreement will not take place as proposed, or specifically, immediately prior to PMA's acquisition of NEGC's assets. Nevertheless, the PMA Agreement, while not subject to our approval, is an integral part of the overall transaction that results in the sale of NEGC's assets to LUC. Moreover, because our public interest analysis above focuses on LUC's ultimate ownership and control of the former NEGC franchise, we find that the consummation of the PMA Agreement is a necessary condition of the approval of the sale of NEGC's assets to PMA. As such, we fully expect that the sale of PMA to LUC will be completed as set forth in the PMA Agreement, and our decision today is conditioned on this transaction taking place prior to PMA's purchase of NEGC's assets.

In this regard, we find assurance in the record that the proposed transaction will occur as structured if approved by the Department, and should circumstances arise post-Order that negate the transaction LG will not assume ownership of NEGC's assets absent a separate filing and specific approval by the Department (Tr. 2, at 213-216). Thus, we find no substantive basis upon which to conclude that the proposed transaction will result in LG owning or controlling the

assets of NEGC by virtue of LG's current ownership of PMA. Based on these findings and considerations, we reject the Attorney General's argument that the Department is required in this case to issue a separate judgment finding that LG has made the requisite showing that acquisition of NEGC's assets by PMA would satisfy the Department's net benefits test under § 96.

G. Confirmation of Franchise Rights

1. Introduction

The Joint Petitioners state that upon approval of the sale of NEGC's assets and closing of the transaction, PMA will operate as a subsidiary of LUC and will become subject to the Department's jurisdiction under G.L. c. 164, § 1 (Amended Joint Petition at 7, ¶ 14). According to the Joint Petitioners, the Department has determined that approval of a transaction under § 96 obviates the need for separate approval under § 21 for the transfer of utility franchises (Amended Joint Petitioner at 7, ¶ 14, citing D.T.E. 98-27, at 75-76). Therefore, the Joint Petitioners state that it is necessary and appropriate for the Department, in approving the sale of NEGC's assets, to confirm that all of the franchise rights and obligations currently held by NEGC shall continue to be held by PMA after the sale and no separate authorization is required under § 21 (Amended Joint Petition at 7-8, ¶ 14, citing D.P.U. 10-170-B at 106-107; D.T.E. 98-27, at 75-76).[52]

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[52] The Joint Petitioners state that there are a myriad of rights and obligations that flow from the threshold determination that a company qualifies as a gas company under G.L. c. 164, § 1, and is subject to the Department's jurisdiction (Exh. DPU-2-25). According to the Joint Petitioners, these rights and obligations include but are not limited to the obligation to provide safe and reliable services to NEGC's customers in all the ways that its business obligations make that possible (Exhs. DPU-2-25; DPU-7-11). Further, the Joint Petitioners state that such rights and obligations include: (1) the exclusive rights and obligations to provide distribution service within the former NEGC's service territories; (2) the rights and obligations to maintain the physical infrastructure necessary to exercise

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department would exceed its authority under G.L. c. 164 if it were to approve the sale of NEGC's assets to PMA, confirm that PMA may hold the franchise rights and obligations of NEGC, and determine that further action under § 21 is not required (Attorney General Brief at 35). The Attorney General asserts that the Department has not previously approved a sale by a utility corporation of all its franchise utility plant and other assets outside the typical mergers and stock acquisition scenarios, nor has the Department ever confirmed that franchise rights and privileges, post-sale of assets, require no further action under § 21 (Attorney General Brief at 36). Moreover, the Attorney General claims that no Department order has approved any transaction in which substantially all of the assets of a utility franchisee would be sold, while unresolved potential regulatory liability would be retained by the seller (Attorney General Brief at 36). Further, the Attorney General notes that the Joint Petitioners have cited no express statutory provision that would permit transfer of the NEGC franchise to PMA (Attorney General Brief at 37).

The Attorney General asserts that § 21 is an express reservation of Department authority by the legislature and that it acts as a consumer protection measure for customers of monopoly

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its transmission and distribution franchise, including, without limitation, (a) rights at railroad crossings to ensure continuity of service along and across these areas; (b) grants of locations in public ways; (3) rights and obligations obtained pursuant to NEGC's statutory authority to construct and operate gas lines and mains; and (4) any and all other rights and responsibilities afforded to NEGC as a distribution company under Chapter 164 and any and all other applicable General Laws with regard to the transmission and distribution of gas within the Commonwealth (Exh. DPU-7-11). Finally, the Joint Petitioners note a gas company's right to recover the reasonable and prudently incurred costs to provide its various services to customers through tariff rates that are reviewed and approved by the Department (Exhs. DPU-2-25; DPU-7-11).

utility service (Attorney General Brief at 36). In this regard, the Attorney General argues that even if the Department can reconcile § 96 and § 21 in this case, the sale of NEGC's assets still must be disallowed (Attorney General Brief at 37). In this regard, the Attorney General notes that the Department must find that the subject transaction involves no "'factors which may negatively impact customer service'" (Attorney General Brief at 37, citing Moulton v. Brookline Rent Control Board, 385 Mass. 228, 230-231 (1982)). According to the Attorney General, the provision in the P&S that requires Southern Union to retain liabilities related to any adverse judgment rendered in D.P.U. 09-GAF-P6 and D.P.U. 11-54 has a negative effect on ratepayers' bills (Attorney General Brief at 37).[53] Thus, the Attorney General asserts that "statute directs the Department to recognize this barrier to approval of the [subject transaction]" (Attorney General Brief at 37). Moreover, the Attorney General argues that the potential for deleterious effects on the Department-approved regulatory mechanism for timely environmental response and equitable balance of ratepayer and shareholder interests threatens another serious negative impact that precludes the Department's approval of the proposed sale of NEGC's assets (Attorney General Brief at 37).

b. Joint Petitioners

The Joint Petitioners argue that there is nothing in § 21 that would preclude Department approval under § 96 in relation to an asset transaction, but not in relation to a utility franchise purchase achieved through a stock purchase (Joint Petitioner Brief at 52). According to the Joint Petitioners, the Attorney General's argument rests exclusively, and erroneously, on the fact

[53] The Attorney General does not elaborate on this argument. In any event, we have determined in Section VI.B.1.b.ii that customers will not experience an immediate rate impact as a result of our approval of the proposed transaction.

that the proposed transaction is an asset transaction, where other transactions approved by the Department under § 96 were in a different form (Joint Petitioner Brief at 52, citing Attorney General Brief at 34). In this regard, the Joint Petitioners note that the cases cited by the Attorney General in support of her position do not expressly exclude asset sales from the purview of § 21 (Joint Petitioner Brief at 52-53 & n.10). Rather, according to the Joint Petitioners, recent transactions implicating § 21 resulted in the transfer of ownership rights to a post-transaction entity that would engage in all of the same activities as a gas company (Joint Petitioner Brief at 53 & n.11). The Joint Petitioners assert that the sale of NEGC's assets presents the same scenario, as there is no aspect of utility operations that LUC is not accepting with the purchase of NEGC's assets (Joint Petitioner Brief at 53-54). The Joint Petitioners dismiss the Attorney General's arguments regarding the retained regulatory liabilities, and note that Southern Union's responsibility is contractual, while LUC would be responsible for complying with the Department's decision in D.P.U. 09-GAF-P6 and D.P.U. 11-54 (Joint Petitioner Brief at 54).

Further, the Joint Petitioners note that the Department previously confirmed the transfer of franchise rights to Southern Union at the time that it purchased Fall River Gas Company and North Attleboro Gas Company, the predecessors of NEGC, despite the fact that (1) neither of these corporate entities "survived" the conveyance; (2) Southern Union did not operate as a utility in Massachusetts at the time it purchased these gas companies; and (3) as the surviving corporation, Southern Union absorbed the gas companies' operations and held them as divisional assets within a larger enterprise encompassing other regulated and unregulated operations (Joint Petitioner Brief at 55-56, citing D.T.E. 00-26, at 2, 29-30; D.T.E. 00-25, at 33. The Joint Petitioners contend that the Attorney General offers no explanation, except for reference to the

retained regulatory liabilities, as to how the conveyance of the entirety of Southern Union's operating division, including its formal corporate identity as NEGC, with PMA being the legal entity surviving the proposed transaction and NEGC being the extinguished corporate entity, is any different from the sale of Fall River Gas Company and North Attleboro Gas Company to Southern Union, where the Department expressly authorized continued operation as an operating division (Joint Petitioner Brief at 56).

For these reasons, the Joint Petitioners assert that there is no basis in law or case precedent to support the Attorney General's position regarding § 21 (Joint Petitioner Brief at 57). Rather, the Joint Petitioners submit the Department has the authority under § 21 to approve transactions under § 96 and to confirm the transfer of NEGC's franchise rights (Joint Petitioner Brief at 56-57).

3. Analysis and Findings

Pursuant to § 21, "[a] corporation subject to this chapter shall not, except as otherwise expressly provided, transfer its franchise, lease its works or contract with any person, association or corporation to carry on its works, without the authority of the general court." The Department has determined that the approval of corporate transactions pursuant to § 96 obviates the need for separate legislative approval under § 21 for the transfer of franchise rights. D.P.U. 09-139, at 33; D.T.E. 99-47, at 65-66 (1999); Haverhill Gas Company, D.P.U. 1301, at 4-5 (1984). The Department has stated that an action properly approved under § 96 would not require separate authorization of the General Court, since the General Court itself authorized the Department to approve such a transaction. D.P.U. 09-139, at 33; D.T.E. 99-47, at 65; D.P.U. 1301, at 4-5.

NEGC operates as a division of Southern Union, and a sale of assets is the means by which Southern Union divests itself of the Company (See Amended Joint Petition at 2, ¶ 2; Exhs. NEGC-2 (Supp.) at 2; DPU-1-50(I)(a) at 2 (Pre-Acquisition); Tr. 2, at 201, 274, 276-277). Although the proposed transaction is structured differently from recent § 96 corporate mergers or stock sales, § 96 provides that companies subject to Chapter 164 "may sell and convey all or substantially all of their properties to another of such companies …." Thus, § 96 expressly provides for the type of asset sale contemplated by the Amended Joint Petition, so long as the transaction satisfies the public interest test. This type of asset sale is by no means unique to this case. See e.g., NSTAR Gas Company/Colonial Gas Company, D.T.E. 02-44, at 5, 7 (2002) (conveyance of gas distribution assets from non-franchise holder to unaffiliated gas company); Commonwealth Gas Company/New Bedford Gas and Edison Light Company, D.P.U. 302, at 6-7 (1980) (conveyance of gas distribution operations of combination utility to affiliated gas utility); Boston Edison Company/Boston Gas Company, D.P.U. 17444, at 2-3 (1972) (conveyance of electric distribution system of combination utility to unaffiliated electric utility); Whitinsville Water Company/Whitin Machine Works, D.P.U. 10732, at 1, 3 (1954) (conveyance of water distribution operations of manufacturing company to newly formed corporation); Worcester County Electric Company et al, D.P.U. 9257 (1950) (separation of gas and electric operations of combination utilities as part of corporate restructuring involved the transfer of various utility assets to newly formed corporations).

As noted above, the Department has long held that an action properly approved by the Department under § 96 would not require separate authorization from the Legislature for the

transfer of franchise rights. See D.P.U. 1301, at 4-5.[54] As set forth in Section VI, the proposed sale of NEGC's assets satisfies the § 96 public interest standard. Based on these considerations, we conclude that separate legislative approval of the transfer of NEGC's franchise to PMA is not required. We find that it is unnecessary to address any remaining arguments concerning this issue.

Accordingly, the Department finds that upon consummation of the sale of NEGC's assets, PMA (to be renamed Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty Utilities) shall have all rights, powers and privileges, franchises, properties, real, personal, or mixed, and immunities held by NEGC as are necessary to engage in all the activities of a gas company in all the cities and towns in which NEGC was engaged immediately prior to the sale of its assets; and that further action pursuant to § 21 is not required to consummate the sale of NEGC's assets to PMA.

H. Corporate Name

G.L. c. 164, § 5A requires that the name of a corporation subject to this chapter include the words "gas company" or "electric company," as the case may be depending on whether the corporation is a gas or electric utility. LUC proposes that upon completion of the transaction, PMA will be renamed "Liberty Utilities (New England Natural Gas Company) Corp. d/b/a

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[54] While § 21 issues were implicated in a December 30, 1911 financing Order of the Department's predecessor, that same year the agency approved two mergers under § 96 without discussion of § 21. See 27th Annual Report of the Board of Gas and Electric Light Commissioners at 53-59; 78-87 (1912)). Further, the agency approved five mergers under § 96 in the year following the December 30, 1911 financing Order without reference to § 21. See 28th Annual Report of the Board of Gas and Electric Light Commissioners at 60-76 (1913)). Hence, the Department has recognized the distinction between § 21 and § 96 since its early days.

Liberty Utilities" (RR-DPU-16 (Amended)).[55] The Joint Petitioners state that LUC has adopted the convention of naming its utility subsidiaries "Liberty Utilities" in order to foster an overall corporate identity, and they consider that proposed name to further this goal (Tr. 2, at 207, 212; RR-DPU-16 (Amended)). For the purposes of customer-facing and public communications, LUC intends to use the trade name "Liberty Utilities" (RR-DPU-16 (Amended))

Based on a review of G.L. 164, § 5A, including those sections of G.L. c. 156B § 11 governing corporate name that are incorporated by reference into G.L. c. 164, § 5A,[56] the Department concludes that there is no statutory bar against the use of the name "Liberty Utilities (New England Natural Gas Company) Corp." Accordingly, the Department finds it appropriate for the new entity to operate under the name "Liberty Utilities (New England Natural Gas Company) Corp." upon completion of the Transaction.

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55 The proposed corporate name change of NEGC has undergone several incarnations. In the original Joint Petition, LG intended to rename PMA as "New England Gas Company" (Joint Petition at 5, ¶ 9). In the Amended Joint Petition, LUC intended to rename NEGC as "Liberty Utilities (NEGASCo) Corp." (Amended Joint Petition at 5, ¶ 9). LUC subsequently stated that in order to resolve any concerns as to whether the name complied with the provisions of G.L. c. 164, § 5A, it would be willing to adopt for PMA the name "Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty Utilities" (Exh. DPU-1-4). Later, LUC represented that it would be willing to conduct its Massachusetts operations under the name "New England Gas Company d/b/a Liberty Utilities" (RR-DPU-16). Finally, LUC determined that "Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty Utilities" would be anomalous to the naming convention used in its other utility operations (RR-DPU-16 (Amended)).

56 Incorporated into G.L. c. 164, § 5A are G.L. c. 156B, § 11, ¶¶ (b), (c), and (d).

Further, the Department has recognized the use of trade names that do not conform to the requirements of G.L. c. 164, § 5A. See D.P.U. 10-55, at 601-602 & n.329 (2010).[57] Thus, if LUC determines that including the d/b/a name of "Liberty Utilities" in the renamed PMA's legal name is essential for either legal or business reasons, then LUC may include the d/b/a name as proposed in Record Request DPU-16 (Amended).

VII. ORDER

Accordingly, after notice, hearing, comment, and due consideration, it is

ORDERED: That pursuant to G.L. c. 164, § 96, and subject to the terms and conditions in this Order, it is hereby determined that the sale of New England Gas Company's assets by Southern Union Company to Plaza Massachusetts Acquisition, Inc., is consistent with the public interest and is hereby APPROVED; and it is

FURTHER ORDERED: That upon consummation of the acquisition, Plaza Massachusetts Acquisition, Inc. (to be renamed Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty Utilities) shall each have all rights, powers and privileges, franchises, properties, real, personal, or mixed, and immunities held by New England Gas Company as are necessary to engage in all the activities of a gas company in all the cities and towns in which New England Gas Company was individually engaged immediately prior to the acquisition; and that further action pursuant to G.L. c. 164, § 21 is not required to consummate the acquisition; and it is

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[57] The Department also has accepted the use of corporate names where the corporation's name did not conform to the requirements of G.L. c. 164, § 5A, provided that the trade name did so conform. See D.T.E. 00-26, at 27-28; D.T.E. 00-25, at 28-29.

FURTHER ORDERED: That the Joint Petitioners shall file with the Department a copy of the journal entries recording the effects of the acquisition upon consummation of the transaction; and it is

FURTHER ORDERED: That the Joint Petitioners shall comply with all directives contained in this Order; and it is

FURTHER ORDERED: That the Secretary of the Department shall within three days of the issuance of this Order cause a certified copy of it to be filed with the Secretary of the Commonwealth.

By Order of the Department,

/s/
_____
Ann G. Berwick, Chair

/s/
_____
Jolette A. Westbrook, Commissioner

/s/
_____
David W. Cash, Commissioner

An appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part. Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. G.L. c. 25, § 5.

Board Matter No. 433

NEW BRUNSWICK ENERGY AND UTILITIES BOARD

IN THE MATTER OF an application by Liberty Utilities (Canada) LP pursuant to subsection 27(2) of the *Gas Distribution Act, 1999*, S.N.B. 1999, c. G-2.11, for an order granting leave for Liberty Utilities LP to acquire the beneficial ownership of Enbridge Gas New Brunswick Limited Partnership.

ORDER

WHEREAS the New Brunswick Energy and Utilities Board (Board) issued a decision on May 24, 2019 wherein Liberty Utilities (Canada) LP (Liberty Utilities) was granted leave to acquire the beneficial ownership of Enbridge Gas New Brunswick Limited Partnership (EGNB).

AND WHEREAS the acquisition was completed on October 1, 2019;

AND WHEREAS on October 2, Liberty Utilities filed an executed copy of the Substitution Agreement and Amendment to the General Franchise Agreement (GFA) which was subsequently approved by the Board;

AND WHEREAS Liberty Utilities advised the Board by letter dated April 24, 2020, that further amendments were needed to the GFA;

AND WHEREAS Liberty Utilities is seeking Board approval of a further Amended and Restated General Franchise Agreement;

AND WHEREAS Notice was provided to parties on May 20 advising of Liberty Utilities' request;

AND WHEREAS parties were given until May 28 to provide any comments they had on the Amended and Restated General Franchise Agreement;

AND WHEREAS the Public Intervener submitted that the Amended and Restated General Franchise Agreement combined with the Board's ongoing regulatory oversight,

satisfies the Board's obligation to ensure that Liberty Utilities is sufficiently financed to perform its obligations;

AND WHEREAS no party objected to the request.

NOW THEREFORE IT IS ORDERED THAT:

1. The Amended and Restated General Franchise Agreement filed by Liberty Utilities on April 24, is approved as filed.

DATED at the City of Saint John, New Brunswick, this 5th day of June, 2020.

BY THE BOARD

Kathleen Mitchell

Kathleen Mitchell
Chief Clerk

New Brunswick Energy and Utilities Board
P.O. Box 5001
Suite 1400, 15 Market Square
Saint John, NB E2L 4Y9
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STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DG 11-040

NATIONAL GRID USA ET AL.

Transfer of Ownership of
Granite State Electric Company and EnergyNorth Natural Gas, Inc.
to Liberty Energy NH

Order Approving Settlement, Granting Motions for Confidential Treatment and Waiver of Certain Filing Requirements

O R D E R N O. 25,370

May 30, 2012

APPEARANCES: Celia B. O'Brien, Esq. and McLane, Graf, Raulerson & Middleton, P.A. by Steven V. Camerino, Esq. and Patrick H. Taylor, Esq. for National Grid USA, National Grid NE Holdings 2 LLC, Granite State Electric Company and EnergyNorth Natural Gas, Inc.; Shannon P. Coleman, Esq. for Liberty Energy Utilities Co. and Liberty Energy Utilities (New Hampshire) Corp.; New Hampshire Legal Assistance by Alan M. Linder, Esq. for The Way Home and Pamela Locke; Law Offices of Shawn J. Sullivan, PLLC by Shawn J. Sullivan, Esq. for the United Steel Workers of America Local 12012-3; James Simpson for the International Brotherhood of Electrical Workers Local 326; the Office of the Consumer Advocate by Rorie E.P. Hollenberg, Esq. on behalf of residential ratepayers; and Lynn Fabrizio, Esq. for the Staff of the Public Utilities Commission.

I. TRANSACTION BACKGROUND

On March 4, 2011, National Grid USA, National Grid NE Holdings 2 LLC, Granite State Electric Company d/b/a National Grid (Granite State), EnergyNorth Natural Gas, Inc. d/b/a National Grid NH (EnergyNorth), Liberty Energy Utilities Co. (Liberty Energy), and Liberty Energy Utilities (New Hampshire) Corp. (Liberty Energy NH) (collectively, the Joint Petitioners) filed with the Commission a joint petition with supporting testimony for authority to transfer ownership of Granite State and EnergyNorth to Liberty Energy NH and for related approvals (the Joint Petition).

Granite State is a New Hampshire corporation and public utility that provides retail electric service to approximately 43,000 customers in 21 communities in southern and western New Hampshire. It is directly and wholly owned by National Grid USA, acquired as a result of National Grid USA's merger with New England Electric System in 2000.

EnergyNorth is a New Hampshire corporation and public utility that provides retail gas service to approximately 86,000 customers in 30 communities throughout southern and central New Hampshire and in Berlin, New Hampshire. EnergyNorth is wholly owned by National Grid NE, which is indirectly owned by National Grid USA (collectively, National Grid). National Grid USA acquired EnergyNorth as a result of its merger with KeySpan Corporation in 2007.

National Grid USA is a public utility holding company that provides electric and natural gas service to customers in New England and New York through a number of indirectly owned subsidiaries, including Granite State and EnergyNorth.

Liberty Utilities Co. (Liberty Utilities) conducts the regulated utility business of Algonquin Power & Utilities Corp. (Algonquin). Algonquin is a publicly traded corporation based in Oakville, Ontario, with a power generation unit that includes 45 renewable power generating facilities and 12 high-efficiency thermal generating facilities located in six U.S. states and Canada, and a utility services unit that owns and operates one electric utility and 19 retail water and sewer utilities. Algonquin has been doing business in New Hampshire since 1998 when it acquired the first of its eight New Hampshire hydroelectric facilities.

Liberty Utilities owns and operates Liberty Energy, a wholly owned subsidiary based in Oakville, Ontario and publicly traded on the Toronto Stock Exchange, with securities registered with the U.S. Securities and Exchange Commission. Liberty Energy NH, in turn, is wholly and

directly owned by Liberty Energy and was formed for the purpose of acquiring ownership of the stock of Granite State and EnergyNorth.

II. PROCEDURAL HISTORY

On March 8, 2011, the Commission acknowledged receipt of the Joint Petition and opened this docket to assess its merits. On March 10, 2011, the OCA notified the Commission that it would participate in the docket on behalf of residential ratepayers pursuant to RSA 363:28.

On March 29, 2011, the Commission issued an Order of Notice setting a prehearing conference and technical session for April 20, 2011, and requiring intervenor petitions by April 15, 2011. The following additional parties sought and were granted status as full intervenors: United Steel Workers of America Local 12012-3 (USWA Local 12012-3), Pamela Locke, The Way Home, John Martino, Granite State Hydropower Association, International Brotherhood of Electrical Workers Local 326 (IBEW Local 326), the Business and Industry Association (BIA), and the New Hampshire Community Action Association (NHCAA). Intervenor John Martino withdrew from the proceedings on February 3, 2012.

Following the April 20, 2011 prehearing conference, Staff, the Joint Petitioners, OCA, and other parties appearing at the prehearing conference met in a technical session and agreed upon a proposed schedule to govern the remainder of the proceeding, which the Commission approved by secretarial letter dated April 25, 2011.

On June 13 and 14, 2011, and September 7 and 8, 2011, technical sessions were held to assist in the discovery process regarding the Joint Petitioners' filing. In addition, the Joint Petitioners responded to multiple rounds of data requests from Staff, OCA, and intervenors, with supplemental responses submitted as additional information became available during the course of the proceeding.

On October 7, 2011, Staff submitted written testimony of Steven E. Mullen, Assistant Director of the Commission's Electric Division; Stephen P. Frink, Assistant Director of the Gas & Water Division; Amanda O. Noonan, Director of the Consumer Affairs Division; Randall S. Knepper, Director of the Safety Division; and Gorham, Gold, Greenwich & Associates, LLC (G3 Associates), consultants to Staff in this proceeding. On the same date, the OCA filed written testimony of consultant Scott J. Rubin. On October 17, 2011, USWA Local 12012-3 submitted written testimony of Kevin Spottiswood. Settlement discussions were held at the Commission on October 13, November 9 and 10, and December 7 and 8, 2011.

On March 14, 2012, Liberty Energy NH, Granite State, and EnergyNorth jointly filed technical statements regarding financing for both Granite State and EnergyNorth, and a motion for waiver of certain filing requirements under N.H. Code Admin. Rules Puc 308.12 and Puc 509.03 pertaining to the technical statements. On April 2, 2012, Liberty Utilities filed supplemental information related to its proposed long-term debt issuances.

On April 19, 2012, the Joint Petitioners jointly filed a motion for protective order and confidential treatment pursuant to Puc 203.08 regarding certain information provided during the discovery phase of these proceedings, and a separate motion for a waiver of certain requirements under Puc 203.08(f). No objections were received.

A settlement agreement was executed among Staff and all parties, with the exception of BIA, and filed on April 9, 2012 (Settlement Agreement). BIA, though not a signatory, did not object to the Settlement Agreement. On April 10, 2012, Steven E. Mullen and G3 Associates filed supplemental testimony on behalf of Staff providing updates of issues addressed in their prior testimony.

III. INITIAL POSITIONS REGARDING THE PROPOSED TRANSACTION

A. Joint Petitioners

The Joint Petitioners request approval pursuant to RSA 374:30 and RSA 374:33 of the proposed transfer of ownership of Granite State and EnergyNorth from National Grid to Liberty Energy NH (Liberty Energy NH). The Joint Petitioners further seek authorization for Granite State and EnergyNorth each to issue additional long-term debt to establish a capital structure of 45 percent debt/55 percent equity, based on the level of rate base at the closing date, and authorization for Granite State and EnergyNorth each to record a regulatory asset or liability in an amount required to reflect the fair value of pension and other post-employment benefit obligations as of the transaction closing date.

Under the proposed transaction, Liberty Energy NH will purchase from National Grid all issued and outstanding shares of common stock of Granite State and Energy North through two separate stock purchase agreements. Under those agreements, National Grid USA proposes to sell its Granite State shares to Liberty Energy NH for an aggregate purchase price of $83,000,000 in cash, less the amount of certain existing indebtedness of Granite State, and further adjusted based on Granite State's working capital, capital expenditures, and regulatory assets as of the date of closing; National Grid NE proposes to sell its EnergyNorth shares to Liberty Energy NH for the aggregate purchase price of $202,000,000 in cash, adjusted based on EnergyNorth's working capital, environmental remediation costs, capital expenditures, and regulatory assets of the date of closing.

According to the Joint Petition, Algonquin will infuse Liberty Energy NH with approximately $135 million of new capital to finance the purchase of stock. In turn, Algonquin will issue debt instruments to institutional lenders to obtain approximately $135 million in

additional capital. Upon execution of each stock transfer, Granite State and EnergyNorth will become directly owned by Liberty Energy NH and indirectly by Algonquin.

In connection with the Purchase Agreements, National Grid USA will enter into Transition Service Agreements (TSAs) with Granite State and EnergyNorth to support utility operations following the stock transfer. Under the TSAs, National Grid USA, either directly or through its affiliates, will provide various specified services to Granite State and EnergyNorth under their respective TSAs until operations are fully transferred to Liberty Energy NH and assistance from National Grid USA is no longer needed. With expiration of the TSA agreements, Granite State and EnergyNorth will receive certain ongoing management, financial and administrative services from Algonquin, Liberty Utilities (Canada) Corp., Liberty Utilities and Liberty Energy NH pursuant to a set of Affiliate Services Agreements.

According to the Joint Petition, Granite State and EnergyNorth will issue promissory notes to Liberty Energy NH for up to $20 million and $85 million, respectively, to support debt financing. The Joint Petitioners seek Commission approval for the issuance of the promissory notes under RSA 369:1. In support of their request, Joint Petitioners state that the issuance will facilitate and support the stock transfers and will result in a capital structure of approximately 45 percent debt and 55 percent equity for each utility, allowing continued access to capital markets on favorable terms.

The Joint Petitioners also submit for Commission review and approval a Site Agreement related to the ongoing operation of six electric substations in New Hampshire, and a Management Services Agreement related to ongoing management services and working capital lending arrangements anticipated between Granite State and EnergyNorth and Algonquin and/or its affiliates. Granite State and EnergyNorth further propose to defer the recognition of

previously unrecognized assets and liabilities associated with their pension plans and post-retirement benefits other than pensions (OPEBs) and, instead, amortize their fair market values as regulatory assets or liabilities over the average remaining service period of active employees expected to receive benefits under the plans.

The Joint Petition outlines a number of anticipated advantages to be realized from the proposed transaction, including local management and operation of the two utilities under a New Hampshire-based President; the return of approximately 60 service company jobs such as management, engineering, accounting and customer service positions to New Hampshire through the employment of knowledgeable employees from National Grid, as well as the continued employment of Granite State and EnergyNorth field employees; a corporate owner committed to investing the capital necessary to provide safe and reliable utility service; and the maintenance of reasonable rates based on costs incurred primarily at the local level and readily identifiable with the services provided. The Joint Petition further states that Liberty Energy NH does not intend to seek rate recovery of any acquisition premium or transaction costs arising from the Stock Transfers, and does not plan to make substantive changes to either Granite State's or EnergyNorth's tariff as a result of the transfers.

B. United Steel Workers of America Local 12012-3

In support of its petition to intervene, USWA Local 12012-3 stated that it represents certain individuals employed by EnergyNorth who live and work in New Hampshire. Pre-filed testimony by Kevin Spottiswood, Unit Chairperson of Local 12012-3, stated that Liberty[1] has demonstrated a willingness to communicate with members of Local 12012 and, throughout the

[1] For ease of reading, "Liberty" hereinafter will refer to Liberty Energy and Liberty Energy NH jointly, with the understanding that ultimate direct ownership will be held by Liberty Energy NH. Where clarity requires, reference will be made to Liberty Utilities, Liberty Energy and/or Liberty Energy NH.

transaction process, has provided information on how it plans to conduct business operations, maintain labor/management relations and implement employee benefit programs. On behalf of USWA Local 12012, Mr. Spottiswood recognized Liberty's stated commitment to safety, public relations and job security, and argued that, to the extent those commitments could be solidified, the proposed sale should benefit all concerned.

C. OCA

In pre-filed testimony by Scott J. Rubin, the OCA argued that Liberty has not demonstrated the requisite financial, technical, and managerial fitness to own and operate EnergyNorth and Granite State. OCA further evaluated the effect of the proposed transaction on the utilities' cost of service and rates, on their quality of service, and on the State's economy, arguing that Liberty's operating costs, and therefore rates, would be higher than the costs EnergyNorth and Granite State would incur if they remained part of National Grid, and that Liberty was not proposing to make significant improvements in the quality of service received by customers. The OCA proposed a number of conditions designed to protect Granite State and EnergyNorth customers from potential negative consequences of the proposed transaction, including conditions to ensure that the level of rates and basic quality of service remain unchanged under new ownership.

D. Staff

Staff provided pre-filed testimony addressing customer service, emergency response, pipeline safety, information technology systems planning and implementation, transition costs and risks, and transaction financing. In terms of customer service, Staff noted Liberty's promises to uphold a customer-focused management philosophy through locally empowered management teams and the re-establishment of a local call center as well as walk-in centers.

Staff identified commitments to low-income customers currently undertaken by National Grid, noting that it was unclear whether Liberty would continue those commitments. Staff emphasized the need for customer service staffing plans that would support the transition and take into account possible cut-over failures.

With respect to emergency response and pipeline safety, Staff stated that Liberty would need to develop a more detailed, comprehensive Emergency Response Plan to eliminate the unnecessary sections applicable to larger regions and areas of response in National Grid's current plan. According to Staff, Liberty would also need to establish effective resource procurement mechanisms for wide-scale emergency events, including participation in regional mutual assistance networks with local management authority to make procurement decisions. Staff urged Liberty to implement and maintain remote readable computer access for designated Commission Staff and outage management system (OMS) capabilities that would provide estimated restoration times on a street-level basis. Finally, Staff urged Liberty's commitment to current pipeline safety conditions, including the sectionalizing of gas pipeline systems, valve maintenance, and adherence to industry best practices and construction standards. Staff also determined that Liberty should establish certain new pipeline safety conditions, including incorporating and integrating global positioning system information with geographic information systems to produce enhanced record keeping capabilities; more frequent odorization sampling; implementing a quality assurance plan for new construction activities; enhanced snow and ice protection for meter sets; and a commitment to reduce Grade 3 leaks, as defined in the Settlement Agreement, throughout the gas distribution system over a ten year period. Staff also urged Liberty to mark out private residential underground electrical facilities that extend beyond

Granite-State-owned facilities, as an added service for customers when using the underground damage prevention system.

Staff noted the various financing instruments the Joint Petitioners propose to support the transaction, including terms and conditions of long-term debt associated with financing the transaction, and short-term credit facilities to be made available to Granite State and EnergyNorth. Staff urged greater transparency in the transition process through quarterly status reports on transition timetables, estimated and actual costs incurred throughout the transition, services added, deleted or completed changes, in cost allocations, updated organizational charts and periodic financial forecasts. Staff further noted the need to reconcile Liberty's assertion that it could operate Granite State at the same cost level as currently operated under National Grid, given projected annual operational and maintenance costs that are higher than current levels.

Staff emphasized the need to clearly identify and distinguish transition costs, including those incurred to modify and acquire new information technology (IT) systems, from normal utility operating costs and capital investments, as well as the need to evaluate incremental transition costs associated with acquisition costs and potential rate impacts. Staff further urged commitment to a capital spending plan that is carefully considered and limited to what is essential to provide safe and reliable service and support economic growth, and not simply to increase rate base and revenues. Toward that end, Staff argued that no recovery of transition costs related to systems implementation should be permitted and that the acquisition premium (purchase price above the book value of regulatory assets) be held in escrow and used to offset significant transition cost overruns that Liberty might experience.

Finally, through its consultants, G3 Associates, Staff emphasized the importance of a transparent, efficient and effective transition of IT systems to Liberty. Toward that end, Staff

recommended a number of commitments that Liberty undertake to ensure the availability of and accessibility to historical data essential to Granite State and EnergyNorth, detailed transition planning to achieve full implementation of a committed IT plan, rigorous IT security measures and technologies to protect business data networks, maintenance of the highest level of access controls to systems and the information within them, a comprehensive systems testing program, and strengthened vendor management processes and protocols. Staff further recommended steps to ensure National Grid's full and continued commitment to a smooth transition, including the appointment of a fully-dedicated senior executive responsible for IT transition activities, the payment of a percentage of fees earned under the TSAs to a publicly-administered escrow account until the transaction is completed, and the posting of a performance bond payable to the State of New Hampshire in the event of non-performance. Staff also recommended monitoring and evaluation of systems implementation throughout the transition.

IV. SUMMARY OF SETTLEMENT AGREEMENT

The Settlement Agreement was signed and filed by the Joint Petitioners, Staff, the OCA and all parties to the proceeding with the exception of the BIA. The Settlement Agreement recommends that the Commission approve the proposed transfer of ownership, authorize the proposed issuance of new, long-term debt, and authorize both Granite State and EnergyNorth to record regulatory assets or liabilities reflecting the fair value of pension and other post-employment benefit obligations as of the transaction closing date. Granite State and EnergyNorth further agree that the Commission's approval of the Settlement be conditioned on their commitment to forego recovery through rates of any acquisition premium, transaction or transition costs that result from the acquisition. A copy of the Settlement Agreement, with the various attachments integral to the Agreement itself, is available at:

www.nh.puc.gov/docketbook/DG11-040. The Settlement includes a number of commitments made by Liberty and National Grid, as outlined below.

A. Commitments by Liberty

Liberty has agreed to certain reporting requirements intended to assist the Commission in monitoring the transition process, including monthly reports with updated organizational charts and transition timetables, costs incurred and estimates of costs to be incurred under the TSAs, the status of services provided under the TSAs, and updates on IT systems development and transfers from National Grid to Liberty.

1. Customer Rates

Liberty has made certain commitments designed to provide benefits to customers and ensure no detrimental rate impacts as a result of the proposed transaction. Those commitments include no recovery through rates of any acquisition premium or transaction costs, including financing, legal and regulatory costs incurred with closing the transition, or transition costs incurred to effect the transaction. Both Granite State and EnergyNorth commit to individual stay-out provisions under which Granite State agrees not to file for a rate increase effective prior to January 1, 2013,[2] and EnergyNorth agrees not to file for a rate increase until the earlier of three years from the date of closing or 270 days after the date on which 70 percent of the transition services are paid for. Granite State's stay-out commitment does not apply to safety or reliability related filings such as those made under its vegetation management plan (VMP), reliability enhancement plan (REP), or provision of default service. EnergyNorth further commits to forego recovery through gas rates for the cost of unaccounted for gas volumes that

[2] Granite State's commitment is consistent with its current multi-year rate agreement in DG 06-107, in which it agreed not to file for a rate increase before January 1, 2013.

exceed 1.28 percent as reported in its cost of gas filings for the period commencing July 1, 2012, and terminating the earlier of the completion of its first rate case or June 30, 2015.

Granite State and EnergyNorth also agree not to seek recovery for rate case expenses in excess of $300,000 and $600,000, respectively, in their respective first rate cases following the transaction close. Granite State's rate case expense commitment not does include the costs of a depreciation study.

2. Information Technology

As part of the Settlement, Liberty Energy developed an IT Plan and a preliminary IT Migration Plan designed to facilitate a seamless transition from National Grid to Liberty Energy's IT systems. The IT Plan sets out high level processes and procedures, while the IT Migration Plan provides specific IT system implementation plans to be followed during the transition process. Liberty will provide Staff an updated IT Migration Plan by August 1, 2012.

Liberty has agreed to an $8.1 million cap on recovery of transition-related IT capital investments, not including capital expenditures required to meet changes in state or federal regulatory requirements. Liberty has also committed to undertake an IT security assessment compliant with International Organization for Standards (ISO) standard 2700-1[3] prior to closing to establish a baseline security analysis, a re-assessment upon completion of the IT Migration Plan, and biennial assessments thereafter. Liberty will also undertake comprehensive IT systems testing in compliance with Institute of Electrical and Electronic Engineers (IEEE) standard 829.[4] Finally, Liberty will strengthen its current practices regarding IT vendor management through testing of deliverables, where applicable, prior to contract payments and annual reviews of vendor performance and services.

[3] ISO standard 2700-1 sets forth specific requirements intended to bring information security under explicit management control.
[4] IEEE standard 829 specifies the format of documents that may be used in software testing.

3. Customer Service

In support of its commitment to maintain high levels of customer service, Liberty will maintain local management, a local customer service presence, and local walk-in centers for customers. Within six months of closing, Liberty will provide detailed plans explaining customer service operations and support functions for the post-transition period and a staffing contingency plan in case of cutover failure. Granite State commits to answering 80 percent of the calls received at its call center within 20 seconds; EnergyNorth commits to answering 80 percent of its call center calls within 30 seconds. Both performance metrics will be measured annually. A local president with decision-making authority and spending authority of at least $250,000 will be headquartered in New Hampshire. Liberty will conduct a residential customer satisfaction survey for both Granite State and EnergyNorth within three months of close to establish a baseline for customer satisfaction. Should the survey results indicate a satisfaction level below 80 percent, Liberty will develop a plan to improve customer satisfaction for Staff review. Residential customer satisfaction surveys will be conducted annually thereafter. Liberty will also assist in determining the root cause of any failure to achieve the performance levels set forth in certain performance metric requirements outlined in Attachment N to the Settlement.

4. Safety

Liberty will appoint an Emergency Liaison who will provide Staff with updates four times daily during emergency events when the New Hampshire Emergency Operations Center is operating. Further commitments to safety are outlined in Attachment J to the Settlement, including marking underground electric facilities on customer property to the meter, bolstered resource procurement policies and practices during wide-scale emergency events, remote readable computer access for designated Commission Staff that enables access to outage

management system (OMS) display screens, OMS capability of displaying estimated restoration times of outages on a neighborhood level, improved valve maintenance, and enhanced reporting. These safety-related measures represent a comprehensive set of conditions that include and supersede existing safety-related standards and requirements set forth in various Commission orders, rules and commitments made in prior settlements.

5. Operations

Liberty commits to maintaining Granite State's existing REP and VMP conditions, as established in DG 06-107, and Granite State will file a new Integrated Resource Plan within six months of the issuance of this order. On acceptance of that commitment, the parties to the Settlement recommend that the current Granite State IRP docket, DE 10-142, be closed. Finally, Liberty commits to continue Granite State's practice of operating energy efficiency programs within budget and achieving kWh savings. Liberty also agrees to review the current level of energy efficiency budgets in the Core Electric and Gas Energy Efficiency dockets to determine whether and to what extent the budgets need revision. In its 2013-2014 Core filing, Liberty will submit a report summarizing its budget review.

6. Transition Process

To help ensure a smooth transition, Liberty commits to maintaining a fully dedicated senior executive responsible for transition activities associated with its various utility acquisitions. That executive, the head of Liberty Utilities (Canada) Corp.'s Project Management Office, will report directly to the President of Liberty Utilities (Canada) and will provide leadership, oversight, and control of any projects related to the integration of newly acquired companies.

B. Commitments by National Grid

To ensure National Grid's ongoing commitment to support Liberty in the transition process and to provide a financial enforcement mechanism to secure the smooth transition of all utility functions, National Grid has agreed to establish a financial escrow account that will be administered by an independent escrow agent, with funds to be released by the escrow agent upon receipt of notification from Staff. Under the escrow arrangement, National Grid will place $28,500,000 into escrow at the transaction close. The escrow funds will be accounted for in three separate "pools", as set forth below.

Pool A will consist of $13,500,000 and will be eligible for release to National Grid in increments at prescribed three-month intervals following the closing and continuing until Day N, which is defined as the date on which all transition services have been cut over from National Grid to Liberty Energy NH and/or its affiliates. The Pool A funds will be released on a pro-rata basis, using the cumulative number of transition services that have been fully transferred pursuant to the terms of the TSAs, as certified by the utilities and National Grid and confirmed by Staff.

Pool B will consist of $5,000,000 to be held in escrow until Granite State, EnergyNorth and National Grid certify to Staff that all transition services (other than certain services identified on Attachment L to the Settlement) have been transferred to Liberty Energy and/or its affiliates.

Pool C will consist of $10,000,000 to be held in escrow as a means for Staff to administer certain performance metrics set forth in Attachments N (Customer Service) and O (Gas and Electric Safety) to the Settlement. Those metrics are intended to ensure that specified performance levels are maintained by the utilities during the period when National Grid is providing transition services, and that the continued provision of those services at the same performance levels by Liberty Energy for a one-year period following cut-over from National

Grid is not rendered defective as a result of any system, database, data, process and/or procedure error that is directly attributable to National Grid.

If 180 days after the cut-over of all transition services (other than the limited number of services identified on Attachment L to the Settlement) there are no unresolved or uncorrected performance failures, 25 percent of Pool C funds not otherwise subject to a set-aside will be released to National Grid. The balance of Pool C funds will be held until a year after all of such services have been cut over. If a failure to achieve any metric has occurred prior to the conclusion of the 365 days and the matter has not yet been finally resolved, a portion of the Pool C funds in an amount equal to $250,000 for each such pending matter will continue to be held in escrow until the matter is resolved.

National Grid will establish an escrow account and engage an independent escrow agent for purposes of administering the escrow funds as contemplated by the Settlement Agreement prior to closing. Funds equaling $28,500,000 will be placed in the escrow account at close. The escrow agent will be required to hold, safeguard, administer, and only disburse funds from the account upon written certification of Staff in accordance with the terms of the Settlement. A copy of the escrow agreement will be filed with the Commission upon execution.

V. POSITIONS REGARDING THE SETTLEMENT

A. Joint Petitioners

In hearing testimony, Algonquin and Liberty Utilities provided an overview of their corporate structure and affiliate relationships, as depicted in Attachment A to the Settlement Agreement. That structure includes Emera, Inc. (Emera), Algonquin's largest shareholder at approximately 7 percent and a $6 billion power utilities company with the contractual opportunity to invest and hold up to 25 percent of Algonquin. Algonquin further stated that

Emera has committed to providing Algonquin with $60 million in additional equity earmarked for the acquisition of Granite State and EnergyNorth. With respect to additional acquisitions that could compete with the New Hampshire utilities for corporate resources, Algonquin stated that while it continues to develop power projects in Canada and the United States, it has no pending utility acquisitions other than the acquisition of some additional natural gas distribution assets in Missouri, Iowa, and Illinois, and that, in the event it were to acquire additional utility businesses, any new acquisition would not be likely to close before 2014. Algonquin agreed that to the extent it invests in an IT system with applicability outside the State of New Hampshire, the costs of that system should be reasonably shared amongst other regulated utilities, but emphasized that its utility and power businesses are legally separate from a debt perspective and would not be cross-collateralized. In New Hampshire, Algonquin stated that it sees an opportunity to increase penetration of its natural gas services, a potential to acquire additional utilities, and continued reinvestment in existing utility infrastructure.

Liberty Utilities described its business strategy as one that invests in moderate return and predictable risk businesses, such as rate-regulated utility companies, adding that its corporate culture focuses on customer service and local management and, in the instant transaction, a commitment to returning jobs to New Hampshire and increasing the penetration of natural gas service to customers in the state. Liberty Utilities stated that the acquisition of Granite State and EnergyNorth would constitute 30 percent of its corporate business, compared to 2 percent of National Grid's corporate portfolio. Liberty Utilities described the corporate structure of Liberty Energy NH, as depicted in Hearings Exhibit 6, noting that Liberty Energy NH continues to populate key management and leadership positions.

Liberty Utilities explained that -- with National Grid -- it has formed a multi-tiered, multi-disciplined transition management organization comprised of a Transition Steering Committee and a Transition Governance Group with representatives of both the Liberty family of companies and National Grid to manage the New Hampshire utility acquisitions and transition, as depicted in Hearings Exhibit 9. According to Liberty Utilities, the New Hampshire-based president of Liberty Energy NH has full accountability for profit-and-loss within the state and will be responsible for executing Liberty Utilities' corporate vision of customer-centricity, community involvement, employee engagement, and regulatory compliance.

Liberty Utilities testified that it created over 25 individual project plans for a series of functions it deems necessary to complete the transition. Those plans assessed people, process and policy issues, technology requirements, branding, and systems testing and readiness. According to Liberty Utilities, as of "Day 1" or the first day following the closing of the proposed transaction, Granite State and EnergyNorth customers will see no change to the phone numbers to call for service, only in the company name and logo. Personnel and employee benefits will transfer from National Grid to Liberty on Day 1. Liberty Utilities emphasized its diligence in getting its financial system up and running with a Microsoft Dynamics Great Plains application, and conducting system acceptance testing in readiness for Day 1.

With respect to the transfer and cut-over of corporate functions, Liberty Utilities stated that no service will be cut over prematurely. Towards that end, the IT Migration Plan (Attachment H to the Settlement) sets forth a significant testing approach and strategy, under which each individual service will be tested multiple times before it is turned over to the users, at which point Liberty will undertake detailed user acceptance testing. A readiness determination will be made on each service and Liberty will enter into a formal notification period with

National Grid prior to the cutover of each service. Liberty Utilities stated that to the extent its IT implementation costs exceed the cap set forth in the Settlement Agreement, all necessary investments would be made and non-recoverable costs would be borne by the shareholders.

National Grid testified that it is fully committed and has been working closely with Liberty Utilities and Liberty Energy NH to ensure that its responsibility to provide transition services under the TSAs is fully met. Roughly 48 personnel from National Grid are focused solely on this transaction and will transfer to Liberty Energy NH on Day 1, at a cost to National Grid of approximately $650,000 a month during the transition period. National Grid further noted that it had committed a sum of $28.5 million to this transition as part of the agreed upon escrow mechanism in the settlement, and is prepared to continue to provide services beyond the timeframes envisioned in the TSAs, if necessary. Toward that end, National Grid will maintain its core transition team in place until the transaction is fully completed.

B. The Way Home and Pamela Locke

On behalf of The Way Home and Pamela Locke, New Hampshire Legal Assistance (NHLA) expressed full support for the Settlement Agreement at hearing, and that Liberty's commitment to local management and a customer-oriented focus that provides the ability to contact personnel who will listen, address concerns, and make decisions was welcome. NHLA further noted that Liberty had immediately embraced the request that it assume full responsibility for the existing low-income programs that National Grid currently operates. Through questioning of petitioner witnesses, NHLA confirmed Liberty's commitment to low-income initiatives and to maintaining Granite State's existing energy efficiency programs within budget and meeting kilowatt-hour savings goals. NHLA concluded that the proposed transaction offers benefits to the customers, particularly to the low-income community.

NHLA also relayed at hearing support for the Settlement Agreement from the NHCAA, a signatory to the settlement.

C. United Steel Workers of America Local 12012-3

USWA Local 12012-3 stated its support for the transaction at hearing and its expectations of higher standards for better service and safer service under Liberty ownership to the benefit of employees, customers and the general public. USWA Local 12012-3 added its appreciation for the cooperation of Liberty management through the course of the transaction and negotiations.

D. International Brotherhood of Electrical Workers Local 326

On behalf of IBEW Local 326, James Simpson stated that in his 30 years in the electric industry he has never met a management group as open and willing to sit down and work with the unions as Liberty, noting that Liberty had taken the initiative to call the unions, hold employee meetings and host conference calls. IBEW Local 326 stated its strong support for the proposed transaction, noting that as a small company with fewer layers of bureaucracy, Liberty will be able to more nimbly respond to emergencies, increasing overall reliability.

E. OCA

The OCA stated its support for the Settlement Agreement, noting in particular the provisions in the settlement that require rate case stay-outs, limit rate case expense recovery, and establish a cap on recovery for the cost of unaccounted for gas. At hearing, OCA testified through its witness, Scott Rubin, that it had continuing concerns with Liberty's technical and managerial fitness, although the settlement provisions address most of his concerns about service quality and the transition process, including several ratemaking provisions, transition period caps on IT-related investment and unaccounted for gas, a bar on changes in accumulated deferred tax

balances as a result of the elected tax treatment of the transaction, and limits on rate case expenses in the utilities' first base rate cases under Liberty ownership.

Mr. Rubin noted that the high level of Staff involvement, called for in implementing the Settlement Agreement provides some limited protection for the public against the consequences of an inexperienced company taking over the Granite State and EnergyNorth utility operations. According to Mr. Rubin, Liberty will not capture some of the economies of scale that National Grid provides today, a concern in the early years of new utility ownership before new investments have depreciated. Stemming from that concern, the caps on expenses and ratemaking provisions in the Settlement Agreement are designed to mitigate and offset Liberty's higher operating costs in the first few years. Mr. Rubin testified that he had no objection to the financing terms proposed by Liberty during the proceedings, and concluded that if the settlement provisions are approved, implemented and vigorously enforced, the transaction is in the public interest and the public will not suffer a net harm.

F. Staff

Staff testified that the Settlement Agreement addresses concerns regarding Liberty's lack of experience in operating electric and gas distribution systems, the expense of the new IT systems and the impact that operating and transition costs might have on rates. According to Staff, Liberty has hired experienced employees with utility and New Hampshire regulatory experience, and the settlement ensures that there will be no recovery through rates of the acquisition premium, transaction or transition costs, and no present or future recovery of IT capital expenditures that exceed $8.1 million. In addition, the settlement includes a rate case stay-out period for EnergyNorth and caps on rate case expenses recoverable through Granite State and EnergyNorth rates, and the unaccounted for gas provision is an added incentive for

EnergyNorth to maintain unaccounted for gas percentages at or below current levels during the transition period. Staff further noted that the escrow mechanism included in the settlement is designed as a financial incentive to ensure National Grid's commitment and involvement throughout the transition process, to ensure that Liberty receives the assistance they contracted for, and to protect the New Hampshire public. Escrow funds will be available to correct issues that may arise following the cut-over of services under the TSAs in the event it is determined that any identified problem is attributable to a failure of National Grid's data, systems, process or procedures. The funds will also be available for the Commission to use for possible penalty consideration in the event of a significant failure.

Staff stated that it had reviewed the proposed plan for financing the stock transfers, as well as the availability of short-term debt to provide for operational needs going forward. Staff found the long-term debt financing plan to be reasonable in its proposed interest rate and maturity terms, which will be reviewed again when final terms and conditions are provided after closing, and in the provision for a capital structure of 45 percent debt/55 percent equity. Staff added that the proposed use of the funds is appropriate and prudent, based on information available at the time of hearing and consistent with the Commission's standard application of the *Easton* test.[5] The Settlement addresses Staff's concern regarding the availability of short-term credit funds for Granite State and EnergyNorth, given the fact that other Liberty Energy affiliates can draw upon the credit facility, as the total facility will be increased to $80 million upon closing of this transaction and $100 million upon the closing of its acquisition of additional gas distribution facilities in the Midwest. Cost allocation amongst the numerous Liberty affiliates will be reviewed by Staff and the OCA with Liberty prior to the filing of Granite State's first

[5] The *Easton* analysis involves looking beyond actual terms of the proposed financing to the use of the proceeds and the effect on rates, in order to insure that the public good is protected. See *Appeal of Easton*, 125 N.H. 205, 211 (1984).

base rate case. Granite State's first rate case will also provide the opportunity to review the existing Major Storm Reserve, and Reliability Enhancement and Vegetation Management Programs, to assess whether those programs should be revised. The parties to the settlement have agreed to close the existing least cost integrated resource plan docket, DE 10-142, and to launch a new docket upon Liberty's filing of its own least cost planning document within six months of the Commission's order in this proceeding.

Staff testified that its concerns regarding Liberty's lack of experience in owning and operating gas and electric utilities, the need for seamless and transparent IT systems conversion, and the concern that low-income initiatives continue to be offered under Liberty ownership were addressed by the settlement. Staff stated that a number of customer service-related metrics are established through the terms of the settlement to help identify potential problems in the areas of billing accuracy, percentage of bills that are estimated, billing exceptions, call center responsiveness, and customer call handling during major storm events. The metrics are intended to ensure that customer service will not deteriorate during the transition period. In addition, Staff noted that Liberty committed to conducting a baseline customer satisfaction survey immediately following the transaction close, and will continue such surveys thereafter. Staff also noted that Liberty will dedicate one full-time equivalent to perform certain customer outreach functions, including specialized enrollment and education services, a calling campaign to customers regarding low-income home energy assistance programs, and continuation of existing low-income assistance programs, the Neighbor Helping Neighbor program, and Core energy efficiency programs.

Staff stated its concern that, as a much smaller corporation than National Grid, Liberty could face challenges in procuring resources and assistance during large, wide-scale outages. As

a result, an electric safety-related metric is included in the Settlement Agreement to ensure National Grid's continued assistance in emergency resource procurement during the transition period. A number of gas safety metrics were agreed to as well, to ensure no degradation in gas service during the transition to Liberty ownership. Attachment O to the Settlement Agreement lists both gas and electric safety performance metrics. In addition, Attachment J includes 20 gas safety performance conditions that will apply to EnergyNorth upon closing. Those conditions include the designation of critical pipeline valves, the incorporation of Global Positioning System (GPS) information into EnergyNorth's Geographic Information System (GIS), enhanced leak reporting, a targeted Grade 3 leak reduction program, and the continuation of certain existing safety-related programs and practices currently followed by National Grid, such as the Cast Iron Bare Steel (CIBS) Replacement Program and emergency response time standards. Attachment J also includes an electric safety condition that pertains to locating and marking out of certain customer owned electric facilities. According to Staff, the safety conditions set forth in Attachment J to the settlement are intended to consolidate and supersede existing safety requirements applicable to Granite State and EnergyNorth.

Through its consultants, G3 Associates, Staff testified that initially Liberty's lack of detailed planning for the back-end of the transition process was disappointing and that its IT implementation schedule was aggressive and would require additional extension before it could be completed. G3 Associates noted, however, that after extensive discovery and discussion, Liberty submitted an IT Plan and an IT Migration Plan that together address Staff's concerns regarding comprehensive systems testing and implementation. According to G3 Associates, the IT Plan outlines the requirements that Liberty's operating company will have for IT support and how Liberty intends to address those requirements, and the IT Migration Plan is a working

document that will guide IT systems implementation by the companies and provide Staff the ability to monitor implementation efforts and results. The IT Migration Plan, for example, includes a change-management process that will govern changes required as implementation proceeds while allowing Staff to monitor the efficiency of the implementation and changes that may affect cost or schedules associated with the systems transition. G3 Associates added that Liberty had gained a number of valuable insights from its experience in the acquisition of CalPeco, an electric distribution utility in California, including the need for more comprehensive IT testing plans and the need to provide sufficient time to train users of the IT systems to be implemented. G3 Associates stated that Liberty has added greater clarity to its IT plans, including longer-term planning requirements, integration testing, stress testing, user needs analysis, a data retention agreement, and a vendor management cost program to ensure that IT vendors deliver the products and services agreed upon. With respect to IT implementation, G3 Associates noted that Staff will need to be actively engaged in monitoring the IT implementation schedule and ensuring that commitments made are fulfilled and that operating expenses associated with IT implementation are judicious and prudent, based on the "reasonable man" theory of prudency (which would involve assessing the options available to and considered by Liberty, and the appropriateness of its decisions). G3 Associates recommended Staff obtain outside technical assistance to monitor and enforce the Settlement Agreement's requirements. G3 Associates concluded that the Settlement Agreement addresses their concerns regarding the proposed transaction and, with active regulatory monitoring throughout the transition period by Staff, the Joint Petitioners can be expected to realize an orderly transition of responsibilities and a cost-effective solution to the IT needs of both Granite State and EnergyNorth.

Staff concluded that the commitments made in the Settlement Agreement ensure that the proposed transaction will be in the public interest.

VI. COMMISSION ANALYSIS

Pursuant to N.H. Code Admin. Rules Puc 203.20(b), the Commission shall approve disposition of a contested case by settlement "if it determines that the result is just and reasonable and serves the public interest." *See also* RSA 541-A:31,V(a). In determining the public interest, the Commission serves as arbiter between the interests of customers and those of the regulated utilities. *See* RSA 363:17-a; *see also Public Service Co. of N.H.*, Order No. 24,919 (Dec. 5, 2008) at 7-8.

In general, the Commission recognizes that settlement of issues through negotiation and compromise provides "an opportunity for creative problem solving, allows the parties to reach a result more in line with their expectations, and is often a more expedient alternative to litigation." *See Unitil Corporation and Northern Utilities, Inc.*, Order No. 24,906 (Oct. 10, 2008) at 32 (citations omitted); *see also EnergyNorth Natural Gas, Inc. d/b/a National Grid NH*, Order No. 24,972 (May 29, 2009) at 48. Even where all parties join a settlement agreement, however, the Commission must independently determine that the result comports with applicable standards. *Unitil Corporation*, *supra* at 32. The issues must be reviewed, considered and ultimately judged according to standards that provide the public with assurance that a just and reasonable result has been reached. *Concord Electric Company*, 87 NHPUC 694, 708, Order No. 24,072 (2002), quoting from *Concord Electric Company*, 87 NHPUC 595, 605, Order No. 24,046 (2002), and orders cited therein.

In this case, we are guided by the standards for approval of a public utility acquisition set forth in RSA 369:8, II(b) (requiring no adverse effect on rates, terms, service or operation of the

utility), RSA 374:30 (requiring a commission finding that transfer of a utility system is for the public good), and RSA 374:33 (requiring the transaction to be lawful, proper and in the public interest). In applying these standards, we consider all interests involved and all relevant circumstances in determining what is reasonable. *See Grafton County Electric Light and Power Co. v. State*, 77 N.H. 539, 540 (1915); *Parker-Young Co. v. State*, 83 N.H. 551, 561-562 (1929); *Appeal of Pinetree Power*, 152 N.H. 92, 97 (2005).

Consistent with the foregoing, we have reviewed the Settlement Agreement in light of the record as a whole. An important factor in our review is whether the concerns raised in testimony by non-utility parties regarding potential harm to customers of Granite State and EnergyNorth as a result of the proposed acquisition are adequately addressed by the settlement. We also look to whether the parties' review of the proposed transaction is sufficiently thorough and comprehensive to warrant confidence in the result reached in settlement.

Our assessment of the Joint Petition and Settlement Agreement in this proceeding includes a review of the request for authority to transfer stock ownership of Granite State and EnergyNorth from National Grid to Liberty Energy NH, as well as the reasonableness of the request to approve long-term debt issuances to finance the transaction. For the reasons discussed below, we conclude that the Settlement Agreement satisfies the applicable legal standards.

A. Request for Authority to Transfer Ownership

The first step in our review is to assess the proposal to transfer ownership of Granite State and EnergyNorth assets and operations from National Grid USA to Liberty Energy NH through the stock purchase agreements. As noted by Staff and the OCA, Liberty Energy has no experience to date operating a gas distribution system, and very limited experience operating an electric distribution system. An additional concern is the cost that Liberty Energy and Liberty

Energy NH must incur to develop and implement the IT systems required to support both the gas and the electric distribution systems. Liberty's ability to manage the gas and electric utility operations and implement the IT systems needed to do so is fundamental to a successful transfer. The implications for ratepayers in terms of reasonable rates, as well as safe and reliable service, are a critical element of our assessment of the transaction. That said, we recognize the importance of National Grid's role in collaborating with and assisting Liberty throughout the transition period and following cut-over. We have assessed the terms and conditions of the Settlement Agreement with a view toward potential rate impacts, operation and service implications.

1. Potential rate-related impacts.

Liberty has committed to a number of measures designed to protect ratepayers from adverse rate impacts that could result from the proposed transaction. Under the terms of the settlement, neither Granite State nor EnergyNorth will seek rate recovery for transaction or transition costs. These include the acquisition premium and other financing, legal and regulatory costs incurred to close the stock purchase transaction and implement the transfer at the operational level. We view Liberty's commitment to protect ratepayers as substantial, given the significance of the transaction in terms of dollars. The concerns expressed by both Staff and the OCA regarding the cost implications of Liberty's need to develop and implement entirely new IT systems, given its lack of experience or prior presence in the State, are addressed by several commitments Liberty has made to limit its potential recovery in future rate filings. Foremost is the agreement to limit recovery of prudently incurred transition related IT capital investments to $8.1 million less depreciation. The cap on IT cost recovery helps to ensure that Liberty will carefully assess its IT needs and options, and will protect ratepayers from unlimited or imprudent

spending. We note, as well, Algonquin's significant commitment during the hearing to underwrite Liberty's IT costs through shareholders to the extent those costs exceed the cap. At the same time, a provision is made for Liberty's potential recovery of IT expenditures necessitated by future changes in state or federal requirements. Thus, Liberty will not be hobbled by the IT cap if non-transaction or non-transition related IT changes are required as a result of new regulatory requirements.

In the Joint Petition, Liberty asserts that customers will not experience an increase in rates as a result of the transaction. Granite State and EnergyNorth each have committed to refrain from raising customer rates for a certain period. Under the terms of the Settlement Agreement, the earliest Granite State customers would see a permanent rate increase would be January 1, 2013, and EnergyNorth will not file for a rate increase until the earlier of three years from the date of closing or 270 days after the date on which 70 percent of the transition services under the TSAs are paid. At the same time, both utilities will be permitted to seek rate increases, as warranted, for certain operational program needs. Granite State may seek rate increases, for example, for safety or reliability related filings pertaining to vegetation management, reliability enhancement, or default service. EnergyNorth may seek adjustments as needed for cost of gas impacts, CIBS program investments, local distribution adjustment charges, and exogenous events that result in annual revenue impacts greater than $1,000,000. We note, as well, the agreements of both EnergyNorth and Granite State to limit rate case expense recovery to $600,000 and $300,000, respectively, excluding the cost of a depreciation study for Granite State.

These commitments provide certain rate impact protections for customers, while assuring the utilities the possibility of recovery for necessary operational expenses. As noted in Staff

testimony, Granite State is currently earning well below its authorized rate of return. We find, therefore, that a rate case filing within a year of the proposed transaction close is not unreasonable and, moreover, is consistent with the terms of the current multi-year rate arrangement approved in DG 06-107. We note as well that, according to Staff testimony, Granite State was expected to come in for a rate case under National Grid ownership. Regardless of who owns the Granite State system, therefore, a rate case would likely occur in the near future. We further find that a longer stay-out period is reasonable for EnergyNorth, which completed a rate case just a year ago.

Liberty also commits to holding customers harmless for the elimination of the historical accumulated deferred income tax (ADIT) liabilities resulting from its election under section 338(h)(10) of the Internal Revenue Service Code in accounting for its acquisition of Granite State common stock in this transaction. Further ratepayer protection is achieved by maintaining pro forma accounting for regulatory purposes to continue to provide ratepayers with the ratemaking benefit of Granite State's pre-acquisition ADIT balances until such time as actual ADIT balances related to the historical utility plant assets acquired equals or exceeds the levels that the pro forma ADIT would have been, absent the proposed transaction. The ADIT balances related to capital additions after the closing date are not affected by the section 338(h)(10) election and the treatment of these balances will not change for accounting and ratemaking purposes.

Finally, Liberty agrees not to seek recovery in its cost of gas rates for unaccounted for gas volumes that exceed 1.28 percent until the completion of EnergyNorth's first rate case or its September 2015 cost of gas filing. This provision serves as a safety measure, as well, because it provides an incentive to EnergyNorth to control unaccounted for gas volumes.

2. Operational and service commitments.

Of equal concern in our assessment of the proposed transaction is Liberty's technical and managerial ability to operate the Granite State and EnergyNorth utility systems. To address the concerns raised in testimony, Liberty has undertaken a number of commitments in the areas of information technology, customer service, low-income assistance, safety, reliability enhancement, vegetation management, and energy efficiency.

As part of the settlement, Liberty Energy developed an IT Plan and a preliminary IT Migration Plan to facilitate the transition from National Grid's to Liberty Energy's IT systems, with a commitment to provide an updated IT Migration Plan by August 1, 2012, in anticipation of completion of IT systems design. As part of its IT planning, Liberty will undertake comprehensive IT testing and conduct an IT security assessment prior to the transaction, with follow-up assessments upon the completion of the IT Migration Plan and biennially thereafter. In response to Staff concerns regarding the scope of Liberty's reliance on its IT vendors, Liberty Energy will implement tighter vendor management procedures, as well as annual reviews of vendor performance and services. Given the magnitude of the IT undertaking involved in this transaction, the commitment to extensive IT testing and security assessments, and the careful management of IT resources, will be critical to a successful transition and the establishment of a strong foundation for Liberty's operations in New Hampshire. We note as well National Grid's commitment to assisting the IT transition by appointing a senior IT management executive to oversee the transition.

The Joint Petition asserted a number of commitments by Liberty to provide high levels of customer service and regulatory responsiveness. Through the terms of the Settlement Agreement, Liberty Energy has reaffirmed those commitments by agreeing to establish and

maintain a strong local presence in New Hampshire, with a local president headquartered in New Hampshire and local call centers and walk-in centers for customer convenience. The commitment to provide the New Hampshire president with spending authority of at least $250,000 to ensure the quickest possible response in emergency situations is of particular note, given the concerns regarding the shift of Granite State and EnergyNorth away from the corporate umbrella of National Grid.

Liberty will conduct annual residential customer service surveys, starting with an initial survey within three months of closing to establish a baseline measure of customer satisfaction. If the baseline satisfaction level is below 80 percent, Liberty Energy will develop a plan to improve customer satisfaction for Staff's review. Within six months of closing, Liberty will submit to Staff detailed plans explaining its customer service operations and support functions for the period following the TSAs and a staffing contingency plan in the event of a cutover failure, as defined in the Settlement Agreement.

Both Granite State and EnergyNorth commit to maintaining current metrics applicable to answering calls to its customer call center and maintaining the current complement of low-income activities and funding levels for low-income initiatives. Liberty further commits to a proactive customer outreach approach by agreeing to allocate the equivalent of a full-time employee to respond to customer requests through early intervention and to provide specialized enrollment and education services, crisis bill management, and outreach and education.

Granite State and EnergyNorth have committed to a comprehensive set of gas and electric safety conditions, that include new conditions as well as existing standards and requirements set forth in various Commission orders, rules and prior settlements. The consolidation of those conditions, including the marking of underground electric facilities on

customer property, improved gas valve maintenance, bolstered resource procurement during wide-scale emergency events, increased OMS capabilities, and in-house emergency response training and drills, is laudable, in terms of a comprehensive commitment to ensuring safe and reliable service, as well as administrative clarity.

In addition, Liberty will continue Granite State's current REP and VMP conditions, as established in DG 06-107. With regard to Granite State's integrated resource plan , the settlement parties have requested that the current planning docket, DE 10-142, be closed and that Granite State file a new integrated resource plan within six months of closing the docket. We find that request to be efficacious and hereby direct Staff to close DE 10-142 upon our issuance of this order.

Similarly, Liberty also commits to ensure a continuation of Granite State's practice of operating energy efficiency programs within budget and meeting kWh savings goals. Toward that end, it will review the current level of energy efficiency budgets in the Core Electric and Gas Energy Efficiency dockets and submit a report of its review of budget requirements in its 2013-2014 Core filing.

To address concerns raised by the Granite State Hydropower Association and consistent with the Commission's affiliate transactions rules, Granite State and EnergyNorth agree not to purchase energy, capacity or services from any of their competitive affiliates, including hydroelectric generating or gas facilities owned directly or indirectly by Algonquin Power Co., on terms more favorable than those offered to or available to any non-affiliated suppliers, including independently owned hydroelectric generating facilities in New Hampshire.

Staff and its consultants raised concerns about the number of utility acquisitions Liberty Utilities is undertaking in close succession and the potential financial as well as management

implications for Granite State and EnergyNorth operations. Pursuant to Staff's recommendation, Liberty Utilities will appoint a senior executive responsible for transition activities associated with the various acquisitions. That individual will head Liberty Utilities' Project Management Office, which will provide leadership, oversight and control of any projects related to the integration of new acquisitions. Throughout the EnergyNorth and Granite State transitions, the project management lead will hold periodic briefing sessions with transition team leads and provide updates in the quarterly reports provided to the Commission. This commitment brings increased transparency as well as a measure of assurance of coordinated management to the multiple acquisitions Liberty Utilities is pursuing. Integral to the success of the transition will be the experienced employees of EnergyNorth and Granite State who will continue to operate the systems. The continuity in senior operational and planning personnel provides considerable benefit to Liberty, which is admittedly less experienced in electric and natural gas utility operations, and is an important basis for our support of the Settlement Agreement.

Further transparency will result, as well, from Liberty's commitment to provide a number of monthly and quarterly reports to the Commission, including updated transition timetables, cost tallies, IT implementation, staffing, corporate cost allocation procedures, and financial forecasts. These reporting commitments are further enhanced by the commitment of the President of Liberty Energy NH and the Chief Executive Officer of Algonquin to hold quarterly sessions with Commission Staff and the OCA to keep them apprised of Granite State and EnergyNorth transition activities.

Finally, Liberty Utilities agrees to guarantee access to a minimum of $18,867,000 to EnergyNorth and $2,731,000 to Granite State under its January 18, 2012 Short-Term Revolving Credit Facility. Future renewals of that facility or any new short-term facilities will be at

favorable terms and conditions that are no more costly than comparable commercial credit facilities. We find this provision to be an important financial commitment underpinning the initial stages of the transition to Liberty operations and management.

3. National Grid Commitments

All parties recognize the magnitude of the transition to be undertaken by Liberty, as well as the crucial role National Grid will play in that transition. To underscore and ensure its support, National Grid has agreed to establish a financial escrow account administered by an independent escrow agent, with funds to be released upon Staff confirmation of readiness. The Settlement Agreement notes that the escrow agreement will be submitted to the Commission upon execution and that funds will be deposited within five business days following the Closing Date. We will direct National Grid to submit a copy of the escrow agreement for our review no later than one week prior to the anticipated Closing Date.

The Settlement Agreement establishes three pools of funds to be held in escrow, each underpinning a particular mode of support from National Grid, including the commitment to provide transaction services to facilitate a smooth and seamless transition, to ensure that service quality does not decline during the course of the transition, and to ensure cutover occurs only when Liberty's systems are fully ready. Release of the $13.5 million in Pool A funds is tied to the completion of transition services under the TSAs and Staff's confirmation of readiness. The $5 million in Pool B funds will be held until both Granite State and EnergyNorth certify to Staff that all services provided under the TSAs are completed satisfactorily. Certain consulting-type services that could be provided beyond the final cutover will be excluded from the Pool B escrow terms, as National Grid will continue to provide those services on an as-needed basis. Release of the $10 million in Pool C funds is contingent on National Grid and, to an extent,

Liberty Energy maintaining certain levels of performance in customer service and gas and electric safety-related operations, subject to Staff monitoring and oversight.

We are persuaded that the commitments outlined above and described in detail in the Settlement Agreement adequately address the concerns raised in this proceeding. The commitments made by both Liberty and National Grid in the areas of ratepayer protections, operational enhancements, customer service levels, and financial restraints provide us with assurance that New Hampshire ratepayers are adequately shielded from potential harm as a result of the proposed stock transfers. We are further assured that Granite State and EnergyNorth will benefit from the affirmed collaboration of National Grid in the transition process and the focused management of Liberty Energy and its corporate affiliates with respect to transition implementation.

B. Approval of long-term debt issuances/overall transaction financing.

In reviewing the proposed financing for this transaction, we must determine whether the issuance is consistent with the public good, pursuant to RSA 369:1 and 4. To do so, we consider the amount of the issue authorized, the purpose for which the proceeds are to be used, and the reasonableness of the terms and conditions of the financing. We are further required to consider whether the object of the financing is reasonably required for use in discharging a utility company's obligation to provide safe and reliable service, whether the utility company's plans to accomplish that object are economically justified when measured against any adequate alternatives, and whether the capitalization resulting from the utility company's plans would be supportable. *Appeal of Easton*, 125 N.H. 205, 211-213 (1984).

Granite State and EnergyNorth have requested approval to issue long-term debt in an amount sufficient to establish a capital structure of 45 percent debt to 55 percent equity, based on

the rate base level at the closing date, to finance the stock purchases. To achieve that structure, Granite State proposes to issue up to $20 million in new long-term debt in addition to retaining the $15 million in long-term debt currently outstanding, and EnergyNorth proposes to issue up to $90 million in long-term debt to refinance the existing long-term debt. According to the pre-filed testimony of Algonquin CFO David Bronicheski, the debt will be raised through a private placement of senior unsecured notes with U.S.-based institutional lenders. Granite State currently has $15 million of unsecured long-term notes that include certain restrictive covenants that stipulate that note holders may declare the debt to be due and payable if total debt becomes greater than 70 percent of the total capitalization. Algonquin does not anticipate this to be an issue, however, given the proposed capital structure. If this were to occur, it would need to be addressed in a future proceeding before the Commission. The debt will be issued by Liberty Utilities Co. and assigned down to, and supported by promissory notes from, Granite State and EnergyNorth.

As part of its request for authority to issue long-term debt instruments connected with the proposed acquisition, Granite State, EnergyNorth and Liberty have filed a motion for waiver of certain filing requirements under Puc 308.12 and Puc 509.03. Puc 308.12 and Puc 509.03 pertained to information filing and format requirements for electric and gas utilities, respectively, seeking to issue securities. The companies request waivers of the requirements under Puc 308.12 to provide: (1) historical and forecasted capitalization information for Granite State; (2) resolutions of the board of directors for both Granite State and EnergyNorth; and (3) the use of a particular format to provide the required information.

According to the motion, the capitalization information provided for Granite State and EnergyNorth reflects information as of September 30, 2011, as well as pro forma adjustments

reflecting the proposed new debt issuance. The companies state that they have provided the more limited information (*i.e.*, without historical or forecasted data) because the sole purpose of the debt issuance is to modify the current debt/equity ratio, not to finance additions to rate base or for other purposes. They add that the required board of directors' resolutions authorizing the proposed long-term financing cannot be obtained until the change in ownership has occurred and a new board of directors has been installed by Liberty Energy NH. According to the motion, the resolutions will be provided promptly after consummation of the loan transactions. With respect to the format of the information provided, the motion states that the companies have complied with the substance of the rule by a reasonable alternative means, that is, by providing most of the required information in the form of technical statements relating to each utility.

Staff testified that it had reviewed the technical statements and found them reasonable and satisfactory. We therefore find that the alternative means of providing the information is sufficient to warrant a waiver of the format requirements of the cited rules. We further find that the provision of the capitalization information is sufficient for the purposes of the financing for which the companies seek approval, and that submission of the relevant resolutions of the board of directors upon their adoption will satisfy the applicable requirements under the cited rules. We therefore grant the requested waivers and direct Liberty, Granite State and EnergyNorth to submit within 10 days of their adoption the applicable resolutions.

Staff testified that it had reviewed the proposed financing terms, as well as the proposed use of the funds, and found the financing plan to be reasonable. Staff noted that the final interest rate and maturity terms will be subject to further review by Staff when finalized closer to the closing date to confirm that the terms do not substantially differ from those initially proposed. Staff testified at hearing that the proposed capital structure of 45/55 debt-to-equity ratio is within

the reasonable range of precedents and close to the standard hypothetical capital structure of 50/50 often used as a benchmark in rate cases. In addition, as noted by Staff, Granite State is currently earning well below its authorized rate of return and its first base rate case following the transfer will provide an opportunity to adjust the capital structure, as appropriate. Similarly, EnergyNorth's capital structure will be reviewed during its first post-close rate case.

Based on the utilities' testimony regarding the proposed use of the financing to support the acquisition and ongoing utility operations, and on Staff's review and testimony that the proposed debt-to-equity capital structure is reasonable and within the range of recent precedent, we find the proposed long-term debt issuance to be reasonable and consistent with the public good. With respect to the equity portion of the transaction financing, we note that $60 million has been pledged as a commitment by Emera. As part of our approval of the overall transaction financing, we will require Liberty to provide proof of Emera's fulfilled commitment within 10 days from the completion of that transaction.

C. Motions for Confidential Treatment and Request for Waiver of Filing Requirements

The Joint Petitioners filed two motions for protective order and confidential treatment pursuant to Puc 203.08 regarding certain information provided with the Joint Petition (March 4, 2011 Motion), as well as during the discovery phase of these proceedings (April 19, 2012 Motion). In addition, Joint Petitioners filed a separate motion for a waiver of certain filing requirements under Puc 203.08(f).

New Hampshire's Right-to-Know Law, RSA 91-A, provides each citizen the right to inspect all public records in the possession of the Commission. *See* RSA 91-A:4, I. The statute contains an exception, invoked here by the Joint Petitioners, for "confidential, commercial, or financial information." RSA 91-A:5, IV. We have had numerous occasions to rule on motions

for confidential treatment in the context of confidential, commercial, and financial information regarding utilities and their affiliates. *See e.g., EnergyNorth Natural Gas, Inc. d/b/a National Grid NH,* Order No. 25,280 (October 25, 2011), *Northern Utilities, Inc.*, Order No. 25,330 (February 6, 2012); and *Public Service Co. of New Hampshire*, Order No. 25,332 (February 6, 2012).

Following the approach used in these cases, we consider the three-step analysis applied by the New Hampshire Supreme Court in *Lambert v. Belknap County Convention*, 157 N.H. 375, 382 (2008) in determining whether the information identified by the movants should be deemed confidential and private. First, the analysis requires an evaluation of whether there is a privacy interest at stake that would be invaded by the disclosure. If no such interest is at stake, the Right-to-Know law requires disclosure. *Id*. at 382-83. Second, when a privacy interest is at stake, the public's interest in disclosure is assessed. *Id*. at 383. Disclosure should inform the public of the conduct and activities of its government; if the information does not serve that purpose, disclosure is not warranted. *Id*. Finally, when there is a public interest in disclosure, that interest is balanced against any privacy interests in non-disclosure. *Id.* We will analyze each category of information for which protective treatment is requested in turn. Confidential treatment is sought for a number of responses made in the discovery process of this proceeding based on two exception categories: personal employee information, and proprietary and competitively sensitive information.

1. *Personal Employee Information*

The Joint Petitioners have requested confidential treatment on the basis of the personnel files exemption of RSA 91-A:5, IV for portions of the Seller Disclosure Schedules (Schedules)

attached to the Stock Purchase Agreements, as well as their responses to certain data requests made during the course of discovery.

In the March 4, 2011 Motion, the Joint Petitioners seek confidential treatment of information contained in the Schedules that is specific to certain corporate employees and employees represented by labor unions, including job titles, annual salaries, ID numbers, and other identifying data. In the April 19, 2012 Motion, the Joint Petitioners request confidential treatment of their response to Staff Data Requests 3-77 and 2-94, and attachments (a) and (b) to their response to Staff Data Request 3-39. Specifically, protection is requested of employee salary and benefit information provided in response to Staff Data Request 3-77; home addresses, base salary and potential bonus percentages included in certain offers of employment for non-officer positions provided in response to Staff Data Request 2-94; and social security numbers, social insurance numbers (the Canadian equivalent of U.S. social security numbers) and passport numbers of officers and board members included in correspondence with the Committee on Foreign Investment in the United States.

The movants argue that there is a clear privacy interest in the information for which they seek protection, the information is not otherwise disclosed to the public, disclosure will not provide any information to the public regarding conduct or activities of government and the privacy interests weigh in favor of confidentiality. With respect to the employment offers, the movants also argue that the information constitutes "confidential, commercial, or financial information" under RSA 91-A:5, IV and that disclosure could cause harm by making it easier for other companies to recruit their employees. *Citing EnergyNorth Natural Gas d/b/a National Grid NH*, Order 25,208 at 5 (March 23, 2011).

We are persuaded that the personnel information for which protection is sought trigger legitimate privacy interests. We also find that public disclosure of that information will not materially advance the public's understanding of the Commission's analysis of the transaction and settlement agreement that are the subject of this proceeding. Because the public interest in disclosure is minimal, we find the interest in protection outweighs the interest in disclosure and will grant the requested protective treatment.

2. Proprietary and Competitively Sensitive Information

The Joint Petitioners also request confidential treatment pursuant to RSA 91-A:5, IV of certain portions of the Schedules and certain data responses based on the proprietary and competitively sensitive nature of the information included therein. The March 4, 2011 Motion seeks protection of information pertaining to potential litigation liabilities, a pending IRS examination, and potential strategies for labor negotiations. The April 19, 2012 Motion seeks protection for discovery responses provided to Staff Data Requests 2-39, 3-30, 3-37, 3-39 (attachment (d)), 4-87, and TS 2-22.

In their March 4, 2011 Motion, the movants seek to protect disclosure of certain information included in Sections 5.8 of the Granite State and EnergyNorth Schedules and 5.12 of the Granite State Schedules pertaining to potential litigation liabilities involving environmental matters and pending legal proceedings. The movants argue that disclosure of that information could expose Granite State and EnergyNorth to costly litigation they may not otherwise have been subject to, and result in economic harm to the companies and their customers. Specifically, the movants seek protection to the extent that potential liabilities are not established, noting that full and candid disclosure of such liabilities is an essential component of a commercial transaction such as the one at issue here, and that public release of potential liability information

could dissuade future buyers from entering into transactions where disclosure would increase the probability of litigation.

The March 4, 2011 Motion also seeks protection of confidential settlement agreements between EnergyNorth and third parties to facilitate and/or receive contribution for remediation activities associated with the pending environmental matters. The movants argue that Section 5.8, paragraphs 3(a), (e), and (f) of the EnergyNorth Schedules describe the parties to or contents of the third party agreements and, therefore, merit protective treatment under RSA 91-A:5, IV, since they constitute confidential commercial or financial information. The movants add that public disclosure of this information would jeopardize the agreements and make it more difficult for EnergyNorth to enter into environmental litigation settlements in the future.

The March 4, 2011 Motion further requests protection of information contained in Section 5.15 of the Granite State Schedules regarding a pending IRS examination and its anticipated result, and Section 7.1, paragraph 4 of the Granite State Schedules and Section 7.1, paragraph 2 of the EnergyNorth Schedules regarding potential strategies for labor negotiations that have not yet occurred. With respect to the pending IRS examination, the movants argue that the information contains a non-public assessment of tax matters that are not yet settled and, therefore, constitute competitively sensitive information that is not otherwise publicly disclosed under RSA 91-A:5, IV. With respect to strategic labor negotiation information, the movants argue that public disclosure of that information would grant an unfair advantage to the unions and would disadvantage Granite State and EnergyNorth in future labor negotiations, and therefore should be protected under RSA 91-A:5, IV.

The April 19, 2012 Motion seeks protection of forward-looking financial assumptions related to a potential future rate increase for Granite State in the discovery response to Staff Data

Requests 2-39; copies of financing documents in response to Staff TS 2-22 Supplemental; expense budget information in response to Staff 3-30; user and technical manuals for National Grid's Energy Management Supervisory Control and Data Acquisition (SCADA) Systems in response to Staff 3-37; information regarding access to National Grid's internal web site in response at attachment (d) to Staff 3-39; and detailed information regarding IT systems architecture in response to Staff 4-87. The movants argue that the information provided in the discovery responses cited above are competitively sensitive information and, in the case of the SCADA user and technical manuals, proprietary, while the release of information regarding access to National Grid's internal website or regarding its IT systems architecture could pose a security risk to National Grid and its customers.

In sum, the movants argue that the information for which they seek protective treatment in the March 4, 2011 and April 19, 2012 Motions constitutes "confidential, commercial, or financial information" under RSA 91-A:5, IV, and that disclosure will not provide the public with information about the conduct or activities of the Commission or other parts of the New Hampshire State or local government.

We are persuaded that the information provided constitutes competitively sensitive information that should not be disclosed. Public disclosure of the information will not materially advance the public's understanding of the Commission's analysis in this proceeding, and that disclosure of the financial information could result in financial or competitive harm. We also agree that disclosure of the information regarding access to National Grid's internal website and regarding its IT systems architecture could pose legitimate security risks. To the extent that information for which protection is granted herein is released or made public by the movants at a

later time - for example, as a result of completion of pending matters, that information would no longer be subject to protective treatment. *See* Puc 203.08(l).

We note that no party or person has objected to confidential treatment requested or asserted that disclosure would inform the public about the activities of the government. Accordingly, in balancing the interests of the companies in protecting their information with the public's interest in disclosure, we conclude that the information should not be disclosed and we grant the Joint Petitioners' motion. Consistent with Puc 203.08(k), our grant of this motion is subject to our on-going authority, on our own motion, on the motion of Staff, or on the motion of any member of the public, to reconsider our determination.

3. Waiver of Certain Filing Requirements under Puc 203.08(f)

Finally, the Joint Petitioners seek a waiver of Puc 203.08(f) to the extent that it requires seven copies of each of the confidential documents provided with its motion for confidential treatment. The movants request that the Commission accept one hard copy and one electronic copy of each document for purposes of the motion filing, as seven copies have already been provided to the Commission in the course of discovery and to provide seven copies at this time would necessitate a voluminous and unnecessary production of material.

We agree that a waiver with respect to the number of copies filed with the related motion for confidential treatment in this instance will not disrupt the orderly and efficient resolution of matters before us in this proceeding. We further find that the public interest is served to the extent that the movants are relieved of the burden of producing thousands of pages of documents where they have previously provided seven copies in the course of discovery and have provided an additional hard copy and electronic copy with their motion for confidential treatment. We therefore grant the requested waiver.

D. Conclusion

In this proceeding, we were asked to assess the proposed transfer of electric and gas distribution companies currently owned by National Grid, an established gas and electric utility operator in New England and New York, to Liberty Energy NH, a new entrant to the New England market with little experience in operating electric distribution companies and no experience in operating gas distribution companies. In order to assess compliance with the applicable legal standards set forth in RSA 369:8, II(b), RSA 374:30, and RSA 374:33, we look at the technical, managerial and financial capability of Liberty. We rely on testimony and evidence offered in hearing to conclude that the proposed transfer as conditioned by the Settlement Agreement is lawful, proper and in the public interest, and will have no adverse effect on rates, terms service or operation of the utilities.

As discussed above, we find that the numerous commitments and contingency provisions set forth in the Settlement Agreement provide significant protections for Granite State and EnergyNorth ratepayers – not only in the immediate period following the transfer, but throughout and even to an extent following the transition period covered by the Transition Services Agreements between National Grid and Liberty. In support of our findings above that Liberty has demonstrated that it has the requisite capability to operate the Granite State and EnergyNorth, we note the confidence Staff expressed at hearing in the reasonableness of Liberty's financing plans, as well as in the managerial and technological ability of the operational employees that are slated to manage utility operations under Liberty ownership. We further note the strong support provided in testimony and at hearing by both the USWA Local 12012-3 and the IBEW Local 329, and that Granite State and EnergyNorth under Liberty ownership will be locally managed and operated, bringing increased local employment and a

greater likelihood of responsiveness to the Commission's regulatory concerns. The testimony of Staff consultants on Liberty's information technology systems plans, including testing and security assessments, provides a further source of confidence in our conclusions. Based on the testimony filed on the record and presented at hearing, we are persuaded that the review of the proposed transaction by the parties and Staff was thorough and comprehensive and we thus have additional confidence that the result represented by the settlement agreement is just and reasonable and serves the public interest.

Based upon the foregoing, it is hereby

ORDERED, as set forth above, the settlement agreement is approved; and it is

FURTHER ORDERED, that National Grid is directed to file a copy of the escrow agreement no later than one week prior to the transaction close; and it is

FURTHER ORDERED, that the long-term financing plan is approved, subject to Staff review of the final terms, which shall be submitted prior to the closing; and it is

FURTHER ORDERED, that Liberty Energy NH submit copies of the board of directors' resolutions authorizing the proposed long-term financing within 10 days of their adoption; and it is

FURTHER ORDERED, that the motions for confidential treatment and waivers of certain rule requirements are granted, as addressed herein.

By order of the Public Utilities Commission of New Hampshire this thirtieth day of May, 2012.

Amy L. Ignatius	Michael D. Harrington	Robert R. Scott
Chairman	Commissioner	Commissioner

Attested by:

Debra A. Howland
Executive Director

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

APPLICATION OF THE EMPIRE DISTRICT ELECTRIC COMPANY, A KANSAS CORPORATION, LIBERTY UTILITIES (CENTRAL) CO., A DELAWARE CORPORATION, AND LIBERTY SUB CORP., A KANSAS CORPORATION, FOR APPROVAL OF AN AGREEMENT AND PLAN OF MERGER DATED FEBRUARY 9, 2016, AND FOR SUCH OTHER RELIEF AS THE COMMISSION DEEMS THE PARTIES ENTITLED.	)	CAUSE NO. PUD 201600098 ORDER NO. 652551

HEARING: April 27, 2016, in Courtroom B
2101 North Lincoln Boulevard, Oklahoma City, Oklahoma 73105
Before Elizabeth A.P. Cates, Administrative Law Judge

APPEARANCES: Jack P. Fite, Attorney *representing* The Empire District Electric Company, Liberty Utilities (Central) Co., and Liberty Sub Corp.
Judith L. Johnson, Deputy General Counsel *representing* Public Utility Division, Oklahoma Corporation Commission
Kimberly Carnley, Dara M. Derryberry and C. Eric Davis, Assistant Attorneys General, *representing* Office of the Attorney General, State of Oklahoma

FINAL ORDER

BY THE COMMISSION:

The Corporation Commission of the State of Oklahoma ("Commission") being regularly in session and the undersigned Commissioners present and participating, there comes on for consideration and action the Application of The Empire District Electric Company ("Empire"), Liberty Utilities (Central) Co. ("LU Central"), and Liberty Sub Corp. ("LSC") (collectively the "Merging Parties" or "Applicants") filed March 16, 2016, requesting approval of the Agreement and Plan of Merger dated February 9, 2016. A copy of the Agreement and Plan of Merger was attached to the Application and is a part of the record herein.

I. PROCEDURAL HISTORY

On March 16, 2016, the Merging Parties filed an Application requesting approval of an Agreement and Plan of Merger dated February 9, 2016. On that same date, the Merging Parties filed the Direct Testimony of Peter Eichler, Brad P. Beecher, David Pasieka, and Christopher D. Krygier.

On March 17, 2016, the Merging Parties filed a Motion to Determine Notice, a Motion for Procedural Order, and a Motion for Protective Order.

On March 22, 2016, the Attorney General's Entry of Appearance was filed.

On April 6, 2016, the Commission issued an Order Granting Motion to Determine Notice (Order No. 651546) and Order Granting Motion for Procedural Schedule (Order No. 651547).

On April 8, 2016, the Public Utility Division ("PUD") filed the Responsive Testimony of Fairo Mitchell.

On April 12, 2016, Exhibits to the Testimony of Mr. David Pasieka Filed on March 16, 2016, and Exhibits to the Testimony of Mr. Peter Eichler Filed on March 16, 2016, were filed.

On April 13, 2016, the Commission issued an Order Granting Withdrawal of Motion for Protective Order (Order No. 651720).

On April 14, 2016, the Affidavit of Kelly S. Walters and the Attorney General's Statement of Position were filed.

On April 20, 2016, a Joint Stipulation and Settlement Agreement, attached hereto as "Attachment A," was filed. Also on that date, the Affidavits of Brad P. Beecher and Christopher D. Krygier were filed.

On April 25, 2016, the Affidavits of Peter Eichler and David Pasieka were filed.

On April 27, 2016, the Parties appeared at the Hearing on the Merits. At the request of the Administrative Law Judge ("ALJ"), Counsel for the Merging Parties addressed notice of the Hearing on the Merits. Counsel stated that notice was proper; the Merging Parties complied with the provisions of Order No. 651546, and that an affidavit of mailing had been filed in the Cause. The ALJ acknowledged that members of the public were afforded opportunity to make public comment and inquired whether any individuals present desired to do so; however, no such requests were made. The ALJ admitted into the record of this Cause all pleadings and documents filed in the Court Clerk's office. At the conclusion of the Hearing on the Merits, the ALJ recommended, based upon the pleadings and testimony filed in the Cause, the testimony of witnesses and statements of Counsel, approval of the Merging Parties' application.

II. SUMMARY OF EVIDENCE

Summaries of the prefiled testimony and Attorney General's Statement of Position are attached hereto as "Attachment B."

Peter Eichler – Liberty Utilities (Canada) Corp.

Mr. Peter Eichler, Vice President of Strategic Planning for Liberty Utilities (Canada) Corp. testified on behalf of the Applicants in support of the Joint Stipulation and Settlement Agreement ("Joint Stipulation"). Following Mr. Eichler's qualification as a witness, he adopted his pre-filed Direct Testimony noting one correction on page 5, line 5 deleting the word "utilities."

Mr. Eichler presented an overview of Liberty Utilities detailing locations and services provided. Mr. Eichler testified that the first element of the Statutory Requirements section set forth in the Joint Stipulation addressed the ten items required by 17 O.S. §191.3 to be addressed in a merger application had been met by the Applicants in their application, pre-filed testimony, and financial information provided to the Parties. Specifically, Mr. Eichler stated that Mr. Pasieka's pre-filed Direct Testimony at pages 15-20 sets forth the ten items required by 17 O.S. §191.3. Further, the financial statements of Liberty Utilities referenced by Mr. Pasieka were provided to both PUD and the Attorney General for their review.

Mr. Eichler further testified that the second element of the Statutory Requirements section set forth in the Joint Stipulation addressed the seven conditions listed in 17 O.S. §191.5 (A). Mr. Pasieka's pre-filed Direct Testimony at pages 9-15 sets forth the seven conditions that must not be found to exist. Mr. Eichler further stated that he addressed financial and other issues in his pre-filed Direct Testimony. The Joint Stipulation seeks approval of the Agreement and Plan of Merger dated February 9, 2016. If the Commission approves the Agreement and Plan of Merger dated February 9, 2016, Mr. Eichler testified that there will be no rate increase as a result of this merger and that reliable service will still be provided by the employees of Empire to customers in Oklahoma.

The ALJ pointed out that on page 14 of Mr. Eichler's pre-filed Direct Testimony, there was a representation that within six months of the closing of the Empire transaction a revised Cost Allocation Methodology ("CAM") would be provided to the Director of PUD. It was also pointed out on page 14 of his pre-filed Direct Testimony that affiliate transactions would be conducted pursuant to the Commission's affiliate rules found at OAC 165: 35-31-1 *et seq.* In response to a question from the ALJ, Mr. Eichler testified that even though those representations were not contained within the Joint Stipulation, it was the intent of the Parties that representations found in the pre-filed Direct Testimony would be followed.

Christopher D. Krygier – Liberty Utilities Service Corp.

Mr. Christopher D. Krygier, Director of Regulatory and Government Affairs for Liberty Utilities Service Corp. testified on behalf of the Merging Parties in support of the Joint Stipulation. Following Mr. Krygier's qualification as a witness he adopted his pre-filed Direct Testimony noting a correction on page 4, line 8, changing the word "promotes" to "promote." He also corrected his pre-filed Direct Testimony on page 2, line 5, changing the word from "LSU" to "LSC."

Mr. Krygier testified that all employees will be retained; therefore, the customer service, as well as service reliability, will be provided by the same people in a seamless transaction.

Mr. Krygier testified that he believed the proposed transaction would provide many benefits. Mr. Krygier testified that increasing the size of the respective organizations, which would include Liberty's California and New Hampshire electric utilities, would result in greater management expertise and best practices. Further, there would be enhanced regional senior leadership support as well as a regional Board of Directors that will be established consisting of senior business and community leaders.

Fairo Mitchell – Public Utility Division

Mr. Fairo Mitchell, Energy and Water Policy Director for PUD testified in support of the Joint Stipulation on behalf of PUD. Mr. Mitchell corrected his pre-filed Responsive Testimony on p. 4, line 6, to change the name "Liberty Utilities Sub Corp." to "Liberty Sub Corp."

Mr. Mitchell testified that he was present during settlement discussions and was familiar with the terms of the Joint Stipulation. He further testified that he was present for, and agreed with, Mr. Eichler and Mr. Krygier's testimony during the Hearing on the Merits.

Mr. Mitchell testified that there were no contested issues and that PUD's review was to examine the facts to see if statutory conditions had been met or were present.

Mr. Mitchell went through each of the seven conditions set forth in 17 O.S. §191.5 (A) which, if the Commission finds one or more are present, then the merger should be disapproved. According to Mr. Mitchell, none of those conditions existed. For example, Mr. Mitchell stated the acquisition would not affect the contractual obligations of Empire; it would not substantially lessen competition in the furnishing of electric service in the state; the financial stability of Empire would not be jeopardized; there were no plans for liquidation of Empire; the competence, experience and integrity of the persons who would control the operation of Empire would not be detrimental; Empire would still be a member of the Southwest Power Pool; and the acquiring party was not substantially engaged in the business of providing utility service.

Mr. Mitchell further testified in response to a question from the ALJ that the same service standards, such as discussed on page 15 of Mr. Mitchell's pre-filed Responsive Testimony, would be followed. Mr. Mitchell testified that PUD supported the Joint Stipulation and believed the statutory requirements of 17 O.S. §§191.3 and 191.5 had been met. Mr. Mitchell further testified the approval of the merger would be in the public interest and would be fair, just and reasonable.

Attorney General

Counsel for the Attorney General made a statement in support of approving the Joint Stipulation. Counsel stated there had been robust dialogue between the Parties; the Attorney General filed a Statement of Position affirmed by the Joint Stipulation; and the Attorney General did not object to the relief requested by the Merging Parties. The Attorney General recommended that the Commission grant the Merging Parties' requested relief by approving the Plan of Merger as it was in the public interest.

III. FINDINGS OF FACT AND CONCLUSIONS OF LAW

THE COMMISSION FINDS that it has jurisdiction in this cause pursuant to Article IX, Section 18 of the Oklahoma Constitution and 17 O.S. §§ 152, 153, 191.1 *et seq*.

THE COMMISSION FURTHER FINDS that Notice of Hearing provided to customers by Empire was conducted pursuant to 17 O.S. §191.6 and Order No. 651546.

THE COMMISSION FURTHER FINDS that based upon the application, testimony and exhibits filed and presented in this Cause, the Applicants have met the statutory requirements of 17 O.S. §191.3.

THE COMMISSION FURTHER FINDS that none of the conditions for disapproval of the acquisition of control or merger found at 17 O.S. §191.5 exist; therefore, the Agreement and Plan of Merger dated February 9, 2016, should be approved.

THE COMMISSION FURTHER FINDS that the transaction will not result in a rate increase or adversely impact the quality of service provided by Empire to customers in Oklahoma.

THE COMMISSION FURTHER FINDS that benefits of the merger include, but are not limited to, retention of Empire's employees; continuance of service reliability; greater access to expertise; and the creation of a regional Board of Directors. Empire's customers will also benefit from Empire becoming part of a larger and more diversified utility business group with the support of a larger balance sheet to meet the capital demands of its customers; and there is also potential for lower costs for Empire's customers. Therefore, approval of the Agreement and Plan of Merger dated February 9, 2016, is in the public interest.

ORDER

THE COMMISSION THEREFORE ORDERS that the Findings of Fact and Conclusions of Law set forth herein are adopted as the Order of the Commission.

THE COMMISSION FURTHER ORDERS that based upon the application, testimony, and exhibits filed and presented in this Cause, the Applicants have met the statutory requirements of 17 O.S. §191.3.

THE COMMISSION FURTHER ORDERS that none of the conditions for disapproval of the acquisition of control or merger found at 17 O.S. §191.5 exist; therefore, the Agreement and Plan of Merger dated February 9, 2016, shall be and is hereby approved.

THIS ORDER SHALL BE EFFECTIVE immediately.

OKLAHOMA CORPORATION COMMISSION

Bob Anthony

BOB ANTHONY, Chairman

Dana L. Murphy

DANA L. MURPHY, Vice Chairman

J. Todd Hiett

J. TODD HIETT, Commissioner

CERTIFICATION

DONE AND PERFORMED by the Commissioners participating in the making of this order as shown by their signatures above this 12 day of May, 2016.

[seal]

PEGGY MITCHELL, Commission Secretary

REPORT OF THE ADMINISTRATIVE LAW JUDGE

The foregoing findings, conclusions and order are the report and recommendation of the undersigned administrative law judge.

ELIZABETH A.P. CATES
Administrative Law Judge

5/4/16
Date

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

APPLICATION OF THE EMPIRE DISTRICT ELECTRIC COMPANY, A KANSAS CORPORATION, LIBERTY UTILITIES (CENTRAL) CO., A DELAWARE CORPORATION, AND LIBERTY SUB CORP., A KANSAS CORPORATION, FOR APPROVAL OF AN AGREEMENT AND PLAN OF MERGER DATED FEBRUARY 9, 2016, AND FOR SUCH OTHER RELIEF AS THE COMMISSION DEEMS THE PARTIES ENTITLED.	)	CAUSE NO. PUD 201600098

FILED
APR 20 2016
COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA

JOINT STIPULATION AND SETTLEMENT AGREEMENT

COME NOW the undersigned parties to the above entitled Cause and present the following Joint Stipulation and Settlement Agreement ("Joint Stipulation") for the review of the Oklahoma Corporation Commission ("Commission") and approval as the parties' compromise and settlement of all issues in this proceeding between the parties to this Joint Stipulation ("Stipulating Parties"). The Stipulating Parties represent to the Commission that this Joint Stipulation represents a fair, just and reasonable settlement of these issues, that the terms and conditions of the Joint Stipulation are in the public interest, and the Stipulating Parties urge the Commission to issue an Order in this Cause adopting and approving this Joint Stipulation.

It is hereby stipulated and agreed by and between the Stipulating Parties as follows:

TERMS OF THE JOINT STIPULATION AND SETTLEMENT AGREEMENT

Effective with the final order of the Commission approving all elements of this Joint Stipulation:

1. Statutory Requirements.

The Stipulating Parties agree that the ten (10) items required to be addressed in a merger application found at 17 O.S. §191.3 have been met by the applicants in their Application, prefiled testimony, and financial information provided to the parties.

Stipulating Parties further agree that the Application package demonstrates that the applicants have satisfied the seven (7) conditions listed at 17 O.S. §191.5 (A).

2. Approval of the Agreement.

The Stipulating Parties further agree that the Agreement and Plan of Merger dated February 9, 2016, should be approved by the Commission.

The Stipulating Parties further agree that Empire's customers will not receive a rate increase as a result of this merger, and Empire will continue to provide safe and reliable service to its customers. Customers will continue to be served by the same Empire personnel.

3. Discovery and Motions.

As between and among the Stipulating Parties, all pending requests for discovery, and all motions pending before either the Commission or the Administrative Law Judge are hereby withdrawn.

4. General Reservations.

The Stipulating Parties represent and agree that, except as specifically otherwise provided herein:

(a) This Joint Stipulation represents a negotiated settlement for the purpose of compromising and settling all issues which were raised relating to this proceeding.

(b) Each of the undersigned counsel of record affirmatively represents that he or she has full authority to execute this Joint Stipulation on behalf of his or her client(s).

(c) None of the signatories hereto shall be prejudiced or bound by the terms of this Joint Stipulation in the event the Commission does not approve this Joint Stipulation nor shall any of the Stipulating Parties be prejudiced or bound by the terms of this Joint Stipulation should any appeal of a Commission order adopting this Joint Stipulation be filed with the Oklahoma Supreme Court.

(d) Nothing contained herein shall constitute an admission by any party that any allegation or contention in these proceedings as to any of the foregoing matters is true or valid and shall not in any respect constitute a determination by the Commission as to the merits of any allegations or contentions made in this proceeding.

(e) The Stipulating Parties agree that the provisions of this Joint Stipulation are the result of extensive negotiations, and the terms and conditions of this Joint Stipulation are interdependent. The Stipulating Parties agree that settling the issues in this Joint Stipulation is in the public interest and, for that reason, they have entered into this Joint Stipulation to settle among themselves the issues in this Joint Stipulation. This Joint Stipulation shall not constitute nor be cited as a precedent nor deemed an admission by any Stipulating Party in any other proceeding except as necessary to enforce its terms before the Commission or any state court of competent jurisdiction. The Commission's decision, if it enters an

order consistent with this Joint Stipulation, will be binding as to the matters decided regarding the issues described in this Joint Stipulation, but the decision will not be binding with respect to similar issues that might arise in other proceedings. A Stipulating Party's support of this Joint Stipulation may differ from its position or testimony in other causes. To the extent there is a difference, the Stipulating Parties are not waiving their positions in other causes. Because this is a stipulated agreement, the Stipulating Parties are under no obligation to take the same position as set out in this Joint Stipulation in other dockets.

5. Non-Severability.

The Stipulating Parties stipulate and agree that the agreements contained in this Joint Stipulation have resulted from negotiations among the Stipulating Parties and are interrelated and interdependent. The Stipulating Parties hereto specifically state and recognize that this Joint Stipulation represents a balancing of positions of each of the Stipulating Parties in consideration for the agreements and commitments made by the other Stipulating Parties in connection therewith. Therefore, in the event that the Commission does not approve and adopt the terms of this Joint Stipulation in total and without modification or condition (provided, however, that the affected party or parties may consent to such modification or condition), this Joint Stipulation shall be void and of no force and effect, and no Stipulating Party shall be bound by the agreements or provisions contained herein. The Stipulating Parties agree that neither this Joint Stipulation nor any of the provisions hereof shall become effective unless and until the Commission shall have entered an Order approving all of the terms and provisions as agreed by the parties to this Joint Stipulation and such Order becomes final and non-appealable.

WHEREFORE, the Stipulating Parties hereby submit this Joint Stipulation and Settlement Agreement to the Commission as their negotiated settlement of this proceeding with respect to all issues which were raised with respect to this Application, and respectfully request the Commission to issue an Order approving this Joint Stipulation and Settlement Agreement.

PUBLIC UTILITY DIVISION
OKLAHOMA CORPORATION COMMISSION

By: Fairo Mitchell
Fairo Mitchell, Energy and Water Policy Director

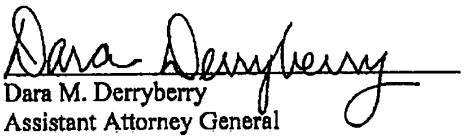
MERGING PARTIES

By: Jack P. Fite
Jack P. Fite

Cause No. PUD 201600098
Joint Stipulation And Settlement Agreement

Attorney for the Empire District Electric Company, Liberty Utilities (Central) Co., and Liberty Sub Corp.

E. SCOTT PRUITT
ATTORNEY GENERAL OF OKLAHOMA

By: 
Dara M. Derryberry
Assistant Attorney General

ATTACHMENT B

Brad P. Beecher – The Empire District Electric Company

Mr. Brad P. Beecher, President and Chief Executive Officer of The Empire District Electric Company ("Empire" or "Company"), testified on behalf of the Merging Parties.

Mr. Beecher testified that Empire is a Kansas corporation with its principal office and place of business at 602 S. Joplin Avenue, Joplin, Missouri 64801. Empire is engaged in the business of providing electric utility services in Missouri, Kansas, Arkansas and Oklahoma: water utility service in Missouri; and, through a wholly-owned subsidiary, certain telecommunications services. In addition, through a wholly-owned subsidiary, The Empire District Gas Company, Empire operates a natural gas distribution business in northwest, north central and west central Missouri, providing regulated natural gas service in 48 communities.

Mr. Beecher further testified that at December 31, 2015, Company-wide, Empire provided electric service to approximately 143,271 residential customers, 24,405 commercial customers, 353 industrial customers, 2,080 public authority and street and highway customers, and four wholesale customers. As of December 31, 2015, in Oklahoma, Empire served approximately 3,783 residential customers, 800 commercial customers, 12 industrial customers and 90 public authority and street and highway customers.

According to Mr. Beecher, his testimony supported the Application filed by Empire and Liberty Utilities (Central) Co. ("LU Central"). The Application seeks an order authorizing the applicants to take certain actions, the results of which will, among other things, permit the acquisition by LU Central of all of the capital stock of Empire, all as more detailed in the Agreement and Plan of Merger (the "Agreement") executed on February 9, 2016. Because the Transaction involves a merger by Empire, Mr. Beecher testified that it must be submitted for the Commission's consideration and approval as contemplated by Oklahoma law (17 O.S. §191.5). The Application has been filed to comply with this requirement.

Mr. Beecher testified that on December 13, 2015, the Board announced it had engaged a financial advisor to explore strategic alternatives for the Company. As a result of those efforts, the Board announced on February 9, 2016, it had approved an agreement and plan of merger whereby Liberty would acquire Empire and its subsidiaries. The transaction benefits Empire's stakeholders by providing benefits to customers, shareholders, and employees alike. Specifically, the transaction benefits Empire and its customers by providing increased corporate capability and scale by making Empire part of the Algonquin Power & Utilities Corp. ("Algonquin") family of utility companies. Following the transaction, Empire will maintain the strong, investment-grade credit rating it will need to address future industry risks and trends.

According to Mr. Beecher, Algonquin operates a U.S.-based subsidiary known as Liberty Utilities Co. ("Liberty Utilities"), a Delaware corporation. Liberty Utilities owns regulated electric, natural gas, and water utilities serving approximately 560,000 customers across the U.S. In the central part of the country, Liberty Utilities owns natural gas local distribution properties in Missouri, Iowa and Illinois that serve about 83,000 customers. Liberty Utilities also owns

regulated water distribution utilities in Missouri, Arkansas and Texas that serve a total of 43,000 customers. Upon Commission approval of the transaction, Empire will become an indirect subsidiary of Liberty Utilities. As part of the transaction, Liberty Utilities has committed to maintaining Joplin, Missouri, as the regional headquarters for all regulated utilities owned by Liberty Utilities in the central states of Missouri, Iowa, Illinois, Arkansas, Oklahoma, Kansas, and Texas.

Mr. Beecher testified that the transaction is in the public interest. There will be no impact on customers with respect to rates or service as a result of the transaction, and there will be a positive long term impact on Empire's customers and employees as a result of the transaction. Liberty Utilities has committed to make Joplin the regional headquarters for all regulated utilities owned by Liberty Utilities in the central states. Liberty Utilities also has committed to retain all of Empire's management team, its workforce following closing of the transaction, and will continue to operate Empire's business under the Empire brand for at least 5 years. Further, a regional board of directors will be established to provide guidance and counsel on local issues and enhanced customer service. All existing board members of Empire will be offered a position on the board.

Mr. Beecher testified that the transaction will not result in involuntary reductions in Empire's current administrative, professional, and field workforce and its existing management team will be retained. In fact, according to Mr. Beecher, the transaction likely will lead to an expansion of employment opportunities as Empire's management team continues to oversee Empire's ongoing operations and assumes additional responsibility for the oversight management of LU Central's other operations in the central United States. Through the expertise of the employees at Empire and LU Central, the capabilities of both organizations will be enhanced.

Mr. Beecher also testified that Empire's customers will see no change in their day-to-day utility service or rates and they will continue to be served safely, effectively, and efficiently without interruption by the same employees who serve them today. The day-to-day operations of Empire in Oklahoma will continue as they have in the past, and continue to be regulated by and be subjected to review by the Commission. As a result of the transaction, Empire customers will be served by a larger, more capable organization. Customers will also see Empire continue its current level of involvement and charitable support for the local communities served by Empire.

The merger adds scale for both Empire and LU Central, thus providing opportunities to pursue efficiencies, share costs across a larger customer base, leverage best practices, and enhance service offerings. The inherent increase in scale and market diversification will also provide increased financial stability and strength, which could not be achieved without the combination of the companies.

As a subsidiary of LU Central, Empire's utility operations will continue to be regulated by each of the five regulatory commissions that currently regulate Empire, including this Commission.

Mr. Beecher testified that it has been Empire's opinion that for a utility merger to be truly beneficial certain consistent core values must exist in the merger partner. Certainly, financial parameters must be achieved in the merger for the company giving up control, but if the resulting entity is not committed to the core values of providing a positive customer experience, continuous improvement, regulatory compliance, commitment to community and focus on safety, the long-term effects of the merger will not be maximized. Mr. Beecher testified that he believes that Liberty had exhibited these core values in its proposal by establishing Joplin as the regional headquarters for LU Central, retaining all employees, demonstrating a history of providing safe, reliable service to customers, and committing to continue to operate the existing businesses under the Empire brand.

Mr. Beecher further testified that the transaction will have no impact on the current case and that the Commission's jurisdiction over Empire will not be reduced or impaired. The Commission will retain full regulatory supervision of Empire after the transaction is completed. In addition, the transaction will not restrict the Commission's access to Empire's books and records as is reasonably necessary to carry out the Commission's responsibilities with respect to Empire's operations, including proper audits.

The Agreement has been approved by the Board of Directors of Empire.

According to Mr. Beecher, a simple majority of the outstanding shares of common stock must vote in favor of the merger for it to be approved.

Peter Eichler – Liberty Utilities (Canada) Corp.

Mr. Peter Eichler, Vice President of Strategic Planning for Liberty Utilities (Canada) Corp. ("Liberty Utilities Canada"), which is the parent company for Liberty Utilities testified in support of the Application.

Mr. Eichler's responsibilities include oversight for Regulatory Strategy, Customer Experience Strategy, and Operations Strategy. He regularly evaluates the regulatory environments within which Liberty Utilities' businesses operate and provides advice to Liberty Utilities' management teams about investment decisions.

Mr. Eichler testified that LU Central, which is a Delaware Corporation and a subsidiary of Liberty Utilities, proposes to acquire all of Empire's capital stock in an all-cash transaction through a merger of a wholly owned subsidiary, Liberty Utilities Sub Corp. ("LSC") and Empire. After the completion of the merger, LSC will cease to exist and LU Central will be the immediate parent of Empire. Empire's shareholders will receive $34 per common share. Additionally, Empire will maintain $900 million dollars of debt currently on its balance sheet for a total purchase price of $2.4 billion dollars. At the close of the transaction, Empire will become a wholly-owned subsidiary of LU Central.

Empire will cease to be a publicly traded corporation under the new corporate structure. All of its shares of common equity will be held by LU Central.

Following the completion of the acquisition of the shares of Empire, all of Empire's assets utilized for the provision of electric, water and natural gas utility operations, as well as its fiber optic line of business will continue to be owned by Empire and these services will continue to be provided by Empire and its existing subsidiary companies, The Empire District Gas Company ("EDG") and Empire District Industries ("EDI").

According to Mr. Eichler, the transaction is expected to significantly strengthen Liberty Utilities' financial profile by creating a consolidated entity with combined utility rate base of approximately $2.9 billion serving nearly 800,000 gas, electric and water customers. Nearly 100% of Liberty Utilities income will be earned from regulated utility operations. All of these factors are expected to contribute to continued strength in Liberty Utilities' investment grade credit rating, financial profile, and overall business operating environment.

Mr. Eichler further testified that all debt for regulated utilities is raised at the Liberty Utilities level. This debt is then mirrored to the individual regulated utility for which it is required. While Empire will maintain the debt currently on its books, future financing is expected to occur at the Liberty Utilities level and will be mirrored to Empire. For this reason, strength in Liberty Utilities credit rating will provide prudent access to capital.

Mr. Eichler also testified that based on discussions with Standard & Poor's undertaken prior to announcement of the Empire transaction, they did not anticipate any changes to Liberty Utilities' current BBB credit rating and believed that the Empire acquisition will be supportive of maintaining the rating.

The overall value of the transaction to Liberty Utilities is $2.4 billion.

The total cash consideration required to purchase the shares of Empire from its shareholders is approximately $1.6 billion. Such amount shall be funded by a combination of equity sourced by Liberty Utilities' ultimate parent, Algonquin and debt sourced by Liberty Utilities and contributed to LU Central to complete the acquisition of the Empire shares. According to Mr. Eichler, Algonquin, which is a publicly traded company on the Toronto Stock Exchange, intends to raise the equity necessary to complete the transaction.

All debt for regulated utilities is raised at the Liberty Utilities level. Specific amounts of this debt is then mirrored to the individual regulated utility for which it is required. There is no cross collateralization, cross default or debt guarantees between the individual regulated utilities. While Empire will maintain the debt which is currently on its books, future financing is expected to occur at the Liberty Utilities level and only that portion required by Empire will be mirrored to Empire. For this reason, the strength in Liberty Utilities credit rating will provide prudent access to capital.

Mr. Eichler testified that permanent financing in the approximate amount of $2.4 billion for the acquisition of Empire is expected to be comprised of $0.9 billion in debt currently on the books of Empire and approximately $1.6 billion in debt obtained by Liberty Utilities and equity obtained by Algonquin and subsequently invested in Liberty Utilities. Contemporaneously with the announcement of the Empire transaction, Algonquin completed a $0.8 billion equity issuance

in the form of mandatorily convertible debentures. According to Mr. Eichler, the timing of additional debt and equity financing activities by Algonquin and Liberty Utilities will be influenced by the regulatory approvals process and is subject to prevailing market conditions.

On March 2, 2016, an offering by Algonquin of mandatorily convertible debentures was successfully completed. Demand in the capital markets for the securities comprising the offering was robust signaling a high level of enthusiasm for the Empire transaction.

Mr. Eichler further testified that the price of $34 per common share represents a 21% premium to the closing price on February 8, 2016. Neither LU Central nor Empire will in any future rate proceedings seek to recover any of the premium associated with LU Central's acquisition of Empire's common shares. At the time of closing, the acquisition premium will be accounted for as goodwill in the accounting records of LU Central.

Mr. Eichler testified regarding the allocation of costs. According to Mr. Eichler, Liberty Utilities and its subsidiaries operate under a shared services model pursuant to which certain services are provided to the operating businesses from affiliates and charged to these utilities based on either a direct charge or defined cost allocation methodology (which methodology is structured pursuant to guidelines set by the National Association of Regulated Utility Commissioners). The majority of operating costs incurred by Liberty Utilities' regulated utilities are direct charges since such costs can be directly attributed to a particular business. In the case of labor costs, time sheets are maintained by all employees and the costs for each employee are charged to the business to which such employee is providing services. By utilizing direct charges whenever feasible, the shared services model has a significant level of transparency and simplicity that enables regulators to readily determine the costs attributable to parent level or affiliate services and whether those costs are appropriate. Costs that cannot be specifically attributed to a particular utility business are allocated across all businesses in proportions determined by a defined cost allocation methodology (again, based on guidelines set by the National Association of Regulated Utility Commissioners).

Mr. Eichler testified that the cost allocations could be categorized into three distinct areas:

> Corporate Costs – These costs relate to the strategic management, capital markets costs, financial control costs, and head office administrative (rent, general office costs, etc.) which benefit all of Algonquin's subsidiaries including Liberty Utilities business. These costs are allocated based on a formulaic methodology that includes considers Net Plant, Number of Employees, Revenue and other factors depending on the type of cost.
>
> Business Services Costs – These costs according to Mr. Eichler, relate to the overall administration of the business including regulated utilities owned by Liberty Utilities and are charged to the various Liberty Utilities subsidiaries using either (a) direct charges or (b) allocated using a formulaic model. Business Services Costs include labor for services such as accounting, administration, corporate finance, human resources, information technology, rates and regulatory affairs, environment health, safety, and security, customer service, procurement, risk management, legal and utility planning. The

allocation methodology is similar to Corporate Costs, a driver based methodology that focuses on factors such as employees, square footage, capital expenditures and revenue among others.

Labor Charges: Liberty Utilities Service Corp. is the legal employer of all U.S. based utility employees. The costs in respect of these employees are charged to each of the operating utilities based on time sheets. As an example, Mr. Krygier charges the vast majority of his time to Missouri, Iowa or Illinois utilities and there are only charges made to other utilities based on his time sheets entries reflecting support for a specific project. Costs other than labor based time sheet costs are allocated to the various Liberty Utilities subsidiary business based on a formulaic allocation methodology similar to that used for allocating Corporate Costs and Business Services Costs.

According to Mr. Eichler, one primary goal and objective is to ensure that there is no duplication of functions across Algonquin, Liberty Utilities, LU Central or each of the individual regulated utilities which will include Empire.

Mr. Eichler testified that there are several reasons why the costs borne by Empire will be lower under the Liberty Utilities allocation methodology. One of the prevailing strategic rationales for the transaction is gaining efficacy of scale. In LU Central, there will be approximately 120,000 more customers than Empire serves today, allowing for the distribution of costs over a larger number of customers.

Certain costs will be saved by the business combination, such as the costs Empire currently incurs to remain a public reporting issuer. Liberty Utilities anticipates there are approximately $2.3 million in costs saved by not requiring Empire to comply with all the requirements of being a public reporting issuer.

While there will be no involuntary job losses within the Empire group, it is anticipated that, through natural attrition, an additional $2.2 million in labor savings will emerge. This is supported by Empire's 2-6 percent rate of annual attrition through employee turnover and retirements.

For Empire, the overall costs will decrease by $704,000 or approximately 1.4%, which translates to approximately $15,000 for Oklahoma customers which will be reflected in future rate cases.

The Company will provide to the Directory of the Public Utility Division the revised CAM within six months of closing the Empire transaction.

The utility business operated by Empire will continue to be under the direct regulation of the Commission. According to Mr. Eichler, LU Central will commit to comply with the Commission's Affiliate rules found at OAC 165:35-31-1 *et seq.*

The businesses undertaken by Liberty Utilities are 'ring-fenced' separately and each operating entity is solely and only responsible for that portion of Liberty Utilities debt

specifically related to such business. As a result, there is no cross subsidization, cross collateralization between any business, regulated or unregulated.

It was Mr. Eichler's opinion that the proposed transaction is in the public interest.

David Pasieka – Liberty Utilities (Canada) Corp.

Mr. David Pasieka, President of Liberty Utilities (Canada) Corp., the holding company that owns Liberty Utilities Co. and indirectly owns LU Central and LSC testified in support of the Application.

As President, he is responsible for the overall strategy and direction of the regulated utilities owned by Liberty Utilities. These responsibilities include, among other things, overseeing Operations, Human Resources, Safety, Regulatory, Customer Service and Finance.

Mr. Pasieka testified that the specific terms of the proposed transaction are set out in the Agreement. Under the Agreement, LU Central will acquire all issued and outstanding shares of Empire's stock and then merge Empire with LSC, a wholly-owned merger subsidiary of LU Central created solely for this transaction, with Empire emerging as the surviving corporation. Following the merger LSC will cease to exist and Empire will be a wholly-owned subsidiary of LU Central.

According to Mr. Pasieka, the ultimate plan is for Empire and certain of Liberty Utilities' existing utilities to be reorganized under LU Central, with Bradley Beecher, the current CEO of Empire assuming the role of the CEO of LU Central. The management team of Empire will provide services to all the utilities within LU Central and shared services may be provided where appropriate and in accordance with affiliate transaction statutes, rules and Commission orders.

The utilities will continue to operate on a standalone basis, with separate tariffs, assets, and books and records.

Mr. Pasieka testified that the following benefits will flow from the transaction. First, there is efficiency of scale. This transaction represents an opportunity to increase the size of the respective organizations to nearly 800,000 combined customers providing service across 13 states with expertise in water, gas, and electric distribution utilities. This scale is expected to result in greater management expertise, access to broader management capabilities, and an ability to capitalize on greater opportunities for future efficiencies.

There is also an increased management capability by combining the expertise of both companies, a joint entity will now enjoy expertise in providing electric utility operations of over 270,000 customers including vertical integration with utility owned and developed renewable energy and conventional generation fleet.

Further there will be access to renewable energy development expertise that has already proven to be beneficial to Liberty's electric utilities it owns in other jurisdictions with

investments in utility owned solar generation that is expected to reduce overall customer energy costs.

By reorganizing Liberty Utilities' operations to include LU Central, each utility will now have access to senior level leadership. Liberty Utilities' operations in Missouri, Arkansas, Illinois, Iowa, and Texas will now have access to the diverse and talented management team based in Joplin, Missouri. This means that senior management of the utilities will be even closer to the service territory, ensuring responsiveness to the local community and expeditious responsiveness to emerging issues within each community.

Another benefit will be a regional board of directors that will be established consisting of senior business and community leaders. This board is expected to provide guidance and counsel on local issues to ensure that the combined entity will enhance its understanding of local operating conditions and be able to better serve the needs of customers. The board will have commensurate fiduciary duties, and all existing board members of Empire will be offered a position on the board.

Mr. Pasieka further testified that combining the financial strength of two organizations with a BBB credit rating will ensure stronger access to financial markets and provide enhanced momentum to work towards enhancing the credit rating in the future by providing increased diversification of modality, geography, and ultimately further diversifying the risks of both organizations.

According to Mr. Pasieka, this transaction is not about cutting jobs. Rather, the rationale of the transaction is to enhance the capabilities of both organizations and as such, there will be no involuntary reductions associated with this transaction.

Over the last 5 years Liberty Utilities has completed 7 major transitions that have been seamless from a customer perspective and has developed a core competence in merging utility operations in to its own. With the Empire transaction, this capability will be enhanced as the acquisition is of a fully functioning standalone utility operation which will allow optimal staging of transition activities.

In the opinion of Mr. Pasieka, these items represent significant benefits of the transaction for customers, employees, regulators, and shareholders of both Empire and Liberty.

It was Mr. Pasieka's understanding that the legal standard applicable to utility acquisitions in Oklahoma is that the proposed acquisition must be approved if it is "in the public interest" and the Commission does not find that any of the conditions in Okla. Stat. tit. 17 O.S. §191.5 are found to exist. It was Mr. Pasieka's testimony that LU Central's proposed acquisition of Empire satisfies this standard.

Mr. Pasieka described the statutory conditions found at Section 191.5 of Title 17.

Mr. Pasieka testified that the Commission should find that the transaction is consistent with the Oklahoma approval statute and that none of the conditions found in 17 O.S. §195.5 are

present and the proposed merger will have no effect on Empire's utility operations in Oklahoma or Empire's customers. Customer service will be seamless and operations will continue as they do today. As a result, there will be no adverse effect on Empire as day-to-day operations will remain unchanged.

Mr. Pasieka further testified in detail that the information required by 17 O.S. §191.3, was provided as required by the statute.

In response to a question about Liberty Utilities' philosophy regarding customer service, Mr. Pasieka testified that Liberty Utilities' approach to customer service is guided by the following principles:

A goal to provide high quality service to all customers at a reasonable price. Liberty Utilities wants satisfied customers and is willing to take steps necessary to achieve that objective.

Liberty Utilities' model is to deliver service to customers primarily through customer service representatives located in, and dedicated to, the local utility service territory. According to Mr. Pasieka, customers respond most favorably to customer service representatives who are familiar with the service territory's geography, demography, and economy. Simply put, Liberty Utilities wants customer service representatives to be from and be part of the communities they serve so they can experience what customers experience at the same time customers are experiencing them.

Liberty Utilities strives to continuously improve customer service. To that end, Liberty Utilities tailors offerings locally and continually measures performance in customer satisfaction surveys and "best in class" surveys where Liberty Utilities seeks to understand Liberty Utilities' performance relative to other utilities in the areas Liberty Utilities serve.

Mr. Pasieka testified that local management teams are given significant authority and autonomy to determine how best to meet customers' needs. Managers and employees who are empowered are more inclined to take initiative, and are more resourceful in resolving customer problems, according to Mr. Pasieka.

Because the Liberty Utilities family of companies includes numerous utilities, ways are constantly sought to share information across companies and benefit from the knowledge and experience of affiliates while still leaving decision making in the hands of local management.

As regulated businesses, Liberty Utilities is committed to satisfying all legal and regulatory obligations, and Mr. Pasieka testified that local management and satisfied customers help enable Liberty Utilities to achieve that objective.

Mr. Pasieka further testified that immediately after announcing the transaction, the management team set out to engage the local communities. Meetings were held at each of the state commissions in Oklahoma, Missouri, Kansas, and Arkansas, other state and local officials, as well as meeting with current Empire employees and Empire retirees.

Mr. Pasieka also testified that Liberty Utilities planned to monitor and measure how effective its customer service efforts are and how successful these efforts are in satisfying customers.

In other jurisdictions, according to Mr. Pasieka, their affiliates have engaged an independent research firm to conduct an annual customer service and satisfaction survey. The results of these surveys have shown consistently good customer service ratings in all utility service territories.

Just like Empire does today, Liberty Utilities will continue third party annual customer service surveys to continue finding the best ways to improve the customer experience.

Mr. Pasieka testified that Liberty Utilities has deep experience in the regulated utility business having acquired their first regulated utility approximately fifteen years ago and have grown to serve over 560,000 customers today. The customer roster will increase to nearly 800,000 customers with the addition of Empire. The utility platform includes regulated water, wastewater, natural gas and electric utilities in eleven states across the country. Mr. Pasieka was of the opinion that the addition of Empire is a perfect fit into Liberty Utilities' current operations. After the acquisition closes, these will be added to customer counts in Missouri and Arkansas while expanding total states served from eleven to thirteen. With the addition of Empire's customers in Kansas and Oklahoma, Liberty Utilities overall customer count will increase from approximately 560,000 to nearly 800,000. Operationally, one of the customer benefits of this transaction is that the existing Empire senior leadership team will continue to run all current Empire operations based out of Joplin and assume additional oversight responsibilities for existing Liberty Utilities Arkansas, Texas, Missouri, Iowa and Illinois operations. With such a regional oversight model, customers of Empire and other Liberty Utilities regulated operations will see benefits from best practices, a deeper knowledge bench and a larger management resource pool that all benefit customers.

Mr. Pasieka further testified that Liberty Utilities uses a de-centralized approach to operating its regulated utility business, which emphasizes the importance of local management and local control of day-to-day business operations. This is especially true for customer service activities and employee and community outreach activities. Liberty Utilities believes these activities are best performed locally.

Mr. Pasieka testified that Liberty Utilities has an overarching approach to the integration of Empire in to the Liberty Utilities family. The transition should be seamless to customers from a customer service, reliability, rates and operational perspective.

Mr. Pasieka testified that Liberty Utilities has the management, technical, and financial expertise and capabilities necessary to ensure Empire continues to provide its Oklahoma customers with safe, adequate, reliable, and cost-effective electric, natural gas, and water utility services. In addition, with the retention of Empire's employees, Liberty Utilities anticipates providing the same great safe, adequate, cost-effective and reliable service that Empire customers have come to expect.

Christopher D. Krygier – Liberty Utilities Service Corp.

Mr. Christopher D. Krygier, Director of Regulatory and Government Affairs for Liberty Utilities Service Corp., testified in support of the Application.

Mr. Krygier testified that LU Central has entered into an Agreement and Plan of Merger whereby LU Central will acquire all of the capital stock of Empire through a merger of Liberty Sub Corp. and Empire. After the merger, Liberty Sub Corp. will cease to exist. At the close of the all cash transaction, Empire will become a wholly-owned subsidiary of LU Central and Empire will continue to be regulated by this Commission.

It was Mr. Krygier's understanding that a proposed acquisition must be approved by the Commission if it is in the "public interest" and none of the conditions in Okla. Stat. tit. 17 O.S. §191.5 are found to exist.

Mr. Krygier's testimony provided information on existing Liberty Utilities operations in neighboring states which included electric, natural gas, water and wastewater services in Missouri and Oklahoma.

Mr. Krygier described the many benefits that would result, in his opinion, of the transaction. Those benefits included the opportunity to increase the size of the perspective organizations which is expected to result in greater management expertise and access to broader management capabilities. The transaction will also provide expertise on electric utility operations and allow Empire access to renewable energy development expertise that has already proven to be beneficial to Liberty's electric utilities it owns in other jurisdictions with investments in utility owned solar generation that is expected to reduce overall customer energy costs.

With the Empire acquisition Liberty's operations in Missouri, Arkansas, Illinois, Iowa and Texas will now have access to the diverse and talented management team based in Joplin, Missouri.

There will also be benefits from having a regional board of directors consisting of senior business and community leaders can provide governments and guidance on local issues. There will be enhanced financial capabilities as well as there will be no voluntary work force reductions associated with the transaction.

Mr. Krygier further testified that the proposed transaction will not result in any change in the rates currently charged to Empire's retail customers. Empire will continue to utilize the rates, rules, regulations and other tariff provisions on file with and approved by the Commission, and will continue to provide service to their customers under those rates, rules and regulations, and other tariff provisions until such time as they may be modified according to applicable law. Further, LU Central committed not to seek any merger related adjustments for acquisition costs or any premiums paid above book value.

According to Mr. Krygier, Empire will continue to comply with any ongoing regulatory commitments that are currently in place.

Further, there will be no change to Empire's customer service standards or to its excellent customer service record.

The Company plans to keep all of Empire's employees, including the management team and those handling field and customer service operations, so there will be no disruption whatsoever in the continued provision of good service to the customers of Empire. The Merger Agreement also provides certain protections to current Empire employees regarding their pay and benefits after the closing of the transaction.

Mr. Krygier also testified that Liberty Utilities will revise or modify its current cost allocation manual, as needed, to reflect the acquisition of Empire within six (6) months following the closing of the transaction.

Mr. Krygier testified that one of the important aspects of this acquisition is the shared customer service philosophy by Empire. While Empire does not always use the same words that Liberty Utilities does to describe customer service, it is clear through the successful results that being customer centric is integral to Empire's success.

Mr. Krygier testified all pay stations that exist today will remain open after the acquisition. He further testified that Empire currently employs a number of customer contact center metrics including an average speed of answer, abandoned call rate, and average handle time, among others. According to Mr. Krygier, none of these reporting metrics will change as a result of the acquisition.

Fairo Mitchell – Public Utility Division

Mr. Fairo Mitchell Energy & Water Policy Director of the Public Utility Division ("PUD") of the Commission testified on behalf of PUD.

Mr. Mitchell described the transaction stating that on February 9, 2016, the Board of Directors of the Empire District Electric Company ("Empire" or "Company") agreed to a transaction where they would have a subsidiary of Liberty Utility Co. ("Liberty Utilities") acquire Empire. Liberty Utilities created Liberty Utilities (Central) Co. ("LCU Central") to be the holding company of Liberty Utilities for regulated operations in the central and midwestern United States. According to Mr. Mitchell, this transaction would have Empire and its subsidiaries merge with Liberty Utilities Sub Corp. ("LSC"), a wholly-owned subsidiary of Liberty Utilities. After the merger, Empire would be a subsidiary of LU Central and LSC would dissolve. Mr. Mitchell further testified the purchase price of the transaction was approximately $2.4 billion which consisted of $34 per common share to Empire's share holders with Empire maintaining its current $900 million of debt.

Mr. Mitchell testified that Empire, LU Central and LSC filed an Application pursuant to 17 O.S. §191.1 *et seq.*, seeking Commission approval of the merger. According to Mr. Mitchell,

the Application sufficiently presented information to address the ten (10) requirements and found in 17 O.S. §191.3. In addition, to gain the Commission's approval of the merger, pursuant to 17 O.S. §191.5, the applicants, according to Mr. Mitchell, had to show that the seven conditions have been satisfied. Mr. Mitchell testified that for the Commission to deny the merger application it must find that one or more of these conditions have not been satisfied.

Mr. Mitchell further testified that the conditions addressed contractual obligations and level of service changes, whether electric competition is less, whether the financial conditions change for the utilities involved, whether there are plans to liquidate the current Oklahoma Public Utility, whether the management of the acquiring entity is competent to run the Oklahoma Public Utility, whether the utility will be operated under current integrated constructs, whether the acquiring party is substantially engaged in the business of providing utility service, and whether the acquiring utility owns more than 50% of an electric generating facility in Oklahoma and is selling that generated power to the acquired utility through a contract approved by the Commission.

Mr. Mitchell testified that based on PUD's analysis of the information presented to address the conditions, PUD believed that those conditions have been satisfied. Therefore, PUD was not able to disprove any conditions.

Mr. Mitchell further testified that PUD believed that the merger was in the public interest because it appeared that Empire customers would not see a decrease in the level of service after the merger because they will be served by the same employees of Empire. As Empire is integrated with Liberty Utilities, the economies of scale will be realized due to the fixed costs being spread over a larger customer base. Resources will be better utilized as best practices are better defined. In addition, according to Mr. Mitchell, Empire customers will not experience rate increases as a result of the merger. Mr. Mitchell testified that PUD supported the merger and recommended that the Commission approve the merger between LSC and Empire, because Empire will continue to provide safe and reliable service to its customers at the existing reasonable rates.

Mr. Mitchell testified PUD reviewed the application package which included the Agreement and Plan of Merger, prefiled testimony, and financial documents that were supplied, Oklahoma Statutes and Commission Rules and researched publicly-available information about the companies involved in the merger.

Attorney General

The Attorney General filed a Statement of Position on April 14, 2016. According to the Statement of Position the Attorney General reviewed the Application and testimony filed in the Cause as well as applicable state laws and Commission Rules. Following this review, the Attorney General advised the Commission that he adopted the Responsive Testimony of PUD witness Fario Mitchell. Accordingly, the Attorney General advised the Commission that he did not object to the relief requested by the Merging Parties. Therefore, the Attorney General recommended that the Commission grant the Merging Parties' requested relief by approving the Plan of Merger.

REGULATORY AUTHORITY OF BERMUDA

2 October 2020

BY EMAIL

BELCO
27 Serpentine Rd
Pembroke HM 07 Bermuda

Attention: Dennis Pimentel, President

Dear Mr. Pimentel,

Re: Proposed Modification of TD&R Licence (TDR2017102701-02)

Pursuant to section 29 of the Electricity Act 2016 ("EA"), as read with section 51(1) of the Regulatory Authority Act 2011 ("RAA"), the Regulatory Authority of Bermuda ("RA") hereby modifies the Transmission, Distribution and Retail Licence (TDR2017102701-02) held by the Bermuda Electric Light Company Limited ("BELCO") (the "TD&R Licence").

This modification follows consideration of BELCO's submissions contained in your letter of 18 September 2020 and the RA's determination that the public interest is met by this modification.

Please find enclosed red-lined and final clean copies of the "TD&R Licence", as modified (TDR2017102701-03), which supersedes all previous versions.

Sincerely,

Jozelle Opoku
Head of Regulation & Interim Chief Executive for Electricity

DATED 2nd October 2020

REGULATORY AUTHORITY OF BERMUDA

TRANSMISSION, DISTRIBUTION AND RETAIL LICENCE

granted to

BERMUDA ELECTRIC LIGHT COMPANY LIMITED ("BELCO")

Licensee: BERMUDA ELECTRIC LIGHT COMPANY LIMITED

Address: 27 SERPENTINE ROAD, PEMBROKE HM 07, BERMUDA

License Number: TDR2017102701-03

Issue Date: 27th October 2017

Modification Dates: 27th October 2017 and 2nd October 2020

CONTENTS

PART I - DEFINITIONS, INTERPRETATION, SCOPE AND TERMS OF THE LICENCE

The Regulatory Authority of Bermuda (**"Authority"**), in exercise of the authority conferred by the Electricity Act 2016 (**"EA"**), and Bermuda Electric Light Company Limited (**"BELCO"**) having fulfilled the criteria set out in Section 23 of the EA, hereby grants to BELCO (**"Licensee"**), a licence (**"this Licence"**) to transmit, distribute and retail electricity within the territorial limits of Bermuda subject to the terms of this Licence, the EA, the Regulatory Authority Act 2011 (**"RAA"**) and any Regulations, Administrative Determinations, and Adjudicative Decisions and Orders made or issued in accordance with these Acts.

1 DEFINITIONS

In this Licence, unless the context otherwise requires:

"Affiliate" in relation to the Licensee means as defined in Section 86(3) of the Companies Act 1981.

"Auditors" means the Licensee's auditors for the time being holding office in accordance with the requirements of the Companies Act 1981.

"Authority" means the Regulatory Authority of Bermuda.

"Bulk Generation" means as defined in the EA.

"Bulk Generation Licence" means a licence granted by the Authority under the EA in respect of Bulk Generation.

"Bulk Generation Licensee" means any person who is granted a Bulk Generation Licence by the Authority.

"Central Dispatch" means the process of scheduling and issuing direct instructions for the dispatch of available Generation Units by the Licensee for the Grid System and which shall comply with the requirements of Section 20(3)(c) of the EA.

"Commencement Date" means the date on which this Licence is issued by the Authority.

"Condition" means a condition of this Licence including any Transitional Conditions set forth in the Annex to this Licence.

"Control" has the meaning set out in Section 86(4) of the Companies Act 1981.

"Controlling Interest Holder" means a company or individual that is in Control of the Licensee.

"Dispatch Instructions" means the operating instructions of the Licensee to Bulk Generation Licensees in respect of their Generation Units and which shall comply with the requirements of Section 20(3)(c) of the EA.

"Disposal" includes any sale, gift, lease, licence, mortgage, charge or the grant of any encumbrance or any other disposition to a third party and **"Dispose"** shall be construed accordingly.

"Distributed Generator" means as defined in the EA.

"Distribution Business" means the business of the Licensee in or ancillary to the transport of electricity through the Licensee's Distribution System and shall include (i) any business in providing connections to the Licensee's Distribution System; (ii) operations; (iii) management; and (iv) investment, but shall not include any other business of the Licensee.

"Distribution System" means the system of medium and low voltage electric lines and electrical plant and meters owned by the Licensee and used for conveying electricity without the use of the Transmission System.

"End-User(s)" means as defined in the EA.

"Feed-in Tariff" means as defined in the EA.

"financial year" means the period from 1 January to 31 December in any calendar year during the term of this Licence and the first financial year shall be the period from the Commencement Date until the succeeding 31 December and the last financial year shall be the period from 1 January until the date on which this Licence is revoked or terminated in accordance with its terms.

"Generation Business" means the authorised business of the Bulk Generation Licensee relating to the Bulk Generation of electricity in Bermuda pursuant to its Bulk Generation Licence.

"Generation Unit" means any plant or apparatus for the generation of electricity including a facility comprising one or more generation units. For the avoidance of doubt, a Generation Unit shall not include any distributed generation systems.

"Government Authorisation Fees" means the fees established pursuant to Section 52 of the RAA and required to be paid by the Licensee under Sections 25 and 26 of the EA.

"Grid Code" means a code developed by the Licensee with the approval of the Authority as more particularly described in the EA and pursuant to the terms of this Licence.

"Grid Connection Policy" means the policy referred to in Condition 20.

"Grid System" means (i) the Transmission System; and (ii) the Distribution System of the Licensee.

"Information" means any documents, records, accounts, estimates, returns, or reports (whether or not prepared specifically at the request of the Authority) of any description and in any format specified by the Authority.

“Insolvency Event” means the occurrence of any of the following events, unless such event is capable of being set aside and proper proceedings to have such event set aside are filed with the appropriate court within thirty (30) days of such event:

a) there is entered against the Licensee a decree or order by a court adjudging the Licensee bankrupt or insolvent or approving as properly filed by or on behalf of the Licensee a petition seeking reorganization, arrangement or reconstruction or appointing a receiver, liquidator, trustee, sequestrator (or other similar official) of the Licensee over a substantial part of its property or assets or ordering the winding up or liquidation of its affairs; or

b) the institution by the Licensee of proceedings to be adjudicated bankrupt or insolvent; or

c) the consent by the Licensee to the institution of bankruptcy or insolvency proceedings against it; or

d) the filing by the Licensee of a petition or consent seeking relief from creditors generally under any applicable Law;

e) the consent by the Licensee of the filing of any petition or for the appointment of a receiver, liquidator, trustee, sequestrator (or other similar official) of the Licensee or any substantial part of its property; or

f) any other event shall have occurred with respect to the Licensee which under applicable Law would have an effect analogous to any of the events referred to in this definition.

"Integrated Resource Plan" or "IRP" means the document to be developed and provided by the Licensee and approved by the Authority in accordance with Sections 40 to 45 of the EA.

"Law" means the laws of Bermuda.

"Licence" means this Transmission, Distribution and Retail Licence granted to the Licensee by the Authority pursuant to the provisions of the EA and any Schedules and Annexures hereto.

"Licensee" means BELCO, a company established in 1904, the governing acts of which were most recently consolidated in the Bermuda Electric Light Company Act 1951 and whose registered office is at 27 Serpentine Road, Pembroke HM 07, Bermuda.

"Merit Order" means an order for ranking available Generation Units as shall be prescribed in the Grid Code and which order shall have as its aim the promotion of Renewable Energy and the optimising of the economy, security, stability and reliability of the Grid System of Bermuda and shall take fully into account cost considerations, and such order shall comply with the requirements of section 20(3) of the EA.

"Minister" means the Minister responsible for energy in Bermuda**.**

"Natural Disaster Contingency Fund" means a sinking fund collected from End-Users, of an amount to be determined by the Authority to be used by the Licensee to effect repairs to the Grid System following the occurrence of any natural disaster in Bermuda.

~~**"Net Benefit Test"** means a test to uniformly evaluate (i) proposed third party investments; and (ii) investments by the Licensee's Generation Business in new generation in Bermuda.~~

"notice" means (unless otherwise specified) notice given in accordance with Condition 37 of this Licence.

"Output" means the electricity generated at the generation facilities of any Bulk Generation Licensee and delivered to the Grid System.

"Power Purchase Agreement" means an agreement between the Licensee and a Bulk Generation Licensee in accordance with Section 48 of the EA for the sale and purchase of the whole or any part of the available capacity of the generation facilities of such Bulk Generation Licensee and/or the sale and purchase of the whole or any part of the Output by the Licensee from such Bulk Generation Licensee**.**

"Protected Information" means any personal data identified in accordance with Section 39 of the EA, any other applicable Law and any General Determinations made pursuant to Section 39 of the EA.

"Prudent Operating Practice" means the practice of a Reasonable and Prudent Operator.

"Reasonable and Prudent Operator" means a person who exercises that degree of skill, diligence, prudence and foresight which could reasonably and ordinarily be expected from a skilled and experienced operator engaged in the same type of undertaking under the same or similar circumstances.

"Regulatory Authority Fees" means the fees established to fund the operation of the Authority under Section 44 of the RAA and payable by the Licensee to the Authority under Condition 5 of this Licence.

"Relevant Asset" has the meaning set out in any General Determination made by the Authority in respect of such definition.

"Renewable Energy" means energy that comes from resources that are constantly replenished, and includes energy produced by solar, wind, biomass, landfill gas, municipal solid waste, ocean (including tidal, wave, current, and thermal), geothermal, or hydro resources.

"Representation" includes any objection or other proposal made in writing.

"Retail Business" means the business of the Licensee as electricity supplier in Bermuda but excluding any activities forming part of (i) the Transmission and Distribution Business and (ii) the Bulk Generation Business and, for the avoidance of doubt, shall

include, amongst other things, the following activities (i) invoicing End-Users; (ii) protecting the rights of End-Users; and (iii) safeguarding Protected Information.

"Retail Tariff" means the tariff at which the Licensee sells electricity to its End-Users, as determined by the Authority in accordance with the methodology set by General Determination made by the Authority under Section 35 of EA and in accordance with the principles set out in Section 35 of the EA.

"Scheduling System" means a system prepared by the Licensee for, amongst other things, identifying the economic cost of electricity from Generation Units which are connected to the Grid System and which are available for the purposes of establishing a Merit Order and which shall comply with the requirements of Section 20(3)(c) of the EA.

"Sectoral Participants" has the meaning set out in the RAA.

"Sectoral Providers" has the meaning set out in the RAA.

"Service Agreement" means an agreement between the Licensee and the End-User as more particularly described in Condition 29.

"Separate Business" means each of the Generation Business, and the TD&R Business of the Licensee taken separately from one another and from any other business of the Licensee or any Affiliate or related undertaking of the Licensee (including the Controlling Interest Holder of the Licensee) and **"Separate Businesses"** shall be construed accordingly.

"Standard Contract" means as defined in the EA.

"Transmission and Distribution Business" means the Transmission Business and the Distribution Business of the Licensee taken together.

"TD&R Business" means the Transmission and Distribution Business of the Licensee and the Retail Business of the Licensee all taken together.

"Transmission Business" means the business of the Licensee in or ancillary to the planning and development, and the construction and maintenance, of the Licensee's Transmission System, including providing connections to the Licensee's Transmission System but shall not include any other business of the Licensee.

"Transmission System" means the system of high voltage electric lines and electrical plant and meters owned by the Licensee and used for conveying electricity from a generating station to a sub-station, from one sub-station to another and from one generating station to another.

"Year" means a period of 12 months commencing on 1 January.

2 INTERPRETATION

For the purposes of interpreting this Licence:

(a) unless a different definition is provided in this Licence, words or expressions shall have the meaning assigned to them in the EA, the RAA and the Interpretation Act 1951;

(b) where there is any conflict between the provisions of this Licence and the EA or RAA, the provisions of the EA or RAA (as the case may be) shall prevail. For the avoidance of doubt the provisions of the EA take precedence over the provisions of the RAA pursuant to Section 3(3) of the EA;

(c) references to Conditions and Annexes are to Conditions and Annexes of this Licence, as modified from time to time in accordance with this Licence and the EA;

(d) headings and titles used in this Licence are for reference only and shall not affect its interpretation or construction;

(e) references to any Law or statutory instrument include any modification, re-enactment or legislative provisions substituted for the same;

(f) expressions cognate with those used in this Licence shall be construed accordingly;

(g) words importing the singular shall include the plural and vice versa, and words importing the whole shall be treated as including a reference to any part unless explicitly limited;

(h) reference to a person includes an individual, firm, partnership, joint venture, company, corporation, body corporate, unincorporated body of persons or any state or any agency of a state or any other legal entity; and

(i) unless the contrary intention appears, words importing the masculine gender include the feminine.

3 SCOPE OF THE LICENCE

3.1 This Licence grants the Licensee the right to transmit, distribute and retail electricity within Bermuda and to purchase or acquire electricity from Bulk Generation Licensees and Distributed Generators, including the right to engage in any other activities which directly support, and which are necessary as regards, its right to transmit, distribute and retail electricity within Bermuda.

3.2 This Licence does not grant the Licensee the right to engage in any other activities in the electricity sector in Bermuda without first obtaining the approval of the Authority in writing in respect of any such additional activities.

3.3 Nothing in this Licence shall relieve the Licensee of the obligations to comply with any other requirement imposed by Law or Prudent Operating Practice to obtain any additional consents, permissions, authorisations, licences or permits as may be necessary to exercise the Licensee's right to discharge its obligations under the Licence.

3.4 Following a written request by the Licensee, the Authority shall be entitled to issue instructions relieving the Licensee of its obligations to comply with any provisions of this Licence to such extent as may be specified in the Authority's instructions.

4 TERM OF THE LICENCE

4.1 This Licence shall be valid from the Commencement Date and shall continue in full force and effect until 27th October 2047 unless revoked in accordance with Condition 9 of this Licence or surrendered in accordance with Condition 10 of this Licence. In the event of revocation by the Authority, this may apply with immediate effect (subject to rights of appeal), or, on any notice period the Authority may specify. In the event of surrender, the Authority may require a period of up to 5 years' notice of the surrender taking effect.

4.2 This Licence may be renewed for an additional term or terms if:

(a) the Licensee files an application requesting renewal no earlier than 36 months and no later than 12 months prior to 27th October 2047; and

(b) the Authority determines that renewal of this Licence would be in the public interest, subject to any modifications that the Authority may deem it necessary or appropriate to impose at the time of renewal.

4.3 A decision by the Authority to revoke this Licence shall be appealable pursuant to Section 33 of the EA.

PART II - CONDITIONS

5 FEES AND PENALTIES

5.1 The Licensee shall pay to the Authority such Government Authorisation Fees as may be prescribed pursuant to Sections 25, 26, and 66(3) of the EA; Section 52 of the RAA; and the Government Fees Act 1965.

5.2 The Licensee shall pay to the Authority such Regulatory Authority Fees as may be prescribed pursuant to Section 44 of the RAA.

5.3 The Licensee shall pay to the Authority any penalties that may be imposed on the Licensee by the Authority in accordance with Section 26(1)(a) of EA and Section 94 of the RAA or otherwise.

5.4 The Licensee shall be liable in accordance with Section 57 of the EA for failure to pay the fees set out in paragraphs 5.1 and 5.2 of this Condition 5.

5.5 The Licensee shall be liable in accordance with Section 60 of the EA for failure to comply with this Licence.

6 COMPLIANCE

6.1 The Licensee shall comply with:

(a) the Conditions of this Licence, including any Schedules and Annexures to this Licence;

(b) the terms of any associated licences, authorisations and permits issued to the Licensee;

(c) any regulations issued by the Minister in accordance with Section 54 of the EA;

(d) any Ministerial directions issued by the Minister pursuant to the EA;

(e) any Administrative Determinations, Adjudicative Decisions and Orders made by the Authority pursuant to the EA and the RAA;

(f) the EA;

(g) the RAA; and

(h) any other applicable Law, enactment, determination, regulation or order in effect in Bermuda to which the Licensee is subject.

6.2 Where there is an irreconcilable conflict between any applicable Laws, regulation, determination or order, the following order of precedence shall apply: Acts of Parliament, Regulations and Orders made by the Minister, international agreements that apply to Bermuda, General or other Administrative Determinations made by the Authority, and this Licence.

7 INFORMATION, AUDITS AND INSPECTION

7.1 The Licensee shall, in accordance with Section 26(1)(f) of the EA, the provisions of Part 8 of the RAA and any General Determination by the Authority, furnish to the Authority, in such manner and at such reasonable times as the Authority may reasonably require, such Information relating to the electricity sector including any Information reasonably required by the Authority in order for it to comply with its obligations under Section 52 of the EA.

7.2 Subject to the provisions of Part 8 of the RAA and any applicable General Determination by the Authority, the Licensee shall permit the Authority or persons designated by the Authority, to examine, investigate or audit, or procure such assistance as the Authority may reasonably require to conduct an examination, investigation or audit of, any aspect of the Licensee's TD&R Business.

7.3 Subject to the provisions of Section 92 of the RAA and any applicable General Determination by the Authority, the Licensee shall permit the Authority or persons designated by the Authority to enter the Licensee's premises, and shall facilitate reasonable access by the Authority or such persons to the premises used by the Licensee, to conduct an inspection, examination, investigation or audit of the Licensee.

7.4 The Licensee shall notify the Authority as soon as possible upon becoming aware that it is in a position in which it may potentially breach any Condition set out in this Licence.

7.5 The Licensee shall place a complete copy of this Licence on the Licensee's website or, if no such website exists, in a conspicuous place in the Licensee's principal place of business such that it is readily available for inspection free of charge by members of the general public during normal office hours.

8 MODIFICATION OF THE LICENCE

8.1 This Licence may be modified:

(a) by the Authority of its own motion pursuant to Section 29 of the EA and Section 51 of the RAA;

(b) with the mutual consent of the Licensee and the Authority pursuant to Section 29 of the EA and Section 51 of the RAA;

(c) by the Authority following an enforcement proceeding, pursuant to the provisions of Section 93 of the RAA; or

(d) by the Authority following any change of Control of the Licensee's TD&R Business pursuant to the operation of Sections 30(3), 21 and 22 of the EA.

9 ENFORCEMENT, SUSPENSION AND REVOCATION

9.1 The Authority may initiate enforcement proceedings pursuant to Section 53 of the EA and Section 93 of the RAA.

9.2 The Authority may revoke this Licence:

(a) in accordance with the provisions of Section 31 of the EA and Section 51 of the RAA; and

(b) in the event of any Insolvency Event affecting the Licensee.

9.3 The Authority shall be entitled to suspend this Licence in accordance with Sections 31 and 53 of the EA and Section 51 of the RAA. The Authority may, in its sole discretion, lift an on-going suspension and re-instate the Licence.

9.4 The Licensee shall not in any circumstance raise as a defence to enforcement or any other regulatory action by the Authority that it was compelled by the direction of its Controlling Interest Holder to act in breach of this Licence.

9.5 In the event of any revocation of this Licence in accordance with Condition 9 of this Licence and/or any surrender of this Licence by the Licensee pursuant to Condition 10 of this Licence, the Licensee shall without delay provide all reasonable assistance and take all reasonable steps to co-operate fully with any new provider of transmission, distribution and retail electricity services in Bermuda to ensure continuity of supply to the public so that there is the minimum of disruption and so as to prevent or mitigate any inconvenience or risk to the health or safety of End-Users, Sectoral Providers, Sectoral Participants and all members of the public.

10 DISCONTINUANCE OF SERVICE, SURRENDER OF LICENCE

Unless the Authority agrees otherwise, the Licensee shall not be entitled to surrender this Licence.

11 ACCOUNTING REQUIREMENTS

11.1 The purpose of this Condition is to ensure that the Licensee (and any Affiliate or related undertaking of the Licensee including the Controlling Interest Holder) maintains accounting and reporting arrangements which enable separate accounts to be prepared for each Separate Business and which show the financial affairs of each such Separate Business.

11.2 The Licensee shall in respect of each of its Generation Business and TD&R Business maintain appropriate management accounts and/or operating accounts that will enable the Authority to assess the Licensee's financial standing, performance and transparency across its business units.

11.3 Annually, the Licensee shall in respect of each of its Generation Business and TD&R Business, prepare from such accounting records:

(a) accounting statements comprising a profit and loss and other comprehensive income statement, a statement of financial position, together with notes thereto to the extent required by General Determination, and showing separately in respect of each of the Generation Business and the TD&R Business details of the amounts of any revenue, cost, asset, liability, reserve or provision, which has been either:

(i) received by each of the Generation Business and TD&R Business from any other business (whether or not a Separate Business and including from the Controlling Interest Holder) together with a description of the basis of such revenue, cost or liability received; or

(ii) charged from each of the Generation Business and TD&R Business to any other business (whether or not a Separate Business and including to the Controlling Interest Holder) together with a description of the basis of that charge; or

(iii) determined by apportionment or allocation between each of the Generation Business and the TD&R Business and any other business (whether or not a Separate Business and including the Controlling Interest Holder) together with a description of the basis of the apportionment or allocation; and

(b) each financial year, sufficient accounting information in respect of each of the Licensee's Generation Business and TD&R Business to allow for reconciliation against the licensee's consolidated financial statements.

11.4 The Licensee shall procure, in respect of the accounting statements prepared in accordance with this Condition, a report by the Auditors addressed to the Authority stating whether in their opinion those statements have been properly prepared in accordance with this Condition and give a true and fair view of the revenues, costs, assets, liabilities, reserves and provisions of, or reasonably attributable to, the Separate Business to which the statements relate.

11.5 The Licensee shall deliver to the Authority a copy of the Auditors' report referred to in paragraph 11.4 and the accounting statements referred to in paragraph 11.3(a) as soon as reasonably practicable.

11.6 The Licensee shall not in relation to the accounting statements in respect of a financial year change the bases of charge, apportionment or allocation referred to in paragraph 11.3(a) from those applied in respect of the previous financial year, unless the Authority has previously issued instructions for the purposes of this Condition instructing the Licensee to change such bases in a manner set out in the instructions or the Authority gives its prior written approval to the change in such bases. The Licensee shall comply with any instructions issued for the purposes of this Condition. If the Licensee changes the bases of charge, apportionment or allocation from those adopted for the immediately preceding financial year, it shall show a reconciliation of the revised and prior-year methodologies.

11.7 Accounting statements in respect of a financial year prepared under paragraph 11.3(a) shall, so far as reasonably practicable, and unless otherwise approved by the Authority having regard to the purposes of this Condition:

(a) reflect the revenues, costs, assets and liabilities of each of the Generation Business and the TD&R Business and be recorded in a manner consistent with the accounting principles applied by BELCO for its financial statements prepared in accordance with generally accepted accounting principles. The Authority may, on application from the Licensee, or in consultation with the Licensee, modify those accounting principles, subject to such conditions as may be specified by General Determination; and

(b) be submitted to the Authority with BELCO’s consolidated financial statements.

11.8 References in this Condition to costs or liabilities of, or reasonably attributable to, any Separate Business shall be construed as excluding taxation, capital liabilities which do not relate principally to a particular Separate Business and interest thereon; and references to any accounting statement shall be construed accordingly.

11.9 Without prejudice to any other paragraph of this Condition, and subject to the Authority giving reasonable notice to the Licensee, the Licensee shall, on request by the Authority, give to the Authority with a reasonable time of such request by the Authority access to the Licensee's accounting records, policies and statements referred to in this Condition.

12 AVAILABILITY OF RESOURCES

12.1 The Licensee shall at all times act in a manner calculated to secure that it has sufficient management resources and financial resources and financial facilities to enable it to:

(a) carry on its TD&R Business; and

(b) comply with its obligations under this Licence and the EA.

12.2 The Licensee shall submit a certificate addressed to the Authority, approved by a resolution of the Board of Directors of the Licensee and signed by a director of the Licensee pursuant to that resolution. Such certificate shall be submitted on 30 April each year and shall be in one of the following forms:

(a) "After making enquiries, the directors of the Licensee have a reasonable expectation that the Licensee will have available to it, after taking into account in particular (but without limitation) any dividend or other distribution which might reasonably be expected to be declared or paid, sufficient financial resources and financial facilities to enable the Licensee to carry on the Separate Businesses for a period of 12 months from the date of this certificate.";

(b) "After making enquiries, the directors of the Licensee have a reasonable expectation, subject to the terms of this certificate, that the Licensee will have available to it, after taking into account in particular (but without limitation) any dividend or other distribution which might reasonably be expected to be declared or paid, sufficient financial resources and financial facilities to enable the Licensee to carry on the TD&R Business for a period of 12 months from the date of this certificate. However, the directors would like to draw attention to the following factors which may cast doubt on the ability of the Licensee to carry on the TD&R Business."; or

(c) "In the opinion of the directors of the Licensee, the Licensee will not have available to it sufficient financial resources and financial facilities to enable the Licensee to carry on the TD&R Business for a period of 12 months from the date of this certificate."

12.3 The Licensee shall submit to the Authority together with the certificate referred to in paragraph 12.2 of this Condition a statement of the main factors which the directors of the Licensee have taken into account in giving that certificate.

12.4 The Licensee shall inform the Authority in writing immediately if the directors of the Licensee become aware of any circumstances which cause them no longer to have the reasonable expectation expressed in the most recent certificate given under paragraph 12.2.

13 PROHIBITION OF CROSS-SUBSIDIES

13.1 The Licensee shall procure that no Separate Businesses of the Licensee:

(a) gives any direct or indirect cross-subsidy to the Licensee; and

(b) receives any direct or indirect cross-subsidy from the Licensee.

13.2 The Licensee shall procure that it shall not give any cross-subsidy to or receive any cross subsidy from the Controlling Interest Holder.

14 SERVICE STANDARDS & PERFORMANCE STANDARDS

14.1 The Licensee shall comply with any applicable service standards including standards relating to power reliability, power quality and customer service standards set out in any General Determinations made pursuant to Section 34 of the EA.

14.2 The Licensee shall report to the Authority in accordance with the provisions of any General Determination.

14.3 The Licensee shall operate the Grid System in accordance with the provisions of Section 20(3) of the EA and applicable standards as set forth in the Grid Code, relevant codes of practice and General Determinations.

14.4 If the Licensee fails to meet its required service standards as set forth in this Licence, the Grid Code, codes of practice or General Determinations, the Licensee shall forthwith discuss with the Authority the reasons for any non-compliance and the steps that the Licensee intends to take in order to remedy such non-compliance.

14.5 The Authority shall give the Licensee reasonable time to implement the remedial measures notified by the Licensee to the Authority pursuant to paragraph 14.4 of this Condition 14.

14.6 The Authority shall review the service standards referred to in this Condition 14 which the Licensee is required to comply with when conducting any tariff review pursuant to Section 37 of the EA.

15 DISPOSAL OF RELEVANT ASSETS

15.1 Subject to Condition 15.4, the Licensee shall obtain the prior written consent of the Authority in order to Dispose of any Relevant Asset and/or to create security over any Relevant Asset and/or to relinquish control over any Relevant Asset, such consent shall not be unreasonably withheld. References to control throughout Condition 15 shall carry their plain meaning.

15.2 Subject to the provisions of any applicable General Determination, the Licensee shall give to the Authority not less than 2 months' prior written notice of its intention to create any security or effect a Disposal of or relinquish control over any Relevant Asset, together with such reasonable further information as the Authority may request relating to such asset or the circumstances of such intended Disposal or relinquishment of control or to the intentions.

15.3 Notwithstanding paragraphs 15.1 and 15.2, the Licensee may effect a Disposal of or relinquish operational control over any Relevant Asset where:

(a) the Authority has issued instructions for the purposes of this Condition containing a general consent (whether or not subject to conditions) to:

(i) transactions of a specified description; and/or

(ii) the Disposal of or relinquishment of operational control over Relevant Asset(s) of a specified description; and

(b) the Disposal or relinquishment of operational control in question is effected pursuant to a transaction of a description specified in the instructions or the Relevant Asset in question is of a description so specified and the Disposal or relinquishment of operational control is in accordance with any conditions to which the consent is subject.

15.4 Notwithstanding paragraph 15.1, the Licensee may Dispose of or relinquish operational control over any Relevant Asset specified in any notice given under paragraph 15.2 in circumstances where:

(a) the Authority confirms in writing that it consents to such Disposal or relinquishment (which consent may be made subject to the acceptance by the Licensee or any third party in favour of whom the Relevant Asset is proposed to be Disposed or operational control is proposed to be relinquished of such conditions as the Authority may specify); or

(b) the Authority does not inform the Licensee in writing of any objection to such Disposal or relinquishment of control within the notice period referred to in paragraph 15.1 (subject to the provisions of any General Determination).

16 RESTRICTION ON USE OF CERTAIN INFORMATION

16.1 The Licensee shall procure that the Licensee shall not obtain any unfair competitive advantage from the Licensee's possession of Protected Information.

16.2 The Licensee shall implement such measures and procedures and take all such other steps as required by Law and any General Determination in accordance with Section 39 of the EA.

16.3 The Licensee shall:

(a) procure and furnish to the Authority, in such manner and at such times as the Authority may require, such Information as the Authority may consider necessary concerning the performance by the Licensee of its obligations under paragraphs 16.1 and 16.2; and

(b) procure that access to any premises of the Licensee shall be given at any time and from time to time to any nominated person(s) for the purpose of investigating

whether the Licensee has performed its obligations under paragraphs 16.1 and 16.2.

16.4 This Condition is without prejudice to the duties at Law of the Licensee towards outside persons.

16.5 Where the Licensee receives Protected Information in its capacity as the Licensee it shall take all reasonable precautions against the risk of failure to restrict the use of that information to the sole purpose it was originally provided.

17 NATIONAL DISASTER CONTINGENCY FUND

The Licensee shall, from the revenues paid to it pursuant to Condition 26 of this Licence set up a Natural Disaster Contingency Fund in an amount to be determined by the Authority and which must be available at any time during the term of this Licence such fund to be provided for as part of the design of the tariff methodology set by General Determination pursuant to Section 35(1) of the EA.

18 BASIS OF CHARGES FOR CONNECTION TO GRID SYSTEM

Preparation of statements on basis of charging for connection to Licensee's Grid System

18.1 The Licensee shall within six months from the Commencement Date prepare a statement, subject to approval by the Authority, setting out the basis upon which charges will be made for connection to the Licensee's Grid System. Such statement shall be in such form and will contain such detail as shall be necessary to enable any person to make a reasonable estimate of the charges, to which it would become liable, for connection to the Licensee's Grid System and shall include the information set out in Condition 18.2 below.

18.2 Except to the extent that the Authority shall otherwise specify, the statement referred to in paragraph 18.1 shall include:

(a) a schedule listing those items (including the carrying out of works and the provision and installation of electric lines or electrical plant or meters) of significant cost liable to be required for the purpose of connection (at entry or exit points) to the Licensee's Grid System for which connection charges may be made or levied and including (where practicable) indicative charges for each such item and (in other cases) an explanation of the methods by which and the principles on which such charges will be calculated;

(b) the methods by which and the principles on which any charges will be made in respect of extension or reinforcement of the Licensee's Grid System rendered necessary or appropriate by virtue of providing connection to any person seeking connection;

(c) the methods by which and the principles on which connection charges will be made in circumstances where the electric lines or electrical plant to be installed

are of greater size or capacity than that required by the person seeking connection;

(d) the methods by which and the principles on which any charges (including any capitalised charge) will be made for maintenance and repair required of electric lines, electrical plant or meters provided and installed for making a connection to the Licensee's Grid System;

(e) the methods by which and the principles on which any charges will be made for the provision of special metering or telemetry or data processing equipment by the Licensee for the purposes of enabling any person which is bound to comply with the Grid Code to comply with its obligations in respect of metering thereunder, or for the performance by the Licensee of any service in relation thereto;

(f) the methods by which and principles on which any charges will be made for disconnection from the Licensee's Grid System and the removal of electrical plant, electric lines and ancillary meters following disconnection; and

(g) such other matters as shall be specified in instructions issued by the Authority from time to time for the purposes of this Condition.

18.3 Connection charges for those items referred to in paragraph 18.2 shall be set at a level which will enable the Licensee to recover:

(a) the appropriate proportion of the costs directly or indirectly incurred in carrying out any works, the extension or reinforcement of the Licensee's system and the provision and installation, maintenance and repair and, following disconnection, removal of any electric lines, electrical plant, meters, special metering, telemetry, data processing equipment or other items; and

(b) a reasonable rate of return on the capital represented by such costs.

19 NON-DISCRIMINATION REGARDING CONNECTION TO THE GRID SYSTEM

In the carrying out of works for the purpose of connection to the Grid System, the Licensee shall not unduly discriminate, as between:

(a) any persons or class or classes of persons; or

(b) the Licensee (in the provision of connections by the Licensee as part of the TD&R Business) and any person or any class or classes of persons; or

(c) the Licensee's TD&R Business and the Licensee's Generation Business,

except insofar as any difference in the amounts charged, or any other terms or conditions of such provision or carrying out of works, reflects to the satisfaction of the Authority, the difference between the costs of such provision to one person or class of

persons or other circumstances of carrying out such connection to one person or class of persons.

20 REQUIREMENT TO OFFER TERMS

Offer of terms for Connection

20.1 The Licensee shall, within twelve months from the grant of this Licence, prepare and submit its Grid Connection Policy in accordance with the requirements of this Condition to the Authority for approval by the Authority. Upon approval by the Authority of such Grid Connection Policy, the Licensee shall implement and comply with such policy.

20.2 The Grid Connection policy to be submitted by the Licensee pursuant to paragraph 20.1 shall:

(a) include conditions in accordance with Section 47(3)(a) of the EA;

(b) take account of Section 47(3)(b) and (c) of the EA;

(c) comply with the Grid Code;

(d) comply with any code of practice issued by the Authority;

(e) set out in detail the terms on which access to the Grid System will be provided to Distributed Generators;

(f) set out in detail the basis on which the Licensee shall offer to enter into agreements for connection to its Grid System with any person requesting connection; and

(g) set out (in detail) the information to be provided by the Licensee by those persons seeking connection.

20.3 For the purpose of determining an appropriate proportion of the costs directly or indirectly incurred in carrying out works under an agreement for making a connection or modification to an existing connection in accordance with Condition 18.3 of this Licence, the Licensee shall have regard to:

(a) the benefit (if any) to be obtained or likely in the future to be obtained by the Licensee or any other person as a result of the carrying out of such works (or of such other matters) whether by reason of the reinforcement or extension of the Licensee's Grid System or the provision of additional entry or exit points on such system or otherwise; and

(b) the ability or likely future ability of the Licensee to recoup a proportion of such costs from third parties.

20.4 The Licensee shall not be obliged pursuant to this Condition to offer to enter or to enter into any connection agreement if to do so would involve the Licensee breaching Condition 6.1 of this Licence.

21 FUNCTIONS OF THE AUTHORITY

21.1 If, after a period which appears to the Authority to be reasonable for the purpose, the Licensee has failed to enter into an agreement with any person entitled or claiming to be entitled thereto pursuant to a request for connection to the Licensee's Grid System, the Authority may, on the application of that person or the Licensee, and in accordance with the provisions of Sections 57 and 58 of the RAA, settle any terms of the agreement in dispute between the Licensee and that person in such manner as appears to the Authority to be reasonable having (insofar as relevant) regard in particular that such person should pay to the Licensee, the whole or an appropriate proportion (as determined in accordance with Conditions 18.3 and 20.3).

21.2 If either party to an agreement for connection to the Licensee's Grid System proposes to vary the contractual terms of such agreement in any manner provided for under such agreement, the Authority may, at the request of the Licensee or other party to such agreement, settle any dispute relating to such variation in accordance with the provisions of Sections 57 and 58 of the RAA.

22 GRID CODE

22.1 The Licensee shall within twelve months of the grant of this Licence, in consultation with Sectoral Participants and Sectoral Providers liable to be materially affected thereby, prepare and submit to the Authority for its approval a Grid Code.

22.2 Upon approval by the Authority of the Grid Code, the Licensee shall implement and comply with such Grid Code.

22.3 The Grid Code shall:

(a) cover all material technical aspects relating to connections to and the operation and use of the Grid System or (insofar as relevant to the operation and use of the Grid System) the operation of electric lines and electrical plant connected to the Grid System;

(b) contain rules and procedures governing generation dispatch and maintenance scheduling, taking into consideration various operating considerations, including but not limited to least cost, planned generator maintenance, operating reserves (both on-peak and off-peak) and subject to the terms and conditions of executed Power Purchase Agreements; and

(c) contain rules and procedures that provide for the safe and reliable operation of the Grid System including the conditions under which the Licensee shall operate the Grid System and under which Bulk Generation Licensees shall operate their licensed generating plant under both normal and abnormal operating conditions; and

(d) be designed so as:

(i) in relation to the Licensee's Grid System:

(A) to ensure that all Bermuda residents are provided with access to a supply of electricity pursuant to Section 20(3) of the EA;

(B) to give effect to the purposes of the EA as set out in Section 6 of the EA; and

(C) comply with any Administrative Determination by the Authority pursuant to Section 14 of the EA.

22.4 Within two years from the grant of this Licence and thereafter, every five years or less as determined by the Authority, (including upon the request of the Authority), the Licensee shall (in consultation with Sectoral Participants and Sectoral Providers liable to be materially affected thereby) periodically review the Grid Code and its implementation. Following any such review, the Licensee shall send to the Authority:

(a) a report on the outcome of such review;

(a) any proposed revisions to the Grid Code from time to time as the Licensee (having regard to the outcome of such review) reasonably thinks fit for the achievement of the objectives referred to in paragraph 22.3(d); and

(b) any Representations from any Sectoral Participants and Sectoral Providers (including any proposals by such persons for revisions to the Grid Code not accepted by the Licensee in the course of the review) arising during the consultation process and subsequently maintained.

22.5 Revisions to the Grid Code proposed by the Licensee and sent to the Authority pursuant to paragraph 22.4 shall require to be approved by the Authority. Any revisions to the Grid Code proposed by the Licensee shall be filed by the Licensee with the Authority and the Authority shall respond within 90 days of the date of filing by the Licensee.

22.6 Having regard to any Representations referred to in paragraph 22.4(c), and following such further consultation (if any) as the Authority may consider appropriate, the Authority may issue instructions requiring the Licensee to revise the Grid Code in such manner as may be specified in the instructions, and the Licensee shall forthwith comply with any such instructions.

22.7 The Authority shall be entitled, in order to implement the requisite arrangements referred to in Condition 22.3(d) to issue instructions to the Licensee requiring the Licensee to revise the Grid Code in such manner and with effect from such date as may be specified in the instructions, and the Licensee shall comply with any such instructions.

22.8 The Licensee shall give or send a copy of the Grid Code to the Authority and the Minister.

22.9 The Licensee shall give or send a copy of the Grid Code to any person requesting the same and shall be entitled to charge such persons a price not exceeding the reasonable cost of duplicating the Grid Code.

22.10 The Licensee shall publish a redacted version of the Grid Code on its website in order to provide sufficient information so as to allow Distributed Generators to connect to the Grid System.

22.11 In preparing, implementing and complying with the Grid Code (including in respect of the scheduling of maintenance of the Grid System and any generation set or associated power station equipment or combination of generation sets or associated power station equipment) the Licensee shall not :

(b) unduly discriminate against or in favour of any person or class or classes of persons;

(a) unduly prefer the Licensee in the conduct of its Generation Business; or

(b) restrict or prevent competition in generation.

22.12 The Licensee shall keep and maintain such records concerning its implementation of and compliance with the Grid Code as are in accordance with such guidelines as the Authority shall from time to time have given to the Licensee and are, in the opinion of the Authority, sufficient to enable the Authority to assess whether the Licensee is complying with its obligations under this Condition.

22.13 The Authority may from time to time (following consultation with the Licensee and Sectoral Participants and Sectoral Providers) issue instructions relieving the Licensee of its obligations to implement or comply with, or to enforce against any other person any provision of, the Grid Code in respect of such parts of the Licensee's Grid System to such extent as may be specified in the instructions.

23 OBLIGATIONS REGARDING INTEGRATED RESOURCE PLAN AND PROCUREMENT OF NEW GENERATION

23.1 The Licensee shall comply with Sections 40 to 45 of the EA as regards the Integrated Resource Plan proposal and the Integrated Resource Plan.

23.2 The Authority shall be entitled to require the Licensee to clarify any matters set out in the Integrated Resource Plan proposal submitted by the Licensee to the Authority pursuant to Section 41 of the EA and the Licensee shall provide any such Information to the Authority within a reasonable timescale having regard to the complexity of the request.

23.3 The Licensee shall abide by the procurement process set by administrative determination.

~~23.3 Following approval of the final draft Integrated Resource Plan by the Authority in accordance with Section 44(2) of the EA, where the Licensee requires to procure new~~

~~generation capacity in accordance with such approved Integrated Resource Plan, the Licensee shall:~~

~~(a) notify the Authority of the size and timing of such future additional generation requirements;~~

~~(b) solicit bids from its Generation Business and other prospective generators and demand side resource providers in respect of such required additional generation capacity;~~

~~(c) following receipt of bids under (b) above, conduct a detailed evaluation and assessment of all bids received under (b) above in accordance with the Net Benefit Test; and~~

~~(d) following its assessment and evaluation under (c) above, submit a report to the Authority which contains (i) detailed information on what bids were received and the proposed costs submitted by each bidder; (ii) a detailed assessment of each bid as against the Net Benefit Test including with reasoned analysis and conclusions and (iii) the Licensee's recommendation on which bidder should be chosen as the successful bidder.~~

~~23.4 If at any time from the Commencement Date, the Authority becomes aware of any circumstances such that it reasonably believes that the Licensee has not procured sufficient future generation or that the Licensee's approach is not in the public interest, then the Authority shall be entitled to issue instructions obliging the Licensee to procure additional generation at the Licensee's cost (as specified in such instructions) and, if applicable, any IRP approved by the Authority pursuant to Section 44 of the EA shall be amended under Section 46 of the EA.~~

24 OBLIGATION TO ENTER INTO POWER PURCHASE AGREEMENTS

24.1 The Licensee shall enter into:

(a) an Authority approved Power Purchase Agreement with a Bulk Generation Licensee for which the payments shall be passed through to End-Users pursuant to the Retail Tariff set in accordance with Section 35 of the EA; and

(b) power purchase arrangements with its Generation Business.

24.2 The Licensee shall ensure that the terms of any power purchase arrangements that will apply between its Generation Business and its TD&R Business are substantially similar to the terms of its Power Purchase Agreements that will be applied with other Bulk Generation Licensees.

25 OBLIGATION TO ENTER INTO STANDARD CONTRACTS WITH DISTRIBUTED GENERATORS

25.1 The Licensee shall enter into a Standard Contract with a Distributed Generator in accordance with Sections 49 and 50 of the EA. Any Standard Contract shall comply with

the Standard Contract template set by Administrative Determination by the Authority pursuant to Section 49 of the EA.

26 RETAIL TARIFF & RESTRICTION ON LICENSEE'S REVENUE

26.1 The Licensee shall sell electricity to its End-Users at the Retail Tariff.

26.2 The Retail Tariff methodology shall include the establishment of a Natural Disaster Contingency Fund.

26.3 The Licensee shall be entitled to pass through the charges set out in Section 35(3) of the EA (**"the Pass-through Charges"**).

26.4 These Pass-through Charges will be shown as separate items on consumer bills (as permitted in accordance with the EA and the RAA).

26.5 If the Licensee persistently fails to comply with the service standards required pursuant to this Licence and/or fails to procure required additional generation capacity in accordance with the Integrated Resource Plan and Condition 23 of this Licence, the Authority shall be entitled to take those actions set out in the General Determination made by the Authority for the purposes of this provision. The Authority shall conduct a review of the Retail Tariff in accordance with the provisions of Section 37 of the EA.

27 FEED-IN TARIFF

27.1 The Licensee shall pay Distributed Generators the Feed-In Tariff set by the Authority in accordance with a methodology determined by the Authority pursuant to a General Determination.

27.2 The methodology referred to in Condition 27.1 shall be determined in accordance with those principles set out in Section 36 of the EA.

27.3 The Authority shall conduct a review of the Feed-In Tariff in accordance with the provisions of Section 37 of the EA.

28 CENTRAL DISPATCH AND MERIT ORDER

28.1 Central Dispatch

The Licensee shall schedule and issue direct instructions for the dispatch of all available Generation Units of each Bulk Generation Licensee in accordance with the Grid Code.

28.2 Merit Order

The Licensee shall establish as part of the Grid Code, and shall operate, a Merit Order system for Generation Units in Bermuda subject to Central Dispatch. The Licensee's Merit Order system shall comply with the requirements of Section 20(3) of the EA.

28.3 The Licensee shall provide to the Authority such information as the Authority shall request concerning the Licensee's Dispatch Instructions, and/or Scheduling System and/or Merit Order system or any aspect of its operation.

28.4 For the purposes of this Condition, the reference to optimal in Section 20(3) of the EA, in the absence of any contrary provision set out in any Administrative Determination made by the Authority shall be construed as lowest cost.

29 DUTY TO OFFER AND SUPPLY UNDER SERVICE AGREEMENTS

29.1 When the Licensee supplies electricity to its End-Users, it must do so under a Service Agreement.

29.2 A Service Agreement must include terms and conditions that are appropriate for a business that is providing transmission, distribution and retail services to an international standard with appropriate service levels and including metering obligations by the Licensee.

29.3 Within two months from the Commencement Date, the Licensee shall submit to the Authority for approval the form of Service Agreement used by the Licensee.

30 END-USER BILLS

30.1 In furtherance of the Authority’s functions pursuant to Section 14(2) (c) (ii) and pursuant to Section 26 (1) (d) of the EA within 6 months from the grant of this Licence, the Licensee shall submit to the Authority for approval the form of End-User bill that is proposing to send to End-Users.

30.2 The Licensee shall comply with any Administrative Determination made by the Authority pursuant to Section 14(2) (c) (ii) in relation to the form and content of End-User bills.

31 CODES OF PRACTICE

The Licensee shall comply with any codes of practice issued by the Authority pursuant to any General Determination made by the Authority under Section 38 of the EA in relation to the commercial and marketing practices of the Licensee to protect the rights of End-Users.

32 ASSIGNMENT, OUTSOURCING AND MORTGAGES

32.1 This Licence shall not be transferred or assigned without the prior consent of the Authority and Section 30 of the EA shall apply accordingly.

32.2 The Licensee may utilize the services of third parties on an ongoing basis in the provision of TD&R services (i.e., the Licensee may "outsource" certain of its TD&R functions), without relieving the Licensee of its obligations under the Licence. The procurement of such outsourced services shall be subject to the Authority's approval. Any such approval shall be based on the cost-effectiveness of the outsourced services,

how it was procured and with whom, and the fitness and propriety of the relevant third parties and shall not be unreasonably withheld.

32.3 The Licensee shall not sub-licence, assign or grant any right, interest or entitlement in the Licence nor transfer the Licence to any other person including an Affiliate of the Licensee without the written authorisation of the Authority.

32.4 The Licensee shall be liable in accordance with Section 56 of the EA if it contravenes this Condition.

33 CHANGE OF CONTROL

33.1 The Licensee shall not complete any proposed change in control of the Licensee without first obtaining the prior written authorisation of the Authority in accordance with Section 30 of the EA and Section 87 of the RAA, which consent shall not be unreasonably withheld. For the purposes of this Condition 33.1, control shall mean as defined in Section 30 of the EA.

33.2 The Licensee shall be liable in accordance with Section 56 of the EA if it contravenes this Condition.

34 INDEMNIFICATION

The Licensee shall indemnify the Authority against all actions, claims and demands which may be brought or made by any person in respect of any injury or death of any person or damage to any property arising from any act of the Licensee permitted or authorized by the Licence. The Authority shall provide the Licensee with notice of any such actions, claims and demands, but the Authority's failure to do so shall not relieve the Licensee of any obligations imposed on the Licensee by this Condition.

35 FORCE MAJEURE; OTHER EVENTS

35.1 If the Licensee is prevented from complying with the Licence by acts of God, war, warlike operations, civil commotion, major strikes or any other significant or protracted industrial action, fire, tempest or any other causes beyond the Licensee's reasonable control;

(a) the Licensee shall notify the Authority, as promptly as reasonably practicable, of the obligations of the Licence with which the Licensee cannot comply, the expected duration of the event of force majeure, and the measures the Licensee is taking to overcome the consequences of the event of force majeure; and

(b) the Authority shall suspend such obligations of the License as the Authority concludes the Licensee cannot comply with for as long as the event of force majeure continues.

35.2 In addition to events of force majeure, the Licensee shall notify the Authority of any fact or event likely to affect materially the Licensee's ability to comply with any Condition of this Licence, or an insolvency-related fact or Insolvency Event in respect of the Licensee

or any Affiliate, or any preparatory steps being taken that might lead to an Insolvency Event, immediately upon becoming aware of such fact or event.

36 NO ABUSE OF DOMINANT POSITION

36.1 The Licensee occupies a dominant position in accordance with the RAA and Section 51 of the EA.

36.2 If the Licensee abuses its dominant position the Authority shall, pursuant to Section 26(1) (e) of the EA be entitled to require the Licensee to comply with any remedy imposed by the Authority and the Authority shall also be entitled to take those actions set out in Section 85(7) of the RAA.

37 NOTICES

Unless the Authority determines otherwise, notices to the Licensee under the Licence shall be in writing and sent by electronic mail to the Chief Executive Officer of the Licensee at the address communicated to the Authority from time to time.

Unless the Authority determines otherwise, notices from the Licensee to the Authority under the Licence shall be in writing and sent by electronic mail to the Chief Executive of the Authority to electricity@RAB.bm.

38 INSURANCE REQUIREMENTS

38.1 The Licensee shall:

(a) at its own cost and expense take out and maintain in full force and effect with reputable insurance companies such policies of insurance, as it, acting in accordance with Prudent Operating Practice, considers appropriate so as to effect cover against the categories of risk set out below:

(i) fixed assets (buildings and their contents, machinery, stock, fixtures, fittings and all other personal property forming part of the Transmission System and Distribution System including substations but not including cabling, lines and poles) against risks of physical loss or damage for their full replacement value;

(ii) machinery breakdown; and

(iii) public liability.

(b) on request, provide the Authority with copies of all policies effected by it, the amount of any premiums payable under such policies and evidence that the premiums payable thereunder have been paid;

(c) provide access to the Authority or its representatives to the Licensee's offices to inspect the original policies; and

(d) apply the proceeds of claims against such policies relating to damage to the Transmission System and Distribution System.

ANNEX

TRANSITIONAL CONDITIONS

The Licensee shall comply with each of the Transitional Conditions set forth below until such time as the Authority makes an Administrative Determination in respect of the subject matter of each such Transitional Condition, or as otherwise provided for in such Transitional Condition.

A1 ACCOUNTING SEPARATION REQUIREMENTS AND PROHIBITION OF CROSS-SUBSIDIES

A1.1 Notwithstanding the provisions of Condition 11 and Condition 13, the Licensee shall not be obliged to comply with the provisions of Conditions 11 and 13 until such time as:

(i) the Authority, in consultation with Licensee, determines the methodologies, mechanisms and other actions to be taken to enable the Licensee to comply with Conditions 11 and 13;

(ii) any such methodologies, mechanisms and other actions are approved by the Authority by General Determination; and

(iii) the Authority determines a practical timeframe for the implementation of the methodologies, mechanisms and other actions that will enable the Licensee to comply with Conditions 11 and 13.

A2. SERVICE STANDARDS

A2.1 Notwithstanding the provisions of Condition 14, the service and performance standards in force immediately before the Commencement Date shall continue to apply after the Commencement Date until such time as the Authority makes a General Determination pursuant to Section 34 of the EA.

A4 GRID CONNECTION POLICY

A4.1 During the period from the Commencement Date until such time as the Authority approves the Grid Connection Policy pursuant to paragraph 20.1 of Condition 20, the Licensee shall adhere to those existing policies and standards which the Licensee maintained immediately prior to the Commencement Date. Within 30 days from the Commencement Date, the Licensee shall submit those existing standards and policies to the Authority.

A5 GRID CODE

A5.1 During the period from the Commencement Date until such time as the Authority approves the Grid Code pursuant to paragraph 22.1 of Condition 22, the Licensee shall adhere to those existing policies and standards which the Licensee maintained

immediately prior to the Commencement Date. Within 30 days from the Commencement Date, the Licensee shall submit such existing standards and policies to the Authority.

A6. DEFINITION OF RELEVANT ASSET

During the period from the Commencement Date until such time as the Authority makes an Administrative Determination in relation to what shall constitute a Relevant Asset for the purposes of this Licence, a Relevant Asset shall be any asset which either (i) has a value in excess of USD 50,000 or (ii) any asset which has a value less than USD 50,000 but which is required for the Licensee to continue to meet any service standard at the same level that existed prior to any intended disposal of such asset.

A7. INTEGRATED RESOURCE PLAN

Notwithstanding the provisions of this Licence or the EA requiring adherence to the Integrated Resource Plan, the Licensee shall not be obliged to comply with such provisions until such time as the Authority approves the Integrated Resource Plan pursuant to Section 44 of the EA.

A8. TARIFF

During the period from the Commencement Date until such time as the Authority makes the General Determination pursuant to Section 35 of the EA, any price, charge or methodology approved by the Energy Commission in accordance with the Energy Act 2009 shall continue in effect subject to any modification the Authority may consider to be necessary.

DATED 2nd October 2020

REGULATORY AUTHORITY OF BERMUDA

TRANSMISSION, DISTRIBUTION AND RETAIL LICENCE

granted to

BERMUDA ELECTRIC LIGHT COMPANY LIMITED ("BELCO")

Licensee: BERMUDA ELECTRIC LIGHT COMPANY LIMITED

Address: 27 SERPENTINE ROAD, PEMBROKE HM 07, BERMUDA

License Number: TDR2017102701-03

Issue Date: 27th October 2017

Modification Dates: 27th October 2017 and 2nd October 2020

CONTENTS

PART I - DEFINITIONS, INTERPRETATION, SCOPE AND TERMS OF THE LICENCE

The Regulatory Authority of Bermuda (**"Authority"**), in exercise of the authority conferred by the Electricity Act 2016 (**"EA"**), and Bermuda Electric Light Company Limited (**"BELCO"**) having fulfilled the criteria set out in Section 23 of the EA, hereby grants to BELCO (**"Licensee"**), a licence (**"this Licence"**) to transmit, distribute and retail electricity within the territorial limits of Bermuda subject to the terms of this Licence, the EA, the Regulatory Authority Act 2011 (**"RAA"**) and any Regulations, Administrative Determinations, and Adjudicative Decisions and Orders made or issued in accordance with these Acts.

1 DEFINITIONS

In this Licence, unless the context otherwise requires:

"Affiliate" in relation to the Licensee means as defined in Section 86(3) of the Companies Act 1981.

"Auditors" means the Licensee's auditors for the time being holding office in accordance with the requirements of the Companies Act 1981.

"Authority" means the Regulatory Authority of Bermuda.

"Bulk Generation" means as defined in the EA.

"Bulk Generation Licence" means a licence granted by the Authority under the EA in respect of Bulk Generation.

"Bulk Generation Licensee" means any person who is granted a Bulk Generation Licence by the Authority.

"Central Dispatch" means the process of scheduling and issuing direct instructions for the dispatch of available Generation Units by the Licensee for the Grid System and which shall comply with the requirements of Section 20(3)(c) of the EA.

"Commencement Date" means the date on which this Licence is issued by the Authority.

"Condition" means a condition of this Licence including any Transitional Conditions set forth in the Annex to this Licence.

"Control" has the meaning set out in Section 86(4) of the Companies Act 1981.

"Controlling Interest Holder" means a company or individual that is in Control of the Licensee.

"Dispatch Instructions" means the operating instructions of the Licensee to Bulk Generation Licensees in respect of their Generation Units and which shall comply with the requirements of Section 20(3)(c) of the EA.

"Disposal" includes any sale, gift, lease, licence, mortgage, charge or the grant of any encumbrance or any other disposition to a third party and **"Dispose"** shall be construed accordingly.

"Distributed Generator" means as defined in the EA.

"Distribution Business" means the business of the Licensee in or ancillary to the transport of electricity through the Licensee's Distribution System and shall include (i) any business in providing connections to the Licensee's Distribution System; (ii) operations; (iii) management; and (iv) investment, but shall not include any other business of the Licensee.

"Distribution System" means the system of medium and low voltage electric lines and electrical plant and meters owned by the Licensee and used for conveying electricity without the use of the Transmission System.

"End-User(s)" means as defined in the EA.

"Feed-in Tariff" means as defined in the EA.

"financial year" means the period from 1 January to 31 December in any calendar year during the term of this Licence and the first financial year shall be the period from the Commencement Date until the succeeding 31 December and the last financial year shall be the period from 1 January until the date on which this Licence is revoked or terminated in accordance with its terms.

"Generation Business" means the authorised business of the Bulk Generation Licensee relating to the Bulk Generation of electricity in Bermuda pursuant to its Bulk Generation Licence.

"Generation Unit" means any plant or apparatus for the generation of electricity including a facility comprising one or more generation units. For the avoidance of doubt, a Generation Unit shall not include any distributed generation systems.

"Government Authorisation Fees" means the fees established pursuant to Section 52 of the RAA and required to be paid by the Licensee under Sections 25 and 26 of the EA.

"Grid Code" means a code developed by the Licensee with the approval of the Authority as more particularly described in the EA and pursuant to the terms of this Licence.

"Grid Connection Policy" means the policy referred to in Condition 20.

"Grid System" means (i) the Transmission System; and (ii) the Distribution System of the Licensee.

"Information" means any documents, records, accounts, estimates, returns, or reports (whether or not prepared specifically at the request of the Authority) of any description and in any format specified by the Authority.

“Insolvency Event” means the occurrence of any of the following events, unless such event is capable of being set aside and proper proceedings to have such event set aside are filed with the appropriate court within thirty (30) days of such event:

a) there is entered against the Licensee a decree or order by a court adjudging the Licensee bankrupt or insolvent or approving as properly filed by or on behalf of the Licensee a petition seeking reorganization, arrangement or reconstruction or appointing a receiver, liquidator, trustee, sequestrator (or other similar official) of the Licensee over a substantial part of its property or assets or ordering the winding up or liquidation of its affairs; or

b) the institution by the Licensee of proceedings to be adjudicated bankrupt or insolvent; or

c) the consent by the Licensee to the institution of bankruptcy or insolvency proceedings against it; or

d) the filing by the Licensee of a petition or consent seeking relief from creditors generally under any applicable Law;

e) the consent by the Licensee of the filing of any petition or for the appointment of a receiver, liquidator, trustee, sequestrator (or other similar official) of the Licensee or any substantial part of its property; or

f) any other event shall have occurred with respect to the Licensee which under applicable Law would have an effect analogous to any of the events referred to in this definition.

"Integrated Resource Plan" or "IRP" means the document to be developed and provided by the Licensee and approved by the Authority in accordance with Sections 40 to 45 of the EA.

"Law" means the laws of Bermuda.

"Licence" means this Transmission, Distribution and Retail Licence granted to the Licensee by the Authority pursuant to the provisions of the EA and any Schedules and Annexures hereto.

"Licensee" means BELCO, a company established in 1904, the governing acts of which were most recently consolidated in the Bermuda Electric Light Company Act 1951 and whose registered office is at 27 Serpentine Road, Pembroke HM 07, Bermuda.

"Merit Order" means an order for ranking available Generation Units as shall be prescribed in the Grid Code and which order shall have as its aim the promotion of Renewable Energy and the optimising of the economy, security, stability and reliability of the Grid System of Bermuda and shall take fully into account cost considerations, and such order shall comply with the requirements of section 20(3) of the EA.

"Minister" means the Minister responsible for energy in Bermuda**.**

"Natural Disaster Contingency Fund" means a sinking fund collected from End-Users, of an amount to be determined by the Authority to be used by the Licensee to effect repairs to the Grid System following the occurrence of any natural disaster in Bermuda.

"notice" means (unless otherwise specified) notice given in accordance with Condition 37 of this Licence.

"Output" means the electricity generated at the generation facilities of any Bulk Generation Licensee and delivered to the Grid System.

"Power Purchase Agreement" means an agreement between the Licensee and a Bulk Generation Licensee in accordance with Section 48 of the EA for the sale and purchase of the whole or any part of the available capacity of the generation facilities of such Bulk Generation Licensee and/or the sale and purchase of the whole or any part of the Output by the Licensee from such Bulk Generation Licensee**.**

"Protected Information" means any personal data identified in accordance with Section 39 of the EA, any other applicable Law and any General Determinations made pursuant to Section 39 of the EA.

"Prudent Operating Practice" means the practice of a Reasonable and Prudent Operator.

"Reasonable and Prudent Operator" means a person who exercises that degree of skill, diligence, prudence and foresight which could reasonably and ordinarily be expected from a skilled and experienced operator engaged in the same type of undertaking under the same or similar circumstances.

"Regulatory Authority Fees" means the fees established to fund the operation of the Authority under Section 44 of the RAA and payable by the Licensee to the Authority under Condition 5 of this Licence.

"Relevant Asset" has the meaning set out in any General Determination made by the Authority in respect of such definition.

"Renewable Energy" means energy that comes from resources that are constantly replenished, and includes energy produced by solar, wind, biomass, landfill gas, municipal solid waste, ocean (including tidal, wave, current, and thermal), geothermal, or hydro resources.

"Representation" includes any objection or other proposal made in writing.

"Retail Business" means the business of the Licensee as electricity supplier in Bermuda but excluding any activities forming part of (i) the Transmission and Distribution Business and (ii) the Bulk Generation Business and, for the avoidance of doubt, shall include, amongst other things, the following activities (i) invoicing End-Users; (ii) protecting the rights of End-Users; and (iii) safeguarding Protected Information.

"Retail Tariff" means the tariff at which the Licensee sells electricity to its End-Users, as determined by the Authority in accordance with the methodology set by General Determination made by the Authority under Section 35 of EA and in accordance with the principles set out in Section 35 of the EA.

"Scheduling System" means a system prepared by the Licensee for, amongst other things, identifying the economic cost of electricity from Generation Units which are connected to the Grid System and which are available for the purposes of establishing a Merit Order and which shall comply with the requirements of Section 20(3)(c) of the EA.

"Sectoral Participants" has the meaning set out in the RAA.

"Sectoral Providers" has the meaning set out in the RAA.

"Service Agreement" means an agreement between the Licensee and the End-User as more particularly described in Condition 29.

"Separate Business" means each of the Generation Business, and the TD&R Business of the Licensee taken separately from one another and from any other business of the Licensee or any Affiliate or related undertaking of the Licensee (including the Controlling Interest Holder of the Licensee) and **"Separate Businesses"** shall be construed accordingly.

"Standard Contract" means as defined in the EA.

"Transmission and Distribution Business" means the Transmission Business and the Distribution Business of the Licensee taken together.

"TD&R Business" means the Transmission and Distribution Business of the Licensee and the Retail Business of the Licensee all taken together.

"Transmission Business" means the business of the Licensee in or ancillary to the planning and development, and the construction and maintenance, of the Licensee's Transmission System, including providing connections to the Licensee's Transmission System but shall not include any other business of the Licensee.

"Transmission System" means the system of high voltage electric lines and electrical plant and meters owned by the Licensee and used for conveying electricity from a generating station to a sub-station, from one sub-station to another and from one generating station to another.

"Year" means a period of 12 months commencing on 1 January.

2 INTERPRETATION

For the purposes of interpreting this Licence:

(a) unless a different definition is provided in this Licence, words or expressions shall have the meaning assigned to them in the EA, the RAA and the Interpretation Act 1951;

(b) where there is any conflict between the provisions of this Licence and the EA or RAA, the provisions of the EA or RAA (as the case may be) shall prevail. For the avoidance of doubt the provisions of the EA take precedence over the provisions of the RAA pursuant to Section 3(3) of the EA;

(c) references to Conditions and Annexes are to Conditions and Annexes of this Licence, as modified from time to time in accordance with this Licence and the EA;

(d) headings and titles used in this Licence are for reference only and shall not affect its interpretation or construction;

(e) references to any Law or statutory instrument include any modification, re-enactment or legislative provisions substituted for the same;

(f) expressions cognate with those used in this Licence shall be construed accordingly;

(g) words importing the singular shall include the plural and vice versa, and words importing the whole shall be treated as including a reference to any part unless explicitly limited;

(h) reference to a person includes an individual, firm, partnership, joint venture, company, corporation, body corporate, unincorporated body of persons or any state or any agency of a state or any other legal entity; and

(i) unless the contrary intention appears, words importing the masculine gender include the feminine.

3 SCOPE OF THE LICENCE

3.1 This Licence grants the Licensee the right to transmit, distribute and retail electricity within Bermuda and to purchase or acquire electricity from Bulk Generation Licensees and Distributed Generators, including the right to engage in any other activities which directly support, and which are necessary as regards, its right to transmit, distribute and retail electricity within Bermuda.

3.2 This Licence does not grant the Licensee the right to engage in any other activities in the electricity sector in Bermuda without first obtaining the approval of the Authority in writing in respect of any such additional activities.

3.3 Nothing in this Licence shall relieve the Licensee of the obligations to comply with any other requirement imposed by Law or Prudent Operating Practice to obtain any additional consents, permissions, authorisations, licences or permits as may be necessary to exercise the Licensee's right to discharge its obligations under the Licence.

3.4 Following a written request by the Licensee, the Authority shall be entitled to issue instructions relieving the Licensee of its obligations to comply with any provisions of this Licence to such extent as may be specified in the Authority's instructions.

4 TERM OF THE LICENCE

4.1 This Licence shall be valid from the Commencement Date and shall continue in full force and effect until 27th October 2047 unless revoked in accordance with Condition 9 of this Licence or surrendered in accordance with Condition 10 of this Licence. In the event of revocation by the Authority, this may apply with immediate effect (subject to rights of appeal), or, on any notice period the Authority may specify. In the event of surrender, the Authority may require a period of up to 5 years' notice of the surrender taking effect.

4.2 This Licence may be renewed for an additional term or terms if:

(a) the Licensee files an application requesting renewal no earlier than 36 months and no later than 12 months prior to 27th October 2047; and

(b) the Authority determines that renewal of this Licence would be in the public interest, subject to any modifications that the Authority may deem it necessary or appropriate to impose at the time of renewal.

4.3 A decision by the Authority to revoke this Licence shall be appealable pursuant to Section 33 of the EA.

PART II - CONDITIONS

5 FEES AND PENALTIES

5.1 The Licensee shall pay to the Authority such Government Authorisation Fees as may be prescribed pursuant to Sections 25, 26, and 66(3) of the EA; Section 52 of the RAA; and the Government Fees Act 1965.

5.2 The Licensee shall pay to the Authority such Regulatory Authority Fees as may be prescribed pursuant to Section 44 of the RAA.

5.3 The Licensee shall pay to the Authority any penalties that may be imposed on the Licensee by the Authority in accordance with Section 26(1)(a) of EA and Section 94 of the RAA or otherwise.

5.4 The Licensee shall be liable in accordance with Section 57 of the EA for failure to pay the fees set out in paragraphs 5.1 and 5.2 of this Condition 5.

5.5 The Licensee shall be liable in accordance with Section 60 of the EA for failure to comply with this Licence.

6 COMPLIANCE

6.1 The Licensee shall comply with:

(a) the Conditions of this Licence, including any Schedules and Annexures to this Licence;

(b) the terms of any associated licences, authorisations and permits issued to the Licensee;

(c) any regulations issued by the Minister in accordance with Section 54 of the EA;

(d) any Ministerial directions issued by the Minister pursuant to the EA;

(e) any Administrative Determinations, Adjudicative Decisions and Orders made by the Authority pursuant to the EA and the RAA;

(f) the EA;

(g) the RAA; and

(h) any other applicable Law, enactment, determination, regulation or order in effect in Bermuda to which the Licensee is subject.

6.2 Where there is an irreconcilable conflict between any applicable Laws, regulation, determination or order, the following order of precedence shall apply: Acts of Parliament, Regulations and Orders made by the Minister, international agreements that apply to Bermuda, General or other Administrative Determinations made by the Authority, and this Licence.

7 INFORMATION, AUDITS AND INSPECTION

7.1 The Licensee shall, in accordance with Section 26(1)(f) of the EA, the provisions of Part 8 of the RAA and any General Determination by the Authority, furnish to the Authority, in such manner and at such reasonable times as the Authority may reasonably require, such Information relating to the electricity sector including any Information reasonably required by the Authority in order for it to comply with its obligations under Section 52 of the EA.

7.2 Subject to the provisions of Part 8 of the RAA and any applicable General Determination by the Authority, the Licensee shall permit the Authority or persons designated by the Authority, to examine, investigate or audit, or procure such assistance as the Authority may reasonably require to conduct an examination, investigation or audit of, any aspect of the Licensee's TD&R Business.

7.3 Subject to the provisions of Section 92 of the RAA and any applicable General Determination by the Authority, the Licensee shall permit the Authority or persons designated by the Authority to enter the Licensee's premises, and shall facilitate reasonable access by the Authority or such persons to the premises used by the Licensee, to conduct an inspection, examination, investigation or audit of the Licensee.

7.4 The Licensee shall notify the Authority as soon as possible upon becoming aware that it is in a position in which it may potentially breach any Condition set out in this Licence.

7.5 The Licensee shall place a complete copy of this Licence on the Licensee's website or, if no such website exists, in a conspicuous place in the Licensee's principal place of business such that it is readily available for inspection free of charge by members of the general public during normal office hours.

8 MODIFICATION OF THE LICENCE

8.1 This Licence may be modified:

(a) by the Authority of its own motion pursuant to Section 29 of the EA and Section 51 of the RAA;

(b) with the mutual consent of the Licensee and the Authority pursuant to Section 29 of the EA and Section 51 of the RAA;

(c) by the Authority following an enforcement proceeding, pursuant to the provisions of Section 93 of the RAA; or

(d) by the Authority following any change of Control of the Licensee's TD&R Business pursuant to the operation of Sections 30(3), 21 and 22 of the EA.

9 ENFORCEMENT, SUSPENSION AND REVOCATION

9.1 The Authority may initiate enforcement proceedings pursuant to Section 53 of the EA and Section 93 of the RAA.

9.2 The Authority may revoke this Licence:

(a) in accordance with the provisions of Section 31 of the EA and Section 51 of the RAA; and

(b) in the event of any Insolvency Event affecting the Licensee.

9.3 The Authority shall be entitled to suspend this Licence in accordance with Sections 31 and 53 of the EA and Section 51 of the RAA. The Authority may, in its sole discretion, lift an on-going suspension and re-instate the Licence.

9.4 The Licensee shall not in any circumstance raise as a defence to enforcement or any other regulatory action by the Authority that it was compelled by the direction of its Controlling Interest Holder to act in breach of this Licence.

9.5 In the event of any revocation of this Licence in accordance with Condition 9 of this Licence and/or any surrender of this Licence by the Licensee pursuant to Condition 10 of this Licence, the Licensee shall without delay provide all reasonable assistance and take all reasonable steps to co-operate fully with any new provider of transmission, distribution and retail electricity services in Bermuda to ensure continuity of supply to the public so that there is the minimum of disruption and so as to prevent or mitigate any inconvenience or risk to the health or safety of End-Users, Sectoral Providers, Sectoral Participants and all members of the public.

10 DISCONTINUANCE OF SERVICE, SURRENDER OF LICENCE

Unless the Authority agrees otherwise, the Licensee shall not be entitled to surrender this Licence.

11 ACCOUNTING REQUIREMENTS

11.1 The purpose of this Condition is to ensure that the Licensee (and any Affiliate or related undertaking of the Licensee including the Controlling Interest Holder) maintains accounting and reporting arrangements which enable separate accounts to be prepared for each Separate Business and which show the financial affairs of each such Separate Business.

11.2 The Licensee shall in respect of each of its Generation Business and TD&R Business maintain appropriate management accounts and/or operating accounts that will enable the Authority to assess the Licensee's financial standing, performance and transparency across its business units.

11.3 Annually, the Licensee shall in respect of each of its Generation Business and TD&R Business, prepare from such accounting records:

(a) accounting statements comprising a profit and loss and other comprehensive income statement, a statement of financial position, together with notes thereto to the extent required by General Determination, and showing separately in respect of each of the Generation Business and the TD&R Business details of the amounts of any revenue, cost, asset, liability, reserve or provision, which has been either:

(i) received by each of the Generation Business and TD&R Business from any other business (whether or not a Separate Business and including from the Controlling Interest Holder) together with a description of the basis of such revenue, cost or liability received; or

(ii) charged from each of the Generation Business and TD&R Business to any other business (whether or not a Separate Business and including to the Controlling Interest Holder) together with a description of the basis of that charge; or

(iii) determined by apportionment or allocation between each of the Generation Business and the TD&R Business and any other business (whether or not a Separate Business and including the Controlling Interest Holder) together with a description of the basis of the apportionment or allocation; and

(b) each financial year, sufficient accounting information in respect of each of the Licensee's Generation Business and TD&R Business to allow for reconciliation against the licensee's consolidated financial statements.

11.4 The Licensee shall procure, in respect of the accounting statements prepared in accordance with this Condition, a report by the Auditors addressed to the Authority stating whether in their opinion those statements have been properly prepared in accordance with this Condition and give a true and fair view of the revenues, costs, assets, liabilities, reserves and provisions of, or reasonably attributable to, the Separate Business to which the statements relate.

11.5 The Licensee shall deliver to the Authority a copy of the Auditors' report referred to in paragraph 11.4 and the accounting statements referred to in paragraph 11.3(a) as soon as reasonably practicable.

11.6 The Licensee shall not in relation to the accounting statements in respect of a financial year change the bases of charge, apportionment or allocation referred to in paragraph 11.3(a) from those applied in respect of the previous financial year, unless the Authority has previously issued instructions for the purposes of this Condition instructing the Licensee to change such bases in a manner set out in the instructions or the Authority gives its prior written approval to the change in such bases. The Licensee shall comply with any instructions issued for the purposes of this Condition. If the Licensee changes the bases of charge, apportionment or allocation from those adopted for the immediately preceding financial year, it shall show a reconciliation of the revised and prior-year methodologies.

11.7 Accounting statements in respect of a financial year prepared under paragraph 11.3(a) shall, so far as reasonably practicable, and unless otherwise approved by the Authority having regard to the purposes of this Condition:

(a) reflect the revenues, costs, assets and liabilities of each of the Generation Business and the TD&R Business and be recorded in a manner consistent with the accounting principles applied by BELCO for its financial statements prepared in accordance with generally accepted accounting principles. The Authority may, on application from the Licensee, or in consultation with the Licensee, modify those accounting principles, subject to such conditions as may be specified by General Determination; and

(b) be submitted to the Authority with BELCO’s consolidated financial statements.

11.8 References in this Condition to costs or liabilities of, or reasonably attributable to, any Separate Business shall be construed as excluding taxation, capital liabilities which do not relate principally to a particular Separate Business and interest thereon; and references to any accounting statement shall be construed accordingly.

11.9 Without prejudice to any other paragraph of this Condition, and subject to the Authority giving reasonable notice to the Licensee, the Licensee shall, on request by the Authority, give to the Authority with a reasonable time of such request by the Authority access to the Licensee's accounting records, policies and statements referred to in this Condition.

12 AVAILABILITY OF RESOURCES

12.1 The Licensee shall at all times act in a manner calculated to secure that it has sufficient management resources and financial resources and financial facilities to enable it to:

(a) carry on its TD&R Business; and

(b) comply with its obligations under this Licence and the EA.

12.2 The Licensee shall submit a certificate addressed to the Authority, approved by a resolution of the Board of Directors of the Licensee and signed by a director of the Licensee pursuant to that resolution. Such certificate shall be submitted on 30 April each year and shall be in one of the following forms:

(a) "After making enquiries, the directors of the Licensee have a reasonable expectation that the Licensee will have available to it, after taking into account in particular (but without limitation) any dividend or other distribution which might reasonably be expected to be declared or paid, sufficient financial resources and financial facilities to enable the Licensee to carry on the Separate Businesses for a period of 12 months from the date of this certificate.";

(b) "After making enquiries, the directors of the Licensee have a reasonable expectation, subject to the terms of this certificate, that the Licensee will have available to it, after taking into account in particular (but without limitation) any dividend or other distribution which might reasonably be expected to be declared or paid, sufficient financial resources and financial facilities to enable the Licensee to carry on the TD&R Business for a period of 12 months from the date of this certificate. However, the directors would like to draw attention to the following factors which may cast doubt on the ability of the Licensee to carry on the TD&R Business."; or

(c) "In the opinion of the directors of the Licensee, the Licensee will not have available to it sufficient financial resources and financial facilities to enable the Licensee to carry on the TD&R Business for a period of 12 months from the date of this certificate."

12.3 The Licensee shall submit to the Authority together with the certificate referred to in paragraph 12.2 of this Condition a statement of the main factors which the directors of the Licensee have taken into account in giving that certificate.

12.4 The Licensee shall inform the Authority in writing immediately if the directors of the Licensee become aware of any circumstances which cause them no longer to have the reasonable expectation expressed in the most recent certificate given under paragraph 12.2.

13 PROHIBITION OF CROSS-SUBSIDIES

13.1 The Licensee shall procure that no Separate Businesses of the Licensee:

(a) gives any direct or indirect cross-subsidy to the Licensee; and

(b) receives any direct or indirect cross-subsidy from the Licensee.

13.2 The Licensee shall procure that it shall not give any cross-subsidy to or receive any cross subsidy from the Controlling Interest Holder.

14 SERVICE STANDARDS & PERFORMANCE STANDARDS

14.1 The Licensee shall comply with any applicable service standards including standards relating to power reliability, power quality and customer service standards set out in any General Determinations made pursuant to Section 34 of the EA.

14.2 The Licensee shall report to the Authority in accordance with the provisions of any General Determination.

14.3 The Licensee shall operate the Grid System in accordance with the provisions of Section 20(3) of the EA and applicable standards as set forth in the Grid Code, relevant codes of practice and General Determinations.

14.4 If the Licensee fails to meet its required service standards as set forth in this Licence, the Grid Code, codes of practice or General Determinations, the Licensee shall forthwith discuss with the Authority the reasons for any non-compliance and the steps that the Licensee intends to take in order to remedy such non-compliance.

14.5 The Authority shall give the Licensee reasonable time to implement the remedial measures notified by the Licensee to the Authority pursuant to paragraph 14.4 of this Condition 14.

14.6 The Authority shall review the service standards referred to in this Condition 14 which the Licensee is required to comply with when conducting any tariff review pursuant to Section 37 of the EA.

15 DISPOSAL OF RELEVANT ASSETS

15.1 Subject to Condition 15.4, the Licensee shall obtain the prior written consent of the Authority in order to Dispose of any Relevant Asset and/or to create security over any Relevant Asset and/or to relinquish control over any Relevant Asset, such consent shall not be unreasonably withheld. References to control throughout Condition 15 shall carry their plain meaning.

15.2 Subject to the provisions of any applicable General Determination, the Licensee shall give to the Authority not less than 2 months' prior written notice of its intention to create any security or effect a Disposal of or relinquish control over any Relevant Asset, together with such reasonable further information as the Authority may request relating to such asset or the circumstances of such intended Disposal or relinquishment of control or to the intentions.

15.3 Notwithstanding paragraphs 15.1 and 15.2, the Licensee may effect a Disposal of or relinquish operational control over any Relevant Asset where:

(a) the Authority has issued instructions for the purposes of this Condition containing a general consent (whether or not subject to conditions) to:

(i) transactions of a specified description; and/or

(ii) the Disposal of or relinquishment of operational control over Relevant Asset(s) of a specified description; and

(b) the Disposal or relinquishment of operational control in question is effected pursuant to a transaction of a description specified in the instructions or the Relevant Asset in question is of a description so specified and the Disposal or relinquishment of operational control is in accordance with any conditions to which the consent is subject.

15.4 Notwithstanding paragraph 15.1, the Licensee may Dispose of or relinquish operational control over any Relevant Asset specified in any notice given under paragraph 15.2 in circumstances where:

(a) the Authority confirms in writing that it consents to such Disposal or relinquishment (which consent may be made subject to the acceptance by the Licensee or any third party in favour of whom the Relevant Asset is proposed to be Disposed or operational control is proposed to be relinquished of such conditions as the Authority may specify); or

(b) the Authority does not inform the Licensee in writing of any objection to such Disposal or relinquishment of control within the notice period referred to in paragraph 15.1 (subject to the provisions of any General Determination).

16 RESTRICTION ON USE OF CERTAIN INFORMATION

16.1 The Licensee shall procure that the Licensee shall not obtain any unfair competitive advantage from the Licensee's possession of Protected Information.

16.2 The Licensee shall implement such measures and procedures and take all such other steps as required by Law and any General Determination in accordance with Section 39 of the EA.

16.3 The Licensee shall:

(a) procure and furnish to the Authority, in such manner and at such times as the Authority may require, such Information as the Authority may consider necessary concerning the performance by the Licensee of its obligations under paragraphs 16.1 and 16.2; and

(b) procure that access to any premises of the Licensee shall be given at any time and from time to time to any nominated person(s) for the purpose of investigating

whether the Licensee has performed its obligations under paragraphs 16.1 and 16.2.

16.4 This Condition is without prejudice to the duties at Law of the Licensee towards outside persons.

16.5 Where the Licensee receives Protected Information in its capacity as the Licensee it shall take all reasonable precautions against the risk of failure to restrict the use of that information to the sole purpose it was originally provided.

17 NATIONAL DISASTER CONTINGENCY FUND

The Licensee shall, from the revenues paid to it pursuant to Condition 26 of this Licence set up a Natural Disaster Contingency Fund in an amount to be determined by the Authority and which must be available at any time during the term of this Licence such fund to be provided for as part of the design of the tariff methodology set by General Determination pursuant to Section 35(1) of the EA.

18 BASIS OF CHARGES FOR CONNECTION TO GRID SYSTEM

Preparation of statements on basis of charging for connection to Licensee's Grid System

18.1 The Licensee shall within six months from the Commencement Date prepare a statement, subject to approval by the Authority, setting out the basis upon which charges will be made for connection to the Licensee's Grid System. Such statement shall be in such form and will contain such detail as shall be necessary to enable any person to make a reasonable estimate of the charges, to which it would become liable, for connection to the Licensee's Grid System and shall include the information set out in Condition 18.2 below.

18.2 Except to the extent that the Authority shall otherwise specify, the statement referred to in paragraph 18.1 shall include:

(a) a schedule listing those items (including the carrying out of works and the provision and installation of electric lines or electrical plant or meters) of significant cost liable to be required for the purpose of connection (at entry or exit points) to the Licensee's Grid System for which connection charges may be made or levied and including (where practicable) indicative charges for each such item and (in other cases) an explanation of the methods by which and the principles on which such charges will be calculated;

(b) the methods by which and the principles on which any charges will be made in respect of extension or reinforcement of the Licensee's Grid System rendered necessary or appropriate by virtue of providing connection to any person seeking connection;

(c) the methods by which and the principles on which connection charges will be made in circumstances where the electric lines or electrical plant to be installed

are of greater size or capacity than that required by the person seeking connection;

(d) the methods by which and the principles on which any charges (including any capitalised charge) will be made for maintenance and repair required of electric lines, electrical plant or meters provided and installed for making a connection to the Licensee's Grid System;

(e) the methods by which and the principles on which any charges will be made for the provision of special metering or telemetry or data processing equipment by the Licensee for the purposes of enabling any person which is bound to comply with the Grid Code to comply with its obligations in respect of metering thereunder, or for the performance by the Licensee of any service in relation thereto;

(f) the methods by which and principles on which any charges will be made for disconnection from the Licensee's Grid System and the removal of electrical plant, electric lines and ancillary meters following disconnection; and

(g) such other matters as shall be specified in instructions issued by the Authority from time to time for the purposes of this Condition.

18.3 Connection charges for those items referred to in paragraph 18.2 shall be set at a level which will enable the Licensee to recover:

(a) the appropriate proportion of the costs directly or indirectly incurred in carrying out any works, the extension or reinforcement of the Licensee's system and the provision and installation, maintenance and repair and, following disconnection, removal of any electric lines, electrical plant, meters, special metering, telemetry, data processing equipment or other items; and

(b) a reasonable rate of return on the capital represented by such costs.

19 NON-DISCRIMINATION REGARDING CONNECTION TO THE GRID SYSTEM

In the carrying out of works for the purpose of connection to the Grid System, the Licensee shall not unduly discriminate, as between:

(a) any persons or class or classes of persons; or

(b) the Licensee (in the provision of connections by the Licensee as part of the TD&R Business) and any person or any class or classes of persons; or

(c) the Licensee's TD&R Business and the Licensee's Generation Business,

except insofar as any difference in the amounts charged, or any other terms or conditions of such provision or carrying out of works, reflects to the satisfaction of the Authority, the difference between the costs of such provision to one person or class of

persons or other circumstances of carrying out such connection to one person or class of persons.

20 REQUIREMENT TO OFFER TERMS

Offer of terms for Connection

20.1 The Licensee shall, within twelve months from the grant of this Licence, prepare and submit its Grid Connection Policy in accordance with the requirements of this Condition to the Authority for approval by the Authority. Upon approval by the Authority of such Grid Connection Policy, the Licensee shall implement and comply with such policy.

20.2 The Grid Connection policy to be submitted by the Licensee pursuant to paragraph 20.1 shall:

(a) include conditions in accordance with Section 47(3)(a) of the EA;

(b) take account of Section 47(3)(b) and (c) of the EA;

(c) comply with the Grid Code;

(d) comply with any code of practice issued by the Authority;

(e) set out in detail the terms on which access to the Grid System will be provided to Distributed Generators;

(f) set out in detail the basis on which the Licensee shall offer to enter into agreements for connection to its Grid System with any person requesting connection; and

(g) set out (in detail) the information to be provided by the Licensee by those persons seeking connection.

20.3 For the purpose of determining an appropriate proportion of the costs directly or indirectly incurred in carrying out works under an agreement for making a connection or modification to an existing connection in accordance with Condition 18.3 of this Licence, the Licensee shall have regard to:

(a) the benefit (if any) to be obtained or likely in the future to be obtained by the Licensee or any other person as a result of the carrying out of such works (or of such other matters) whether by reason of the reinforcement or extension of the Licensee's Grid System or the provision of additional entry or exit points on such system or otherwise; and

(b) the ability or likely future ability of the Licensee to recoup a proportion of such costs from third parties.

20.4 The Licensee shall not be obliged pursuant to this Condition to offer to enter or to enter into any connection agreement if to do so would involve the Licensee breaching Condition 6.1 of this Licence.

21 FUNCTIONS OF THE AUTHORITY

21.1 If, after a period which appears to the Authority to be reasonable for the purpose, the Licensee has failed to enter into an agreement with any person entitled or claiming to be entitled thereto pursuant to a request for connection to the Licensee's Grid System, the Authority may, on the application of that person or the Licensee, and in accordance with the provisions of Sections 57 and 58 of the RAA, settle any terms of the agreement in dispute between the Licensee and that person in such manner as appears to the Authority to be reasonable having (insofar as relevant) regard in particular that such person should pay to the Licensee, the whole or an appropriate proportion (as determined in accordance with Conditions 18.3 and 20.3).

21.2 If either party to an agreement for connection to the Licensee's Grid System proposes to vary the contractual terms of such agreement in any manner provided for under such agreement, the Authority may, at the request of the Licensee or other party to such agreement, settle any dispute relating to such variation in accordance with the provisions of Sections 57 and 58 of the RAA.

22 GRID CODE

22.1 The Licensee shall within twelve months of the grant of this Licence, in consultation with Sectoral Participants and Sectoral Providers liable to be materially affected thereby, prepare and submit to the Authority for its approval a Grid Code.

22.2 Upon approval by the Authority of the Grid Code, the Licensee shall implement and comply with such Grid Code.

22.3 The Grid Code shall:

(a) cover all material technical aspects relating to connections to and the operation and use of the Grid System or (insofar as relevant to the operation and use of the Grid System) the operation of electric lines and electrical plant connected to the Grid System;

(b) contain rules and procedures governing generation dispatch and maintenance scheduling, taking into consideration various operating considerations, including but not limited to least cost, planned generator maintenance, operating reserves (both on-peak and off-peak) and subject to the terms and conditions of executed Power Purchase Agreements; and

(c) contain rules and procedures that provide for the safe and reliable operation of the Grid System including the conditions under which the Licensee shall operate the Grid System and under which Bulk Generation Licensees shall operate their licensed generating plant under both normal and abnormal operating conditions; and

(d) be designed so as:

(i) in relation to the Licensee's Grid System:

(A) to ensure that all Bermuda residents are provided with access to a supply of electricity pursuant to Section 20(3) of the EA;

(B) to give effect to the purposes of the EA as set out in Section 6 of the EA; and

(C) comply with any Administrative Determination by the Authority pursuant to Section 14 of the EA.

22.4 Within two years from the grant of this Licence and thereafter, every five years or less as determined by the Authority, (including upon the request of the Authority), the Licensee shall (in consultation with Sectoral Participants and Sectoral Providers liable to be materially affected thereby) periodically review the Grid Code and its implementation. Following any such review, the Licensee shall send to the Authority:

(a) a report on the outcome of such review;

(a) any proposed revisions to the Grid Code from time to time as the Licensee (having regard to the outcome of such review) reasonably thinks fit for the achievement of the objectives referred to in paragraph 22.3(d); and

(b) any Representations from any Sectoral Participants and Sectoral Providers (including any proposals by such persons for revisions to the Grid Code not accepted by the Licensee in the course of the review) arising during the consultation process and subsequently maintained.

22.5 Revisions to the Grid Code proposed by the Licensee and sent to the Authority pursuant to paragraph 22.4 shall require to be approved by the Authority. Any revisions to the Grid Code proposed by the Licensee shall be filed by the Licensee with the Authority and the Authority shall respond within 90 days of the date of filing by the Licensee.

22.6 Having regard to any Representations referred to in paragraph 22.4(c), and following such further consultation (if any) as the Authority may consider appropriate, the Authority may issue instructions requiring the Licensee to revise the Grid Code in such manner as may be specified in the instructions, and the Licensee shall forthwith comply with any such instructions.

22.7 The Authority shall be entitled, in order to implement the requisite arrangements referred to in Condition 22.3(d) to issue instructions to the Licensee requiring the Licensee to revise the Grid Code in such manner and with effect from such date as may be specified in the instructions, and the Licensee shall comply with any such instructions.

22.8 The Licensee shall give or send a copy of the Grid Code to the Authority and the Minister.

22.9 The Licensee shall give or send a copy of the Grid Code to any person requesting the same and shall be entitled to charge such persons a price not exceeding the reasonable cost of duplicating the Grid Code.

22.10 The Licensee shall publish a redacted version of the Grid Code on its website in order to provide sufficient information so as to allow Distributed Generators to connect to the Grid System.

22.11 In preparing, implementing and complying with the Grid Code (including in respect of the scheduling of maintenance of the Grid System and any generation set or associated power station equipment or combination of generation sets or associated power station equipment) the Licensee shall not :

(b) unduly discriminate against or in favour of any person or class or classes of persons;

(a) unduly prefer the Licensee in the conduct of its Generation Business; or

(b) restrict or prevent competition in generation.

22.12 The Licensee shall keep and maintain such records concerning its implementation of and compliance with the Grid Code as are in accordance with such guidelines as the Authority shall from time to time have given to the Licensee and are, in the opinion of the Authority, sufficient to enable the Authority to assess whether the Licensee is complying with its obligations under this Condition.

22.13 The Authority may from time to time (following consultation with the Licensee and Sectoral Participants and Sectoral Providers) issue instructions relieving the Licensee of its obligations to implement or comply with, or to enforce against any other person any provision of, the Grid Code in respect of such parts of the Licensee's Grid System to such extent as may be specified in the instructions.

23 OBLIGATIONS REGARDING INTEGRATED RESOURCE PLAN AND PROCUREMENT OF NEW GENERATION

23.1 The Licensee shall comply with Sections 40 to 45 of the EA as regards the Integrated Resource Plan proposal and the Integrated Resource Plan.

23.2 The Authority shall be entitled to require the Licensee to clarify any matters set out in the Integrated Resource Plan proposal submitted by the Licensee to the Authority pursuant to Section 41 of the EA and the Licensee shall provide any such Information to the Authority within a reasonable timescale having regard to the complexity of the request.

23.3 The Licensee shall abide by the procurement process set by administrative determination.

24 OBLIGATION TO ENTER INTO POWER PURCHASE AGREEMENTS

24.1 The Licensee shall enter into:

(a) an Authority approved Power Purchase Agreement with a Bulk Generation Licensee for which the payments shall be passed through to End-Users pursuant to the Retail Tariff set in accordance with Section 35 of the EA; and

(b) power purchase arrangements with its Generation Business.

24.2 The Licensee shall ensure that the terms of any power purchase arrangements that will apply between its Generation Business and its TD&R Business are substantially similar to the terms of its Power Purchase Agreements that will be applied with other Bulk Generation Licensees.

25 OBLIGATION TO ENTER INTO STANDARD CONTRACTS WITH DISTRIBUTED GENERATORS

25.1 The Licensee shall enter into a Standard Contract with a Distributed Generator in accordance with Sections 49 and 50 of the EA. Any Standard Contract shall comply with the Standard Contract template set by Administrative Determination by the Authority pursuant to Section 49 of the EA.

26 RETAIL TARIFF & RESTRICTION ON LICENSEE'S REVENUE

26.1 The Licensee shall sell electricity to its End-Users at the Retail Tariff.

26.2 The Retail Tariff methodology shall include the establishment of a Natural Disaster Contingency Fund.

26.3 The Licensee shall be entitled to pass through the charges set out in Section 35(3) of the EA (**"the Pass-through Charges"**).

26.4 These Pass-through Charges will be shown as separate items on consumer bills (as permitted in accordance with the EA and the RAA).

26.5 If the Licensee persistently fails to comply with the service standards required pursuant to this Licence and/or fails to procure required additional generation capacity in accordance with the Integrated Resource Plan and Condition 23 of this Licence, the Authority shall be entitled to take those actions set out in the General Determination made by the Authority for the purposes of this provision. The Authority shall conduct a review of the Retail Tariff in accordance with the provisions of Section 37 of the EA.

27 FEED-IN TARIFF

27.1 The Licensee shall pay Distributed Generators the Feed-In Tariff set by the Authority in accordance with a methodology determined by the Authority pursuant to a General Determination.

27.2 The methodology referred to in Condition 27.1 shall be determined in accordance with those principles set out in Section 36 of the EA.

27.3 The Authority shall conduct a review of the Feed-In Tariff in accordance with the provisions of Section 37 of the EA.

28 CENTRAL DISPATCH AND MERIT ORDER

28.1 Central Dispatch

The Licensee shall schedule and issue direct instructions for the dispatch of all available Generation Units of each Bulk Generation Licensee in accordance with the Grid Code.

28.2 Merit Order

The Licensee shall establish as part of the Grid Code, and shall operate, a Merit Order system for Generation Units in Bermuda subject to Central Dispatch. The Licensee's Merit Order system shall comply with the requirements of Section 20(3) of the EA.

28.3 The Licensee shall provide to the Authority such information as the Authority shall request concerning the Licensee's Dispatch Instructions, and/or Scheduling System and/or Merit Order system or any aspect of its operation.

28.4 For the purposes of this Condition, the reference to optimal in Section 20(3) of the EA, in the absence of any contrary provision set out in any Administrative Determination made by the Authority shall be construed as lowest cost.

29 DUTY TO OFFER AND SUPPLY UNDER SERVICE AGREEMENTS

29.1 When the Licensee supplies electricity to its End-Users, it must do so under a Service Agreement.

29.2 A Service Agreement must include terms and conditions that are appropriate for a business that is providing transmission, distribution and retail services to an international standard with appropriate service levels and including metering obligations by the Licensee.

29.3 Within two months from the Commencement Date, the Licensee shall submit to the Authority for approval the form of Service Agreement used by the Licensee.

30 END-USER BILLS

30.1 In furtherance of the Authority’s functions pursuant to Section 14(2) (c) (ii) and pursuant to Section 26 (1) (d) of the EA within 6 months from the grant of this Licence, the Licensee shall submit to the Authority for approval the form of End-User bill that is proposing to send to End-Users.

30.2 The Licensee shall comply with any Administrative Determination made by the Authority pursuant to Section 14(2) (c) (ii) in relation to the form and content of End-User bills.

31 CODES OF PRACTICE

The Licensee shall comply with any codes of practice issued by the Authority pursuant to any General Determination made by the Authority under Section 38 of the EA in relation to the commercial and marketing practices of the Licensee to protect the rights of End-Users.

32 ASSIGNMENT, OUTSOURCING AND MORTGAGES

32.1 This Licence shall not be transferred or assigned without the prior consent of the Authority and Section 30 of the EA shall apply accordingly.

32.2 The Licensee may utilize the services of third parties on an ongoing basis in the provision of TD&R services (i.e., the Licensee may "outsource" certain of its TD&R functions), without relieving the Licensee of its obligations under the Licence. The procurement of such outsourced services shall be subject to the Authority's approval. Any such approval shall be based on the cost-effectiveness of the outsourced services, how it was procured and with whom, and the fitness and propriety of the relevant third parties and shall not be unreasonably withheld.

32.3 The Licensee shall not sub-licence, assign or grant any right, interest or entitlement in the Licence nor transfer the Licence to any other person including an Affiliate of the Licensee without the written authorisation of the Authority.

32.4 The Licensee shall be liable in accordance with Section 56 of the EA if it contravenes this Condition.

33 CHANGE OF CONTROL

33.1 The Licensee shall not complete any proposed change in control of the Licensee without first obtaining the prior written authorisation of the Authority in accordance with Section 30 of the EA and Section 87 of the RAA, which consent shall not be unreasonably withheld. For the purposes of this Condition 33.1, control shall mean as defined in Section 30 of the EA.

33.2 The Licensee shall be liable in accordance with Section 56 of the EA if it contravenes this Condition.

34 INDEMNIFICATION

The Licensee shall indemnify the Authority against all actions, claims and demands which may be brought or made by any person in respect of any injury or death of any person or damage to any property arising from any act of the Licensee permitted or authorized by the Licence. The Authority shall provide the Licensee with notice of any such actions, claims and demands, but the Authority's failure to do so shall not relieve the Licensee of any obligations imposed on the Licensee by this Condition.

35 FORCE MAJEURE; OTHER EVENTS

35.1 If the Licensee is prevented from complying with the Licence by acts of God, war, warlike operations, civil commotion, major strikes or any other significant or protracted industrial action, fire, tempest or any other causes beyond the Licensee's reasonable control;

(a) the Licensee shall notify the Authority, as promptly as reasonably practicable, of the obligations of the Licence with which the Licensee cannot comply, the expected duration of the event of force majeure, and the measures the Licensee is taking to overcome the consequences of the event of force majeure; and

(b) the Authority shall suspend such obligations of the License as the Authority concludes the Licensee cannot comply with for as long as the event of force majeure continues.

35.2 In addition to events of force majeure, the Licensee shall notify the Authority of any fact or event likely to affect materially the Licensee's ability to comply with any Condition of this Licence, or an insolvency-related fact or Insolvency Event in respect of the Licensee or any Affiliate, or any preparatory steps being taken that might lead to an Insolvency Event, immediately upon becoming aware of such fact or event.

36 NO ABUSE OF DOMINANT POSITION

36.1 The Licensee occupies a dominant position in accordance with the RAA and Section 51 of the EA.

36.2 If the Licensee abuses its dominant position the Authority shall, pursuant to Section 26(1) (e) of the EA be entitled to require the Licensee to comply with any remedy imposed by the Authority and the Authority shall also be entitled to take those actions set out in Section 85(7) of the RAA.

37 NOTICES

Unless the Authority determines otherwise, notices to the Licensee under the Licence shall be in writing and sent by electronic mail to the Chief Executive Officer of the Licensee at the address communicated to the Authority from time to time.

Unless the Authority determines otherwise, notices from the Licensee to the Authority under the Licence shall be in writing and sent by electronic mail to the Chief Executive of the Authority to electricity@RAB.bm.

38 INSURANCE REQUIREMENTS

38.1 The Licensee shall:

(a) at its own cost and expense take out and maintain in full force and effect with reputable insurance companies such policies of insurance, as it, acting in accordance with Prudent Operating Practice, considers appropriate so as to effect cover against the categories of risk set out below:

(i) fixed assets (buildings and their contents, machinery, stock, fixtures, fittings and all other personal property forming part of the Transmission System and Distribution System including substations but not including cabling, lines and poles) against risks of physical loss or damage for their full replacement value;

(ii) machinery breakdown; and

(iii) public liability.

(b) on request, provide the Authority with copies of all policies effected by it, the amount of any premiums payable under such policies and evidence that the premiums payable thereunder have been paid;

(c) provide access to the Authority or its representatives to the Licensee's offices to inspect the original policies; and

(d) apply the proceeds of claims against such policies relating to damage to the Transmission System and Distribution System.

ANNEX

TRANSITIONAL CONDITIONS

The Licensee shall comply with each of the Transitional Conditions set forth below until such time as the Authority makes an Administrative Determination in respect of the subject matter of each such Transitional Condition, or as otherwise provided for in such Transitional Condition.

A1 ACCOUNTING SEPARATION REQUIREMENTS AND PROHIBITION OF CROSS-SUBSIDIES

A1.1 Notwithstanding the provisions of Condition 11 and Condition 13, the Licensee shall not be obliged to comply with the provisions of Conditions 11 and 13 until such time as:

(i) the Authority, in consultation with Licensee, determines the methodologies, mechanisms and other actions to be taken to enable the Licensee to comply with Conditions 11 and 13;

(ii) any such methodologies, mechanisms and other actions are approved by the Authority by General Determination; and

(iii) the Authority determines a practical timeframe for the implementation of the methodologies, mechanisms and other actions that will enable the Licensee to comply with Conditions 11 and 13.

A2. SERVICE STANDARDS

A2.1 Notwithstanding the provisions of Condition 14, the service and performance standards in force immediately before the Commencement Date shall continue to apply after the Commencement Date until such time as the Authority makes a General Determination pursuant to Section 34 of the EA.

A4 GRID CONNECTION POLICY

A4.1 During the period from the Commencement Date until such time as the Authority approves the Grid Connection Policy pursuant to paragraph 20.1 of Condition 20, the Licensee shall adhere to those existing policies and standards which the Licensee maintained immediately prior to the Commencement Date. Within 30 days from the Commencement Date, the Licensee shall submit those existing standards and policies to the Authority.

A5 GRID CODE

A5.1 During the period from the Commencement Date until such time as the Authority approves the Grid Code pursuant to paragraph 22.1 of Condition 22, the Licensee shall adhere to those existing policies and standards which the Licensee maintained

immediately prior to the Commencement Date. Within 30 days from the Commencement Date, the Licensee shall submit such existing standards and policies to the Authority.

A6. DEFINITION OF RELEVANT ASSET

During the period from the Commencement Date until such time as the Authority makes an Administrative Determination in relation to what shall constitute a Relevant Asset for the purposes of this Licence, a Relevant Asset shall be any asset which either (i) has a value in excess of USD 50,000 or (ii) any asset which has a value less than USD 50,000 but which is required for the Licensee to continue to meet any service standard at the same level that existed prior to any intended disposal of such asset.

A7. INTEGRATED RESOURCE PLAN

Notwithstanding the provisions of this Licence or the EA requiring adherence to the Integrated Resource Plan, the Licensee shall not be obliged to comply with such provisions until such time as the Authority approves the Integrated Resource Plan pursuant to Section 44 of the EA.

A8. TARIFF

During the period from the Commencement Date until such time as the Authority makes the General Determination pursuant to Section 35 of the EA, any price, charge or methodology approved by the Energy Commission in accordance with the Energy Act 2009 shall continue in effect subject to any modification the Authority may consider to be necessary.

REGULATORY AUTHORITY
OF BERMUDA

2 October 2020

BY EMAIL

BELCO
27 Serpentine Rd
Pembroke HM 07 Bermuda

Attention: Dennis Pimentel, President

Dear Mr. Pimentel,

Re: Change in Control of BELCO

I refer to the notice of a concentration review dated 4 October 2019, the revised application on 31 January 2020 relating to the above-captioned matter, my letter of 27 August 2020 and your response of 30 August 2020.

The Regulatory Authority of Bermuda hereby (1) consents to the change in control of BELCO's ("Bermuda Electric Light Company") Transmission, Distribution and Retail ("TD&R") Licence and Bulk Generation Licence, in accordance with section 30(1) of the Electricity Act 2016, and (2) issues its written approval of the afore-mentioned concentration, in accordance with section 87(3) of the Regulatory Authority Act 2011.

Please find attached the RA's Order to that effect. Said consent and approval are subject to the conditions set out therein.

Sincerely,

Mark Fields
Chairman of the Board of Commissioners
Regulatory Authority of Bermuda

REGULATORY AUTHORITY OF BERMUDA

Order -
BELCO Change in Control Application

Date: 2 October 2020

1st Floor, Craig Appin House, 8 Wesley Street, Hamilton HM 11, Bermuda
T: (441) 405-6000 • E: info@ra.bm

1. Further to a notice of change in control made by Algonquin Power & Utilities Corp. ("Algonquin"), Bermuda Sustainability Holdings Ltd ("BSHL"), Bermuda Sustainability Midco Ltd ("Midco"), Bermuda Sustainability Acquisition Ltd ("BSAL"), Ascendant Group Limited ("Ascendant") and Bermuda Electric Light Company Limited ("BELCO") (the "Application"), the Regulatory Authority ("RA"), pursuant to Section 87 of the Regulatory Authority Act 2011 and Sections 26(1), 26(3), 29(1) and (2), 30 of the Electricity Act 2016, hereby:

    a. consents to the transfer of the Bulk Generation Licence (BG2017102701-02) held by BELCO and the Transmission, Distribution and Retail Licence (TDR2017102701-02) held by BELCO (the "TD&R Licence") (together, the "Transfer") by way of change in control from Ascendant to Algonquin (the "Change in Control"); and

    b. approves the proposed concentration represented by the Transfer and Change in Control.

2. The consent in paragraph a. and the approval in paragraph b. are subject to –

    a. the conditions set out in Annex A; and

    b. reasonable efforts by Algonquin, Ascendant[1] and BELCO to abide by, and fulfil, the commitments made in and concurrent with the Application set out in Annex B (the "Commitments").

So ordered this 2nd day of October

[1] Further references to "Ascendant" in this order refer to the amalgamated company following the amalgamation of Ascendant and Bermuda Sustainability Acquisition Ltd upon completion of the Change in Control.

Annex A
Conditions

1. Inter-company services will be rendered at market rates and will contribute to improving the operational efficiency of BELCO.

2. To maintain a Bermudian influence of the company, BELCO's head office will be located in Bermuda and its board of directors must comprise a majority of directors possessing Bermudian Status.

3. In selecting a service provider to provide services to BELCO, as the licensee, on an ongoing basis as part of its day-to-day business or in connection with its carrying on of its transmission, distribution and retail business, BELCO may enter into services agreements with affiliated companies (as defined under the Companies Act 1981 (the "Companies Act") (each an "Affiliate" and, together, the "Affiliates")), provided that any such services agreements shall be entered into—

    a. on a sufficiently independent basis, which is to say that BELCO and the counterparty shall settle such service agreements without coordination and without taking common direction from their respective boards of directors and/or officers;

    b. at rates that do not exceed the then prevailing market rates reasonably available for the provision of the same or similar services in the same or similar circumstances;

    c. in the reasonable belief that it will improve BELCO's operational efficiency;

    d. on the basis that the Affiliate abides by the same service standards as BELCO in the performance of any duties under the service agreement entered into, with the said agreement setting out the nature and scope of same.

4. BELCO shall demonstrate the extent to which the cost savings anticipated by the business plan provided as Revised Annex U of the Application and submitted with the letter sent to the RA dated 17 April 2020 have been achieved and shall provide any related evidence that the RA may request to substantiate its submission.

5. The Conditions contained within the TD&R Licence shall be modified as follows:

    a. In paragraph 1, delete the definition for "Net Benefit Test";

    b. Delete paragraph 23.3 and substitute the following—

        "The Licensee shall abide by the procurement process set by administrative determination."; and

    c. Delete paragraph 23.4.

6. BELCO shall maintain its membership in the Caribbean Electric Utility Services Corporation ("CARILEC").

7. The BELCO Legacy Liabilities shall not, in whole or part, be recovered from end users under any mechanism, and as a material commercial matter must be fully settled between Algonquin and Ascendant as part of the Change in Control transaction. BELCO Legacy Liabilities means those pension and post-retirement benefit costs totalling $100,738,739 that were not previously recorded in operating expenses as further detailed in Exhibit 3 WP-4 of BELCO's 2019 retail tariff application filed with the RA on 10 October 2019.

8. Algonquin, Ascendant and BELCO must commit to filling all positions within BELCO with qualified Bermudians, including those organization-wide positions that may be created pursuant to paragraph 14 of the Commitments. Where no qualified Bermudian is available, they must similarly commit to training Bermudians to fill these positions where a non-Bermudian might be employed.

9. BELCO shall provide to the RA within 6 months of the date on which this order is made, a human resources plan demonstrating how it proposes to meet commitments towards empowering Bermudians within its workforce.

10. Algonquin must, either directly or through its Affiliates, invest in areas relating to renewable energy regarding enabling infrastructure in Bermuda to ensure the reliability, public health, safety and security of supply, subject to a regulatory approval process (including, but not limited to, a competitive bid process and retail tariff review).

11. BELCO shall comply with all environmental laws, meaning those laws, in force from time to time, whose purpose is the protection of the environment, including the protection of human health, flora, fauna and the eco-systems on which they depend and, for the avoidance of doubt, shall include, all relevant Law relating to the assessment of environmental impact and the protection of air, land and water and shall include the Public Health Act 1949[2] and Clean Air Act 1991.

12. Algonquin, Ascendant and BELCO shall make all reasonable efforts to abide by, and fulfil, the Commitments, and the Commitments shall remain in force until such time as the relevant parties are relieved of the Commitments by the RA. Algonquin and Ascendant shall be deemed to be abiding by and fulfilling the Commitments whether they act directly or through their Affiliates.

13. The RA may make any request of Algonquin, Ascendant and BELCO at any time to substantiate compliance with any of the Commitments for so long as they remain in force.

14. BELCO shall provide to the RA within 6 months of the date on which this order is made an initial report on the extent of its compliance with these conditions and with the Commitments. Thereafter, BELCO shall provide to the RA within six months of the end of each financial year an

[2] For example, section 51(1) of the Act, as read with the First Schedule, defines 'statutory nuisances' as including "3 Any accumulation or deposit which is prejudicial to the health of, or is offensive to, any person in the neighbourhood, and "4 Any dust, smoke or effluvia caused by any trade, business, manufacture or process and which is prejudicial to the health of, or is offensive to, the inhabitants of the neighbourhood."

updated report on such compliance. The RA may waive this requirement or change the interval at which BELCO provides this report.

15. All publicity and media for any investment or programs implemented pursuant to the Commitments shall have a statement printed “In compliance with an order from the Regulatory Authority of Bermuda” or similar text as approved by the RA at a later date.

Annex B
Commitments

1. There will be no company-initiated job cuts in connection with the Change in Control, but the voluntary early retirement program will continue to be offered where prudent.

2. BELCO will not guarantee any debt of Algonquin, BSAL, BSHL, and/or Midco.

3. BELCO will continue to abide by the standards set out in the Regulatory Authority (Service Standards Indicators for Electricity Licensees) General Determination 2019; and Algonquin and Ascendant will support BELCO in reporting on measures provided in those standards and ensure that BELCO has the resources available in order to improve performance and exceed minimum standards when set.

4. BELCO will, together with the RA, work on maintaining the RA's goal of ensuring fair and stable pricing.

5. Algonquin and Ascendant will ensure BELCO's participation in their network of subsidiary utilities allowing for the exchange of best practices and for participants to learn from each other.

6. BELCO and Liberty Utilities (Canada) Corp. ("Liberty Utilities"), a subsidiary of Algonquin, may enter into: (1) a services support agreement whereby Liberty Utilities will provide strategic support and advisory services to BELCO in areas including, but not limited to, finance, operations, IT, human resources, and engineering; and (2) a mutual aid agreement whereby Liberty Utilities will provide assistance to BELCO with restoration services in the event of storms and major outages.

7. Algonquin and BELCO will leverage their commitment to sustainability and their leadership in renewable energy and energy storage development to assist Bermuda in achieving a greener and less carbon-intensive future, as contemplated by the Bermuda Integrated Resource Plan dated 30 June 2019 (the "IRP"), including the goal to reach 85% renewable energy generation by 2035.

8. Algonquin and Ascendant will assist BELCO in developing a residential storage program in Bermuda, similar to such programs on offer by members of the Algonquin group of companies in other jurisdictions.

9. Ascendant and its Affiliates will not be required to guarantee or assume any liability for obligations of Algonquin or any of BSHL, Midco, and BSAL including, without limitation, any of the debt incurred by BSHL to fund the Change in Control.

10. Algonquin will provide its in-house expertise in fulfilling the IRP as well as meeting other obligations set out in this order.

11. Algonquin will work with BELCO to develop a foundation in Bermuda to be called the "Sustainable Bermuda Foundation" that will serve as an educational and informational initiative which shall be initially capitalised in an amount of $5m.

12. Algonquin will provide BELCO employees with access to advanced training opportunities, both locally and overseas and with the opportunity to work in other Algonquin-owned utilities to broaden and enhance skillsets.

13. Algonquin will support continued funding for safety and technical training programs and Algonquin will leverage its own similar programs where it can do so to the benefit of BELCO employees.

14. Algonquin will explore the creation of additional new jobs for Bermudians in Bermuda within Ascendant and its Affiliates through opportunities for certain organization-wide functions to be performed by individuals located in Bermuda in areas related to finance, risk management, renewable development, regulatory support and e-mobility.

15. At no time will Algonquin or Ascendant seek the recovery of transaction costs or any premium paid over the book value of the assets of BELCO (including, but not limited to, any extra remuneration or bonuses paid to directors, officers or other executives directly tied to the transaction), and BELCO's cost of service will not increase due to any of the transactions in connection with or in furtherance of the Change in Control.

16. Algonquin will provide support and guidance to BELCO to enable BELCO to refinance its existing credit facilities (estimated at approximately $144 million), and Algonquin will in conjunction with BELCO create an appropriate structure to support this debt.

17. Funding to achieve the structure referred to in the previous subparagraph and for day-to-day activities and investment projects required under BELCO's two licences will be provided through the reinvestment of BELCO earnings as well as intercompany debt and equity provided by Algonquin and Ascendant.

18. Algonquin will provide the backstop funding required to meet BELCO's future capital needs.

DECISION

IN THE MATTER OF an application by Liberty Utilities (Canada) LP pursuant to Section 27(2) of the *Gas Distribution Act, 1999*, S.N.B. 1999, c. G-2.11, for an order granting leave for Liberty Utilities LP to acquire the beneficial ownership of Enbridge Gas New Brunswick Limited Partnership.

(Matter No. 433)

May 24, 2019

NEW BRUNSWICK ENERGY AND UTILITIES BOARD

NEW BRUNSWICK ENERGY AND UTILITIES BOARD

IN THE MATTER OF an application by Liberty Utilities (Canada) LP pursuant to Section 27(2) of the *Gas Distribution Act, 1999*, S.N.B. 1999, c. G-2.11, for an order granting leave for Liberty Utilities LP to acquire the beneficial ownership of Enbridge Gas New Brunswick Limited Partnership.

(Matter No. 433)

NEW BRUNSWICK ENERGY AND UTILITIES BOARD:

Chairperson:	Raymond Gorman, Q.C.
Members:	Michael Costello
	John Patrick Herron
Counsel:	Ellen Desmond, Q.C.
Chief Clerk:	Kathleen Mitchell

APPLICANT:

Liberty Utilities (Canada) LP:	Len Hoyt, Q.C.

INTERVENERS:

J.D. Irving, Limited:	Christopher J. Stewart
PUBLIC INTERVENER:	Heather Black

A. Introduction

[1] Liberty Utilities (Canada) LP, as represented by its general partner, Liberty Utilities (Canada) GP Inc. (Liberty Utilities or Applicant), applied to the New Brunswick Energy and Utilities Board (Board) on January 21, 2019 for an order granting leave for Liberty Utilities to acquire the beneficial ownership of Enbridge Gas New Brunswick Limited Partnership.

[2] Liberty Utilities is a wholly-owned subsidiary of Algonquin Power & Utilities Corp. (Algonquin), which is a Canadian-based corporation. Liberty Utilities owns and operates 27 utilities in the United States, including regulated natural gas utilities.

[3] Enbridge Gas New Brunswick Limited Partnership, as represented by its general partner, Enbridge Gas New Brunswick Inc. (EGNB) is a privately-owned utility that distributes and sells natural gas in New Brunswick. EGNB was awarded the general distribution franchise for the province in 1999. In 2016, the Government of New Brunswick passed legislation to renew EGNB's franchise agreement for a 25-year renewable term. EGNB currently provides natural gas to approximately 12,000 customers.

[4] Liberty Utilities is required, pursuant to subsection 27(2) under the *Gas Distribution Act, 1999*, S.N.B. 1999 c. G-2.11 (GDA), to apply to the Board for leave in the event it intends to acquire directly, or indirectly, 20 per cent or more of the ownership of EGNB. This subsection provides as follows:

> **Prohibition against disposal of a gas distribution system, or sale or merger of a gas utility, without leave of the Board**
>
> **27**(2) Without first obtaining an order granting leave from the Board, no person shall acquire directly or indirectly 20 per cent or more of the beneficial ownership of a gas distributor.

[5] EGNB and Liberty Utilities entered into a Securities Purchase Agreement (SPA) on December 3, 2018. Pursuant to this agreement, Liberty Utilities will acquire all of the issued and outstanding limited partnership interests of Enbridge Gas New Brunswick Limited Partnership and all of the issued and outstanding shares in its general partner, EGNB.

[6] Pursuant to the SPA, Liberty Utilities will be making this purchase for $331 million, subject to certain adjustments that will be made at the time of closing the transaction. The SPA expressly

acknowledges that approval of the Board is a pre-condition to closing the transaction and that closing will not occur until after Board approval.

[7] Liberty Utilities must also obtain the consent of the Province of New Brunswick, as represented by the Minister of Energy and Resource Development, to the change of control of EGNB and the release of any Enbridge affiliate from any and all obligations in relation to EGNB's Amended and Restated General Franchise Agreement (GFA) dated December 23, 2016. This consent has not yet been granted.

[8] In addition, *Competition Act* approval, as defined in the SPA, is also required. A No-Action letter was provided by the Competition Bureau of Canada on December 20, 2018.

[9] Liberty Utilities also requested the following relief:

(i) Board approval of the amendments to the GFA, pursuant to section 10 of the GDA; and

(ii) a determination that the transaction and consequential name changes shall not be cause for termination of EGNB's GFA pursuant to section 4.4(a)(vii) of that agreement.

[10] The Board held a pre-hearing conference on February 20, 2019 at which time a hearing schedule was confirmed.

[11] The hearing was held on May 6th in Saint John. In addition to the pre-filed evidence, Liberty Utilities presented its witness panel for cross-examination by other parties.

[12] There were two interveners registered in this Matter, namely J.D. Irving, Limited and the Public Intervener. Neither intervener filed evidence and only the Public Intervener participated at the oral hearing.

B. Issues

[13] The following issues must be considered:

1. What test should be adopted by the Board, in applying subsection 27(2) of the GDA;

2. Whether Liberty Utilities has met the requirements of this test;

3. What, if any, Board approvals are required as a result of changes to the GFA; and

4. What, if any, conditions should apply if the Board grants leave.

C. Analysis

1. What test should be adopted by the Board in applying subsection 27(2) of the GDA

[14] EGNB was granted the first provincial natural gas distribution system in New Brunswick in 1999. EGNB has been the distributor since that time, a period of almost 20 years. This is the first time the Board has considered a request under subsection 27(2) of the GDA and the Board must consider under what circumstances leave should be granted.

[15] While the *Energy and Utilities Board Act*, S.N.B. 2006, c. E-9.18 (EUB Act) provides the Board with general supervisory power with respect to the distribution of natural gas, and the Board has full jurisdiction to make orders in the public interest, both the GDA and the EUB Act are silent on the factors to be considered when determining whether to grant leave pursuant to subsection 27(2).

[16] The Applicant submits that the proper test to be applied is the "no-harm" test, which examines whether a proposed transaction will have a positive or neutral effect. If there is no harm arising from the sale of the utility, then leave should be granted. The Applicant submits that this test has been applied in other Canadian jurisdictions.

[17] This test has, in fact, been widely used both in Alberta and Ontario. The Alberta Utilities Commission (AUC) in its decision dated April 18, 2019, being decision 24105-D01-2019, articulated this test as follows:

> 39. In deciding an application for Commission approval of a transaction outside of the ordinary course of business under sections 101 and 102 of the *Public Utilities Act*, the Commission has traditionally applied a no-harm test. The Commission's predecessor, the Alberta Energy and Utilities Board (the board), in Decision 2000-41 articulated this test as follows:
>
> > ….that it should weigh the potential positive and negative impacts of the transactions to determine whether the balance favours customers or at least leaves them no worse off, having regard to all of the circumstances of the

> case. If so, then the Board considers that the transactions should be approved[35]

40. The board also determined that where harm is identified, some form of mitigation may be necessary in order for the transaction to proceed.

41. The no-harm test and the factors considered by the Commission have continued to evolve. In Decision 2014-326[36], dealing with the sale of AltaLink, L.P's transmission assets and business to MidAmerican (Alberta) Canada Holdings Corporation, the Commission provided its summary of the factors that may be considered when applying the no-harm test, and referenced previous Commission decisions discussing each of those factors.

[18] In Decision 2014-326, dated November 28, 2014, the AUC stated as follows:

> 107. In fulfilling its public interest mandate when considering applications pursuant to sections 101 and 102 of the *Public Utilities Act*, the Commission has traditionally applied a no harm test, a test which parties have identified in their submissions in this proceedings.
>
> 108. The no harm test and the factors considered by the Commission has evolved from past decisions of the Commission and its predecessors. In its September 22, 2014 ruling, the Commission referenced the overview presented by the submissions of MC Alberta. These factors have been reproduced as follows:
>
> > The first is whether there will be any impact to the rates and charges passed on to customers, and that you'll find in Decision 2005-118,[81] Decision 2004-35[82] and Decision 2011-374.
> >
> > … second, whether any operational benefit or risk arises related to the acquiring party's utility experience. That's in Decision 2005-118, 2004-35, Decision 2006-38. …
> >
> > Third, whether the financial profile of the utility will be impacted for the purposes of attracting capital. That's in Decision 2006-56, Decision 2006-38 and Decision 2011-374. Fourth, in the case of AltaLink, whether the utility will remain sufficiently legally, financially and operationally separate from the acquiring party, which is, of course, the ring-fencing provisions, code of conduct, et cetera, and that's in Decision 2006-56 and 2011-374.
> >
> > Fifth, whether the Commission will maintain sufficient regulatory oversight of the utility; Decision 2004-35, Decision 2011-374
> >
> > Sixth, whether the management and operational expertise will remain in place post transaction; Decision 2006-38, Decision 2011-374.

> Seventh, whether the transmission [*sic*] [transaction] will result in any cost impacts for customers relating to such things as tax and pension funds. And that's Decision 2000-41.
>
> And eight, that the acquiring party wishes to be in the utility business in Alberta whereas the divesting party does not. That's in Decision 2005-118, Decision 2004-5 and Decision 2006-38.[83]

109. In addition to the factors summarized by MC Alberta from past Commission and Board decisions, the no harm test must also reflects that:

- customers are, to the maximum extent possible, to be protected against any negative ramifications arising from the transactions (Decision 2006-056)[84]
- customers are not entitled to a level of post-transaction regulatory certainty they would not have realized if the transaction had not been approved. (Decision 2006-056)[85]
- customers are at least no worse off after the transaction is completed after consideration of the potential positive and negative impacts of the proposed share transactions (Decision 2011-374)[86]

110. The application of the no harm test is conducted in two stages. First, the Commission must assess whether the transaction results in harm to customers. If the Commission concludes that customers may be harmed, the Commission proceeds to the second stage of its determination and considers whether any identified harms can be mitigated through approval conditions.[87]

[19] Similarly, In Ontario, the “no-harm” test was articulated in a combined proceeding before the Ontario Energy Board. In proceeding RP-2005-0018/EB-2005-0234/EB-2005-0254/ EB-2005-0257 the Ontario Energy Board offered the following comments at pages 6 and 7 of its decision dated August 31, 2005:

> The Board believes that the “no harm” test is the appropriate test. It provides greater certainty and, most importantly, in the context of share acquisition and amalgamation applications it is the test that best lends itself to the objectives of the Board as set out in section 1 of the Act. The Board is of the view that its mandate in these matters is to consider whether the transaction that has been placed before it will have an adverse effect relative to the status quo in terms of the Board’s statutory objectives. It is not to determine whether another transaction, whether real or potential, can have a more positive effect than the one that has been negotiated to completion by the parties. In that sense, in section 86 applications of this nature the Board equates “protecting the interests of consumers” with ensuring that there is “no harm to consumers”.

[20] The Public Intervener also supported the use of the no-harm test. In her view, this test does serve the public interest by ensuring that the transaction will not be approved unless the evidence demonstrates there will be no harm to ratepayers.

[21] Having considered the submissions of the parties and the jurisprudence from other jurisdictions, the Board finds that the "no-harm" test is the appropriate test to be used when considering subsection 27(2) of the GDA and in a transaction of this nature.

2. Whether Liberty Utilities has met the requirements of the "no-harm" test

[22] There are a number of factors that can be considered when applying the "no-harm" test. It may be that, in any given case, some or all of these factors may apply. The Board finds the following factors to be relevant to this Application:

a. Whether there will be any impact to the rates and charges passed on to customers;

b. Operational benefits or risk that may arise as a result of the Applicant's experience;

c. Whether the financial profile of the utility will be impacted, for the purposes of attracting capital;

d. Whether the Board will continue to maintain sufficient regulatory oversight of the utility;

e. Whether the management and operational expertise that currently exists at EGNB, will remain in place, post transaction; and

f. Whether there will be any cost impacts related to such things as tax or pension obligations that will occur post transaction and that may negatively affect customers.

a. Impact on rates and charges passed on to customers

[23] Liberty Utilities does not seek to pass along to customers of EGNB either the premium above book value (i.e. good will), or the costs associated with the transaction. It states that, given its operational plans, it will be able to maintain the current cost structure.

[24] When asked specifically during cross examination about whether this transaction would have any impact on customer rates or charges, Mr. McEachran, Senior Director of

Regulatory Strategy at Liberty Utilities Canada Corp., testified that he did not think there would be any rate impacts, although rates may possibly move "slightly downward" because of reduced affiliate charges.

b. Operational benefits or risk

[25] In its evidence, Liberty Utilities states that it places a high value on system reliability, integrity and safety and that it has demonstrated this commitment in the utilities that it operates. While EGNB is a relatively new system, Liberty Utilities' stated commitment to safety and reliability will be foundational to the business as the system ages.

[26] When asked specifically about the operation of the pipelines, Liberty Utilities states that a Transition Services Agreement will be executed with EGNB, which will include an obligation for EGNB to continue providing all engineering-related support for a period of up to eighteen months. During this transition period, Liberty Utilities will have an opportunity to fully develop and implement a transfer of these responsibilities. Similarly, the technical manuals which EGNB has developed, will transition to Liberty Utilities, allowing for knowledge transfer.

[27] In addition, Liberty Utilities owns and operates 27 utilities in various states. This specific utility will become part of the East region, where it has extensive experience and has safely provided service to many thousands of customers.

c. Financial profile of the utility

[28] Liberty Utilities states that it will finance the acquisition of EGNB by using a combination of intercompany debt and equity provided by Algonquin, its parent company. It states that Algonquin is financially sound with a sound investment grade rating.

[29] Financial information related to Algonquin was provided and was the subject of both interrogatories and cross-examination. Liberty Utilities indicates, through its evidence, that it is a stable company with a history of utility operations. It has the financial means to operate the distribution company.

d. Energy and Utilities Board - Regulatory oversight of the utility

[30] It is anticipated that Liberty Utilities will have a positive and constructive regulatory relationship with the Board.

[31] The Applicant acknowledges the role of the Board and the need for oversight, and willingly agreed to continue providing reports that may assist the Board in its role.

e. Management and operational expertise

[32] Liberty Utilities states that minimal operating changes are expected. It will take advantage of its shared services model, which provides the benefit of relying on a service group with broad experience while delivering economies of scale.

[33] At the same time, the day-to-day operations of EGNB will be managed full time and exclusively by the current General Manager. It indicated that it empowers employees at the local level and uses a decentralized approach to business operations. The transition from EGNB into Liberty Utilities is designed to be seamless and there will be few changes with respect to how employees conduct their work.

f. Post-transactional cost impacts related to such things as tax or pension obligations, that may negatively affect customers

[34] During the course of this hearing, the Applicant confirmed that it did not expect any post-transactional costs that would negatively impact customers.

[35] Having considered all of these factors, the Board is satisfied that Liberty Utilities has met the requirements of the no-harm test. The Board is satisfied that, as much as may be possible, customers will be protected from any negative ramifications arising from this transaction. The Board is also satisfied that customers will be at least no worse off, after the transaction is completed.

3. What, if any, Board approvals are required as a result of changes to the GFA

[36] Liberty Utilities made two specific requests, arising from expected changes to the GFA.

[37] The first request was pursuant to subsection 10(1) of the GDA which states as follows:

Amendment of franchise agreements

10(1) After January 31, 2000, no amendment to a franchise agreement is effective unless it is in writing, has been executed by the parties and has been approved by the Board.

[38] Mr. Hoyt, counsel to Liberty Utilities, submitted that there would be amendments to the existing GFA, in the form of what will be called a Substitution Agreement and Amendment to General Franchise Agreement. The intent of this document is to confirm, in writing, the consent of the Province to the transfer and to substitute Algonquin as a guarantor in place of Enbridge Inc. Subsection 10(1) requires the Board to approve this executed amendment.

[39] Mr. Hoyt notes that while the Board does not yet have an executed agreement to consider, it was anticipated that the document would be available in the immediate future.

[40] As a result, the Board will reserve making a decision or granting an approval on this issue, until such time as the executed agreement has been filed and considered by the parties. Further direction on this issue will follow in due course.

[41] The second request relates to section 4.4(a)(vii) of the GFA, which states as follows:

4.4 Rights of Termination

(a) Upon the Board determining that any of such have occurred, the following circumstances shall be sufficient cause for the Province to give notice of termination of this Agreement to the General Franchise Holder:

(vii) if at any time during the Term there occurs any addition, deletion or change in the General Franchise Holder or any Guarantor or change in the effective control thereof or a material adverse change, financial or otherwise to any such party, and in any such event the Board determines that this Agreement should be terminated.

[42] In light of this provision, Liberty Utilities is seeking a determination from the Board that the anticipated transaction and consequential name changes shall not be cause for termination.

[43] The Board finds that such a determination is appropriate in this instance. While this transaction will result in a change in the effective control of the General Franchise Holder, Liberty Utilities has specifically requested approval from both the Province of New Brunswick and the Board. If the Province does consent to this transfer, clearly there would not be cause for termination.

[44] In these circumstances, the Board finds that the GFA is not terminated.

4. What, if any, conditions should apply if the Board grants leave

[45] While the Public Intervener did not oppose the transfer, she did suggest that the Applicant should be required to file additional information that will assist the Board in its ongoing oversight. She specifically suggested that Liberty Utilities should account for its transaction costs, file details of its corporate allocations and regularly report on safety and customer service metrics.

[46] The Board considers each of these issues to be important and it will continue to oversee them. While additional reporting will not be ordered at this time, the Board will consider including some of these items as minimum filing requirements. They will also be carefully considered in the next general rate application.

[47] There are however, other conditions that are necessary and will apply in this instance.

D. Conclusion

[48] Having considered all of the evidence in this matter, the Board does grant leave pursuant to subsection 27(2) of the GDA, on the following conditions:

a. The transaction is approved, subject to Liberty Utilities obtaining the consent of the Province of New Brunswick.

b. The leave shall expire three months from the date of this Decision. If the transaction has not been completed by that date, or the Board has not extended this leave in writing, a new application will be required in order for the non-completed transaction to proceed.

c. All regulatory approvals and orders, previously issued to EGNB, will continue to apply to Liberty Utilities.

d. Notice of completion of the transfer shall be promptly given to the Board.

e. Immediately thereafter, all permits and licenses should transfer to Liberty Utilities and in the event new permits or licenses are required, the Chief Clerk is directed to prepare the same.

f. Proof of insurance is to be provided immediately to the Board.

g. Reporting requirements, as they currently apply to EGNB, will continue to apply to Liberty Utilities once the transfer is complete.

Dated in Saint John, New Brunswick, this 24th day of May, 2019.

Raymond Gorman, Q.C.
Chairperson

Michael Costello
Member

John Patrick Herron
Member

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 18-G-0133 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of St. Lawrence Gas Company, Inc. for Gas Service.

CASE 18-G-0140 – Joint Petition of Liberty Utilities Co. and St. Lawrence Gas Company, Inc. for Approval, Pursuant to Section 70 of the PSL, of the Acquisition of St. Lawrence Gas Company, Inc. by Liberty Utilities Co. and for Approval, Pursuant to Section 69 of the PSL, of the Issuance of Long-Term Indebtedness.

ORDER ADOPTING THE TERMS OF JOINT PROPOSAL

Issued and Effective: October 18, 2019

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on October 17, 2019

COMMISSIONERS PRESENT:

John B. Rhodes, Chair
Diane X. Burman
James S. Alesi
Tracey A. Edwards
John B. Howard

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ORDER ADOPTING THE TERMS OF JOINT PROPOSAL

(Issued and Effective October 18, 2019)

BY THE COMMISSION:

I. INTRODUCTION

This Order adopts the terms set forth in the attached Joint Proposal, which was filed on May 31, 2019.[1] Signatories to the Joint Proposal include St. Lawrence Gas Company, Inc. d/b/a Enbridge St. Lawrence Gas (St. Lawrence), Liberty Utilities Co.[2]

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[1] The Joint Proposal is appended to this Order as Attachment A.

[2] Liberty Utilities, a Delaware Corporation, is a subsidiary of Algonquin Power & Utilities Corp.

(Liberty Utilities)(collectively, Joint Petitioners), Staff of the Department of Public Service (DPS Staff), Multiple Intervenors (MI), Agri-Mark, Inc. (Agri-Mark), and Upstate Niagara Cooperative, Inc. (Upstate Niagara)(collectively, Signatory Parties).[3]

In adopting the Joint Proposal, this Order resolves the issues in Case 18-G-0133 (Expansion Rate Case), regarding surcharges in St. Lawrence's Expansion Area[4] and Case 18-G-0140 (Acquisition and Financing Case), regarding Liberty Utilities' acquisition of St. Lawrence and related financing. Among other things, this Order continues St. Lawrence's base rates at current levels through May 31, 2022.[5] The Order also continues the Contribution-in-Aid-of-Construction (CIAC) surcharge, currently paid by customers in the Expansion Area, but establishes an end date of no later than January 31, 2023. The Order directs St. Lawrence to write-down plant-in-service related to the Expansion Area by $19 million and forego recovery of certain Expansion Area expenses until the Expansion Area provides enough revenue to meet the utility's cost to serve that area. St. Lawrence will be required to make an additional

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[3] The Signatory Parties, except Agri-Mark, filed statements supporting the Joint Proposal and recommending that the Commission adopt its terms.

[4] See Case 10-T-0154, St. Lawrence Gas Company, Inc. – Gas Transmission Siting and 10-G-0295, St. Lawrence Gas Company, Inc. – Gas Franchise, Order Granting Certificate of Environmental Compatibility and Public Need and Authorizing Exercise of New Franchises (issued February 18, 2011)(Expansion Area).

[5] Case 15-G-0382, St. Lawrence Gas Company, Inc. – Gas Rates, Order Establishing Multi-Year Rate Plan (issued July 15, 2016). The 2016 Rate Plan provides for certain customer credits to decrease each year, beginning on June 1, 2019 and June 1, 2020. Those changes will occur as previously authorized by the Commission.

write-down to plant-in-service if the Expansion Area is not self-sufficient by January 31, 2023.

The Order also requires Liberty Utilities to provide $1.5 million in shareholder funds for the benefit of St. Lawrence's customers. Further, it adopts the Joint Proposal's metrics and revenue adjustments intended to protect St. Lawrence customers through improved customer service, gas safety, reliability, and revamped capital investment processes and procedures. The Order also protects St. Lawrence's customers by requiring certain financial and credit rating protections, appointing a local independent member to the board overseeing St. Lawrence's operations, requiring retention of a local headquarters for a minimum of five years, and optimizing St. Lawrence's contracted pipeline capacity. Finally, the Order authorizes St. Lawrence to issue up to $28.2 million in long-term financing.

II. BACKGROUND

St. Lawrence is a wholly-owned subsidiary of Enbridge Gas Distribution, Inc., which in turn is owned by Enbridge, Inc. St. Lawrence employs approximately 50 full-time employees. Prior to 2012, St. Lawrence provided gas service in rural northern New York to approximately 16,300 customers in St. Lawrence County and a small portion of Lewis County (Legacy Area).

In 2010, St. Lawrence filed Cases 10-G-0295 and 10-T-0154, seeking approval to construct an approximately 48-mile transmission line and related distribution facilities (the Expansion Project) to provide gas to various communities in St. Lawrence County and Franklin County (the Expansion Area). St. Lawrence indicated that it expected the Expansion Project to attach two industrial customers, 372 commercial or institutional

customers, and 2,133 residential customers in the project's first five years. On February 18, 2011, the Commission authorized St. Lawrence to construct the transmission and distribution facilities.[6] In addition, it established a five-year development period and allowed St. Lawrence to charge a temporary revenue surcharge to Expansion Area customers.[7] At the time, the Expansion Project's expected cost, including the transmission line and the associated distribution systems, was $23.5 million. Before construction began, St. Lawrence sought amendment of its Certificate of Public Convenience and Necessity (CPCN) for the Expansion Area because of increased cost estimates.

In 2012, the Commission issued an order amending the CPCN (the 2012 Order).[8] The 2012 Order authorized the Expansion Project with an estimated cost of $40.5 million and approved a Temporary Revenue Surcharge (TRS) for Expansion Area customers for a period of 60 months beginning when the first Expansion Area customer received gas service. The 2012 Order required St. Lawrence to charge Expansion Area customers a CIAC surcharge, a volumetric-charge specific to each customer service class. The Commission continued the previously-established five-year development period and approved an updated return on equity.

In July 2016, the Commission issued an order establishing the 2016 Rate Plan, a three-year rate plan for St.

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6 St. Lawrence received $6.3 million in public funding from various sources including the State of New York and Franklin County.

7 Case 10-T-0154, supra, Order Granting Certificate of Environmental Compatibility and Public Need and Authorizing Exercise of New Franchises.

8 Case 10-G-0295, supra, Order Granting Amendment of Certificate of Public Convenience and Necessity (issued July 13, 2012.

Lawrence covering the period June 1, 2016 through May 31, 2019. The rates currently apply to both the Legacy Area and the Expansion Area.[9] Although the Commission authorized increased rates for each year of the plan, customer bill impacts were moderated through the application of customer credits that had accrued from a variety of overcollections.[10]

III. PROCEDURAL HISTORY

A. Expansion Rate Case

On February 26, 2018, in Case 18-G-0133 (Expansion Rate Case), St. Lawrence filed tariff leaves and supporting testimony seeking to recover cost overruns related to the Expansion Project of $11.7 million. St. Lawrence explained that the actual cost of the completed portion of the Expansion Project at the time of filing was $52.2 million. St. Lawrence also sought authorization to recover the cost to complete the remaining portion of the Expansion Project, estimated at approximately $18.6 million.

St. Lawrence proposed to: (1) extend the development period applicable to Expansion Area customers for an additional 15 years, (2) increase the temporary revenue surcharge (TRS) charged to customers in the Expansion Area, and (3) reduce the CIAC but extend it through the additional 15-year development period. St. Lawrence stated that the increased TRS and extended development period modifications would allow it to recover the

[9] Case 15-G-0382, supra, Order Establishing Multi-Year Rate Plan.

[10] Id., p. 9. As explained in more detail below, The Joint Proposal in this proceeding provides for the 2016 Rate Plan RY3 (i.e., the period ending May 31, 2019) base rates to continue, subject to any surcharges or surcredits authorized in the 2016 Rate Plan, until the Commission sets new base rates for St. Lawrence.

unanticipated cost overruns associated with the Expansion Project and complete the remaining distribution facilities in the Expansion Area. St. Lawrence did not propose to increase its base delivery revenue. According to St. Lawrence, the proposed tariff changes would have resulted in a decrease in customers' monthly bill. On March 8, 2018, the Commission suspended the proposed rates in the Expansion Rate Case through July 29, 2018, pursuant to New York Public Service Law (PSL) §66.

B. Acquisition and Financing Petition

On February 28, 2018, in Case 18-G-0140 (Acquisition Case), St. Lawrence and Liberty Utilities filed a petition for Commission approval pursuant to PSL §70 for Liberty Utilities to purchase all the outstanding common stock of St. Lawrence and, as a result, ownership of St. Lawrence.[11] If approved, Liberty Utilities would own St. Lawrence and its two non-regulated subsidiaries, St. Lawrence Gas Co. Service & Merchandising Corp. (SLG Service & Merchandising) and S.L.G. Communications Corp.

[11] Pursuant to the Securities Purchase Agreement (the "Agreement") executed by the Joint Petitioners on August 31, 2017 (Attachment 2 to the Petition), Liberty Utilities, or its subsidiaries, would acquire all of St. Lawrence's outstanding shares in exchange for the consideration of $70 million, subject to certain adjustments to be determined as of the closing date of the transaction. The Agreement expressly acknowledges that Commission approval is a pre-condition to closing on the transaction. Accordingly, closing will not occur until three business days after Commission approval of the transaction and satisfaction of any other conditions precedent in the Agreement.

(SLG Communications).[12] St. Lawrence and Liberty Utilities also sought Commission approval, pursuant to PSL §69, for the issuance of long-term indebtedness to replace St. Lawrence's existing indebtedness (the Financing). Specifically, the Joint Petitioners requested authority for St. Lawrence to issue indebtedness in the amount of $32.5 million, to replace the balance of a note payable to Enbridge U.S.[13] and a $7.0 million term loan from KeyBank. The Joint Petitioners sought clarification or, to the extent necessary, modification of the St. Lawrence Affiliate Code of Conduct (the Code) to accommodate St. Lawrence's participation, together with the Company's non-regulated subsidiaries, in the Liberty Utilities Money Pool Agreement (Money Pool). The Petition included attachments, prepared direct testimony and exhibits, supporting the proposed transaction and related financing.

On April 17, 2018, the Administrative Law Judges (ALJs) convened a procedural and technical conference and on May 31, 2018, they issued a ruling joining the two cases. Following the ruling, the parties conducted discovery[14] and on June 11, 2018, St. Lawrence filed additional revenue requirement

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[12] SLG Service & Merchandising, a New York Corporation, is primarily engaged in the rental of furnaces, boilers, water heaters and other natural gas appliances. SLG Communications, a New York Corporation, is primarily engaged in providing communications services to St. Lawrence.

[13] At the time of filing $25.5 million. The Joint Proposal indicates that as of May 15, 2019, the balance on the note was approximately $23.0 million.

[14] According to the Joint Proposal, the Joint Petitioners responded to 190 interrogatories from DPS Staff in the Expansion Rate Case and a total of 145 from Staff in the Acquisition and Financing Case. In addition, the Joint Petitioners answered one consolidated set of interrogatories with 31 individual questions from MI in the Acquisition and Financing Case.

forecasts and testimony in the Acquisition and Financing Case related to the 12-month period following the term of the 2016 Rate Plan, June 1, 2019 to May 31, 2020 (Rate Year 4 information).[15]

On July 3, 2018, the Commission, further suspended the effective date of the rates through January 29, 2019, in Case 18-G-0133. Public statement hearings were held in Malone on August 15, 2018, and in Potsdam on August 16, 2018.[16] On August 16, 2018, a Ruling on Schedule Modifications, was issued adopting a schedule that required the filing of direct testimony by parties other than the Joint Petitioners by October 4, 2018, and the filing of rebuttal testimony by October 25, 2018.

On October 4, 2019, Staff and Agri-Mark filed direct testimony and exhibits. On October 23, 2018, the Joint Petitioners filed and served a Notice of Impending Settlement Negotiations, proposing that the initial settlement conference be held in Albany on October 30, 2018.

On October 25, 2018, St. Lawrence and Liberty Utilities filed rebuttal testimony and exhibits. To accommodate settlement negotiations, several requests to postpone the commencement of evidentiary hearings and due-dates for pre-hearing submissions were granted. In addition, St. Lawrence agreed to a series of extensions to the statutory suspension period in the Expansion Rate Case. The most recent extension is through November 30, 2019.[17] The Signatory Parties filed the Joint Proposal on May 31, 2019 and statements supporting the

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[15] Rate Year 5 is the period from June 1, 2020 to May 31, 2021 and Rate Year 6 is from June 1, 2021 to May 31, 2022.

[16] Three individuals spoke in Malone and four individuals spoke in Potsdam.

[17] Case 18-G-0133, supra, Order Approving Extension of Maximum Suspension Period of Major Rate Filing.

Joint Proposal on June 21, 2019 and June 24, 2019.[18] The evidentiary hearing occurred on July 16, 2019.

IV. NOTICE AND PUBLIC COMMENTS

Notice of St. Lawrence's Expansion Rate Case filing was published in newspapers of general circulation in its service area once each week for four weeks pursuant to PSL §66.[19] Pursuant to the State Administrative Procedure Act (SAPA) §202(1), Notice of Proposed Rulemaking for St. Lawrence's tariff filings was published in the State Register on June 6, 2018 and Notice of Proposed Rulemaking for the Joint Petition of St. Lawrence and Liberty Utilities was published in the State Register on July 25, 2018.[20] Also on July 25, 2018, the Secretary issued a Notice Soliciting Comments and Announcing Public Statement Hearings to be held in Malone on August 15, 2018 and Potsdam on August 16, 2018.[21] On June 7, 2019, the Secretary issued a Notice of Joint Proposal and Soliciting Public Comment.

A total of seven individuals commented at the Public Statement Hearings (PSH) held in August 2018[22] and eight written

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18 On June 24, 2019, Liberty Utilities and St. Lawrence filed a "corrected" statement which added a table of contents to its previously filed statement. Also, on June 24, 2019, Upstate Niagara filed its statement in support and a "revised" statement correcting a typographical error.

19 Notice of the tariff filings was published weekly in the Malone Telegram, the Press Republican, and the Watertown Daily Times from March 3, 2018 to March 24, 2018.

20 PSC SAPA Nos. 18-G-0133SP1 and 18-G-0140SP1 respectively.

21 Notice of the Public Statement Hearing was published in the Malone Telegram, the Press Republican, and the Watertown Daily Times on August 7 and 10, 2018.

22 Garry Douglas, North Country Chamber of Commerce; Dr. Calvin Martin, Farms Against Rural Mismanagement; Anne Britton; Mark Peets, Supervisor Town of Brasher; William Demo; Robert Stewart, Superintendent, Brasher Falls Central School; Chuck Wilson, North Country Dairy.

comments were submitted.[23] All commenters indicated general support for the Expansion Project, as originally proposed, but opposed continuation of the TRS for 15 years. Many of the commenters expressed disappointment and mistrust having invested time and equipment to convert to natural gas under the promise of cost savings, much of which would be negated by St. Lawrence's proposal to continue its surcharge for another 15 years.

Representatives from the Towns of Brasher and Stockholm opposed continuing the TRS and noted the impact to residents and businesses. Dr. Calvin Martin spoke in favor of a System Benefits Charge for St. Lawrence customers with the funds to be used to help offset the cost of weatherization and high-efficiency equipment. James Britell also supported a System Benefit Charge and further extension of St. Lawrence's system. Howard Zemsky, President and Chief Executive Officer of Empire State Development, noted that significant expansion projects related to agriculture would be jeopardized by extending the surcharge.

All comments have been fully reviewed and considered in the preparation of this Order.

V. STANDARD OF REVIEW AND LEGAL AUTHORITY

Pursuant to PSL §§5, 65(1) and (8), and 66 (1) and (12), the Commission has the legal authority to review the proposed tariff leaves, as well as modify, reject or approve such filed tariffs.

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[23] Mark Peets, Supervisor Town of Brasher; Brian Bujnowski, Howard Zemsky, President and CEO of Empire State Development; James Britell; Clark Decker, Supervisor Town of Stockholm, Donald LaFave, Ritchie LeFeve, Brasher-Stockholm Recreation Commission, Donald Dabiew, Chairman Franklin County Legislature.

Pursuant to PSL §§5, 66(1) and 69, the Commission has the legal authority to review requests for the issuance of securities and forms of indebtedness, as well as modify, reject or approve such requests.

Pursuant to PSL §70, transfer of ownership of all or any part of the franchise, works or system of any gas or electric corporation is prohibited without the consent of the Commission. That consent may be given only if the Commission determines that the proposed acquisition, with such terms and conditions as the Commission may fix and impose, "is in the public interest." In evaluating whether a proposed transaction is in the public interest, "petitioners must show that the transaction would provide customers positive net benefits after considering the expected benefits offset by any risks or detriments that would remain after applying reasonable mitigation measures."[24]

In reviewing a joint proposal, the Commission's obligation is to ensure that its terms, when viewed together, produce a result that is in the public interest. The Commission must find that the terms of a joint proposal fall within the range of litigated outcomes and that the rates proposed are just and reasonable and are in the public interest.[25] A joint proposal should balance protection of consumers with fairness to investors and the long-term viability of the utility.

The factors the Commission takes into account in evaluating a joint proposal, are "themselves elements of the

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[24] Case 07-M-0906, Iberdrola, S.A. et al. Acquisition Petition, Order Authorizing Acquisition Subject to Conditions (issued January 6, 2009), p. 111.

[25] Cases 90-M-0255, et al., Procedures for Settlements and Stipulation Agreements, Opinion 92-2 (issued March 24, 1992).

public interest standard."[26] These factors are: (1) the settlement's consistency with law and with the regulatory, economic, social and environmental policies of the Commission and the State; (2) whether the result compares favorably with the likely result of full litigation and is within the range of reasonable outcomes; (3) whether the settlement strikes a fair balance among the interests of ratepayers and investors and the long-term soundness of the utility; and (4) the existence of a rational basis for the decision.

VI. TERMS OF THE JOINT PROPOSAL REGARDING EXPANSION AREA RATES

A. Rate Base and Capital Additions

The Joint Proposal requires St. Lawrence to remove from its books $19.0 million of plant-in-service in the Expansion Area. St. Lawrence must file the actual journal entries recording the write-down with the Secretary within 30 days after this Order. Originally, St. Lawrence sought recovery of $70.8 million of capital costs from customers, comprised of $52.2 million of actual incurred project costs as of September 30, 2017 and an estimated additional $18.6 million of capital costs that were projected to be incurred to complete the remaining portion of the Expansion Area project.[27] DPS Staff testified that the Company should reduce plant-in-service by $26.3 million reflecting a disallowance of $16.3 million in cost overruns and $9 million for CIAC revenues that would have been received had St. Lawrence completed the Expansion Project on time and connected the customers as it forecasted.[28]

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[26] Id.

[27] Initial Testimony of the Construction Panel, p. 14.

[28] Testimony of the Staff Policy Panel (18-G-0133), p. 58

The Joint Proposal calls for the rate base of the Expansion Area and the Legacy Area to remain separate for ratemaking purposes until the base rate revenues from the Expansion Area are sufficient to cover the Company's cost of service for the Expansion Area, including the proposed rate of return, without subsidization from Legacy Area revenues (self-supporting) or January 31, 2023, whichever occurs earlier.

Similarly, the Joint Proposal continues the current CIAC charges[29] in the Expansion Area until the earlier of (1) the date that the Expansion Area is self-supporting, or (2) January 31, 2023. However, if the Expansion Area is not self-supporting on January 31, 2023, and the CIAC charges terminate automatically, shareholders would be required to write-down plant-in-service to a level that allows the Expansion Area to be self-sufficient without subsidization from Legacy Area customers. The Joint Proposal prohibits St. Lawrence and Liberty Utilities from requesting an extension of or increase to the current CIAC charges. By July 31st of each year until the CIAC charges terminate, St. Lawrence must file a report with the Secretary comparing Expansion Area revenues and cost of service for the previous year. In addition, St. Lawrence shall file a report with the Secretary identifying its estimate of when the CIAC will end, no later than 6 months prior to the anticipated end date. The report shall include detail to support the estimate and must be filed no later than July 31, 2022 (i.e. six months prior to the January 31, 2023 automatic CIAC termination).

St. Lawrence originally proposed extending the development period for an additional 15 years. St. Lawrence

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[29] The CIAC charge is equal to $3.61 per dekatherm (Dth) for residential customers, $5.15 per Dth for commercial customers, $3.86 per Dth for industrial customers.

proposed that, during this extended development period, it would charge customers a TRS and a CIAC surcharge. The Company proposed adjusting the surcharges to minimize short-term impacts while still allowing full recovery of Expansion Area cost over time.[30] DPS Staff recommended continuing the CIAC charges at the current rates and not restarting the TRS.[31]

The Joint Proposal includes limits regarding attachment of new customers. For calendar year 2019, St. Lawrence would only be authorized to connect customers who meet the criteria for attachment to existing gas mains.[32] For any distribution system enhancements planned for calendar year 2020, the Joint Proposal requires St. Lawrence to file with the Secretary a demonstration that the planned enhancement is economic, inclusive of estimated capital expenditures. The filing would include: (1) project cost estimates; (2) prospective customer survey results (with prospective customers' current energy type); (3) historic and projected natural gas and alternative energy costs; (4) number of total potential new customers and number of committed customers (5) annual conversion estimates for the first five years; (6) annual projected volumetric throughput for the first five years; (7) annual projected revenues for the first five years; and, (8) any other information St. Lawrence considers relevant.

DPS Staff will review the filing and St. Lawrence commits to cooperating with DPS Staff and, if necessary, modifying the proposal to resolve any concerns DPS Staff may have. Issues that cannot be resolved between DPS Staff and St. Lawrence would be brought to the Commission. Construction

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30 Initial Testimony of the Finance Panel, p. 42.

31 Testimony of the Staff Policy Panel (18-G-0133), pp. 43, 73.

32 See 16 NYCRR §230.2.

proposed for calendar year 2020, would only begin after May 1, 2020. For calendar year 2021 and each following year until the Commission resets St. Lawrence's base rates, the same requirements would apply.

The Joint Proposal indicates that this review process will not preclude St. Lawrence from connecting prospective customers that meet the requirements for provision of service under the Commission's regulations or that otherwise agree to pay the full cost of the main extensions required to connect them.

St. Lawrence originally proposed spending an additional $18.6 million to complete the build out of the Expansion Area distribution system. The Company proposed to add 198,224 feet of main, 2,551 services, 2,794 meters and four district stations.[33] In its testimony, DPS Staff expressed concerns with St. Lawrence's plans based on its capital investment planning process,[34] and, in DPS Staff's view, less than realistic cost projections.[35]

The Joint Proposal also provides procedures for addressing construction budgeting and variances in the Expansion Area as described below.

Discussion

The requirement to write-down $19.0 million of plant-in-service serves the public interest because it avoids burdening St. Lawrence's customers with the cost overruns. It also recognizes our policies of avoiding the undue subsidization of expansion areas by existing customers and placing the risks

33 Initial Testimony of the Finance Panel, p. 6.

34 Testimony of the Staff Rates Panel, p. 14.

35 Testimony of the Staff Infrastructure Panel, p.64.

associated with cost overruns primarily on utilities, not their customers.[36]

Also, the adopted approach for consolidating the Expansion area and the Legacy Area is reasonable and equitable. Requiring that the Legacy Area and Expansion Area rate bases will be consolidated, no later than January 31, 2023 provides beneficial certainty to customers and St. Lawrence. The requirement that St. Lawrence make an additional write-down to plant-in-service, if the Expansion Area is not self-supporting by January 31, 2023, protects Legacy Area customers from cross-subsidization and provides the correct incentives to St. Lawrence. This provision also addresses the concern raised by the Empire Development Authority regarding the negative impact to agriculture expansion investments of continuing surcharges for an additional 15 years, as originally proposed by St. Lawrence. Further, continuation of CIAC surcharges at the current rate for a limited period, until January 31, 2023, provides St. Lawrence the opportunity to recover Expansion Area capital costs while providing certainty to existing and prospective customers in the Expansion Area.

The limitations on St. Lawrence's ability to construct additional network enhancements in addition to the requirement for the Company to adopt improved capital expenditure standards and procedures related to construction budget variances will protect customers from unnecessary cost overruns and help avoid

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[36] See Case 89-G-078, Policy for Rate Treatment of Gas Service Expansion into New Franchise Areas, Statement of Policy Regarding Rate Treatment to be Afforded to the Expansion of Gas Service Into New Franchise Areas (issued December 11, 1989) and Case 12-G-0297, Proceeding on Motion of the Commission To Examine Policies Regarding the Expansion of Natural Gas Service, Order Instituting Proceeding and Establishing Further Process.

uneconomic buildout of gas infrastructure.[37] Improvements to the decision-making and budgeting processes will benefit shareholders and customers alike and are a necessary aspect of the overall response to the issues encountered during Expansion Project construction. Once the improvements have been adopted, St. Lawrence will have additional opportunities for further buildout of the system. However, it must file a detailed business plan demonstrating that the planned enhancement is feasible economically which will help impose an appropriate level of discipline to the process. These provisions strike an appropriate balance between the need for close oversight and an opportunity for the Company to enhance the value of its system for its shareholders and existing and potential customers.

B. Expansion Area Cost of Service

As indicated in the Joint Proposal, the TRS, which terminated on November 25, 2018, will not be revived. The Joint Proposal limits recovery of the cost to serve the Expansion Area, including operation and maintenance (O&M) expenses, depreciation expenses, taxes other than income taxes and return on investment within the Expansion Area, to the collection of base rate charges that St. Lawrence has already been authorized to charge Expansion Area customers. The Joint Proposal explicitly states that it contains no provision for recovery or

[37] The construction budget and variance procedures must address: (1) a process to base projects on engineering analysis and design; (2) project investment thresholds to allow for timely monitoring and oversight by the St. Lawrence Board and the Commission; (3) procedures to enter into construction contracts before any work commences; and (4) a process requiring pre-approval of projects by the St. Lawrence Board when a significant change in scope or budget will cause an increase of 10% or more in capital expenditures, compared with the previously approved budget.

deferral of the cost to serve the Expansion Area, including, but not limited to those costs for which St. Lawrence sought recovery in its Expansion Area Rate filing:[38] (1) the expenses incurred during fiscal years 2014 through 2017;[39] (2) additional expenses incurred in the period of 2018 through the date when the Expansion Area and Legacy Area rate bases are combined, which St. Lawrence had proposed to collect through a continuation of the TRS;[40] and (3) rate case expenses incurred in this proceeding.[41]

St. Lawrence originally proposed to restart the temporary revenue surcharge, at approximately double the rate authorized in the 2012 Order and proposed to apply it for an extended 15-year development period, i.e., through 2033.[42] In its testimony, Staff recommended that the Commission reject the proposal to restart the temporary revenue surcharge arguing that requiring the Company to forego this revenue while continuing the CIAC at current levels was an equitable approach.[43] Similarly, Agri-Mark opposed continuation of the TRS and CIAC beyond the period that the Commission originally approved.[44]

Discussion

Denying St. Lawrence's request to reestablish the TRS is reasonable and equitable as it reflects the expectation of

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38 See Hearing Ex. 35, St. Lawrence Exhibit FP-1A, Model Summary, Pro Forma Incremental Statement.

39 Approximately $3.0 million.

40 As presented in St. Lawrence's filing, these cost estimates include the proposed 15-year development period.

41 St. Lawrence estimates this cost at $658,000 as of February 26, 2018. See St. Lawrence Finance Rebuttal Testimony, p. 23.

42 Initial Testimony of the Finance Panel, pp. 19-21.

43 Testimony of the Staff Policy Panel (18-G-0133), pp. 73-74.

44 Testimony of Mehm, pp. 2-3.

existing Expansion Area customers. St. Lawrence will still receive Expansion Area revenues through collection of base rates and the continuation of the CIAC through, potentially, January 31, 2023, which will allow the Expansion Area to become self-sufficient in a reasonable time-frame without disrupting existing customer expectations.

C. Outreach and Education Plan

The Joint Proposal contemplates an outreach and education program specific to the Expansion Area to inform customers of the outcome of these proceedings. St. Lawrence, on or before January 1st of each year until the CIAC charges cease, must file an Outreach and Education Plan for the Expansion Area. As part of the Outreach and Education Plan, St. Lawrence would be required to conduct a minimum of two public information forums at different locations within the Expansion Area. The public forums must take place within 60 days of this Order addressing the Joint Proposal.

St. Lawrence originally proposed a Community Engagement Plan to inform customers of the construction issues the Company encountered in the Expansion Area and the need to continue the Expansion Project and recover all its costs.[45] DPS Staff recommended a separate Outreach and Education Plan for the Expansion Area to operate until the surcharges terminate and to include Company-sponsored public information sessions to explain the outcome of this proceeding.[46]

[45] Testimony of Gilles Volpé, p. 18.

[46] Testimony of the Staff Consumer Policy Panel (18-G-0133), pp. 14-17.

Discussion

The Outreach and Education Plan and forums specific to the Expansion Area are a reasonable way to inform the public of the both the specific outcome of this proceeding and more generally, the opportunities and costs related to gas service.

D. Accumulated Deferred Federal Income Taxes

St. Lawrence must adjust its Accumulated Deferred Federal Income Taxes (ADFIT) balance to reflect the write-downs to plant-in-service and evaluate the excess amount of ADFIT deferred in response to the federal tax law changes, which included a corporate income tax rate reduction, that was passed in 2017.[47] The Joint Proposal recognizes that St. Lawrence will defer excess ADFIT until it can be addressed in the Company's next base rate proceeding, in accordance with the Commission's Order in Case 17-M-0815.[48] St. Lawrence must file with the Secretary the journal entries implementing any adjustment within 30 days of the issuance of this order. If St. Lawrence concludes that no adjustment is required, it will file an explanation for its conclusion instead of the journal entries effectuating the adjustments. If the Company must make an additional write-down to plant-in-service, it will revise the ADFIT balance to reflect the impact of the write-down, including the balance of excess ADFIT as required.

St. Lawrence originally proposed reflecting ADFIT associated with forecasted plant investment during its proposed

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[47] See Public Law 115-17 ("The Act to Provide for Reconciliation Pursuant to Titles II and V of The Concurrent Resolution on the Budget for Fiscal Year 2018")(often colloquially referred to as the Tax Cuts and Jobs Act of 2017).

[48] Case 17-M-0815, Proceeding on Motion of the Commission on Changes in Law that May Affect Rates, Order Determining Rate Treatment of Tax Changes (issued August 9, 2018).

extended development period and included a regulatory liability related to excess ADFIT in its cost of service forecast.[49] DPS Staff countered that the Company's ADFIT balance and the regulatory liability related to the excess deferred federal income taxes be adjusted to reflect the impact of DPS Staff's proposed plant-in-service write down.[50]

Discussion

The requirement that St. Lawrence evaluate and make necessary adjustments to its excess ADFIT related to recent tax law changes and reflecting the required right-downs is appropriate because it appropriately reflects the impact of the write-down to plant-in-service on St. Lawrence's deferred income taxes.

E. Rate of Return and Capital Structure

The Joint Proposal states that a return on equity (ROE) of 8.60% would be used solely for determining whether the Expansion Area is self-supporting. In their litigated positions, the Company proposed a 9.0% ROE and DPS Staff proposed an ROE of 8.6%.

For determining whether the Expansion Area is self-supporting, the Signatory Parties propose a total cost of capital based upon a 48.0% common equity ratio, a debt ratio of 51.2% and a customer deposits ratio of 0.8%. The proposed capital structure would include the long-term debt the Joint Petitioners requested in the Acquisition and Financing Case, as described below. The Joint Proposal includes cost rates of 8.6%

[49] Initial Testimony of the Finance Panel, pp. 53-55.

[50] Testimony of the Staff Accounting Panel (18-G-0133), pp. 47-48; 54-55.

for ROE, 4.4%[51] for long-term debt and 2.45%[52] for customer deposits. These rates would be used to determine the total cost of capital.

St. Lawrence proposed utilizing a capital structure consisting of a 48.0% common equity ratio, a 52.0% short-term debt ratio and a short-term debt cost rate of 2.29%.[53] DPS Staff recommended a capital structure comprised of 48.0% common equity, 15.9% long-term debt, 35.3% short-term debt and 0.80% customer deposits and a long-term debt cost rate of 2.98%, a short term debt cost rate of 3.05%, and a customer deposit rate of 1.05%.[54]

Discussion

The adopted Rate of Return and capital structure are reasonable for determining when the Expansion Area becomes self-supporting. The cost rates associated with the proposed capital structure include an ROE of 8.6%, a long-term debt cost rate of 4.4% and a customer deposits cost rate of 2.45%. These figures are reasonable because they are reflective of current market conditions at the time the Joint Proposal was executed and the debt cost rate also reflects Liberty Utilities embedded cost of debt which will be updated once the transaction is closed. Further, the new debt provided by Liberty Utilities will have a longer term than St. Lawrence's existing obligations which will more closely match the utility's debt obligations with the long

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[51] This figure reflects Liberty Utilities' current embedded cost of debt that is subject to change once the requested transaction is closed.

[52] This figure reflects the Commission's currently approved Customer Deposit Rate. This rate is updated annually, and the Joint Proposal indicates that the rate in effect at the time of the calculation will used.

[53] Initial Testimony of the Finance Panel, p. 55.

[54] Exhibit___(SFP-2).

lives of utility assets such as gas transmission lines and delivery mains.

VII. TERMS OF THE JOINT PROPOSAL REGARDING THE ACQUISITION AND FINANCING

A. Acquisition of St. Lawrence

1. Local Presence

The Joint Proposal includes a requirement that within one year of the closing of the acquisition of St. Lawrence, Liberty Utilities will appoint an independent director who resides within St. Lawrence's service territory to its East Region Board of Directors (resident Board member). However, if Liberty Utilities acquires any additional Commission-regulated utilities within the State of New York, this requirement may be fulfilled by appointing a resident of either St. Lawrence's service territory or the service area of another New York utility acquired by Liberty Utilities. The Joint Proposal clarifies that a resident of one of the counties in which the utility provides service, even if that individual is not in the relevant service area itself, is enough to fulfill this requirement. The resident Board member would be subject to all the requirements generally applicable to other Board members. If the appointed resident Board member retires or is removed, Liberty Utilities would be required to appoint a replacement director meeting the residency requirements as soon as practical.

The Joint Proposal also includes a requirement that St. Lawrence keep its corporate headquarters within the St. Lawrence service territory. However, St. Lawrence may petition the Commission to relocate its corporate headquarters no sooner than five years after closing of the acquisition of St. Lawrence.

Liberty Utilities proposed that St. Lawrence be governed, managed, and overseen by its East Regional Board of Directors (Board), East Region President, and St. Lawrence's General Manager.[55] DPS Staff recommended that the Commission require an independent board member who is located within St. Lawrence's service territory to ensure that the interest of St. Lawrence customers are appropriately reflected within the Board.[56] Liberty Utilities and St. Lawrence stated that St. Lawrence's headquarters and management team would remain in Massena. DPS Staff recommended requiring that the headquarters remain within St. Lawrence's service territory until the Commission approves a relocation.

Discussion

The provisions requiring local management, headquarters and board representation help to ensure that the interests of St. Lawrence and its customers are appropriately represented, and that St. Lawrence's management remains close to and responsive to customers' interest. Further, they are consistent with terms we have previously approved.[57]

2. Financial Transparency and Reporting

The Joint Proposal calls for St. Lawrence to file with the Commission the amount of charges made among Liberty Utilities and its affiliates that are applicable to St. Lawrence. The report must be filed within six months of the closing of Liberty Utilities' acquisition of St. Lawrence and

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55 Exhibit___(SPP-1) (18-G-0140).

56 Testimony of the Staff Policy Panel (18-G-0140), pp. 30-31.

57 Case 12-M-0192, Joint Petition of Fortis Inc., Fortis US Inc., Cascade Acquisition Sub Inc., CH Energy Group, Inc., and Central Hudson Gas & Electric Corporation for Approval of the Acquisition of CH Energy Group, Inc. by Fortis Inc. and Related Transactions, Order Authorizing Acquisition Subject to Conditions (Issued June 26, 2013), pp. 18-19.

annually, within 45 days of the end of the calendar year. The report must include a description of how Liberty Utilities derived the intercompany charges.

Under the Joint Proposal, Liberty Utilities would provide DPS Staff access to its accounting policies, books, and records, including consolidated tax returns. Liberty Utilities would also be required to file annually with the Secretary consolidated audited financial statement, including balance sheets, income statements, cash flow statements and related notes. The documents may be accompanied by a request for confidential treatment as appropriate. There was general agreement among the parties on these issues.[58]

DPS Staff and Liberty Utilities generally agreed on the Company's proposed affiliate transaction and cost allocation methods.[59] Liberty Utilities stated that, in the context of settlement discussions, it did not oppose DPS Staff's recommendation for annual reporting on the level of intercompany charges.[60]

3. Code of Conduct

The Joint Proposal includes a revised Code of Conduct attached as Appendix 2.[61] The Signatory Parties agreed that Liberty Utilities and its affiliates will be bound by and comply with the revised Code upon Commission adoption of the Joint Proposal. This provision generally reflects DPS Staff's recommendation that St. Lawrence's participation in the money pool as a borrower and a lender only be permitted if the other participants in the pool are regulated utilities.

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58 DPS Staff Statement in Support, pp. 24-25.

59 Testimony of the Staff Policy Panel (18-G-0140), pp. 53-55.

60 Rebuttal Testimony of the Liberty Utilities Panel, p. 19.

61 The Commission approved the existing code as part of the 2016 Rate Plan.

Discussion

The Code of Conduct is reasonable and appropriate. The provisions regarding the money pool appropriately protect St. Lawrence and its customers while providing St. Lawrence access to funds on a short-term basis to ease cash-flow management.

4. Rate Freeze

The Joint Proposal limits when St. Lawrence may file for new base rates by requiring that its next filing include a test period reflecting a full year of Liberty Utilities' ownership of St. Lawrence.[62] The Joint Proposal further requires that St. Lawrence's next rate filing utilize a Rate Year commencing on or after June 1 of the earliest calendar year in which new rates could go into effect given the required test period. Until such time that the Commission approves new base rates, the rates currently in effect pursuant to the 2016 Rate Plan (i.e. the rates the Commission established for the 12 months ending May 31, 2019), will remain in effect, subject to any surcharges or surcredits authorized in the 2016 Rate Plan. The requirement that the test period reflect at least a full year of Liberty Utilities' ownership precludes any change in base rates prior to June 1, 2022. The Joint Proposal clarifies that unless the Signatory Parties specifically recommends a

[62] The Joint Proposal recognizes that St. Lawrence may file for rate changes during the term of the rate freeze under limited circumstances including a minor change in any individual base delivery service rate or rates which has a de minimus revenue effect. It further recognizes the Commission's authority to act on St. Lawrence's rates if an unforeseen event requires a change to ensure the Company can maintain safe and adequate service, or causes the rates to become excessive. This provision is standard in joint proposals recommending multi-year rate plans, which, regarding the rate freeze, this Joint Proposal does. See Joint Proposal VI.F.

change to the 2016 Rate plan, the provisions of the rate plan remain in effect.[63]

Liberty Utilities did not propose a rate freeze as part of its Acquisition filing.[64] The Joint Proposal limits on filing for new base rates generally reflect DPS Staff's view that utilizing a historic test year occurring entirely after Liberty Utilities acquires St. Lawrence will provide a better baseline to assess St. Lawrence's rate proposals in a future rate proceeding.[65]

Discussion

The rate freeze is an important aspect of the Joint Proposal by providing rate stability to consumers including predictability and minimizing cost increases. Maintaining base rates at current levels protects rate payers without negatively impacting the viability of the utility. We note, however, that the 2016 Rate Plan continued base rates subject to any surcharges or surcredits authorized in the 2016 Rate Plan until the Commission sets new base rates for St. Lawrence. The 2016 Rate Plan included customer credits which decreased on June 1, 2019 and will decrease again on June 1, 2020.[66] We previously authorized those changes, and they will result in an annual bill increase of approximately 1% in Rate Year 4 and Rate Year 5 and approximately 0.6 in Rate Year 6.[67] Further, the

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63 Similarly, Appendix 9 of the Joint Proposal lists the provisions of the rate plan for illustrative purposes only and does not impact St. Lawrence's obligations under its current rate plan.

64 Testimony of the Staff Policy Panel (18-G-0140), p. 71.

65 Testimony of the Staff Policy Panel (18-G-0140), p. 70.

66 See Case 15-G-0382, supra, Order Establishing Multi-Year Rate Plan (issued July 15, 2016), Appendix A, p. 16 of 17 and Appendix B, p. 5.

67 Id.

requirement that St. Lawrence maintain the same rate year (i.e. the 12-months ending on May 31 of a given year) will ensure any increase in rates will begin during the summer season when bills are typically lower, mitigating the impacts for the first few months of any future rate increase.

5. Capital Structure and Financial Protections

The Joint Proposal contemplates St. Lawrence utilizing Liberty Utilities' embedded cost of debt for long-term debt. The 2016 Rate Plan contained a true-up mechanism for short-term interest rates. The Signatory Parties propose that this mechanism be continued until changed by further Commission action, except that, at the time of the refinancing of the existing short-term Enbridge U.S. note with long-term debt, Liberty Utilities' embedded cost of debt will be used in place of St. Lawrence's actual short-term debt cost rate.

If, according to its annual earnings filing, St. Lawrence is overearning in its Legacy Area and the true-up would result in a deferral to be recovered from customers, St. Lawrence would not be allowed to true up its actual interest rate with the cost figure used to set rates during the time that St. Lawrence is overearning. If the true-up results in a deferral amount to be recovered from customers that is larger than the amount of St. Lawrence's overearnings, St. Lawrence would be permitted to recover the true-up amount net of the overearnings.

Liberty Utilities testified that it did not intend to pass along the premium over book value (i.e., goodwill) to customers.[68] The Joint Proposal prevents St. Lawrence and Liberty Utilities from passing through to customers any portion of goodwill. Therefore, St. Lawrence will not include the

[68] Initial Testimony of the Liberty Utilities Panel, p. 28.

goodwill associated with this transaction on the Company's annual Commission report, or in the equity component of St. Lawrence's capitalization for purposes of calculating St. Lawrence's return, future revenue requirement or any other component of St. Lawrence's rates. St. Lawrence must file its goodwill calculation as soon as it is available but in accordance with the U.S. Generally Accepted Accounting Principles (GAAP).

The Joint Proposal indicates that Liberty and St. Lawrence have agreed to work to maintain the common equity capitalization ratio for St. Lawrence that the Commission used to establish St. Lawrence's rates. In that regard, St. Lawrence would be required to maintain: a minimum common equity (MER) subject to dividend restriction; and a minimum debt rating of BBB. Liberty Utilities and St. Lawrence have agreed to maintain a minimum common equity, as measured by a trailing 13-month average, in relation to the common equity ratio of 48% used to set rates. The Joint Proposal defines minimum common equity as no less than 300 basis points below the common equity ratio used to set rates. If the minimum common equity ratio requirement is not maintained, no dividends are payable until the minimum common equity ratio is regained. The 300 basis points reflects a compromise between the 400 basis point[69] cushion suggested by Liberty Utilities and the 200 basis points recommended by DPS Staff.[70]

If Liberty Utilities' Standard and Poor's (S&P) debt rating falls below BBB within the three years directly following closing of the acquisition of St. Lawrence, a BBB rating will be

[69] Rebuttal Testimony of the Liberty Utilities Panel, p. 16.

[70] Testimony of the Staff Policy Panel (18-G-0140), pp. 47-48.

imputed to the cost of any debt issued during that three-year period.

The Joint Proposal states that in the three-year period after the Acquisition closes, when Liberty Utilities issues debt, it shall provide DPS Staff with comparable debt issuance data of like tenor for other public utilities for the period 60 days prior to and 60 days following the debt issuance. If Liberty Utilities' credit rating at the time of the debt issuance is below BBB (S&P) or Baa2 (Moody's), the credit spread differential between the comparable debt data and Liberty Utilities' debt will be used to calculate St. Lawrence's cost of debt in subsequent rate cases. The Joint Proposal indicates that if there are comparable public utility debt issuances of like tenor, the credit spread for a like tenor will be interpolated from available data. Liberty Utilities and DPS Staff agree to work in good faith to determine the credit spread differential to be applied. Liberty Utilities testified that it did not expect the transaction to significantly impact St. Lawrence's credit rating. The Joint Proposal generally reflects DPS Staff's recommendations for required safeguards to protect St. Lawrence's customer if such negative impacts do occur.

The Earnings Sharing Mechanism (ESM) For Rate Years 4, 5, and 6 shall be reported for each Rate Year on an annual basis but be calculated cumulatively. The Joint Proposal requires the annual report to be filed within 90 days of the end of each Rate Year. The Joint Proposal states that the ESM calculations for Rate Years 4-6 will include only the Legacy Area and the lower of St. Lawrence's actual common equity ratio or the common equity ratio used to set rates, i.e., 48.0%. If the Expansion Area becomes self-sufficient and the CIAC terminates, St. Lawrence's earnings shall be determined company-wide. For purposes of the earnings calculation required by the 2016 Rate

Plan, the incremental cost attributable to the Acquisition will be excluded. If St. Lawrence does not file for new rates to be effective on June 1, 2022, the ESM for any additional period beyond June 1, 2022,[71] shall be determined on an annual basis and filed annually within 90 days after the end of each Rate Year.[72] Liberty Utilities did not address St. Lawrence's current earnings sharing mechanism (ESM) in its testimony. Staff stated in its testimony that the current rate plan contains an ESM that will protect customers from paying excessive rates and that it will capture a portion of any excess earnings for the benefit of customers.[73]

Discussion

The Joint Proposal recommends that the Commission require a capital structure with 48.0% common equity, 51.2% long-term debt and .8% customer deposits. The cost rates are 9.0% for ROE, 4.4% for long-term debt and 2.45% for customer deposits. The Joint Proposal also recommends that the Commission require updating the debt cost true-up contained in the 2016 Rate Order to reflect the anticipated refinancing of a portion of St. Lawrence's existing short-term debt with long-term debt. The Joint Proposal allows St. Lawrence to true-up the debt costs to reflect Liberty Utilities' embedded cost of debt.

The capital structure and cost rates adopted here are reasonable for the purposes of valuing a rate freeze. It also reflects the updated cost rates for long-term debt proposed as

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[71] The Joint Proposal refers to this period colloquially as "Rate Year 7."

[72] Appendix 3 of the Joint Proposal sets forth St. Lawrence's Capital Structure and Cost of Capital.

[73] Testimony of the Staff Policy Panel (18-G-0140), p. 69.

part of the Joint Proposal and customer deposits.[74] Allowing St. Lawrence to true-up the cost associated with its existing short-term debt when it does refinance with long-term debt is rational and will ensure that the refinancing occurs.

The prohibition against passing along costs associated with goodwill is in the public interest as it protects rate payers from paying such costs and is consistent with our treatment of goodwill in previous transaction proceedings.[75] Similarly, the customer protections connected to St. Lawrence's maintenance of a minimum common equity ratio and Liberty Utilities' maintenance of a minimum S&P debt rating protect St. Lawrence customers not only if Liberty Utilities permits St. Lawrence's financial situation to degrade, but also if Liberty Utilities fails to protect its BBB rating. However, the structure of the Negative Revenue Adjustment (NRA) should provide sufficient flexibility to St. Lawrence and Liberty Utilities to manage their operations. Overall, the acquisition by Liberty Utilities will provide St. Lawrence better access to capital markets on terms that are more favorable than it can otherwise obtain on a stand-alone basis. Moreover, the financial protections should maintain St. Lawrence's ability to attract capital on its own if necessary.

Incremental costs attributable to the Acquisition, as provided in such cost summaries, will be appropriately excluded from the earnings calculation required by the 2016 Rate Plan. If the Expansion Area becomes self-sufficient and the CIAC is terminated before we reset St. Lawrence's base rates, the Company's earnings will be measured on a company-wide basis for

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74 Joint Proposal, pp. 32-33.

75 See Case 15-G-0382, supra, Order Establishing Multi-Year Rate Plan, Appendix 1, p. 1 and Case 12-M-0192, supra, Order Authorizing Acquisition Subject to Conditions, pp. 40-41.

the Rate Year beginning after the CIAC ends and thereafter. The earnings sharing mechanism rationally excludes the Expansion area to avoid skewing the results lower and will continue to provide the Company with incentive to control costs while allowing ratepayers to share in efficiency gains.

6. Positive Benefit Adjustments

St. Lawrence's shareholders would provide a total of $1.0 million over three years to fund the development of a Carbon Reduction Initiative which would be developed in consultation with DPS Staff. The Joint Proposal indicates the initiative is intended to assist new and existing residential and small general firm service customers to install high-efficiency gas equipment and weatherization. The Joint Proposal also contemplates a deferral of $0.5 million for the future benefit of customers, as determined by the Commission. The Joint Proposal clarifies that the Carbon Reduction Initiative is distinct from the Marketing and Incentives for Conversions program authorized as part of the 2016 Rate Plan which is intended to continue until the Commission resets base rates. The Carbon Reduction Initiative will expire on May 31, 2022, and St. Lawrence will be required to defer any unspent monies for the future benefit of ratepayers, as determined by the Commission. However, the Joint Proposal provides for the possibility of continuing the initiative if the parties to the next rate proceeding propose such continuance.

In its testimony, Liberty Utilities argued that any risk involved with the transaction would be neutralized by the measures it proposed, and therefore a positive benefit adjustment (PBA) was not warranted. DPS Staff disagreed with Liberty Utilities and recommended that the Commission require a PBA of $3.3 million as a condition of authorizing the acquisition.

Discussion

The positive benefit adjustment reasonably and equitably balances the risks and benefits associated with this transaction. In addition, the amount of the positive benefit adjustment recommended in the Joint Proposal, as a percent of delivery revenue, is within the range required in other recent Commission-authorized acquisitions. The positive benefit adjustment is reasonable in the context of this entire Joint Proposal, including a three-year rate freeze, improved safety and customer service metrics, and provisions setting the Expansion Area on a path to self-sufficiency. By assisting customers with the installation cost of weatherization and high-efficiency equipment, the program addresses comments requesting a System Benefit program. Further, reduction of greenhouse gas emissions from all Commission-regulated activities is a primary policy goal and these efforts will provide a small contribution toward that goal. The shareholder contribution toward funding an energy efficiency program in this Joint Proposal is not typical but is meant to provide additional benefits of the acquisition by Liberty to ratepayers. As part of the Joint Proposal that includes rate freezes for existing customers, the Carbon Reduction Initiative funded by shareholders will enable ratepayers to make energy related improvements to their homes.

7. Savings and Cost Trackers

St. Lawrence is required to separately track and report (1) costs attributable to the Acquisition and (2) costs that would have been incurred without the transaction. St. Lawrence is also required to track transition expenses, capitalized costs, and benefits arising from the transition. This information would be included in St. Lawrence’s first post-Acquisition rate proceeding filing to enable the Commission to

determine the appropriate treatment of the expenses and capitalized costs.

Similarly, the Joint Proposal requires St. Lawrence to track and report any synergy savings. In its first post-Acquisition rate filing, St. Lawrence would identify gross savings attributable to specific operational changes and the cost of achieving the savings to illustrate the net synergy savings.

The Joint Proposal contemplates the possibility that Liberty Utilities, its parent company, Algonquin Power & Utilities Corp., or an affiliate of either may complete additional mergers or acquisitions within the United States or Canada prior to the Commission establishing new base rates for St. Lawrence. The Joint Proposal would require St. Lawrence to track and report to the Secretary any savings attributable to such a transaction that would be reasonably applicable to St. Lawrence or its customers. The Joint Proposal provides for deferral of such savings with a 50/50 sharing with St. Lawrence customers if the savings are material, defined as five percent or more of St. Lawrence's net income on an after-tax basis. St. Lawrence will also be required to report increased costs related to such transactions on an annual basis.[76] Liberty Utilities generally did not oppose DPS Staff's recommendation to track the transition costs related to the Acquisition, except it opposed the recommendation to exclude all the Acquisition costs from St. Lawrence's earnings calculation.[77]

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[76] Appendix 3 of the Joint Proposal sets forth St. Lawrence's Capital Structure and Cost of Capital.

[77] Rebuttal Testimony of the Liberty Utilities Panel, pp. 13-15.

Discussion

The requirements for tracking costs and savings and other benefits associated with the Acquisition and associated operational changes will ensure that costs and benefits related to the Acquisition are properly tracked and reported. They will also protect St. Lawrence customers from inappropriate costs and ensure that savings and costs are appropriately considered in the next rate proceeding. Similarly, tracking and reporting related to any future mergers or acquisitions that Liberty Utilities may transact will ensure appropriate allocation of material savings. While encouraging the Joint Petitioners to take advantage of economic efficiencies through improved operations and beneficial transactions, they also provide for an appropriate allocation of related benefits to St. Lawrence and its customers until such savings are accounted for in the Company's base rates.

8. Gas Safety

Appendix 5 of the Joint Proposal includes metrics for company performance related to Emergency Response Time, Damage Prevention, Leak Backlog, and Safety Violations (High Risk and Other Risk) on a calendar year basis for 2019 and 2020. The Joint Proposal places revenues equivalent to a total of 138 pre-tax basis points at risk for St. Lawrence related to the gas safety metrics.[78] The Joint Proposal provides for the safety targets, NRAs and positive revenue adjustments applicable in

[78] DPS Staff stated at the evidentiary hearing that the dollar value of a basis point in the Legacy Area is equal to $1,970 pursuant to the 2016 Rate Plan. The dollar value for the Expansion Area based on forecasts and reflecting write-down is equal to $1,114. Tr. 24-25. However, these figures would be updated to reflect the basis point values for the year the NRA or PRA is applicable.

calendar year 2020 to remain in effect until changed by Commission action.

Emergency Response metrics are tied to the statewide emergency response targets of responding to leak and odor call at a rate of 75% within 30 minutes, 90% within 45 minutes, and 95% within 60 minutes. Failure to meet each performance level will result in varying NRAs: nine pre-tax basis points for the 30-minute metric; six for the 45-minute metric; and three for the 60-minute metric. The Joint Proposal establishes a maximum annual NRA related to emergency response targets of 18 pre-tax basis points. The Joint Proposal also provides St. Lawrence the opportunity for a positive revenue adjustment (PRA) if the Company exceeds the targets: three pre-tax basis points for responding to greater than 85% of leak or odor calls in 30 minutes; six pre-tax basis points for greater than 90%. The maximum PRA applied in any one calendar year is six pre-tax basis points. The NRA would be increased by 150% if a target is missed during a dividend restriction related to a failure to maintain the minimum equity ratio required by the Joint Proposal and by 200% if a target is missed three of the next five calendar years (through 2023).

Beginning in calendar year 2019 and on a calendar year basis thereafter, if St. Lawrence exceeds targets related to damages to its facilities, it will be subject to an NRA. The facility damage metrics are measured annually in terms of instances of damaged facilities per 1,000 Dig Safely or “one-call” tickets. In 2019, St. Lawrence will incur an NRA of: five pre-tax basis points for exceeding 2.85 instances per 1000 calls; 15 pre-tax basis points for exceeding 2.95 instances per 1000 calls; and 27 basis points for exceeding 3.00 instances per 1000 tickets. In 2020, the threshold incident rates would change to 2.75, 2.85, and 3.00 with the pre-tax basis point NRA

staying at 5, 15 and 27, respectively. However, if an annual target is missed, St. Lawrence also would have had to miss the target on a two-year lookback basis for the NRA to apply.

The PRA related to damage prevention for 2019 would be five pre-tax basis point for less than 2.25 instances of damage per 1,000 tickets and 10 pre-tax basis points for less than 2.00 instances. In 2020, St. Lawrence would earn a PRA of five pre-tax basis points for achieving a rate of 2.15 instances per 1,000 tickets and 10 pre-tax basis points for 1.90 instances per 1,000 tickets. St. Lawrence could not earn more than 10 pre-tax basis point each year related to damage prevention.

The Joint Proposal also includes an NRA related to St. Lawrence's leak backlog. In 2019, the Company would be assessed an NRA of 18 pre-tax basis points if it has more than five Type 1, 2, 2A and 3 leaks in backlog pending repair, including failed rechecks on December 31 of the respective year. In 2020, the NRA remains at 18 pre-tax basis points, but the threshold is reduced to four Type 1, 2, 2A and 3 leaks including failed recheck as of December 31 of the respective year. The maximum NRA related to St. Lawrence's leak backlog is 18 pre-tax basis points each year. The NRA will be increased by 150% if it is triggered during a dividend restriction related to the required minimum common equity ratio and by 200% if triggered in three of the next five calendar years.

Beginning in calendar year 2019, St. Lawrence will be assessed an NRA for instances of High Risk and Other Risk noncompliance of certain safety regulations contained in 16 NYCRR Parts 255 and 261. The listing of what code sections represent High Risk or Other Risk are contained in Appendix 5 of the Joint Proposal. The maximum NRA for non-compliance with safety regulations is 75 pre-tax basis points each calendar year. Repeated failures to follow a step or requirement

resulting in a violation are considered multiple occurrences. Failure to follow a St. Lawrence procedure will be considered a single occurrence under 16 NYCRR 255.603.

The Joint Proposal recognizes that on February 12, 2019, the Department of Public Service, Office of Electric, Gas and Water, Pipeline Safety Section filed the Operator Qualification White Paper.[79] The Joint Proposal does not preclude St. Lawrence from requesting deferred accounting treatment, if Commission action on the whitepaper results in incremental costs for Rate Years 4, 5, or 6.

Liberty Utilities did not propose any changes in gas safety metrics. The specific metrics and associated NRAs and PRAs contained in the Joint Proposal generally reflect DPS Staff's recommendations with some adjustments to the targets for damage prevention.

Discussion

The Joint Proposal includes several provisions for improving performance targets and associated revenue adjustments related to gas safety metrics including emergency response, damage prevention, leak backlog and gas safety violations. The changes related to gas safety that we adopt here,[80] reflect St. Lawrence's recent performance and our policy of working collaboratively with distribution utilities to constantly

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[79] Case 14-G-0212, Proceeding on Motion of the Commission to Investigate the Practices of Qualifying Persons to Perform Plastic Fusions on Natural Gas Facilities and Case 17-G-0318, In the Matter of an Investigation into Local Distribution Company Use of Northeast Gas Association Operator Qualification Program.

[80] Joint Proposal, Appendix 5 Schedule A contains a complete list of gas safety performance metrics and associated revenue adjustments.

improve gas safety.[81] Moreover, they appropriately include both NRAs and PRAs.

The 150% and 200% incremental NRAs related to dividends restrictions and multiple target misses appropriately recognize the importance of gas safety and complying with applicable safety regulations, the importance of which cannot be overstated. The targets reflect an expectation of improving performance, are in accordance with our safety goals and are in the public interest.

9. Customer Service

The Service Quality Performance Mechanism (SQPM) approved by the Commission as part of the 2016 Rate Plan is proposed to continue until changed by the Commission with revised targets and revenue adjustments to two of the three metrics. Performance for all measures shall be assessed on a calendar year basis. The SQPM has targets for complaint rates with escalating NRAs up to $36,000 for a complaint rate of equal or greater than 2.5. The complaint rate is defined as the 12-month escalated complaint rate as reported to St. Lawrence by DPS Staff each January 15 for the previous calendar year. The maximum NRA tied to the customer satisfaction index is $36,000 for a customer satisfaction index equal to or less than 84%. The Joint Proposal provides for NRAs that are doubled from those imposed by the 2016 Rate Plan. Further, the Joint Proposal provides for the proposed NRAs to triple if the targets are missed during a dividend restriction and quadruple if the targets are missed in three out the next five calendar years. Revenue adjustments pursuant to the SQPM are in pre-tax dollars and will be deferred for future customer benefit.

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[81] Case 17-G-0245, In the Matter of Staff's Analysis of Local Distribution Company Performance Related to the Gas Safety Measures.

St. Lawrence would be entitled to a PRA of $12,000 per year related to terminations and collectibles if both measures are at or below the annual target of 451 customer terminations and $173,000 bad debt. St. Lawrence would receive a PRA of $6,000 if one measure is at or below and the other is at or below the three-year average (i.e., terminations = 466 and bad debt = $204,000). If both measures are below the targets, St. Lawrence will not be entitled to any positive adjustments, nor subject to negative adjustments.

The Joint Proposal would require St. Lawrence to continue to employ an independent customer satisfaction survey, with the results of such surveys filed with the Secretary within 60 days after they are completed, accompanied by the Company's plans to address legitimate customer suggestions received as part of the survey.

The Joint Proposal adopts Staff's proposal for the doubling, tripling, and quadrupling the NRAs associated with customer service performance. Regarding performance targets, the Joint Proposal reflects a compromise among the parties.[82]

Under the Joint Proposal, in order to ensure that the Company's customer service related staffing does not decline following the acquisition, St. Lawrence is required to provide a formal training plan, developed with Liberty Utilities' guidance, for Staff review within 90 days following this Order. The Joint Proposal requires all St. Lawrence employees involved in customer service to complete the training by December 31 of the calendar following the year the Acquisition closes, and further specifies that a minimum of 10 employees must complete the training program. St. Lawrence must report to the Secretary the employees who have received the training by January 31

[82] DPS Staff's Statement in Support.

following each calendar year. The report would also include lists of employees who, during the year, received refresher customer service training and performed customer service duties, and who no longer perform customer service duties. St. Lawrence would be required to maintain a minimum of 10 employees trained to perform customer service going forward.

Liberty Utilities testified that it planned to retain St. Lawrence employees for at least 12 months following the Acquisition.[83] Staff recommended extending the retention period until rates are next set.[84] Liberty Utilities responded that the recommendation may be harmful to customers by removing St. Lawrence's ability to manage employee performance and restructure assignments as needed.[85]

The Joint Proposal includes specific provisions for improving customer service including the development and implementation of a Customer Service Improvement Plan to be filed with the Secretary within 60 days of the issuance of this Order. Company shareholders are responsible for the cost of developing and implementing the plan until the Commission next establishes rates of St. Lawrence.

Discussion

Service Quality Performance Mechanism will continue albeit with modified targets and revenue adjustment. The modifications are a reasonable improvement and will help ensure that St. Lawrence customers receive a consistent and adequate level of customer service by providing St. Lawrence with the appropriate incentives to provide such service. The other

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83 Initial Testimony of the Liberty Utilities Panel, p. 44.

84 Testimony of the Staff Consumer Policy Panel (18-G-0140), p. 25.

85 Rebuttal Testimony of the Liberty Utilities Panel, pp. 63-64.

customer service-oriented requirements are also expected to help maintain a level of customer service that is appropriate.

10. Timely Filings

The Joint Proposal includes a provision whereby St. Lawrence will incur an NRA equal to three pre-tax basis points for each instance it fails to make a complete filing by the deadline as specified in the relevant statute, regulation or Commission order or fails to request an extension or waiver of such deadline, where an extension or waiver is possible, in a timely fashion.[86]

Discussion

We adopt the provision imposing an NRA of three basis points for each instance St. Lawrence fails to make a timely filing or to timely ask for an extension. This provision reasonably provides an incentive for St. Lawrence to focus on improving its performance related to compliance with filing deadlines, a recurring issue for the Company in the past. Timely filings are a minimum requirement for DPS Staff to perform its duties without undue strain on limited resources.

11. Capital Expenditures and Reporting

St. Lawrence will comply with the "Liberty Way Policy and Procedure: Capital Expenditures – Planning and Management," which defines Liberty Utilities' capital processes from planning through construction. However, if those processes conflict with more stringent standards specified in any Commission orders, the more stringent standards will apply.

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[86] The Joint Proposal, p. 27, states that "a timely request is understood to mean a request made in writing not less than one day in advance of the relevant deadline" except "as provided in the relevant requirement e.g., in the relevant Commission order or issuance from the Secretary." This Order provides that requests for extension are timely only if received at least three days prior to the relevant deadline.

For any future Expansion Area construction, the Joint Proposal requires that St. Lawrence develop and follow a construction budget and variance procedure. St. Lawrence must establish a set of procedures and controls including: a process for basing projects on engineering analysis and design; project investment thresholds for timely oversight by its Board and the Commission; procedures to enter construction contracts before any work commences; and a process requiring re-approval of projects by the Board when a significant change in scope or budget will cause an increase of 10% or more in capital expenditures, compared with the previously-approved budget.

St. Lawrence is also required to file with the Secretary its annual capital expenditure budget within 30 days of Board approval. Further, within two months of the end of a calendar year, St. Lawrence would file with the Secretary its monthly variance reports for the calendar year.

The Joint Proposal provides for downward-only net plant true-up to determine if St. Lawrence has spent its Legacy Area capital budget in Rate Years 4 and 5, as measured on a cumulative basis. The Joint Proposal indicates that the analysis should begin with the Rate Year 3 actual ending balances of plant in service, Construction Work in Progress, and accumulated depreciation. For Rate Years 4 and 5, the estimated Legacy Area capital investment amounts are $2.028 million and $1.732 million, respectively. Minimum net plant target levels for Rate Year 5 will continue until the Commission next establishes base rates for St. Lawrence.

The Joint Proposal does not establish a set capital investment amount for Rate Year 6, but it does indicate that St. Lawrence would be expected to spend the amount of capital required to prudently own and operate the system. The Joint Proposal contemplates St. Lawrence reviewing actual net plant in

service for Rate Year 5 to determine whether that amount is in line with the net plant in service target for that year. If the actual net plant in service exceeds the target, there will not be a deferral. However, if at the end of Rate Year 5, actual net plant in service is less than targeted, St. Lawrence will defer, for the future benefit of customers, the carrying cost of the variance between the actual and the target. Each month after Rate Year 5, St. Lawrence will calculate whether net plant in service exceeds the target. If net plant in service remains below the target figure, an appropriate deferral will be made on the calculated carrying charges. Deferrals shall accrue at the Company's pre-tax rate of return until the full deferred balance is returned to customers. St. Lawrence would be required to report the results of its net plant in service evaluation within 90 days of the end of Rate Year 5, if the target is not yet met, and St. Lawrence must file a supplemental report 90 days after the target is achieved.

These provisions generally reflect DPS Staff's recommendations. Liberty Utilities presented no concerns with requiring St. Lawrence to adopt its capital expenditure standards and otherwise improving St. Lawrence's planning and budgeting.

Discussion

Requiring St. Lawrence to comply with the "Liberty Way Policy and Procedure: Capital Expenditures – Planning and Management," unless the manual conflicts with more stringent standards in Commission orders, should help improve St. Lawrence's performance. The requirement to file information related to St. Lawrence's capital expenditure budgets and variances will allow us to exercise appropriate oversight of the Company. The downward only true-up incentivizes the appropriate level of spending by not allowing contemporaneous recovery of

overspending while reimbursing customers for underspending. Given issues that arose with the Expansion Area Project, these provisions are reasonable and in accordance with our treatment of capital expenditure spending for other utilities.

12. Optimization of Assets

St. Lawrence is required to issue a request for proposals (RFP) within 120 days of Acquisition closing in order to enter into an asset management agreement with a term of one to three years. St. Lawrence must file with the Secretary a copy of the RFP and, upon completion of the process, a report detailing the outcome. St. Lawrence will continue to operate under its existing agreement with Tidal Energy until the RFP results in a new asset management agreement. St. Lawrence also must utilize an RFP process each time the asset management agreement is renewed.

Discussion

Requiring that St. Lawrence make best efforts to enter into an asset management agreement optimizing its pipeline assets helps ensure that St. Lawrence's firm customers will benefit from the market value of the capacity assets which are supported by those customers in rates. It will also help to avoid a decrease in revenue associated with asset optimization.

13. Documentation and Reporting Requirements

The Joint Proposal also includes various documentation and reporting requirements in addition to those described above including an annual report identifying outcome and benefits of the Companies' outreach and education programs. St. Lawrence must also submit for DPS Staff review a draft plan regarding outreach and education specific to the Acquisition. Following DPS Staff's review, the Acquisition Outreach and Education plan will be incorporated into St. Lawrence's 2019 companywide

Outreach and Education plan. St. Lawrence will submit an Outreach and Education Plan to the Secretary by January 1 of each year.

St. Lawrence must document all gas service requests. Requests from the Expansion Area will be recorded separately from the Legacy Area, with such documentation, including date and location of request, among other information, with other information required to be provided by St. Lawrence to DPS Staff within 10 days of DPS Staff's requests.

B. Issuance of Long-term Indebtedness

The Signatory Parties recommend that the Commission authorize St. Lawrence to issued debt up to $28.2 million, an amount intended to allow St. Lawrence some flexibility to manage its debt and equity ratios. The recommended debt issuance would allow St. Lawrence to refinance nearly all of its current debt consisting of a note payable to Enbridge of $23.0 million and the Key Bank loan of $7.0 million. No later than 120 days after Acquisition closing, St. Lawrence will issue a 10- or 15-year promissory note to Liberty Utilities. The loan will be priced at Liberty Utilities' embedded cost of debt calculated using the most recent quarter end for which a financial closing has been completed. The Joint Proposal requires Liberty Utilities to recapitalize any of St. Lawrence's remaining outstanding debt with the goal of achieving an actual common equity ratio approximating the 48.0% ratio to be used for ratemaking purposes. Liberty Utilities will also use its Money Pool to replace the $6.0 million short-term line of credit St. Lawrence has with Key Bank.[87] These provisions reflect an agreement among

[87] Appendix 8, contains the "Reimbursement Margin" that supports the Signatory Parties recommendation regarding the debt issuance.

the parties that the terms and tenor of the indebtedness available to St. Lawrence following the transaction will be an improvement to what the Company has been able to access in the past.

Discussion

The issuance of indebtedness authorized here will permit St. Lawrence to refinance most its outstanding debt. Because St. Lawrence has a history of being unable to secure permanent financing for its long-term utility assets, the issuance of long-term promissory notes to Liberty Utilities will stabilize its finances. The debt is reasonably priced and provides maturities that better match the lives of St. Lawrence's utility assets. Given St. Lawrence's relatively small size and history, the Company is unlikely to attract long-term financing on better terms as a stand-alone entity. St. Lawrence has relied on its parent for most of its capital, both equity and debt in the past. Aside from grants associated with the Expansion Area, outside bank funding only accounts for $7 million of its capital (plus the short-term $6 million line of credit with Key Bank). St. Lawrence's access to reasonably priced and structured capital through Liberty Utilities is likely to be a significant benefit to customers relative to alternatives such as commercial bank term loans, which typically offer less generous terms and include greater restrictions. Accordingly, this provision of the Joint Proposal is reasonable and is adopted.

CONCLUSION

We adopt the terms of the Joint Proposal. Viewed in its entirety, as it must be, the Joint Proposal provides for resolution of these two proceeding that is just and in the public interest. The proposed resolutions of contested issues

are consistent with the law and the Commission's policies related to, among other issues, system expansion and acquisition of regulated utilities. The record demonstrates that the terms of the Joint Proposal are within the reasonable range of litigated outcomes.

The required write-down of $19.0 million of plant-in-service provides an equitable result to the cost overruns incurred by St. Lawrence and appropriately places the risk of the expansion project on shareholders. Further, requiring St. Lawrence to write-down additional plant-in-service, if the Expansion Area is not self-supporting by January 31, 2023, protects Legacy Area customers from cross-subsidization and provides the correct incentives to St. Lawrence. Continuation of CIAC surcharges at the current rate until January 31, 2023 provides St. Lawrence the opportunity to recover Expansion Area capital costs while providing certainty to existing and prospective customers in the Expansion Area. Moreover, the $28.2 million in long-term financing authorized in this Order will also stabilize the St. Lawrence's finances.

The metrics and revenue adjustments adopted by the Order will help protect St. Lawrence customers by incentivizing improved customer service, gas safety, reliability, and revamped capital investment processes and procedures. Further, the provision requiring $1.5 million in shareholder funds for the benefit of St. Lawrence's customers will ensure that the transaction will provide a net benefit. The financial and credit rating protections, appointment of a local independent member to the board, retention of a local headquarters, and optimizing St. Lawrence's contracted pipeline capacity will also protect St Lawrence's customers.

In summary, we approve the Joint Proposal including he proposed resolution of St. Lawrence's rate filing and Liberty Utilities' acquisition of St. Lawrence.

The Commission orders:

1. In accordance with the foregoing discussion, and subject to the determinations and understandings set forth above, the terms of the Joint Proposal filed in these proceedings on May 31, 2019, and attached hereto as Attachment A, are adopted and are incorporated as part of this order, with the exception of Section VI.

2. St. Lawrence Gas Company, Inc. is directed to file a cancellation supplement, effective on not less than one day's notice, on or before October 28, 2019, cancelling the tariff amendments and supplements listed in Attachment B to this order.

3. St. Lawrence Gas Company Inc. is directed to file, on not less than one day's notice, to become effective on November 1, 2019, such further tariff amendments as are necessary to effectuate the terms of this order and to incorporate in such filing tariff amendments that were previously approved by the Commission in Case 18-G-0731 since the tariff amendments listed in Attachment B were filed.

4. St. Lawrence Gas Company, Inc. shall serve copies of its filing on all parties to these proceedings. Any party wishing to comment on the tariff amendments may do so by filing its comments with the Secretary to the Commission and serving its comments upon all active parties within ten days of service of the tariff amendments. The amendments specified in the compliance filing shall not become effective on a permanent basis until approved by the Commission and will be subject to

refund if any showing is made that the revisions are not in compliance with this order.

5. The requirements of the Public Service Law §66(12)(b) that newspaper publication be completed prior to the effective date of the amendments is waived; provided, however, that St. Lawrence Gas Company Inc. shall file with the Secretary to the Commission, not later than six weeks following the amendments' effective date of the amendments, proof that notice to the public of the changers made by the amendments and their effective date has been published, once a week for four consecutive weeks in daily or weekly newspapers having general circulation in the service territory and areas affected by the amendments.

6. In the Secretary's sole discretion, the deadlines set forth in this order may be extended. Any request for an extension must be in writing, must include a justification for the extension, and must be filed at least three days prior to the affected deadline.

7. These proceedings are continued.

By the Commission,

(SIGNED) KATHLEEN H. BURGESS
Secretary

CASES 18-G-0133 & 18-G-0140 Attachment B

SUBJECT: Filing by ST. LAWRENCE GAS COMPANY, INC.

Amendments to Schedule P.S.C. No. 3 – Gas

Third Revised Leaf No. 42
Tenth Revised Leaves Nos. 267, 276
Eleventh Revised Leaf No. 261
Supplement Nos. 12, 13, 14, 15

BEFORE THE
NEW YORK STATE
PUBLIC SERVICE COMMISSION

PROCEEDING ON MOTION OF THE COMMISSION AS TO THE RATES, CHARGES, RULES AND REGULATIONS OF ST. LAWRENCE GAS COMPANY, INC. REGARDING FRANKLIN AND ST. LAWRENCE COUNTIES EXPANSION PROJECT	Case 18-G-0133
JOINT PETITION OF LIBERTY UTILITIES CO. AND ST. LAWRENCE GAS COMPANY, INC. FOR APPROVAL, PURSUANT TO SECTION 70 OF THE PSL, OF THE ACQUISITION OF ST. LAWRENCE GAS COMPANY, INC. BY LIBERTY UTILITIES CO. AND FOR APPROVAL, PURSUANT TO SECTION 69 OF THE PSL, OF THE ISSUANCE OF LONG-TERM INDEBTEDNESS	Case 18-G-0140

JOINT PROPOSAL

May 31, 2019

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BEFORE THE
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JOINT PROPOSAL

I. INTRODUCTION

This Joint Proposal ("Joint Proposal") is made as of the 31st day of May, 2019, by and among St. Lawrence Gas Company, Inc. (d/b/a Enbridge St. Lawrence Gas) ("St. Lawrence Gas," "SLG" or the "Company"), Liberty Utilities Co. ("Liberty Utilities") (collectively, "Joint Petitioners"), the Staff of the Department of Public Service ("Staff"), Multiple Intervenors ("MI"), Agri-Mark, Inc. ("Agri-Mark"), and Upstate Niagara Cooperative, Inc. ("Upstate Niagara") (collectively, the "Signatory Parties" or the "Signatories"). The only other party that participated in settlement negotiations, the Utility Intervention Unit, Division of Consumer

Protection, of the Department of State ("UIU"), stated that it would neither support nor oppose this Joint Proposal.[1] This Joint Proposal settles all contested issues among the Signatory Parties in the above-captioned cases.[2]

A. Definitions

As used in this Joint Proposal, the following terms have the following meanings:

"2016 Rate Plan" shall mean the Commission's Order Establishing Multi-Year Rate Plan issued in Cases 15-G-0382 and 13-G-0076 on July 15, 2016 and the Joint Proposal attached to that Order.

"Expansion Area" shall mean the service territory served by the Expansion Project.

"Expansion Project" shall mean the 48-mile high-pressure natural gas transmission line installed by SLG in new portions of St. Lawrence County and Franklin County and the distribution system branching from that line.

"Legacy Area" shall mean the portion of SLG's service territory that is not served by the Expansion Project.

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[1] The Signatory Parties, together with UIU, are referred to herein as the "Settlement Parties." One additional party, Friends Against Rural Mismanagement ("FARM"), appeared in these proceedings. FARM had the opportunity to participate in the negotiations that led to this Joint Proposal, however it chose not to participate in settlement negotiations.

[2] Case 18-G-0133, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of St. Lawrence Gas Company, Inc. for Gas Service*, is referred to herein as the "Expansion Rate Case" because it addresses the rates to be charged in SLG's "Expansion Area" served and to be served by the construction of new facilities authorized by the Commission in prior proceedings, including Case 10-T-0154, *Application of St. Lawrence Gas Company, Inc. for a Certificate of Environmental Compatibility and Public Need Pursuant to Article VII of the PSL for the Construction, Operation and Maintenance of a New 8, 6 and 4-inch Steel, High Pressure Natural Gas Transmission Line and Related Land and Equipment from the Town of Norfolk, St. Lawrence County to the Town of Chateaugay, Franklin County* and Case 10-G-0295, *Petition of St. Lawrence Gas Company, Inc. for an Original Certificate of Public Convenience and Necessity Under Section 68 of the PSL for the Exercise of Gas Franchises of Numerous Municipalities in the Counties of Franklin and St. Lawrence*. Case 18-G-0140, *Joint Petition of Liberty Utilities Co. and St. Lawrence Gas Company, Inc. for Approval, Pursuant to Section 70 of the PSL, of the Acquisition of St. Lawrence Gas Company, Inc. by Liberty Utilities Co. and for Approval, Pursuant to Section 69 of the PSL, for the Issuance of Long-Term Indebtedness* (the "Acquisition and Financing Case"), which addresses the proposed acquisition of St. Lawrence Gas by Liberty Utilities (the "Acquisition" or the "Transaction"), is referred to herein as the "Acquisition and Financing Case."

"Pre-Tax Basis Point" shall mean the revenue requirement equivalent of a basis point on common equity, as measured for the Legacy Area system.

"Rate Year 1" or "RY 1" shall mean the 12-month period ending May 31, 2017. This is the same period as "Rate Year 1" in the 2016 Rate Plan.

"Rate Year 2" or "RY 2" shall mean the 12-month period ending May 31, 2018. This is the same period as "Rate Year 2" in the 2016 Rate Plan.

"Rate Year 3" or "RY 3" shall mean the 12-month period ending May 31, 2019. This is the same period as "Rate Year 3" in the 2016 Rate Plan.

"Rate Year 4" or "RY 4" shall mean the 12-month period ending May 31, 2020.

"Rate Year 5" or "RY 5" shall mean the 12-month period ending May 31, 2021.

"Rate Year 6" or "RY 6" shall mean the 12-month period ending May 31, 2022.

"Secretary" shall mean the Secretary to the Commission.

B. Background

1. Expansion Rate Case

On February 26, 2018, SLG filed revised leaves to its gas tariff, PSC No. 3—GAS, to take effect April 1, 2018, along with prepared written testimony and exhibits of SLG witnesses in support of the proposed tariff changes. SLG's revised tariff leaves sought to: (1) extend the development period for the Expansion Project for an additional 15 years, (2) renew the Temporary Revenue Surcharge applicable to Expansion Area customers,[3] and (3) reduce the applicable Contribution in Aid of Construction ("CIAC") volumetric surcharge rate applicable to Expansion Area customers and extend the CIAC payment term through the proposed

[3] When SLG filed the Expansion Rate Case, the Temporary Revenue Surcharge was set to expire in November 2018. SLG proposed to renew the surcharge and have it continue through the proposed extended development period.

development period. SLG's proposed, revised tariff leaves did not propose an increase to its base delivery revenues.

In 2011, the Commission issued an order that, among other things, issued a Certificate of Public Convenience and Necessity authorizing SLG to exercise gas franchises in numerous municipalities in the Expansion Area.[4] At the time, the Expansion Project's expected cost was projected to be $23.5 million. Before beginning construction, SLG sought to revise the terms under which it could construct the Expansion Project, as the estimated costs had increased. In 2012, the Commission issued an order amending the Company's Certificate of Public Convenience and Necessity (the "2012 Order").[5] As is relevant here, the 2012 Order authorized the Expansion Project to move forward with an expected cost of $40.5 million. Further, the 2012 Order provided for a Temporary Revenue Surcharge to be paid by Expansion Area customers. That Temporary Revenue Surcharge would be charged for the first 60 months beginning when service was provided to the first Expansion Area customer. The 2012 Order also required SLG to charge Expansion Area customers a CIAC surcharge, the volumetric rate of which varied by customer service classification. SLG was required to charge the CIAC surcharge to Expansion Area customers. In addition, the 2012 Order continued the five-year development period, and updated the Company's return on equity.

In its February 26, 2018 filing in the Expansion Rate Case, SLG explained that the Expansion Project costs had increased above $40.5 million. By September 30, 2017, the actual cost of the portion of the Expansion Project completed at the time of filing was $52.2 million. SLG's Expansion Rate Case filing sought authorization to recover the cost overruns associated

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4 *See* Cases 10-G-0295 and 10-T-0154, *supra*, Order Granting Certificate of Environmental Compatibility and Public Need and Authorizing Exercise of Gas Franchises (Issued Feb. 18, 2011).

5 *See* Case 10-G-0295, *supra*, Order Granting Amendment of Certificate of Public Convenience and Necessity (Issued July 13, 2012).

with that portion of the Expansion Project, approximately $11.7 million, and to recover the estimated cost to complete the remainder of the Expansion Project, approximately $18.6 million.

2. Acquisition and Financing Case

On February 28, 2018 in the Acquisition and Financing Case, SLG and Liberty Utilities[6] filed a petition (the "Petition") for Commission approval under Section 70 of the New York Public Service Law ("PSL") for the purchase of all of the outstanding common stock of SLG by Liberty Utilities and, as a result, ownership of SLG and its two non-regulated subsidiaries, St. Lawrence Gas Co. Service & Merchandising Corp. ("SLG Service & Merchandising") and S.L.G. Communications Corp. ("SLG Communications"),[7] by Liberty Utilities.[8] The Joint Petitioners also sought Commission approval, pursuant to PSL § 69, for the issuance of long-term indebtedness to replace existing indebtedness of SLG (the "Financing"). With regard to the Financing, the Joint Petitioners requested authority for SLG to issue indebtedness in the amount of $32.5 million.[9] Further, the Joint Petitioners sought clarification or, to the extent necessary, modification of the SLG Affiliate Code of Conduct (the "Code") to accommodate participation of SLG, together with SLG Service & Merchandising and SLG Communications, under the Liberty Utilities Money Pool Agreement ("Money Pool"). The Petition was accompanied by

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6 Liberty Utilities, a Delaware Corporation, is a subsidiary of Algonquin Power & Utilities Corp. ("Algonquin").

7 SLG Service & Merchandising, a New York Corporation, is primarily engaged in the rental of water heaters and other natural gas appliances. SLG Communications, a New York Corporation, is primarily engaged in providing communications services to SLG.

8 Pursuant to the Securities Purchase Agreement (the "Agreement") executed by the Joint Petitioners on August 31, 2017 (Attachment 2 to the Petition), Liberty Utilities, or its subsidiaries, will acquire all of SLG's outstanding shares in exchange for the consideration of $70 million, subject to certain adjustments to be determined as of the closing date of the Transaction. The Agreement expressly acknowledges that Commission approval is a pre-condition to closing on the Transaction. Accordingly, closing will not occur until three business days after Commission approval of the Transaction and satisfaction of any other conditions precedent in the Agreement.

9 As indicated in the Petition, this amount consists of the balance on a note payable to Enbridge U.S. ($25.5 million at the time of filing) and a $7.0 million term loan from KeyBank. As described in Section V.B, *infra*, as of May 15, 2019, the balance on the note was approximately $23.0 million.

attachments, including prepared direct testimony and exhibits, supporting the proposed Transaction and Financing.[10]

II. PROCEDURAL SUMMARY

Following the filing of both the Expansion Rate Case and the Acquisition and Financing Case, on March 8, 2018, the Commission issued a notice, pursuant to PSL § 66, suspending the rates proposed in the Expansion Rate Case through July 29, 2018. A procedural and technical conference was held in that proceeding in Albany on April 17, 2018. Following that conference, various rulings were issued by the presiding Administrative Law Judges ("ALJs") in one or both cases to address scheduling and joinder of the two cases.[11] The parties to the two proceedings engaged in an exchange of discovery requests.[12] On June 11, 2018, SLG filed additional information in the Acquisition and Financing Case pertaining to the initial 12 months following the term of the 2016 Rate Plan (*i.e.*, Rate Year 4 information). Thereafter, the Commission, by Notice issued July 3, 2018, further suspended the effective date of rates in Case 18-G-0133 through January 29, 2019, the maximum period provided for in PSL § 66. Public Statement Hearings were held in both proceedings in Malone on August 15, 2018 and in Potsdam on August 16, 2018.[13] By Ruling on Schedule Modifications, issued August 16, 2018, the ALJs adopted a schedule requiring the filing of direct testimony by parties other than the Joint Petitioners by October 4, 2018 and the filing of rebuttal testimony by October 25, 2018.

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[10] For purposes of this Joint Proposal, references to the "Petition" are deemed to include its accompanying attachments, unless the context requires otherwise.

[11] In their Third Ruling on Schedule and Procedure, issued May 31, 2018 in both cases, the ALJs joined the cases.

[12] A total of 190 interrogatories were received from Staff and answered or otherwise addressed in the Expansion Rate Case; a total of 145 were received from Staff and answered in the Acquisition and Financing Case. In addition, MI propounded, and the Companies answered, one consolidated set of interrogatories with 31 individual questions in the Acquisition and Financing Case.

[13] A total of three individuals spoke in Malone and four in Potsdam.

Staff and Agri-Mark filed direct testimony and exhibits on October 4, 2018. Following that filing, Staff and the Joint Petitioners conducted exploratory discussions to determine whether settlement of some or all issues might be feasible and, on October 23, 2018, the Joint Petitioners filed and served a Notice of Impending Settlement Negotiations, proposing that the initial settlement conference be held in Albany on October 30, 2018. SLG and Liberty Utilities filed their rebuttal testimony and exhibits on October 25, 2018.

To accommodate settlement negotiations, which began on October 30, 2018 and continued, either in person or by telephone conference calls, among the Settlement Parties until the date the Signatory Parties filed this Joint Proposal, the ALJs repeatedly postponed the commencement of evidentiary hearings, as well as the filing of pre-hearing submissions. In addition, to enable such postponements in the litigation schedule and to allow sufficient time for the post-hearing process leading to a Commission decision, SLG agreed to a series of extensions to the statutory suspension period in the Expansion Rate Case, the most recent of which is through November 30, 2019.[14]

III. APPROVAL OF JOINT PROPOSAL AS IN THE PUBLIC INTEREST

The Signatory Parties recommend that the Commission approve the terms of this Joint Proposal without modification. The Signatories have concluded that the terms and conditions herein resolve all issues raised in the Expansion Rate Case and Acquisition and Financing Case in a manner that: (1) allows SLG to provide safe and adequate service at just and reasonable rates pursuant to PSL § 65; and, (2) provides for the acquisition of SLG by Liberty Utilities and issuance of indebtedness by SLG, in a manner that is in the "public interest" pursuant to PSL §§ 70 and 69, respectively.

[14] *See* Case 18-G-0133, *supra*, Request for Extension of Time (Filed May 3, 2019).

IV. TERMS GOVERNING THE EXPANSION RATE CASE

A. Rate Base and Capital Additions

1. Plant-in-Service Write-Down

The Expansion Area Plant-in-Service balance shall be reduced by $19.0 million (*i.e.*, removed from SLG's books of record). SLG shall file the actual journal entries with the Secretary effectuating this adjustment not later than 30 days after the issuance of the Commission order addressing this Joint Proposal.

2. Consolidation of Legacy and Expansion Rate Bases

The respective rate bases of the Legacy and Expansion Areas will be consolidated for ratemaking purposes no earlier than the date on which the Expansion Area is self-supporting or January 31, 2023, whichever occurs first. As used herein, "self-supporting" means that Expansion Area base rate revenues support the Expansion Area cost of service, including the rate of return as set forth in Section IV.E.1.a, below, without subsidization from Legacy Area customers.

3. Contributions in Aid of Construction

The current CIAC charges in the Expansion Area will continue until the earlier of: (a) the date that the Expansion Area is self-supporting, as described in Section IV.A.4, *supra*; or (b) January 31, 2023. If the CIAC charges terminate automatically on January 31, 2023 and the Expansion Area is not self-supporting at that time, shareholders will write-down plant-in-service to a level that allows the base rate revenues from the Expansion Area to cover the cost of service (excluding gas costs) for the Expansion Area without subsidization from Legacy Area customers. SLG and Liberty will not seek to otherwise extend or increase the current CIAC charges in future filings. On or before July 31st of each year until the CIAC charges terminate, SLG will file with the Secretary a report comparing of Expansion Area revenues and cost of service for the

preceding Rate Year ending May 31st. In addition, no later than six months prior to the anticipated termination of the CIAC charges, SLG will file with the Secretary a report identifying the estimated date by which the Company expects the Expansion Area to be self-supporting and provide the detail to support the basis for such estimate. The report six months prior to the termination of the CIAC charges shall be filed no later than July 31, 2022, *i.e.*, six months prior to the January 31, 2023 sunset date for the CIAC charges. Each of these reports shall include the form included in Appendix 1.

4. <u>Network Enhancement</u>

For Calendar Year ("CY") 2019, SLG will limit its network enhancement in the Expansion Area to prospective customers who meet the criteria for attachment to existing gas mains pursuant to the Commission's entitlement regulations. For CY 2020, SLG will file with the Secretary, by December 31, 2019, a business case demonstrating the economic feasibility, inclusive of estimated capital expenditures, for SLG's intended distribution enhancements it intends to construct in CY 2020. The business case will include: (1) project cost estimates; (2) prospective customer survey results (with potential customers' current energy type); (3) historic and projected natural gas and alternative energy costs; (4) number of total potential new customers, number of committed customers (5) annual conversion estimates for the first five years; (6) annual projected volumetric throughput for the first five years; (7) annual projected revenues for the first five years; and, (8) any other information SLG considers relevant. Any proposed construction would begin after May 1, 2020. Staff will review the filing and SLG commits to working with Staff to resolve any concerns with or to make modifications to the filed plan. Should issues arise that SLG and Staff cannot resolve, the matter may be brought to the Commission for action. For CY 2021 and each calendar year thereafter until base rates are next reset by the Commission, SLG will follow this procedure with regard to proposed Expansion

Area capital projects and expenditures for each year. The foregoing requirement for a business plan shall not preclude SLG from extending service to prospective customers who meet the requirements of the Commission's rules and regulations for extensions of service or who otherwise agree to pay the full cost of such main extensions.

5. Construction Budget and Variance Procedures

For any future Expansion Area construction, SLG will follow the construction budget and variance procedures set forth below in Section V.A.9.b.

B. Expansion Area Cost of Service

1. Temporary Revenue Surcharge

The Temporary Revenue Surcharge, that had been authorized for a five-year "development period," as described in the 2012 Order, terminated as of November 25, 2018 and will not be renewed.

2. Recovery of Expansion Area Cost of Service

The prospective cost of service related to the Expansion Area, including operation and maintenance ("O&M") expenses, depreciation expenses, taxes other than income taxes, and return on investment associated with the Expansion Area, will only be recovered through base rates. The Signatory Parties agree that there shall be no special provision for recovery or deferral of the cost of service related to the Expansion Area, including, but not limited to, the following costs specifically requested by SLG in the Expansion Rate Case: (1) the expenses incurred during the fiscal years 2014 through 2017;[15] (2) additional expenses incurred in the period from 2018 through the date when the Expansion Area and Legacy Area rate bases are combined, that

[15] SLG set forth the costs it sought to recover in Case 18-G-0133, Exhibit __ (FP-1A). As proposed by SLG, these costs amount to approximately $3.0 million.

were intended to be recovered through the Temporary Revenue Surcharge;[16] and, (3) the rate case expenses incurred in this proceeding.[17]

C. Outreach and Education Plan

On or before January 1st of each year until the CIAC charges discussed above in Section IV.A.3. cease, SLG will prepare and submit to the Secretary, in Case 18-G-0133, an Outreach and Education ("O&E") Plan pertaining to the Expansion Area. In addition, following the issuance of an order adopting the terms of this Joint Proposal, SLG will sponsor at least two public information forums at different locations within the Expansion Area to inform customers of the outcome of this proceeding. These public information forums shall take place within 60 days of the date of the Commission's order regarding this Joint Proposal.

D. Accumulated Deferred Federal Income Taxes

SLG will adjust the Accumulated Deferred Federal Income Taxes ("ADFIT") balance to reflect the impact of the write-down to plant-in-service. In addition, SLG will evaluate the amount of excess ADFIT that was deferred as a result of the Tax Cuts and Jobs Act of 2017, and, if necessary, will adjust the balance to reflect the impact of the write-down to plant-in-service. The Signatory Parties recognize that, in accordance, with the Commission Order in Case 17-M-0815, SLG will defer the excess ADFIT until it can be addressed in the Company's next base rate proceeding.[18] Not later than 30 days after the date of the Commission order addressing this Joint Proposal, SLG shall file with the Secretary the actual journal entries effectuating any adjustments. If as a result of its evaluation, SLG understands that it does not need to adjust

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16 These expenses are identified in Case 18-G-0133, Exhibit __ (FP-1A) and, as presented, covered the originally proposed 15-year development period.

17 At the time of filing of Case 18-G-0133, SLG estimated these expenses at $658,000. *See* Case 18-G-0133, SLG Finance Rebuttal Testimony at 23.

18 For purposes of clarity, the Commission's Order in Case 17-M-0815 requires that SLG defer the excess ADFIT related to the Legacy Area until addressed in the Company's next base rate proceeding.

excess ADFIT, it will file an explanation of its evaluation in lieu of the applicable journal entries. Further, in the event the Company makes an additional write-down to plant-in-service, the ADFIT balance would be revised to reflect the impact of that write-down, including the balance of excess ADFIT, as needed.

E. Rate of Return and Capital Structure

1. Cost of Capital

a. Return on Equity

Solely for purposes of determining whether the Expansion Area is self-supporting, a return on equity ("ROE") of 8.60% will be used.

b. Capital Structure and Cost Rates

The total cost of capital for the purpose of measuring whether the Expansion Area is self-supporting is based upon a 48.0% common equity ratio, together with a debt ratio of 51.2% and a customer deposits ratio of 0.8%. The capital structure will include the long-term debt to be issued pursuant to the request in the Acquisition and Financing Case. The cost rates are 8.6% for ROE, 4.4% for long-term debt[19] and 2.45% for customer deposits[20] and will be incorporated into the total cost of capital.

[19] The cited rate, 4.4%, is the current embedded cost of debt for Liberty Utilities, which is subject to change to reflect Liberty Utilities' embedded cost of debt when the Acquisition closes.

[20] The cited rate, 2.45%, is the current Commission-approved Customer Deposit Rate. The Commission updates this rate annually, and SLG's calculations shall reflect the rate currently in effect at the time of the calculation.

V. TERMS GOVERNING THE ACQUISITION AND FINANCING CASE

A. Acquisition of SLG

1. Corporate Structure

a. Corporate Governance and Operational Provisions

(i) Liberty Utilities East Region Board of Directors Membership

No later than one year after the closing of the Acquisition of SLG, Liberty Utilities will appoint to its East Region Board of Directors ("Board") an independent director who is a resident of the service area of SLG within the State of New York; provided that, in the event that Liberty Utilities acquires one or more additional utilities within the State of New York that are regulated by the Commission, this requirement may be satisfied by the appointment of an independent director who is a resident of either the service area of SLG or the service area of such other utility or utilities as may be acquired by Liberty Utilities. For purposes of this requirement, "resident of the service area" may include the circumstance in which the personal residence of the director is within one of the counties in which the utility provides service, but not within the relevant service area itself; provided that the director's principal place of business or employment is within such service area. Except for this residency requirement, an independent director selected in compliance with such requirement will be subject to the requirements for Board membership that apply generally to other Board members. In the event of retirement or removal of a director selected to comply with the foregoing residency requirement, a replacement director meeting this residency requirement will be selected as soon as practicable, consistent with the requirements generally applicable to the selection of directors.

(ii) Headquarters

SLG's corporate headquarters will remain within SLG's service territory, subject to the right of SLG to petition the Commission for approval to relocate its corporate headquarters

outside of SLG's service territory no earlier than five years following the closing of the Acquisition.

b. Financial Transparency and Reporting

To enable Staff to determine whether the rates and charges of SLG are just and reasonable, Liberty Utilities shall provide Staff access to its accounting policies, books and records, including consolidated tax returns. In addition, Liberty Utilities shall annually file with the Secretary the consolidated audited financial statements of Liberty Utilities, including balance sheets, income statements, cash flow statements and related notes. The parties recognize that Liberty Utilities may request confidential treatment for the filing (*i.e.*, filed with the Department of Public Service Records Access Officer).

c. Affiliate Transactions and Cost Allocation

Within six months following the closing of the Acquisition and annually, within 45 days of the end of the CY, thereafter, SLG shall file with the Commission the amount of Liberty Utilities intercompany charges made among Liberty Utilities and its affiliates that are applicable to SLG. Such filing shall include a description of how the identified intercompany charges were derived.

d. Code of Conduct

Upon closing of the Acquisition, Liberty Utilities and its affiliates will comply with the Code (Appendix 2), which is a revision of, and, upon adoption of this Joint Proposal, will supersede, the Code filed pursuant to Joint Proposal Section VIII.D.2 of the 2016 Rate Plan.

2. Rate Freeze

SLG's next base rate filing will be dependent on the use of a test period reflecting a full year of Liberty Utilities ownership of SLG. Additionally, the first such filing will provide for continuity from the Rate Years under the 2016 Rate Plan by using a Rate Year commencing on

or after June 1 of the earliest CY in which new rates could go into effect using such test period.[21] Prior to the effective date of any new rates that are approved pursuant to such filing, the rates currently in effect pursuant to the 2016 Rate Plan for the third rate year referenced therein (*i.e.*, the 12 months ending May 31, 2019) will remain in effect, subject to any surcharges or surcredits authorized by the 2016 Rate Plan.

3. Capital Structure and Financial Protections

a. Debt Cost Rates and True-Up

For future rate filings following the closing of the Acquisition, SLG will use the Liberty Utilities embedded cost of debt for long-term debt. The true-up mechanism for short-term interest rates adopted in the 2016 Rate Plan will continue in effect during the term of this Joint Proposal and thereafter, until changed by the Commission, with the exception that, at the time of the refinancing of the Enbridge U.S. Note Payable short-term debt with long-term debt, Liberty Utilities' embedded cost of debt will be used in place of SLG's actual short-term debt cost rate. If, however, SLG's annual earnings filing with the Secretary indicates that SLG's Legacy Area is overearning the allowed rate of return and the true-up would result in a deferral to be recovered from customers, SLG will not be allowed to true up its actual interest rate cost with the cost upon which its rates were set ("True-Up Interest Rate Cost") for the period during which SLG was overearning. Should the true-up result in a deferral to be recovered from customers in excess of SLG's overearnings, SLG shall be permitted to recover its True-Up Interest Rate Costs net of overearnings.

[21] As a practical matter, these conditions preclude any change in rates prior to June 1, 2022, subject to the provisions of Section VI.F, *infra.*

b. Financial Protections

(i) Goodwill

SLG and Liberty Utilities shall not pass along to customers of SLG the premium above book value paid by Liberty Utilities to acquire SLG (*i.e.*, goodwill) or the transaction costs attributable to the Acquisition. Thus, the goodwill associated with this transaction shall not be shown in SLG's PSC annual report or included in the equity component of SLG's capitalization for purposes of calculating SLG's return, future revenue requirements, or any other component of SLG's rates. Following closing of the Acquisition, SLG shall file the goodwill calculation as soon as it is available, subject to the time frame determined in accordance with U.S. Generally Accepted Accounting Principles.

(ii) Minimum Common Equity Ratio & Minimum Credit Quality

To support the stand-alone ability of SLG to attract capital, Liberty Utilities and SLG will seek to maintain the common equity capitalization ratio of SLG at the level used by the Commission in establishing SLG's rates. In furtherance thereof, (1) SLG shall maintain a minimum common equity ratio ("MER") subject to a dividend restriction; and, (2) Liberty Utilities shall maintain a minimum BBB debt rating as described in parts (a) and (b), respectively, below.

(a) Minimum Common Equity Ratio

At each month end, Liberty Utilities and SLG agree to maintain an MER (measured using a trailing 13-month average) in relation to the common equity ratio used to set rates, *i.e.*, 48%. The MER is defined as no less than 300 basis points below the approved common equity ratio used to set rates. In the event that the MER is not met, no dividends are payable until such time as the MER is restored.

(b) Minimum Credit Quality

In the event that Liberty Utilities' Standard & Poor's ("S&P") debt rating is downgraded below BBB within three years following the closing of the Acquisition, the cost of any debt issued during such three-year period will be determined using an imputed BBB rating. If Liberty Utilities debt rating is downgraded below BBB within three years of the closing of the Acquisition and Liberty Utilities issues debt, then in subsequent rate cases Liberty Utilities' cost of debt for any debt issued within the three years following the closing of the Acquisition will be adjusted downward as if the debt had been issued at an S&P credit rating of BBB or a Moody's Investor Service ("Moody's") credit rating of Baa2.

During the three years following the closing of the Acquisition and, at the time of debt issuance, Liberty Utilities shall submit to Staff comparable public utility debt issuance data for a time period commencing and ending 60 days before and after the Liberty Utilities debt issuance. The credit spreads for the Liberty Utilities debt issuance will then be compared to the public debt issuance data for like tenors to determine the credit spread differential resulting from the Liberty Utilities debt issuance not carrying an S&P credit rating of BBB or a Moody's credit rating of Baa2. This credit spread differential will be applied to the Liberty Utilities debt so issued for purposes of calculating Liberty Utilities' cost of debt in a subsequent rate case. Should there not be a matching tenor between any of the Liberty Utilities debt issued and the comparable public utility debt issuances, the credit spread for the missing tenor will be interpolated based on the available credit spreads. Liberty Utilities and Staff will work in good faith to determine the credit spread differential to be applied.

(iii) Money Pooling

SLG may participate in a money pool as a borrower or lender only if the other participants are regulated utilities, with the exception that Liberty Utilities may participate, but

only as a guarantor of loans made by that money pool and to provide funding to the money pool in the event that other participant-supplied funds on any given day are insufficient to meet the need for funds by the borrowing participants. SLG shall not participate in a money pool as a lender if any of the other participants are not regulated utilities. This does not preclude the unregulated affiliates of SLG in participating in a separate money pool that does not include SLG.

c. Earnings Sharing Mechanism

For Rate Years 4, 5 and 6, the Earnings Sharing Mechanism ("ESM") shall be reported each Rate Year on an annual basis but measured cumulatively. The annual report shall be filed not more than 90 days following the end of each Rate Year. To ensure clarity for the ESM calculations for Rate Years 4, 5 and 6, SLG's earnings shall be measured for the Legacy Area only[22] and shall be calculated using the lower of SLG's actual common equity ratio or the common equity ratio used to set rates, *i.e.*, 48.0%. For purposes of the earnings calculation required by the 2016 Rate Plan, the incremental costs attributable to the Acquisition, as provided in such cost summaries, will be excluded. Should SLG not file for new rates to be effective on June 1, 2022, the ESM for any additional periods, *e.g.*, what could be thought of as a "Rate Year 7," shall be measured on an annual basis and filed annually not more than 90 days following the end of each Rate Year. Appendix 3 sets forth the SLG Capital Structure and Cost of Capital.

4. Positive Benefit Adjustments

SLG's shareholders shall fund: (a) a Carbon Reduction Initiative ("CRI"), to be developed in consultation with Staff, in the total amount of $1.0 million over three years to assist

[22] Should the Expansion Area be self-sufficient and the CIAC terminated, prior to the next time SLG's base rates are reset, SLG's earnings would be measured on a Company-wide basis for the Rate Year beginning after the CIAC ends and thereafter.

new and existing residential and small general firm service customers seeking to install high-efficiency natural gas equipment and weatherization;[23] and, (b) a deferral of $0.5 million for the future benefit of customers, as determined by the Commission. With regard to the CRI, at the conclusion of the aforementioned three-year period, the Shareholder-funded CRI will expire, and SLG shall defer any unspent funds for the future benefit of customers, as determined by the Commission. In the next proceeding to set base rates for SLG, the parties to that proceeding may propose to continue the CRI and address the source of funding for the continued or re-established CRI.

5. Savings and Cost Trackers

a. Acquisition and Transition Costs

Within 90 days after the issuance of a Commission order approving the Acquisition, SLG shall file cost summaries separating the incremental costs attributable to the Acquisition (*i.e.*, the costs that would not have been incurred in the absence of the Acquisition) from those costs that would have been incurred absent the Acquisition. SLG shall also track any transition expenses and capitalized costs and any benefits arising from such costs and provide the results of such tracking in the filing for its first post-Acquisition rate proceeding to enable the Commission to determine whether any of the capitalized costs should be recovered from customers, as well as to determine whether any of the expenses should be removed from the historic test year data. The mechanism to be used in tracking the aforementioned costs and benefits is described in Appendix 4.

[23] The CRI is separate and distinct from the "Marketing and Incentives for Conversions" (the "M&IC Program") authorized in Paragraph III (g) of the 2016 Rate Plan. The M&IC Program will continue until the Commission resets SLG's base rates.

b. Synergy Savings

SLG shall track any synergy savings and provide the results of such tracking in the filing of its first post-Acquisition rate proceeding. The synergy savings will identify the gross savings attributable to particular operational changes, as well as the costs to achieve, so as to arrive at the net synergy savings. The mechanism to be used in tracking any synergy savings that result from the Acquisition during the period until base rates are next re-set is described in Appendix 4.

c. Future Acquisition Savings

In the event that Liberty Utilities, Algonquin, or an affiliate of either completes any additional mergers or acquisitions within the United States or Canada, before the Commission adopts its next order approving new base rates for SLG, Liberty Utilities will track and report to the Secretary any savings resulting from such merger or acquisition that would reasonably be applicable to SLG or its customers. Such savings will be deferred and shared between shareholders and customers, on a 50/50 basis, to the extent that the portions of such savings realized by Liberty Utilities are material (*i.e.*, five percent or more of SLG net income on an after-tax basis). In the event that such a merger or acquisition results in any increased costs to SLG, SLG shall file, on an annual basis, a report describing such costs. The mechanism to be used in tracking the aforementioned savings and costs is described in Appendix 4.

6. Gas Safety

a. Metrics

Appendix 5 hereto sets forth the metrics applicable to SLG in the subject areas of Emergency Response Time, Damage Prevention, Leak Backlog and Safety Violations (both High-Risk and Other Risk) on a CY basis for CY 2019 and CY 2020. A total of 138 Pre-Tax Basis Points will be at risk per CY for SLG's performance under the Gas Safety Performance Metrics, as described below. All safety metric targets, Negative Revenue Adjustments

("NRAs") and Positive Revenue Adjustments ("PRAs") applicable in CY 2020 will remain in effect until changed by the Commission.

(i) Emergency Response

SLG will incur an NRA if it fails to meet the current CY statewide emergency response performance levels of responding to 75% of leak and odor calls in 30 minutes, 90% of leak and odor calls in 45 minutes and 95% of leak and odor calls in 60 minutes. Failure to meet the goal of 75% in 30 minutes will result in an NRA of nine Pre-Tax Basis Points. Failure to meet the goal of 90% in 45 minutes will result in an NRA of six Pre-Tax Basis Points. Failure to meet the goal of 95% in 60 minutes will result in an NRA of three Pre-Tax Basis Points. The foregoing emergency response CY targets and associated CY NRAs are subject to a maximum annual NRA of 18 Pre-Tax Basis Points.

SLG will earn a PRA of three Pre-Tax Basis Points if SLG meets the CY emergency response performance of greater than 85% of leak and odor calls in 30 minutes. SLG will earn a PRA of six Pre-Tax Basis Points for CY emergency response performance of greater than 90% of leak and odor calls in 30 minutes. The limit on PRAs as applied in any one CY is six Pre-Tax Basis Points.

The Emergency Response NRA BP shall be increased by 150% if a target is missed during a dividend restriction, as described above in Section V.A.3.b.*(ii)(a)* of this Joint Proposal, and increased by 200% if a target is missed three years within the next consecutive five CYs.

(ii) Damage Prevention

Beginning with CY 2019, SLG will incur an NRA for exceeding the following targets, measured in instances per 1,000 "one-call" tickets, for damages to Company facilities. In CY 2019, the Company will incur an NRA of five Pre-Tax Basis Points for exceeding 2.85 instances of overall (total) damages, 15 Pre-Tax Basis Points for exceeding 2.95 instances of

overall (total) damages, and 27 Pre-Tax Basis Points for exceeding 3.00 instances of overall (total) damages. In CY 2020, the Company will incur an NRA of five Pre-Tax Basis Points for exceeding 2.75 instances of overall (total) damages, 15 Pre-Tax Basis Points for exceeding 2.85 instances of overall (total) damages, and 27 Pre-Tax Basis Points for exceeding 3.00 instances of overall (total) damages. The limit on NRAs as applied in any one CY is 27 Pre-Tax Basis Points. Imposition of the foregoing NRAs is subject to the additional requirement that, if a target is missed on an annual basis, the NRA will only be triggered if the Company also misses the target on a two-year "lookback" basis.

In CY 2019, the Company will earn a PRA of five Pre-Tax Basis Points for performance less than or equal to 2.25 instances of overall (total) damages and ten Pre-Tax Basis Points for less than 2.00 instances of overall (total) damages. In CY 2020, the Company will earn a PRA of five Pre-Tax Basis Points for performance less than or equal to 2.15 instances of overall (total) damages and ten Pre-Tax Basis Points for less than 1.90 instances of overall (total) damages. The limit on PRAs as applied in any one CY is ten Pre-Tax Basis Points.

(iii) Leak Backlog

For CY 2019, SLG will be assessed an NRA of 18 Pre-Tax Basis Points if the Company has more than five Type 1, 2, 2A and 3 leaks in backlog pending repair, including repairs that failed re-checks, on December 31 of the respective year. For CY 2020, SLG will be assessed an NRA of 18 Pre-Tax Basis Points if the Company has more than four Type 1, 2, 2A and 3 leaks in backlog pending repair, including repairs that failed re-checks, on December 31 of the respective year. The maximum NRA that may be assessed for this metrics is 18 Pre-Tax Basis Points. The Leak Backlog NRA BP shall be increased by 150% if a target is missed during a dividend restriction, as described above in Section V.A.3.b*(ii)(a)* of this Joint Proposal, and shall be increased by 200% if a target is missed three years within the next consecutive five CYs.

(iv) Gas Safety Violations Performance Measures

Beginning CY 2019, the Company will be assessed an NRA for instances of High Risk and Other Risk noncompliance (occurrences) of certain pipeline safety regulations set forth in 16 NYCRR Parts 255 and 261, as identified during Staff's annual field and record audits. Appendix 5 sets forth the type of audit (record or field), the violation category risk (high or other), the number of occurrences and associated NRAs. Appendix 5 also contains a list of identified High Risk and Other Risk pipeline safety regulations pertaining to this metric. The limit on NRAs as applied in any one CY is 75 Pre-Tax Basis Points.

Repeated failure to follow a step or requirement that constitutes a violation will result in multiple occurrences of such violation. Failure to follow a Company procedure will be cited as a single occurrence under 16 NYCRR Part 255.603.

b. Operator Qualification and Other Safety Requirements

On February 12, 2019, the Department of Public Service, Office of Electric, Gas and Water, Pipeline Safety Section filed the Operator Qualification White Paper.[24] In the event that Commission action regarding the White Paper leads SLG to incur incremental costs in RYs 4, 5 and/or 6, SLG is not precluded from filing a petition with the Secretary requesting deferred accounting treatment, as provided for below in Section V.A.12.

7. Customer Service

a. Service Quality Performance Mechanism

The Service Quality Performance Mechanism ("SQPM") shall continue in its current form, with adjusted targets and revenue adjustments to two of the three metrics. Performance for all measures shall be assessed on a CY basis. The SQPM shall continue until modified by the

[24] Case 14-G-0212, *Proceeding on Motion of the Commission to Investigate the Practices of Qualifying Persons to Perform Plastic Fusions on Natural Gas Facilities*; and Case 17-G-0318, *In the Matter of an Investigation into Local Distribution Company Use of Northeast Gas Association Operator Qualification Program.*

Commission. In any CY that SLG fails to achieve any of the service quality thresholds, a revenue adjustment will be imposed for the year equal to the dollar amount assigned to the threshold. Revenue adjustments will be in pre-tax dollars. Revenue adjustments pursuant to this mechanism will be deferred for future customer use. Appendix 6 hereto sets forth the metrics applicable to SLG in the subject areas of PSC Complaint Rate, Customer Satisfaction Index and Terminations and Uncollectible Expense on a CY basis. In each case, the targets and NRA and PRA applicable in CY 2019 will be modified for CY 2020, as indicated in Appendix 6, and will remain in effect at their 2020 levels until modified by the Commission.

(i) PSC Complaint Rate

A complaint threshold shall be measured by PSC complaint data for the 12-month period covered by each CY. During the term of this Rate Plan, and until otherwise directed by the Commission, the PSC Complaint Rate is the 12-month escalated complaint rate as reported by Staff to the Company by January 15 of the following year that includes data for January through December of each CY. If the PSC Complaint Rate in any year of the Rate Plan is greater than or equal to 1.5, SLG will be subject to a minimum NRA. If the PSC Complaint Rate for any year is greater than or equal to 2.5, SLG will incur the maximum NRA. SLG will be assessed potential NRAs on this measure, shown in Appendix 6.

If changes are made to the complaint handling procedures or contact classifications on which these threshold rates are based, then the measurement method and the complaint targets should be modified. Any such modifications would be established based on a reasonable period of experience, be mutually agreed upon by Staff and SLG and filed with the Secretary. In the event that Staff and SLG cannot agree on such a period, the matter would be handled in accordance with the dispute resolution mechanism described in Section VI.G. of this Joint

Proposal. The threshold and complaint rate targets set forth in Appendix 6 shall remain in effect until the matter is resolved by agreement or Commission order.

(ii) Overall Customer Satisfaction Index

An overall customer satisfaction index shall be calculated based on the results of the annual customer satisfaction survey and will reflect the percentage of customers satisfied with the service they receive from SLG. The survey will be conducted by an independent vendor on a group deemed to be representative of SLG's residential customers and a second group deemed to be representative of its commercial and industrial customers. If the overall satisfaction index in any year of the Rate Plan is equal to or below 86%, SLG will be subject to a minimum negative revenue adjustment. If the satisfaction index is equal to or below 84%, SLG will incur the maximum negative revenue adjustment. SLG will be assessed potential negative revenue adjustments on this measure, shown in Appendix 6.

(iii) Customer Satisfaction Survey

SLG shall continue to have an independent customer satisfaction survey that will allow SLG to accurately assess its level of service and make any necessary improvements. Within 60 days after such surveys are completed, SLG shall report to the Secretary the results of the survey, propose any changes to minimum, intermediate and maximum customer satisfaction indices to be used in determining performance according to the scale shown in Appendix 6, and describe how it plans to address legitimate customer suggestions, if any, that are developed as a result of the survey.

(iv) Negative Revenue Adjustment Multiplier

The NRAs shown in Appendix 6 have been doubled from those in the 2016 Rate Plan. In addition, the NRAs shall be tripled if targets are missed during a dividend restriction and quadrupled if targets are missed in three years out of the next five consecutive CYs.

(v) Terminations and Uncollectible Expense Incentive

SLG shall continue the Terminations and Uncollectible Expense measure to foster a reduction in customer terminations and in uncollectible expenses. This measure shall be positive only and calculated on a CY basis, as shown in Appendix 6. Specifically, SLG shall be entitled to an incentive of $12,000 per year if both measures are at or below target set forth in Appendix 6, unchanged from the 2016 Rate Plan, and $6,000 per year if one measure is at or below target and the other is at or below the three-year average (set in 2016). If neither measure is at or below the target, SLG shall not be entitled to any positive incentive but shall not be subject to any NRA.

b. Employment Levels

To ensure the Company's customer service related staffing does not decline following the Acquisition, the Signatory Parties agree that SLG will provide the formal training plan, it will develop with Liberty Utilities' guidance, for Staff review within 90 days of the date of the Commission's order regarding this Joint Proposal. Once the plan is reviewed by Staff, all employees currently involved in customer service duties at SLG will take the training no later than December 31 of the CY following the year in which the Acquisition closes. SLG shall ensure that a minimum of ten employees receive this training. SLG shall submit to the Secretary a report specifying the employees trained to perform customer service duties January 31 of the following CY. Following this initial report, SLG shall annually submit a report on January 31 of each subsequent year updating the list of employees who receive full training for the first time, employees who receive an annual refresher, listing the employees who perform customer service duties, and listing any employees who no longer perform such duties, if applicable. Following the implementation of training, SLG will ensure that it maintains at least a minimum of ten employees trained to perform customer service duties. The requirement regarding the minimum

number of employees trained to perform customer service duties will remain in effect until modified by the Commission.

c. Actions to Improve Customer Service

To improve service to its customers, SLG will prepare and file with the Secretary, within 60 days of a Commission Order addressing this Joint Proposal, a Customer Service Improvement Plan. Commencement of implementation of such Customer Service Improvement Plan will occur no later than 30 days following such filing. The cost of implementing such a Customer Service Improvement Plan will be borne by shareholders until rates are next set by the Commission. When it next files a base rate case, SLG shall address the plan and whether it should continue.

8. Timely Filings

SLG will incur an NRA of three Pre-Tax Basis Points for each instance in which SLG fails to make a complete filing by the relevant deadline specified by applicable statute, regulation or Commission order, or fails to request an extension or waiver of such deadline, where an extension or waiver is possible,[25] in a timely fashion.[26] SLG will have the right to request a waiver of the imposition of an NRA by demonstrating good cause for the failure. This requirement shall remain in effect until changed by the Commission. The Signatory Parties recognize that SLG may request discontinuance of this requirement when it next files a base rate case.

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[25] The Signatory Parties recognize that the Secretary may not have the authority to extend a particular deadline. Should SLG seek to rely on a request to the Secretary for an extension to demonstrate that it has meet the requirements of this provision, SLG must demonstrate that the requested extension is one that the Secretary has the authority to grant.

[26] For requests for extensions made to the Secretary, except as otherwise provided in the relevant requirement, *e.g.*, in the relevant Commission order or issuance from the Secretary, a timely request is understood to mean a request made in writing not less than one day in advance of the relevant deadline. For requests for extensions or waivers that would require Commission action, a timely request means a request made in writing, *e.g.*, in the form of a petition, at a time that allows the Commission to act on the request prior to the relevant deadline.

9. Capital Expenditures and Reporting

a. Budgeting Process

SLG will comply with the "Liberty Way Policy and Procedure: Capital Expenditures – Planning and Management," which defines the Liberty Utilities capital processes from planning through construction, unless such processes are in conflict with more stringent standards specified in Commission orders, in which case, the latter will supersede the former.

b. Construction Budget and Variance Procedures

For any future Expansion Area construction, SLG will follow the construction budget and variance procedures set forth below in Section V.A.9.c. No later than December 31, 2019, SLG will establish and provide to Staff a set of procedures and appropriate controls to address the following four areas pertaining to construction budget and variance procedures: (a) a process to base projects on engineering analysis and design; (b) project investment thresholds to allow for timely monitoring and oversight by the Board and the Commission; (c) procedures to enter into construction contracts before any work commences; and (d) a process requiring re-approval of projects by the Board when a significant change in scope or budget will cause an increase of 10% or more in capital expenditures, compared with the previously approved budget.

c. Filing of Capital Budgets and Variance Reports

Within 30 days of approval by the Board, SLG will file its approved annual capital expenditure budget with the Secretary. In addition, within two months following the end of the CY, SLG will file with the Secretary the Company's monthly variance reports for such CY.

d. Legacy Area Net Plant True-Up Mechanism

A downward-only net plant true-up shall be used to determine if SLG has spent its Legacy Area capital budget in Rate Years 4 and 5 on a cumulative basis. The starting point for the analysis is the Rate Year 3 actual ending balances of plant in service, Construction Work in

Progress, and accumulated depreciation. For Rate Years 4 and 5, the estimated Legacy Area capital investment amounts are $2.028 million and $1.732 million, respectively. The foregoing two capital investment amounts will be included in the first line ("Utility Plant") as shown in Appendix 7 to determine the "Net Plant Targets."

The net plant targets will continue at the Rate Year 5 minimum level until SLG's rates are next reset. Rate Year 6 will not have a set capital investment amount, but SLG will be expected to spend the amount of capital required to prudently own and operate the system. At the end of Rate Year 5, SLG shall review the actual net plant in service for Rate Year 5 to determine whether that amount is greater or less than the net plant in service target for that year, computed as indicated above. If the actual net plant in service amount exceeds the target, there will be no deferral. If, at the end of Rate Year 5, the actual net plant in service amount is less than the target amount, SLG will book a deferral, for the benefit of customers, of the carrying cost of the variance,[27] and each month after Rate Year 5, SLG will test to determine if the net plant in service target has been exceeded. If the target has not been exceeded, additional carrying charges will be calculated and a deferral will be recorded until the target has been met. The deferral balance shall accrue interest at the pre-tax rate of return until the deferral balance is returned to customers. Within 90 days of the end of Rate Year 5, SLG shall file with the Secretary a report of its review. Should the target not yet be exceeded, SLG shall file a supplementary report within 90 days of the date the target is actually met.

10. <u>Asset Optimization</u>

Within 120 days following the closing of the Acquisition, SLG will issue a Request for Proposals ("RFP") for the purpose of entering into the best available asset management

[27] Carrying costs shall mean the amount equivalent to the return on investment (*i.e.*, the pre-tax rate of return multiplied by the net plant variance) and the depreciation expense associated with the variance.

agreement ("AMA") having a term between one and three years. Within 30 days following issuance of the RFP, SLG will file a copy of the RFP with the Secretary. Within 30 days following completion of the RFP process, SLG will report on the outcome of the process to the Secretary. Until the RFP process is concluded and any resulting changes to SLG's asset optimization program are made, SLG will continue to operate under its existing agreement with Tidal Energy. The Company will follow this RFP process each time the AMA agreement is up for renewal. Nothing contained herein shall preclude SLG from seeking modification or elimination of this RFP process in the future.

11. Additional Documentation and Reporting Requirements

a. Reporting on Liberty Days/Community Engagement

Within 90 days following the end of each Rate Year, SLG will file a report with the Secretary identifying the benefits of the Liberty Days program.

b. Outreach and Education Plan

i. Acquisition Plan

Not later than 30 days following the filing of this Joint Proposal, SLG and Liberty Utilities will submit for Staff review a draft plan regarding O&E specific to the Acquisition, which, following Staff review and any revisions resulting from such review, will be included in the Company's 2019 O&E Plan.[28] The draft plan will include discussion of any changes brought about by the Acquisition that will affect customers, with the final plan detailing any material provisions set forth in the Commission's order approving the Acquisition.

[28] If the 2019 O&E Plan has already been filed, then SLG shall submit the portion relating to the Acquisition as a supplement.

ii. Annual Outreach & Education Plan

SLG shall submit its annual O&E Plan to the Secretary by January 1st of each year in Cases 08-G-1392 and 17-M-0475.

c. Gas Service Requests

SLG will document all gas service requests, separately, for the Legacy and Expansion Areas. Such documentation will include: location, including whether within the Legacy Area or the Expansion Area; date of request for service; applicant's current heating fuel; length of both main and service (separately) required to serve the customer; estimated cost to extend service to the customer, including, as applicable, single up-front payment and monthly surcharge, as set forth in the Commission's regulations (16 NYCRR Part 230); and date of connection or change to request, including discussion of any changes. If requested by Staff, the Company will be required to provide such documentation to Staff within 10 days of the request.

12. Impact of Mandatory Changes

To the extent that a mandatory change not specifically addressed in the 2016 Rate Plan or in this Joint Proposal occurs, SLG is not precluded from petitioning the Commission for deferred accounting treatment of the revenue requirement impacts of revenues, expenses and rate base (including income or other federal or State tax expense) for such changes, for refund to or recovery from customers in a manner to be determined by the Commission.

A "mandatory change" shall mean a change in the revenues or expenses of SLG due to: generic policy decisions of the Commission that become effective during the period covered by this Joint Proposal; any externally imposed accounting change; any change in federal, state or local rates, regulation, or precedent governing income, revenue sales or franchise taxes; or any legislative, court, or regulatory change, which imposes or modifies existing obligations or duties. Consistent with the foregoing, the Signatory Parties recognize that generic policy decisions of

the Commission will be applicable to SLG according to their terms unless stayed by the Commission or a court or provided otherwise by the Commission during the period covered by this Joint Proposal. All Signatory Parties reserve all of their administrative and judicial rights in connection with such generic proceedings and in connection with any filing by SLG pursuant to this provision. This provision is not intended to preclude SLG from petitioning the Commission for deferred accounting treatment of other costs that may arise prior to or during the period covered by this Joint Proposal.

B. Issuance of Long-Term Indebtedness

Pursuant to Public Service Law §69, in connection with the Acquisition, the Signatory Parties recommend that the Commission authorize SLG to issue indebtedness up to $28.2 million.[29] This will allow SLG to refinance a portion of its current debt, *i.e.*, the Enbridge Note Payable of $23.0 million and the Key Bank loan of $7.0 million. SLG will issue a 10-year or 15-year promissory note to Liberty Utilities at or following the closing of the Acquisition, but no later than 120 days after the Acquisition. The loan will be priced at Liberty Utilities' embedded cost of debt calculated using the most recent quarter end for which a financial closing has been completed. Liberty Utilities will recapitalize the remainder of SLG's outstanding debt with the intent to achieve an actual common equity ratio approximating the 48.0% common equity ratio used for ratemaking purposes. SLG also has a short-term line of credit with Key Bank for $6.0 million and Liberty Utilities will utilize its' Money Pool as a substitute vehicle as discussed earlier in this Joint Proposal.

The Signatory Parties recognize that the debt authority for SLG shall be subject to the conditions the Commission may impose, consistent with those typically associated with

[29] This amount of indebtedness provides SLG some flexibility to manage its debt and common equity ratios, while reflecting that the Company is required to maintain a minimum common equity ratio as described in Section V.A.3.b(ii)(a), above.

Commission orders authorizing utility financing pursuant to PSL §69.[30] Appendix 8, contains the "Reimbursement Margin" that supports granting SLG the requested debt authority.

VI. GENERAL AND MISCELLANEOUS PROVISIONS

A. Provisions Not Separable

It is understood that each provision of this Joint Proposal is in consideration and support of all the other provisions and each provision is expressly conditioned upon acceptance by the Commission of this Joint Proposal in its entirety without change. If the Commission fails to adopt this Joint Proposal according to its terms without change, then the Signatory Parties will be free to pursue their respective positions in this proceeding without prejudice.

B. Provisions Not Precedent

The terms and conditions of the Joint Proposal apply solely to, and are binding on each Signatory Party only in the context of the purposes and results of this Joint Proposal. None of the terms and provisions of this Joint Proposal, nor any methodology or principle utilized herein, and none of the positions taken herein by any Signatory Party may be referred to, cited or relied upon by any other Signatory Party in any fashion as precedent or in any other proceedings before the Commission, or any other regulatory agency, or before any court of law for any purpose except in furtherance of the purposes and results of the Joint Proposal, or as may be necessary in explaining derivation of specific costs or accounting treatments as relevant to future ratemaking proceedings.

[30] *See, e.g.,* Case 18-M-0271, *Central Hudson Gas & Electric Corporation – Financing,* Order Authorizing Issuance of Securities (issued September 13, 2018); Case 18-G-0558, *KeySpan Gas East Corp. d/b/a National Grid – Financing,* Order Authorizing Issuance of Securities (Issued February 8, 2019); Case 18-G-0559, *The Brooklyn Union Gas Company d/b/a National Grid NY – Financing,* Order Authorizing Issuance of Securities (Issued February 8, 2019).

C. Cooperation on Implementation

The Signatory Parties recognize that certain provisions of this Joint Proposal require that actions be taken in the future to effectuate fully this Joint Proposal. Accordingly, the Signatory Parties agree to cooperate with each other in good faith in taking such actions.

D. Continuation of Provisions in Subsequent Years

Except as expressly stated herein, all provisions of this Joint Proposal will continue beyond the end of the last Rate Year during which base rates are frozen pursuant to this Joint Proposal until changed by order of the Commission. For those provisions in this Joint Proposal that establish targets, the targets in effect during such Rate Year will apply to subsequent years.

E. Tariff Filings

The Signatory Parties agree that St. Lawrence Gas will file a cancellation of the proposed tariff leaves currently suspended through July 31, 2019 and file new tariff leaves in a manner consistent with any Commission order(s) regarding the terms of this Joint Proposal.

F. Rate Changes

Changes to St. Lawrence Gas's base delivery service rates during the period of the rate freeze described herein will not be permitted, except for (a) changes provided for in this Joint Proposal; or (b) subject to Commission approval, changes as a result of the following circumstances:

1. A minor change in any individual base delivery service rate or rates whose revenue effect is de minimis, or essentially offset by associated changes within the same class. It is understood that, over time, such minor changes are routinely made and that they may continue to be sought during the term of the Rate Plans, provided they will not result in a change (other than a de minimis change) in the

revenues that SLG's base delivery service rates are designed to produce overall before such changes.

2. If a circumstance occurs which, in the judgment of the Commission, so threatens St. Lawrence Gas's economic viability or ability to maintain safe, reliable and adequate service as to warrant an exception to this undertaking, SLG will be permitted to file for an increase in base delivery service rates at any time under such circumstances.

3. The Signatory Parties recognize that the Commission reserves the authority to act on the level of St. Lawrence Gas's gas rates in the event of unforeseen circumstances that, in the Commission's opinion, have such a substantial impact on the range of earnings levels or equity costs envisioned by this Joint Proposal as to render SLG's gas rates unreasonable or insufficient for the provision of safe and adequate service at just and reasonable rates.

4. The Signatory Parties reserve the right to support or oppose any filings made by St. Lawrence Gas under this Section.

G. Dispute Resolution

In the event of any disagreement over the interpretation of this Joint Proposal or the implementation of any of the provisions of this Joint Proposal the Signatory Parties will use the following process. First the Signatory Parties will seek to resolve the dispute informally. If any such disagreement cannot be resolved informally, any Signatory Party may petition the Commission for a determination on the disputed matter.

H. Effect of Commission Adoption of Terms of This Joint Proposal

No provision of this Joint Proposal or the Commission's adoption of the terms of this Joint Proposal shall in any way abrogate or limit the Commission's statutory authority under the

PSL. The Signatory Parties recognize that any Commission adoption of the terms of this Joint Proposal does not abrogate or limit the Commission's ongoing rights and responsibilities to enforce its orders and effectuate the goals expressed therein, nor the rights and responsibilities of Staff to conduct investigations or take other actions in furtherance of its duties and responsibilities.

I. Relationship to 2016 Joint Proposal

Except as specifically modified by this Joint Proposal, the provisions of the 2016 Rate Plan remain in effect. Solely for the convenience of the parties, Appendix 9 sets forth the provisions of the Joint Proposal adopted by the Commission to institute the 2016 Rate Plan, and identifies the provisions of that 2016 Joint Proposal that the Signatory Parties understand will be modified should the Commission adopt this Joint Proposal. The list contained in Appendix 9 is intended solely for the convenience of the parties in understanding the relationship between this Joint Proposal and the 2016 Rate Plan and shall not in any way affect the legal requirements set forth in the 2016 Rate Plan.

J. Entire Agreement

This Joint Proposal, including all attachments, exhibits and appendices, if any, represents the entire agreement of the Signatory Parties with respect to the matters resolved herein.

K. Execution

This Joint Proposal is being executed in counterpart originals, and will be binding on each Signatory Party when the counterparts have been executed.

L. Notice

Except for notices or filings with the Secretary, all communications provided for herein or with reference to this Joint Proposal will be deemed to have been sufficiently given or served for all purposes if sent by electronic mail, to the following persons:

If to St. Lawrence Gas:

Kimberly S. Baxter, Manager, Regulatory Affairs
kbaxter@stlawrencegas.com

and

Aubrey A. Ohanian, Harris Beach PLLC
aohanian@harrisbeach.com

If to Liberty Utilities:

Mark Saltsman, Vice President & General Manager of New York Operations
Mark.Saltsman@libertyutilities.com

and

Stanley W. Widger, Jr., Nixon Peabody LLP
swidger@nixonpeabody.com

If to Staff:

Brandon F. Goodrich, Assistant Counsel
Brandon.Goodrich@dps.ny.gov

If to Multiple Intervenors:

Amanda De Vito Trinsey, Couch White, LLP
adevito@couchwhite.com

If to Agri-Mark:

Frank Mehm, Sr. V.P. Finance
fmehm@agrimark.net

and

Donna Brooks, Shipman & Goodwin LLP
DBrooks@goodwin.com

If to Upstate Niagara:

Mike Patterson, Chief Financial Officer
mpatterson@upstateniagara.com

and

Lynn Scott, Paralegal
lscott@upstateniagara.com

and

Joseph G. Casion, Harter Secrest & Emery, LLP
jcasion@hselaw.com

or such other persons as the Signatory Parties may designate from time to time by notice given in accordance with the foregoing.

IN WITNESS WHEREOF, the Signatory Parties hereto have this day signed and executed this Joint Proposal.

ST. LAWRENCE GAS COMPANY, INC.

By: _____
Aubrey A. Ohanian

Date: 5/31/19

CASES 18-G-0133 & 18-G-0140

IN WITNESS WHEREOF, the Signatory Parties hereto have this day signed and executed this Joint Proposal.

LIBERTY UTILITIES CO.

By: Stanley W. Widger Jr.
Stanley W. Widger, Jr.

Date: 5/31/19

CASES 18-G-0133 & 18-G-0140

IN WITNESS WHEREOF, the Signatory Parties hereto have this day signed and executed this Joint Proposal.

STAFF OF THE DEPARTMENT OF PUBLIC SERVICE

By: 
Brandon F. Goodrich

Date: May 31, 2019

CASES 18-G-0133 & 18-G-0140

IN WITNESS WHEREOF, the Signatory Parties hereto have this day signed and executed this Joint Proposal.

MULTIPLE INTERVENORS

By: Amanda De Vito Trinsey
Amanda De Vito Trinsey

Date: 5-30-19

CASES 18-G-0133 & 18-G-0140

IN WITNESS WHEREOF, the Signatory Parties hereto have this day signed and executed this Joint Proposal.

AGRI-MARK, INC.

By: _____ SVP - FINANCE
Frank Mehm

Date: 5/31/19

CASES 18-G-0133 & 18-G-0140

IN WITNESS WHEREOF, the Signatory Parties hereto have this day signed and executed this Joint Proposal.

UPSTATE NIAGARA COOPERATIVE, INC.

By: _____
Mike Patterson

Date: 5/30/19

APPENDIX 1

St. Lawrence Gas Company, Inc.
Case 18-G-0133
Expansion Area Self-Supporting Mechanism
For the Twelve Months Ended (Month/Day/Year)

Base Delivery Revenues	$	-
Operations & Maintenance Expenses		-
Depreciation		-
Taxes Other Than Income Taxes		-
Operating Income Before Taxes	$	-
Income Taxes	$	-
Operating Income After Taxes	$	-
Overall Rate of Return		6.40%
Rate Base (Self-Supporting)	$	-
Actual Rate Base		-
Additional Net Plant Write-Down Remaining	$	-

Rate of Return (ROR)	6.40%
Weighted Cost of Debt and Customer Deposit	2.27%
Equity Ratio	48%
Rate of Return on Common Equity	8.60%

St. Lawrence Gas Company, Inc.
Case 18-G-0133
Expansion Area Self-Supporting Mechanism
Income Statement For the Twelve Months Ended (Month/Day/Year)

	Company Rate Year Ending XX XX, XXXX
Base Delivery Revenues	
Operation & Maintenance Expenses	
Meter Reading	
Vehicle Expense	
Building Rent	
Fringe Benefits	
Marketing	
Payroll	
Uncollectible Expense	
Total Operation & Maintenance Expenses	$ -
Depreciation Expense	
Taxes Other Than Income Taxes	
Property Taxes	
Payroll Taxes	
Revenue Taxes	
Total Taxes Other Than Revenue and Income Taxes	$ -
Operating Income Before Income Taxes	$ -
Income Taxes	
Federal Income Taxes	
State Income Taxes	
Total Income Taxes	$ -
Operating Income After Income Taxes	$ -

St. Lawrence Gas Company, Inc.
Case 18-G-0133
Expansion Area Self-Supporting Mechanism
Summary of Rate Base For the Twelve Months Ended (Month/Day/Year)

Plant In Service	
Accumulated Depreciation	
Net Plant	$ -
Working Capital	
Earnings Base Capitalization Adjustment	
Accumulated Deferred Income Tax	
Unamortized Deferrals	
Rate Base	$ -

St. Lawrence Gas Company, Inc.
Case 18-G-0133
Expansion Area Self-Supporting Mechanism
Capital Sturcture

	Weighting Percent	Cost Rate	Weighted After Tax Cost
Long Term Debt	51.20%	4.40%	2.25%
Customer Deposits	0.80%	2.45%	0.02%
Common Equity	48.00%	8.60%	4.13%
Total	100%		6.40%

Notes:
a) Capital Structure (i.e. weighting percentages) reflects agreed upon terms
b) Cost Rate for Common Equity reflects agreed upon terms
c) Cost Rate for Long Term Debt reflects Liberty Utilities current embedded cost of debt and is subject to update at closing of the Acquistion
d) Cost Rate for Customer Deposits reflects the current Commission approved rate. This would reflect the Commission approved rate at the time of calculation.

APPENDIX 2

St. Lawrence Gas Company, Inc.

Affiliate Code of Conduct

1. Purpose, Application and Corporate Statement

1.1 Purpose and Objectives of the Affiliate Code of Conduct ("Code")

The purpose of this Code is to establish parameters and standards for transactions, information sharing and the sharing of services and resources between St. Lawrence Gas Company, Inc. ("St. Lawrence Gas" or "SLG"), Affiliates and Representatives while permitting each party to achieve appropriate efficiencies and economies of scope and scale.

This Code will be reviewed and, as warranted, revised in each future rate proceeding for SLG and in any proceeding concerning a change in ownership of SLG.

Specifically, the Code is designed to meet the following objectives:

- Provide transparent and consistent guidance for SLG employees, Affiliates' employees and Representatives respecting Affiliate interactions,
- Create an awareness of compliance and ethics issues and accountabilities among SLG employees, Affiliates' employees and Representatives,
- To set standards that result in Affiliates and Customers being treated fairly and consistently and to prevent unduly preferential treatment,
- To set standards that result in Affiliates being treated fairly and that avoid cross-subsidizing Affiliate services or facilities,
- To protect and set standards for the use of confidential Customer information collected in the course of providing services and access to facilities,
- Avoid practices that could impede market competition that could occur between SLG and Affiliates and that may be detrimental to the interests of Customers.

1.2 Who This Code of Conduct Applies To

All employees (including managers, directors, full-time employees and part-time employees) and Representatives of SLG and all Affiliates' employees are expected to comply with all aspects of this Code.

The above objectives can only be realized through a demonstrated observance of and respect for the spirit and intent of this Code by all SLG employees, Representatives and Affiliates' employees to which it applies.

As this Code cannot address each specific issue that may arise, when necessary, employees and Representatives should be encouraged to seek additional guidance from their supervisor or others within St. Lawrence Gas.

1.3 Definitions

1.3.1 Affiliate Activities – General business activities of an Affiliate relating to construction, operation, maintenance, generation, transportation, marketing, handling, storage of natural resources and energy such as oil, gas or electricity and facilities associated with the same.

1.3.2 Affiliates – An "affiliate" of SLG carrying out business in the United States or Canada, as defined by applicable federal, state or local laws, including, but not limited to New York State Public Service Law ("PSL") § 110(2). SLG's current and known Affiliates, both regulated and unregulated, and including SLG's Parent Company, are listed in the **Appendix**, along with a description of each Affiliates' service territory and operations.

1.3.3 Code – This Affiliate Code of Conduct.

1.3.4 Compliance Officer – The individual tasked with the responsibilities specified in section 6.2 of this Code

1.3.5 Confidential Information – Any information of a proprietary, intellectual or similar nature relating to any current or potential Customer of SLG, which information has been obtained or compiled in the process of providing current or prospective services and which is not otherwise available to the public.

1.3.6 Customer(s) – Any current or potential person or organization to which SLG distributes natural gas.

1.3.7 Fair Market Value – The price reached in an open and unrestricted market between informed and prudent parties, acting at arm's length and under no compulsion to act. In determining the Fair Market Value, the seller may use any method that it believes is commercially reasonable in the circumstances.

1.3.8 For Profit Affiliate Services – Any service, provided by SLG to an Affiliate or vice versa, on a for-profit basis.

1.3.9 Fully Burdened Costs – The sum of direct costs plus a proportional share of indirect costs that may include a return on invested capital, which shall not exceed the weighted average costs of capital for SLG.

1.3.10 Information Services – Any computer systems including: computer services, databases, electronic storage services or electronic communication media, printing services or electronic communication media utilized by SLG or Affiliates relating to their respective Customers or respective operation.

1.3.11 Parent Company – The Parent Company of SLG refers to either or both of Liberty Utilities Co., SLG's direct Parent Company, and Algonquin Power & Utilities Corp., SLG's ultimate Parent Company.

1.3.12 PSC – The New York State Public Service Commission.

1.3.13 Regulated Affiliates – Affiliates whose tolls and tariffs are under the jurisdiction of the PSC or the equivalent of the PSC in another US state or Canadian province.

1.3.14 Representative – Contract workers, independent consultants, agents and any other entities that are not Affiliates, but who act on behalf of SLG.

1.3.15 Resources – Includes employees, intellectual property, materials, supplies, computer systems, equipment and facilities.

1.3.16 Senior Management Team – Employees designated as officers of St. Lawrence Gas as determined by the Company's Board of Directors.

1.3.17 Services Agreement – An agreement entered into between SLG and one or more Affiliate for the provision of Shared Services and shall provide the following matters, as appropriate in the circumstances:

a. The type, quantity and quality of service,

b. Pricing, allocation or cost recovery provisions,

c. Confidentiality arrangements,

d. Apportionment of risk (including the risk of over or under provision of service),

e. Dispute resolution provisions, and

f. A representation by SLG and each Affiliate party to the agreement that the agreement complies with this Code.

1.3.18 Shared Core Corporate Services – SLG department functions that provide or receive shared strategic management and policy support to or from the corporate group of which SLG and Affiliates are members and may include legal, finance, tax, treasury, pensions, risk management, audit services, corporate planning, human resources, health and safety, communications, investor relations, trustee or public affairs.

1.3.19 Shared Customer Services – Any service provided to or from an Affiliate in relation to coordination and logistics, customer support services, legal and regulatory affairs, operation services, planning and analysis, system optimization, asset management, inventory management, facilities management and control center operations; the charges for such services shall be reimbursed on a Fully Burden Cost basis.

1.3.20 Shared Services – Any service provided by SLG to an Affiliate or by an Affiliate to SLG, the charges for such services to be reimbursed on a Fully Burdened Cost basis.

1.3.21 SLG Services – Services provided by SLG to an Affiliate or Customer in relation to the distribution of Natural Gas including: interconnections; access to SLG facilities pipelines, lands, rights-of-way, leases, operations and maintenance, construction, regulatory services, technical and design; control center; and any other general services provided in relation to construction, operation, maintenance, removal, abandonment, deactivation or decommissioning of liquids pipeline.

1.3.22 St. Lawrence Gas Company, Inc. – SLG is owned by its immediate parent company, Liberty Utilities Co.. Liberty Utilities Co. is the subsidiary of its parent company, Algonquin Power & Utilities Corp. Both SLG and Liberty Utilities Co. are subsidiaries of their ultimate parent company, Algonquin Power & Utilities Corp.

1.3.23 Unregulated Affiliate Activities – General business activities of an Unregulated Affiliate relating to construction, operation, maintenance, generation, transportation, marketing, handling, storage of natural resources and energy, as well as the facilities associated with the same.

1.3.24 Unregulated Affiliate – An Affiliate that is not regulated by the PSC or the equivalent of the PSC in another US state or Canadian province.

1.4 Affiliate Code of Conduct Policy and Corporate Statement

SLG is committed to conducting its business in a socially responsible, legally compliant and ethical manner in accordance with a core set of corporate values, key components of the corporate values include operating with integrity, honesty, respect and transparency in all of its dealings with stakeholders. This commitment requires that SLG operates in compliance with both the letter and the spirit of the law. The interactions between SLG and Affiliates are governed by various legal and contractual provisions that are designed to ensure that these inter-affiliate interactions are appropriate and transparent.

2. Corporate Governance of SLG and Affiliates

2.1 Separate Operations

The commercial and business affairs of SLG should be managed and conducted independently from the commercial and business affairs of its Unregulated Affiliates, except as required to fulfill Shared Core Corporate Services and Shared Customer Services.

2.2 SLG Board of Directors

Liberty Utilities East Region Board of Directors shall act as the board of directors for SLG. The East Region Board of Directors shall include an independent director who is a resident of the service area of SLG. For purposes of this requirement, “resident of the service area” may include the circumstance in which the personal residence of the director is within one of the counties in which SLG provides service, but not within the relevant service area; provided that the director’s principal place of business or employment is within such service area. An Independent Director shall mean an individual who is not : (1) an officer or director of SLG’s parent, (2) an officer or director of any of SLG’s Regulated Affiliates or (3) and officer or director of any of SLG’s Unregulated Affiliates. Furthermore, no person holding any other position that could reasonably be considered to be detrimental to the interests of SLG or Affiliate Customers can be a SLG Director.

2.3 Separate Management

Subject to Sections 2.3 and 2.4, members of SLG’s Senior Management Team must be separate from the managers of its Unregulated Affiliates. Subject to Sections 2.3 and 2.4, SLG may share management team members and managers with Regulated Affiliates.

2.4 Exception to Separate Management

SLG managers may also be managers of an Affiliate in order to perform Shared Core Corporate Services. However, this exception shall not allow an SLG officer in a commercial or business development role to be an officer of an Unregulated Affiliate that has or reasonably expects to have marketing functions and/or significant commercial or business development arrangements with SLG.

2.5 Guiding Principle

Notwithstanding sections 2.2 and 2.3, an individual shall not act both as a director or officer, or member of a management team of SLG and as a director, officer or member of a management team of any other Affiliate (thereby acting in a dual capacity) unless the individual is able to carry out his/her responsibilities in a manner that preserves the form, spirit and intent of this Code.

Specifically, an individual:

a. Shall not agree to act in a dual capacity if the individual, acting reasonably, determines that acting in a dual capacity could be detrimental to the interests of Customers, and

b. If or when acting in a dual capacity, shall abstain from engaging in any activity that the individual, acting reasonably, determines could be detrimental to the interests of Customers.

2.6 Accounting Separation

SLG must maintain separate financial records and books of accounts from those of its Affiliates. There shall be no cross -subsidization between SLG and any Affiliate.

2.7 Physical Separation

SLG must put appropriate measures in place to restrict access to SLG's Confidential Information by employees of Unregulated Affiliates with significant commercial and business development responsibilities.

Commercial and business development employees of an Unregulated Affiliate must be physically separated from SLG staff.

Where SLG provides services to an Unregulated Affiliate that operates in whole or in part as a producer, marketer, shipper or refiner, that Unregulated Affiliates' employees whose functions include commercial development, business development, marketing, producing, refining and shipping must be physically located in a separate building or complex for SLG's office that are used for its day to day operations.

2.8 Separation of Information Services

Subject to Section 2.11 where SLG shares Information Services with an Unregulated Affiliate, Confidential Information must be protected from unauthorized access by an Unregulated Affiliate and vice versa. Access to SLG and each Unregulated Affiliate's respective Information Services must include appropriate computer data management and data access protocols as well as contractual provisions regarding the breach of any access protocols. Compliance with the access protocols must be confirmed in writing every two years from the effective date of this Code by SLG through a review that complies with applicable federal, state and local laws.

2.9 Financial Transactions with Affiliates

SLG may participate in a money pool as a borrower or lender only if the other participants are regulated utilities, with the exception that Liberty Utilities Co. may participate, but only as a guarantor of loans made by that money pool and to provide funding to the money pool in the event that other participant-supplied funds on any given day are insufficient to meet the need for funds by the borrowing participants. SLG shall not participate in a money pool as a lender if any of the other participants are not regulated utilities. This does not preclude the unregulated affiliates of SLG in participating in a separate money pool that does not include SLG.

2.10 Sharing of Assets

The operation plant, assets and equipment of SLG shall be separated in ownership from that of its Affiliates. For the purposes of this section, operational plant, assets and equipment means any pipeline or portion thereof that is capable of being operated as a line for the transmission of gas or oil and includes all branches, extensions, tanks, reservoirs, storage facilities, pumps, racks and compressors.

2.11 Sharing Services Permitted

Where SLG determines that it is prudent in operating its business, it may obtain Shared Services or Shared Customer Services from, or provide Shared Services or Shared Customer Services to, an Affiliate. SLG must periodically review the prudence of such sharing arrangements and make any adjustments necessary to ensure that each of SLG and their Affiliates bears its proportionate share of costs. If services are shared between SLG and an Affiliate, a Services Agreement must be put into place.

Employees providing Shared Customer Services will be required to undertake training in relation to protecting and using Confidential Information within a reasonable period of time of their commencing their job and annually, thereafter.

2.12 Sharing of Employees

SLG may share employees with an Affiliate on a Fully Burdened Cost recovery basis provided that the shared employees are able to carry out their responsibilities in a manner that is consistent with the spirit and intent of this Code. In particular, an employee must not be shared if it could reasonably be considered detrimental to the interests of SLG Customers of the Affiliate's Customers. If employees are shared, such employees must abstain from engaging in any activity that could reasonably be considered detrimental to the interests of SLG Customers or Affiliate's Customers.

Certain employees must not be shared. Unless they are providing Shared Corporate Services or Shared Customer Services, SLG may not share employees with an Unregulated Affiliate if that employee:

- Routinely participates in management level decision-making respecting the provision of SLG Services or Unregulated Affiliate Activities or how SLG Services or Unregulated Affiliate Activities and services are delivered,
- Routinely deals with or has direct contact with SLG or Unregulated Affiliate Customers, and
- Is routinely involved in senior commercial management of SLG or an Unregulated Affiliate's business.

Despite the above, for Shared Core Corporate Services or Shared Customer Services, Fully Burdened Costs may be applied where applicable. Cost allocation shall be applied in a reasonable manner to avoid

cross subsidizations with respect to all Shared Core Corporate Services and Shared Customer Services. Such cost allocation shall be documented for audit purposes.

2.13 Occasional Services Permitted

Where SLG has otherwise acted prudently, it may receive or provide one-off, infrequent or occasional services to or from an Affiliate and such services shall be properly documented. For example, an employee of SLG may provide an Unregulated Entity with assistance resolving a database question, if needed. In the event that such occasional services become regular occurrences, SLG must enter into a Services Agreement with the Affiliate for Shared Services.

2.14 Emergency Services Permitted

In the event of an emergency, SLG may share services and resources with an Affiliate without a Services Agreement on a Fully Burdened Cost recovery basis.

2.15 Shared Services Employees

An employee or contractor to an Affiliate that, except in cases of emergency under section 2.14 of the Code, provides Shared Core Corporate Services, Shared Customer Services or Shared Services to SLG will, for purposes of the Code, be treated as if employed directly by SLG.

2.16 Debt Limits

"Average Total Debt" is defined as an amount equal to (i) long-term debt, plus (ii) notes payable (including current maturities of long-term debt), minus the average daily balance of cash and cash equivalents appearing on SLG's consolidated balance sheet. "Average Total Capital" is defined as the sum of (i) Average Total Debt, (ii) common shareholder equity (excluding goodwill), and (iii) preferred stock. It is expected that, for any six month period ending at the end of a quarter, SLG's Average Total Debt will not exceed 55 percent of its Average Total Capital, excluding any goodwill.

If SLG's Average Total Debt does not exceed 55 percent for the most recent six or three month period ending at the end of a quarter, there will be no dividend restrictions. If SLG's Average Total Debt exceeds 55 percent for both the most recent three and six month periods, but does not exceed 57 percent in the most recent three or six month period, then SLG will be permitted to pay dividends up to an amount equal to but no greater than 50 percent of its net income for the previous twelve months ending at the end of a quarter until its Average Total Debt for the most recent six month period ending at the end of a quarter is less than or equal to 55 percent. In addition, absent a Commission order to the contrary, if during both the most recent six and three month period ending at the end of a quarter, SLG's Average Total Debt exceeds 57 percent, then SLG will not pay further dividends until the Average Total Debt is reduced to 55 percent or less over the most recent six months ending at the end of a quarter.

3. Transfer Pricing

3.1 For Profit Affiliate Services

Where SLG determines it is prudent to do so, it may obtain For Profit Affiliate Services from an Affiliate.

Prior to outsourcing to an Affiliate a service that SLG presently conducts itself, SLG shall undertake a prudent cost-benefit analysis over an appropriate timeframe in the circumstances. An Affiliate shall

likewise undertake a prudent cost-benefit analysis over an appropriate timeframe in the circumstances, prior to outsourcing a service to SLG.

When SLG contracts to receive For Profit Affiliate Services it shall pay in accordance with any terms required pursuant to an order from the PSC or other applicable regulatory body or pay no more than the Fair Market Value of such services.

3.2 Asset Transfers

Assets transferred, mortgaged, leased or otherwise disposed of by SLG to an Affiliate must be at the higher of book value or fair market value of such assets or, where required, upon terms approved by the appropriate regulatory agency. If an asset is transferred, leased, sold or otherwise disposed of by SLG to an Affiliate, SLG shall notify **the Secretary of the Commission** not less than 90 days prior to such transfer. Assets transferred, mortgaged, leased or otherwise disposed of by an Affiliate to SLG must be at the lower of book value or fair market value of such assets or, where required, upon terms approved by the appropriate regulatory agency.

Where operational efficiencies between SLG and Affiliates can be obtained through the use of common facilities, combined purchasing power or through the use of other cost saving procedures, assets used in SLG and Affiliates' operations may be transferred between each other at net book value or other reasonable standard. All such transitions must be properly documented and accounted for in SLG and the Affiliates' respective accounting records.

4. Mitigation of Market Power and Equal Treatment of Representatives

SLG and its Affiliates shall conduct themselves in accordance with all applicable competition laws in the jurisdictions in which they conduct business.

SLG shall apply and enforce all tariff provisions in accordance with applicable legislation, regulatory orders, permits and licenses. Such tariff provisions shall be applied to Affiliates in the same manner as other Customers and/or prospective Customers in order to ensure no undue discrimination, preference or prejudice, except as approved by the appropriate regulatory agency. SLG shall not provide special rebates, rebates or different rates for like and contemporaneous service to Affiliates and Customers, except as approved by the appropriate regulatory agency.

SLG shall not favor any Affiliate with respect to access to information concerning services to Customers or scheduling of their transportation. All requests to SLG by an Affiliate for access to their respective services shall be processed and provided in accordance with this Code in the same manner as it would be processed or provided for any Customer.

SLG shall not condition or otherwise require any Customer to deal with an Affiliate in order to receive SLG transportation services.

SLG shall not explicitly or implicitly suggest that a Customer may receive an inappropriate advantage if that Customer also deals with an Affiliate.

Affiliates may not imply in any marketing material, other public documents or communications that Customers or potential Customers of the Affiliate may also receive preferential access to or service from

SLG. If SLG becomes aware of any such inappropriate marketing material, public documents or communication, SLG shall:

- Immediately take reasonable steps to notify affected Customers or potential customers of the inaccurate information, and
- Take necessary steps to ensure that Affiliate is aware of this concern and to request that no further communications be made to suggest preferential access to or services from SLG.

There are no restrictions on any Affiliate using the same name, trade names, trademarks, service names, service marks or a derivative of a name of SLG, or in identifying itself as being affiliated with SLG. However, no non-SLG affiliate will be allowed to use the same name, trade names, trademarks, service names, service marks or a derivative of a name of SLG in any manner.

Affiliates are prohibited from giving any appearance that they represent SLG in matters involving the marketing of services by SLG or other Affiliates. If a customer requests information about securing any service or product offered within SLG's service territory by an Affiliate, SLG must offer to provide a list of all companies that are qualified and approved pursuant to governmental or SLG standards (including retail access standards) as providers of similar products or services within SLG's service territory.

5. Confidentiality

5.1 Release of SLG Information to Unregulated Affiliates

SLG must not provide any Affiliate who is a producer, refiner, marketer or shipper with information relating to the planning, operations, finances or strategy of SLG before such information is publicly available. In other words, subject to sections 2.1, 2.2, 2.4 and 2.12, SLG must take care that it does not disclose SLG information to any Affiliate who is a producer, refiner, marketer or shipper that it would not disclose to other Customers or potential Customers. This would include any Confidential Information and non-aggregated customer information gathered by SLG to generate annual supply forecasts for planning purposes.

Managers of SLG who are also managers of an Affiliate, as permitted by this Code, may disclose SLG planning, operational, financial and strategic information to the Affiliate to fulfill their responsibilities with respect to corporate governance, policy and strategic direction of an Affiliated entity, but only to the extent necessary and not for any other purpose.

5.2 No Release of Confidential Customer Information

SLG must not, without the Customer's prior written consent, use or disclose to an Affiliate any Confidential Information for the purpose of pursuing commercial or business development activities.

Where an Affiliate acquires specific Confidential Information, such information may not be used for commercial or business development activities without the Customer's consent. SLG may disclose Confidential Information for operational purposes, Shared Customer Services, emergencies or on an as-needed basis, to an Affiliate provided the Affiliate does not release the Confidential Information to any other entity without receiving the prior written consent of the Customer.

SLG and its Affiliates seek to achieve operational efficiencies through the sharing of Resources. Where such Resource-sharing opportunities arise, SLG will:

- Not directly or indirectly disclose any Confidential Information provided to it by Customers unless:
  - It obtains consent for disclosure by the Customer,
  - The information is required for Shared Customer Services, Shared Corporate Services, emergency, operations purposes, or
  - The information is required by law.
- Implement reasonable measures to prevent any direct or indirect disclosure of any Customer proprietary or Confidential Information.

SLG and its Affiliates may respectively disclose Confidential Information when aggregated with the Confidential Information of other Customers in such a manner that an individual Customer's Confidential Information cannot be identified.

SLG employees whose primary job functions include commercial and business development services will be required to undertake training in relation to protecting and using Confidential Information within a reasonable period of time of their commencing their job and annually, thereafter.

6. Compliance Measures

6.1 Compliance Requirements

SLG is responsible for ensuring compliance with this Code.

SLG shall communicate the contents of this Code and any modifications to it from time to time to its employees, directors, managers, Representatives and Affiliates.

SLG shall make this Code available on its internal and external websites.

SLG shall appoint a compliance officer (the "Compliance Officer"). SLG shall ensure that the Compliance Officer has access to adequate resources to fulfill his or her responsibilities.

6.2 Responsibility of Compliance Officer

The responsibilities of the Compliance Officer with respect to this Code shall include:

- Providing guidance, advice and information to SLG for the purpose of ensuring compliance with this Code,
- Monitoring and documenting compliance with this Code by SLG, their employees, directors, managers, Representatives and Affiliates,
- Monitoring and documenting compliance with this Code by Affiliates with respect to the interactions of the Affiliates with SLG,
- Providing for the preparation and updating of a Compliance Report and Compliance Plan for SLG,

- Performing annual reviews of compliance with these Compliance Reports and Compliance Plans,
- Receiving and investigating internal and external disputes, complaints and inquires with respect to the application of and alleged non-compliance with this Code,
- Recommending measures to SLG to address events of non-compliance with the Code, and
- Maintaining and retaining for a period of seven years adequate records with respect to all aspects of the Compliance Officer's responsibility.

6.3 Communication of Code of Conduct Requirements

SLG shall communicate this Code as follows:

- On its internal and external websites, and
- Through orientation and training of all SLG employees, managers and directors.

6.4 Compliance Plan

SLG shall prepare a Compliance Plan and make it available on internal and external websites.

The Compliance Plan shall detail the measures, policies, procedures and monitoring mechanisms that SLG will employ to ensure full compliance with the provisions of this Code by their employees, directors, managers, Representatives and Affiliates. SLG shall review and update its Compliance Plan annually.

6.5 Annual Compliance Report

The Compliance Report referenced in Section 6.2 shall be prepared annually and will include the following information prepared in respect to the period of time covered by the Compliance Report:

- A list of all Services Agreements entered into during the period covered by the Compliance Report,
- An overall assessment of compliance with the Code,
- An assessment of the effectiveness of the Compliance Plan and any recommendations for modifications, and
- In the event of any material non-compliance with this Code, a description of same and an explanation of all steps taken to correct such non-compliance.

SLG shall provide Department Staff with a copy of these annual Compliance Reports, upon request.

6.6 Dispute, Compliant and Inquiry Resolution

Disputes, complaints or inquiries from within SLG, an Affiliate, Customers of SLG or from a Representative respecting the application of, or alleged non-compliance with this Code, may be made verbally or submitted in writing to the Compliance Officer and may be made confidentially. The identity of any party making a submission to the Compliance Officer shall be kept confidential by the Compliance Officer unless the party otherwise agrees.

The Compliance Officer shall acknowledge all disputes, complaints or inquires in writing within five business days of receipt of the same.

The Compliance Officer shall respond to the dispute, complaint or inquiry within 25 business days of its receipt. The response shall include a description of the dispute, compliant of inquire and the initial response of SLG or Affiliate to the issues identified in the submission. A final disposition of the dispute, compliant or inquiry shall be completed as expeditiously as possible in the circumstances and, in any event, within 90 days of receipt of the dispute, compliant or inquires, except where the party making the submission otherwise agrees.

All records of the Compliance Officer in relation to a dispute, complaint or inquiry shall be kept for a period of at least seven years. Compliance records shall be maintained in a manner sufficient to support a third party independent audit of the state of compliance with this Code.

6.7 Non-Compliance

Any non-compliance with this Code by any employee, director, officer or Representative of SLG or an Affiliate with respect to the interactions of the Affiliate with SLG will be considered to be addressed pursuant to this Code.

Non-compliance with this Code by an employee, director, officer, Representative or SLG or an Affiliate may subject such individual to internal disciplinary action.

7. General Provisions

7.1 Interpretation

Headings are for convenience only and shall not affect the interpretation of this Code. Words importing the singular include the plural and vice versa. A reference to a statue, document or a provision of a document includes an amendment or supplement to, or a replacement of that statue, document or that provision of that document.

7.2 Coming into Force

This Code comes into effect upon closing of the Acquisition of SLG by Liberty Utilities Co. However, to the extent existing agreements or arrangements are in place between parties to whom this Code applies that do not conform with this Code, SLG shall use reasonable efforts to ensure that such agreements or arrangements are brought into compliance with this Code within 90 days after this Code comes into force.

7.3 Amendments to this Code

This Code may be reviewed and amended by SLG from time to time.

7.4 Authority of Regulators

This Code does not detract from, reduce or modify in any way the powers of SLG or Affiliates' respective regulators. Compliance with this Codes does not eliminate the requirement for specific approval or filings where required by legislation, regulation or by a regulator's decisions, orders or directions.

Appendix
List of Affiliates

i. Affiliates Regulated by the NYS PSC:

None.

ii. Affiliates Regulated by the Equivalent of the NYS PSC in other US states or Canadian Provinces:

	Name	Territory and Operations
a.	**Liberty Utilities (New Brunswick Gas) Corp.**	On December 4, 2018, the Liberty Utilities Group entered into an agreement to purchase Enbridge Gas New Brunswick Limited Partnership ("EGNB"), a subsidiary of Enbridge Inc., along with its general partner (the "EGNB Acquisition"). EGNB is a utility regulated by the New Brunswick Energy and Utilities Board that provides natural gas to approximately 12,000 customers in 12 communities across New Brunswick and operates approximately 800 kilometers of natural gas distribution pipeline. Closing of the EGNB Acquisition is expected to occur in July/August 2019 and remains subject to customary closing conditions, including the receipt of regulatory and government approvals.
b.	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**	EnergyNorth is a regulated natural gas utility providing natural gas distribution service in 30 communities covering five counties in New Hampshire. Its franchise service area includes the communities of Nashua, Manchester and Concord. It is regulated by the NHPUC.
c.	**Liberty Utilities (Granite State Electric) Corp.**	Granite State Electric, regulated by the NHPUC, provides distribution service in southern and northwestern New Hampshire, centered around operating centers in Salem in the south and Lebanon in the northwest. Granite State Electric's customer base consists of a mixture of residential, commercial and industrial customers. Granite State Electric is required to provide electric commodity supply for all customers who do not choose to take supply from a competitive supplier ("Default Service") in the New England power market and is allowed to fully recover its costs for the provision and administration of Default Service under the Default Service Adjustment Provision, as approved by the NHPUC. Granite State Electric must file with the NHPUC twice a year to adjust for market prices of power purchased and is also subject to limited FERC regulation.
d.	**Liberty Utilities (New England Natural Gas Company) Corp.**	New England Gas is a natural gas utility, regulated by the MA DPU, providing natural gas distribution services in six communities located in the southeastern portion of Massachusetts. New England Gas customer base consists of a mixture of residential, commercial, and industrial customers.
e.	**Liberty Utilities (Peach State Natural Gas) Corp.**	Peach State Gas is a Georgia PSC -regulated natural gas system providing natural gas distribution services in 13 communities covering six counties in Georgia. Its franchise service area includes the communities of Columbus, Gainesville, Waverly Hall, Oakwood, and Hamilton. Peach State Gas' customer base consists of a mixture of residential, commercial, industrial and transportation customers.

	Name	Territory and Operations
f.	**Liberty Utilities (CalPeco Electric) LLC**	CalPeco Electric is a California PUC-regulated utility that provides electric distribution service to the Lake Tahoe basin and surrounding areas. The service territory, centered on a highly popular tourist destination, has a customer base spread throughout Alpine, El Dorado, Mono, Nevada, Placer, Plumas and Sierra Counties in northeastern California. CalPeco Electric's connection base is primarily residential. Its commercial connections consist primarily of ski resorts, hotels, hospitals, schools and grocery stores. The Corporation has entered into a multi-year services agreement with NV Energy that commenced in January 2016. On January 31, 2017, the Federal Energy Regulatory Commission authorized transactions between the Luning Solar Facility and CalPeco Electric pursuant to the services agreement with NV Energy. CalPeco Electric is also subject to FERC regulation.
g.	**Liberty Utilities (Park Water) Corp.**	Liberty Park Water owns and operates two California PUC-regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in southern California
h.	**Liberty Utilities (Apple Valley Ranchos Water) Corp.**	Liberty Utilities (Apple Valley Ranchos Water) Corp. (wholly-owned by Liberty Park Water) is a California PUC-regulated water utility which owns and operates the water system in Apple Valley.
i.	**Liberty Utilities (Bella Vista Water) Corp.**	The Liberty Utilities Bella Vista Water utility is located in Sierra Vista Arizona. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
j.	**Liberty Utilities (Gold Canyon Sewer) Corp.**	The Liberty Utilities Gold Canyon Sewer utility is located in Avondale Arizona. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
k.	**Liberty Utilities (Litchfield Park Water & Sewer) Corp.**	The LPSCo System, located in and around the city of Goodyear 15 miles west of Phoenix, Arizona has a service area that includes the City of Litchfield Park and sections of the cities of Goodyear and Avondale as well as portions of unincorporated Maricopa County. The wastewater system's Palm Valley Water Reclamation Facility has permitted treatment capacity of 6.5 million gallons per day.
l.	**Liberty Utilities (Northwest Sewer) Corp.**	The Liberty Utilities Northwest Sewer utility is located in Goodyear Arizona serving several HOA's in the area. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.

	Name	Territory and Operations
m.	**Liberty Utilities (Black Mountain Sewer) Corp.**	The Liberty Utilities Black Mountain Sewer utility is located in Carefree Arizona. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
n.	**Liberty Utilities (Entrada Del Oro Sewer) Corp.**	The Liberty Utilities Entrada Del Oro Sewer utility is located in Avondale Arizona. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
o.	**Liberty Utilities (Pine Bluff Water) Inc.**	The Liberty Utilities Pine Bluff Water utility is located in Pine Bluff Arkansas. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
p.	**Liberty Utilities (Rio Rico Water & Sewer) Corp.**	The Liberty Utilities Rio Rico Water & Sewer utility is located in Rio Rico Arizona. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
q.	**Liberty Utilities (Seaside Water) LLC**	The Liberty Utilities Seaside Water utility is located at Seaside Resort in Texas. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
r.	**Liberty Utilities (Fox River Water) LLC**	The Liberty Utilities Fox River Water utility is located at Sheridan Illinois and based in Jackson Missouri. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
s.	**Liberty Utilities (Missouri Water) LLC**	The Liberty Utilities Missouri Water utility is located in Jackson Missouri. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
t.	**Liberty Utilities (Silverleaf Water) LLC**	The Liberty Utilities Silverleaf Water utility is located in Wood County Texas. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.

	Name	Territory and Operations
u.	**Liberty Utilities (Tall Timbers Sewer) Corp.**	The Liberty Utilities Tall Timbers Sewer utility is located in Tyler Texas. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
v.	**Liberty Utilities (White Hall Sewer) Corp.**	The Liberty Utilities White Hall Sewer utility is located in White Hall Arkansas. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
w.	**Liberty Utilities (White Hall Water) Corp.**	The Liberty Utilities White Hall Water utility is located in White Hall Arkansas. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
x.	**Liberty Utilities (Woodmark Sewer) Corp.**	The Liberty Utilities Woodmark Sewer utility is located in Smith County Texas. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
y.	**Liberty Utilities (Woodson-Hensley Water) Corp.**	The Liberty Utilities Woodson-Hensley Water utility is located in in the towns of Woodson and Hensley Arkansas. All of Liberty Utilities water and wastewater utilities are generally subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters.
z.	**Liberty Utilities (Midstates Natural Gas) Corp.**	Midstates Gas owns regulated natural gas utilities providing natural gas distribution services to approximately 190 communities in the states of Illinois, Iowa and Missouri, with a mix of residential, commercial, industrial and transportation customers. The franchise service area includes the communities of Virden, Vandalia, Harrisburg and Metropolis in Illinois, Keokuk in Iowa, and Butler, Kirksville, Canton, Hannibal, Jackson, Sikeston, Malden and Caruthersville in Missouri. The utilities in each of these states are regulated by their respective state PUCs.

	Name	Territory and Operations
aa.	**The Empire District Electric Company**	Based in Joplin, Missouri, Empire is a regulated utility providing electric, natural gas and water service in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of its electric segment, it provides water service to three towns in Missouri. The vertically-integrated regulated electricity operations of Empire represent the majority of its operating revenues and assets. The largest urban area served is the city of Joplin, Missouri, and its immediate vicinity. Empire also operates a fiber optics business. The utility portions of the business are subject to regulation by the MPSC, the KCC, the OCC, the APSC and the FERC. Owner of, among other things, (i) electric and water distribution and electric transmission utility assets serving locations in Missouri, Kansas, Oklahoma and Arkansas, (ii) the Mid-West wind development project, and (iii) the Ozark Beach hydro facility in Missouri, the Riverton, Energy Center, and Stateline No. 1 natural gas-fired power generation facilities in Kansas and Missouri, the Asbury coal-fired power generation facility in Missouri and a 40% interest in the Stateline combined cycle gas facility in Missouri.
bb.	**The Empire District Gas Company**	Empire District Gas is engaged in the distribution of natural gas in Missouri and is regulated by the MO PSC. A PGA allows EDG to recover from its customers, subject to audit and final determination by regulators, the cost of purchased gas supplies and related carrying costs associated with EDG's use of natural gas financial instruments to hedge the purchase price of natural gas. This PGA allows EDG to make rate changes periodically (up to four times) throughout the year in response to weather conditions and supply demands, rather than in one possibly extreme change per year.

iii. Unregulated Affiliates:

	Name	Territory and Operations
a.	**Algonquin Power & Utilities Corp.**	The Corporation owns and operates a diversified portfolio of regulated and non-regulated generation, distribution, and transmission utility assets. The Corporation's operations are organized across two primary North American business units consisting of: the Liberty Utilities Group, which primarily owns and operates a portfolio of regulated electric, natural gas, water distribution and wastewater collection utility systems, and transmission operations; and the Liberty Power Group.
b.	**Empire District Industries, Inc.**	An unregulated Affiliate of the Empire District Electric Company located in Joplin Missouri, primarily engaged in providing fiber optic services in the Empire District service territory.
c.	**St. Lawrence Gas Co. Service & Merchandising Corp.**	A direct, wholly owned Subsidiary of SLG, and an unregulated business, primarily engaged in the rental of water heaters and other natural gas appliances to its customers in St. Lawrence County, Lewis County, Franklin County and Jefferson County in New York State.
d.	**S.L.G. Communications Corp.**	A direct, wholly owned Subsidiary of SLG, and an unregulated business, primarily to serve as a holding company for maintaining FCC licenses for two-way radio communications for the parent company.

APPENDIX 3

Appendix 3

St. Lawrence Gas Company, Inc.
Case 18-G-0140
Capital Structure and Cost of Capital

	Percentage of Capital	Cost Rate	Weighted After Tax Cost	Pre-Tax Cost	**Effective Tax Rate**
Long-term Debt	51.20%	4.40%	2.25%	2.25%	
Common Equity	48.00%	9.00%	4.32%	5.85%	26.135%
Customer Deposits	0.80%	2.45%	0.02%	0.02%	
TOTAL	100.00%		6.59%	8.12%	

APPENDIX 4

Appendix 4
Schedule 1

St. Lawrence Gas Company, Inc.
Case 18-G-0140
Synergy Savings Tracking Mechanism
For the Twelve Months Ended (Month/Day/Year)

Initiative:
Description of Initiative:

Savings

Capital								
Category	Baseline for Savings	Savings	% Allocated to SLG	Savings Allocated to SLG	Baseline for Costs Avoided	Costs Avoided	% Allocated to SLG	Costs Avoided Allocated to SLG

O&M								
Category	Baseline for Savings	Savings	% Allocated to SLG	Savings Allocated to SLG	Baseline for Costs Avoided	Cost Avoided	% Allocated to SLG	Cost Avoided Allocated to SLG

Total Savings		
Category	Savings/Cost Avoided	Annual Ongoing Savings/Cost Avoided

Costs To Achieve

Capital								
Category	Baseline for Incremental Costs	Incremental Costs	% Allocated to SLG	Incremental Costs Allocated to SLG	Baseline for Ongoing Costs	Ongoing Costs	% Allocated to SLG	Ongoing Costs Allocated to SLG

O&M								
Category	Baseline for Costs	Incremental Costs	% Allocated to SLG	Incremental Costs Allocated to SLG	Baseline for Ongoing Costs	Ongoing Costs	% Allocated to SLG	Ongoing Costs Allocated to SLG

Total Costs To Achieve		
Category	Incremental Costs	Annual Ongoing Costs

Net Savings

Capital						
Category	Capital Savings	% Allocated to SLG	Capital Savings Allocated to SLG	Ongoing Capital Savings	% Allocated to SLG	Ongoing Capital Savings Allocated to SLG

O&M						
Category	O&M Savings	% Allocated to SLG	O&M Savings Allocated to SLG	Ongoing O&M Savings	% Allocated to SLG	Ongoing O&M Savings Allocated to SLG

Total Net Savings		
Category	Net Savings/Cost Avoided	Net Annual Ongoing Savings/Cost Avoided

Appendix 4
Schedule 2

St. Lawrence Gas Company, Inc.
Case 18-G-0140
Future Acquisition Savings Tracking Mechanism
For the Twelve Months Ended (Month/Day/Year)

Acquisition:
Description of Savings:

Materiality Test
Incremental Savings
Net Income Available for Common
Incremental Savings As a % of Net Income Available for Common

Savings

Capital								
Category	Baseline for Savings	Savings	% Allocated to SLG	Savings Allocated to SLG	Baseline for Costs Avoided	Costs Avoided	% Allocated to SLG	Costs Avoided Allocated to SLG

O&M								
Category	Baseline for Savings	Savings	% Allocated to SLG	Savings Allocated to SLG	Baseline for Costs Avoided	Cost Avoided	% Allocated to SLG	Cost Avoided Allocated to SLG

Total Savings				
Category	Total Savings/Cost Avoided	Customers Share of the Savings (i.e. 50%)	Total Annual Ongoing Savings/Cost Avoided	Customers Share of the Savings (i.e. 50%)

Additional Costs as a Result of the Acquisition

Capital								
Category	Baseline for Additional Costs	Additional Costs	% Allocated to SLG	Additional Costs Allocated to SLG	Baseline for Additional Ongoing Costs	Additional Ongoing Costs	% Allocated to SLG	Additional Ongoing Costs Allocated to SLG

O&M								
Category	Baseline for Additional Costs	Additional Costs	% Allocated to SLG	Additional Costs Allocated to SLG	Baseline for Additional Ongoing Costs	Additional Ongoing Costs	% Allocated to SLG	Additional Ongoing Costs Allocated to SLG

Total Additional Costs		
Category	Additional Costs	Annual Ongoing Additional Costs

Appendix 4
Schedule 3

St. Lawrence Gas Company, Inc.
Case 18-G-0140
Transition Costs Tracking Mechanism
For the Twelve Months Ended (Month/Day/Year)

Transition Cost:
Description of Transition Cost:

Transition Costs as a Result of the Acquisition

Capital								
Category	Baseline for Transition Costs	Transition Costs	% Allocated to SLG	Transition Costs Allocated to SLG	Baseline for Ongoing Transition Costs	Ongoing Transition Costs	% Allocated to SLG	Ongoing Transition Costs Allocated to SLG

O&M								
Category	Baseline for Transition Costs	Transition Costs	% Allocated to SLG	Transition Costs Allocated to SLG	Baseline for Ongoing Transition Costs	Ongoing Transition Costs	% Allocated to SLG	Ongoing Transition Costs Allocated to SLG

Total Transition Costs		
Category	Transition Costs	Annual Ongoing Transition Costs

APPENDIX 5

St. Lawrence Gas Company, Inc.
Cases 18-G-0133 & 18-G-0140

Appendix 5
Schedule A

Gas Safety Performance Metrics and Negative (NRA) / Positive (PRA) Revenue Adjustments

Gas Safety Metrics	Targets		Basis Points (BP)
Emergency Response (percent completed)			**(NRA) / PRA (BP)**
	2019	**2020**	
30 Minute Response	> 90%	> 90%	6 bp
	>85% - 90%	>85% - 90%	3 bp
	75% - 85%	75% - 85%	0 bp
	< 75%	< 75%	(9) bp
45 Minute Response	<90%	<90%	(6) bp
60 Minute Response	<95%	<95%	(3) bp
Excavation Damages (per 1000 Tickets)			**(NRA) / PRA (BP)**
	2019	**2020**	
Total Damages	> 3.00	> 3.00	(27) bp
	>2.95 - 3.00	>2.85 - 3.00	(15) bp
	>2.85 - 2.95	>2.75 -2.85	(5) bp
	>2.25 - 2.85	>2.15 - 2.75	0 bp
	2.00-2.25	1.90-2.15	5 bp
	<2.00	<1.90	10 bp
Leak Management			**(NRA) / PRA (BP)**
	2019	**2020**	
Total Year-End Leak Backlog (Type 1, 2, 2A and 3)	0 1 - 5 leaks >5 leaks	0 1 - 4 leaks >4 leaks	NA 0 bp (18) bp
Gas Safety Violations (NYCRR Parts 255 & 261)			**(NRA) / PRA (BP)**
	2019	**2020**	
Record Violations			
High Risk	1-4 5-8 >8	1-4 5-8 >8	0 (1/2) bp (1) bp
Other Risk	1-8 >8	1-8 >8	0 (1/4) bp
Field Violations			
High Risk	1-8 >8	1-8 >8	(1/2) bp (1) bp
Other Risk	>0	>0	(1/4) bp

St. Lawrence Gas Company, Inc.
Cases 18-G-0133 & 18-G-0140
Part 255 / 261
High and Other Gas Risk Safety Violations

HIGH RISK SECTIONS PART 255

ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Material - General	255.53	HIGH
Transportation of Pipe	255.65	HIGH
Pipe Design - General	255.103	HIGH
Design of Components - General Requirements	255.143	HIGH
Design of Components - Flexibility	255.159	HIGH
Design of Components - Supports and anchors	255.161	HIGH
Compressor Stations: Emergency shutdown	255.167	HIGH
Compressor Stations: Pressure limiting devices	255.169	HIGH
Compressor Stations: Ventilation	255.173	HIGH
Valves on pipelines to operate at 125 psig or more	255.179	HIGH
Distribution line valves	255.181	HIGH
Vaults: Structural Design requirements	255.183	HIGH
Vaults: Drainage and waterproofing	255.189	HIGH
Protection against accidental overpressuring	255.195	HIGH
Control of the pressure of gas delivered from high pressure distribution	255.197	HIGH
Requirements for design of pressure relief and limiting devices	255.199	HIGH
Required capacity of pressure relieving and limiting stations	255.201	HIGH
Qualification of welding procedures	255.225	HIGH
Qualification of Welders	255.227	HIGH
Protection from weather	255.231	HIGH
Miter Joints	255.233	HIGH
Preparation for welding	255.235	HIGH
Inspection and test of welds	255.241(a),(b)	HIGH
Nondestructive testing-Pipeline to operate at 125 PSIG or more	255.243(a)-(e)	HIGH
Welding inspector	255.244(a),(b),(c)	HIGH
Repair or removal of defects	255.245	HIGH
Joining Of Materials Other Than By Welding - General	255.273	HIGH
Joining Of Materials Other Than By Welding - Copper Pipe	255.279	HIGH
Joining Of Materials Other Than By Welding - Plastic Pipe	255.281	HIGH
Plastic pipe: Qualifying persons to make joints	255.285(a),(b),(d)	HIGH
Notification requirements	255.302	HIGH
Compliance with construction standards	255.303	HIGH
Inspection: General	255.305	HIGH
Inspection of materials	255.307	HIGH

Repair of steel pipe	255.309	HIGH
Repair of plastic pipe	255.311	HIGH

HIGH RISK SECTIONS PART 255 (continued)

ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Bends and elbows	255.313(a),(b),(c)	HIGH
Wrinkle bends in steel pipe	255.315	HIGH
Installation of plastic pipe	255.321	HIGH
Underground clearance	255.325	HIGH
Customer meters and service regulators: Installation	255.357(d)	HIGH
Service lines: Installation	255.361(e),(f),(g),(h),(i)	HIGH
Service lines: Location of valves	255.365(b)	HIGH
External corrosion control: Buried or submerged pipelines installed after July 31, 1971	255.455(d),(e)	HIGH
External corrosion control: Buried or submerged pipelines installed before August 1, 1971	255.457	HIGH
External corrosion control: Protective coating	255.461(c)	HIGH
External corrosion control: Cathodic protection	255.463	HIGH
External corrosion control: Monitoring	255.465(a),(e)	HIGH
Internal corrosion control: Design and construction of transmission line	255.476(a),(c)	HIGH
Remedial measures: General	255.483	HIGH
Remedial measures: transmission lines	255.485(a),(b)	HIGH
Strength test requirements for steel pipelines to operate at 125 PSIG or	255.505(a),(b),(c),(d)	HIGH
General requirements (UPGRADES)	255.553 (a),(b),(c),(f)	HIGH
Upgrading to a pressure of 125 PSIG or more in steel pipelines	255.555	HIGH
Upgrading to a pressure less than 125 PSIG	255.557	HIGH
Conversion to service subject to this Part	255.559(a)	HIGH
General provisions	255.603	HIGH
Operator Qualification	255.604	HIGH
Essentials of operating and maintenance plan	255.605	HIGH
Change in class location: Required study	255.609	HIGH
Damage prevention program	255.614	HIGH
Emergency Plans	255.615	HIGH
Customer education and information program	255.616	HIGH
Maximum allowable operating pressure: Steel or plastic pipelines	255.619	HIGH
Maximum allowable operating pressure: High pressure distribution	255.621	HIGH
Maximum and minimum allowable operating pressure: Low pressure	255.623	HIGH
Odorization of gas	255.625(a),(b)	HIGH
Tapping pipelines under pressure	255.627	HIGH
Purging of pipelines	255.629	HIGH
Control Room Management	255.631	HIGH
Transmission lines: Patrolling	255.705	HIGH
Leakage Surveys - Transmission	255.706	HIGH

Transmission lines: General requirements for repair procedures	255.711	HIGH
Transmission lines: Permanent field repair of imperfections and damages	255.713	HIGH
Transmission lines: Permanent field repair of welds	255.715	HIGH

HIGH RISK SECTIONS PART 255 (continued)

ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Transmission lines: Permanent field repair of leaks	255.717	HIGH
Transmission lines: Testing of repairs	255.719	HIGH
Distribution systems: Leak surveys and procedures	255.723	HIGH
Compressor stations: procedures	255.729	HIGH
Compressor stations: Inspection and testing relief devices	255.731	HIGH
Compressor stations: Additional inspections	255.732	HIGH
Compressor stations: Gas detection	255.736	HIGH
Pressure limiting and regulating stations: Inspection and testing	255.739(a),(b)	HIGH
Regulator Station Overpressure Protection	255.743(a),(b)	HIGH
Transmission Line Valves	255.745	HIGH
Prevention of accidental ignition	255.751	HIGH
Protecting cast iron pipelines	255.755	HIGH
Replacement of exposed or undermined cast iron piping	255.756	HIGH
Replacement of cast iron mains paralleling excavations	255.757	HIGH
Leaks: Records	255.807(d)	HIGH
Leaks: Instrument sensitivity verification	255.809	HIGH
Leaks: Type 1	255.811(b),(c),(d),(e)	HIGH
Leaks: Type 2A	255.813(b),(c),(d)	HIGH
Leaks: Type 2	255.815 (b),(c),(d)	HIGH
Leak Follow-up	255.819(a)	HIGH
Leaks - Nonreportable Reading	255.821	HIGH
High Consequence Areas	255.905	HIGH
Required Elements (IMP)	255.911	HIGH
Knowledge and Training (IMP)	255.915	HIGH
Identification of Potential Threats to Pipeline Integrity and Use of the	255.917	HIGH
Baseline Assessment Plan(IMP)	255.919	HIGH
Conducting a Baseline Assessment (IMP)	255.921	HIGH
Direct Assessment (IMP)	255.923	HIGH
External Corrosion Direct Assessment (ECDA) (IMP)	255.925	HIGH
Internal Corrosion Direct Assessment (ICDA) (IMP)	255.927	HIGH
Confirmatory Direct Assessment (CDA) (IMP)	255.931	HIGH
Addressing Integrity Issues (IMP)	255.933	HIGH
Preventive and Mitigative Measures to Protect the High Consequence	255.935	HIGH
Continual Process of Evaluation and Assessment (IMP)	255.937	HIGH
Reassessment Intervals (IMP)	255.939	HIGH
General requirements of a GDPIM plan	255.1003	HIGH

Implementation requirements of a GDPIM plan.	255.1005	HIGH
Required elements of a GDPIM plan.	255.1007	HIGH
Required report when compression couplings fail.	255.1009	HIGH
Requirements a small liquefied petroleum gas (LPG) operator must satisfy to implement a GDPIM plan	255.1015	HIGH

HIGH RISK SECTIONS PART 261

ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Operation and maintenance plan	261.15	HIGH
Leakage Survey	261.17(a),(c)	HIGH
Carbon monoxide prevention	261.21	HIGH
Warning tag procedures	261.51	HIGH
HEFPA Liaison	261.53	HIGH
Warning Tag Inspection	261.55	HIGH
Warning tag: Class A condition	261.57	HIGH
Warning tag: Class B condition	261.59	HIGH

OTHER RISK SECTIONS PART 255

ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Preservation of records	255.17	OTHER
Compressor station: Design and construction	255.163	OTHER
Compressor station: Liquid removal	255.165	OTHER
Compressor stations: Additional safety equipment	255.171	OTHER
Vaults: Accessibility	255.185	OTHER
Vaults: Sealing, venting, and ventilation	255.187	OTHER
Calorimeter or calorimeter structures	255.190	OTHER
Design pressure of plastic fittings	255.191	OTHER
Valve installtion in plastic pipe	255.193	OTHER
Instrument, control, and sampling piping and components	255.203	OTHER
Limitations On Welders	255.229	OTHER
Quality assurance program	255.230	OTHER
Preheating	255.237	OTHER
Stress relieving	255.239	OTHER
Inspection and test of welds	255.241(c)	OTHER
Nondestructive testing-Pipeline to operate at 125 PSIG or more	255.243(f)	OTHER
Plastic pipe: Qualifying joining procedures	255.283	OTHER
Plastic pipe: Qualifying persons to make joints	255.285(c),(e)	OTHER
Plastic pipe: Inspection of joints	255.287	OTHER
Bends and elbows	255.313(d)	OTHER
Protection from hazards	255.317	OTHER
Installation of pipe in a ditch	255.319	OTHER

Casing	255.323	OTHER
Cover	255.327	OTHER
Customer meters and regulators: Location	255.353	OTHER
Customer meters and regulators: Protection from damage	255.355	OTHER
Customer meters and service regulators: Installation	255.357(a),(b),(c)	OTHER
Customer meter installations: Operating pressure	255.359	OTHER

OTHER RISK SECTIONS PART 255 (continued)

ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Service lines: Installation	255.361(a),(b),(c),(d)	OTHER
Service lines: valve requirements	255.363	OTHER
Service lines: Location of valves	255.365(a),(c)	OTHER
Service lines: General requirements for connections to main piping	255.367	OTHER
Service lines: Connections to cast iron or ductile iron mains	255.369	OTHER
Service lines: Steel	255.371	OTHER
Service lines: Cast iron and ductile iron	255.373	OTHER
Service lines: Plastic	255.375	OTHER
Service lines: Copper	255.377	OTHER
New service lines not in use	255.379	OTHER
Service lines: excess flow valve performance standards	255.381	OTHER
External corrosion control: Buried or submerged pipelines installed after July 31, 1971	255.455(a)	OTHER
External corrosion control: Examination of buried pipeline when	255.459	OTHER
External corrosion control: Protective coating	255.461(a),(b),(d),(e),(f),(	OTHER
External Corrosion Control - Monitoring	255.465 (b),(c),(d),(f)	OTHER
External corrosion control: Electrical isolation	255.467	OTHER
External corrosion control: Test stations	255.469	OTHER
External corrosion control: Test lead	255.471	OTHER
External corrosion control: Interference currents	255.473	OTHER
Internal corrosion control: General	255.475	OTHER
Internal corrosion control: Design and Construction of transmission line	255.476(d)	OTHER
Atmospheric corrosion control: General	255.479	OTHER
Atmospheric corrosion control: Monitoring	255.481	OTHER
Remedial measures: transmission lines	255.485(c)	OTHER
Remedial measures: Pipelines lines other than cast iron or ductile iron	255.487	OTHER
Remedial measures: Cast iron and ductile iron pipelines	255.489	OTHER
Direct Assessment	255.490	OTHER
Corrosion control records	255.491	OTHER
General requirements (TESTING)	255.503	OTHER
Strength test requirements for steel pipelines to operate at 125 PSIG or	255.505(e),(h),(i)	OTHER
Test requirements for pipelines to operate at less than 125 PSIG	255.507	OTHER
Test requirements for service lines	255.511	OTHER
Environmental protection and safety requirements	255.515	OTHER

Records (TESTING)	255.517	OTHER
Notification requirements (UPGRADES)	255.552	OTHER
General requirements (UPGRADES)	255.553(d),(e)	OTHER
Conversion to service subject to this Part	255.559(b)	OTHER
Change in class location: Confirmation or revision of maximum	255.611(a),(d)	OTHER
Continuing surveillance	255.613	OTHER
Odorization	255.625(e),(f)	OTHER
Pipeline Markers	255.707(a),(c),(d),(e)	OTHER

OTHER RISK SECTIONS PART 255 (continued)

ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Transmission lines: Record keeping	255.709	OTHER
Distribution systems: Patrolling	255.721(b)	OTHER
Test requirements for reinstating service lines	255.725	OTHER
Inactive Services	255.726	OTHER
Abandonment or inactivation of facilities	255.727(b)-(g)	OTHER
Compressor stations: storage of combustible materials	255.735	OTHER
Pressure limiting and regulating stations: Inspection and testing	255.739(c),(d),(e),(f)	OTHER
Pressure limiting and regulating stations: Telemetering or recording	255.741	OTHER
Regulator Station MAOP	255.743 (c)	OTHER
Service Regulator - Min.& Oper. Load	255.744 (c),(d),(e)	OTHER
Distribution Line Valves	255.747	OTHER
Valve maintenance: Service line valves	255.748	OTHER
Regulator Station Vaults	255.749	OTHER
Caulked bell and spigot joints	255.753	OTHER
Reports of accidents	255.801	OTHER
Emergency lists of operator personnel	255.803	OTHER
Leaks General	255.805(a),(b),(e),(g),(h)	OTHER
Leaks: Records	255.807(a),(b),(c)	OTHER
Type 3	255.817	OTHER
Interruptions of service	255.823(a),(b)	OTHER
Logging and analysis of gas emergency reports	255.825	OTHER
Annual Report	255.829	OTHER
Reporting safety-related conditions	255.831	OTHER
General (IMP)	255.907	OTHER
Changes to an Integrity Management Program (IMP)	255.909	OTHER
Low Stress Reassessment (IMP)	255.941	OTHER
Measuring Program Effectiveness (IMP)	255.945	OTHER
Records (IMP)	255.947	OTHER
Records an operator must keep	255.1011	OTHER

OTHER RISK SECTIONS PART 261

ACTIVITY TITLE	CODE SECTION	RISK FACTOR
High Pressure Piping - Annual Notice	261.19	OTHER
Warning tag: Class C condition	261.61	OTHER
Warning tag: Action and follow-up	261.63(a)-(h)	OTHER
Warning Tag Records	261.65	OTHER

APPENDIX 6

Appendix 6

St. Lawrence Gas Company, Inc.
Case 18-G-0140
Service Quality Performance Mechanism

PSC Complaint Rate	
Targets	NRAs
< 1.5	$0
>= 1.5	$12,000
>= 2.0	$24,000
>= 2.5	$36,000

Customer Satisfaction Index	
Targets	NRAs
>86%	$0
<=86%	$12,000
<=85%	$24,000
<=84%	$36,000

Terminations and Uncollectibles		
	Customer Terminations	Bad Debt
Three Year Average (set in 2016)	466	$204,000
Target	<=451	$173,000

PRA Only

The Company shall be entitled to an incentive of $12,000 per year if both measures are at or below target set forth above; and $6,000 per year if one measure is at or below target and the other is at or below the three-year average. If neither measure is at or below the target, the Company shall not be entitled to any positive incentive, but shall not be subject to any financial penalty.

Negative Revenue Adjustment Multiplier

The NRAs shown in this appendix have been doubled from those in the 2016 Rate Plan. In addition, the NRAs shall be tripled if targets are missed during a dividend restriction and quadrupled if targets are missed in three years out of the next five consecutive CYs.

APPENDIX 7

Appendix 7

St. Lawrence Gas Company, Inc.
Case 18-G-0140
Net Plant - Legacy Area Only

	Rate Year 4 Monthly Average	Rate Year 5 Monthly Average
Utility Plant	$62,905,844	$64,536,152
CWIP	$219,696	$219,696
Total Utility Plant	$63,125,540	$64,755,848
Less: Accum. Depre.	$31,713,816	$33,070,043
Net Utility Plant	$31,411,724	$31,685,805

APPENDIX 8

Appendix 8

St. Lawrence Gas Company, Inc.
Case 18-G-0140
Reimbursement Margin as of December 31, 2018

	Before Write-Down	Write-Down Adj	After Write-Down
Net Utility Plant (net of goodwill)	$ 67,094,686	$ (19,000,000)	$ 48,094,686
Deferred Debits			
Unamortized Debt Expense	4,199		4,199
Miscellaneous Deferred Debits	4,594,944		4,594,944
Deferred Credits			
Customer Advances Per Constructions	(303,824)		(303,824)
Other Deferred Credits	(35,895)		(35,895)
Other Regulatory Liabilities	(295,275)		(295,275)
Accumulated Deferred Income Taxes (net)	(5,593,031)	4,965,580	(627,451)
Reimbursable Plant	**$ 65,465,805**		**$ 51,431,385**
Long-Term Securities	7,000,000		7,000,000
Short-Term Debt Obligations	23,000,000		23,000,000
Common Stock			
Common Stock Issued	$ 4,350,000		$ 4,350,000
Other Paid-In Capital	13,000,000		13,000,000
Total Long-Term Securities	**$ 47,350,000**		**$ 47,350,000**
Reimbursement Margin - December 31, 2018	**$ 18,115,805**		**$ 4,081,385**
Pro-Forma 2019 - 2023 Adjustments			
Capital Expenditures	$ 20,496,000		$ 20,496,000
CIAC	(11,354,925)		(11,354,925)
Depreciation	(10,033,035)		(10,033,035)
Deferred Federal Income Tax	(598,349)		(598,349)
Enbridge Paid-In Capital	13,000,000		13,000,000
Liberty Equity Infusion	(13,000,000)		(13,000,000)
Refinancing of Debt Obligations	30,000,000		30,000,000
Forecasted Reimbursement Margin - December 31, 2023	**$ 46,625,496**		**$ 32,591,076**
Current Petition Requirements			
Replace Long-Term Debt	$ 7,000,000		$ 7,000,000
Replace Enbridge US Note Payable with Long-Term Debt	21,185,000		21,185,000
Excess Reimbursement Margin Through December 31, 2023	**$ 18,440,496**		**$ 4,406,076**

Notes:
Typically short-term debt obligations are not included in the reimbursement margin, however SLG has been funding a portion of its capital expenditures with short term debt and therefore it has been included in its capital structure for ratemaking purposes.

APPENDIX 9

Appendix 9

St. Lawrence Gas Company, Inc.
Cases 18-G-0133 & 18-G-0140
15-G-0382 Joint Proposal
Table of Contents
For Reference Only

Georgia Public Service Commission

(404) 656-4501
(800) 282-5813

244 WASHINGTON STREET, S.W.
ATLANTA, GEORGIA 30334-9052

FAX: (404) 656-2341
www.psc.state.ga.us

DOCKET NO. 36278

IN RE: JOINT APPLICATION OF ATMOS ENERGY CORPORATION AND LIBERTY ENERGY (GEORGIA) CORP. FOR AUTHORITY TO TRANSFER GEORGIA UTILITY ASSETS AND CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY, FOR FINANCING AUTHORITY RELATED THERETO, AND FOR WAIVER OF COMPETITIVE BIDDING RULE 515-4-1-.15 AND RULE 515-4-1-.13 ("HEARINGS BEFORE COMMISSION") APPLYING TO STOCK AND BOND APPLICATIONS

ORDER APPROVING JOINT APPLICATION

Decided: February 19, 2013

APPEARANCES:

FOR ATMOS ENERGY CORPORATION AND LIBERTY ENERGY (GEORGIA) CORP.:

Julius Hulsey, Attorney and Mark Caudill, Attorney

FOR THE COMMISSION PUBLIC INTEREST ADVOCACY STAFF:

Nancy Gibson, Attorney

JURISDICTION

O.C.G.A. § 46-2-20(a) provides that the Commission has general supervisory authority over gas companies.

O.C.G.A. § 46-4-21(a) provides that the Commission has the authority to issue certificates of public convenience and necessity authorizing the construction, ownership, control and operation of intrastate pipelines and distribution systems, as well as the sale of natural or manufactured gas from such pipeline.

O.C.G.A. § 46-4-20(c) provides that the Commission has jurisdiction over distribution and sales in intrastate commerce, including but not limited to rates, regulations, service, financing, and accounts.

O.C.G.A. § 46-4-29 provides that the Commission has the authority to approve applications for the transfer of certificates of public convenience and necessity that have been issued by the Commission.

O.C.G.A. § 46-2-28 provides that the Commission has the authority to authorize companies subject to its jurisdiction to issue stocks, bonds, notes, or other evidences of debt reasonably required for the acquisition of property and other lawful purposes.

STATEMENT OF THE PROCEEDINGS

On September 19, 2012, Atmos Energy Corporation ("Atmos Energy" and an "Applicant") and Liberty Energy (Georgia) Corp. ("Liberty Georgia" and an "Applicant") filed with the Georgia Public Service Commission ("Commission") a Joint Application requesting authorization for Atmos Energy to sell and transfer to Liberty Georgia certain utility assets currently owned and operated in Georgia by Atmos Energy, together with all certificates of public convenience and necessity. Applicants also requested authorization for Liberty Georgia to purchase, finance, own, and operate those utility assets to provide service to customers in the service areas currently served by Atmos Energy. The verified application was accompanied by pre-filed direct testimony of Ian Robertson, Peter Eichler, and Chico DaFonte.

Staff issued its First Set of Data Requests on October 2, 2012, to which the Joint Applicants filed responses on October 12 and 15, 2012. The Staff issued its Second Set of Data Requests on October 11, 2012, to which the Joint Applicants filed responses on October 20 and 24, 2012. Notice of the Joint Application was provided to the designated local government officials, and notices were published in the *Gainesville Times*, the *Columbus Ledger-Enquirer*, the *Jackson County Harold* and the *Harris County Journal* pursuant to Commission Rule 515-7-1-.04. No interventions were filed, and there were no objections or protest to the Joint Application.

Pursuant to the October 16, 2012 Procedural and Scheduling Order, the hearing of the Joint Application was held on January 10, 2013, at which time the Commission heard the direct testimony of Ian Robertson, Peter Eichler, and Chico DaFonte, which had been pre-filed simultaneously with the Joint Application and accompanying Exhibits. No other witnesses presented evidence. At the hearing, the witnesses also tendered a letter from the Joint Applicants, indicating that, in response to matters raised by Staff, the facilities owned and operated by Atmos

Energy to liquefy, store, and vaporize natural gas in the Columbus service territory (the "LNG Facilities") would be removed from the Georgia Assets[1] prior to the transfer, and would be retained by Atmos Energy.

Recommendations were submitted to the Commission by the Staff and by the Joint Applicants on January 31, 2013. This matter was discussed during the Commission's Energy Committee meeting on February 14, and was decided at the Commission's Administrative Session on February 19, 2013. Upon consideration of the evidence presented and the recommendations made by the Joint Applicants and the Staff, the Commission herewith makes its findings.

OVERVIEW

Atmos Energy and Liberty Georgia applied for authority to complete the transaction described within the Asset Purchase Agreement dated August 8, 2012 ("Purchase Agreement"), a copy of which was attached to the Joint Application as Exhibit C and incorporated therein by reference. The Purchase Agreement sets forth the terms and conditions for a transaction (the "Transaction"), pursuant to which Liberty Georgia would purchase and Atmos Energy would sell the Georgia Assets (which include substantially all of the assets of Atmos Energy used to provide natural gas distribution and intrastate transportation service within the State of Georgia as defined in footnote 1), as specifically described in the Purchase Agreement. Additionally, the Applicants are requesting the transfer of the existing certificates of public convenience and necessity pursuant to which Atmos Energy currently owns and operates the Georgia Assets, pursuant to the Commission's authority as provided for in O.G.C.A. §§ 46-4-21 *et seq.* and Commission Rule 515-7-1-.02 *et seq.*

Atmos Energy has been serving customers in Georgia since it acquired United Cities Gas Company through a merger in 1997. Atmos Energy's certificated areas within Georgia include, but are not limited to, the cities and vicinities near Gainesville, Oakwood, and Columbus, and all or portions of Barrow, Chattahoochee, Hall, Harris, Jackson, Muscogee, and Oconee Counties. Service is provided pursuant to Distribution Certificates 24, 27, and 144, and pursuant to Pipeline Certificates 2 and 26.

Liberty Georgia is a Georgia Corporation and was formed for the purpose of acquiring, owning, and operating the Georgia Assets. Liberty Georgia is a wholly-owned subsidiary of Liberty Energy Utilities Co., which is a wholly owned subsidiary of Liberty Utilities Co., and an indirect subsidiary of Algonquin Power & Utilities Corp. ("Algonquin"). Algonquin is a publicly traded corporation that is traded on the Toronto Stock exchange and is incorporated under the laws of Canada, with its principal place of business in Oakville, Ontario. Algonquin provides generation, distribution and transmission utility services through two business units: (i)

[1] The term "Georgia Assets" was initially defined in the Purchase Agreement attached to the Joint Application as Exhibit C and incorporated therein. As a result of the letter presented by the witnesses at the hearing on January 10, the term "Georgia Assets" was effectively redefined to exclude the LNG Facilities. This Order uses the revised definition. By agreement of the Applicants, the LNG Facilities are excluded from the Transaction.

an electric power generation business unit that includes 41 renewable power generating facilities and 12 high-efficiency thermal generating facilities located in eight U.S. states and Canada, and (ii) a regulated utility business that owns and operates 25 utilities located in seven U.S. states providing retail water, sewer, electric, and natural gas distribution service. In total, Algonquin owns and operates an approximately $1.7 billion (U.S.) portfolio of utility assets. Organized in 1987, Algonquin traces its history to development and operation of independent electric generating facilities and its current electric generating operations represent one of the largest renewable power generating portfolios in Canada. Approximately 50% of Algonquin's revenues are generated through its U.S.-based operations. Algonquin acquired its first regulated utility system in 2001, and since then has acquired twenty four additional water, wastewater, electric, and natural gas utility systems providing service to approximately 330,000 customers in the United States. Liberty Utilities Co., Algonquin's utility operating company subsidiary, has regulated electric distribution operations in California and New Hampshire, natural gas distribution operations in New Hampshire, Iowa, Illinois and Missouri, and water and wastewater operations in Texas, Arizona, and Missouri.

Upon consummation of the Transaction contemplated by the Purchase Agreement, Liberty Georgia will provide natural gas service within the State of Georgia in those areas previously certificated to Atmos Energy without service interruptions as a result of the asset transfer. To ensure that service is transitioned smoothly, Liberty Georgia proposes to assume the then-current tariffs on file and approved for Atmos Energy as of the closing of the Transaction. To accomplish this, Liberty Georgia proposes to reissue and file with this Commission the then-current tariffs, with the only changes from the Atmos Energy tariffs being the name change to Liberty Energy (Georgia) Corp. and corresponding changes in contact information. Moreover, Liberty Georgia proposes to assume all of the duties, obligations, rights and privileges of Atmos Energy as established by this Commission for Atmos Energy and its Georgia customers regarding on-going rate and regulatory programs, rates, riders, and initiatives, including, but not limited to base rates, purchased gas cost adjustments, weather normalization, gas supply plan, margin loss recovery rider, performance based regulation authority, and the cast iron and bare steel pipeline replacement program. When Liberty Georgia reissues and files its initial Rates, Tariffs, and Terms and Conditions in compliance with the Order in this docket, the same should be effective immediately without notice or suspension. Any subsequent changes to the rates, regulations, terms and conditions of service, riders and initiatives applicable to the regulated services provided by Liberty Georgia must be sought in compliance with the substantive and procedural requirements established by this Commission and the laws of the State of Georgia. Liberty Georgia will continue to make Quarterly and Annual Georgia Rate Adjustment Mechanism ("GRAM") Filings established in Docket 34734, unless and until Liberty Georgia files a traditional rate case application.

Liberty Georgia proposed to establish its initial capitalization with a debt-to-equity ratio of approximately 45% debt and 55% equity. The purchase price agreed to by Atmos Energy and Liberty Georgia is set out in the Purchase Agreement, including Appendix A of the Purchase Agreement; the purchase price is $140,660,000, comprised of Net Assets for ratemaking purposes of approximately $128,145,000 and an acquisition premium of approximately $12,515,000, subject to either a positive or negative Adjustment Amount (as defined within the

Purchase Agreement) to be calculated in connection with the closing of the Transaction. Liberty Georgia will not seek to recover the acquisition premium in rates. To accomplish the initial capitalization, Liberty Georgia seeks authority to issue shares of its common stock. Based on the estimated purchase price of approximately $140.7 million, Liberty Georgia expects to issue approximately $80 million of common stock to its parent, Liberty Energy Utilities Co. in connection with its initial equity capitalization. Similarly, Liberty Georgia seeks authority to issue intercompany debt instruments. Based on the estimated purchase price of approximately $140.7 million, Liberty Georgia proposes to borrow approximately $61 million in long-term debt from its parent Liberty Energy Utilities Co. Liberty Georgia noted that because the purchase price was subject to either a positive or negative Adjustment Amount, which would not be known until the time of the closing, the exact amounts of debt and equity would be adjusted up or down. Nonetheless, the approximate capital structure of 45% debt and 55% equity will be achieved. In testimony before this Commission, Liberty Georgia indicated that it intends to establish a capital structure that has more equity than Atmos Energy's current capital structure, but Liberty Georgia also expects to issue debt instruments at more favorable rates than are reflected in Atmos Energy's current cost of capital.

The funding for the long-term debt is expected to come from issuance of unsecured notes by an affiliate of Liberty Georgia on a private placement basis. Such funds will then be re-lent based on the long term debt rate provided by the unsecured notes, to Liberty Georgia. Liberty Georgia will also be provided access to Liberty Utilities Co.'s revolving short-term credit facility for uses including but not limited to satisfying Liberty Georgia's on-going operational working capital requirements. The final terms of the long-term indebtedness will be established in the context of the fixed income capital market conditions in effect at the time of funding. Liberty Georgia believes that allowing it flexibility to adapt its borrowings to market conditions in effect nearer in time to the closing date will improve its ability to obtain the most reasonable terms for the debt. Therefore, Liberty Georgia requests authority to issue debt in the amounts sufficient to close the Transaction pursuant to the Purchase Agreement on terms consistent with those indicated to the Commission in this docket.

SPECIFIC FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. This Commission concludes that it has authority to approve the transfer of the Georgia Assets, including the transfer of the existing certificates of public convenience and necessity pursuant to which Atmos Energy currently owns and operates the Georgia Assets (O.G.C.A. §§ 46-4-21 *et seq.* and Commission Rule 515-7-1-.02 *et seq.*).

2. The Commission finds that the Purchase Agreement and resulting transfer of the Georgia Assets from Atmos Energy to Liberty Georgia are in the public interest.

3. The Commission finds that it is in the public interest to authorize both Atmos Energy and Liberty Georgia to execute and act in accordance with the terms of the Purchase Agreement.

4. The Commission finds that it is in the public interest to specifically authorize Atmos Energy to abandon the Georgia Assets and the provision of services within Georgia, and to sell and transfer the Georgia Assets to Liberty Georgia, together with all certificates of public convenience and necessity.

5. The Commission finds that it is in the public interest to authorize Liberty Georgia to purchase, finance, own, manage and operate the Georgia Assets and to provide service within the areas currently certificated to Atmos Energy.

6. The Commission finds that Liberty Georgia is fully qualified to own and operate the Georgia Assets and to provide safe, reliable and affordable service to customers within the areas certificated to Atmos Energy within Georgia.

7. The Commission finds Liberty Georgia has the financial strength and stability and the technical expertise to operate, maintain, and expand the facilities within the certificated service areas and to contract for and purchase necessary gas supply, storage and interstate transportation to meet the needs of its customers in Georgia.

8. The Commission finds that the proposed capitalization for Liberty Georgia is appropriate and that it is in the public interest to approve the requested financing authority in amounts sufficient to achieve the initial capitalization of Liberty Georgia in the manner described herein, authorizing the use of the funds for the purposes stated herein, and granting waivers of Commission Rules regarding financing to the extent necessary to effectuate the financing plan described herein.

9. The Commission concludes that the Georgia Assets to be acquired by Liberty Georgia will remain subject to the jurisdiction of this Commission.

10. The Commission concludes that Liberty Georgia will be a "gas company" as that term is defined under O.C.G.A. § 46-1-1(5), and a "utility" as that term is defined in O.C.G.A § 46-1-1(9) and Commission Rule 515-7-1-.01(j) upon the close of the Transaction.

11. The Commission finds that the public interest is served by substituting Liberty Georgia in place of Atmos Energy with regard to ongoing rate and regulatory programs, rates, riders, and initiatives, and by transferring to Liberty Georgia all duties, obligations, rights, and privileges related thereto.

12. The Commission finds that it is in the public interest to authorize Liberty Georgia to reissue and file the Rates, Tariffs and Terms and Conditions of Service presently approved for Atmos Energy within Georgia as the Rates, Tariffs and Terms and Conditions of Service of Liberty Georgia to be effective immediately upon filing with the Commission's Executive Secretary without additional notice or suspension of rates.

13. The Commission finds that the public interest is served by Liberty Georgia, upon the close of the Transaction, assuming all of the duties, obligations, rights and privileges of Atmos Energy as established by this Commission for Atmos Energy and its Georgia customers

regarding on-going pipeline safety, rate and regulatory programs, rates, riders, and initiatives, including, but not limited to base rates, purchased gas cost adjustments, weather normalization, gas supply plan, margin loss recovery rider, performance based regulation authority, and the cast iron and bare steel pipeline replacement program.

14. The Commission concludes and finds that after Liberty Georgia files its initial Rates, Tariffs and Terms and Conditions of Service based on those in place for Atmos Energy in compliance with this Order, any subsequent changes to the rates, regulations, terms and conditions of service, riders and initiatives applicable to Liberty Georgia's regulated services will be made only in compliance with the substantive and procedural requirements established by this Commission and the laws of the State of Georgia.

15. The Commission finds and concludes that following the close of the Transaction, Liberty Georgia will make Quarterly and Annual GRAM Filings in the form and containing the information established in Docket 34734, unless and until Liberty Georgia files a traditional rate case application.

16. The Commission finds and concludes that Liberty Georgia shall file its 2013 and 2014 Annual GRAM Filings using its actual capital structure. Nonetheless, if (a) pursuant to Liberty's 2013 or 2014 Annual GRAM Filings (for rates to be effective February 1, 2014 and February 1, 2015 respectively) base rates increase above the base rates effective February 1, 2013, and (b) the revenue requirements calculated by using Liberty Georgia's actual capital structure and cost of debt are higher than the revenue requirements that would have resulted if Atmos Energy's capital structure and cost of debt as established in its 2012 Annual GRAM Filing (for rates effective February 1, 2013) had been used, then for the purposes of the 2013 and 2014 Annual GRAM Filings, Liberty shall submit rates using the same capital structure and cost of debt as submitted by Atmos Energy in its 2012 Annual GRAM Filing.

17. The Commission finds and concludes that Liberty Georgia shall not seek to recover (a) any of the expenses incurred to negotiate, contract for, and close the Purchase Agreement, and (b) any acquisition premium associated with the Transaction in any future GRAM filings or rate cases.

ORDERING PARAGRAPHS

After consideration of all of the evidence presented in this proceeding and upon the Commission's findings of fact and conclusions of law, the Commission adopts and sets out the Ordering Paragraphs below.

WHEREFORE IT IS ORDERED, that except as modified herein to remove the LNG Facilities from the Georgia Assets, Atmos Energy and Liberty Georgia are authorized to complete the Transaction described within the Asset Purchase Agreement dated August 8, 2012 ("Purchase Agreement"), a copy of which was attached to the Joint Application as Exhibit C and incorporated therein by reference.

ORDERED FURTHER, the LNG Facilities are to be removed from the Georgia Assets prior to the consummation of the Transaction, and shall not be transferred to Liberty Georgia.

ORDERED FURTHER, Atmos Energy is authorized to sell and transfer the Georgia Assets to Liberty Georgia, together with all associated certificates of public convenience and necessity.

ORDERED FURTHER, Liberty Georgia is authorized to purchase, finance, own, manage and operate the Georgia Assets.

ORDERED FURTHER, Liberty Georgia is authorized to issue common stock and debt instruments and use the funds for the purposes stated in the Joint Application in amounts sufficient to purchase the Georgia Assets, capitalize Liberty Georgia, and finance ongoing utility operations in a manner consistent with the general criteria outlined below:

a. Liberty Georgia's initial capitalization will be established with a debt-to-equity ratio of approximately 45% debt and 55% equity. Provided, however, that nothing herein should be construed as prejudging the appropriate capital structure to be used by the Commission in any future proceeding to set rates. The purchase price agreed to by Atmos Energy and Liberty Georgia is set out in the Purchase Agreement, including Appendix A of the Purchase Agreement; the purchase price is $140,660,000, comprised of Net Assets for ratemaking purposes of approximately $128,145,000 and an acquisition premium of approximately $12,515,000, subject to either a positive or negative Adjustment Amount (as defined within the Purchase Agreement) to be calculated in connection with the closing of the Transaction. Liberty Georgia will not seek to recover the acquisition premium in rates.

b. To accomplish the initial capitalization, Liberty Georgia is authorized to issue shares of its common stock. Based on the estimated purchase price of approximately $140.7 million, Liberty Georgia expects to issue approximately $80 million of common stock to its parent, Liberty Energy Utilities Co. in connection with its initial equity capitalization. In the event the Adjustment Amount makes the actual purchase price higher or lower than the approximately $140.7 million, the amount of common stock issued by Liberty Georgia to Liberty Energy Utilities Co. will vary accordingly.

c. Similarly, Liberty Georgia is authorized to issue intercompany debt instruments. Based on the estimated purchase price of approximately $140.7 million, Liberty Georgia expects to borrow approximately $61 million in long-term debt from its parent Liberty Energy Utilities Co. In the event the Adjustment Amount makes the actual purchase price higher or lower than the approximately $140.7 million, the amount of debt will vary accordingly.

d. Liberty Georgia shall file details regarding the final terms of the long-term indebtedness no later than ten (10) days prior to closing the Transaction.

ORDERED FURTHER, because the financing authority granted herein will be used exclusively to accomplish the purposes of the Purchase Agreement that was the subject of the January 10, 2013 hearing and for the purposes stated herein, the Commission waives its rules regarding such financing authority (specifically, but not limited to, the rules regarding negotiation or competitive bidding for security issues pursuant to Rule 515-4-1-.15(f) and requirements of Rule 515-4-1-.13 regarding additional hearings).

ORDERED FURTHER, upon the close of the Transaction, Atmos Energy is authorized to abandon the Georgia Assets and shall cease providing services within Georgia.

ORDERED FURTHER, all Georgia Certificates of Public Convenience and Necessity held by Atmos Energy (including, but not limited to Pipeline Certificate Nos. 2 and 26 and Distribution Certificate Nos. 24, 27 and 144, as amended from time to time) shall be transferred to Liberty Georgia upon the close of the Transaction.

ORDERED FURTHER, following the close of the Transaction, Liberty Georgia shall own, manage, control and operate the Georgia Assets pursuant to the transferred certificates of public convenience and necessity, and shall provide service to customers within Georgia service territories currently certificated to Atmos Energy.

ORDERED FURTHER, Liberty Georgia shall be a "gas company" as that term is defined under O.C.G.A. § 46-1-1(5), and a "utility" as that term is defined in O.C.G.A § 46-1-1(9) and Commission Rule 515-7-1-.01(j) upon the close of the Transaction.

ORDERED FURTHER, upon the close of the Transaction, Liberty Georgia shall provide service to customers pursuant to the then-current Rates, Tariffs and Terms and Conditions of Service on file and approved for Atmos Energy.

ORDERED FURTHER, following the close of the Transaction, Liberty Georgia shall reissue and file with this Commission the then-current Rates, Tariffs and Terms and Conditions of Service, with the only changes from the Atmos Energy Rates, Tariffs and Terms and Conditions of Service being the name change to Liberty Energy (Georgia) Corp. and corresponding changes in contact information. The Rates, Tariffs and Terms and Conditions of Service of Liberty Georgia filed in compliance with this Ordering Paragraph shall become effective immediately without additional notice or suspension of rates.

ORDERED FURTHER, upon the close of the Transaction, Liberty Georgia shall assume all of the duties, obligations, rights and privileges of Atmos Energy as established by this Commission for Atmos Energy and its Georgia customers regarding on-going rate and regulatory programs, rates, riders, and initiatives, including, but not limited to base rates, purchased gas cost adjustments, weather normalization, gas supply plan, margin loss recovery rider, performance based regulation authority, and the cast iron and bare steel pipeline replacement program.

ORDERED FURTHER, after Liberty Georgia files its initial Rates, Tariffs and Terms and Conditions of Service based on those in place for Atmos Energy in compliance with this Order, any subsequent changes to the rates, regulations, terms and conditions of service, riders

and initiatives applicable to Liberty Georgia's regulated services shall be made only in compliance with the substantive and procedural requirements established by this Commission and the laws of the State of Georgia.

ORDERED FURTHER, following the close of the Transaction, Liberty Georgia will make Quarterly and Annual GRAM Filings in the form and containing the information established in Docket 34734, unless and until Liberty Georgia files a traditional rate case application.

ORDERED FURTHER, Liberty Georgia shall file its 2013 and 2014 Annual GRAM Filings using its actual capital structure. Nonetheless, if (a) pursuant to Liberty's 2013 or 2014 Annual GRAM Filings (for rates to be effective February 1, 2014 and February 1, 2015 respectively) base rates increase above the base rates effective February 1, 2013, and (b) the revenue requirements calculated by using Liberty Georgia's actual capital structure and cost of debt are higher than the revenue requirements that would have resulted if Atmos Energy's capital structure and cost of debt as established in its 2012 Annual GRAM Filing (for rates effective February 1, 2013) had been used, then for purposes of its 2013 and 2014 Annual GRAM filings, Liberty shall submit rates using the same capital structure and cost of debt as submitted by Atmos Energy in its 2012 Annual GRAM Filing.

ORDERED FURTHER, Liberty Georgia shall not seek to recover (a) any of the expenses incurred to negotiate, contract for, and close the Purchase Agreement, and (b) any acquisition premium associated with the Transaction in any future GRAM filings.

ORDERED FURTHER, jurisdiction over this proceeding is expressly retained for the purpose of entering such further order or orders as this Commission may deem proper.

ORDERED FURTHER, a motion for reconsideration, rehearing, or oral argument shall not stay the effectiveness of this Order unless expressly so ordered by this Commission.

The above action of the Commission in Administrative Session on February 19, 2013.

Reece McAlister
Executive Secretary

2-25-13
Date

Chuck Eaton
Chairman

2/26/13
Date

CERTIFICATE OF SERVICE
ATLANTA GAS LIGHT COMPANY

DOCKET NO. 36278

IN RE: LIBERTY ENERGY (GEORGIA) CORP. & ATMOS ENERGY CORP. JOINT APPLICATION

I, the undersigned, do herewith certify that I have caused to be served the required copies of the enclosed Staff's Order Approving Joint Application to Liberty Energy Corporation. All parties are being provided an electronic copy.

Reece McAlister
Executive Secretary
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Respectfully submitted, this 27th day of February, 2013

Janice Sears
Administrative Assistant

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

LEA MÁRQUEZ PETERSON– CHAIRWOMAN
SANDRA D. KENNEDY
JUSTIN OLSON
ANNA TOVAR
JIM O'CONNOR

IN THE MATTER OF THE JOINT APPLICATION OF LIBERTY UTILITIES (BELLA VISTA WATER) CORP. AND HEART CAB CO., INC. D/B/A SULGER WATER COMPANY #2 FOR APPROVAL OF (1) THE SALE OF HEART CAB CO., INC. D/B/A SULGER WATER COMPANY'S ASSETS TO LIBERTY UTILITIES (BELLA VISTA WATER) CORP. AND (2) THE TRANSFER OF HEART CAB CO., INC. D/B/A SULGER WATER COMPANY'S CERTIFICATE OF CONVENIENCE AND NECESSITY TO LIBERTY UTILITIES (BELLA VISTA WATER) CORP.

DOCKET NO. W-02465A-20-0029
W-02355A-20-0029

DECISION NO. 77887

ORDER AMENDING DECISION NO. 77741 PURSUANT TO A.R.S. § 40-252

Open Meeting
January 12, 2021
Phoenix, Arizona

BY THE COMMISSION:

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Arizona Corporation Commission ("Commission") finds, concludes, and orders that:

FINDINGS OF FACT

1. On February 19, 2020, Liberty Utilities (Bella Vista Water) Corp. ("Liberty Bella Vista") and Heart Cab Co., Inc. d/b/a Sulger Water Company No. 2 ("Sulger") filed a joint application with the Commission for approval of the sale of Sulger's assets and the transfer of Sulger's Certificate of Convenience and Necessity ("CC&N") to Liberty Bella Vista.

2. On October 20, 2020, the Commission issued Decision No. 77741, which approved the application. Decision No. 77741 ordered Liberty Bella Vista to: (1) "file with Docket Control, as a Compliance item in this docket, within 60 days of the effective date of this Decision all pertinent documents evidencing the consummation of the transaction" and (2) "make an appropriate filing in Docket No. W-02355A-09-0275 addressing Heart Cab Co., Inc. d/b/a Sulger Water Company No. 2's

outstanding compliance items within 60 days of this Decision."

3. On November 30, 2020, Liberty Bella Vista filed a Request for Extension of Time to properly complete the legal transfer of several assets and infrastructure owned by Sulger. Liberty Bella Vista stated that the parties have been actively working on the transactions necessary for Liberty to acquire the assets of Sulger, but have determined that additional time is needed to complete the legal transfer and believe that the outstanding matters can be completed within the next 60 days.

4. On December 29, 2020, the Commission's Utilities Division ("Staff") filed a Memorandum stating that Staff finds it appropriate to grant the Company's extension until March 1, 2021, to consummate the sale of Sulger's assets and to comply with Decision No. 77741.

5. No party will be harmed by the short extension of time to complete the legal transfer. The Request and Staff's recommendation are reasonable and should be approved.

CONCLUSIONS OF LAW

1. Sulger and Liberty Bella Vista are public service corporations within the meaning of Article XV of the Arizona Constitution and A.R.S. §§ 40-281, 40-282, and 40-285.

2. The Commission has jurisdiction over Sulger, Liberty Bella Vista, and the subject matter of the Request to amend Decision No. 77741.

3. A.R.S. § 40-252 authorizes the Commission to alter or amend a Decision.

4. It is reasonable and appropriate and in the public interest to grant the Request to amend Decision No. 77741, as recommended by Staff.

ORDER

IT IS THEREFORE ORDERED that the request by Liberty Utilities (Bella Vista Water) Corp. for an extension of time to comply with Decision No. 77741 to consummate the sale of Heart Cab Co., Inc. d/b/a Sulger Water Company No. 2's assets, is hereby granted.

IT IS FURTHER ORDERED that Decision No. 77741 is hereby amended to order Liberty Utilities (Bella Vista Water) Corp. to comply with the directives of that Decision by March 1, 2021.

. . .

. . .

. . .

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRWOMAN MARQUEZ PETERSON | COMMISSIONER KENNEDY

COMMISSIONER OLSON | COMMISSIONER TOVAR | COMMISSIONER O'CONNOR

IN WITNESS WHEREOF, I, MATTHEW J. NEUBERT, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 22 day of January 2021.

MATTHEW J. NEUBERT
EXECUTIVE DIRECTOR

DISSENT _____

DISSENT _____
JLR/(gb)

SERVICE LIST FOR: LIBERTY UTILITIES (Bella Vista Water) CORP.

HEART CAB Co., INC dba SULGER WATER COMPANY # 2

DOCKET NOS.: W-02465A-20-0029 & W-02355A-20-0029

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ALJ/XJV/tcg **Date of Issuance 10/15/2010**

Decision 10-10-017 October 14, 2010

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Joint Application of Sierra Pacific Power Company (U903E) and California Pacific Electric Company, LLC for Transfer of Control and Additional Requests Relating to Proposed Transaction.	Application 09-10-028 (Filed October 16, 2009)
And Related Matters.	Application 10-04-032 (Filed April 30, 2010)

DECISION CONDITIONALLY APPROVING CONSOLIDATED APPLICATIONS

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LIST OF APPENDICES

DECISION CONDITIONALLY APPROVING CONSOLIDATED APPLICATIONS

1. Summary

Subject to the following conditions, we approve the transfer to California Pacific Electric Company, LLC (CalPeco) of the California electric distribution facilities and the Kings Beach Generating Station owned by Sierra Pacific Power Company (Sierra):

- Power from Sierra's Valmy Power Plant may be included in the supply provided under the Power Purchase Agreement and any additional power purchase agreement which Sierra and CalPeco may enter upon the expiration of the initial five-year agreement as long a Sierra makes no new ownership investment in Valmy, within the context of the Emissions Performance Standard rules adopted in Decision 07-01-039 and any relevant, subsequent modifications of that decision;
- The Internal Transfer Authority is not approved and any change of ownership affecting CalPeco's upstream owners must be sought by application filed pursuant to Public Utilities Code Section 854;
- CalPeco and its upstream owners must expressly recognize the Commission's legal right to call their officers and employees to testify in California regarding matters pertinent to CalPeco, consistent with established principles of due process and fundamental fairness.

In all other respects we approve the authority sought in the transfer application, as amended in the course of this proceeding and as conditioned by the Regulatory Commitments attached to this decision as Appendix 3. Joint Applicants have established that the transfer will not harm ratepayers; in fact, certain service improvements are likely in the near term, at no cost to ratepayers.

We also approve the two ancillary agreements involving Sierra, CalPeco and Truckee-Donner Public Utility District in order to permit the continued

cooperation that permits cost-effective, reliable service to customers in both of these contiguous, small service territories.

2. Identification of Parties

2.1. Overview

For ease of discussion, today's decision generally refers to Application (A.) 09-10-028, which asks the Commission to approve a change in public utility ownership and control, as the transfer application.

The three active parties include the proposed seller, Sierra Pacific Power Company (Sierra) and the proposed buyer, California Pacific Electric Company, LLC (CalPeco).[1] We refer to these project proponents, collectively, as Joint Applicants. The third active party, the Commission's Division of Ratepayer Advocates (DRA), opposes the transfer from Sierra to CalPeco.

Several other parties initially protested the proposed transfer, but all of them reached settlements with Joint Applicants and withdrew their protests prior to evidentiary hearing. These parties include Truckee-Donner Public Utilities District (TDPUD), which withdrew its protest on February 22, 2010, and the following entities, referred to as Aligned Protestants, which collectively withdrew their individual protests on March 29, 2010: the City of Loyalton, the City of Portola, Plumas County, Sierra County, and Plumas-Sierra Rural Electric Cooperative (PSREC).

We are aware that two other entities, which are not parties, have submitted letters of support for the proposed transfer and urge us to approve it -- the International Brotherhood of Electrical Workers Local Union 1245 (Local

[1] Appendix 1 contains a list of the abbreviations and acronyms used in today's decision.

1245), whose members work for Sierra and have been offered continued employment by CalPeco, and Sierra Pacific Industries, which owns a 14 megawatt (MW) biomass cogeneration facility in the City of Loyalton. Sierra Pacific Industries previously wrote to oppose the transfer but subsequently has resolved its dispute with Sierra and now supports the transfer.[2]

2.2. Sierra

Sierra is a public utility that generates, transmits and distributes electricity to some 366,000 customers in northern Nevada and California; Sierra also serves about 150,000 natural gas customers in Reno and Sparks, Nevada. Organized as a Nevada corporation, Sierra is wholly-owned by NV Energy Inc. (NV Energy), an investor-owned holding company incorporated under Nevada law. NV Energy has five other, wholly-owned subsidiaries, including Nevada Power, the regulated public utility which serves Las Vegas and southern Nevada. In total, NV Energy serves about 1.2 million customers in Nevada.

Sierra's California retail electric customer base encompasses about 46,000 customers in seven counties (Nevada, Placer, Sierra, Plumas, Mono, Alpine and El Dorado), with approximately 80% of those customers located in the Lake Tahoe Basin. Sierra's California service territory is a winter-peaking load; the mountainous terrain rises from nearly 5,000 feet to 9,000 feet and most customers are located at elevations above 6,000 feet. In addition, the California service territory is outside the control area of the California Independent System Operator. Electricity generated in Nevada and delivered into California through

[2] These letters have been placed in the correspondence file for this docket.

Sierra's transmission facilities is the source of most of the electric power supplied to the California service territory.

2.3. CalPeco

CalPeco is a newly created, California limited liability company directly owned by California Pacific Utility Ventures, LLC, a California limited liability company. CalPeco's ultimate, indirect owners are two publicly traded Canadian companies -- Algonquin Power & Utilities Corp. (Algonquin) and Emera Incorporated (Emera). These entities' will hold their indirect ownership stakes -- 50.001% by Algonquin and 49.999% by Emera -- through their respective, wholly owned subsidiaries, Liberty Electric Co. and Emera US Holdings, Inc., both Delaware corporations.[3] Appendix 2 to today's decision illustrates this ownership chain.

Initially formed in 1987, Algonquin is a diversified electrical power generation and utility infrastructure company with a principal place of business in Toronto, Ontario. According to the transfer application: "Algonquin owns

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[3] The Algonquin and Emera 50%/50% ownership arrangement initially described in the transfer application has changed. Joint Applicants explain:

> This change results from Canada transitioning to the International Financial Reporting Standards in 2011. Algonquin and Emera have determined that enabling Algonquin to "control" CalPeco within the meaning of these accounting standards facilitates Algonquin being authorized to account for its investment in CalPeco on a fully-consolidated basis and enables Emera to use equity consolidation treatment." (Exhibit (Ex.) 3 at 6.)

In addition, the chain of ownership of CalPeco on the Algonquin side has changed. According to the transfer application, initially Algonquin planned for its subsidiary, Algonquin Power Fund (America) Inc., to directly hold CalPeco. However, Algonquin subsequently had that subsidiary transfer 100% of its ownership interest in CalPeco to another Algonquin subsidiary, Liberty Electric Co.

and operates an approximately $1 billion (Cdn) portfolio of renewable power generation and utility operations across North America. Over 50% of Algonquin's revenues are generated through its US-based operations."[4] Algonquin has two business units, a Power Generation unit that includes 45 renewable power generating facilities and 16 high-efficiency thermal generating facilities in four states and four Canadian provinces, and a Utility Services unit that owns and operates regulated water and sewer utility systems in four states.[5] At hearing, Joint Applicants' witness testified that the recent acquisition of a water and wastewater system in Texas has increased Algonquin's regulated utility business to 19 systems with 75,000 total customers.

Following its conversion on October 27, 2009, to a conventional, publicly traded corporation, Algonquin now trades under the symbol "AQN" on the Toronto Stock Exchange. Previously, Algonquin was known as Algonquin Power Income Fund, a mutual fund trust established under the laws of the Province of Ontario, Canada.

Emera, incorporated under the laws of the Province of Nova Scotia, Canada, is an energy holding company with a principal place of business in Halifax, Nova Scotia. According to the transfer application, Emera holds "approximately $5.3 billion of assets (Cdn)" and "owns and operates utilities participating in the generation, transmission and distribution of electricity; utilities participating in the transmission of natural gas; and unregulated

[4] Transfer Application at 4.

[5] In California, Algonquin owns the Sanger Cogeneration project, a 56 MW natural gas-fired facility near Fresno. Sanger sells power to Pacific Gas and Electric Company under a Commission-approved standard offer contract that will expire in 2012.

businesses participating in the energy marketing and electric generation."[6] Emera has over 130 years of experience in owning and operating utility assets, a safety record nationally recognized in Canada, and extensive experience in partnership and joint ownership arrangements, including a 600 MW pumped storage facility in northern Massachusetts.

Regarding the relationship with Algonquin, Joint Applicants state:

> Emera is engaged in a strategic partnership with Algonquin through which the companies may collaborate in select utility infrastructure and renewable generation investment, such as the proposed co-ownership of CalPeco. Emera has also agreed to acquire a 9.9% interest in Algonquin upon Closing.[7]

The transfer application does not name CalPeco's direct owner, California Pacific Utility Ventures, LLC, or its indirect owners, Emera, Algonquin and their subsidiaries, as applicants. DRA's opening brief raises this, for the first time, as a fatal flaw that must be corrected by amendment of the transfer application to name each of these entities. According to DRA, Public Utilities Code Section 854(a) requires such amendment.[8]

Section 854(a) provides, in relevant part:

> No person or corporation, whether or not organized under the laws of this state, shall merge, acquire, or control either directly or indirectly any public utility organized and doing business in this state without first securing authorization to do so from the commission … Any merger, acquisition, or control without that prior authorization shall be void and of no effect …

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[6] Transfer Application at 5.

[7] Transfer Application at 7.

[8] Unless otherwise noted, all subsequent references to a statutory section or sections are to the California Public Utilities Code.

Joint Applicants' reply brief argues that DRA's contention is not only untimely but also incorrect. According to Joint Applicants, only when an upstream owner is being sold, resulting in a change of indirect ownership, must the application name indirect owners. Neither brief cites authority.

Joint Applicants also state that there is no substantive need to amend the application. They point out that Algonquin and Emera have been active participants in this proceeding from the beginning, have voluntary presented senior executives as witnesses at hearing, and have conceded the Commission's jurisdiction to enforce the various promises and representations, termed Regulatory Commitments (see Appendix 3 to today's decision), that CalPeco and its direct and indirect owners have made to customers and to the Commission.

We need not undertake an exhaustive statutory analysis here, where CalPeco's owners are not contesting the Commission's jurisdiction. However, when a utility tier transfer results in new indirect owners for that utility, we think naming all such entities as applicants is the better practice, and we urge the Docket Office and our administrative law judges to be more vigilant in ensuring that this better practice is broadly and consistently followed.[9] Because Joint Applicants have fully disclosed the existence of California Pacific Utility Ventures, LLC, as well as Emera and Algonquin and their immediate subsidiaries in the chain of control of CalPeco, have presented witnesses from

[9] See for example, *Joint Application of California-American Water Company, RWE Aktiengesellschaft, Thames Water Aqua Holdings GmbH, Thames Water Plc, and Apollo Acquisition Company to merge with and into American Water Works Company, resulting in a change of control of California-American Water Company,* D.02-12-068 (2002). The merger between the parent of CalAm and the subsidiary of RWE, resulted in RWE and each intervening subsidiary obtaining indirect control of CalAm and all were named as applicants.

Algonquin and Emera, and have placed issues concerning these entities directly before the Commission for decision, our ability to fully consider this transfer has not been circumscribed. We intend that the reach of today's decision extend to the direct and indirect owners of CalPeco and will require their assent as a condition of any authority granted in the Ordering Paragraphs.

3. Summary of Authority Sought

Sierra proposes to transfer to CalPeco ownership and operation of Sierra's California service territory and all distribution assets, as well as the King's Beach Generating Station (King's Beach facility), a 12-MW diesel-fired generator located in King's Beach near Lake Tahoe (collectively, the California Utility).

The transfer application describes the transaction as "functionally the sale of Sierra's entire Commission-jurisdictional utility."[10] The sales price, to be calculated more precisely based upon various factors including outstanding accounts payables and accounts receivables at closing, is estimated to range between approximately $132 and $137 million. CalPeco commits not to seek to recover in rates either the premium paid for the assets of the California Utility or any transactions costs. CalPeco commits to ask, in a future 2012 CalPeco general rate case, that the Commission establish the revenue requirement according to the dollar value of CalPeco's rate base, not the purchase price, and that those subsequent ratemaking computations include any cost savings CalPeco may have realized, compared to the pre-savings baseline in Sierra's last general rate case. Appendix 3 of today's decision lists these and all other Regulatory Commitments by CalPeco and its owners. The transfer application also

[10] Transfer Application at 19.

incorporates seven agreements, referred to collectively as the Operating Agreements, and asks the Commission to make certain findings about them concurrent with approval of the transfer.

We have consolidated the transfer application with A.10-04-032, which seeks approval of two ancillary agreements resulting from Joint Applicants' settlement with TDPUD. The ancillary agreements, termed the Fringe Agreement and the Reliability Support Agreement, are structured to ensure the continuation of existing, cooperative arrangements that benefit the contiguous service territories of both, small electric utilities.

Today's decision reviews the transfer application first because the ancillary agreements are dependent upon it in substantial part. Our discussion of the transfer application begins in Section 5. Our discussion of the ancillary agreements begins in Section 6.

4. Standard of Review

No party disputes that we should apply § 854, which generally governs mergers and similar transfers of control, rather than § 851, which typically governs sales of assets. In fact, Joint Applicants explain that they have structured the transaction as a sale of all California-jurisdictional assets, rather than a merger or sale of stock, simply because the California Utility is not organized, legally, as a separate entity from Sierra. Review under § 854 is consistent with the Commission's procedural approach in Decision (D.) 05-03-010, where the Commission approved the sale of Avista Corporation's South Lake Tahoe gas facilities (the California portions of Avista's multi-state utility operations) to Southwest Gas Corporation.

Consistent with the scoping memo, our review of the transfer under § 854 focuses on § 854(a), which we quote in relevant part in Section 2.3, above. Thus,

to approve the proposed transfer of control, the Commission must find that the proposal meets the public interest standard that prior Commission decisions define for § 854(a). Typically the Commission has required an applicant to show that a proposed transfer is "not adverse to the public interest" though occasionally the Commission has articulated the standard as requiring a showing that a transfer is "in the public interest."[11] The scoping memo directed the parties to brief these alternative terms, if they contend that the distinction is material.

The parties' witness testimony and briefs recast this nuanced disagreement as a much more fundamental one centered on whether the public interest requires a showing of "no harm to ratepayers" (Joint Applicants' contention) or "positive benefits to ratepayers and the community" (DRA's contention). DRA argues that the Commission should require showings on at least some of the criteria that §§ 854(b) and (c) specify for inquiry when one or more parties to a proposed transfer has gross California revenues of more than $500 million, and moreover, that these showings should establish that the transfer yields net benefits to ratepayers compared to the status quo.[12] DRA does not dispute that

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[11] See for example, D.07-05-031, which approved the transfer of control over California-American Water Company (CalAm) at the holding company level:

> The primary standard used by the commission to determine if a transaction should be authorized under § 854(a) is whether the transaction will adversely affect the public interest. (D.07-05-031 at 3, citing D.00-06-079 at 13.)

[12] Section 854(b) requires the Commission to find short-term and long-term benefits for ratepayers, an equitable allocation of such benefits between shareholders and ratepayers, and no adverse impact upon competition. Section 854(c) requires that the public interest assessment result in express findings on eight criteria (impact on the financial condition of the resulting utility, on service quality, on management quality, on utility employees, on shareholders, on state and local economies, on the

Footnote continued on next page

Sierra's 2008 annual California revenues were approximately $72 million or that CalPeco had no California revenues. DRA relies on two prior Commission decisions: D.01-09-057, which authorized California-American Water Company (CalAm) to acquire Citizens Utilities Company of California and D.06-02-033, which authorized PacifiCorp's acquisition by MidAmerican Energy Holdings Company (MidAmerican). Neither decision establishes a positive benefits test for transactions such as the proposed Sierra/CalPeco transfer.

The first decision DRA cites, D.01-09-057, concerns the acquisition of one water utility by another under § 854(a) and the Public Water System Investment and Consolidation Act of 1997, consisting of §§ 2718-2720 (the Act). The Act authorizes the post-acquisition rate base of a transferred water distribution system to be set at fair market value, which in some instances may be higher than the historical value, and which therefore places an additional cost on ratepayers. Before approving such a rate base increase the Commission must find that the transaction proposed improves the health and stability of the water system in several enumerated ways, thereby benefiting ratepayers. The Office of Ratepayer Advocates, the predecessor of DRA, argued that the Commission could – and should -- look to the criteria listed in § 854(b) and (c) in assessing ratepayer value. CalAm argued that the Commission's long-term standard requires a showing of no harm to ratepayers and that its proposal clearly met

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Commission's jurisdiction, and on whether any proposed mitigations avoid adverse consequences). For a proposed transaction to gain approval, review of the first three criteria must result in findings that the transfer will "maintain or improve" the status quo; review of the second three criteria must result in findings that the transfer is "fair and reasonable."

that test, but also would meet a positive ratepayer benefits standard. Regarding the appropriate standard, Conclusion of Law 9 in D.01-09-057 merely states:

> Sections 854(b) and 854(c) do not by their terms apply to water utilities. The Commission may, but need not, consider the extent to which the factors set forth in those sections bear on the public interest in this proceeding.

Furthermore, while D.01-09-057 summarizes information the applicants had put forward on some § 854(c) criteria, the decision does not tie its public interest findings or approval to § 854(c).

The second decision DRA cites, D.06-02-033, concerns a transfer at the holding company level by which MidAmerican acquired indirect ownership and control of PacifiCorp, an energy utility, from Scottish Power PLC. The decision observes that no entity to the transaction has sufficient California revenues to trigger application of § 854(b) and (c) and it does not discuss either subsection further. The decision's public interest assessment begins by setting out seven criteria to be considered given the facts of the transfer at issue, however, and simple comparison of these criteria with those in § 854(b) and (c) shows an overlap. D.06-02-033 focuses on the proposed transaction's impact on: the financial condition of the utility, service quality, management quality, affected utility employees, the state of California and local communities, Commission jurisdiction, and competition. D.06-02-033 states:

> Although we are not obligated to use the above criteria to evaluate the proposed transaction, these criteria provide a useful framework for analyzing the transaction. Our use of the above

> criteria is completely discretionary, and we may choose to use none, some, or all of these criteria in future proceedings.[13]

After assessing the evidence put forward, D.06-02-033 concludes that the transaction should be approved and rejects DRA's contention that the benefits are "meager" or insufficient:

> The transaction provides modest but concrete benefits to ratepayers and the communities served by PacifiCorp, and there will be no harm to ratepayers or others with the conditions adopted by today's Decision. This is enough for the proposed transaction to garner our approval under § 854(a).[14]

Though we address Joint Applicants' showing in Section 5, we observe here that the transfer application, as filed, addresses each of the criteria examined in D.06-02-033.

Similarly, in D.00-06-079, which issued more than a decade ago, the Commission observed "… our decisions over the years have laid out a number of factors that should be considered in making the determination of whether a transaction will be adverse to the public interest."[15] D.00-06-079 mentions several factors -- antitrust considerations, economic and financial feasibility, purchase price, value of consideration exchanged, efficiencies, operating costs savings – and there are others. Clearly, not every one of them is relevant to every review under § 854(a).

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[13] D.06-02-033 at 23.

[14] D.06-02-033 at 36.

[15] D.00-06-079 at 14.

The parties' dispute about the standard of review applicable to the transfer application suggests confusion about several distinct concepts and so, based on the foregoing review of precedent, we provide the following guidance.

First, to ensure that a proposed transfer is not adverse to the public interest under § 854(a), the Commission must be able to evaluate evidence on the important impacts of that transfer – whatever they might be – and find no harm to ratepayers. Second, some of the criteria enumerated in §§ 854(b) and (c) mirror criteria identified by past Commission decisions as relevant to a public interest assessment under § 854(a), and depending upon the nature of the transfer at issue, may well be relevant and even necessary to the specific public interest assessment required. Third, only where §§ 854(b) and (c) expressly apply, must the Commission make all of the findings those subsections require.

Next, we turn to § 854(d), which in relevant part, requires the Commission to "consider reasonable options to the proposal recommended by other parties." Initially PSREC challenged the proposed transfer and argued that it should be allowed to purchase the Loyalton/Portola portion of Sierra's California service territory. However, following a meeting held in the Loyalton/Portola area pursuant to the scoping memo's direction, PSREC and Joint Applications settled their differences.[16] PSREC, which withdrew its opposition to the transfer application before evidentiary hearings and without having put forward prepared testimony on its alternative proposal, now urges us to authorize the transfer. No other party has introduced facts to describe any alternative for us to consider under 854(d). Though DRA opposes the transfer and urges us to reject

[16] The PSREC Settlement Agreement is Exhibit Q to Exhibit 1.

it, we have that authority already under § 854(a). Specifically, were we to determine that Joint Applicants have failed to show that the transfer is not adverse to the public interest, we would be obliged to deny it, unless conditions could be imposed to cure the identified defect(s). Given the procedural status of the transfer application, § 854(d) is no longer pertinent to our review.

Section 816 and § 818, which concern issuance of stocks, bonds, etc., and § 851, which as relevant here concerns the encumbrance of utility assets, provide the statutory basis for the financing authority sought. No dispute exists here.

Finally, we address application of Public Resources Code § 21080 et seq., known as of the California Environmental Quality Act (CEQA). Joint Applicants' assert and no party contests that the transfer of control of the California Utility from Sierra to CalPeco "will not result in any change in the operation of the public utility serving these California customers … [and] does not request any new construction, or changes in the use of existing assets and facilities."[17] We find no evidence that operational change will result and no new facilities are proposed. Pursuant to § 15061(b)(3) of the CEQA guidelines, inasmuch as it can be seen with certainty that the project will have no significant impact upon the environment, the transfer application qualifies for an exemption from CEQA and the Commission need not perform any further environmental review.

Joint Applicants have the burden of proof to establish that the Commission should approve the transfer application and the ancillary agreements.

[17] Transfer Application at 72.

5. The Transfer Application: Discussion

Below we review Joint Applicants' explanation for why they and their owners seek this transfer, the evidence Joint Applicants have offered in support of the transfer, and the basis for DRA's opposition. The discussion largely follows the common organizational outline the parties' use in their concurrent briefs.

5.1. Reason for the Transfer

According to the transfer application and witness testimony, Sierra wishes to sell the California Utility to enable its owner, NV Energy, to focus on Nevada operations, which now extend to most of that state. Load growth in Nevada has required NV Energy to invest an average of $1 billion annually over the past five years to maintain reliable service to the nearly 1.2 million customers it now serves there. Because that load growth has been heaviest in areas that do not border Lake Tahoe (where most of the California Utility's 46,000 customers are located), California operations now serve less than 4% of NV Energy's customer base. The sale, if approved, also provides NV Energy the ability to consolidate all of its operations under a single state regulatory agency and respond to a single set of regulatory directives.

The transfer application describes the genesis of the proposed transaction. Sierra commenced a search in early 2008 for suitable, potential bidders and distributed bid information to an initial list of 40 entities. Sierra required any potential bidder to contractually agree to a list of regulatory commitments and to meet the following criteria:

- experience at operating, and the proven capability to operate, a distribution utility;
- the commitment and ability to continue to offer the same, or greater, level of service at comparable rates;

- the commitment and ability to carry out the regulatory initiatives and policies of California law and this Commission;
- a desire to focus primarily on California operations;
- the commitment and ability to maintain a strong local presence in the service territory within the Lake Tahoe area;
- the commitment and ability to retain Sierra's California labor force; a long-term business objective to operate an electric distribution utility; and
- in general, the abilities, qualifications, and characteristics that would best ensure that the Commission would approve the transaction and entrust the purchaser with the responsibility to provide service to Sierra's California customers and to be the employer for Sierra's California employees.[18]

Sierra received non-binding bids from seven entities and short-listed four of them, based on review of various criteria (price, bid viability, the completeness of the bid, the bidder's financial and operational qualifications, etc.). Following further review of these criteria and others (impact on employees and customers, etc.), Algonquin emerged as the entity with the best "overall fit."[19] In late 2008, Sierra and Algonquin contemplated executing a purchase agreement, but against the backdrop of the continuing, global financial crisis, Algonquin determined to form CalPeco jointly with Emera. Joint Applicants' witness readily admitted that like many other entities, Algonquin's stock price dropped during the fall of 2008 and its access to capital was impaired. The witness testified that Algonquin's board believed that a joint acquisition with

[18] Transfer Application at 16-17. The complete, initial list (Ex. 17 to the transfer application) is an earlier version of the Regulatory Commitments found in Appendix 3 of today's decision.

[19] Transfer Application at 15.

Emera would be "prudent" but that the rationale was not based solely on Emera's financial strength.[20] The transfer application reports that the financial markets appear to have viewed the formation of CalPeco by Algonquin and Emera positively, based on stock prices and debt ratings following public announcement of their joint enterprise to purchase the California Utility.

The transfer application states that from the standpoint of CalPeco's owners, Algonquin and Emera, the proposed transfer fits with their mutual business objectives to expand ownership and operation of regulated utility assets, with a view to long-term acquisition and, in some instances, opportunities "to develop and implement renewable energy initiatives."[21] Further,

> [F]or Emera, this transaction opens up a new market, while providing the opportunity to increase value to its jointly-owned energy infrastructure assets with Algonquin. For Algonquin, this transaction represent an important element in the strategic expansion of its utility infrastructure portfolio and the predictable, long-term related returns that the California Utility will contribute to the stability of its earnings year to year.[22]

DRA has not put forward evidence that challenges Joint Applicants' explanation of the interest of either the sellers or the buyers in the proposed transaction.

5.2. Impact on Service

Joint Applicants represent that the proposed transfer will continue safe and reliable service and will maintain, and in some instances improve, the

[20] Tr. at 30.

[21] Transfer Application at 18.

[22] Transfer Application at 18-19.

quality of service customers experience today. Aligned Protestants, who are located in Loyalton, Portola and adjacent portions of the California Utility's service territory and who raised the sole customer challenge to the proposed transfer, now support it. Initially they criticized the reliability of electric service in their remote area, claiming: (1) local generation is insufficient; (2) existing transmission cannot deliver sufficient power from more distant sources; and (3) field staffing (one person) cannot possibly handle the other kinds of equipment and infrastructure failures that occur in this mountainous and largely rural area. Notably, at the PHC Aligned Protestants did not contend that Sierra should be required to continue to serve them, but rather that PSREC should be authorized to serve instead.

Without conceding any of the alleged service problems, Joint Applicants have agreed to investigate partnering with PSREC to improve local reliability in the Loyalton/Portola area. Generally, however, electric power throughout the entire service territory will continue to move into California from Nevada or elsewhere outside California over the same facilities as it does now (the small King's Beach facility provides very limited local generation). The Power Purchase Agreement, Ex. 10 to the transfer application, ensures delivery of CalPeco's full requirements, including 20% from renewable sources eligible for California's Renewable Portfolio Standard (RPS), at rates reflecting Sierra's actual costs and based on Sierra's system-average cost, for an initial term of five years. The Power Purchase Agreement gives CalPeco certain rights to develop and/or procure other renewable sources during the five-year term. It also provides an additional, five-year right to obtain power from Sierra in an amount up to CalPeco's full requirements for nonrenewable sources. Ongoing transmission will be negotiated in accordance with federal law on non-

discriminatory, open access transmission and Sierra's Federal Energy Regulatory Commission (FERC) tariffs.

With respect to reliability in the Loyalton/Portola area, Joint Applicants have reached an agreement with PSREC for CalPeco to contract for additional line crew assistance as needed (we discuss this below in Section 5.3.3, as part of the PSREC Settlement). In South Lake Tahoe, they propose to reopen a customer service counter that now is closed. While generally CalPeco expects to hire the same employees who now operate the system for Sierra, Joint Applicants also have disclosed CalPeco's plans to locate corporate headquarters, senior management and a customer service headquarters in the service territory. They suggest these initiatives should benefit service by increasing local accountability. Further, Joint Applicants describe CalPeco's intention to introduce software capabilities that will give customers electronic options for bill receipt, payment, service initiation, and scheduling service calls. They claim this initiative follows on Algonquin's successful efforts to introduce "innovative, state-of-the-art billing systems and customer communication programs designed to cost-effectively enhance customer service" to other, small, regulated water and sewer utilities it owns and operates in four states.[23] They predict the CalPeco initiative, similarly, will yield both economic and service quality benefits for many customers who live in remote areas and for others who are not domiciled in the service territory year-round. Likewise, Joint Applicants describe CalPeco's preliminary involvement in the Lake Tahoe Green Energy District, which is working to implement, locally, a number of energy efficiency measures and to pursue other

[23] Transfer Application at 5.

"green" projects. Other participants in this enterprise include the local school district and community college, as well as the City of South Lake Tahoe, the State of California Tahoe Conservancy, and the United States Forest Service.

Joint Applicants also point to the favorable assessment by Local 1245 of the proposed transfer's service quality impacts:

> We [Local 1245] also believe that CalPeco's local presence, smaller size, resulting sharper focus, and ability to concentrate on matters of particular importance to California and the Lake Tahoe Basin communities will benefit its customers in terms of the quality of the service.[24]

DRA disputes the need for any of the service improvements proposed for Portola/Loyalton and elsewhere. DRA's primary contention is that these and other changes necessarily will increase costs for CalPeco. DRA predicts that as a standalone utility with 46,000 customers, CalPeco will lack the economies of scale available to Sierra and that therefore, the transfer will lead to a substantial rate increase request in the next general rate case. Service quality cannot be divorced completely from its cost, and we discuss these cost concerns below. However, nothing in the record suggests that service quality will decline under CalPeco. Rather service quality will continue at present levels generally, and in some respects may improve, given Joint Applicants' stated intentions as well as its responsiveness to registered customer concerns.

5.3. Impact on Costs

Joint Applicants maintain that the transaction has been structured to enable CalPeco, post-closing, to collect from customers the same total revenues

that Sierra is authorized to charge and collect, at the same rate levels now applicable to individual customers.[25] DRA does not dispute this but argues that cost increases are inevitable, that they will lead to rate increases in the future, and that for these reasons the Commission simply should deny the transfer application.

The "Premium and Cost Synergies" section of the Regulatory Commitments contains three promises that shield customers from costs solely attributable to the proposed transfer from Sierra's ownership: (1) CalPeco will not seek to recover from customers the purchase premium (the excess of the purchase price over recorded, regulatory book values for utility assets); (2) CalPeco will use its actual recorded costs levels, including any cost savings (from installation of electronic systems, etc.), as its basis for rate requests in future general rate cases; and (3) CalPeco will not seek to recover from customers transaction costs (investment banking and legal fees, and perimeter metering costs).

However, DRA warns that if the transfer is approved, CalPeco likely will seek a sizable rate increase when it files its first general rate case in 2012. DRA

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[24] Ex. 1, Attachment G, November 30, 2009 letter from Local 1245 to Commissioner Grueneich.

[25] Joint Applicants ask the Commission to authorize CalPeco to reclassify certain components of general rates to Energy Cost Adjustment Clause (ECAC) rates. This reallocation request arises because CalPeco, which will own no transmission assets and no generation assets other than the King's Beach facility, will purchase both services under the Power Purchase Agreement. Thus, while total revenues will not change, a greater portion of the total will be attributable to fuel and purchased power. The reallocation will avoid cost-shifting between customers and the aggregate, per kilowatt hour (kWh) charge in each customer's monthly bill will remain the same. DRA has not opposed this reallocation.

identifies the following as areas of particular concern: Operations and Maintenance (O&M) and certain, other miscellaneous costs; the Transition Services Agreement between CalPeco and Sierra; the settlement with PSREC; and the uncertainty regarding imports of power from Sierra's coal-fired Valmy Power Plant (Valmy). We examine each of these below. Joint Applicants are correct that this transfer application should not be turned into a general rate case. Nonetheless, it is incumbent upon us to assess the record before us for signs of the kinds of serious cost consequences that necessarily must affect any public interest assessment under § 854(a).

DRA's opening brief also argues, for the first time, that CalPeco should agree to forego filing a general rate case until three years beyond 2012. Joint Applicants object to this so-called, three-year, rate case "stay out." Not only do we lack a record on any alleged benefits and detriments of this proposal vis a vis CalPeco, but a general rate case deferral is at odds with our policy preference for regular, orderly review of utility operations. We denied DRA's request for one-year rate deferrals for PacifiCorp in D.07-05-031 and for CalAm in D.02-12-068. We decline to impose a three-year deferral here.

5.3.1. O&M and Other Miscellaneous Costs

DRA contends that CalPeco's smaller size will translate into reduced purchasing power, resulting in increased costs, and ultimately, higher rates. Joint Applicants contend that the evidence does not support DRA's position. They point out that over half ($45 to $50 million) of the current $75 to $80 million revenue requirement is attributable to power supply, which will continue to be incurred at the same cost under the Power Purchase Agreement. While they dispute DRA's claim that CalPeco's smaller size means the certain loss of any economies of scale that Sierra has enjoyed, they also argue that such purchasing

advantage could only apply to a portion of the O&M and administrative costs that comprise, in the aggregate, about 10% of the total revenue requirement. Over half of these costs can be expected to be quite stable, since CalPeco expects to hire the same employees under similar compensation packages (presently about $4.6 million) and to purchase and operate the same trucks and other vehicles.

On this point Joint Applicants' witness testified:

> [A]s [CalPeco looks] at the 2012 GRC . . . sitting here today there is nothing in evidence from our perspective that would lead us to believe that there would be any cost increase arising from administration or operating costs that wouldn't be present if Sierra continued to own [the California Utility].[26]

Joint Applicants' brief quantifies the theoretical "risk" of the rest of the O&M costs ($3 to $4 million) escalating at 15% and argues that the resulting increase ($450,000 to $600,000), which would raise the total revenue requirement by less than 1 %, could not reasonably be termed rate shock. Joint Applicants hasten to state that they do not anticipate that CalPeco's recorded costs will cause them to ask for 15% rate increase in O&M, however. Their witness testified:

> CalPeco expects no such 15% increase. Nonetheless, CalPeco is comfortable that its costs with respect to the O&M costs would be comparable to the costs that Sierra would incur if it retained ownership.[27]

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[26] Tr. at 59.

[27] Joint Applicants Opening Brief at 40.

While a general rate case will be the place to review the reasonableness of actual costs incurred, this record does not suggest cost consequences of a magnitude large enough for us to find that the proposed transfer will harm ratepayers and therefore, is adverse to the public interest. Our assessment should not be construed to support a reasonableness finding or authorize rate recovery in a future general rate case.

DRA also discounts Joint Applicants' suggestion that cost savings will result from new, electronic capabilities for billing and for scheduling service. DRA relies on testimony that Sierra previously determined electronic billing for the California Utility did not make economic sense. But as Joint Applicants explain, CalPeco would be installing a standalone system based on California rates and tariffs, not adapting an existing system, based on Nevada rates and tariffs, for a small group of customers in California. To be sure, neither party has offered any quantification to support its economic claims. Given Algonquin's apparent past success in this area, we are not persuaded by DRA's assertion that the plan has no merit.

DRA contends that other service enhancements (the reopened customer service counter, etc.) will increase costs without providing value. Again, Joint Applicants state they expect such measures to be cost-effective. Regardless, a general rate case is the place to assess whether undertakings of this nature and relative magnitude are reasonable and warrant recovery in rates.

These issues do not compel a finding that the proposed transaction is adverse to the public interest. Again, this assessment should not be construed to support a reasonableness finding or authorize rate recovery in a future general rate case.

5.3.2. Transition Services Agreement

Under the Transition Service Agreement, Ex. 12 to the transfer application, CalPeco has the option to ask Sierra to perform at cost for 24 months, with a 12-month extension, any of the services Sierra now provides to the California Utility. DRA faults the agreement and Joint Applicants for not specifying, now, precisely which services CalPeco will request. DRA also speculates that once the agreement expires, CalPeco will likely incur higher costs and will seek to collect those higher costs in rates. The Transition Services Agreement appears to be a prudent, interim arrangement to ensure continued good service to ratepayers, rather than a measure that will cause them harm. A general rate case is the place to assess the reasonableness of projections of future costs. These issues do not compel a finding that the proposed transaction is adverse to the public interest.

5.3.3. PSREC Settlement

Joint Applicants' settlement with PSREC is not before us for approval. We discuss the settlement here because of its implications for future costs. While PSREC and the other Aligned Protestants in the Loyalton/Portola area support the settlement, DRA asserts that it "does not offer any benefit to the CalPeco ratepayers at all" and "has generated $1.4 million in additional incremental costs that would not otherwise exist."[28]

The PSREC Settlement has two primary components. One concerns development of additional transmission capacity in that portion of the service territory and the other, line crew support for the single lineman based there. The Assigned Commissioner's scoping memo directed Joint Applicants to meet in the

[28] Ex. 50 at 11.

Loyalton/Portola area with PSREC and the other Aligned Protestants to discuss the problems alleged "and assess how reasonable concerns might be addressed."[29] Again, while Joint Applicants have not conceded that any portion of the California Utility suffers from reliability or service deficiencies, we observe that the executed settlement responds to all of Aligned Protestants' allegations (lack of sufficient transmission, lack of back-up generation, and assignment of a single lineman to the area). Nonetheless, if in a future general rate case Joint Applicants fail to prove the reasonableness of either part of the settlement, neither part will ever have any effect upon rates.

With respect to transmission, the settlement provides for CalPeco and Sierra shareholders to make a capital investment of $250,000 in PSREC's Herlong Transmission Project. In addition, Sierra will work with PSREC to increase transmission capacity through PSREC's Marble Substation, in order to expand reliability for both by means of additional, backup transmission service. Joint Applicants describe the Herlong Project as follows:

> This project is to be structured to connect PSREC's system directly with Sierra's system to provide PSREC greater access to less expensive power from sources east of California. PSREC also intends that this project provide CalPeco's customers greater reliability by the addition of an additional transmission line and also access to additional generation sources north and east of California.[30]

Under the settlement, if CalPeco determines the Herlong Project has sufficient, independent merit to CalPeco's ratepayers to warrant a further capital

[29] Scoping Memo and Ruling of Assigned Commissioner, February 25, 2010 at 16.

[30] Ex. 1 at 37.

investment, and if the Commission subsequently agrees and grants CalPeco authority to make that investment on behalf of ratepayers, CalPeco will commit a total of $1 million to the project. In that case, the settlement provides for the initial $250,000 shareholder payment to be credited against CalPeco's $1 million investment. We have no reason to attempt to weigh here whether the Herlong Project will have value for CalPeco. That issue belongs in a future general rate case.[31]

The resource support agreement in the PSREC Settlement provides the terms by which CalPeco will obtain additional line crew services in the Loyalton/Portola area (one lineman and a bucket truck, or the equivalent, for a minimum number of hours annually over a ten-year initial term). CalPeco agrees to absorb 100% of the cost of the resource support agreement between the date of closing and the effective date for rates authorized in a 2012 general rate case.

These issues do not compel a finding that the proposed transaction is adverse to the public interest.

5.3.4. Valmy

As discussed above in Section 5.2, the Power Purchase Agreement provides for five years' continued delivery of CalPeco's full requirements for electric power at Sierra's system-average cost. Currently, Sierra's power supply mix to its California customers includes electricity generated at Sierra's coal-fired

[31] Joint Applicants admit that at present there is no transmission path between the Herlong Project and customers in the Loyalton/Portola area and that this "could render the Herlong project to be of potentially limited value" to CalPeco. (Ex. 1 at 39.) For this reason the PSREC Settlement has been structured to commit PSREC to enter into other commercial arrangements that will yield a solution for CalPeco.

Valmy plant, which commenced operations in the early 1980's. The question arises whether CalPeco may contract for five years for a power supply mix that includes Valmy, given California's statutorily-mandated greenhouse gas (GHG) Emissions Performance Standard (EPS). According to DRA, the rate consequences of prohibiting inclusion of Valmy make the proposed transfer uneconomical – the 2012 impact will be an increase in the average residential rate by "9.95% from $0.12405 per kWh to $.13639 per kWh," following close upon a sizeable residential rate increase (7.75%) in Sierra's 2009 general rate case.[32] Joint Applicants calculate the rate impact for the more expensive cost supply mix at $7.6 million starting in 2011.[33]

In accordance with the statutory guidance in Senate Bill (SB) 1368 (Stats. 2006, ch. 598), enacted in September 2006, the Commission opened a rulemaking to develop the EPS and appropriate rules to implement it. D.07-01-039 approves Adopted Interim EPS Rules.[34] Central to the issues before us is this definition in SB 1368:

> "Long-term financial commitment" means either a new ownership investment in baseload generation or a new or renewed contract with a term of five years or more years, which includes procurement of baseload generation."[35]

The statute explicitly prohibits the Commission from approving a long-term financial commitment, and any load-serving entity from entering into one,

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[32] Ex. 50 at 14.

[33] Ex. 1 at 43.

[34] *Interim Opinion on Phase 1 Issues: Greenhouse Gas Emissions Performance Standard* (2007), D.07-01-039; the Adopted Interim EPS Rules are found at Attachment 7.

[35] SB 1368, Section 2, codifying Pub. Util. Code § 8340 (subpart (j)).

unless the baseload generation supplied under that long-term financial commitment complies with the EPS.[36] Under current law, Sierra may continue to supply power to its California customers from the non-EPS compliant, coal-fired Valmy, however, because Sierra has owned Valmy for several decades. Joint Applicants' witness testified that Sierra has no plans, at present, to make what D.07-01-039 has defined as new ownership investments in Valmy (major retrofits, etc., that would prolong Valmy's useful life by five years or more). Hence, as long as Sierra makes no prohibited, new ownership investments, there is no long-term financial commitment in the context of SB 1368. Enter the contractual arrangement with CalPeco, however, and the picture changes somewhat -- does the Power Purchase Agreement represent a prohibited new contract? D.07-01-039 looks at other contracting issues (what constitutes baseload, how to prevent gaming in contracts with unspecified sources for system reliability, etc.) but does not examine the issue the transfer application raises. Nor has the Commission had occasion to consider the question to date.

Joint Applicants, who argue Valmy should remain in the supply mix, urge us to "allow the pre-Closing status quo to continue – maintenance of existing power sources and customer costs."[37] They point out that while approving the transfer but excluding Valmy supply from California will affect the costs for California customers (since power from Valmy is produced below Sierra's system average cost), nothing else will change. Sierra will continue to operate

[36] Joint Applicants report that they initially contemplated a three-year term for the Power Purchase Agreement but that discussion with the Commission's Energy Division caused them to expand the period to five years to increase supply and price stability.

[37] Joint Applicants' Opening Brief at 56.

the highly-depreciated Valmy at the same capacity for the benefit of Nevada customers and any emissions that migrate into California now will continue to do so. On the other hand, rejecting the transfer will obligate Sierra to continue to serve the California Utility, which also ensures the continued operation of Valmy.

Since D.07-01-039 provides no direct guidance, we turn to the policy goals of SB 1368, which D.07-01-039 summarizes as follows:

> An EPS is needed to reduce California's financial risk exposure to the compliance costs associated with future GHG emissions (state and federal) and associated future reliability problems in electricity supplies. Put another way, it is needed to ensure that there is no "backsliding" as California transitions to a statewide GHG emissions cap: If LSEs [load serving entities] enter into long-term commitments with high-GHG emitting baseload plants during this transition, California ratepayers will be exposed to the high cost of retrofits (or potentially the need to purchase expensive offsets) under future emission control regulations. They will also be exposed to potential supply disruptions when these high-emitting facilities are taken off line for retrofits, or retired early, in order to comply with future regulations. A facility-based GHG emissions performance standard protects California ratepayers from these backsliding risks and costs during the transition to a load-based GHG emissions cap.[38]

Under the facts applicable here, it is difficult to see how prohibiting inclusion of Valmy power in the Power Purchase Agreement's supply mix for a term of five years would further SB 1368's policy goals. Rather, continued import of Valmy power under the Power Purchase Agreement simply preserves the status quo, operationally and economically. Therefore, we find that inclusion

[38] D.07-01-039 at 3.

of Valmy power under the Power Purchase Agreement for a five-year term is not a covered procurement, within the context of SB 1368 and D.07-01-039, and thus, is not subject to our EPS rules.[39] Beyond the contract's five-year term, we should continue to view Valmy under the same rules that would apply were Sierra to continue to serve the California Utility. Thus, Valmy power may be included in the supply provided under any additional power purchase agreement which Sierra and CalPeco may enter upon the expiration of the initial five-year Power Purchase Agreement as long a Sierra makes no new ownership investment in Valmy, as defined by D.07-01-039, and any relevant, subsequent modifications. Our determination interprets D.07-01-039 solely with respect to Valmy and does not modify D.07-01-039.

5.4. Impact on the Financial Condition of the California Utility

In summary, in addition to a public interest finding under § 854(a), Joint Applicants seek authority under § 816, § 818, and § 851 for CalPeco to finance up to 50% of the acquisition price and to encumber utility assets, including accounts receivables, as security for the debt issuance. As stated previously, Algonquin and Emera have committed to fund CalPeco to ensure initial capitalization of at least 50% equity; their respective ownership shares are Algonquin, 50.001%, and Emera, 49.999%. CalPeco will exist as a stand alone financial entity, with its own capital structure, debt, and credit rating.

Joint Applicants represent that they developed the Regulatory Commitments (Appendix 3) to incorporate conditions the Commission has

[39] D.07-01-039 uses the term "covered procurement" to mean the types of generation and financial commitments subject to the EPS, pursuant to SB 1368.

required in prior § 854(a) applications to safeguard the financial condition of the California jurisdictional utility. The Regulatory Commitments, which confirm a high degree of separateness in CalPeco's structural and financial relationship with its owners and their subsidiaries, include these promises:

- The sole purpose of CalPeco's immediate parent, California Pacific Utility Ventures, LLC, will be to own CalPeco;
- CalPeco's assets will be used solely to provide electric distribution services to its customers and to secure any debt it obtains;
- Any financing by Algonquin and Emera of any business activities other than CalPeco will provide the financing parties no recourse to CalPeco's assets;
- Algonquin and Emera will fund all other business activities independently of CalPeco;
- CalPeco will not provide financing to, guarantees for, extend credit to, or pledge any of its assets on behalf of Algonquin, Emera, or any of their subsidiaries;
- Algonquin and Emera commit to ensure that CalPeco has sufficient capital available for necessary capital investments;
- Dividend distributions by CalPeco may be restricted to maintain minimum, required equity levels;
- CalPeco will retain separate books, financial records, employees and assets and these will be based in California.

Joint Applicants and DRA disagree about whether these commitments provide adequate financial security and we discuss their contentions below.

5.4.1. Capital and Debt Guarantees; Ring-Fencing

DRA contends that CalPeco's owners must guarantee its needs for capital and debt, that their commitments in this respect are inadequate, and therefore, that the Commission should impose a first priority condition on them as a

condition of any transfer.[40] DRA also contends that the ring-fencing measures proposed are inadequate, describing them as "two-way" measures designed to protect Algonquin and Emera as much as or more than CalPeco.[41] From DRA's perspective, if the Commission approves this transaction without imposing a first priority condition, it should require Joint Applicants to obtain a non-

[40] The first priority condition is fundamental to the Commission's authorization of the formation of the California holding companies that own and control this state's major energy utilities. See for example, D.88-01-063, 1988 Cal. PUC LEXIS 2 *78 (Southern California Edison Company); D.95-12-018, 1995 Cal. PUC LEXIS 931 *72 (San Diego Gas & Electric Company), D.96-11-017, 1996 Cal. PUC LEXIS 1141 *74; as modified by D.99-04-068, 1999 Cal. PUC LEXIS 242 *151 (Pacific Gas and Electric Company); D.98-03-073, 1998 Cal. PUC LEXIS 1 *260, *290 (Enova [Southern California Gas Company, San Diego Gas & Electric Company merger]). The Commission also imposed a first priority condition on the transfer of control affecting jurisdictional portions of two common carrier pipeline utilities, SFPP, L.P. and Calnev Pipe Line, L.L.C., where the new ownership structure comprised a privately-held, limited liability company and a consortium of investment banks, diversified financial services providers, and private equity funds. See D.07-05-061.

[41] Ex. 50 at 8. The Commission discussed ring-fencing in D.07-05-061, as follows:

> Ring-fencing is the legal walling off of certain assets or liabilities within a corporation. Conceptually, in the context of a public utility within a holding company structure, ring-fencing includes a number of measures that may be implemented to protect the economic viability of the utility by insulating it from the potentially riskier activities of unregulated affiliates and thereby, ensuring the utility's financial stability and the reliability of its service. (See Beach Andrew N., Gunter J. Elert, Brook C. Hutton, and Miles H. Mitchell. Maryland Commission Staff Analysis of Ring-Fencing Measures For Investor-Owner Electric and Gas Utilities. The National Regulatory Research Institute-Volume 3, December 2005 at 7). A non-consolidation opinion is not a ring-fencing measure per se, but focuses on the effect of ring-fencing. A non-consolidation opinion demonstrates that a utility has enough ring-fencing provisions to protect it from being pulled into a holding company bankruptcy. (D.07-05-061, footnote 22.)

consolidation opinion that demonstrates the adequacy of the ring-fencing measures.

Joint Applicants' briefs generally challenge DRA for focusing too much on the potential for harm to CalPeco should exigent financial circumstances arise. While Joint Applicants' are correct that it is impossible to guarantee, with absolute assurance, the financial security of any entity into the unknowable future, we do not agree that DRA is amiss for seriously considering the impact of exigent circumstances. At a minimum, recent financial history urges caution. However, we do not find it unreasonable that Joint Applicants oppose imposition of a first priority condition. Algonquin and Emera own regulated utilities in Canada and in four other states in this country and argue that, legally and practically, they cannot put CalPeco in first place before those other entities. As Joint Applicants observe, the Commission recognized this reality in D.02-12-068, when it approved the change of control of CalAm but declined to impose a first priority condition. Joint Applicants further contend that their situation is similar to PacifiCorp's acquisition by MidAmerican, where the Commission found an acceptable safety net in MidAmerican's promise to "obtain sufficient cash from its operations, regular infusions of equity capital from [MidAmerican's holding company], and steady increases in short-term debt."[42] Joint Applicants point to the Regulatory Commitments for similar promises by Algonquin and Emera.

Regarding equity infusions, Joint Applicants full commitment now states:

[42] D.06-02-033 at 26.

> Emera and Algonquin will provide sufficient initial equity to fund fifty percent (50%) of the purchase price for CalPeco. CalPeco shall seek to obtain the balance of the required capital necessary for the purchase price through stand-alone debt issued by CalPeco. Algonquin and Emera are prepared to make this initial equity investment and invest any additional equity in CalPeco based on their understanding that the Commission shall grant CalPeco timely recovery in rates (i) for the reasonable expenses it will make or undertake, respectively, to provide electric service; and (ii) for CalPeco to earn a reasonable return of and on CalPeco's investment in rate base. On this basis Emera and Algonquin are committed to ensure that CalPeco maintains sufficient funds to operate and has sufficient capital available for necessary capital investments. CalPeco, Algonquin, and Emera acknowledge that dividends or similar distributions by CalPeco may be restricted as necessary to maintain minimum equity levels that are reasonable in relation to any equity ratio requirements.[43]

An earlier version did not commit Algonquin and Emera to provide equity beyond the initial capital infusion; the change was made after hearings, at least in part in response to DRA's criticism. DRA's opening brief argues that the amended commitment remains deficient. DRA faults the amended version because it "put[s] the onus on CalPeco to maintain the necessary funding to operate" and also, as DRA reads the commitment, because it means that rate recovery must be assured before any capital infusions are made.[44] DRA further contends that the commitment effectively defines capital as additional equity, only, and therefore "is too limiting."[45] DRA refers to the Commission's discussion of capital in D.02-01-039, an interim decision in the Commission's

[43] Appendix B, Regulatory Commitments, Section 1(g).

[44] DRA Opening Brief at 20.

[45] DRA Opening Brief at 21.

2002 investigation into, among other things, the meaning of the first priority condition in the context of the holding company structures for the major California energy utilities. There, the Commission examined the holding companies' policies in the context of the electricity crisis. Findings 5 and 6 of D.02-01-039 provide:

> 5. The term "capital," where not otherwise limited or qualified, encompasses all of the following: the money and property with which a company carries on its corporate business; a company's assets, regardless of source, utilized for the conduct of the corporate business and for the purpose of deriving gains and profits; and a company's working capital.
>
> 6. The term "capital" is not limited in the first priority condition to mean only "equity capital," infrastructure investment, or any other term that does not include, simply, money or working cash.[46]

We conclude that DRA overstates its case on this point. While we agree with DRA that the definition of capital should be understood, plainly, to include money or working cash, the following, very broad clause in Regulatory Commitment 1(g) is reasonably read to encompass working capital as well as capital expenditure: "… Emera and Algonquin are committed to ensure that CalPeco maintains sufficient funds to operate and has sufficient capital available for necessary capital investments."

DRA's other interpretations of Regulatory Commitment 1(g) also fail to persuade. Rather, the language reflects two established, general principles: (1) a regulated utility should be self-supporting where possible, and (2) under the

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[46] *Investigation into Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company and their respective holding companies,* D.02-01-039 (2002)

decades old regulatory compact, rate recovery can be expected for all reasonable expenditures made in the provision of safe and reliable utility service. We do not think the amended commitment can fairly be read to suggest that Algonquin or Emera plan to abandon CalPeco if an unusual or extreme need for cash should arise. Even before Joint Applicant's revised this commitment to extend it to additional equity infusions, their witness testified:

> [I]f there were an extraordinary event – a storm of some profound magnitude that required some kind of capital infusion to protect the asset, then I would assume that CalPeco would either seek to obtain those funds or they'd be forthcoming from the parent to protect the asset.[47]

In addition, DRA argues that CalPeco's small size may increase its cost of debt. As DRA notes, this claim is frequently heard in ratemaking proceedings at the Commission, though it is not accurate in all instances. DRA has not shown, however, how a parental guarantee will benefit ratepayers by ensuring a lower debt rating for CalPeco, particularly when such a guarantee is at odds with standard ring-fencing measures. While the actual cost of debt cannot be known in advance, Joint Applicants' witness testimony further explains their representation that it should be competitive with NV Energy's debt:

> Our discussion with the capital markets and lenders in the capital markets have led us on behalf of CalPeco to conclude that the cost of debt that will be sought by CalPeco will be competitive with the cost of debt which is currently outstanding on behalf of NVE.
>
> ….

[47] Tr. at 85.

> It is through looking at the ratios – the debt-to-energy ratios, looking at interest coverage ratios – that leads us to conclude that the rating that CalPeco will enjoy will be competitive, if not perhaps better in some respects, than NV Energy who has obviously a much broader business offering.[48]

A parental debt guarantee also serves to undermine the separateness which ring-fencing establishes. DRA does not discuss this issue. Its ring-fencing concerns focus on what DRA's terms the "two way" rather than "one way" nature of the measures that Joint Applicants propose. According to DRA, while the ring-fencing proposals do protect CalPeco from the bankruptcy of its upstream owners, they unreasonably protect Algonquin and Emera from providing any assistance in the case of CalPeco's financial distress. However, the testimony of DRA's witness suggests that DRA's concern really is that CalPeco's owners provide additional capital if needed – and subject to the definitional clarification discussed above, Joint Applicants have addressed that. Asked what Joint Applicants should do to mitigate problems with their ring-fencing proposal, DRA's witness testified that "… the Commission could order the parent company to infuse money into CalPeco if there's future financial hardship."[49]

With respect to the comparative adequacy of the ring-fencing measures that Joint Applicants' propose, we observe the measures offer value, though they are structured differently than those that MidAmerican developed in the context of the PacifiCorp acquisition. The PacifiCorp ring-fencing includes provision for an independent director at PacifiCorp; before any amendment can be made to

[48] Tr. at 91-92.

[49] Tr. at 138.

the ring-fencing, the independent director must approve the amendment and there must be rating agency confirmation that the amendment will not result in a credit downgrade.[50] In Regulatory Commitment 1(e), Joint Applicants propose that no ring-fencing changes be made without Commission approval, which provides a high degree of oversight and ratepayer protection. Moreover, we retain regulatory jurisdiction to proactively require revisions to the ring-fencing measures, given appropriate notice and opportunity to be heard. On balance then, we find the ring-fencing measures adequate – at least at this time – and need not require Joint Applicants to undertake the additional expense of obtaining a nonconsolidation opinion.

5.4.2. Emera Minimum Hold Condition; Internal Transfer Approval

Algonquin commits to own at least 50% of CalPeco for at least ten years. Emera makes no such commitment, though according to Ex. 3, the first of several status update letters letter submitted prior to hearing, upon closing Emera now plans to acquire a 9.9% interest in Algonquin in addition to its indirect interest in

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[50] See D.06-02-033 at 25 and Appendix D: Adopted Conditions, 11.

The National Regulatory Research Institute publication quoted above in footnote 41 discusses a number of ring-fencing measures designed to protect the financial viability of a utility, including: (1) capital structure requirements, (2) dividend restrictions, (3) unregulated investment restrictions, (4) prohibition on utility asset sales, (5) collateralization requirements, (6) working capital restrictions, (7) prohibitions on inter-company loans, (8) maintenance of stand-alone bonds, and (9) independence of board members. (The National Regulatory Research Institute-Volume 3, December 2005 at 5.)

We observe that statute and our regulatory policies effectively impose several of the enumerated measures (for example, utility sales restrictions and capital structure requirements).

CalPeco. However, the Emera Minimum Hold Condition, a condition to the closing contained in the Purchase Agreement specifies that "[n]o Final Regulatory Order shall have imposed an affirmative obligation on Emera to continue to own its interest in [CalPeco] for any specific period of time following the Closing Date."[51] Joint Applicants represent that Emera's disinclination to be bound to hold its interest in CalPeco for any specific period should not be construed as "any intent to 'flip' or otherwise shortly sell" its interest in CalPeco but "is simply a matter of maintaining corporate flexibility."[52] In response to DRA's cross-examination at hearing, Joint Applicants' witness testified: "I believe we have the ultimate track record of maintaining and holding our investments. I think we are the poster children for the buy-and-hold strategy for the assets that we … own." [53] Emera's position on this issue basically reflects a "different philosophy" than Algonquin's, he testified, and would wrongly be construed to mean anything else.[54]

DRA links its concern about the Emera Minimum Hold Condition to a second proposal, termed the Internal Transfer Approval. As described in the transfer application, the Internal Transfer Approval would permit "either Algonquin or Emera to transfer to the other all or any portion of its ownership interest in CalPeco, and without the need for an additional approval by this Commission."[55] In Ex. 3, Joint Applicants clarify that they do not intend that this

[51] Transfer Application, Ex. 8, Article VIII, 8.2(h).

[52] Transfer Application at 69.

[53] Tr. at 87.

[54] Tr. at 87.

[55] Transfer Application at 70.

authority override Algonquin's commitment to retain its investment in CalPeco for at least ten years. Ex. 3 also indicates that Joint Applicants would not object to the conditioning of the Internal Transfer Approval upon a requirement that any decrease in Emera's interest in CalPeco occur concurrently with a proportional increase of Emera's ownership interest in Algonquin. Joint Applicants' witness explained that the companies want the Internal Transfer Approval "for convenience and investment flexibility."[56] However much they might like to have it, the Internal Transfer Approval is not a deal breaker. Joint Applicants' witness also testified: "[I]f it would increase the Commission's comfort, we would be comfortable with filing, if necessary, for any of those transfers an 854(a) application for your approval."[57]

DRA contends that the Internal Transfer Approval is not only a bad idea that effectively would permit Emera to abandon CalPeco, posing risks for ratepayers, but more critically, that it is contrary to law. DRA observes that (1) § 851 and § 854 require Commission approval before any transfer of assets or change of control, and that lacking such approval, a transaction is void, and (2) that any attempt by this Commission to pre-approve such transactions, even if lawful, cannot bind future Commissions.

We agree with DRA that these two requests are inter-related. We do not agree that we should impose a minimum hold condition upon Emera. We desire stability for regulated utilities, but we also recognize that § 851 and § 854 provide legal means for approval of reasonable requests for changes in ownership and

[56] Tr. at 33.

[57] Tr. at 34.

control. The record does not establish that the proposed transfer is unreasonable unless we impose a minimum hold condition upon Emera. We are less sanguine about the internal transfer authority sought. Whether or not it is lawful (the briefs do not adequately discuss whether the Commission effectively may pre-approve transactions that otherwise would require the filing and review of § 851 and/or § 854 applications), Joint Applicants have not established the Internal Transfer Approval is free of risk to ratepayers. By filing the transfer application as they did, Joint Applicants clearly reached their own determination that Emera and Algonquin should partner in the way proposed. Should they wish to change the financial arrangement at some time in the future, they must file a new application that explains why the proposed change would not be adverse to the public interest.

5.5. Impact on Quality of Management

DRA favorably acknowledges Emera's more than 130-year history of owning and operating electric utility facilities, including electric distribution and transmission systems. But because Algonquin's own, direct expertise is with electric generation facilities and small water and sewer systems, DRA registers concern that without Emera's long-term involvement, the transfer will result in weakened management. Joint Applicants have made a sufficient showing that CalPeco will have competent, professional management, including a competent initial board of directors, whose credentials are listed in Ex. 23 to the transfer application.

5.6. Impact on Utility Employees

As mentioned above in Section 5.2, Local 1245 submitted a letter in support of the transaction shortly after Joint Applicants filed the transfer application. DRA challenges Local 1245's support (though it did not call a union

representative or any other employee at hearing), contending that CalPeco has not proposed to offer affected employees continued employment under precisely the same terms and conditions that Sierra now offers. While the witness testimony is not entirely clear on this point, it suggests that the terms for retirement vesting may change for one or more employees who are not vested at present. Regulatory Commitment 4(c) merely states: "CalPeco will recognize the service and seniority of the former employees of Sierra who accept CalPeco's offer of employment for all non-pension purposes including vacation, sick pay benefits and for non-pension post retirement benefits such as retiree health benefits." It appears Local 1245 has not expressed pension concerns and DRA has not discredited Local 1245's letter of support. We find that Joint Applicants have made a sufficient showing that CalPeco will treat employees fairly.

5.7. Impact on California and Local Communities

Joint Applicants focus on service improvements, local hiring as needed, and an increased local presence under CalPeco, all of which can only yield some benefit to the state and local community. DRA's contends that the likelihood of future rate increases render any change uneconomical. We will carefully consider the reasonableness of any rate increase requests in a future rate case filing, weighing evidence on actual costs and actual benefits in that forum. The record on these issues in the transfer application does not establish ratepayer harm.

5.8. Impact on Commission Jurisdiction

Joint Applicants represent that Sierra not only undertook to fully apprise potential bidders of California's jurisdictional requirements but that CalPeco and its owners accept the Commission's jurisdiction and commit to comply with the

Commission's orders and with state law. Witness testimony and the Regulatory Commitments confirm the latter, generally, and DRA does not contest this aspect of the proposed transfer. We agree that Joint Applicants have made a sufficient showing that the transfer will not undermine or interfere with the Commission's jurisdiction regarding access to books and records of its owners or with respect to regulatory policies such as the RPS and the GHG EPS. However, though the issue is raised in the Assigned Commissioner's scoping memo, the record does not fully address the Commission's ability to call officers and employees of CalPeco's jurisdictionally foreign, upstream owners to testify in California regarding matters pertinent to CalPeco. To avoid the possibility of future confusion, any approval of the proposed transaction must be conditioned upon access to such officers and employees as the Commission, itself, may determine to be necessary, consistent with established principles of due process and fundamental fairness.

5.9. Impact on Competition

Joint Applicants contend, and DRA does not contest, that the proposed transaction will have no adverse impact on energy markets in California. As Joint Applicants note, the proposed transaction is not a merger of two existing utilities, which might raise market power concerns. Joint Applicants also report that Algonquin, as the 50.001% owner of CalPeco, and Sierra will make the filings with the Federal Trade Commission required under the federal law know as Hart-Scott-Rodino. The record on this issue shows no ratepayer harm.

5.10. Other Operating Agreements

We discuss above two of the seven Operating Agreements that are integral to the proposed transfer – the Power Purchase Agreement (Section 5.2), including inclusion of supply from Valmy (Section 5.3.4) and the Transition

Services Agreement (Section 5.3.2). The remaining five, uncontested agreements comprise the following:

- Emergency Backup Service Agreement (Ex. 11 to the transfer application);
- Interconnection Agreement (Ex. 16 to the transfer application);
- System Coordination Agreement (Ex. 15 to the transfer application);
- Borderline Customer Agreement (Ex. 13 to the transfer application); and
- Distribution Capacity Agreement (Ex. 14 to the transfer application).

The Emergency Backup Service Agreement governs CalPeco's proposed provision to Sierra of capacity and energy from the Kings Beach facility for emergency backup service.

The Interconnection Agreement provides how Sierra and CalPeco propose to ensure continued interconnection and coordinated operations between the California Utility's Commission-jurisdictional facilities and Sierra's transmission assets in California, which are subject to jurisdiction by FERC. In particular, if FERC accepts Sierra's request to file the agreement under Section 205 of the Federal Power Act, Joint Applicants ask the Commission to authorize CalPeco to recover any payments it must make to Sierra under the agreement, subject only to ongoing Commission review of the reasonableness of CalPeco's administration of the agreement.

The System Coordination Agreement provides how CalPeco and Sierra propose to coordinate non FERC-jurisdictional, operational matters related to the integrated nature of the California service territory and Sierra's distribution system in Nevada.

The Borderline Customer Agreement provides how CalPeco and Sierra propose to sell wholesale power in order to permit each utility to serve, in the

most cost effective way with existing resources, certain customers located near the California-Nevada border. Under the agreement, each utility will apply to FERC for authority to sell power at the rates set forth in the agreement. Joint Applicants ask the Commission to authorize CalPeco to recover payments to Sierra in rates, subject only to ongoing Commission review of the reasonableness of CalPeco's administration of the agreement. Joint Applicants ask the Commission to authorize CalPeco to account for any revenues it receives from Sierra as an offset against its ECAC purchased power costs.

The Distribution Capacity Agreement governs how CalPeco proposes to make capacity on the California Utility's distribution system available to Sierra so that Sierra can cost-effectively serve certain of its Nevada customers located near the California-Nevada border, recognizing that Sierra currently uses electric distribution facilities within California to receive power from Nevada and then to flow that power back to those customers. Joint Applicants' analysis (see Appendix 4 to today's decision) describes why these distribution facilities of the California Utility are "local distribution" facilities subject to the exclusive jurisdiction of the Commission under FERC's seven-factor test. Joint Applicants ask the Commission to retain jurisdiction over the facilities after the closing and authorize CalPeco to provide distribution to Sierra based on the rates and terms in the agreement.

Each of these Operating Agreements has been drafted to permit CalPeco and Sierra to continue to provide electric power, post-closing, to their respective customers in the same way and at the same price as occurs at present.

5.11. Conclusion

Subject to the conditions specifically identified above and in the related Ordering Paragraphs, the transfer application is not adverse to the public interest

and should be approved. Joint Applicants' have established that the transfer will not harm ratepayers; in fact, certain service improvements are likely in the near term, at no cost to ratepayers. To the extent service improvements trigger higher costs that result in a request for an increase in rates in 2012 and beyond, CalPeco is on notice that we will carefully scrutinize its 2012 general rate case showing. As is standard in a general rate case, CalPeco will have the burden of proof to establish the reasonableness of its request.

6. Ancillary Agreements to the TDPUD Settlement: Discussion

As mentioned in Section 3, Joint Applicants' settlement with TDPUD requires Commission approval of the two ancillary agreements filed as exhibits to A.10-04-032, the Fringe Agreement (Ex. A to that application) and the Reliability Support Agreement (Ex. B). TDPUD initially filed a protest to the transfer application, claiming that it would be harmed by the proposed transfer unless steps were taken to avoid that harm. Joint Applicants and TDPUD reached a settlement that resolved TDPUD's concerns and the two ancillary agreements implement that settlement. DRA does not specifically contest either agreement.

6.1. Fringe Agreement

The Fringe Agreement memorializes certain informal, cooperative arrangements between TDPUD and Sierra that have permitted them to serve customers located on or near the border of their contiguous service territories without building uneconomic and duplicative electric distribution facilities. The cooperation has been and continues to be necessary given the terrain and the location of the service territory boundary, which bisects certain roads and residential neighborhoods. The Fringe Agreement obligates Sierra to assign its

rights and responsibilities to CalPeco upon the closing of the proposed transaction. The agreement also memorializes Sierra's, and subsequently CalPeco's, right to rate recovery from those fringe customers served by the California-jurisdictional utility. Since these costs are included within Sierra's revenue requirement calculations at present, the Fringe Agreement will not change revenue requirement.

6.2. Reliability Support Agreement

The Reliability Support Agreement obligates CalPeco, upon closing, to continue to participate in the arrangement that Sierra and TDPUD have negotiated to provide their customers with an alternative path for delivery of electric power, should backup be needed because of an outage on either utility's primary delivery paths. A.10-04-032 describes, in detail, the physical configuration and specific facilities involved. The agreement provides that neither entity will charge for use of any of its distribution facilities for backup delivery. Joint Applicants explain: "It is anticipated that the circumstances in which the use of either of these backup facilities under the [Reliability Support Agreement] will be provided will be rare and largely the result of unpredictable line outages."[58] As with the Distribution Capacity Agreement discussed in Section 5.10, approval of the Reliability Support Agreement relies upon a Commission determination that local distribution facilities are involved (see Appendix 4 to today's decision).

[58] A.10-04-032 at 8.

6.3. Conclusion

Each agreement essentially memorializes the status quo and permits CalPeco to stand in the shoes of Sierra vis a vis TDPUD, to the mutual benefit of both CalPeco and TDPUD. Joint Applicants have established good reason for the authority sought by A.10-04-032. Accordingly, that application should be approved, as more particularly set out in the Ordering Paragraphs of today's decision.

7. Compliance with the California Environmental Quality Act (CEQA)

The sole remaining issue is whether, as Joint Applicants assert, the proposed transfer qualifies for an exemption from CEQA. Under CEQA and Rule 2.4 of the Commission's Rules of Practice and Procedure, we are required to consider the environmental consequences of projects that are subject to our discretionary approval. [59]

We acknowledge that in some cases it is possible that a change of ownership and/or control may alter an approved project, result in new projects, or change facility operations in ways that have an environmental impact. However, as the transfer application states, the proposed change of control will not result in a change in operation or change in the use of existing assets and facilities. Nor do Joint Applicants seek approval of new construction or request approval for any future utility infrastructure. In accordance with today's decision and except as otherwise authorized herein, CalPeco will continue to operate the California Utility in the manner the Commission has approved for Sierra.

[59] See, Public Resources Code § 21080.

8. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Joint Applicants and DRA filed comments on October 4, 2010 and Joint Applicants filed reply comments on October 11, 2010.

Joint Applicants agree to comply with each of the three conditions on the transfer that the proposed decision recommends. Joint Applicants also suggest several minor modifications to the decision text, findings, conclusions, and ordering paragraphs to provide further clarity, or in a few instances, to make corrections. The suggestions are well taken and we revise the proposed decision accordingly.

DRA opposes the proposed decision and reiterates the major arguments in its briefs. DRA's contentions do not establish factual or legal error, however. DRA proposes that the Commission impose one, additional condition on the transfer by requiring that Sierra take back the California Utility if CalPeco is unable to fulfill the other conditions. This proposal goes beyond the scope of comments recognized by Rule 14.3(c). Since we have no record upon which to evaluate the proposal, we accord it no weight.

We make other, minor revisions to the proposed decision to correct typographical errors. To cure an inadvertent omission and support the relevant ordering paragraph, we include a brief discussion of the reason the transfer does not require review under CEQA, together with an associated finding and conclusion.

9. Assignment of Proceeding

Dian M. Grueneich is the assigned Commissioner and Jean Vieth is the assigned ALJ in this proceeding.

Findings of Fact

1. The proposed transfer from Sierra to CalPeco has been structured as a sale of all California-jurisdictional assets, rather than a merger or sale of stock, because the California Utility is not organized, legally, as a separate entity from Sierra. Sierra's California Utility consists of its California-jurisdictional service territory and all distribution assets, as well as the King's Beach Generating Station, a 12-MW diesel-fired generator located in King's Beach near Lake Tahoe.

2. Sierra wishes to sell the California Utility to enable its owner, NV Energy, to focus on Nevada operations, which now serve nearly 1.2 million customers located throughout most of that state, given recent load growth. The California Utility's operations represent less than 4% of NV Energy's customer base. The sale would permit NV Energy to consolidate all of its operations under a single, state regulatory agency and respond to a single set of regulatory directives

3. CalPeco is a newly created, California limited liability company. Appendix 2 reflects the organizational ownership chain. CalPeco's ultimate, indirect owners are two publicly traded Canadian companies, Algonquin, which will hold 50.001% stake in CalPeco, and Emera, which will hold 49.999%.

4. The proposed transfer fits the mutual business objectives of CalPeco's owners, Algonquin and Emera, to expand ownership and operation of regulated utility assets, with a view to long-term acquisition and, in some instances, the potential for investment in renewable energy.

5. As qualified in Finding 33, CalPeco's owners do not contest the Commission's jurisdiction. Because Joint Applicants have fully disclosed the

existence of California Pacific Utility Ventures, LLC, as well as Emera and Algonquin and their immediate subsidiaries in the chain of control of CalPeco, have presented witnesses from Algonquin and Emera at hearing, have offered Regulatory Commitments that include promises by Algonquin and Emera, and have placed issues concerning these entities directly before the Commission for decision, our ability to fully consider this transfer has not been circumscribed.

6. Sierra's 2008 annual California revenues were approximately $72 million and CalPeco had no California revenues.

7. The record contains no evidence that the transfer will result in operational change and no new facilities are proposed.

8. Appendix 3 lists all Regulatory Commitments by CalPeco and its owners; subject to clarification of Regulatory Commitment 1(g) as described in Finding 25, the Regulatory Commitments are reasonable, will not result in harm to ratepayers, and may yield some ratepayer benefits.

9. The sales price which is estimated to range between approximately $132 and $137 million, will be calculated more precisely based upon various factors including outstanding accounts payables and accounts receivables at closing; however, the Regulatory Commitments prohibit CalPeco from seeking to recover in rates either the premium paid for the assets of the California Utility or any transactions costs.

10. The proposed transfer will continue safe and reliable service and generally, will maintain the quality of service customers experience today. Service for customers in the remote Loyalton/Portola area should improve given CalPeco's promises to undertake the reliability measures discussed in the body of this decision. Some customers may experience other service improvements, also discussed in the body of this decision.

11. Post-closing CalPeco will collect from customers the same total revenues that Sierra is authorized to charge and collect, at the same rate levels now applicable to individual customers.

12. O&M and administrative costs, which arguably might benefit the most from any economies of scale, comprise in the aggregate about 10% of the California Utility's total revenue requirement. Over half of these costs should be quite stable (given similar compensation packages for the same work force and continued use of the same trucks and other vehicles), which leaves only about $3 to $4 million potentially subject to cost escalation in a 2012 general rate case. For the purposes of illustration, only, a 15% escalation of that $3 to $4 million would result in a revenue requirement increase of $450,000 to $600,000, which is less than 1% of total revenue requirement.

13. CalPeco expects to be able to economically install electronic capabilities for billing and for scheduling service, based upon Algonquin's past success in this area.

14. CalPeco expects the reopening of the customer service counter in South Lake Tahoe to be cost-effective.

15. Under the Transition Service Agreement, which is one of the Operating Agreements, CalPeco has the reasonable option to ask Sierra to perform at cost for 24 months, with a 12-month extension, any of the services Sierra now provides to the California Utility.

16. The settlement with PSREC is not before the Commission in this docket and will have no impact on the rates of California customers, if at all, unless and until CalPeco seeks recovery for any expenditures associated with the PSREC settlement in the CalPeco 2012 general rate case and the Commission authorizes the recovery.

17. Sierra's coal-fired Valmy Power Plant commenced operations in the early 1980's and Sierra has no plans, at present, to make new ownership investments in Valmy.

18. Given the facts, prohibiting inclusion of Valmy power in the Power Purchase Agreement's supply mix for a term of five years will not further SB 1368's policy goals. The exclusion will affect costs for California customers (since power from Valmy is produced below Sierra's system average cost) but nothing else will change, as Sierra will continue to operate the highly-depreciated Valmy at the same capacity for the benefit of Nevada customers and any emissions that migrate into California now will continue to do so.

19. The rate consequences of prohibiting inclusion of Valmy power in the Power Purchase Agreement's supply mix will increase power costs by $7.6 million starting in 2011, or put another way, increase the average residential rate in 2012 by 9.95% from $0.12405 per kWh to $.13639 per kWh.

20. Rejecting the transfer will obligate Sierra to continue to serve the California Utility, which also ensures the continued operation of Valmy.

21. Continued import of Valmy power under the Power Purchase Agreement simply preserves the status quo, operationally and economically, and therefore is not a covered procurement, within the context of SB 1368 and D.07-01-039 and is not subject to the Commission's EPS rules.

22. Beyond the Power Purchase Agreement's five-year term, Valmy should be viewed under the same rules that would apply were Sierra to continue to serve the California Utility. Thus, as long a Sierra makes no new ownership investment in Valmy, power from that plant may be included in the supply mix provided under any additional power purchase agreement, which Sierra and

CalPeco may enter upon the expiration of the initial, five-year Power Purchase Agreement.

23. While the cost consequences of the transfer in 2012 and beyond are uncertain, the evidence does not suggest cost consequences of a magnitude large enough to support a finding that proposed transfer will harm ratepayers and therefore, is adverse to the public interest.

24. Algonquin and Emera own regulated utilities in Canada and in four other states in the United States.

25. CalPeco's amended Regulatory Commitment 1(g), which promises infusions of necessary equity from CalPeco's indirect owners, is reasonably read to encompass working capital as well as capital expenditure.

26. A parental guarantee of debt serves to undermine the separateness which ring-fencing establishes.

27. The ring-fencing measures that Joint Applicants' propose offer value as discussed in the body of this decision.

28. The record does not establish that unless we impose a minimum hold condition upon Emera, the proposed transfer is unreasonable.

29. Joint Applicants have not established their Internal Transfer Authority is free of risk for ratepayers.

30. Joint Applicants have made a sufficient showing that CalPeco will have competent, professional management, including a competent initial board of directors.

31. Local 1245 supports the transfer and in other respects, Joint Applicants have made a sufficient showing that CalPeco will treat employees fairly.

32. Service improvements (even if minor), local hiring as needed, and an increased local presence for the utility can only yield some benefit to the state and local community; the record does not establish ratepayer harm.

33. With one exception, the record generally confirms that CalPeco and its owners accept the Commission's jurisdiction and commit to comply with the Commission's orders and with state law. To avoid the possibility of future confusion, any approval of the proposed transaction must be conditioned upon access to such officers and employees of CalPeco's jurisdictionally foreign, upstream owners as the Commission, itself, may determine to be necessary, consistent with established principles of due process and fundamental fairness.

34. The transfer application incorporates seven Operating Agreements, which comprise, in addition to the Power Purchase Agreement and Transition Services Agreement, these five: Emergency Backup Service Agreement, Interconnection Agreement, System Coordination Agreement, Borderline Customer Agreement, and Distribution Capacity Agreement. Each of these agreements has been drafted to permit CalPeco and Sierra to continue to provide electric power, post-closing, to their respective customers in the same way and at the same price as occurs at present.

35. Joint Applicants' settlement with TDPUD requires Commission approval of the two ancillary agreements filed as exhibits to A.10-04-032, the Fringe Agreement and the Reliability Support Agreement.

36. The Fringe Agreement memorializes certain informal, cooperative arrangements between TDPUD and Sierra that have permitted them to serve customers located on or near the border of their contiguous service territories without building uneconomic and duplicative electric distribution facilities. The

agreement obligates Sierra to assign its rights and responsibilities to CalPeco upon closing and will not change revenue requirement.

37. The Reliability Support Agreement obligates CalPeco, upon closing, to continue to participate in the arrangement that Sierra and TDPUD have negotiated to provide their customers, at no additional charge, with an alternative path for delivery of electric power, should backup be needed because of an outage on either utility's primary delivery paths.

38. The Fringe Agreement and the Reliability Support Agreement essentially memorialize the status quo and permit CalPeco to stand in the shoes of Sierra vis a vis TDPUD, to the mutual benefit of both CalPeco and TDPUD. Joint Applicants have established good reason for the authority sought by A.10-04-032.

39. With respect to the Distribution Capacity Agreement (in A.09-10-028) and the Reliability Support Agreement (in A.10-04-032), the Commission should determine that local distribution facilities are involved and assert jurisdiction over them.

40. The proposed transfer of control will have no significant effect upon the environment, because after the transfer CalPeco will continue to operate the California Utility in the manner the Commission has approved for Sierra, except as modified by today's decision.

Conclusions of Law

1. The proposed transfer from Sierra to CalPeco should be reviewed under § 854, which generally governs mergers and similar transfers of control, rather than § 851, which typically governs sales of assets. More particularly, the transfer should be reviewed under § 854(a).

2. Neither D.01-09-057 nor D.06-02-033 established a positive benefits test for transactions such as the proposed Sierra/CalPeco transfer.

3. The following principles apply to a transfer proposed under § 854(a):

   (a) to ensure that a transfer is not adverse to the public interest, the Commission must be able to evaluate evidence on the important impacts of that transfer – whatever they might be – and find no harm to ratepayers;

   (b) some of the criteria enumerated in §§ 854(b) and (c) mirror criteria identified by past Commission decisions as relevant to a public interest assessment under § 854(a), and depending upon the nature of the transfer at issue, may well be relevant and even necessary to the specific public interest assessment required; and

   (c) only where §§ 854(b) and (c) expressly apply, must the Commission make all of the findings those subsections require.

4. No party has introduced facts to describe any alternative for the Commission to consider under § 854(d).

5. The requested financing authority is governed by is § 816 and § 818, which concern issuance of stocks, bonds, etc., and § 851, which as relevant here, concerns the encumbrance of utility assets.

6. Pursuant to § 15061(b)(3) of the CEQA guidelines, inasmuch as it can be seen with certainty that the project will have no significant impact upon the environment, the transfer application qualifies for an exemption from CEQA and the Commission need not perform any further environmental review.

7. The reach of today's decision necessarily extends to the direct and indirect owners of CalPeco; specifically, any approval of the proposed transaction must be conditioned upon access to such officers and employees of CalPeco's jurisdictionally foreign, upstream owners as the Commission, itself, may determine to be necessary, consistent with established principles of due process and fundamental fairness.

8. A general rate case is the forum for review of the reasonableness of actual costs incurred and actual benefits associated with those costs.

9. No finding or conclusions of law in this decision supports a reasonableness finding or authorizes rate recovery in a future general rate case.

10. D.07-01-039 provides no direct guidance regarding whether the supply mix under the Power Purchase Agreement may or may not include electric power from Valmy.

11. The Commission has not imposed a first priority condition on the owners of a California-jurisdictional utility that also own utilities in other regulatory jurisdictions.

12. The Commission retains regulatory jurisdiction to proactively require revisions to the ring-fencing measures included in the Regulatory Commitments, given appropriate notice and opportunity to be heard.

13. Section 851 and § 854 provide legal means for approval of reasonable requests for changes in ownership and control of public utilities regulated by this Commission.

14. Should any of CalPeco's direct or indirect owners wish to change arrangements governing their ownership and control of CalPeco, they must file a new application under § 854 that explains why the change proposed would not be adverse to the public interest.

15. Subject to the condition on the Power Purchase Agreement's inclusion of power from Valmy, CalPeco should be authorized to enter into the Power Purchase Agreement, the Interconnection Agreement and the Borderline Customer Agreement under the terms and conditions therein, which we deem to be reasonable. Accordingly, the costs incurred under each agreement will be deemed to be prudently incurred and CalPeco is authorized to recover those

costs, subject to review for reasonableness of CalPeco's administration of each agreement.

16. The Distribution Capacity Agreement (in A.09-10-028) and the Reliability Support Agreement (in A.10-04-032) involve local distribution facilities subject to the jurisdiction of this Commission.

17. The proposed transfer qualifies for an exemption from CEQA pursuant to the CEQA guidelines § 1506(b)(3) and so additional environmental review is not required.

18. This decision should be effective immediately to minimize business uncertainty for the parties and all affected by the transfer of Sierra's California Utility to CalPeco.

O R D E R

IT IS ORDERED that:

1. As conditioned by this Ordering Paragraph, the transfer from Sierra Pacific Power Company (Sierra) to California Pacific Electric Company, LLC (CalPeco) is not adverse to the public interest. Accordingly, subject to the Regulatory Commitments attached to this Order as Appendix 3 and subject to the following conditions, Application 09-10-028 is granted, the seven Operating Agreements are approved, and Sierra may transfer to CalPeco, Sierra's California-jurisdictional electric distribution facilities and the Kings Beach Generating Station, together with those Certificates of Public Convenience and Necessity held by Sierra that are required for CalPeco to serve California customers:

(a) Power from Sierra's Valmy Power Plant (Valmy) may be included in the supply provided under the five-year term of the Power Purchase Agreement (one of the Operating Agreements) and any extension of that term as long a Sierra makes no new ownership investment in Valmy,

within the context of the Emissions Performance Standard rules adopted by Decision 07-01-039, and any subsequent modifications of that decision.

(b) The Internal Transfer Authority is not approved and any change of ownership affecting CalPeco's upstream owners must be sought by application filed pursuant to Public Utilities Code Section 854.

(c) Liberty Electric Co., Algonquin Power & Utilities Corp., Emera US Holdings, Inc., and Emera Incorporated must each notify the Director of the Commission's Energy Division in writing within 30 days of the effective date of this decision of its agreement to provide its officers and employees to testify in California regarding matters pertinent to CalPeco, as the Commission, itself, may determine to be necessary, consistent with established principles of due process and fundamental fairness.

2. The California Public Utilities Commission affirmatively asserts jurisdiction over the Distribution Capacity Agreement (one of the Operating Agreements) and the local distribution facilities described therein.

3. The financing authority requested by California Pacific Electric Company, LLC pursuant to Public Utilities Code Sections 816, 818, and 851 is granted.

4. The ratemaking adjustments requested by California Pacific Electric Company, LLC to recognize the provision of power under the Purchase Power Agreement and accordingly, reallocate certain components of general rates to Energy Cost Adjustment Clause rates without increasing total revenues, are approved.

5. Application 09-10-028 qualifies for an exemption from the California Environmental Quality Act and the Commission need not perform any further environmental review.

6. California Pacific Electric Company, LLC (CalPeco) shall file tariffs consistent with this Order no less than 15 days prior to the anticipated closing of the transfer from Sierra Pacific Power Company to CalPeco. The tariffs shall be effective upon the closing, subject to confirmation of compliance by the Director of the Commission's Energy Division or her designee.

7. Effective upon the closing of the transfer, the responsibilities of Sierra Pacific Power Company as a pubic utility in California shall terminate.

8. Sierra Pacific Power Company (Sierra) and California Pacific Electric Company, LLC (CalPeco) shall notify the Director of the Commission's Energy Division in writing of the transfer from Sierra to CalPeco within 30 days of the date of the transfer. A true copy of the instruments of transfer shall be attached to the notification.

9. The authority for the transfer from Sierra Pacific Power Company to California Pacific Electric Company, LLC shall expire if not exercised within one year from the effective date of this Order.

10. Application 10-04-032 is granted and Sierra Pacific Power Company (Sierra) may enter into the Fringe Agreement and the Reliability Support Agreement as requested in that application. During the period prior to the closing of the transfer from Sierra to California Pacific Electric Company, LLC (CalPeco), Sierra is authorized to account for the expenses it incurs and the revenues it receives to serve customers under the Fringe Agreement, pursuant to the terms therein. Upon closing, CalPeco is authorized to accept assignment of the Fringe Agreement from Sierra and to account for the expenses it incurs and the revenues it receives to serve customers under the Fringe Agreement, pursuant to the terms therein. CalPeco also may enter into the Reliability Support Agreement. The California Public Utilities Commission affirmatively

asserts jurisdiction over the Reliability Support Agreement and the local distribution facilities described therein.

11. Application (A.) 09-10-028 and A.10-04-032 are closed.

This order is effective today.

Dated October 14, 2010, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
TIMOTHY ALAN SIMON
NANCY E. RYAN
Commissioners

APPENDIX 1

LIST OF ABBREVIATIONS AND ACRONYMS

A.	Application
Algonquin	Algonquin Power Income Fund
CalAm	California American Water Company
CalPeco	California Pacific Electric Company, LLC
CEQA	California Environmental Quality Act
D.	Decision
DRA	Division of Ratepayer Advocates
ECAC	Energy Cost Adjustment Clause
Emera	Emera Incorporated
EPS	Emissions Performance Standard
Ex.	Exhibit
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
kWh	kilowatt hour
King's Beach facility	King's Beach Generating Station
Local 1245	International Brotherhood of Electrical Workers Local Union 1245
MidAmerican	MidAmerican Energy Holdings Company
MW	megawatt
NV Energy	NV Energy Inc.
O&M	Operations and Maintenance
PSREC	Plumas-Sierra Rural Electric Cooperative
RPS	Renewable Portfolio Standard
Sierra	Sierra Pacific Power Company
TDPUD	Truckee-Donner Public Utilities District
Valmy	Valmy Power Plant

(END OF APPENDIX 1)

ALJ/TIM/acr **Date of Issuance 6/12/2012**

Decision 12-06-005 June 7, 2012

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Joint Application of California Pacific Electric Company, LLC (U933E), Algonquin Power & Utilities Corp., Liberty Energy Utilities Co., Emera Incorporated, Emera US Holdings Inc., and California Pacific Utility Ventures, LLC for Expedited Approval of Indirect Transfer of Control of California Pacific Electric Company, LLC (U933E) Pursuant to California Public Utilities Code Section 854(a).	Application 11-09-012 (Filed September 14, 2011)

DECISION APPROVING SETTLEMENT AGREEMENT

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DECISION APPROVING SETTLEMENT AGREEMENT

1. Summary

This decision approves a settlement agreement between the Commission's Division of Ratepayer Advocates and the Joint Applicants consisting of California Pacific Electric Company, LLC (CalPeco), California Pacific Utility Ventures, LLC, Liberty Energy Utilities Co., Algonquin Power & Utilities Corp. (Algonquin), Emera US Holdings Inc., and Emera Incorporated (Emera).

The approved settlement agreement provides the Joint Applicants with authority under California Public Utilities Code Section 854(a) to revise the ownership structure for CalPeco, a regulated electric utility that serves much of the Lake Tahoe area. Currently, Algonquin holds a 50.001% indirect ownership interest in CalPeco, and Emera holds a 49.999% indirect ownership interest. Algonquin will acquire the 49.999% interest held by Emera, resulting in Algonquin having a 100% indirect ownership interest in CalPeco. The approved settlement agreement contains provisions that ensure the revised ownership structure will not harm CalPeco's regulated operations and customers.

2. Background

In Decision (D.) 10-10-017, the Commission approved the sale of Sierra Pacific Power Company's (Sierra) electric utility operations and facilities in California to California Pacific Electric Company, LLC (CalPeco). At the time, Sierra had 46,000 retail electric customers in California, mostly in the Lake Tahoe area. The sale was completed on January 1, 2011.

On September 14, 2011, the following parties jointly filed Application (A.) 11-09-012 for authority under California Public Utilities Code Section 854(a)[1] to revise the ownership structure for CalPeco: California Pacific Utility Ventures, LLC, Liberty Energy Utilities Co., Emera Incorporated, Emera US Holdings Inc., Algonquin Power & Utilities Corp., and CalPeco (together, the "Joint Applicants"). The Division of Ratepayer Advocates (DRA) filed a protest on October 24, 2011. There were no other protests or responses to the application. The Joint Applicants filed a reply on November 11, 2011.

A prehearing conference (PHC) was held on November 30, 2011. During the PHC, the Joint Applicants were instructed to submit two compliance filings containing specified information about the proposed transaction. The first compliance filing was submitted on December 9, 2011, and the second on December 16, 2011. The assigned Commissioner issued a scoping memo pursuant to Rule 7.3 of the Commission's Rules of Practice and Procedure (Rule) on December 23, 2011.

On December 16, 2011, DRA sent an e-mail to the service list in which DRA announced that it had reached a settlement agreement in principle with the Joint Applicants. DRA and the Joint Applicants held a properly noticed settlement conference on January 11, 2012, pursuant to Rule 12.1(b).

On April 5, DRA and the Joint Applicants filed an all-party motion for Commission approval of a settlement agreement pursuant to Rule 12.1(a) (the "Settlement Agreement"). The Settlement Agreement was attached to the

[1] The term "Section" hereafter means a statutory provision of the California Public Utilities Code unless otherwise stated.

motion. The motion explains why the settlement is reasonable in light of the record, consistent with the law, and in the public interest.

3. Description of the Joint Applicants

California Pacific Electric Company, LLC (CalPeco)

CalPeco is a California limited liability company and a regulated electric utility subject to the Commission's jurisdiction. CalPeco's service territory covers parts of following seven counties in the Lake Tahoe area: Alpine, El Dorado, Mono, Nevada, Plumas, Placer, and Sierra. CalPeco is a wholly owned by CPUV.

California Pacific Utility Ventures, LLC (CPUV)

CPUV is a California limited liability company. It is the sole owner and direct parent of CalPeco. CPUV is currently owned 50.001% by Liberty Energy Utilities Co. and 49.999% by Emera US Holdings, Inc.

Liberty Energy Utilities Co. (Liberty Energy)

Liberty Energy is a Delaware corporation that holds a 50.001% ownership interest in CPUV, the direct parent of CalPeco. Liberty Energy also owns several other small electric and natural gas utilities. Pursuant to previously announced agreements, Liberty Energy plans to acquire (1) Granite State Electric Company, an electric utility with 43,000 customers in New Hampshire; (2) EnergyNorth Natural Gas Inc., a natural gas utility with 83,000 customers in New Hampshire; and (3) the natural gas utility assets of Atmos Energy Corp. that serve 84,000 customers in Missouri, Iowa, and Illinois.

Algonquin Power & Utilities Corp. (Algonquin)

Algonquin is a Canadian corporation whose common shares are traded on the Toronto Stock Exchange. Through its operating subsidiaries, Algonquin owns renewable electric generation and utility businesses in North America.

Algonquin indirectly owns 50.001% of CalPeco through its wholly-owned subsidiary, Liberty Energy.[2]

Emera US Holdings Inc. (EUSHI)

EUSHI is a Delaware corporation that currently holds a 49.999% ownership interest in CPUV. EUSHI is a wholly-owned subsidiary of Emera Incorporated.

Emera Incorporated (Emera)

Emera is an energy holding company incorporated under the laws of the Province of Nova Scotia, Canada. Its common shares are traded on the Toronto Stock Exchange. Emera has approximately $6.6 billion of assets (Canadian). It owns electric utilities, natural gas utilities, and unregulated businesses involved in energy marketing and electric generation. Emera indirectly owns 49.999% of CalPeco through its wholly-owned subsidiary, EUSHI.

4. The Proposed Transaction

4.1. Summary of the Proposed Transaction

As described previously, CalPeco is wholly owned by CPUV. The owners of CPUV are Liberty Energy (50.001%) and EUSHI (49.999%). Liberty Energy is an indirect wholly-owned subsidiary of Algonquin. EUSHI is a direct wholly-owned subsidiary of Emera.

In A.11-09-012, the Joint Applicants request authority under Section 854(a) to revise the upstream ownership structure for CalPeco (the "Proposed Transaction"). Under the Proposed Transaction, Liberty Energy will acquire the

[2] Algonquin owns Liberty Energy through its wholly owned subsidiary, Liberty Utilities Co., which, in turn, owns 100% of Liberty Energy.

49.999% ownership interest in CPUV that is held by EUSHI, giving Liberty Energy 100% ownership of CPUV. This will change the ownership of CalPeco from Algonquin and Emera being essentially equal indirect owners, to Algonquin being the sole indirect owner of CalPeco. At the same time, Emera will increase its investment in Algonquin from 7.15% of the outstanding common shares to 14.05% of the outstanding common shares. The effect of the Proposed Transaction is that Emera will exchange its 49.999% indirect ownership interest in CalPeco for an additional 6.9% direct ownership interest in Algonquin. Corporate organization charts showing the current and post-transaction ownership structures for CalPeco are in Appendix 2 of today's decision.

4.2. Reasons for the Proposed Transaction

The joint acquisition of CalPeco was the first step in a strategic relationship between Algonquin and Emera. Following the closing of the CalPeco acquisition, Algonquin and Emera executed a Strategic Investment Agreement that outlines a joint-investment strategy whereby Algonquin will seek to acquire 100% indirect ownership of small electric and natural gas utilities. Emera may participate in these acquisitions through investment in Algonquin's common shares. This ownership structure for acquired small utilities capitalizes on Algonquin's expertise in operating small utilities and, at the same time, enables Algonquin and Emera to efficiently coordinate their investments.

In A.11-09-012, Algonquin and Emera seek to revise the current ownership structure for CalPeco to conform to the structure they are using in the Strategic Investment Agreement for the acquisition of other small utilities. Thus, consistent with Strategic Investment Agreement and upon the consummation of the Proposed Transaction, Algonquin will indirectly own 100% of CalPeco, and Emera will participate through investment in Algonquin's common shares.

4.3. Effect of the Proposed Transaction on CalPeco

The Joint Applicants aver that the Proposed Transaction will have no adverse effects on CalPeco's operations and customers. In particular, the Proposed Transaction will not affect any rates, terms, or conditions of utility service. CalPeco's customers will continue to receive the same electric service from the same facilities under the same tariffs. Customer service functions will continue unchanged, including billing, new connections, and responding to outages. CalPeco will employ the same personnel, and the roles and responsibilities of employees will not change.

The Joint Applicants state that they will continue to comply with the Regulatory Commitments that were adopted by D.10-10-017. The Regulatory Commitments require, among other things, that CalPeco's upstream owners provide access to sufficient capital for CalPeco's utility operations. In addition, the Joint Applicants will continue to comply with the requirement in Ordering Paragraph (OP) 1(c) of D.10-10-017 to provide their officers and employees to testify in California about matters pertinent to CalPeco, as the Commission may deem necessary, consistent with principles of due process and fairness.

4.4. The Compliance Filings

The Joint Applicants submitted two compliance filings in response to directives from the assigned Commissioner and the assigned Administrative Law Judge (ALJ). In the first Compliance Filing on December 9, 2011, the Joint Applicants submitted a declaration from a senior officer of each Joint Applicant. By these declarations, the Joint Applicants swear under oath that if the Commission approves the proposed change in the upstream ownership for CalPeco, the Joint Applicants will continue to comply with (1) the Regulatory

Commitments adopted by D.10-10-017, and (2) the requirement in OP 1(c) of D.10-10-017 to provide their officers and employees to testify in California regarding matters pertinent to CalPeco, as the Commission may determine to be necessary, consistent with established principles of due process and fairness.[3]

In the second Compliance Filing on December 16, 2011, the Joint Applicants provided the Subscription Agreement between Algonquin and Emera. The Subscription Agreement establishes the contractual terms and conditions by which EUSHI will transfer its 49.999% interest in CPUV to Liberty Energy, and Emera will acquire an additional equity stake in Algonquin.

5. Summary of DRA's Protest

In its protest, DRA expressed concern that the proposed change in the upstream ownership of CalPeco might vitiate the Regulatory Commitments that were adopted by the Commission in D.10-10-017.

6. The Settlement Agreement

The purpose of the Settlement Agreement is to resolve DRA's concern that the Proposed Transaction might undermine the ratepayer protections adopted by D.10-10-017. To resolve DRA's concern, the Settlement Agreement affirms that the ratepayer protections adopted by D.10-10-017 will remain in full force and effect with respect to each of the Joint Applicants following the Commission's approval of A.11-09-012. These ratepayer protections include the Regulatory Commitments in Appendix 3 of D.10-10-017, and the requirement in OP 1(c) of D.10-10-017 that the Joint Applicants will provide their officers and

[3] The Joint Applicants provided a draft of the declarations to DRA. DRA's feedback was incorporated into the declarations that were filed on December 9, 2011.

employees to testify in California about matters pertinent to CalPeco, as the Commission may determine to be necessary, consistent with established principles of due process and fairness. The Settlement Agreement extends OP 1(c) to include the "Additional Algonquin Entities[4]" that are not explicitly subject to OP 1(c).

DRA joins the Joint Applicants in requesting that the Commission approve A.11-09-012 and adopt the Settlement Agreement. A copy of the Settlement Agreement is attached to today's decision as Appendix 1.

7. Discussion

We will first review A.11-09-012 in the context of Section 854(a). We will then evaluate the Settlement Agreement using the criteria in Rule 12.1(d).

7.1. Section 854(a)

The Joint Applicants request authority under Section 854(a) to revise the upstream ownership structure for CalPeco whereby Emera will transfer its 49.999% indirect ownership interest in CalPeco to Algonquin, and Algonquin will increase its indirect ownership interest in CalPeco from 50.001% to 100%. Section 854(a) states, in relevant part, as follows:

[4] The Settlement Agreement defines the "Additional Algonquin Entities" as Liberties Utilities (Canada) Corp. (LUCC) and Liberty Utilities Co. (LUC). LUCC is a wholly owned subsidiary of Algonquin that, in turn, wholly owns LUC, a Delaware corporation that wholly owns Liberty Energy. The Additional Algonquin Entities are not included as applicants to A.11-09-012.

> No person or corporation . . . shall merge, acquire, or control either directly or indirectly any public utility organized and doing business in this state without first securing authorization to do so from the commission . . . . Any merger, acquisition, or control without prior authorization shall be void and of no effect.

The purpose of Section 854(a) is to enable the Commission to review a proposed transaction, before it takes place, so that the Commission can take such actions as the public interest may require.[5] In general, the Commission will approve a proposed transaction pursuant to Section 854(a) if the transaction does not harm ratepayers and is not otherwise adverse to the public interest.[6]

The record of this proceeding establishes that Algonquin is qualified to assume 100% indirect ownership of CalPeco. Algonquin has sufficient managerial and technical expertise to operate CalPeco, as demonstrated by its ownership of electric, natural gas, water, and sewer utilities in North America. Algonquin also has adequate financial resources to fulfill its Regulatory Commitments, discussed below, should that become necessary. In particular, Algonquin's financial statements show that it had total revenues of $183 million (Canadian) in 2010, and total assets and shareholder equity of $981 million and $349 million (Canadian), respectively, on December 31, 2010.[7] We are not aware of any issues since Algonquin acquired its current 50.001% indirect ownership in

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[5] Sections 854(b) and 854(c) apply only when a transacting utility has annual California revenues exceeding $500 million. As shown in Exhibit C of A.11-09-012, CalPeco's annual revenues are less than $100 million.

[6] D.10-10-017 at 60, Conclusion of Law 3, and D.09-08-017 at 7.

[7] A.11-09-012, Appendix F.

CalPeco pursuant to D.10-10-017 that indicate Algonquin should not be allowed to acquire 100% indirect ownership.

The record further establishes that the Proposed Transaction will have no adverse effects on CalPeco's regulated operations and customers. As set forth in A.11-09-012, there will be no changes to CalPeco's operations, personnel, revenue requirement, rates, or service from the Proposed Transaction. The Joint Applicants affirm that the Regulatory Commitments adopted by D.10-10-017 will remain in full force and effect. The Regulatory Commitments require, among other things, the following:

- The California utility CalPeco shall be held as a separate legal entity with no other operations. CalPeco shall hold all of its assets in its own name, and shall maintain adequate capital and number of employees in light of its business purposes.
- CalPeco shall not provide financing or guarantees for, extend credit to, or pledge utility assets in support of Algonquin, Emera, or their affiliates. Algonquin and Emera shall finance and fund their business activities independently of CalPeco, with no recourse to CalPeco's assets. The assets of CalPeco shall be used solely for the purpose of providing electric utility service to its customers and securing any debt obtained by CalPeco.
- CalPeco shall not transfer any physical assets used to provide utility services to Algonquin, Emera, or their affiliates without first obtaining the necessary approvals from the Commission and shall in no event transfer any physical assets if doing so would impair CalPeco's ability to fulfill its public utility obligations.
- Based on the understanding that the Commission will grant CalPeco timely recovery in rates for the reasonable costs it incurs to provide electric service, including a reasonable return on rate base, Emera and Algonquin shall

ensure that CalPeco maintains sufficient funds for operations and necessary capital investments.

- CalPeco shall maintain separate books and records, systems of accounts, financial statements, and bank accounts. All financial books and records will be kept in California and, together with records of any Emera and/or Algonquin affiliate that are relevant to CalPeco (wherever held), will be made available for review by the Commission upon request.

The complete set of Regulatory Commitments is contained in Appendix 3 of today's decision.

The Joint Applicants also affirm that OP 1(c) of D.10-10-017 will remain in full force and effect. OP 1(c) requires each Joint Applicant to provide its officers and employees to testify in California about matters pertinent to CalPeco, as the Commission may determine to be necessary, consistent with established principles of due process and fairness.

For the preceding reasons, we find the Proposed Transaction will not harm ratepayers or the public interest. Therefore, the Proposed Transaction satisfies the Commission's standard for approval under Section 854(a).

7.2. Rule 12.1(d)

Rule 12.1(d) provides that the Commission may approve a settlement agreement that is reasonable in light of the whole record, consistent with the law, and in the public interest. We address these criteria below.

7.2.1. Reasonable in Light of the Whole Record

The Settlement Agreement ensures that the ratepayer protections adopted by D.10-10-017 will remain in full force and effect if the Commission approves the Proposed Transaction, including the Regulatory Commitments in Appendix 3 of D.10-10-017 and the requirement in OP 1(c) of D.10-10-017 that the

Joint Applicants' officers and employees will testify in California, if necessary. The Settlement Agreement adds the new ratepayer protection that the Additional Algonquin Entities, who are not parties to A.11-09-012, will provide their officers and employees to testify in California about matters pertinent to CalPeco, as the Commission may determine to be necessary, consistent with established principles of due process and fairness.

Based on our review of the record of this proceeding, which includes A.11-09-012, DRA's protest and the Joint Applicants' reply, the written PHC statements and the PHC transcript, and the Joint Applicants' Compliance Filings, we find the Settlement Agreement is reasonable in light of the whole record.

7.2.2. Consistent with the Law

We find the Settlement Agreement is consistent with the law, including the California Public Utilities Code and Commission decisions, rules, and general orders. Of particular relevance here, the Settlement Agreement ensures that the ratepayer protections adopted by D.10-10-017 will remain in full force and effect with respect to the upstream owners of CalPeco, including Emera, notwithstanding Emera's transfer of its 49.999% indirect ownership interest in CalPeco to Algonquin in accordance with A.11-09-012.

7.2.3. In the Public Interest

The Commission has long favored the settlement of disputes. This policy supports many worthwhile goals, including reducing the expense of litigation, conserving scarce Commission resources, and allowing parties to reduce the risk that litigation will produce unacceptable results. The Settlement Agreement achieves these goals in a way that allows the Proposed Transaction to proceed with no adverse effects on CalPeco's regulated operations and customers. We conclude, therefore, that the Settlement Agreement is in the public interest.

7.3. Conclusion

For the reasons stated previously, we find the Proposed Transaction and the associated Settlement Agreement are reasonable in light of the whole record, consistent with the law, and in the public interest, and should be approved pursuant to Section 854(a) and Rule 12.1(d). In accordance with Rule 12.5, the approved Settlement Agreement is binding on the settling parties, but the settlement does not establish a precedent for any principle or issue.

8. California Environmental Quality Act

The California Environmental Quality Act (CEQA)[8] applies to any project that has a potential for resulting in a direct physical change in the environment or a reasonably foreseeable indirect physical change in the environment.[9] CEQA does not apply where "it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment."[10] The Commission is the lead agency under CEQA with respect to A.11-09-012.

A.11-09-012 does not request, and today's decision does not approve, any new construction, any changes to CalPeco's operations or facilities, or any other activities that could result in a direct physical change in the environment or a reasonably foreseeable indirect physical change in the environment. Consequently, our review and approval of A.11-09-012 and the associated Settlement Agreement is exempt from CEQA.

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8 CEQA is contained in Cal. Pub. Resource Code § 21000 et seq.

9 Cal. Pub. Res. Code § 21065 and 14 Cal. Code of Regulations, § 15378.

10 14 Cal. Code of Reg., § 15061(b)(3).

9. Categorization and Need for Hearing

In Resolution ALJ 176-3282 dated October 6, 2011, the Commission preliminary categorized this application as ratesetting and preliminarily determined that hearings were not necessary. These preliminary determinations were affirmed in the assigned Commissioner's scoping memo that was issued on December 23, 2011, pursuant to Rule 7.3.

10. Waiver of Comment Period

This is an uncontested matter in which the decision grants the relief requested. Accordingly, pursuant to Section 311(g)(2) of the Public Utilities Code and Rule 14.6(c)(2) of the Commission's Rules of Practice and Procedure, the otherwise applicable 30-day period for public review and comment is waived.

11. Assignment of the Proceeding

Catherine J. K. Sandoval is the assigned Commissioner and Timothy Kenney is the assigned ALJ for this proceeding.

Findings of Fact

1. The Proposed Transaction will not have any adverse effects on CalPeco's regulated operations or customers.

2. The Proposed Transaction and the associated Settlement Agreement will not result in a direct physical change in the environment or a reasonably foreseeable indirect physical change in the environment.

Conclusions of Law

1. The ratepayer protections adopted by D.10-10-017, including those protections in OP 1(c) of D.10-10-017 and the Regulatory Commitments in Appendix 3 of D.10-10-017, will remain in full force and effect if the Proposed Transaction and the Settlement Agreement are approved.

2. The Proposed Transaction is not adverse to the public interest and, therefore, should be approved pursuant to Section 854(a).

3. The Settlement Agreement should be approved pursuant to Rule 12.1(d) because it is reasonable in light of the whole record, consistent with the law, and in the public interest. The all-party motion for approval of the Settlement Agreement should be granted.

4. The Commission is the lead agency under CEQA for A.11-09-012.

5. A.11-09-012 and the associated Settlement Agreement are exempt from CEQA pursuant to 14 Cal. Code Regs., § 15061(b)(3).

6. The following order should be effective immediately so that the Proposed Transaction may be consummated expeditiously.

O R D E R

IT IS ORDERED that:

1. Application 11-09-012 is granted pursuant to California Public Utilities Code Section 854(a).

2. The attached Settlement Agreement between the Commission's Division of Ratepayer Advocates and the Joint Applicants is approved. The all-party motion for approval of the attached Settlement Agreement is granted.

3. The Joint Applicants shall comply with all provisions, terms, and conditions of the Settlement Agreement, including the following:

i. The Joint Applicants' duties and obligations under the Regulatory Commitments in Appendix 3 of Decision 10-10-017 shall remain in full force and effect, notwithstanding any changes made in the Upstream Ownership of California Pacific Electric Company, LLC, (CalPeco) resulting from Commission's approval of Application 11-09-012.

ii. The Joint Applicants and the Additional Algonquin Entities, as defined in Section 2.3 of the Settlement Agreement, shall provide their officers and employees to testify in California regarding matters pertinent to CalPeco, as the Commission itself may determine to be necessary, consistent with established principles of due process and fundamental fairness.

4. The ratepayer protections adopted by Decision (D.) 10-10-017 remain in full force and effect, including the protections in Ordering Paragraph 1(c) of D.10-10-017 and the Regulatory Commitments in Appendix 3 of D.10-10-017. The Regulatory Commitments are reproduced in Appendix 3 of today's decision.

5. Application 11-09-012 is closed.

This order is effective today.

Dated June 7, 2012, at San Francisco, California.

MICHAEL R. PEEVEY
President
TIMOTHY ALAN SIMON
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
MARK J. FERRON
Commissioners

APPENDIX 1: SETTLEMENT AGREEMENT

Note: The signatures of the Settling Parties are not included on the signature pages of the Settlement Agreement attached to today's decision. The signatures are included with the Settlement Agreement that was filed at the Commission's Docket Office, copies of which were served on the service list.

Note: The attached Settlement Agreement has non-substantive pagination and formatting changes that are not reflected in the copies of the Settlement Agreement that were filed and served.

Note: The attached Settlement Agreement does not include the Joint Applicants' First and Second Compliance Filings that were filed on December 9 and 16, 2011, respectively. These Compliance Filings are incorporated by reference into the Settlement Agreement as if fully stated therein, and are appended to the Settlement Agreement that was filed and served.

ALL-PARTY SETTLEMENT AGREEMENT

1. Introduction

1.1. In accordance with Rule 12.1, subdivision (a) of the California Public Utilities Commission (Commission) Rules of Practice and Procedure (Rule), the Settling Parties (as defined in section 2 below) enter into this settlement agreement (Settlement) for purposes of resolving this matter without having an evidentiary hearing.

1.2. The attached Motion states the factual and legal bases of the Settlement; advises the Commission of its scope; and presents the grounds on which Commission approval and adoption are urged.

1.3. As the Motion explains, the Settlement complies with Section 854, subdivision (a)[1] as well as Commission requirements for approval of settlements under Rule 12.1, subdivision (d), because it is reasonable in light of the whole record, consistent with the law, and in the public interest. Accordingly, the Settling Parties respectfully urge the Commission to adopt and approve this Settlement.

2. Definitions

2.1. The term "Settling Parties" means the "Joint Applicants" and the Division of Ratepayer Advocates (DRA).

2.2. The term "Joint Applicants" means the following:

2.2.1. Algonquin Power & Utilities Corp. (Algonquin), which is incorporated under the Canada Business Corporations Act;

2.2.2. Liberty Energy Utilities Co. (Liberty Energy Utilities), a Delaware corporation, which currently owns 50.001% of California Pacific Utility Ventures, LLC

[1] The term "Section" means a statutory provision of the California Public Utilities Code, unless otherwise indicated.

(CPUV) and will own 100% of CPUV if the Commission approves Application (A.) 11-09-012;

2.2.3. CPUV, a California limited liability company which wholly owns California Pacific Electric Company, LLC (CalPeco);

2.2.4. CalPeco, a California limited liability company;

2.2.5. Emera Incorporated (Emera), which is incorporated under the laws of the Province of Nova Scotia, Canada, and wholly owns Emera US Holdings Inc. (EUSHI); and

2.2.6. EUSHI, a Delaware corporation, which currently owns 49.999% of CPUV and will transfer its entire CPUV ownership to Liberty Energy Utilities if the Commission approves A.11-09-012.

2.3. The term "Additional Algonquin Entities" means the following:

2.3.1. Liberties Utilities (Canada) Corp. (LUCC), a wholly-owned subsidiary of Algonquin, which was formed under the Canada Business Corporations Act and wholly owns Liberty Utilities Co. (LUC); and

2.3.2. LUC, a Delaware corporation, which wholly owns Liberty Energy Utilities.[2]

2.4. The term "Upstream Owner" or "Upstream Ownership" means a business entity that has a direct or indirect ownership interest in CalPeco, as per Commission Decision (D.) 10-10-017, at Ordering Paragraph (O.P.) 1, subdivision (b) ("[A]ny change of ownership

[2] While A.11-09-012 at p. 6 n.7 mentions LUC's ownership of Liberty Energy Utilities, LUC's upstream owner, LUCC, was not referenced.

affecting CalPeco's upstream owners must be sought by application filed pursuant to Public Utilities Code Section 854."[3]).

2.5. The term "Regulatory Commitments" means those provisions that Ordering Paragraph (O.P.) 1 of Commission Decision (D.) 10-10-017 refers to as "the Regulatory Commitments attached to this Order as Appendix 3."[4]

3. Terms and Conditions

3.1. DRA was concerned that if approved, A.11-09-012's changes of upstream owners would "vitiate" the force and effect of the Regulatory Commitments that D.10-10-017 adopted for the protection of the ratepayers.[5] This Settlement ensures that those Regulatory Commitments remain binding on the Joint Applicants, even if A.11-09-012 were approved.

3.2. The Joint Applicants acknowledge and reaffirm that their duties and obligations under the Regulatory Commitments shall remain in full force and effect, notwithstanding any changes made in the Upstream Ownership of CalPeco resulting from Commission approval of A. 11-09-012.

3.3 In accordance with D.10-10-017, O.P. 1, subdivision (c), the Joint Applicants agree to provide their officers and employees to testify in California regarding matters pertinent to CalPeco, as the Commission, itself, may determine to be necessary, consistent with established principles of due process and fundamental fairness.

3.4. While the Additional Algonquin Entities are not included as applicants in A.11-09-012, Algonquin agrees for Settlement purposes to provide the officers and employees of the Additional Algonquin Entities to testify in California regarding matters pertinent to CalPeco, as the Commission, itself, may determine to

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[3] CalPeco, D.10-10-017, O.P. 1(b), at p. 63, available at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/124926.pdf/·

[4] Id., O.P. 1, at 62.

[5] See supra note 4, definition of the term "Regulatory Commitments."

be necessary, consistent with established principles of due process and fundamental fairness.

3.5. Attached to this Settlement are the Joint Applicants' First and Second Compliance Filings, which respectively were made on December 9 and 16, 2011, and consisted of their Declarations and a Subscription Agreement between Algonquin and Emera. Both the Declarations and Subscription Agreement are incorporated by reference as if fully stated herein.

3.6. Based on the Joint Applicants' acceptance of the Terms and Conditions herein, DRA enters into this Settlement to resolve this matter without having an evidentiary hearing, notwithstanding its Protest filed November 22, 2011. DRA joins the Joint Applicants in requesting that the Commission approve and adopt the Settlement, because it is reasonable in light of the whole record, consistent with the law, and in the public interest.

4. Other Terms and Conditions

4.1. **Commission's Primary Jurisdiction**. The Settling Parties agree that the Commission has primary jurisdiction over any interpretation, enforcement, or remedies regarding this Settlement. None of the Settling Parties may bring an action regarding this Settlement in any court of competent jurisdiction or another administrative agency without having first exhausted its administrative remedies at the Commission.

4.2. **Further Actions**. The Settling Parties acknowledge that this Settlement is subject to approval by the Commission. As soon as practicable after all the Settling Parties have signed the Settlement, the Settling Parties through their respective attorneys will prepare and file the Settling Parties' Motion for Commission Approval and Adoption of the Settlement Agreement. The Settling Parties will furnish such additional information, documents, or testimonies as the Commission may require for purposes of granting the Motion and approving and adopting the Settlement.

4.3. **No Personal Liability**. None of the Settling Parties, or their respective employees, attorneys, or any other individual representative or agent, assumes any personal liability as a result of the Joint Parties signing this Settlement.

4.4. **Non-Severability**. The provisions of this Settlement are non-severable. If any of the Settling Parties fails to perform its respective obligations under this Settlement, the Settlement will be regarded as rescinded. Further, if the Commission or any court of competent jurisdiction overrules or modifies as legally invalid any material provision of this Settlement, this Settlement will be deemed rescinded as of the date when such ruling, decision, or modification becomes final.

4.5. **Voluntary and Knowing Acceptance**. Each Settling Party hereto acknowledges and stipulates that it is agreeing to this Settlement freely, voluntarily, and without any fraud, duress, or undue influence by any other Settling Party. Each Settling Party has read and fully understands its rights, privileges, and duties under this Settlement, including its right to discuss this Settlement with its legal counsel, which has been exercised to the extent deemed necessary.

4.6. **No Modification.** This Settlement constitutes the entire Settlement among the Settling Parties regarding the matters set forth herein, which may not be altered, amended, or modified in any respect except in writing and with the express written and signed consent of all the Settling Parties hereto. All prior settlements, agreements, or other understandings, whether oral or in writing, regarding the matters set forth in this Settlement are expressly waived and have no further force or effect.

4.7. **No Reliance**. None of the Settling Parties has relied or presently relies on any statement, promise, or representation by any other Settling Party, whether oral or written, except as specifically set forth in this Settlement. Each Settling Party expressly assumes the risk of any mistake of law or fact made by such Settling Party or its authorized representative.

4.8. **Counterparts**. This Settlement may be executed in separate counterparts by the different Settling Parties hereto and all so executed will be binding and have the same effect as if all the Settling Parties had signed one and the same document. All such counterparts will be deemed to be an original and together constitute one and the same Settlement, notwithstanding that the signatures of all the Settling Parties and/or of a Settling Party's

attorney or other representative do not appear on the same page of this Settlement or the related Motion.

4.9. **Binding upon Full Execution.** This Settlement will become effective and binding on each of the Settling Parties as of the date when it is fully executed. It will also be binding upon each of the Settling Parties' respective successors, subsidiaries, affiliates, representatives, agents, officers, directors, employees, and personal representatives, whether past, present, or future.

4.10. **Commission Adoption Not Precedential**. In accordance with Rule 12.5, the Settling Parties agree and acknowledge that unless the Commission expressly provides otherwise, its adoption of this Settlement does not constitute approval of or precedent regarding any principle or issue of law or fact in this or any other current or future proceeding.

4.11. **Enforceability**. The Settling Parties agree and acknowledge that after issuance of a Commission Decision approving and adopting this Settlement, the Commission may reassert jurisdiction and reopen this proceeding to enforce the terms and conditions of this Settlement, including the Regulatory Commitments.

4.12. **Finality**. Once fully executed by the Settling Parties and adopted and approved by a Commission Decision, this Settlement fully and finally settles any and all disputes between the Joint Applicants and DRA in this proceeding, unless otherwise specifically provided in the Settlement.

4.13. **No Admission**. Nothing in this Settlement or related negotiations may be construed as an admission of any law or fact by any of the Settling Parties, or as precedential or binding on any of the Settling Parties in any other proceeding, whether before the Commission, in any court of competent jurisdiction, or in any other state or federal administrative agency. Further, unless expressly stated herein this Settlement does not constitute an acknowledgement, admission, or acceptance by any of the Settling Parties regarding any issue of law or fact in this matter, or the validity or invalidity of any particular method, theory, or principle of ratemaking or regulation in this or any other proceeding.

4.14. **Authority to Sign**. Each Settling Party who executes this Settlement represents and warrants to each other Settling Party that

the individual signing this Settlement and the related Motion has the legal authority to do so on behalf of the Settling Party.

4.15. **Future Admissibility**. Each Settling Party signing this Settlement agrees and acknowledges that this Settlement will be admissible in any subsequent Commission proceeding for the sole purpose of enforcing the Terms and Conditions of this Settlement.

4.16. **Estoppel or Waiver**. Unless expressly stated herein, the Settling Parties' execution of this Settlement is not intended to provide any of the Settling Parties in any manner a basis of estoppel or waiver in this or any other proceeding.

4.17. **Rescission.** If the Commission rejects or materially alters any provision of the Settlement, it will be deemed rescinded by the Settling Parties and of no legal effect as of the date of issuance of the Commission decision rejecting or materially altering the Settlement. The Settling Parties may negotiate in good faith regarding whether they want to accept the Commission changes and resubmit a revised Settlement.

5. Conclusion.

5.1. The Settling Parties have executed this Settlement as of the date appearing below each of their respective signatures.

[SIGNATURE PAGES FOLLOW NEXT]

ALGONQUIN POWER & UTILITIES CORP.

_____, Dated:_____
Ian E. Robertson, Chief Executive Officer

LIBERTY ENERGY UTILITIES CO.

_____, Dated:_____
Ian E. Robertson, President

CALIFORNIA PACIFIC UTILITY VENTURES, LLC

_____, Dated:_____
Ian E. Robertson, Designated Representative

CALIFORNIA PACIFIC ELECTRIC COMPANY, LLC

_____, Dated:_____
Michael R. Smart, President

EMERA INCORPORATED

_____, Dated:_____
Nancy G. Tower, Executive Vice President
of Business Development

EMERA US HOLDINGS INC.

_____, Dated:_____
Stephen Aftanas, Assistant Secretary

DIVISION OF RATEPAYER ADVOCATES

_____, Dated:_____
Joe Como, Acting Director

(END OF APPENDIX 1)

APPENDIX 2: CURRENT AND POST-TRANSACTION OWNERSHIP STRUCTURE

Current CalPeco Ownership Structure

Some Intermediate Holding Companies Not Shown

Post-Transaction CalPeco Ownership Structure

Some Intermediate Holding Companies Not Shown

(END OF APPENDIX 2)

APPENDIX 3: REGULATORY COMMITMENTS

The Following Regulatory Commitments Were Adopted by Decision 10-10-017 and Are Affirmed by Today's Decision

1. Separateness.

a. The California Utility[1] shall be held in a separate legal subsidiary (CalPeco) with no other operations. The only other California business activity currently undertaken by Algonquin Power & Utilities Corp. ("Algonquin") and/or by Emera Incorporated ("Emera") and/or their respective affiliates is a non-utility cogeneration power plant in the Fresno area ("Sanger Cogeneration"), which is owned and operated by Algonquin. Sanger Cogeneration sells power only at wholesale. It owns no electric distribution or transmission lines and it serves no retail electric customers. Sanger Cogeneration shall have no ownership or other interest in CalPeco. There shall be no overlapping of employees or responsibilities between the operations of Sanger Cogeneration and CalPeco.

b. Although each of Algonquin and Emera is an experienced owner/operator of regulated utilities and actively involved in developing and operating electric generating assets, including renewable generation sources, neither Algonquin nor Emera owns utility assets in the State of California subject to public utility regulation. In the event that either Algonquin or Emera were to acquire any other regulated utility in addition to CalPeco:

1. The assets of such other public utility would be held in a legal entity separate from CalPeco;

[1] Capitalized terms used in the Regulatory Commitments and not otherwise defined in the Regulatory Commitments have the meanings ascribed to such terms in the Joint Application [i.e., Applications 09-10-028 and 10-04-032].

2. Algonquin or Emera, as the case may be, would segregate the capitalization, financing, and working cash for such other utility and CalPeco in totally separate money pools;

3. There would be no cross ownership or other interests between such other utility and CalPeco; and

4. The operations of such other utility and CalPeco would be totally discrete.

c. CalPeco will not provide financing or guarantees for, extend credit to, or pledge utility assets in support of either Algonquin or Emera or any of their respective affiliates. Algonquin and Emera each shall finance and fund their respective other business activities independently of CalPeco. The assets of CalPeco shall be used solely and exclusively for the purpose of providing electric distribution services to its customers and securing any debt financing obtained by CalPeco.

d. To the extent that Algonquin or Emera shall finance its non-utility or any business activities other than CalPeco's provision of public utility service, any such financing shall provide the financing parties no recourse to CalPeco's assets.

e. CalPeco shall not alter the "ring fencing" provisions set forth in sections 1(a)-1(d) above without first requesting and obtaining approval from the Commission to make any such change.

f. CalPeco shall not transfer any physical assets used to provide services to its customers to either Algonquin or Emera or any of their respective affiliates without first obtaining the necessary approvals from the Commission and shall in no event request approval to transfer any physical assets if such transfer would impair CalPeco's ability to fulfill its public utility obligations to serve, or to operate in a prudent and efficient manner.

g. Emera and Algonquin will provide sufficient initial equity to fund fifty percent (50%) of the purchase price for CalPeco. CalPeco shall seek to obtain the balance of the required capital necessary for the purchase price through stand-alone debt issued by CalPeco. Algonquin and Emera are prepared to make this initial equity investment and invest any additional equity in CalPeco based on

their understanding that the Commission shall grant CalPeco timely recovery in rates (i) for the reasonable expenses it will make or undertake, respectively, to provide electric service; and (ii) for CalPeco to earn a reasonable return of and on CalPeco's investment in rate base. On this basis Emera and Algonquin are committed to ensure that CalPeco maintains sufficient funds to operate and has sufficient capital available for necessary capital investments. CalPeco, Algonquin and Emera acknowledge that dividends or similar distributions by CalPeco may be restricted as necessary to maintain minimum equity levels that are reasonable in relation to any equity ratio requirements.

h. CalPeco shall hold all of its assets in its own name, and will maintain adequate capital and number of employees in light of its business purposes. CalPeco shall maintain the current level of employees for a period of at least three (3) years.

2. Books and Records.

a. CalPeco shall maintain separate books and records, systems of accounts, financial statements and bank accounts and shall in all events maintain its books and records in full compliance with Commission, and to the extent applicable, FERC, rules and regulations. All financial books and records of CalPeco will be kept in the California operations office, and, together with any records of any Emera and/or Algonquin affiliate that are relevant to CalPeco (wherever held), will be made available for review by the Commission upon request. Algonquin and Emera will make available to the Commission upon request its books and records and the books and records of any of their respective affiliates that allocate overhead or have operational or financial dealings with CalPeco, including any Algonquin or Emera affiliate that is a recipient of any funds (including dividends or similar distributions) from CalPeco. Algonquin, Emera and CalPeco have reviewed the Commission's regulations and decisions on affiliate transactions and commit to comply fully with such rules and regulations.

b. Neither Algonquin nor Emera nor any of their respective affiliates conducts any other business within the geographic proximity of the California Utility. Accordingly, Algonquin and Emera (and their respective affiliates) do not anticipate that CalPeco and either

Algonquin and/or Emera (and/or their respective affiliates) will be providing any operations-related services to one another. It is, however, contemplated that Algonquin or Emera (or their respective affiliates) may provide management, administrative, and regulatory services to CalPeco with respect to the California Utility. In the event that Algonquin and/or Emera (and/or or their respective affiliates) provide services to CalPeco or CalPeco provides services to Algonquin and/or Emera (and/or their respective affiliates), CalPeco will develop and file with the Commission such shared services agreements and such agreements will comply with applicable affiliate rules and regulations of the Commission.

3. Operating Commitments.

a. Credit extended by Algonquin or Emera, jointly or individually, to CalPeco will be at rates and upon terms no less advantageous than those otherwise available to CalPeco from unaffiliated third parties for similar transactions.

b. CalPeco will conduct business in the same or similar manner as it has under Sierra's ownership concerning functions such as power delivery, contracting and management, system operation and maintenance activities, safety and service reliability, customer service functions, and billing operations. With respect to regulatory relations, CalPeco will maintain a manager level representative (having such authority as may be required by the Commission) physically present in an office located within the California Utility's service territory with primary responsibility for maintaining Sierra's positive relationships with, and responding to requests for information from, the Commission and other regulatory agencies. CalPeco will also engage competent and respected area consultants such as the Davis Wright Tremaine law firm to provide CalPeco with San Francisco-based support and presence with respect to the maintenance of such positive relationship.

c. For an initial period extending through the filing of the next general rate case for the California Utility, CalPeco will maintain and accept all tariffs of the California Utility existing at the Closing or approved by the Commission in response to filings made by Sierra prior to the Closing and as requested to be modified in this proceeding with

respect to (i) the reallocation of certain amounts of revenue recovery from general rate to ECAC rate recovery and (ii) the ECAC tariff as explained and requested at pages 30-37 of the Joint Application (but shall not be required to accept a reduction or roll-back in such rates pursuant to the Required Regulatory Approvals).[2] In this § 854(a) proceeding, CalPeco is requesting no increase in rates or in the total revenue requirement; on the day after Closing, rates for the customers of the California Utility shall remain at the same rate levels as the day prior to Closing and the total revenue requirement shall remain the same.

d. CalPeco shall provide service to its customers in compliance with all rules, regulations and decisions issued by the Commission. Among other matters, CalPeco will not change any rate or any other terms and conditions of service for its customers without first having obtained the necessary Commission approvals and CalPeco shall comply with all existing statutes and Commission regulations regarding affiliated interest transactions.

e. CalPeco agrees to maintain the existing low-income programs as part of the pending request under § 854(a) to acquire the California Utility. CalPeco shall operate within the existing rate case cycles now in effect for Sierra, including for general rates and ECAC rates.

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[2] References to "Joint Application" herein are to the Joint Application of Sierra Pacific Power Company (U903E) and California Pacific Electric Company, LLC for Transfer of Control and Additional Requests Relating to Proposed Transaction filed with the Commission on October 16, 2009, as updated and supplemented by Joint Applicants' letters to Administrative Law Judge Vieth dated April 7, 2010, June 11, 2010, and June 16, 2010. (A.09-10-028 and A.10-04-032.)

f. CalPeco and Sierra have entered into a settlement agreement with the Plumas-Sierra Rural Electric Cooperative ("PSREC"), City of Loyalton, City of Portola, Sierra County and Plumas County ("PSREC Settlement"). The PSREC Settlement is Exhibit Q to Exhibit 1 to the proceeding. The PSREC Settlement obligates Sierra and CalPeco to make certain payments to PSREC at specified times and subject to certain conditions. Among these is a payment of $250,000 to be made to PSREC within fifteen days of Closing. Under the terms of the PSREC Settlement, in the event that the Commission were to ultimately approve CalPeco making an $1 million investment in the Herlong Transmission Project (as defined in the PSREC Settlement) and to authorize CalPeco to recover rates on this investment, PSREC has agreed that it will credit the $250,000 payment as an advance payment against CalPeco's $1 million investment. CalPeco and Sierra commit that if CalPeco never requests authority to make an investment in the PSREC Herlong Transmission Project or if CalPeco requests Commission authorization to invest in the Herlong Transmission Project and the Commission rejects such request in its entirety, that CalPeco and Sierra will retain 100% of the cost responsibility for the $250,000 payment to PSREC (i.e., customers will be held harmless).

g. CalPeco shall adopt, maintain and strive to improve the high quality of service standards that Sierra presently provides its customers.

h. Algonquin shall own at least fifty percent (50%) of CalPeco for a minimum period of ten (10) years.

i. CalPeco has requested that the Commission approve that either Algonquin or Emera be allowed to transfer to the other all or any portion of its ownership interest in CalPeco and without the need for any additional approval by the Commission ("Internal Transfer Approval"). The Internal Transfer Approval is described at page 70 and 71 of the Joint Application. In the event that the Commission were to grant the request for the Internal Transfer Approval, Emera and Algonquin will also commit to the following additional terms and conditions:

   1. Any reduction in the dollar amount of Emera's direct investment in CalPeco will be made up by an increase in a

corresponding dollar amount of Emera's investment in Algonquin;

2. Emera shall maintain its investment in Algonquin for a minimum period of three (3) years;

3. Should Emera use the Internal Transfer Approval process to sell down all or any portion of its direct ownership in CalPeco, Emera nonetheless through its ownership in Algonquin would continue to be active in the oversight of CalPeco in a manner designed to enable CalPeco to continue to realize the benefits of Emera's financial and operating strengths and resources and in developing renewable projects; and

4. Regardless of the authority that the Commission grants with respect to the Internal Transfer Approval with respect to changes of ownership interests in CalPeco between Algonquin and Emera, in no event shall Algonquin reduce for a minimum period of ten (10) years its ownership interest in CalPeco below the fifty percent (50%) interest committed to in Section 3(h) above.

4. Employees and Management Team.

a. CalPeco intends to the extent practicable to retain the same experienced operations team that has been responsible for operations of the California Utility under Sierra's ownership. Any additional management team members which need to be recruited by CalPeco shall be experienced in electric utility operations.

b. CalPeco intends to maintain a local headquarters within the California Utility's service territory, including maintaining a local management and customer service headquarters at a location within such service territory.

c. CalPeco intends to offer each of Sierra's current administration and operations employees located within the service territory employment with CalPeco at the same locations with responsibilities and remuneration consistent with each of their existing roles. Accordingly, CalPeco shall make no material changes in the nature of the employment roles of the California Utility fulfilled by individuals located within the service territory

and intends, to the extent practical, to recruit within the California Utility service territory any additional operations staff necessary to replace functions currently performed by staff of Sierra located in Nevada. CalPeco will recognize the service and seniority of the former employees of Sierra who accept CalPeco's offer of employment for all non-pension purposes including vacation, sick pay benefits and for non-pension post retirement benefits such as retiree health benefits.

5. Premium and Cost Synergies.

a. CalPeco agrees that its rate recovery shall be calculated based on the regulatory value of the California Utility, as depreciated by Sierra, and totally independent of the purchase price to acquire the California Utility. CalPeco shall in no event seek to recover the excess of the purchase price over the regulatory book value of the utility assets (i.e., "premium") in rates. Any premium which CalPeco shall pay shall not be recorded in the accounts of CalPeco utilized in the establishment of rates and tariffs for the California Utility.

b. The cost levels CalPeco shall use to request rates in future general rate cases shall be based on the actual recorded cost levels of CalPeco and will incorporate any cost savings synergies arising in comparison to the baseline costs established in Sierra's 2008 rate case with respect to the California Utility.

c. CalPeco shall not seek to recover from ratepayers the "transaction costs" (e.g. investment banking and legal fees, and perimeter metering costs) associated with its acquisition of the California Utility. CalPeco recognizes that its incurrence of any such "transaction costs" is not related to the provision of electric service to the ratepayers of the California Utility and thus these costs are necessarily to be borne exclusively by its owners.

6. California Regulatory Programs.

a. Subject to the exemptions which are to be sought pursuant to the Required Regulatory Approvals as set out in the Power Purchase Agreement, CalPeco shall reaffirm Sierra's commitment to comply fully with the California RPS standards, the Commission's GHG Emissions Performance Standard, and the compliance requirements for operators of generating units imposed by the Commission's General Order 167.

(END OF APPENDIX 3)

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

SOAH DOCKET NO. 582-07-0804
TCEQ DOCKET NO. 2006-1431-UCR

APPLICATIONS BY ALGONQUIN WATER RESOURCES OF TEXAS, LLC, TO PURCHASE AND TRANSFER A PORTION OF CERTFICIATE OF CONVENIENCE AND NECESSITY (CCN) NO. 11072 FROM SILVERLEAF RESORTS, INC. AND OBTAIN WATER CCN NO. 13131 IN COMAL, MONTGOMERY, SMITH AND WOOD COUNTIES; AND TO PURCHASE AND TRANSFER ALL OF CCN NO. 20815 FROM SILVERLEAF RESORTS, INC. IN COMAL, MONTGOMERY, SMITH AND WOOD COUNTIES; APPLICATIONS NOS. 35017-S; 35018-S	§	**BEFORE THE TEXAS COMMISSION** **ON** **ENVIRONMENTAL QUALITY**

ORDER

An application by Algonquin Water Resources of Texas, LLC (Algonquin), was presented to the Executive Director of the Texas Commission on Environmental Quality (Commission) on July 12, 2005 for review pursuant to Section 5.122 of the Texas Water Code and Commission rules. The application sought to purchase and transfer a portion of Certificate of Convenience and Necessity (CCN) No. 11072 (water) and all of CCN No. 20815 (sewer) from Silverleaf Resorts, Inc., and to obtain Water CCN No. 13131 in Comal, Montgomery, Smith and Wood Counties pursuant to Section 13.301 of the Code. The petition was accepted for filing and assigned application Nos. 35017-S and 35018-S. Algonquin provides sewer service in Smith County, Texas and is a public utility as defined in Section 13.002(23) of Code.

Notice was provided to the customers of the transferor and transferee and other affected parties on July 5, 2006, by Algonquin. The notice of the application complied with the notice requirements of 30 Texas Administrative Code (TAC) Section 291.112(c) and was sufficient to place affected persons on notice regarding the transfer of service.

TCEQ received two letters of protest requesting a contested case hearing under Section 13.301 of the Code. Pursuant to Section 13.301(e), the Executive Director determined that a hearing should be held on this matter and referred it to the State Office of Administrative Hearings (SOAH) for a contested-case hearing.

Catherine Egan, an administrative law judge of the SOAH, convened a preliminary hearing on January 30, 2007. Present were the following parties: Algonquin Water Resources of Texas, LLC, represented by Mark Zeppa; the Executive Director of the TCEQ, represented by Gabriel Soto. Also present were the following hearing requestors: Ronald Robertson, manager of Fouke Water Supply Corporation, and Robbie Arrington, manager of Pritchett Water Supply Corporation.

All of those present at the preliminary hearing announced that they had reached an agreement that settled all issues in controversy, and the matter was remanded to the Commission for approval by the Executive Director on February 6, 2007.

The Commission finds that Algonquin is capable of rendering adequate and continuous water and sewer utility service to every customer within the areas proposed to be added to Algonquin's service area and the certification of Algonquin is necessary for the service, accommodation, convenience, or safety of the public.

NOW, THEREFORE, BE IT ORDERED BY THE TEXAS COMMISSION ON ENVIRONMENTAL QUALITY that:

The applications by Algonquin Water Resources of Texas, LLC to purchase a portion of the utility service areas covered by CCN Nos. 11072 and all of 20815, and to transfer those areas to Algonquin in Comal, Montgomery, Smith and Wood Counties, Texas, as reflected in the attached copy of the official water and sewer CCN maps of Comal, Montgomery, Smith and Wood Counties, is hereby approved.

The Chief Clerk of the Texas Commission on Environmental Quality shall forward a copy of this Order to all parties and issue Certificate of Convenience and Necessity Nos. 13131 (water) and 20815 (sewer) to Algonquin Water Resources of Texas, LLC.

If any provision, sentence, clause, or phrase of this Order is for any reason held to be invalid, the invalidity of any portion shall not affect the validity of the remaining portions of the Order.

Issue Date: FEB 13 2008

TEXAS COMMISSION ON
ENVIRONMENTAL QUALITY

For the Commission

Texas Commission On Environmental Quality

By These Presents Be It Known To All That

Algonquin Water Resources of Texas, LLC

having duly applied for certification to provide water utility service for the convenience and necessity of the public, and it having been determined by this commission that the public convenience and necessity would in fact be advanced by the provision of such service by this Applicant, is entitled to and is hereby granted this

Certificate of Convenience and Necessity No. 13131

to provide continuous and adequate water utility service to that service area or those service areas in Comal, Montgomery, Smith and Wood Counties as by final Order or Orders duly entered by this Commission, which Order or Orders resulting from Application No. 35017-S are on file at the Commission offices in Austin, Texas; and are matters of official record available for public inspection; and be it known further that these presents do evidence the authority and the duty of Algonquin Water Resources of Texas, LLC to provide such utility service in accordance with the laws of this State and Rules of this Commission, subject only to any power and responsibility of this Commission to revoke or amend this Certificate in whole or in part upon a subsequent showing that the public convenience and necessity would be better served thereby.

Issued at Austin, Texas, this FEB 13 2008

For the Commission

Texas Commission On Environmental Quality

By These Presents Be It Known To All That

Algonquin Water Resources of Texas, LLC

having duly applied for certification to provide sewer utility service for the convenience and necessity of the public, and it having been determined by this commission that the public convenience and necessity would in fact be advanced by the provision of such service by this Applicant, is entitled to and is hereby granted this

Certificate of Convenience and Necessity No. 20815

to provide continuous and adequate sewer utility service to that service area or those service areas in Comal, Montgomery, Smith and Wood Counties as by final Order or Orders duly entered by this Commission, which Order or Orders resulting from Application No. 35018-S are on file at the Commission offices in Austin, Texas; and are matters of official record available for public inspection; and be it known further that these presents do evidence the authority and the duty of Algonquin Water Resources of Texas, LLC to provide such utility service in accordance with the laws of this State and Rules of this Commission, subject only to any power and responsibility of this Commission to revoke or amend this Certificate in whole or in part upon a subsequent showing that the public convenience and necessity would be better served thereby.

Issued at Austin, Texas, this FEB 13 2008

For the Commission

TRANSFER OF
CERTIFICATE OF CONVENIENCE AND NECESSITY

To Provide Sewer Service Under V.T.C.A., Water Code
and Texas Commission on Environmental Quality Substantive Rules

Certificate No. 20815

Certificate No. 20815 was transferred by Order of the Commission in Docket No. 35018-S. Silverleaf Resorts, Inc.'s facilities and lines were transferred to Algonquin Water Resources of Texas, LLC (CCN No. 20818) in Comal, Montgomery, Smith and Wood Counties.

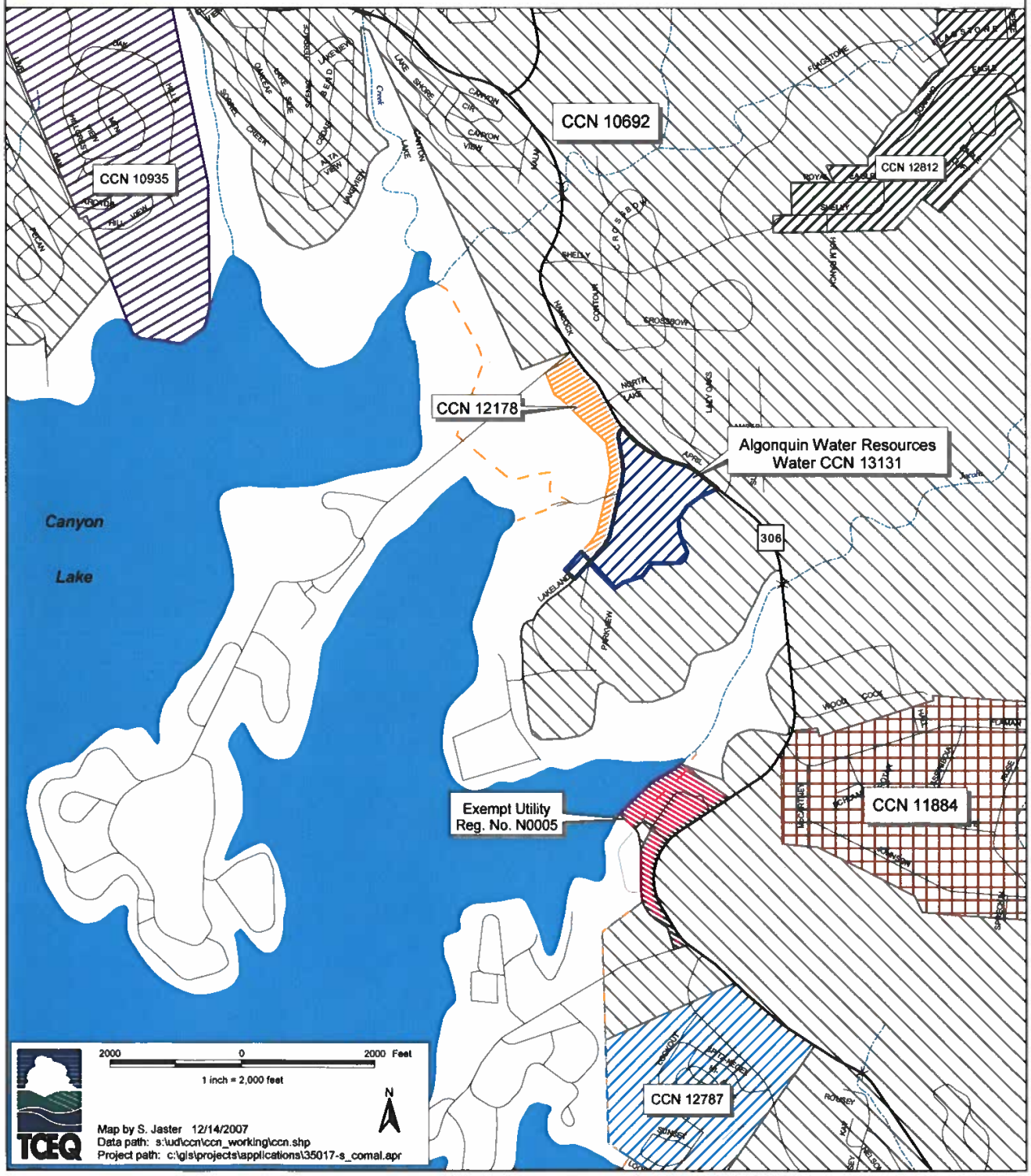
Please reference Certificate No. 20815 for the location of maps and other information related to the service area transferred.

Certificate of Convenience and Necessity No. 20815 is hereby TRANSFERRED by order of the Texas Commission on Environmental Quality.

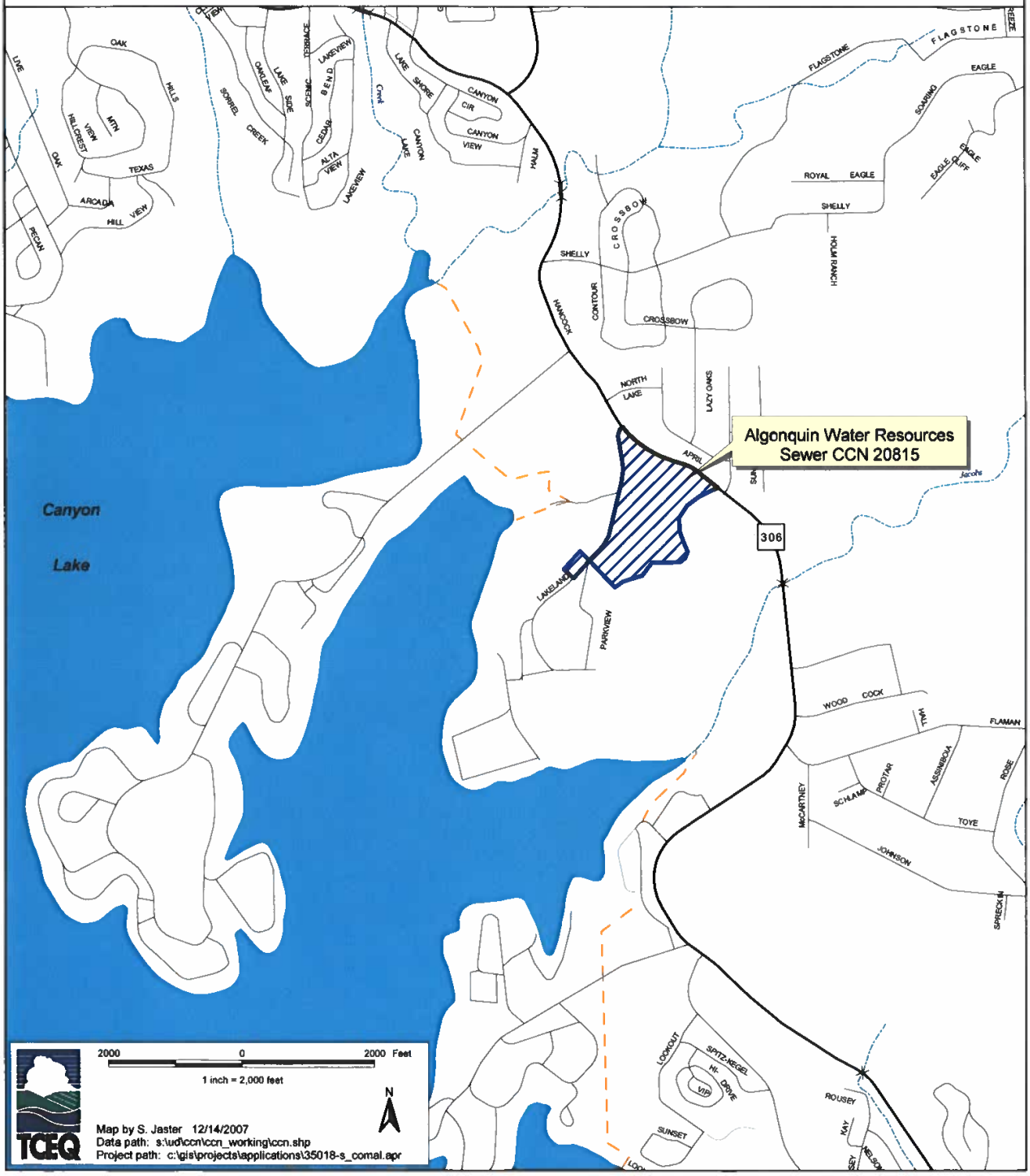
Issued Date: FEB 13 2008

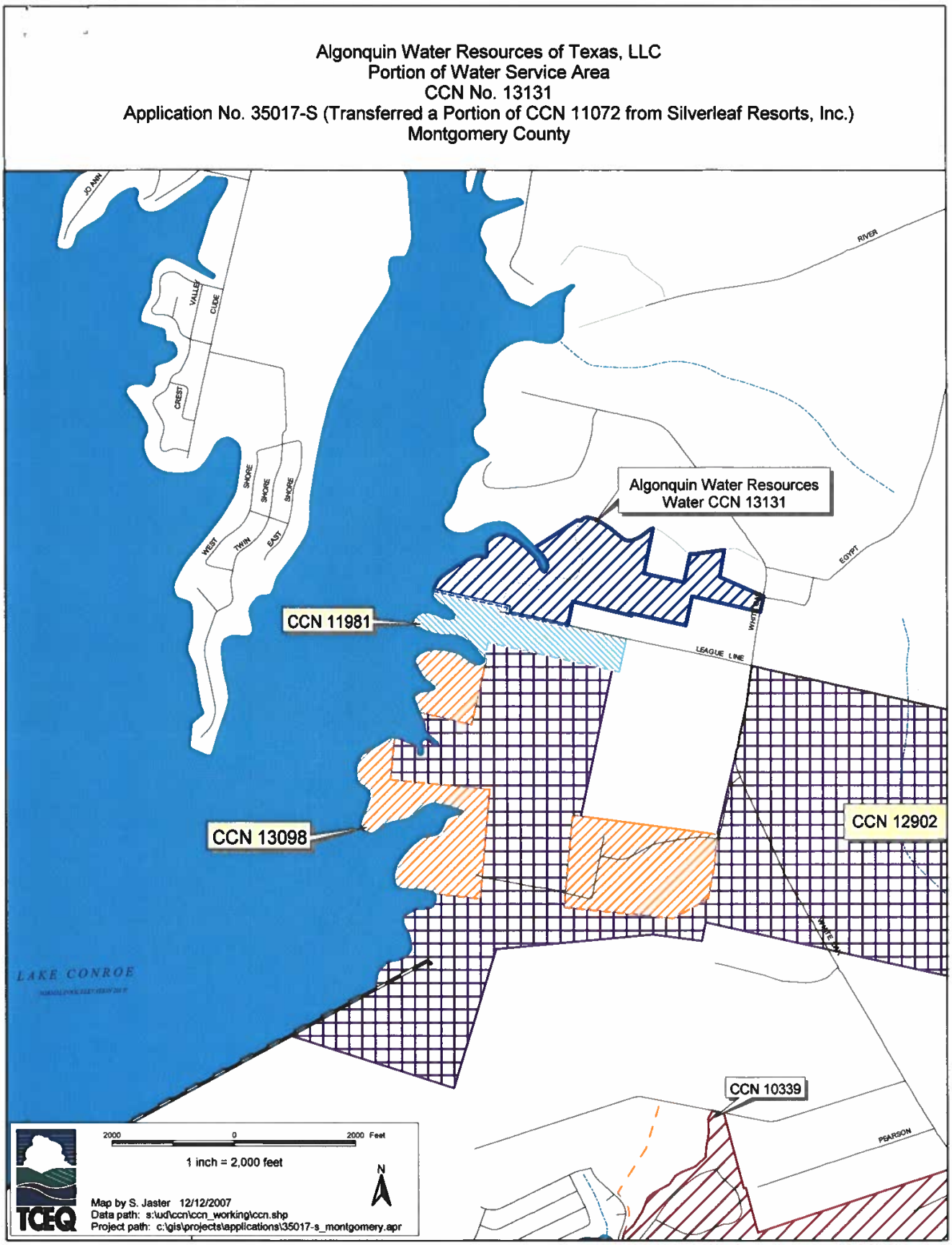
For the Commission

Algonquin Water Resources of Texas, LLC
Portion of Water Service Area
CCN No. 13131
Application No. 35017-S (Transferred a Portion of CCN 11072 from Silverleaf Resorts, Inc.)
Comal County



Algonquin Water Resources of Texas, LLC
Portion of Sewer Service Area
CCN No. 20815
Application No. 35018-S (Transferred CCN 20815 from Silverleaf Resorts, Inc.)
Comal County




Algonquin Water Resources of Texas, LLC
Portion of Water Service Area
CCN No. 13131
Application No. 35017-S (Transferred a Portion of CCN 11072 from Silverleaf Resorts, Inc.)
Montgomery County
Algonquin Water Resources
Water CCN 13131
CCN 11981
CCN 13098
CCN 12902
CCN 10339
LAKE CONROE
JO ANN
VALLEY
CLOE
CREST
SHORE
SHORE
SHORE
WEST
TWIN
EAST
RIVER
EGYPT
LEAGUE LINE
PEARSON
2000
0
2000 Feet
1 inch = 2,000 feet
N
TCEQ
Map by S. Jaster 12/12/2007
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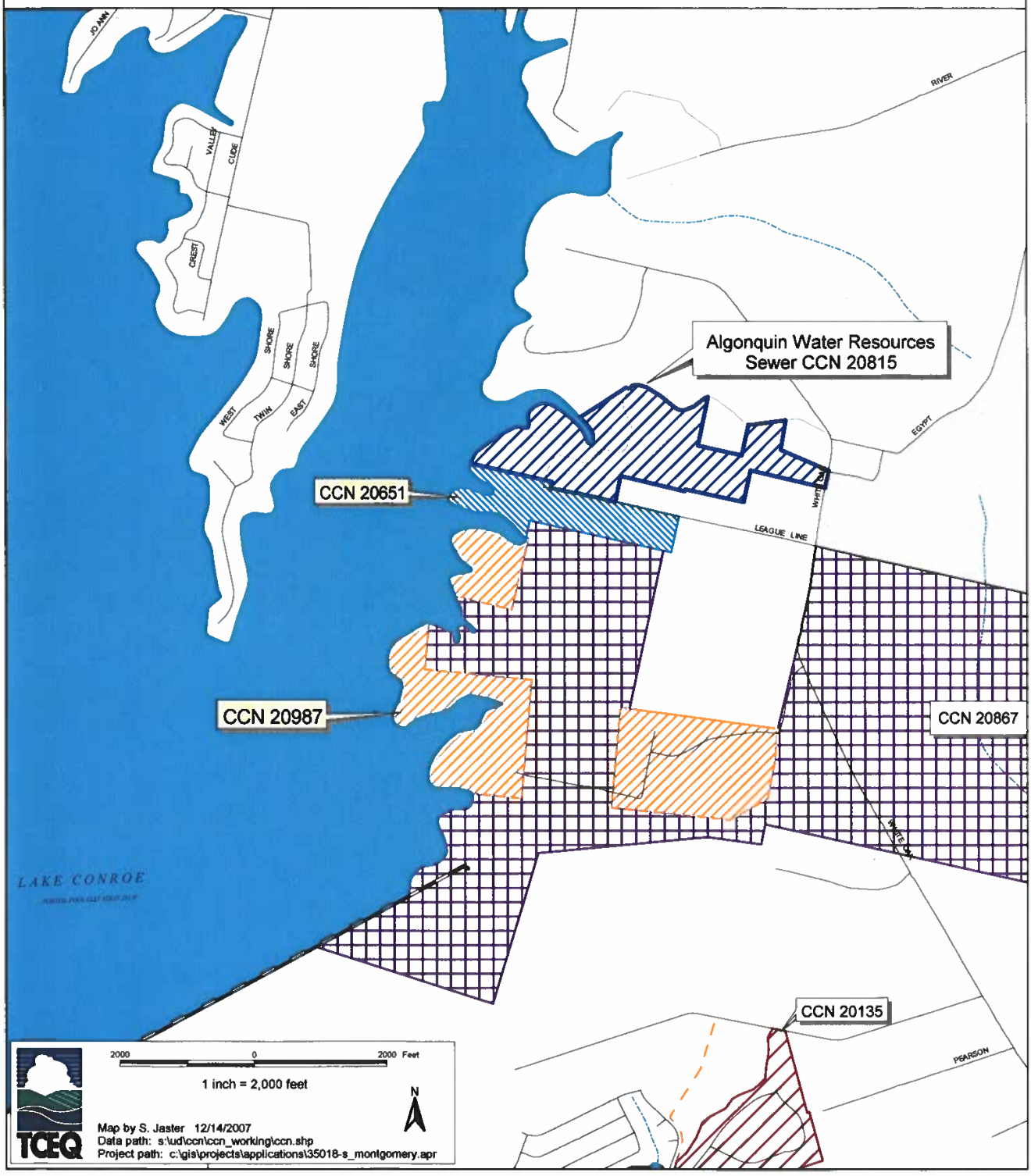
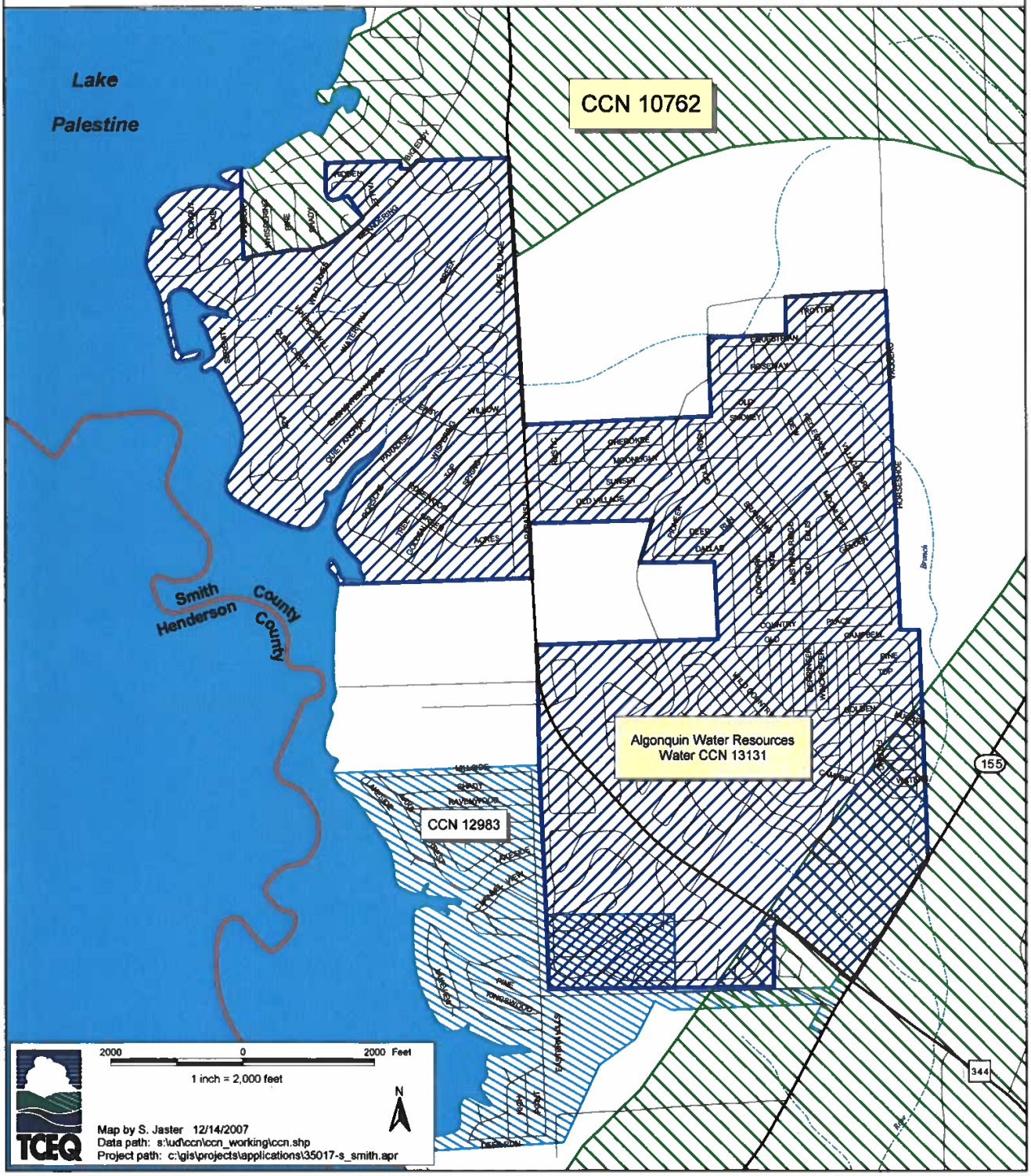
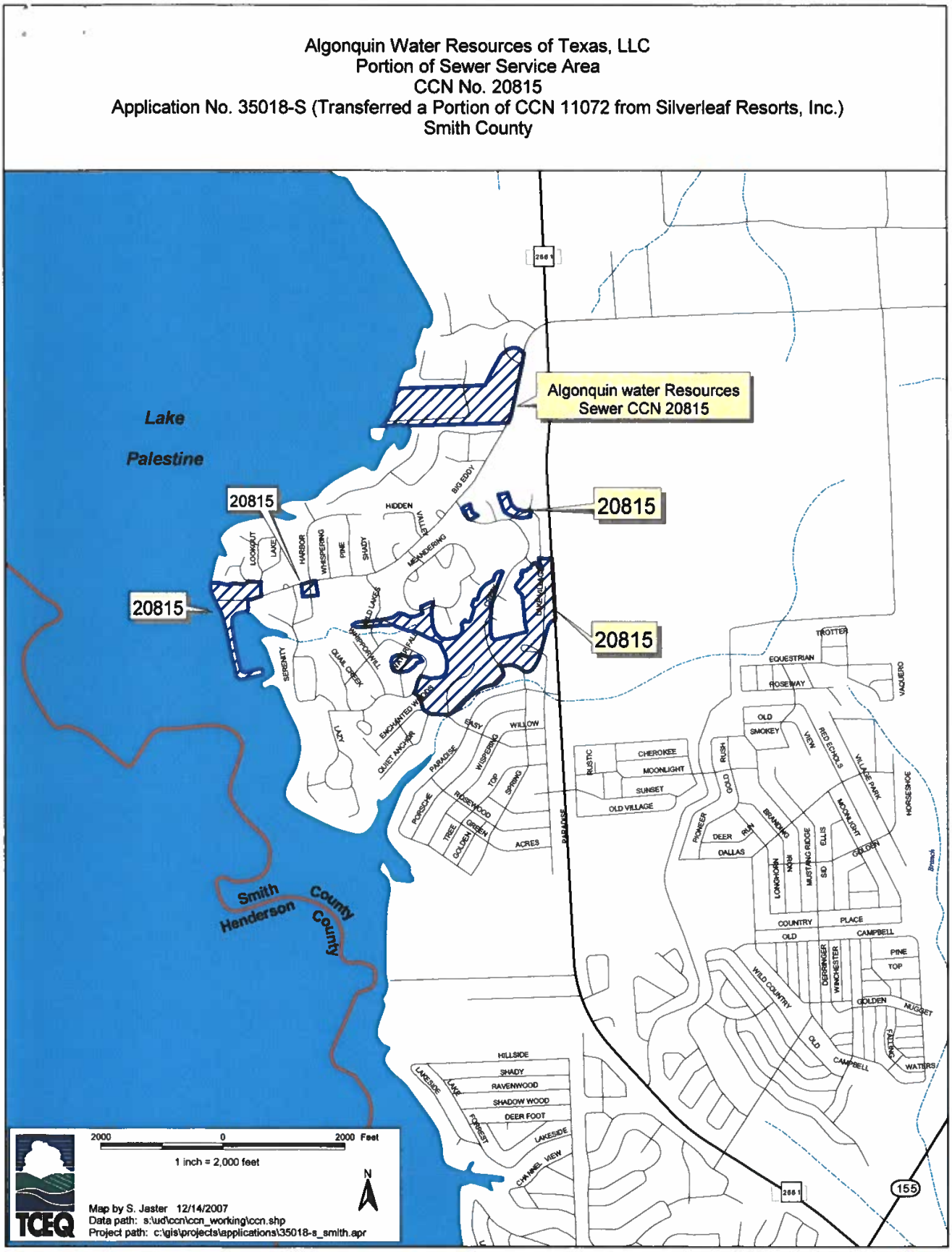
Algonquin Water Resources of Texas, LLC
Portion of Sewer Service Area
CCN No. 20815
Application No. 35018-S (Transferred CCN 20815 from Silverleaf Resorts, Inc.)
Montgomery County



Algonquin Water Resources of Texas, LLC
Portion of Water Service Area
CCN No. 13131
Application No. 35017-S (Transferred a Portion of CCN 11072 from Silverleaf Resorts, Inc.)
Smith County




Algonquin Water Resources of Texas, LLC
Portion of Sewer Service Area
CCN No. 20815
Application No. 35018-S (Transferred a Portion of CCN 11072 from Silverleaf Resorts, Inc.)
Smith County
Algonquin water Resources
Sewer CCN 20815
20815
20815
20815
20815
Lake
Palestine
Smith County
Henderson County
2000 0 2000 Feet
1 inch = 2,000 feet
N
Map by S. Jaster 12/14/2007
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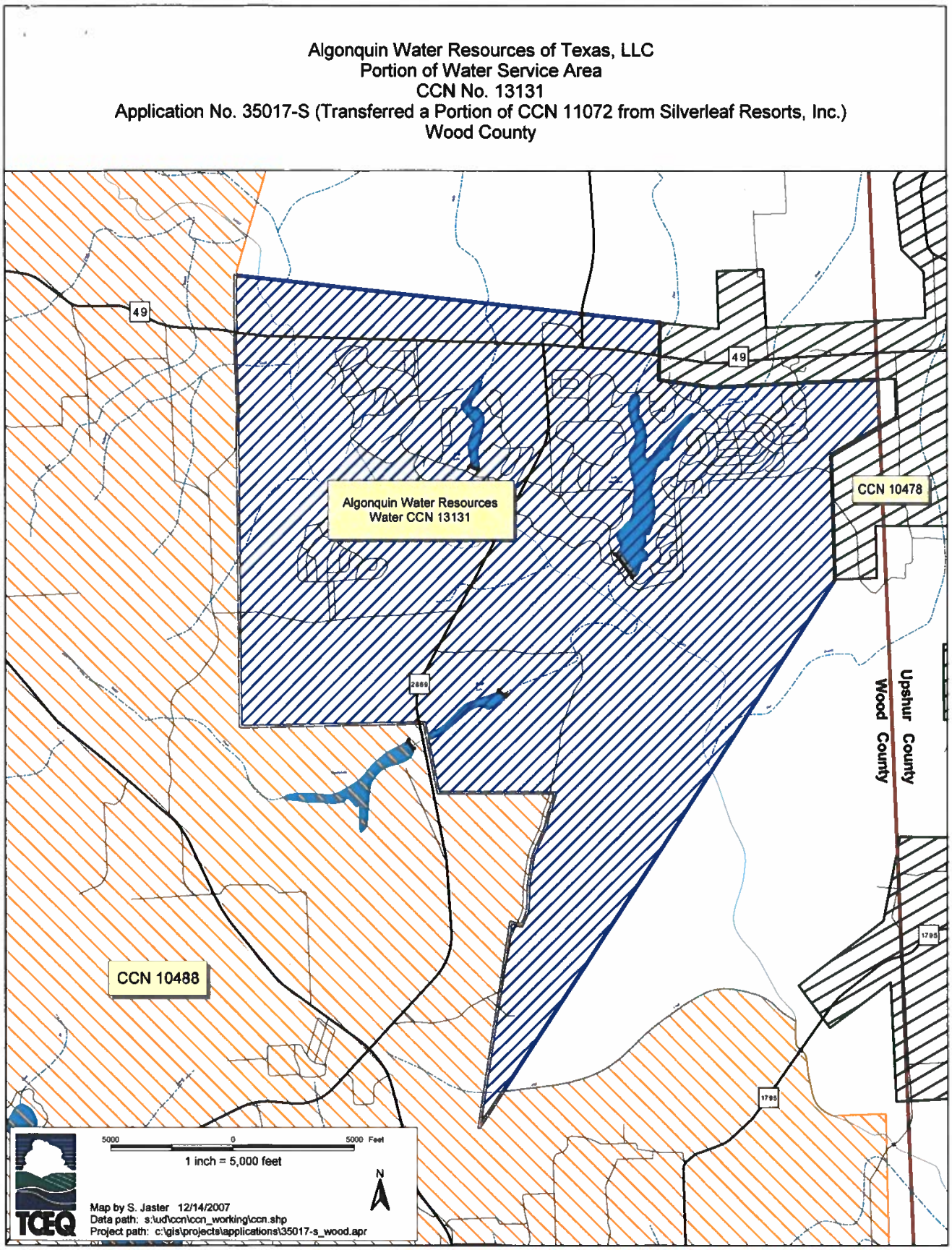
TCEQ
155


Algonquin Water Resources of Texas, LLC
Portion of Water Service Area
CCN No. 13131
Application No. 35017-S (Transferred a Portion of CCN 11072 from Silverleaf Resorts, Inc.)
Wood County
49
49
Algonquin Water Resources
Water CCN 13131
CCN 10478
2869
Upshur County
Wood County
1795
1795
CCN 10488
5000
0
5000 Feet
1 inch = 5,000 feet
N
TCEQ
Map by S. Jaster 12/14/2007
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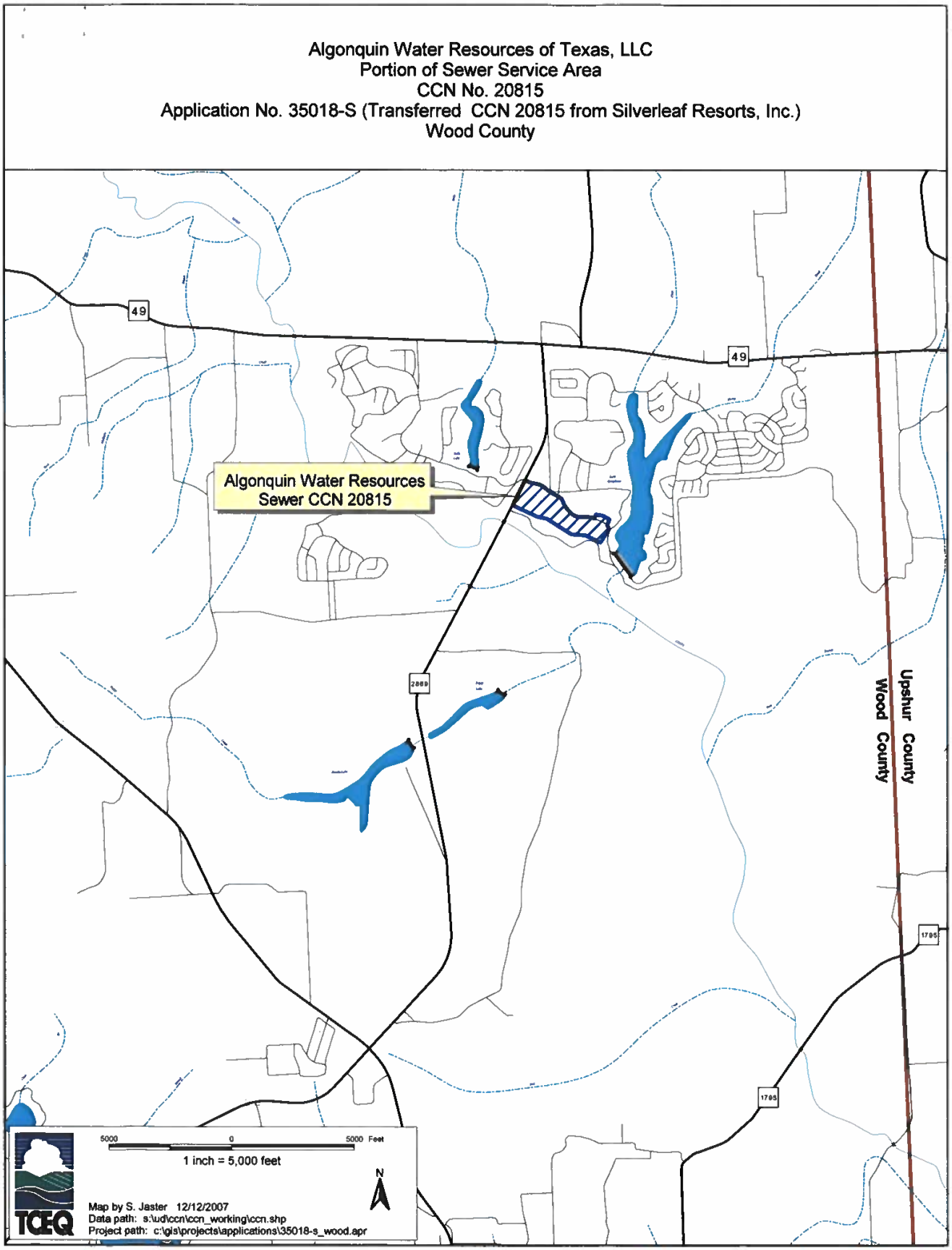
Algonquin Water Resources of Texas, LLC
Portion of Sewer Service Area
CCN No. 20815
Application No. 35018-S (Transferred CCN 20815 from Silverleaf Resorts, Inc.)
Wood County
Algonquin Water Resources
Sewer CCN 20815
49
49
2869
Upshur County
Wood County
1795
1795
5000 0 5000 Feet
1 inch = 5,000 feet
N
TCEQ
Map by S. Jaster 12/12/2007
Data path: s:\ud\ccn\ccn_working\ccn.shp
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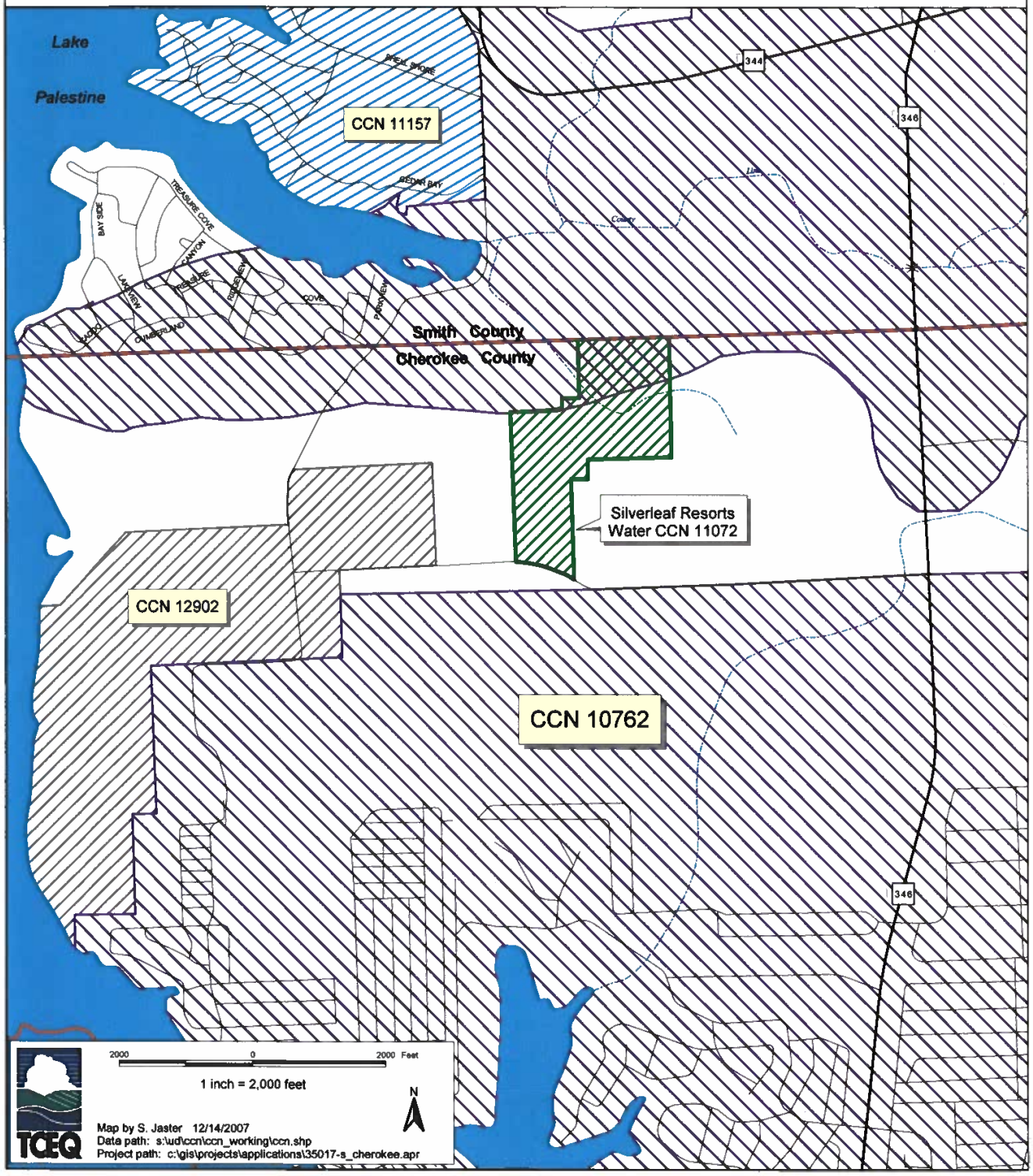
Sliverleaf Resorts, Inc.
Water Service Area
CCN No. 11072
Application No. 35017-S (Algonquin Water Resources of Texas, LLC, CCN No. 13131
Transferred a Portion of CCN 11072 from Silverleaf Resorts, Inc.)
Cherokee County



CCN 13131 582-07-0804 SO

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

February 27, 2008

TO: Persons on the attached mailing list.

RE: Algonquin Water Resources of Texas, LLC
CCN Nos. 11072, 13131, and 20815
TCEQ Docket No. 2006-1431-UCR; SOAH Docket No. 582-07-0804

This letter is your notice that the Texas Commission on Environmental Quality (TCEQ) executive director has issued final approval of the above-named application.

You may file a **motion to overturn** with the chief clerk. A motion to overturn is a request for the commission to review the TCEQ executive director's approval of the application. Any motion must explain why the commission should review the TCEQ executive director's action.

A motion to overturn must be received by the chief clerk within 23 days after the date of this letter. An original and 11 copies of a motion must be filed with the chief clerk in person or by mail. The Chief Clerk's mailing address is Office of the Chief Clerk (MC 105), TCEQ, P.O. Box 13087, Austin, Texas 78711-3087. On the same day the motion is transmitted to the chief clerk, please provide copies to the applicant, the Executive Director's attorney, and the Public Interest Counsel at the addresses listed on the attached mailing list. If a motion is not acted on by the commission within 45 days after the date of this letter, then the motion shall be deemed overruled.

Individual members of the public may seek further information by calling the TCEQ Office of Public Assistance, toll free, at 1-800-687-4040.

Sincerely,

LaDonna Castañuela
Chief Clerk

LDC/mr

MAILING LIST
for
Algonquin Water Resources of Texas, LLC
CCN Nos. 11072, 13131, and 20815
TCEQ Docket No. 2006-1431-UCR; SOAH Docket No. 582-07-0804

FOR THE APPLICANT:

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Elizabeth Flores, Technical Staff
Texas Commission on Environmental Quality
Water Supply Division MC-153
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FOR PUBLIC INTEREST COUNSEL:

Blas J. Coy, Jr., Attorney
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Public Interest Counsel MC-103
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FOR THE CHIEF CLERK:

LaDonna Castañuela
Texas Commission on Environmental Quality
Office of Chief Clerk MC-105
P.O. Box 13087
Austin, Texas 78711-3087

WATER UTILITY TARIFF
FOR

Algonquin Water Resources of Texas, LLC
(Utility Name)

111 West Wigwam Blvd., Suite B
(Business Address)

Litchfield Park, Arizona 85340
(City, State, Zip Code)

(693) 935-9367
(Area Code/Telephone)

This tariff is effective for utility operations under the following Certificate of Convenience and Necessity:

13131

This tariff is effective in the following county(ies):

Comal, Montgomery, Smith, Wood

This tariff is effective in the following cities or unincorporated towns (if any):

None

This tariff is effective in the following subdivisions or systems:

Holly Lake Ranch and Woodland Village, the Villages/Big Eddy, Piney Shores Resort Area and Hill Country Resort Area

This tariff is effective for the following public water system number(s):
Holly Lake Ranch PWS 2500012, The Village/Big Eddy PWS 2120037, Piney Shores Resort PWS 1700532, Hill Country Resort PWS 0450180

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The above utility lists the following sections of its tariff (if additional pages are needed for a section, all pages should be numbered consecutively):

SECTION 1.0 -- RATE SCHEDULE

Section 1.01 - Rates

Customer Class*	Monthly Minimum Charge	Gallonage Charge (per 1,000 Gallons same for all meter sizes)
LUE	$21.26 (Includes 0 gallons)	$1.94
Other Customer:		
3/4"	$33.03	
1"	$55.05	
1 ½ "	$110.10	
2"	$176.16	
3"	$330.30	
4"	$550.50	
6"	$1,101.00	

* LUE (living unit equivalent) is defined as a single family residence requiring water service through a single 5/8" x 3/4" water meter, single condominium unit, single time share unit, single apartment unit, a single quadraplex unit or single commercial connection requiring water service through a single 5/8" 2 3/4" water meter.

* Other customer is defined as potable water consumer requiring a meter larger than 5/8" x 3/4" to meet customer-specific service demands. This customer class' monthly minimum rate shall be calculated by multiplying the LUE monthly minimum rate times the standard TCEQ water meter equivalency factor (as shown in the TCEQ's most recent rate change application) for the water meter size serving that customer.

FORM OF PAYMENT: The utility will accept the following forms of payment:
Cash_X_, Check_X_, Money Order_X_, Credit Card_____, Other (specify)_____
THE UTILITY MAY REQUIRE EXACT CHANGE FOR PAYMENTS AND MAY REFUSE TO ACCEPT PAYMENTS MADE USING MORE THAN $1.00 IN SMALL COINS. A WRITTEN RECEIPT WILL BE GIVEN FOR CASH PAYMENTS.

REGULATORY ASSESSMENT 1.0%
TCEQ RULES REQUIRE THE UTILITY TO COLLECT A FEE OF ONE PERCENT OF THE RETAIL MONTHLY BILL.

Section 1.02 - Miscellaneous Fees

TAP FEE $500.00
TAP FEE COVERS THE UTILITY'S COSTS FOR MATERIALS AND LABOR TO INSTALL A STANDARD RESIDENTIAL 5/8" or 3/4" METER. AN ADDITIONAL FEE TO COVER UNIQUE COSTS IS PERMITTED IF LISTED ON THIS TARIFF.

TAP FEE (Unique costs) ..... Actual Cost
FOR EXAMPLE, A ROAD BORE FOR CUSTOMERS OUTSIDE OF SUBDIVISIONS OR RESIDENTIAL AREAS.

RATES LISTED ARE EFFECTIVE ONLY IF THIS PAGE HAS TCEQ APPROVAL STAMP

Texas Commission on Environmental Quality
35017-S, CCN 13131, January 30, 2007
Approved Tariff by JEF

SECTION 1.0 – RATE SCHEDULE (Continued)

TAP FEE (Large meter) ..... Actual Cost
TAP FEE IS THE UTILITY'S ACTUAL COST FOR MATERIALS AND LABOR FOR METER SIZE INSTALLED.

METER RELOCATION FEE ..... Actual Relocation Cost, Not to Exceed Tap Fee
THIS FEE MAY BE CHARGED IF A CUSTOMER REQUESTS THAT AN EXISTING METER BE RELOCATED.

METER TEST FEE $25.00
THIS FEE WHICH SHOULD REFLECT THE UTILITY'S COST MAY BE CHARGED IF A CUSTOMER REQUESTS A SECOND METER TEST WITHIN A TWO-YEAR PERIOD AND THE TEST INDICATES THAT THE METER IS RECORDING ACCURATELY. THE FEE MAY NOT EXCEED $25.

RECONNECTION FEE
THE RECONNECT FEE MUST BE PAID BEFORE SERVICE CAN BE RESTORED TO A CUSTOMER WHO HAS BEEN DISCONNECTED FOR THE FOLLOWING REASONS (OR OTHER REASONS LISTED UNDER SECTION 2.0 OF THIS TARIFF):

a)Non payment of bill (Maximum $25.00)..... $25.00
b)Customer's request that service be disconnected..... $35.00

TRANSFER FEE..... $35.00
THE TRANSFER FEE WILL BE CHARGED FOR CHANGING AN ACCOUNT NAME AT THE SAME SERVICE LOCATION WHEN THE SERVICE IS NOT DISCONNECTED

LATE CHARGE (EITHER $5.00 OR 10% OF THE BILL) 10%
TCEQ RULES ALLOW A ONE-TIME PENALTY TO BE CHARGED ON DELINQUENT BILLS. A LATE CHARGE MAY NOT BE APPLIED TO ANY BALANCE TO WHICH THE PENALTY WAS APPLIED IN A PREVIOUS BILLING.

RETURNED CHECK CHARGE $15.00
RETURNED CHECK CHARGES MUST BE BASED ON THE UTILITY'S DOCUMENTABLE COST.

CUSTOMER DEPOSIT RESIDENTIAL (Maximum $50) $50.00

COMMERCIAL & NON-RESIDENTIAL DEPOSIT ..... 1/6TH OF ESTIMATED ANNUAL BILL

GOVERNMENTAL TESTING, INSPECTION AND COSTS SURCHARGE
WHEN AUTHORIZED IN WRITING BY TCEQ AND AFTER NOTICE TO CUSTOMERS, THE UTILITY MAY INCREASE RATES TO RECOVER INCREASED COSTS FOR INSPECTION FEES AND WATER TESTING. [30 TAC 291.21(K)(2)]

LINE EXTENSION AND CONSTRUCTION CHARGES:
REFER TO SECTION 3.0--EXTENSION POLICY FOR TERMS, CONDITIONS, AND CHARGES WHEN NEW CONSTRUCTION IS NECESSARY TO PROVIDE SERVICE.

SEASONAL RECONNECTION FEE ..... Base Rate for meter size times number of months off the system not to exceed six months when leave and return within a twelve month period.

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Texas Commission on Environmental Quality
35017-S, CCN 13131, January 30, 2007
Approved Tariff by

SECTION 1.0 – MISCELLANEOUS FEES (Continued)

METER RELOCATION FEE ..... Actual cost to relocate that meter
THIS FEE MAY BE CHARGED IF A CUSTOMER REQUESTS RELOCATION OF AN EXISTING METER.

METER CONVERSION FEE ..... Actual cost to relocate that meter
THIS FEE MAY BE CHARGED IF A CUSTOMER REQUESTS CHANGE OF SIZE OF AN EXISTING METER OR CHANGE IS REQUIRED BY MATERIAL CHANGE IN CUSTOMERS SERVICE DEMAND.

TEMPORARY WATER RATE:

Unless otherwise superseded by TCEQ order or rule, if the Utility is ordered by a court or governmental body of competent jurisdiction to reduce its pumpage, production or water sales, the Utility shall be authorized to increase its approved gallonage charge according to the formula:

$$TGC = cgc + prr \times r / (1.0 - r), \text{ where}$$

TCG = temporary gallonage charge
cgc = current gallonage charge
r = water use reduction expressed as a decimal fraction (the pumping restriction)
prr = percentage of revenues to be recovered expressed as a decimal fraction 0.5 (i.e., 50% - 0.5)

To implement the Temporary Water Rate, the utility must comply with all notice and other requirements of 30 TAC 291.21(l).

UNDERGROUND WATER DISTRICT FEE PASS THROUGH CLAUSE:

Changes in fees imposed by any underground district having jurisdiction over the Utility shall be passed through as an adjustment to the water gallonage charge according to the following formula:

$$AG = G + B/(1-L), \text{ where}$$

AG = adjusted gallonage charge, rounded to the nearest one cent;
G = approved gallonage charge (per 1,000 gallons);
B = change in fee/costs (per 1,000 gallons);
L = percentage system-wide line losses for the preceeding 12 months, not to exceed 0.15.

To implement or modify the Underground Water District Fee, the utility must comply with all notice and other requirements of 30 TAC 291.21(h).

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Texas Commission on Environmental Quality
35017-S, CCN 13131, January 30, 2007
Approved Tariff by RLEF

SECTION 2.0 -- SERVICE RULES AND POLICIES

The utility will have the most current Texas Commission on Environmental Quality Rules, Chapter 291, Water Utility Regulation, available at its office for reference purposes. The Rules and this tariff shall be available for public inspection and reproduction at a reasonable cost. The latest Rules or Commission approved changes to the Rules supersede any rules or requirements in this tariff.

Section 2.01 - Application for Water Service

All applications for service will be made on the utility's standard application or contract form (attached in the Appendix to this tariff), will be signed by the applicant, any required fees (deposits, reconnect, tap, extension fees, etc. as applicable) will be paid and easements, if required, will be granted before service is provided by the utility. A separate application or contract will be made for each service location.

Section 2.02 - Refusal of Service

The utility may decline to serve an applicant until the applicant has complied with the regulations of the regulatory agencies (state and municipal regulations) and for the reasons outlined in the TCEQ Rules. In the event that the utility refuses to serve an applicant, the utility will inform the applicant in writing of the basis of its refusal. The utility is also required to inform the applicant that a complaint may be filed with the Commission.

Section 2.03 - Fees and Charges & Easements Required Before Service Can Be Connected

(A) Customer Deposits

If a residential applicant cannot establish credit to the satisfaction of the utility, the applicant may be required to pay a deposit as provided for in Section 1.02 - Miscellaneous Fees of this tariff. The utility will keep records of the deposit and credit interest in accordance with TCEQ Rules.

Residential applicants 65 years of age or older may not be required to pay deposits unless the applicant has an outstanding account balance with the utility or another water or sewer utility which accrued within the last two years.

Nonresidential applicants who cannot establish credit to the satisfaction of the utility may be required to make a deposit that does not exceed an amount equivalent to one-sixth of the estimated annual billings.

SECTION 2.0 – SERVICE RULES AND POLICIES (Continued)

Refund of deposit - If service is not connected, or after disconnection of service, the utility will promptly refund the customer's deposit plus accrued interest or the balance, if any, in excess of the unpaid bills for service furnished. The utility may refund the deposit at any time prior to termination of utility service but must refund the deposit plus interest for any residential customer who has paid 18 consecutive billings without being delinquent.

(B) Tap or Reconnect Fees

A new customer requesting service at a location where service has not previously been provided must pay a tap fee as provided in Section 1. A customer requesting service where service has previously been provided must pay a reconnect fee as provided in Section 1. Any applicant or existing customer required to pay for any costs not specifically set forth in the rate schedule pages of this tariff shall be given a written explanation of such costs prior to request for payment and/or commencement of construction. If the applicant or existing customer does not believe that these costs are reasonable or necessary, the applicant or existing customer shall be informed of their right to appeal such costs to the TCEQ or such other regulatory authority having jurisdiction over the utility's rates in that portion of the utility's service area in which the applicant's or existing customer's property(ies) is located.

Fees in addition to the regular tap fee may be charged if listed specifically in Section 1 to cover unique costs not normally incurred as permitted by 30 T. A. C. 291.86(a)(1)(C). For example, a road bore for customers outside a subdivision or residential area could be considered a unique cost.

(C) Easement Requirement

Where recorded public utility easements on the service applicant's property do not exist or public road right-of-way easements are not available to access the applicant's property, the Utility may require the applicant to provide it with a permanent recorded public utility easement on and across the applicant's real property sufficient to provide service to that applicant. Such easement(s) shall not be used for the construction of production, storage, transmission or pressure facilities unless they are needed for adequate service to that applicant.

Section 2.04 - Utility Response to Applications for Service

After the applicant has met all the requirements, conditions and regulations for service, the utility will install tap, meter and utility cut-off valve and/or take all necessary actions to initiate service. The utility will serve each qualified applicant for service within 5 working days unless line extensions or new facilities are required. If construction is required to fill the order and if it cannot be completed within 30 days, the utility will provide the applicant with a written explanation of the construction required and an expected date of service.

Except for good cause where service has previously been provided, service will be reconnected within one working day after the applicant has met the requirements for reconnection.

SECTION 2.0 – SERVICE RULES AND POLICIES (Continued)

Section 2.05 - Customer Responsibility

The customer will be responsible for furnishing and laying the necessary customer service pipe from the meter location to the place of consumption. Customers will not be allowed to use the utility's cutoff valve on the utility's side of the meter. Existing customers may install cutoff valves on their side of the meter and are encouraged to do so. All new customers may be required to install and maintain a cutoff valve on their side of the meter.

No direct connection between a public water supply system and any potential source of contamination or between a public water supply system and a private water source (ex. private well) will be allowed. A customer shall not connect, or allow any other person or party to connect, onto any water lines on his premises.

Section 2.06 - Customer Service Inspections

Applicants for new service connections or facilities which have undergone extensive plumbing modifications are required to furnish the utility a completed customer service inspection certificate. The inspection certificate shall certify that the establishment is in compliance with the Texas Commission on Environmental Quality Rules and Regulations for Public Water Systems, Section 290.46(j). The Utility is not required to perform these inspections for the applicant/customer, but will assist the applicant/customer in locating and obtaining the services of a certified inspector.

Section 2.07 - Back Flow Prevention Devices

No water connection shall be allowed to any residence or establishment where an actual or potential contamination hazard exists unless the public water facilities are protected from contamination by either an approved air gap, backflow prevention assembly, or other approved device. The type of device or backflow prevention assembly required shall be determined by the specific potential hazard identified in §290.47(i) Appendix I, Assessment of Hazards and Selection of Assemblies of the TCEQ Rules and Regulations for Public Water Systems.

The use of a backflow prevention assembly at the service connection shall be considered as additional backflow protection and shall not negate the use of backflow protection on internal hazards as outlined and enforced by local plumbing codes. When a customer service inspection certificate indicates that an adequate internal cross-connection control program is in effect, backflow protection at the water service entrance or meter is not required.

SECTION 2.0 – SERVICE RULES AND POLICIES (Continued)

At any residence or establishment where it has been determined by a customer service inspection, that there is no actual or potential contamination hazard, as referenced in Section 290.47(i) Appendix I, Assessment of Hazards and Selection of Assemblies of the TCEQ Rules and Regulations for Public Water Systems, then a backflow prevention assembly or device is not required. Outside hose bibs do require, at a minimum, the installation and maintenance of a working atmospheric vacuum breaker.

All backflow prevention assemblies or devices shall be tested upon installation by a TCEQ certified backflow prevention assembly tester and certified to be operating within specifications. Backflow prevention assemblies which are installed to provide protection against health hazards must also be tested and certified to be operating within specifications at least annually by a certified backflow prevention assembly tester.

If the utility determines that a backflow prevention assembly or device is required, the utility will provide the customer or applicant with a list of TCEQ certified backflow prevention assembly testers. The customer will be responsible for the cost of installation and testing, if any, of backflow prevention assembly or device. The customer should contact several qualified installers to compare prices before installation. The customer must pay for any required maintenance and annual testing and must furnish a copy of the test results demonstrating that the assembly is functioning properly to the utility within 30 days after the anniversary date of the installation unless a different date is agreed upon.

Section 2.08 - Access to Customer's Premises

The utility will have the right of access to the customer's premises at all reasonable times for the purpose of installing, testing, inspecting or repairing water mains or other equipment used in connection with its provision of water service, or for the purpose of removing its property and disconnecting lines, and for all other purposes necessary to the operation of the utility system including inspecting the customer's plumbing for code, plumbing or tariff violations. The customer shall allow the utility and its personnel access to the customer's property to conduct any water quality tests or inspections required by law. Unless necessary to respond to equipment failure, leak or other condition creating an immediate threat to public health and safety or the continued provision of adequate utility service to others, such entry upon the customer's property shall be during normal business hours and the utility personnel will attempt to notify the customer that they will be working on the customer's property. The customer may require any utility representative, employee, contractor, or agent seeking to make such entry identify themselves, their affiliation with the utility, and the purpose of their entry.

All customers or service applicants shall provide access to meters and utility cutoff valves at all times reasonably necessary to conduct ordinary utility business and after normal business hours as needed to protect and preserve the integrity of the public drinking water supply.

SECTION 2.0 – SERVICE RULES AND POLICIES (Continued)

Section 2.09 - Meter Requirements, Readings, and Testing

One meter is required for each residential, commercial, or industrial connection. All water sold by the utility will be billed based on meter measurements. The utility will provide, install, own and maintain meters to measure amounts of water consumed by its customers.

Meters will be read at monthly intervals and as nearly as possible on the corresponding day of each monthly meter reading period unless otherwise authorized by the Commission.

Meter tests. The utility will, upon the request of a customer, and, if the customer so desires, in his or her presence or in that of his or her authorized representative, make without charge a test of the accuracy of the customer's meter. If the customer asks to observe the test, the test will be made during the utility's normal working hours at a time convenient to the customer. Whenever possible, the test will be made on the customer's premises, but may, at the utility's discretion, be made at the utility's testing facility. If within a period of two years the customer requests a new test, the utility will make the test, but if the meter is found to be within the accuracy standards established by the American Water Works Association, the utility will charge the customer a fee which reflects the cost to test the meter up to a maximum $25 for a residential customer. Following the completion of any requested test, the utility will promptly advise the customer of the date of removal of the meter, the date of the test, the result of the test, and who made the test.

Section 2.10 - Billing

(A) Regular Billing
Bills from the utility will be mailed monthly unless otherwise authorized by the Commission. The due date of bills for utility service will be at least sixteen (16) days from the date of issuance. The postmark on the bill or, if there is no postmark on the bill, the recorded date of mailing by the utility will constitute proof of the date of issuance. Payment for utility service is delinquent if full payment, including late fees and the regulatory assessment, is not received at the utility or the utility's authorized payment agency by 5:00 p.m. on the due date. If the due date falls on a holiday or weekend, the due date for payment purposes will be the next workday after the due date.

(B) Late Fees
A late penalty of either $5.00 or 10.0% will be charged on bills received after the due date. The penalty on delinquent bills will not be applied to any balance to which the penalty was applied in a previous billing. The utility must maintain a record of the date of mailing to charge the late penalty.

SECTION 2.0 – SERVICE RULES AND POLICIES (Continued)

(C) Information on Bill
Each bill will provide all information required by the TCEQ Rules. For each of the systems it operates, the utility will maintain and note on the monthly bill a local or toll-free telephone number (or numbers) to which customers can direct questions about their utility service.

(D) Prorated Bills
If service is interrupted or seriously impaired for 24 consecutive hours or more, the utility will prorate the monthly base bill in proportion to the time service was not available to reflect this loss of service.

Section 2.11- Payments

All payments for utility service shall be delivered or mailed to the utility's business office. If the business office fails to receive payment prior to the time of noticed disconnection for non-payment of a delinquent account, service will be terminated as scheduled. Utility service crews shall not be allowed to collect payments on customer accounts in the field.

Payment of an account by any means that has been dishonored and returned by the payor or payee's bank, shall be deemed to be delinquent. All returned payments must be redeemed with cash or valid money order. If a customer has two returned payments within a twelve month period, the customer shall be required to pay a deposit if one has not already been paid.

Section 2.12 - Service Disconnection

(A) With Notice
Utility service may be disconnected if the bill has not been paid in full by the date listed on the termination notice. The termination date must be at least 10 days after the notice is mailed or hand delivered.

The utility is encouraged to offer a deferred payment plan to a customer who cannot pay an outstanding bill in full and is willing to pay the balance in reasonable installments. However, a customer's utility service may be disconnected if a bill has not been paid or a deferred payment agreement entered into within 26 days from the date of issuance of a bill and if proper notice of termination has been given.

Notice of termination must be a separate mailing or hand delivery in accordance with the TCEQ Rules.

B) Without Notice
Utility service may also be disconnected without notice for reasons as described in the TCEQ Rules.

SECTION 2.0 – SERVICE RULES AND POLICIES (Continued)

Section 2.13 - Reconnection of Service

Utility personnel must be available during normal business hours to accept payments on the day service is disconnected and the following day unless service was disconnected at the customer's request or due to a hazardous condition.

Service will be reconnected within 36 hours after the past due bill, reconnect fees and any other outstanding charges are paid or the conditions which caused service to be disconnected are corrected.

Section 2.14 - Service Interruptions

The utility will make all reasonable efforts to prevent interruptions of service. If interruptions occur, the utility will re-establish service within the shortest possible time. Except for momentary interruptions due to automatic equipment operations, the utility will keep a complete record of all interruptions, both emergency and scheduled and will notify the Commission in writing of any service interruptions affecting the entire system or any major division of the system lasting more than four hours. The notice will explain the cause of the interruptions.

Section 2.15 - Quality of Service

The utility will plan, furnish, and maintain production, treatment, storage, transmission, and distribution facilities of sufficient size and capacity to provide a continuous and adequate supply of water for all reasonable consumer uses. Unless otherwise authorized by the Commission, the utility will maintain facilities as described in the Texas Commission on Environmental Quality Rules and Regulations for Public Water Systems.

Section 2.16 - Customer Complaints and Disputes

If a customer or applicant for service lodges a complaint, the utility will promptly make a suitable investigation and advise the complainant of the results. Service will not be disconnected pending completion of the investigation. If the complainant is dissatisfied with the utility's response, the utility must advise the complainant that he has recourse through the Texas Commission on Environmental Quality complaint process. Pending resolution of a complaint, the commission may require continuation or restoration of service.

The utility will maintain a record of all complaints which shows the name and address of the complainant, the date and nature of the complaint and the adjustment or disposition thereof, for a period of two years after the final settlement of the complaint.

SECTION 2.0 – SERVICE RULES AND POLICIES (Continued)

In the event of a dispute between a customer and a utility regarding any bill for utility service, the utility will conduct an investigation and report the results to the customer. If the dispute is not resolved, the utility will inform the customer that a complaint may be filed with the Commission.

Section 2.17 - Customer Liability

Customer shall be liable for any damage or injury to utility-owned property shown to be caused by the customer.

SECTION 3.0 -- EXTENSION POLICY

Section 3.01 - Standard Extension Requirements

LINE EXTENSION AND CONSTRUCTION CHARGES: NO CONTRIBUTION IN AID OF CONSTRUCTION MAY BE REQUIRED OF ANY CUSTOMER EXCEPT AS PROVIDED FOR IN THIS APPROVED EXTENSION POLICY.

The Utility is not required to extend service to any applicant outside of its certified service area and will only do so under terms and conditions mutually agreeable to the Utility and the applicant, in compliance with TCEQ rules and policies, and upon extension of the Utility's certified service area boundaries by the TCEQ.

The applicant for service will be given an itemized statement of the costs, options such as rebates to the customer, sharing of construction costs between the utility and the customer, or sharing of costs between the customer and other applicants prior to beginning construction.

The Utility is not required to extend service to any applicant outside of its certificated service area and will only do so under terms and conditions mutually agreeable to the Utility and the applicant, in compliance with TCEQ rules and policies, and upon extension of the Utility's certificated service area boundaries by the TCEQ.

Section 3.02 - Costs Utilities and Service Applicants Shall Bear

Within its certified area, the utility will pay the cost of the first 200 feet of any water main or distribution line necessary to extend service to an individual residential customer within a platted subdivision.

However, if the residential customer requesting service purchased the property after the developer was notified in writing of the need to provide facilities to the utility, the utility may charge for the first 200 feet. The utility must also be able to document that the developer of the subdivision refused to provide facilities compatible with the utility's facilities in accordance with the utility's approved extension policy after receiving a written request from the utility.

Residential customers will be charged the equivalent of the costs of extending service to their property from the nearest transmission or distribution line even if that line does not have adequate capacity to serve the customer. However, if the customer places unique, non-standard service demands upon the system, the customer may be charged the additional cost of extending service to and throughout their property, including the cost of all necessary transmission and storage facilities necessary to meet the service demands anticipated to be created by that property.

SECTION 3.0 -- EXTENSION POLICY (Continued)

Unless an exception is granted by the TCEQ's Executive Director, the residential service applicant shall not be required to pay for costs of main extensions greater than 2" in diameter for water distribution and pressure wastewater collection lines and 6" in diameter for gravity wastewater lines.

Exceptions may be granted by the TCEQ Executive Director if

- adequate service cannot be provided to the applicant using the maximum line sizes listed due to distance or elevation, in which case, it shall be the utility's burden to justify that a larger diameter pipe is required for adequate service;

- or larger minimum line sizes are required under subdivision platting requirements or building codes of municipalities within whose corporate limits or extraterritorial jurisdiction the point of use is located; or the residential service applicant is located outside the CCN service area.

If an exception is granted, the Utility shall establish a proportional cost plan for the specific extension or a rebate plan which may be limited to seven years to return the portion of the applicant's costs for oversizing as new customers are added to ensure that future applicants for service on the line pay at least as much as the initial service applicant.

For purposes of determining the costs that service applicants shall pay, commercial customers with service demands greater than residential customer demands in the certified area, industrial, and wholesale customers shall be treated as developers. A service applicant requesting a one inch meter for a lawn sprinkler system to service a residential lot is not considered nonstandard service.

If an applicant requires service other than the standard service provided by the utility, such applicant will be required to pay all expenses incurred by the utility in excess of the expenses that would be incurred in providing the standard service and connection beyond 200 feet and throughout his property including the cost of all necessary transmission facilities.

The utility will bear the full cost of any over-sizing of water mains necessary to serve other customers in the immediate area. The individual residential customer shall not be charged for any additional production, storage, or treatment facilities. Contributions in aid of construction may not be required of individual residential customers for production, storage, treatment or transmission facilities unless otherwise approved by the Commission under this specific extension policy.

SECTION 3.0 -- EXTENSION POLICY (Continued)

Section 3.03 - Contributions in Aid of Construction

Developers may be required to provide contributions in aid of construction in amounts sufficient to furnish the development with all facilities necessary to provide for reasonable local demand requirements and to comply with Texas Commission on Environmental Quality minimum design criteria for facilities used in the production, transmission, pumping, or treatment of water or Texas Commission on Environmental Quality minimum requirements. For purposes of this subsection, a developer is one who subdivides or requests more than two meters on a piece of property. Commercial, industrial, and wholesale customers will be treated as developers.

Any applicant who places unique or non-standard service demands on the system may be required to provide contributions in aid of construction for the actual costs of any additional facilities required to maintain compliance with the Texas Commission on Environmental Quality minimum design criteria for water production, treatment, pumping, storage and transmission.

Any service extension to a subdivision (recorded or unrecorded) may be subject to the provisions and restrictions of 30 TAC 291.86(d). When a developer wishes to extend the system to prepare to service multiple new connections, the charge shall be the cost of such extension, plus a pro-rata charge for facilities which must be committed to such extension compliant with the Texas Commission on Environmental Quality minimum design criteria. As provided by 30 T.A.C. 291.85(e)(3), for purposes of this section, commercial, industrial, and wholesale customers shall be treated as developers.

A utility may only charge a developer standby fees for unrecovered costs of facilities committed to a developer's property under the following circumstances:

- Under a contract and only in accordance with the terms of the contract; or
- if service is not being provided to a lot or lots within two years after installation of facilities necessary to provide service to the lots has been completed and if the standby fees are included on the utility's approved tariff after a rate change application has been filed. The fees cannot be billed to the developer or collected until the standby fees have been approved by the commission or executive director.
- for purposes of this section, a manufactured housing rental community can only be charged standby fees under a contract or if the utility installs the facilities necessary to provide individually metered service to each of the rental lots or spaces in the community.

SECTION 3.0 -- EXTENSION POLICY (Continued)

Section 3.04 - Appealing Connection Costs

The imposition of additional extension costs or charges as provided by Sections 3.0 - Extension Policy of this tariff shall be subject to appeal as provided in this tariff, TCEQ rules, or the rules of such other regulatory authority as may have jurisdiction over the utility's rates and services. Any applicant required to pay for any costs not specifically set forth in the rate schedule pages of this tariff shall be given a written explanation of such costs prior to payment and/or commencement of construction. If the applicant does not believe that these costs are reasonable or necessary, the applicant shall be informed of the right to appeal such costs to the TCEQ or such other regulatory authority having jurisdiction over the utility's rates in that portion of the utility's service area in which the applicant's property(ies) is located.

Section 3.05 - Applying for Service

The Utility will provide a written service application form to the applicant for each request for service received by the Utility's business offices. A separate application shall be required for each potential service location if more than one service connection is desired by any individual applicant. Service application forms will be available at the Utility's business office during normal weekday business hours. Service applications will be sent by prepaid first class United States mail to the address provided by the applicant upon request. Completed applications should be returned by hand delivery in case there are questions which might delay fulfilling the service request. Completed service applications may be submitted by mail if hand delivery is not possible.

Where a new tap or service connection is required, the service applicant shall be required to submit a written service application and request that a tap be made. A diagram, map, plat, or written metes and bounds description of precisely where the applicant desires each tap or service connection is to be made and, if necessary, where the meter is to be installed, along the applicant's property line may also be required with the tap request. The actual point of connection and meter installation must be readily accessible to Utility personnel for inspection, servicing, and meter reading while being reasonably secure from damage by vehicles and mowers. If the Utility has more than one main adjacent to the service applicant's property, the tap or service connection will be made to the Utility's nearest service main with adequate capacity to service the applicant's full potential service demand. Beyond the initial 200 feet, the customer shall bear only the equivalent cost of extending from the nearest main. If the tap or service connection cannot be made at the applicant's desired location, it will be made at another location mutually acceptable to the applicant and the Utility. If no agreement on location can be made, the applicant may refer the matter to the TCEQ for resolution.

SECTION 3.0 -- EXTENSION POLICY (Continued)

Section 3.06 - Qualified Service Applicant

A "qualified service applicant" is an applicant who has: (1) met all of the Utility's requirements for service contained in this tariff, TCEQ rules and/or TCEQ order, (2) has made payment or made arrangement for payment of tap fees, (3) has provided all easements and rights-of-way required to provide service to the requested location, (4) delivered an executed customer service inspection certificate to the Utility, if applicable, and (5) has executed a customer service application for each location to which service is being requested.

The Utility shall serve each qualified service applicant within its certified service area as soon as practical after receiving a completed service application. All service requests will be fulfilled within the time limits prescribed by TCEQ rules once the applicant has met all conditions precedent to achieving "qualified service applicant" status. If a service request cannot be fulfilled within the required period, the applicant shall be notified in writing of the delay, its cause and the anticipated date that service will be available. The TCEQ service dates shall not become applicable until the service applicant has met all conditions precedent to becoming a qualified service applicant as defined by TCEQ rules.

Section 3.07 - Developer Requirements

As a condition of service to a new subdivision, the Utility shall require a developer (as defined by TCEQ rule) to provide permanent recorded public utility easements as a condition of service to any location within the developer's property.

SECTION 4.0 -- DROUGHT CONTINGENCY PLAN

SEWER UTILITY TARIFF
FOR

Algonquin Water Resources of Texas, LLC
(Utility Name)

111 West Wigwam Blvd., Suite B
(Business Address)

Litchfield Park, Arizona 85340
(City, State, Zip Code)

(693) 935-9367
(Area Code/Telephone)

This tariff is effective for utility operations under the following Certificate of Convenience and Necessity:

20815

This tariff is effective in the following county(ies):

Comal, Montgomery, Smith and Wood

This tariff is effective in the following cities or unincorporated towns (if any):

None

This tariff is effective in the following subdivisions or systems:

Holly Lake Ranch, the Villages/Big Eddy, Piney Shores Resort Area and Hill Country Resort Area

This tariff is effective for the following water quality permit number(s):

WQ12482-001, WQ13849-001, WQ13417-001

The above utility lists the following sections of its tariff (if additional pages are needed for a section, all pages should be numbered consecutively):

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Texas Commission on Environmental Quality
35018-S, CCN 20815, January 30, 2007
Approved Tariff by RLEF

SECTION 1.0 - RATE SCHEDULE

Meter Size	Monthly Minimum Charge	Gallonage Charge (per 1,000 Gallons same for all meter sizes)
LUE	$68.39 (Includes 0 gallons)	$5.05
Other Commercial Customer:		
3/4"	$102.59	
1"	$170.98	
1 ½ "	$341.95	
2"	$547.12	
3"	$1,025.85	
4"	$1,709.75	
6"	$3,419.50	

* LUE (living unit equivalent) is defined as a single family residence, single condominium unit, single time share unit, single apartment unit, a single quadraplex unit or single commercial connection requiring water service through a single 5/8" x 3/4" water meter.

* Other Commercial customer is defined as non-residential generator of water borne domestic or food preparation waste. This customer class' monthly minimum rate shall be calculated by multiplying the LUE monthly minimum rate times the standard TCEQ water meter equivalency factor (as shown in the TCEQ rate change application).

** Gallonage charges will be computed on each customer's winter average water consumption during the preceding December, January, and February billing periods. The winter average consumption shall be recomputed each March. Customers without a winter water consumption history shall be imputed to have consumed the utility wide average for their customer class.

FORM OF PAYMENT: The utility will accept the following form(s) of payment:
Cash_X___, Check_X___, Money Order_X___, Credit Card_____, Other (specify)_____
THE UTILITY MAY REQUIRE EXACT CHANGE FOR PAYMENTS AND MAY REFUSE TO ACCEPT PAYMENTS MADE USING MORE THAN $1.00 IN SMALL COINS. A WRITTEN RECEIPT WILL BE GIVEN FOR CASH PAYMENTS.

REGULATORY ASSESSMENT 1.0%
TCEQ RULES REQUIRE THE UTILITY TO COLLECT A FEE OF ONE PERCENT OF THE RETAIL MONTHLY BILL.

Section 1.02 - Miscellaneous Fees

TAP FEE $500.00
TAP FEE COVERS THE UTILITY'S COSTS FOR MATERIALS AND LABOR TO INSTALL A STANDARD RESIDENTIAL CONNECTION. AN ADDITIONAL FEE TO COVER UNIQUE COSTS IS PERMITTED IF LISTED ON THIS TARIFF.

TAP FEE (Large Connection Tap) ..... Actual Cost
TAP FEE IS THE UTILITY'S ACTUAL COST FOR MATERIALS AND LABOR FOR TAP SIZE INSTALLED.

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Texas Commission on Environmental Quality
35018-S, CCN 20815, January 30, 2007
Approved Tariff by JEF

SECTION 1.0 - RATE SCHEDULE

RECONNECTION FEE

THE RECONNECT FEE MUST BE PAID BEFORE SERVICE CAN BE RESTORED TO A CUSTOMER WHO HAS BEEN DISCONNECTED FOR THE FOLLOWING REASONS (OR OTHER REASONS LISTED UNDER SECTION 2.0 OF THIS TARIFF):

a)Non payment of bill (Maximum $25.00).....$25.00
b)Customer's request that service be disconnected.....$35.00

TRANSFER FEE.....$35.00

THE TRANSFER FEE WILL BE CHARGED FOR CHANGING AN ACCOUNT NAME AT THE SAME SERVICE LOCATION WHEN THE SERVICE IS NOT DISCONNECTED

LATE CHARGE (EITHER $5.00 OR 10% OF THE BILL) 10%

TCEQ RULES ALLOW A ONE-TIME PENALTY TO BE CHARGED ON DELINQUENT BILLS. A LATE CHARGE MAY NOT BE APPLIED TO ANY BALANCE TO WHICH THE PENALTY WAS APPLIED IN A PREVIOUS BILLING.

RETURNED CHECK CHARGE $15.00

RETURNED CHECK CHARGES MUST BE BASED ON THE UTILITY'S DOCUMENTABLE COST.

LUE CUSTOMER DEPOSIT (Maximum $50) .....$50.00 per LUE

COMMERCIAL & NON-RESIDENTIAL DEPOSIT ..... 1/6TH OF ESTIMATED ANNUAL BILL

GOVERNMENTAL TESTING, INSPECTION AND COSTS SURCHARGE.....

WHEN AUTHORIZED IN WRITING BY TCEQ AND AFTER NOTICE TO CUSTOMERS, THE UTILITY MAY INCREASE RATES TO RECOVER INCREASED COSTS FOR INSPECTION FEES AND WATER TESTING. [30 TAC 291.21(K)(2)]

LINE EXTENSION AND CONSTRUCTION CHARGES:

REFER TO SECTION 3.0--EXTENSION POLICY FOR TERMS, CONDITIONS, AND CHARGES WHEN NEW CONSTRUCTION IS NECESSARY TO PROVIDE SERVICE.

SEASONAL RECONECTIN FEE ..... Monthly minimum bill for meter size for each month of disconnection not to exceed six months when leave and return within 12 month period.

SERVICE RELOCATION FEE ..... Actual Cost to relocate that Service

THIS FEE MAY BE CHARGED IF A CUSTOMER REQUESTS RELOCATION OF AN EXISTING SERVICE.

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Texas Commission on Environmental Quality
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Algonquin Water Resources of Texas, LLC
Holly Lake Ranch

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SECTION 1.0 - RATE SCHEDULE

Meter Size	Monthly Minimum Charge	Gallonage Charge (per 1,000 Gallons)
LUE	$35.00 (Includes 0 gallons)	$5.05

* LUE (living unit equivalent) is defined as a single family residence, single condominium unit, single time share unit, single apartment unit, a single quadraplex unit or single commercial connection requiring water service through a single 5/8" x 3/4" water meter.

* Other Commercial customer is defined as non-residential generator of water borne domestic or food preparation waste. This customer class' monthly minimum rate shall be calculated by multiplying the LUE monthly minimum rate times the standard TCEQ water meter equivalency factor (as shown in the TCEQ rate change application).

** Gallonage charges will be computed on each customer's winter average water consumption during the preceding December, January, and February billing periods. The winter average consumption shall be recomputed each March. Customers without a winter water consumption history shall be imputed to have consumed the utility wide average for their customer class.

FORM OF PAYMENT: The utility will accept the following form(s) of payment:
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THE UTILITY MAY REQUIRE EXACT CHANGE FOR PAYMENTS AND MAY REFUSE TO ACCEPT PAYMENTS MADE USING MORE THAN $1.00 IN SMALL COINS. A WRITTEN RECEIPT WILL BE GIVEN FOR CASH PAYMENTS.

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Algonquin Water Resources of Texas, LLC
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SECTION 2.0 -- SERVICE RULES AND POLICIES

The utility will have the most current Texas Commission on Environmental Quality Rules, Chapter 291, Water Utility Regulation, available at its office for reference purposes. The Rules and this tariff shall be available for public inspection and reproduction at a reasonable cost. The latest Rules or Commission approved changes to the Rules supersede any rules or requirements in this tariff.

Section 2.01 - Application for Sewer Service

All applications for service will be made on the utility's standard application or contract form (attached in the Appendix to this tariff), will be signed by the applicant, any required fees (deposits, reconnect, tap, extension fees, etc. as applicable) will be paid and easements, if required, will be granted before service is provided by the utility. A separate application or contract will be made for each service location.

Section 2.02 - Refusal of Service

The utility may decline to serve an applicant until the applicant has complied with the regulations of the regulatory agencies (state and municipal regulations) and for the reasons outlined in the TCEQ Rules. In the event that the utility refuses to serve an applicant, the utility will inform the applicant in writing of the basis of its refusal. The utility is also required to inform the applicant that a complaint may be filed with the Commission.

Section 2.03 - Fees and Charges & Easements Required Before Service Can Be Connected

(A) Customer Deposits

If a residential applicant cannot establish credit to the satisfaction of the utility, the applicant may be required to pay a deposit as provided for in Section 1.02 - Miscellaneous Fees of this tariff. The utility will keep records of the deposit and credit interest in accordance with TCEQ Rules.

Residential applicants 65 years of age or older may not be required to pay deposits unless the applicant has an outstanding account balance with the utility or another water or sewer utility which accrued within the last two years.

Nonresidential applicants who cannot establish credit to the satisfaction of the utility may be required to make a deposit that does not exceed an amount equivalent to one-sixth of the estimated annual billings.

Refund of deposit - If service is not connected, or after disconnection of service, the utility will promptly refund the customer's deposit plus accrued interest or the balance, if any, in excess of the unpaid bills for service furnished. The utility may refund the residential customer's deposit at any time prior to termination of utility service but must refund the deposit plus interest for any residential customer who has paid 18 consecutive billings without being delinquent.

SECTION 2.0 -- SERVICE RULES AND POLICIES (Continued)

(B) Tap or Reconnect Fees

A new customer requesting service at a location where service has not previously been provided must pay a tap fee as provided in Section 1. A customer requesting service where service has previously been provided must pay a reconnect fee as provided in Section 1. Any applicant or existing customer required to pay for any costs not specifically set forth in the rate schedule pages of this tariff shall be given a written explanation of such costs prior to request for payment and/or commencement of construction. If the applicant or existing customer does not believe that these costs are reasonable or necessary, the applicant or existing customer shall be informed of their right to appeal such costs to the TCEQ or such other regulatory authority having jurisdiction over the utility's rates in that portion of the utility's service area in which the applicant's or existing customer's property(ies) is located.

Fees in addition to the regular tap fee may be charged to cover unique costs not normally incurred as permitted by 30 T. A. C. 291.86(a)(1)(C) if they are listed on this approved tariff. For example, a road bore for customers outside a subdivision or residential area could be considered a unique cost.

(C) Easement Requirement

Where recorded public utility easements on the service applicant's property do not exist or public road right-of-way easements are not available to access the applicant's property, the Utility may require the applicant to provide it with a permanent recorded public utility easement on and across the applicant's real property sufficient to provide service to that applicant. Such easement(s) shall not be used for the construction of production, storage, transmission or pressure facilities unless they are needed for adequate service to that applicant.

Section 2.04 - Utility Response to Applications for Service

After the applicant has met all the requirements, conditions and regulations for service, the utility will install tap and utility cut-off and/or take all necessary actions to initiate service. The utility will serve each qualified applicant for service within 5 working days unless line extensions or new facilities are required. If construction is required to fill the order and if it cannot be completed within 30 days, the utility will provide the applicant with a written explanation of the construction required and an expected date of service.

Except for good cause where service has previously been provided, service will be reconnected within one working day after the applicant has met the requirements for reconnection.

Section 2.05 - Customer Responsibility

The customer will be responsible for furnishing and laying the necessary customer service pipe from the tap location to the place of consumption. Customers will not be allowed to use the utility's cutoff.

SECTION 2.0 -- SERVICE RULES AND POLICIES (Continued)

2.06 Access to Customer's Premises

All customers or service applicants shall provide access to utility cutoffs at all times reasonably necessary to conduct ordinary utility business and after normal business hours as needed to protect and preserve the integrity of the public drinking water supply.

Section 2.07 - Back Flow Prevention Devices

No water connection shall be made to any establishment where an actual or potential contamination or system hazard exists without an approved air gap or mechanical backflow prevention assembly. The air gap or backflow prevention assembly shall be installed in accordance with the American Water Works Association (AWWA) standards C510, C511 and AWWA Manual M14 or the University of Southern California Manual of Cross-Connection Control, current edition. The backflow assembly installation by a licensed plumber shall occur at the customer's expense.

The back flow assembly shall be tested upon installation by a recognized prevention assembly tester and certified to be operating within specifications. Back flow prevention assemblies which are installed to provide protection against high health hazards must be tested and certified to be operating within specifications at least annually by a recognized back flow prevention device tester. The maintenance and testing of the back flow assembly shall occur at the customer's expense.

Section 2.10 - Billing

(A) Regular Billing
Bills from the utility will be mailed monthly unless otherwise authorized by the Commission. The due date of bills for utility service will be at least sixteen (16) days from the date of issuance. The postmark on the bill or, if there is no postmark on the bill, the recorded date of mailing by the utility will constitute proof of the date of issuance. Payment for utility service is delinquent if full payment, including late fees and the regulatory assessment, is not received at the utility or the utility's authorized payment agency by 5:00 p.m. on the due date. If the due date falls on a holiday or weekend, the due date for payment purposes will be the next workday after the due date.

(B) Late Fees
A late penalty of either $5.00 or 10.0% will be charged on bills received after the due date. The penalty on delinquent bills will not be applied to any balance to which the penalty was applied in a previous billing. The utility must maintain a record of the date of mailing to charge the late penalty.

SECTION 2.0 -- SERVICE RULES AND POLICIES (Continued)

(C) Information on Bill
Each bill will provide all information required by the TCEQ Rules. For each of the systems it operates, the utility will maintain and note on the monthly bill a local or toll-free telephone number (or numbers) to which customers can direct questions about their utility service.

(D) Prorated Bills
If service is interrupted or seriously impaired for 24 consecutive hours or more, the utility will prorate the monthly base bill in proportion to the time service was not available to reflect this loss of service.

Section 2.11- Payments

All payments for utility service shall be delivered or mailed to the utility's business office. If the business office fails to receive payment prior to the time of noticed disconnection for non-payment of a delinquent account, service will be terminated as scheduled. Utility service crews shall not be allowed to collect payments on customer accounts in the field.

Payment of an account by any means that has been dishonored and returned by the payor or payee's bank, shall be deemed to be delinquent. All returned payments must be redeemed with cash or valid money order. If a customer has two returned payments within a twelve month period, the customer shall be required to pay a deposit if one has not already been paid.

Section 2.12 - Service Disconnection

(A) With Notice
Utility service may be disconnected if the bill has not been paid in full by the date listed on the termination notice. The termination date must be at least 10 days after the notice is mailed or hand delivered.

The utility is encouraged to offer a deferred payment plan to a customer who cannot pay an outstanding bill in full and is willing to pay the balance in reasonable installments. However, a customer's utility service may be disconnected if a bill has not been paid or a deferred payment agreement entered into within 26 days from the date of issuance of a bill and if proper notice of termination has been given.

Notice of termination must be a separate mailing or hand delivery in accordance with the TCEQ Rules.

(B) Without Notice
Utility service may also be disconnected without notice for reasons as described in the TCEQ Rules.

SECTION 2.0 -- SERVICE RULES AND POLICIES (Continued)

Section 2.13 - Reconnection of Service

Utility personnel must be available during normal business hours to accept payments on the day service is disconnected and the following day unless service was disconnected at the customer's request or due to a hazardous condition.

Service will be reconnected within 24 hours after the past due bill, reconnect fees and any other outstanding charges are paid or the conditions which caused service to be disconnected are corrected.

Section 2.14 - Service Interruptions

The utility will make all reasonable efforts to prevent interruptions of service. If interruptions occur, the utility will re-establish service within the shortest possible time. Except for momentary interruptions due to automatic equipment operations, the utility will keep a complete record of all interruptions, both emergency and scheduled and will notify the Commission in writing of any service interruptions affecting the entire system or any major division of the system lasting more than four hours. The notice will explain the cause of the interruptions.

Section 2.15 - Quality of Service

The utility will plan, furnish, and maintain and operate production, treatment, storage, transmission, and collection facilities of sufficient size and capacity to provide continuous and adequate service for all reasonable consumer uses and to treat sewage and discharge effluent of the quality required by its discharge permit issued by the Commission. Unless otherwise authorized by the Commission, the utility will maintain facilities as described in the TCEQ Rules.

Section 2.16 - Customer Complaints and Disputes

If a customer or applicant for service lodges a complaint, the utility will promptly make a suitable investigation and advise the complainant of the results. Service will not be disconnected pending completion of the investigation. If the complainant is dissatisfied with the utility's response, the utility must advise the complainant that he has recourse through the Texas Commission on Environmental Quality complaint process. Pending resolution of a complaint, the commission may require continuation or restoration of service.

The utility will maintain a record of all complaints which shows the name and address of the complainant, the date and nature of the complaint and the adjustment or disposition thereof, for a period of two years after the final settlement of the complaint.

SECTION 2.0 -- SERVICE RULES AND POLICIES (Continued)

In the event of a dispute between a customer and a utility regarding any bill for utility service, the utility will conduct an investigation and report the results to the customer. If the dispute is not resolved, the utility will inform the customer that a complaint may be filed with the Commission.

Section 2.17 - Customer Liability

Customer shall be liable for any damage or injury to utility-owned property shown to be caused by the customer.

SECTION 3.0 -- EXTENSION POLICY

Section 3.01 - Standard Extension Requirements

LINE EXTENSION AND CONSTRUCTION CHARGES: NO CONTRIBUTION IN AID OF CONSTRUCTION MAY BE REQUIRED OF ANY CUSTOMER EXCEPT AS PROVIDED FOR IN THIS APPROVED EXTENSION POLICY.

The Utility is not required to extend service to any applicant outside of its certified service area and will only do so under terms and conditions mutually agreeable to the Utility and the applicant, in compliance with TCEQ rules and policies, and upon extension of the Utility's certified service area boundaries by the TCEQ.

The applicant for service will be given an itemized statement of the costs, options such as rebates to the customer, sharing of construction costs between the utility and the customer, or sharing of costs between the customer and other applicants prior to beginning construction.

The Utility is not required to extend service to any applicant outside of its certificated service area and will only do so under terms and conditions mutually agreeable to the Utility and the applicant, in compliance with TCEQ rules and policies, and upon extension of the Utility's certificated service area boundaries by the TCEQ.

Section 3.02 - Costs Utilities and Service Applicants Shall Bear

Within its certified area, the utility will pay the cost of the first 200 feet of any water main or distribution line necessary to extend service to an individual residential customer within a platted subdivision.

However, if the residential customer requesting service purchased the property after the developer was notified in writing of the need to provide facilities to the utility, the utility may charge for the first 200 feet. The utility must also be able to document that the developer of the subdivision refused to provide facilities compatible with the utility's facilities in accordance with the utility's approved extension policy after receiving a written request from the utility.

Residential customers will be charged the equivalent of the costs of extending service to their property from the nearest collection line even if that line does not have adequate capacity to serve the customer. However, if the customer places unique, non-standard service demands upon the system, the customer may be charged the additional cost of extending service to and throughout their property, including the cost of all necessary transmission and storage facilities necessary to meet the service demands anticipated to be created by that property.

SECTION 3.0 -- EXTENSION POLICY (Continued)

Unless an exception is granted by the TCEQ's Executive Director, the residential service applicant shall not be required to pay for costs of main extensions greater than 6" in diameter for gravity wastewater lines.

Exceptions may be granted by the TCEQ Executive Director if

- adequate service cannot be provided to the applicant using the maximum line sizes listed due to distance or elevation, in which case, it shall be the utility's burden to justify that a larger diameter pipe is required for adequate service;

- or larger minimum line sizes are required under subdivision platting requirements or building codes of municipalities within whose corporate limits or extraterritorial jurisdiction the point of use is located; or the residential service applicant is located outside the CCN service area.

If an exception is granted, the Utility shall establish a proportional cost plan for the specific extension or a rebate plan which may be limited to seven years to return the portion of the applicant's costs for oversizing as new customers are added to ensure that future applicants for service on the line pay at least as much as the initial service applicant.

For purposes of determining the costs that service applicants shall pay, commercial customers with service demands greater than residential customer demands in the certified area, industrial, and wholesale customers shall be treated as developers.

If an applicant requires service other than the standard service provided by the utility, such applicant will be required to pay all expenses incurred by the utility in excess of the expenses that would be incurred in providing the standard service and connection beyond 200 feet and throughout his property including the cost of all necessary transmission facilities.

The utility will bear the full cost of any over-sizing of sewer mains necessary to serve other customers in the immediate area. The individual residential customer shall not be charged for any additional treatment facilities. Contributions in aid of construction may not be required of individual residential customers for production, storage, treatment or transmission facilities unless otherwise approved by the Commission under this specific extension policy.

SECTION 3.0 -- EXTENSION POLICY (Continued)

Section 3.03 - Contributions in Aid of Construction

Developers may be required to provide contributions in aid of construction in amounts sufficient to furnish the development with all facilities necessary to provide for reasonable local demand requirements and to comply with Texas Commission on Environmental Quality minimum design criteria for facilities used in the production, collection, transmission, pumping, or treatment of sewage or Texas Commission on Environmental Quality minimum requirements. For purposes of this subsection, a developer is one who subdivides or requests more than two meters on a piece of property. Commercial, industrial, and wholesale customers will be treated as developers.

Any applicant who places unique or non-standard service demands on the system may be required to provide contributions in aid of construction for the actual costs of any additional facilities required to maintain compliance with the Texas Commission on Environmental Quality minimum design criteria for water production, treatment, pumping, storage and transmission.

Any service extension to a subdivision (recorded or unrecorded) may be subject to the provisions and restrictions of 30 TAC 291.86(d). When a developer wishes to extend the system to prepare to service multiple new connections, the charge shall be the cost of such extension, plus a pro-rata charge for facilities which must be committed to such extension compliant with the Texas Commission on Environmental Quality minimum design criteria. As provided by 30 T.A.C. 291.85(e)(3), for purposes of this section, commercial, industrial, and wholesale customers shall be treated as developers.

A utility may only charge a developer standby fees for unrecovered costs of facilities committed to a developer's property under the following circumstances:

- Under a contract and only in accordance with the terms of the contract; or
- if service is not being provided to a lot or lots within two years after installation of facilities necessary to provide service to the lots has been completed and if the standby fees are included on the utility's approved tariff after a rate change application has been filed. The fees cannot be billed to the developer or collected until the standby fees have been approved by the commission or executive director.
- for purposes of this section, a manufactured housing rental community can only be charged standby fees under a contract or if the utility installs the facilities necessary to provide individually metered service to each of the rental lots or spaces in the community.

SECTION 3.0 -- EXTENSION POLICY (Continued)

Section 3.04 - Appealing Connection Costs

The imposition of additional extension costs or charges as provided by Sections 3.0 - Extension Policy of this tariff shall be subject to appeal as provided in this tariff, TCEQ rules, or the rules of such other regulatory authority as may have jurisdiction over the utility's rates and services. Any applicant required to pay for any costs not specifically set forth in the rate schedule pages of this tariff shall be given a written explanation of such costs prior to payment and/or commencement of construction. If the applicant does not believe that these costs are reasonable or necessary, the applicant shall be informed of the right to appeal such costs to the TCEQ or such other regulatory authority having jurisdiction over the utility's rates in that portion of the utility's service area in which the applicant's property(ies) is located.

Section 3.05 - Applying for Service

The Utility will provide a written service application form to the applicant for each request for service received by the Utility's business offices. A separate application shall be required for each potential service location if more than one service connection is desired by any individual applicant. Service application forms will be available at the Utility's business office during normal weekday business hours. Service applications will be sent by prepaid first class United States mail to the address provided by the applicant upon request. Completed applications should be returned by hand delivery in case there are questions which might delay fulfilling the service request. Completed service applications may be submitted by mail if hand delivery is not possible.

Where a new tap or service connection is required, the service applicant shall be required to submit a written service application and request that a tap be made. A diagram, map, plat, or written metes and bounds description of precisely where the applicant desires each tap or service connection is to be made and, if necessary, where the meter is to be installed, along the applicant's property line may also be required with the tap request. The actual point of connection and meter installation must be readily accessible to Utility personnel for inspection, servicing, and meter reading while being reasonably secure from damage by vehicles and mowers. If the Utility has more than one main adjacent to the service applicant's property, the tap or service connection will be made to the Utility's nearest service main with adequate capacity to service the applicant's full potential service demand. Beyond the initial 200 feet, the customer shall bear only the equivalent cost of extending from the nearest main. If the tap or service connection cannot be made at the applicant's desired location, it will be made at another location mutually acceptable to the applicant and the Utility. If no agreement on location can be made, the applicant may refer the matter to the TCEQ for resolution.

SECTION 3.0 -- EXTENSION POLICY (Continued)

Section 3.06 - Qualified Service Applicant

A "qualified service applicant" is an applicant who has: (1) met all of the Utility's requirements for service contained in this tariff, TCEQ rules and/or TCEQ order, (2) has made payment or made arrangement for payment of tap fees, (3) has provided all easements and rights-of-way required to provide service to the requested location, (4) delivered an executed customer service inspection certificate to the Utility, if applicable, and (5) has executed a customer service application for each location to which service is being requested.

The Utility shall serve each qualified service applicant within its certified service area as soon as practical after receiving a completed service application. All service requests will be fulfilled within the time limits prescribed by TCEQ rules once the applicant has met all conditions precedent to achieving "qualified service applicant" status. If a service request cannot be fulfilled within the required period, the applicant shall be notified in writing of the delay, its cause and the anticipated date that service will be available. The TCEQ service dates shall not become applicable until the service applicant has met all conditions precedent to becoming a qualified service applicant as defined by TCEQ rules.

Section 3.07 - Developer Requirements

As a condition of service to a new subdivision, the Utility shall require a developer (as defined by TCEQ rule) to provide permanent recorded public utility easements as a condition of service to any location within the developer's property.

APPENDIX A -- SAMPLE SERVICE AGREEMENT

From 30 TAC Chapter 290.47(b), Appendix B

SERVICE AGREEMENT

I. PURPOSE. The NAME OF SEWER SYSTEM is responsible for protecting the drinking water supply from contamination or pollution which could result from improper private water distribution system construction or configuration. The purpose of this service agreement is to notify each customer of the restrictions which are in place to provide this protection. The utility enforces these restrictions to ensure the public health and welfare. Each customer must sign this agreement before the NAME OF SEWER SYSTEM will begin service. In addition, when service to an existing connection has been suspended or terminated, the sewer system will not re-establish service unless it has a signed copy of this agreement.

II. RESTRICTIONS. The following unacceptable practices are prohibited by State regulations.

A. No direct connection between the public drinking water supply and a potential source of contamination is permitted. Potential sources of contamination shall be isolated from the public water system by an air-gap or an appropriate backflow prevention device.

B. No cross-connection between the public drinking water supply and a private water system is permitted. These potential threats to the public drinking water supply shall be eliminated at the service connection by the installation of an air-gap or a reduced pressure-zone backflow prevention device.

C. No connection which allows water to be returned to the public drinking water supply is permitted.

D. No pipe or pipe fitting which contains more than 8.0% lead may be used for the installation or repair of plumbing at any connection which provides water for human use.

E. No solder or flux which contains more than 0.2% lead can be used for the installation or repair of plumbing at any connection which provides water for human use.

III. SERVICE AGREEMENT. The following are the terms of the service agreement between the NAME OF SEWER SYSTEM (the Sewer System) and NAME OF CUSTOMER (the Customer).

A. The Sewer System will maintain a copy of this agreement as long as the Customer and/or the premises is connected to the Sewer System.

B. The Customer shall allow his property to be inspected for possible cross-connections and other potential contamination hazards. These inspections shall be conducted by the Sewer System or its designated agent prior to initiating new water service; when there is reason to believe that cross-connections or other potential contamination hazards exist; or after any major changes to the private water distribution facilities. The inspections shall be conducted during the Sewer System's normal business hours.

C. The Sewer System shall notify the Customer in writing of any cross-connection or other potential contamination hazard which has been identified during the initial inspection or the periodic reinspection.

D. The Customer shall immediately remove or adequately isolate any potential cross-connections or other potential contamination hazards on his premises.

E. The Customer shall, at his expense, properly install, test, and maintain any backflow prevention device required by the Sewer System. Copies of all testing and maintenance records shall be provided to the Sewer System.

IV. ENFORCEMENT. If the Customer fails to comply with the terms of the Service Agreement, the Sewer System shall, at its option, either terminate service or properly install, test, and maintain an appropriate backflow prevention device at the service connection. Any expenses associated with the enforcement of this agreement shall be billed to the Customer.

CUSTOMER'S SIGNATURE:_____

DATE:_____

Texas Commission on Environmental Quality

INTEROFFICE MEMORANDUM

To: Marisa Weber
Offices of the Chief Clerk

Date: February 8, 2008

From: Angela Littlejohn
Administrative Support
Water Supply Division

Subject: Item for the Executive Director's Signature

Algonquin Water Resources of Texas LLC, Application Number 35017-S/35018-S, CCN 11072/20815,
CN: 602882839; RN: 104709811 (water) RN: 104729637 (sewer)

35017-S; Algonquin Water Resources of Texas, LLC, filed this application to purchase faciliteis and transfer a portion of Certificate of Convenience and Necessity (CCN) No. 11072 from Silverleaf Resorts, Inc.; this application is also granting a Water CCN to Algonquin Water Resources of Texas, LLC in Comal, Montgomery, Smith and Wood Counties

35018-S; Algonquin Water Resources of Texas, LLC, filed this application to purchase facilities and transfer all of CCN No. 20815 from SilverleafResorts, Inc., in Comal, Montgomery, Smith and Wood Counties

The item listed above is for the Executive Director's Signature. Please present this to Marisa Weber.

Contact Name: Elizabeth Flores

Date Stamp This Page Only !

CID 54744 NC

Texas Commission on Environmental Quality

INTEROFFICE MEMORANDUM

To: Marisa Weber
Offices of the Chief Clerk

Date: February 1, 2008

From: Angela Littlejohn
Administrative Support
Water Supply Division

Subject: Item for the Executive Director's Signature

Algonquin Water Resources of Texas, LLC, Application Number 35017-S/35018-S,
CCN 11072/20815,
CN: 602882839 RN: 104709811 (Water)/104729637 (Sewer)

The item listed above is for the Executive Director's Signature. Please present this to Marisa Weber.

Contact Name: Elizabeth Flores

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
2008 FEB -1 AM 10:01
CHIEF CLERKS OFFICE

CCN/20815/582-07-0804/SO

CROSS REFERENCE SHEET

FILE NAME/NUMBER: Silverleaf Resorts, Inc.; CCN No. 20815

DATE: February 27, 2008

REGARDING:

LETTERS, MEMOS, CERTIFICATES OF CONVENIENCE AND NECESSITY, MAPS, & ORDER ISSUED/SIGNED BY EXECUTIVE DIRECTOR ON FEBRUARY 13, 2008

SEE:

FILE NAME / NUMBER: Algonquin Water Resources of Texas, LLC; CCN No. 13131

LOCATION: CCN/13131/582-07-0804/SO

ALJ/KK2/jt2 **Date of Issuance 12/28/15**

Decision 15-12-029 December 17, 2015

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Joint Application of Liberty Utilities Co., Liberty WWH, Inc., Western Water Holdings, LLC, Park Water Company (U 314 W), and Apple Valley Ranchos Water Company (U346W) for Authority for Liberty Utilities Co. to Acquire and Control Park Water Company and Apple Valley Ranchos Water Company.	Application 14-11-013 (Filed November 24, 2014)

DECISION ADOPTING THE SETTLEMENT AGREEMENT AND CONDITIONALLY APPROVING THE APPLICATION

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DECISION ADOPTING THE SETTLEMENT AGREEMENT AND CONDITIONALLY APPROVING THE APPLICATION

Summary

This decision adopts the proposed settlement agreement (Agreement, attached as Appendix A) between Liberty Utilities Co. (Liberty Utilities), Liberty WWH, Inc. (Liberty WWH), Western Water Holdings, LLC (Western Water Holdings), Park Water Company (Park Water), and Apple Valley Ranchos Water Company (AVR) (collectively, the Joint Applicants) and the Office of Ratepayer Advocates.

This decision also conditionally approves the Application 14-11-013 and authorizes Liberty WWH to merge with Western Water Holdings and Liberty Utilities to indirectly acquire and control Park Water and AVR. Conditions of our authorization are the terms of the Agreement which reflect commitments by the Joint Applicants to (1) ensure continued safe, reliable and reasonable operation of Park Water and AVR; (2) safeguard against post-transaction rate increase; and (3) acknowledge and reaffirm the Commission's continued regulatory oversight over Park Water and AVR. These commitments address the ratepayer impact concerns raised by the parties in this proceeding.

The terms and conditions of the Agreement do not limit the Commission's future regulatory discretion. This decision changes no rates or charges, and it closes the proceeding.

1. Background

Since 2011, Park Water Company (Park Water) and Apple Valley Ranchos Water Company (AVR) have been wholly-owned subsidiaries of Western Water

Holdings, LLC (Western Water Holdings).[1] Prior to 2011, AVR was a wholly-owned subsidiary of Park Water, which was wholly-owned by Henry Wheeler, Sr. (Wheeler). In 2011, Wheeler retired.[2]

Park Water and AVR are Class A water utilities subject to the Commission's jurisdiction. Park Water operates in the southeastern portion of Los Angeles, serving approximately 133,000 people. AVR serves a population of roughly 61,000 people in and near the Town of Apple Valley (Apple Valley) in San Bernardino County.[3]

In Decision (D.) 11-12-017, the Commission recognized that Western Water Holdings' parent company (Carlyle Infrastructure Partners L.P.) "will dissolve no later than September 28, 2021;" the Commission therefore envisioned that another application would be filed before that time "for a transfer of control [over Park Water and AVR] for Commission review of such transaction."[4]

Liberty Utilities Co. (Liberty Utilities) is owned by Algonquin Power & Utilities Corp. (Algonquin)[5] and holds all of Algonquin's $1.8 billion in regulated utility assets, including water distribution and wastewater collection and treatment utilities, electricity distribution utilities, and natural gas distribution utilities serving an aggregate of approximately 485,000 customers in ten states,

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[1] *See* D.11-12-017 granting conditional authorization to Western Water Holdings to acquire Park Water and AVR.

[2] Wheeler incorporated Park Water in the 1930s. He stayed on as a consultant when Western Water Holdings acquired and began operating Park Water and AVR pursuant to D.11-12-017.

[3] Mountain Water Company is also wholly owned by Park Water.

[4] D.11-12-017 at 17.

[5] Algonquin has never sold a regulated entity that it has acquired.

including California. More than a third of those Liberty Utilities' customers are water utility customers. Liberty Utilities is also the parent company of Liberty WWH, Inc. (Liberty WWH). Liberty WWH was created expressly for the purposes of the Liberty Utilities' planned acquisition of Park Water and AVR.

On November 24, 2014, Liberty Utilities, Liberty WWH, Western Water Holdings, Park Water, and AVR (collectively, the Joint Applicants) filed Application (A.) 14-11-013 (the Application) to request Commission authorization for Liberty WWH to merge with Western Water Holdings and for Liberty Utilities to indirectly acquire control over Park Water and AVR (collectively, the Transaction). Appendix B to this decision illustrates the proposed post-Transaction corporate structure. Notice of the Application appeared in the Commission's December 1, 2014, Daily Calendar.

The Office of Ratepayer Advocates (ORA) and Apple Valley filed protests to the Application. ORA questioned whether the Transaction would result in rate increases or other negative impacts to the ratepayers. Apple Valley echoed some of ORA's concerns and also raised concerns that AVR customers may see future rate increases as results of certain pending legal actions in Montana against Park Water and/or one of its subsidiaries. Apple Valley also questioned whether the Transaction meets the Commission's "ratepayer indifference standard" and obliquely suggests that Apple Valley, not Liberty WWH, should become the owner and operator of AVR, at some point, as a municipal utility. The Joint Applicants filed a reply to the protests.

On February 6, 2015, the Commission held a prehearing conference. On March 16, 2015, the Commission held two public participation hearings (PPHs) in Apple Valley. The PPHs were attended by total of 273 representatives and residents of Apple Valley. The representatives of the Joint Applicants, Apple

Valley and ORA were present at the PPHs to answer questions and provide information.

At the PPHs, the majority of the speakers supported approval of the Transaction. Many, including AVR employees and ratepayers, consider the current AVR operation and service satisfactory and are supportive of the fact that Liberty WWH is proposing to operate AVR in a business-as-usual manner while also bringing in its experience as a utility company to deliver safe and reliable water service. Some speakers objected to Apple Valley's ultimate plans to own and operate AVR. A few speakers generally objected to rate increases in AVR's service area and questioned whether the Transaction would result in a rate hike. Some opposed foreign ownership of AVR, noting that Liberty Utilities' parent company is headquartered in Canada.

On April 27, 2015, the assigned Commissioner and Administrative Law Judge (ALJ) issued the Scoping Memo and Ruling setting forth the issues in the proceeding, adopting a schedule, and confirming the preliminary determination that hearings would be necessary. The parties were also directed to file a Joint Case Management Statement by June 24, 2015, in the event that a settlement was not reached on all issues by June 22, 2015.

On May 29, 2015, the Joint Applicants and ORA (collectively, the Settling Parties) filed a Joint Motion for Approval of Settlement Agreement (Motion).[6] Apple Valley was not a party to the Settlement Agreement (Agreement), and on June 29, 2015, Apple Valley filed its comments on the Motion. No party filed any objection or opposition to the Motion.

[6] The Settling Parties timely informed Apple Valley of developments in the negotiation and settlement phase and also provided Apple Valley copies of drafts of the Settlement. Apple Valley, however, is not a signatory to the Settlement Agreement.

2. Standard of Review

The Settling Parties in the Motion support approval of the Application and request adoption of the Agreement and its terms as conditions of the Commission's approval of the Application. Under Rule 12.1 of the Commission's Rules of Practice and Procedure (Rules), to approve and adopt a settlement, the Commission must find that a settlement is reasonable in light of the whole record, consistent with the law, and in the public interest.

3. Discussion

The Transaction involves a merger of two holding companies wherein Liberty WWH would merge with and into Western Water Holdings. As a result, Liberty Utilities will acquire control over Park Water and AVR. This will effectively transfer the control over Park Water and AVR from Carlyle Infrastructure to Liberty Utilities.[7] As discussed below, we conditionally authorize the Transaction and adopt the Agreement based on these findings:

(1) The Agreement addresses the ratepayer impact concerns raised by the parties in this proceeding;

(2) The Transaction set forth in the Application, with the proposed additional conditions set forth in the Agreement, complies with the requirements of the applicable statutes, including California Public Utilities Code[8] § 854(a) and the ratepayer indifference standard;

(3) The Settling Parties complied with the Rules 12.1 (a) and (b); and

[7] *See* Appendix B to this decision which shows the post-Transaction schematics.

[8] In this decision, all references to Code refer to California Public Utilities Code, unless otherwise specified, and all citations to "section" or "§" are to the California Public Utilities Code, unless otherwise specified.

(4) The Agreement complies with Rule 12.1(d) and is consistent with law, in the public interest, and reasonable in light of the whole record.

3.1. Review of the Agreement and Ratepayers' Concerns

As discussed below, the Agreement directly responds to and addresses the three key concerns raised by the parties in this proceeding. In doing so, it also addresses the concerns noted by the members of the public during the PPHs.[9]

Safeguard against post-Transaction Rate Increase

The Agreement protects ratepayers from rate increases and additional costs resulting from the Transaction. One of the notable concerns raised by Apple Valley in its protest was the concern that the purchase price of Park Water and AVR would result in rate increases. This concern was also shared by some members of the Apple Valley community at the PPHs and examined by ORA.

We observe that the Agreement in Section 3.26(a) specifically affirms the understanding and commitment by the Settling Parties that there will be no recovery in rates for any excess of the purchase price over the regulatory basis of the utility assets (or "premium") that Liberty Utilities may pay. Specifically, Park Water and AVR shall not record any such premium in their respective accounts utilized in their respective establishment of rates and tariffs. This commitment is also reaffirmed in Section 3.19 of the Agreement, which provides:

[9] Although PPH speakers' statements are not evidence, we have reviewed the speakers' statements to note the sentiments and concerns. In this proceeding, ORA has aptly represented the ratepayers by raising the concerns noted by the speakers and addressing those concerns in its negotiation of the Agreement terms. Apple Valley has raised some of the same ratepayer impact concerns.

> The utility customers of Park Water and AVR shall not incur, directly or indirectly, any transaction costs or other liabilities or obligations arising from the proposed transaction….

Thus, we are satisfied that nothing requested in the Application, or contained in the Agreement, will increase rates to the customers. As noted above, rates for Park Water and AVR will only change pursuant to the Commission's review of subsequent rate applications and advice letters, as part of the Commission's ongoing regulatory oversight.

Continued safe, reliable and reasonable operation

Another concern raised by ORA and shared by some members of the Apple Valley community is the importance of continued high quality water service for the desert community of Apple Valley. This concern includes both safe and reliable water service as well as reasonable management and operation of the utility. To address this concern, the Agreement ensures that the operation of Park Water and AVR will continue seamlessly in the business-as-usual manner after the Transaction. The Application proposes to do this by delivering the current or improved quality of service under the same terms and conditions of existing tariffs.

Specifically, Section 3.16 of the Agreement states: "Customer service to Park Water's and AVR's customers will not be affected by the transaction. Park Water's and AVR's commitment to high quality public utility water service and community involvement shall be maintained." Similarly, Section 3.25(f) provides: "Park Water and AVR shall adopt, maintain and strive to improve the high quality of service standards that Park Water and AVR presently provide their customers."

We find that the Agreement and its conditions provide reasonable protection for the customers of Park Water and AVR by ensuring continued safe and reliable

water service and reasonable operation.

Preserve Commission's Regulatory Oversight

Last of the concerns raised by ORA, and echoed by some members of the public, was that the acquiring company's (Liberty Utilities') parent company, Algonquin, was foreign-owned and headquartered in Canada. This concern had to do with how Park Water and AVR would operate under such ownership and whether such ownership would weaken the Commission's regulatory authority and oversight over Park Water and AVR.

As noted above, the Agreement addresses this concern by ensuring that Park Water and AVR will operate in a business-as-usual manner after the Transaction. In addition and as discussed below, the Agreement ensures that the Commission's regulatory authority and oversight remain unaffected by the change in ownership.

By several terms in the Agreement, the Joint Applicants acknowledge and commit to the Commission's future oversight. Specifically, these commitments include agreement that the Commission's existing Affiliate Transaction Rules (adopted in D.10-10-019) and other regulatory policies will continue to apply to Park Water, AVR, and the proposed owner, Liberty Utilities. In part, Affiliate Transaction Rule, Section VIII provides:

> (1) The officers and employees of the utility and its affiliated companies shall be available to appear and testify in any proceeding before the Commission involving the utility;
>
> (2) The utility and its affiliated companies shall provide the Commission, its staff, and its agents with access to the relevant books and records of such entities in connection with the exercise by the Commission of its regulatory responsibilities in examining any of the costs sought to be recovered by the utility in rate

> proceedings or in connection with a transaction or transactions between the utility and its affiliates; and
>
> (3) The utility shall continue to maintain its books and records in accordance with all Commission rules and maintain and make them available in California.

This commitment directly addresses the concern about the Commission's jurisdiction over foreign management, because Affiliate Transaction Rule VIII would ensure Commission's ongoing regulatory authority over the operation, management and record keeping activities of the officers and employees of the utility *and its affiliated companies*.

The Agreement also does not restrict this Commission's ongoing authority over any of the Joint Applicants. The Agreement does not limit the applicability of our previously adopted regulatory rules and policies, reduce our oversight, or limit our ability to adopt new or revised rules and policies for any of these matters. The rates for Park Water and AVR will only change pursuant to the Commission's future review of subsequent rate applications and advice letters. Specifically, Section 3.25 (d) of the Agreement provides:

> Park Water and AVR shall provide service to their customers in compliance with all rules, regulations and decisions issued by the Commission. Among other matters, Park Water and AVR will not change any rate or any other terms and conditions of service for their respective customers without first having obtained the necessary Commission approvals and Park Water and AVR shall comply with all existing statutes and applicable Commission regulations regarding affiliated interest transactions.

The Agreement further protects the ratepayers' benefits from the water rights held by Park Water and AVR. Regulatory Commitment 3.13 provides that neither Park Water nor AVR shall sell, transfer, or encumber any utility assets

necessary or useful to provide utility service, *or any water rights*, without prior approval by the Commission. Therefore, we retain and will exercise our full jurisdiction and oversight over those protected water rights. Park Water and AVR will continue in uninterrupted operation and the transfer of control will not impact any existing water rights.

In sum, the Agreement imposes no new obligation or duty on the Joint Applicants; however, the express acknowledgments and commitments confirm Joint Applicants', including Liberty Utilities', awareness of and commitment to abide by the Commission's regulatory rules and policies.

3.2. Review of Public Utilities Code §§ 851 *et seq.*, Ratepayer Indifference Standard and Reasonable Options or Alternatives

Sections 851 *et seq.* provide the general statutory framework that governs Commission authority over a proposal to transfer or encumber utility property. Germane to the instant proceeding, § 854(a) requires Commission authorization before any person or corporation may acquire or merge with any public utility. To determine whether the Transaction should be authorized under § 854, the Commission must weigh the affected public interests[10] and apply the "ratepayer indifference standard" to determine that no harm or negative effect on the ratepayer would result from the change of control.[11]

[10] D.10-09-012, 2010 Cal.PUC LEXIS 333, *13 (citing *In the matter of Qwest Corporation et al.*, (2000) 7CPUC 3d 101, 107).

[11] D.11-12-007 at 5.

In weighing the potential negative impacts and applying the ratepayer indifference standard, we consider the factors set forth in §§ 854(b) and 854(c),[12] and we also evaluate reasonable options/alternatives, if any, presented under § 854(d). Under the ratepayer indifference standard, the Transaction does not need to fully meet the §§ 854(b) and (c) requirements. Instead, the ratepayer indifference standard provides that, looking at those considerations, we must find that there is no negative ratepayer impact.

As explained below, we find that no negative impact results from the Transaction, and that the Transaction, combined with the proposed additional conditions set forth in the Agreement, complies with the applicable legal requirements, including § 854(a) and the ratepayer indifference standard.

§ 854(b) Considerations

§ 854(b) considerations are whether the proposal:

(1) Provides short-term and long-term economic benefits to ratepayers.

(2) Equitably allocates, where the Commission has ratemaking authority, the total short-term and long-term forecasted economic benefits, as determined by the commission, of the proposed merger, acquisition, or control, between shareholders and ratepayers. Ratepayers shall receive not less than 50 percent of those benefits.

(3) Not adversely affect competition. In making this finding, the Commission shall request an advisory opinion from the Attorney General regarding whether competition will be

[12] The Commission has determined that while §§ 854(b) and 854(c) do not, by their terms, apply to water utilities, the Commission could consider some or all of those factors in examining the public interest impacts; and the Commission found that the proposed transaction there met the applicable "ratepayer indifference standard" of not adversely affecting the public interest. *See* D.01-09-057 at 7-10 and Conclusion of Law 9.

adversely affected and what mitigation measures could be adopted to avoid this result.

Based on the record of this proceeding, we find that: (1) there is no evidence of quantifiable short- and long-term economic benefits to ratepayers resulting from the Transaction; (2) without any evidence of short- and long-term quantifiable economic benefits to ratepayers resulting from the Transaction, there is no need to consider equitable allocations of forecasted benefits between shareholders and ratepayers; and (3) there is no evidence that the Transaction would adversely affect competition.

§ 854(c) Considerations

Below, we also consider the eight § 854(c) factors:

(1) Maintain or improve the financial condition of the resulting public utility doing business in the state.

(2) Maintain or improve the quality of service to public utility ratepayers in the state.

(3) Maintain or improve the quality of management of the resulting public utility doing business in the state.

(4) Be fair and reasonable to affected public utility employees, including both union and nonunion employees.

(5) Be fair and reasonable to the majority of all affected public utility shareholders.

(6) Be beneficial on an overall basis to state and local economies, and to the communities in the area served by the resulting public utility.

(7) Preserve the jurisdiction of the commission and the capacity of the commission to effectively regulate and audit public utility operations in the state.

(8) Provide mitigation measures to prevent significant adverse consequences which may result.

Based on the record of this proceeding and as discussed below, we find that the Transaction, as conditioned by the Agreement, will:

(1) Maintain or improve (a) the financial condition of the resulting public utility doing business in the state, (b) the quality of service to public utility ratepayers in the state, and (c) maintain or improve the quality of management of the resulting public utility doing business in the state;

(2) Be fair and reasonable to (a) affected public utility employees, including both union and nonunion employees, and (b) the majority of all affected public utility shareholders;

(3) Be beneficial on an overall basis to state and local economies, and to the communities in the area served by the utilities; and

(4) Not result in any known significant adverse consequences, such as safety impacts, for which the Joint Applicants should provide mitigation measures.

As proposed, after consummation of the Transaction, Park Water and AVR will continue to operate business as usual. Operation and service will not be disrupted or changed. A notable benefit to both the ratepayers and shareholders would be that the new owners bring significant management and industry experience with a long-term commitment to maintaining high-quality service for the customers of Park Water and AVR. Liberty Utilities demonstrated the resources, expertise and service track record with water utilities (e.g., 1/3 of its 485,000 customers receiving water service) to operate Park Water and AVR. No party has provided any evidence to the contrary. Similarly, there is no evidence that the Transaction will have any adverse effect on the financial condition, quality of customer service, or quality of management of the affected utilities.

The Joint Applicants reassure the Commission that the Transaction will not impact the utilities' costs of capital or operations, assets or liabilities, or their revenue requirements. They also reassure the Commission that the Transaction will not affect the policies of either Park Water or AVR with respect to customer service, capitalization, rates, or other matters relating to the public interest or to the utilities' operations.[13]

The Transaction is fair and reasonable for the utilities' employees, because it assures the Park Water and AVR employees future stability and certainty of employment after consummation of the Transaction. The Transaction ensures the stable future operation of Park Water and AVR beyond 2021 (or sooner) when the Carlyle Infrastructure dissolves. The Exhibit B to the Application, the Merger Agreement, also explicitly requires that continuing employees will be compensated at current or greater wage and salary levels and be provided benefits and terms of employment that are substantially equivalent to those they currently enjoy. In addition, Liberty Utilities has committed to retaining the operational headquarters of Park Water and AVR in California.

The Transaction is fair and reasonable for the utilities' shareholders, because it assures them long-term commitment, support and backing of Algonquin that has never sold any of the utilities it previously acquired. The Joint Applicants further assure the Commission that Liberty Utilities has no plan to sell Park Water or AVR after acquisition.

The Transaction is also beneficial on an overall basis to state and local economies, and to the communities in the area served by the utilities. As discussed in Section 3.1 of this decision, one of the key concerns raised by the

[13] *Id.* at 4.

parties (and echoed by the members of the public at the PPHs) is ensuring continued safe and reliable water service for the Park Water and AVR customers. Such continuity has both direct and indirect beneficial effects on the local and state economies. Safe and reliable water service is vital to the production of goods and services in many sectors including agriculture, tourism, fishing, manufacturing, and energy production. Moreover, the ripple effects of disrupted or uncertain water service in the affected local regions will go far beyond the local areas to impact the state's economy. The Transaction resolves service continuity concerns by putting in place a qualified owner/operator for Park Water and AVR well in advance of the planned dissolution of Carlyle Infrastructure, which currently controls these utilities.

No Negative Ratepayer Impact under Code §§ 854(b) and (c)

Given the circumstances of the Transaction and based on our foregoing discussion, we find that there are numerous positive public interest effects of the Transaction and no negative adverse impact to ratepayers resulting from the Transaction. We find that, the Transaction, as conditioned by the Agreement, meets the ratepayer indifference standard and is in the public interest.

No Negative Safety Impact

Based on our foregoing discussion and our review of the record, we find that there is no adverse safety impact resulting from the Transaction.

§ 854(d) and Reasonable Options/Alternatives

§ 854(d) provides that when reviewing a merger, acquisition, or control proposal, such as the Transaction here, the Commission shall consider reasonable options or alternatives recommended by other parties, including no new merger, acquisition, or control, to determine whether comparable short-term and long-

term economic savings can be achieved through other means while avoiding the possible adverse consequences of the proposal.

Here, in considering other reasonable options or alternatives to the Transaction, no alternative option has been presented by any of the parties to this proceeding. We note, in particular that Apple Valley did not oppose the Agreement or present any alternate proposal. Moreover, as discussed above, the Transaction does not result in any adverse consequence. As such, there is no need to explore alternatives or options to avoid or mitigate any adverse consequences here.

3.3. Compliance with Rule 12.1

The record of this proceeding shows that the Settling Parties made timely and required filings of the Motion and the Agreement. The record also shows that the settlement conference was timely and properly noticed and held. The Motion states factual and legal considerations adequate to advise the Commission of the scope of the Agreement and of the grounds for its adoption, and the Agreement was limited to the issues in this proceeding. We therefore find that the Settling Parties complied with the Rules 12.1 (a) and (b).

The Agreement complies with Rule 12.1(d). As discussed in the foregoing Section 3.2 of this decision, we find that the Agreement complies with the applicable statutes, prior Commission decisions, and other applicable laws governing the Transaction, including §§ 851 *et seq.* and the ratepayer indifference standard. Also as discussed in Sections 3.1 and 3.2 of this decision, we find the Agreement reasonable and in the public interest.

3.4. Conclusion

Based on the foregoing, we conditionally authorize the Transaction and adopt the Agreement.

4. California Environmental Quality Act

Under the California Environmental Quality Act (CEQA)[14] and Rule 2.4, we are required to consider the environmental consequences of projects that are subject to our discretionary approval.[15] The Application demonstrates that Park Water and AVR will continue to operate as they did before the transfer of control under the Transaction. Therefore, the Transaction qualifies for an exemption from CEQA pursuant to § 15061(b)(3) of the CEQA Guidelines, inasmuch as it can be seen with certainty that the project will have no significant impact upon the environment. As such, there is no need for an environmental review here.

5. Categorization and Need for Hearings

In Resolution ALJ 176-3347 dated December 4, 2014, the Commission preliminarily categorized this application as Ratesetting and preliminarily determined that hearings were necessary. However, based upon the Agreement and the Motion, we determine that a hearing is no longer necessary.

6. Assignment of Proceeding

Carla J. Peterman is the assigned Commissioner and Kimberly Kim is the assigned ALJ in this proceeding.

Findings of Fact

1. The Transaction proposed in the Application involves a merger of two holding companies wherein Liberty WWH would merge with and into Western Water Holdings.

2. The surviving entity, Western Water Holdings, will continue to be the direct parent company of Park Water and AVR, but will become a direct

[14] California Public Resources Code §§ 21000 *et seq.*

[15] *See* Public Resources Code § 21080.

wholly-owned subsidiary of Liberty Utilities. As a result, Liberty Utilities will acquire control over Park Water and AVR from Carlyle Infrastructure.

3. Park Water and AVR will continue to operate as they did before the transfer of control.

4. On May 29, 2015, in accordance with Rule 12.1 of the Commission's Rules, the Settling Parties filed the Motion seeking Commission adoption of the Agreement which includes 26 Regulatory Commitments to govern various aspects of the future governance and operations of Park Water and AVR.

5. The 26 Regulatory Commitments reflect (a) the commitments proposed and set forth in Exhibit I of the Application; (b) the same conditions that the Commission adopted in approving similar recent transfers of control of utilities; and (c) additional regulatory commitments to address the concerns raised by the protesting parties to this proceeding.

6. The 26 Regulatory Commitments directly respond to and address the ratepayer impact concerns raised by the parties in this proceeding, including those raised by the members of the public at the PPHs by (a) ensuring continued safe, reliable and reasonable operation of Park Water and AVR; (b) protecting the ratepayers from post-Transaction rate increases; and (b) expressly acknowledging and reaffirming Commission's continued regulatory oversight over Park Water and AVR.

7. All of the parties to this proceeding, with the exception of Apple Valley, are parties to the Agreement and support the Motion and the adoption of the Agreement. No party filed any objection or opposition to the Motion.

8. To determine whether the Transaction should be authorized under § 854, the Commission must weigh the affected public interests and apply the

"ratepayer indifference standard" to determine that no harm or negative effect on the ratepayer would result from the change of control.

9. Under the ratepayer indifference standard, the Transaction does not need to fully meet the §§ 854(b) and (c) requirements. Instead, the ratepayer indifference standard provides that, looking at those considerations, we must find that there is no negative ratepayer impact.

10. In weighing the potential negative public interest impacts of the Transaction, the Commission may consider some or all of the § 854(b) and § 854(c) factors.

11. Under § 854(d), the Commission must consider reasonable options, if any, as alternatives to the Transaction to determine whether comparable short-term and long-term economic savings can be achieved while avoiding the possible adverse consequences of the Transaction.

12. No alternative option has been presented by any of the parties to this proceeding; and the Transaction does not result in any adverse consequence.

13. The Transaction has numerous positive public interest effects and no adverse impact on ratepayers.

14. There is no adverse safety impact resulting from the Transaction.

15. This decision makes no changes to rates or charges.

Conclusions of Law

1. The Agreement should be adopted.

2. The Application should be conditionally approved and the conditions of our approval should be the 26 Regulatory Commitments set forth in the Agreement.

3. The Transaction set forth in the Application, combined with conditions set forth in the Agreement, complies with and meets the requirements of the

applicable statutes, prior Commission decisions, and other applicable laws governing the Transaction, including Code §§ 851 *et seq.* and the ratepayer indifference standard.

4. The Settling Parties complied with the Rules 12.1 (a) and (b); and the Agreement complies with Rule 12.1(d) and is consistent with law, in the public interest and reasonable in light of the whole record.

5. Because there is no adverse consequence of the Transaction, there is no need to explore alternative options to avoid or mitigate any adverse consequences from the Transaction.

6. The Transaction is exempt from CEQA pursuant to § 15061(b)(3) of the CEQA Guidelines, inasmuch as it can be seen with certainty that the project will have no significant impact upon the environment.

7. Adoption of the Agreement does not constitute approval of, or precedent regarding, any principle or issue in the proceeding or in any future proceeding.

8. Adoption of the Agreement does not prejudge or limit the Commission's discretion in the future regulation of Park Water or AVR.

9. This decision makes no changes to rates or charges.

10. A hearing is no longer necessary.

11. This proceeding should be closed, and the decision should take effect immediately.

O R D E R

IT IS ORDERED that:

1. The proposed settlement agreement of the Office of Ratepayer Advocates with Liberty Utilities Co, Liberty WWH, Inc., Western Water Holdings, LLC, Park Water Company, and Apple Valley Ranchos Water Company, is attached and incorporated as Appendix A to this decision and is approved and adopted.

2. Pursuant to Public Utilities Code Sections 851, 852, and 854, the merger of Liberty WWH, Inc. with and into Western Water Holdings, LLC. is conditionally authorized, subject to the 26 Regulatory Commitments detailed in Appendix A to this decision.

3. Hearings are not necessary.

4. Application 14-11-013 is closed.

This decision is effective today.

Dated December 17, 2015, at San Francisco, California.

MICHAEL PICKER
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
LIANE M. RANDOLPH
Commissioners

A.14-11-013 ALJ/KK2/jt2

APPENDIX A

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Joint Application of Liberty Utilities Co., Liberty WWH, Inc., Western Water Holdings, LLC, Park Water Company (U 314 W), and Apple Valley Ranchos Water Company (U 346 W) for Authority for Liberty Utilities Co. to Acquire and Control Park Water Company and Apple Valley Ranchos Water Company.	Application 14-11-013 (Filed November 24, 2014)

SETTLEMENT AGREEMENT AMONG THE OFFICE OF RATEPAYER ADVOCATES, LIBERTY UTILITIES CO., LIBERTY WWH, INC., WESTERN WATER HOLDINGS, LLC, PARK WATER COMPANY (U 314 W), AND APPLE VALLEY RANCHOS WATER COMPANY (U-346-W)

1. GENERAL

1.1 Pursuant to Article 12 of the Rules of Practice and Procedure ("Rules") of the California Public Utilities Commission ("Commission"), Liberty Utilities Co. ("Liberty Utilities"), Liberty WWH, Inc. ("Liberty WWH"), Western Water Holdings, LLC ("Western Water Holdings"), Park Water Company ("Park Water"), and Apple Valley Ranchos Water Company ("AVR") (collectively, "Joint Applicants") and the Office of Ratepayer Advocates ("ORA") (collectively, the "Parties") have agreed on the terms of this Settlement Agreement which they now submit for approval. This Settlement Agreement addresses the Joint Application of Liberty Utilities, Liberty WWH, Western Water, Park Water, and AVR for authority for Liberty WWH to merge with and into Western Water Holdings, and Liberty Utilities, as a consequence of such merger, to acquire Western Water Holdings and thus indirectly control Park

Water and AVR ("Application"). The Parties respectfully request that the Commission grant such authorization, subject to the terms and conditions of this Settlement Agreement.

1.2 Since this Settlement Agreement represents a compromise by each of them, the Parties have entered into each stipulation contained in the Settlement Agreement on the basis that its approval by the Commission should not be construed as an admission or concession by any Party regarding any fact or matter of law in dispute in this proceeding. Furthermore, the Parties intend that the approval of this Settlement Agreement by the Commission not be construed as a precedent or statement of policy of any kind for or against any Party in any current or future proceeding (Rule 12.5, Commission's Rules on Practice and Procedure).

1.3 The Parties agree that no signatory to the Settlement Agreement assumes any personal liability as a result of their agreement. All rights and remedies of the Parties are limited to those available before the Commission.

1.4 The Parties agree that this Settlement Agreement is an integrated agreement, so that if the Commission rejects any portion of this Settlement Agreement, each Party has the right to withdraw. Furthermore, the Settlement Agreement is being presented as an integrated package such that Parties are agreeing to the Settlement Agreement as a whole rather than agreeing to specific elements of the Settlement Agreement.

1.5 This Settlement Agreement may be executed in counterparts, each of which shall be deemed an original, and the counterparts together shall constitute one and the same instrument.

1.6 No Party has relied or presently relies upon any statement, promise or representation by any other Party, whether oral or written, except as specifically set forth in this

Settlement Agreement. Each Party expressly assumes the risk of any mistake of law or fact made by such Party or its authorized representatives.

1.7 This Settlement Agreement constitutes and represents the entire agreement among the Parties and supersedes all prior and contemporaneous agreements, negotiations, representations, warranties and understandings of the Parties with respect to the subject matter set forth herein.

1.8 This Settlement Agreement settles all outstanding issues in this proceeding among the Parties.

2. BACKGROUND

2.1 On September 19, 2014, Liberty Utilities, Liberty WWH, Inc. and Western Water Holdings executed a Plan and Agreement of Merger (the "Merger Agreement"). Pursuant to the terms of the Merger Agreement, Liberty WWH and Western Water Holdings will merge and the surviving entity, Western Water Holdings, will become a direct wholly owned subsidiary of Liberty Utilities, as of the effective time of the merger (the "Effective Time"). Thus, as of the Effective Time, Western Water Holdings will continue to be the direct parent company of Park Water and AVR.

2.2 On November 24, 2014, the Joint Applicants filed the Application, A.14-11-013, to request Commission authorization of the proposed acquisition of ownership and control over Park Water and AVR by Liberty Utilities Co. pursuant to the Merger Agreement. A prehearing conference was held on February 6, 2015, before Administrative Law Judge ("ALJ") Kim, and ALJ Kim also presided over public participation hearings held in the afternoon and evening of March 16, 2015, in the Town of Apple Valley.

2.3 On May 6, 2015, ORA delivered a set of proposed regulatory commitments to the Joint Applicants that provided the framework for a settlement. The terms of the present Settlement Agreement were developed through a series of further communications among the Parties.

2.4 On May 19, 2015, in accordance with Rule 12.1(b), the Joint Applicants, with the concurrence of the Office of Ratepayer Advocates and the Town of Apple Valley, convened and invited all parties to the proceeding to participate in a conference for the purpose of discussing settlement, to be held by conference telephone call on May 27, 2015.

2.5 A draft document with terms identical to those of the present Settlement Agreement was sent to all parties to the proceeding on May 21, 2015, along with a draft Motion for Commission approval of the Settlement Agreement.

2.6 The previously noticed settlement conference was held as scheduled on May 27, 2015, with participants including representatives of the Parties as well as the Town of Apple Valley. Participants discussed and clarified certain aspects of the Settlement Agreement and also discussed the Parties' intention to file a joint motion for Commission approval of the Settlement Agreement and the procedural events to follow.

2.7 The Parties executed the Settlement Agreement and submitted it for filing with the Commission on May 29, 2015.

3. REGULATORY COMMITMENTS

3.1 The proposed transaction shall have no effect on the Commission's authority over the provision of public utility service to the public by Park Water Company ("Park Water") and Apple Valley Ranchos Water Company ("AVR").

3.2 Park Water and AVR shall comply with all applicable California and federal laws and administrative regulations.

3.3 Park Water and AVR shall each continue to be held in separate legal entities. Affiliates of Liberty Utilities own and operate a non-utility cogeneration power plant in the Fresno area ("Sanger Cogeneration"). Affiliates of Liberty Utilities also own, are constructing and intend to operate a solar generation facility project in the Bakersfield area ("South Kern Solar"). There shall be no overlapping of employees or responsibilities between the operations of Sanger Cogeneration and/or South Kern Solar and Park Water and/or AVR.

3.4 Affiliates of Liberty Utilities own and operate Liberty Utilities (CalPeco Electric) LLC (U-933), ("Liberty Utilities CalPeco"), which is an electric distribution public utility regulated by the California Public Utilities Commission. With respect to the relationships between Liberty Utilities CalPeco and Park Water and/or AVR:

3.4 (a) The assets of Park Water and AVR shall be held in legal entities separate from Liberty Utilities CalPeco; and

3.4 (b) The capitalization and financing for Park Water and AVR and for Liberty Utilities CalPeco shall be separate.

3.5 Park Water and/or AVR shall not provide financing or guarantees for, extend credit to, or pledge utility assets in support of Liberty Utilities CalPeco, Liberty Utilities, Western Water Holdings, LLC ("Western Water Holdings"), Sanger Cogeneration or South Kern Solar or any of their affiliates except as permitted by the Affiliate Transaction Rules. Liberty Utilities CalPeco, Liberty Utilities, Western Water Holdings, Sanger Cogeneration, and South Kern Solar each shall finance and fund their respective other business activities independently of Park Water and AVR.

3.6 To the extent that Liberty Utilities, Liberty Utilities CalPeco, Western Water Holdings, Sanger Cogeneration, or South Kern Solar shall finance their respective business activities other than Park Water and AVR's respective provision of public utility water service, any such financing shall provide the financing parties no recourse to either Park Water's and/or AVR's assets.

3.7 Park Water and AVR shall not transfer any physical assets owned by Park Water or AVR and used to provide regulated utility services to their respective customers to either Liberty Utilities, Western Water Holdings, or Liberty Utilities CalPeco or any of their respective affiliates without first obtaining the necessary approvals from the Commission.

3.8 Park Water and AVR shall each hold all of their respective assets in their own name, and will maintain adequate capital and have access to sufficient employees and other personnel to perform their respective public utility responsibilities.

3.9 Park Water and AVR shall be provided adequate capital to fulfill all of their public utility service obligations. The term "capital" encompasses "money and property with which a company carries on their corporate business; a company's assets, regardless of source, utilized for the conduct of its corporate business and for the purpose of deriving gains and profits; and a company's working capital," and is not limited to mean only "equity capital, infrastructure investment, or any other term that does not include, simply, money or working cash." (Decision 02-01-039, Findings of Fact 5 and 6. 2002 Cal. PUC LEXIS 5 *57.)

3.10 Park Water and AVR shall be provided the capital necessary to provide safe and reliable utility standard water service.

3.11 Park Water and AVR will notify the Commission of any dividends and distributions to Western Water Holdings or other affiliates in their Annual Reports to the Commission (filed on or about March 31 of each year).

3.12 Neither Park Water nor AVR shall issue long-term debt or guarantee any debt of any of their affiliates without prior approval by the Commission.

3.13 Neither Park Water nor AVR shall sell, transfer, or encumber any utility assets necessary or useful to provide utility service, or any water rights, without prior approval by the Commission.

3.14 Park Water and AVR shall continue to maintain their books and records in accordance with all Commission rules. Park Water's and AVR's books and records shall be maintained and be available in California. With respect to any charge or allocation from an affiliate for which Park Water or AVR seeks rate recovery, the documents necessary to support and substantiate the charge shall be available to the Commission.

3.15 The transfer of ownership and control will not adversely affect Park Water's or AVR's provision of regulated water service to customers, or practices relating to operations, financing, accounting, capitalization, rates, depreciation, maintenance, or other matters relating to the public interest or utility operations.

3.16 Customer service to Park Water's and AVR's customers will not be affected by the transaction. Park Water's and AVR's commitment to high quality public utility water service and community involvement shall be maintained.

3.17 Park Water and AVR shall maintain their current operational headquarters in California and shall maintain local offices as appropriate to maintain the high quality of customer service and community involvement.

3.18 The proposed transaction shall not adversely affect any of the outstanding debt owed and recorded as liabilities on the regulated books of Park Water and AVR. There shall be no increase in Park Water's or AVR's cost of service or reduction in quality of service resulting from the proposed transaction. Credit extended by Liberty Utilities, Western Water Holdings or

any of their parents or affiliates to Park Water or AVR will be at rates and upon terms no less advantageous than those otherwise available to Park Water and AVR from unaffiliated third parties for similar transactions.

3.19 The utility customers of Park Water and AVR shall not incur, directly or indirectly, any transaction costs or other liabilities or obligations arising from the proposed transaction. In particular, any expenses incurred by Park Water or AVR due to the proposed transaction or the related Commission proceeding in which the parties to the transaction are seeking Commission approval for the transaction (such as outside legal expense and travel costs) shall be accounted for as non-utility expense and shall not be included in the recorded base of any account included in the calculation of revenue requirement for future rate cases. Park Water and AVR, respectively, recognize that their incurrence of any such "transaction costs" is not related to the provision of water service to their respective customers and thus these costs are necessarily to be borne exclusively by their owners.

3.20 Park Water and AVR shall not incur any additional indebtedness, issue any additional securities, or pledge any assets to finance any part of the proposed transaction.

3.21 Affiliates of Park Water and Western Water Holdings shall take no actions that would impair Park Water's or AVR's ability to fulfill their public utility obligations to serve and to operate in a prudent and efficient manner.

3.22 Any activities or actions directed at enhancing or increasing Western Water Holdings' investment in Park Water or AVR will require Commission approval for reflection of such investment in rates.

3.23 Affiliates of Park Water, including Western Water Holdings, shall not require Park Water or AVR to take any action inconsistent with AVR's rights under the terms of the Mojave Basin Adjudication (City of Barstow v. City of Adelanto, Riverside Superior Court Case No. 208568) and the Judgment After Trial, entered January 10, 1996, as amended December 5, 2002, in that case.

3.24 Park Water and AVR, and Western Water Holdings as the parent of Park Water, shall comply with the Affiliate Transaction Rules adopted by the Commission in Rulemaking 09-04-012, Decision No. 10-10-019 as modified in D. 11-10-034 and D. 12-01-042.

3.25 Operating Commitments.

3.25 (a) Park Water or AVR will conduct business in the same or similar manner as it has under Western Water's ownership concerning functions such as water supply and delivery, contracting and management, system operation and maintenance activities, safety and service reliability, customer service functions, and billing operations.

3.25 (b) With respect to regulatory relations, Park Water or AVR will maintain a manager level representative (having such authority as may be required by the Commission) physically present in an office located within or in close proximity to their California service territories with primary responsibility for maintaining the companies' positive relationships with, and responding to requests for information from, the Commission and other State regulatory agencies.

3.25 (c) For an initial period extending through the filing of their respective next general rate cases, Park Water and AVR will maintain all their respective tariff rates existing at the day of completion of the transfer of ownership to Liberty Utilities (Closing Date) or approved by the Commission in response to filings made by Park Water or AVR prior to the Closing Date, or arising from such filings (*e.g.*, step rate adjustments, rate base offsets provided

for in GRC decisions, or applications for rehearing), cost of capital filings in accordance with the rate case plan, or cost offset filings as allowed by the Commission. In this § 854(a) proceeding, neither Park Water nor AVR is requesting any increase in rates or in the total revenue requirement as a result of this transaction. Accordingly, on the day after the Closing Date, rates for the customers of each of Park Water and AVR shall not change as a result of this transaction and the total revenue requirement for each of Park Water and AVR also shall not change as a result of this transaction.

3.25 (d) Park Water and AVR shall provide service to their customers in compliance with all rules, regulations and decisions issued by the Commission. Among other matters, Park Water and AVR will not change any rate or any other terms and conditions of service for their respective customers without first having obtained the necessary Commission approvals and Park Water and AVR shall comply with all existing statutes and applicable Commission regulations regarding affiliated interest transactions.

3.25 (e) Liberty Utilities agrees, as part of the pending request under § 854(a) to acquire Park Water and AVR, that the acquired utilities shall maintain their respective existing low-income programs. Park Water and AVR shall each operate within the existing rate case cycles now in effect for Park Water and AVR, respectively, including for general rates, annual step rate adjustments, and cost of capital reviews, in accordance with the rate case plan (*see*, D.07-05-062, App. A).

3.25 (f) Park Water and AVR shall adopt, maintain and strive to improve the high quality of service standards that Park Water and AVR presently provide their customers.

3.26 Premium and Cost Synergies.

3.26 (a) Park Water and AVR agree that their respective rate recovery shall be calculated based on the amount of their respective rate base that has been or will be authorized, totally independent of the purchase price for Liberty Utilities to acquire Park Water and AVR. Park Water and AVR shall in no event seek to recover the excess of the purchase price over the regulatory basis of the utility assets (i.e., "premium") in rates. Any premium which Liberty Utilities shall pay shall not be recorded in the accounts of Park Water or AVR utilized in the establishment of rates and tariffs for either Park Water or AVR.

3.26 (b) The cost levels Park Water and AVR shall use to request rates in future general rate cases shall be based on the actual recorded and forecasted costs of Park Water and AVR, respectively, consistent with Commission practice and precedents for the setting of general rates and will incorporate any cost savings synergies arising in comparison to the baseline costs to be established in AVR's Test Year 2015 and Park Water's Test Year 2016 rate cases, respectively. In AVR's Test Year 2018 and 2021 general rate applications and in Park Water's Test Year 2019 and 2022 general rate applications, respectively, the applicant shall report on any significant changes that have been made, or are intended to be made, to their respective corporate structure and on their estimated financial impacts on the AVR and Park Water operations, respectively.

4. REGULATORY COMMITMENTS AS CONDITIONS OF APPROVAL OF THE PROPOSED TRANSACTION

4.1 As conditions of approval of the proposed transaction, the Joint Applicants accept and agree to all of the specific regulatory commitments set forth in Part 3 of this Settlement Agreement, which will govern certain aspects of the relationship among Park Water and AVR on

the one hand and the acquiring company, Liberty Utilities, and its affiliates on the other, as well as the Commission's oversight of Park Water's and AVR's future operations.

4.2 The Joint Applicants agree to abide by each and every one of the regulatory commitments set forth in Part 3 of this Settlement Agreement upon the Commission's approval of the Application and consummation of the proposed transaction.

Respectfully submitted,

OFFICE OF RATEPAYER ADVOCATES

By: _____
Joseph P. Como
Its: Interim Director

LIBERTY UTILITIES CO.

By: _____
Greg Sorensen
Its: President

LIBERTY WWH, INC

By: _____
Greg Sorensen
Its: Chief Financial Officer, Secretary and Treasurer

WESTERN WATER HOLDINGS, LLC

By: _____
Robert Dove
Its: Chairman of the Board

PARK WATER COMPANY

By: _____
Christopher Schilling
Its: President / Chief Executive Officer

APPLE VALLEY RANCHOS WATER COMPANY

By: _____
Leigh K. Jordan
Its: Executive Vice President

Dated: May 29, 2015

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Christopher Schilling
Its: President / Chief Executive Officer

APPLE VALLEY RANCHOS WATER COMPANY

By: _____
Leigh K. Jordan
Its: Executive Vice President

Dated: May 29, 2015

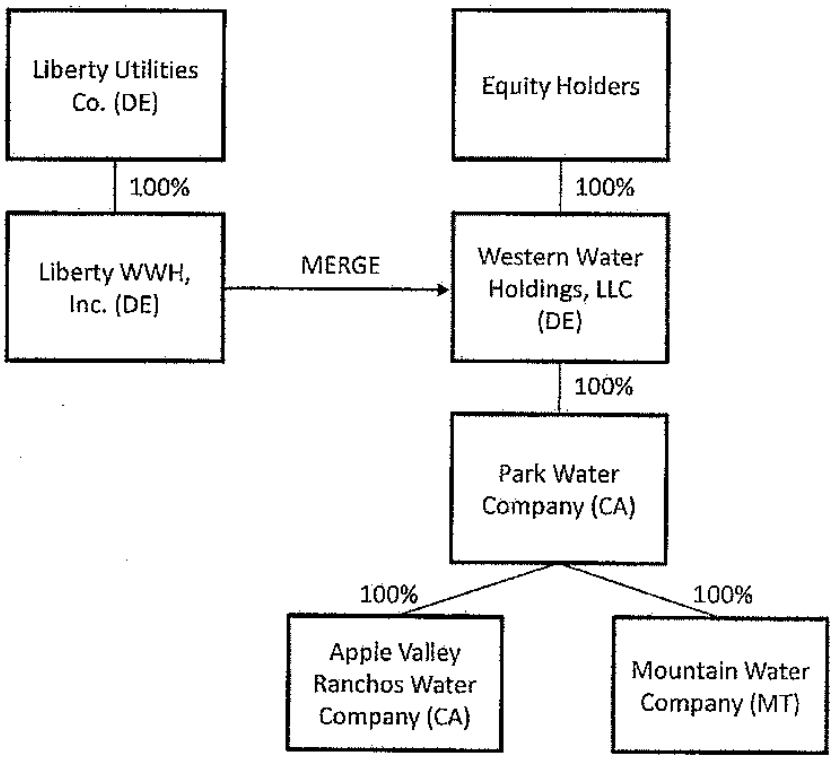
(End of Appendix A)

A1411013 ALJ/KK2/jt2

APPENDIX B

A1411013 ALJ/KK2/jt2

PROPOSED POST-TRANSACTION CORPORATE



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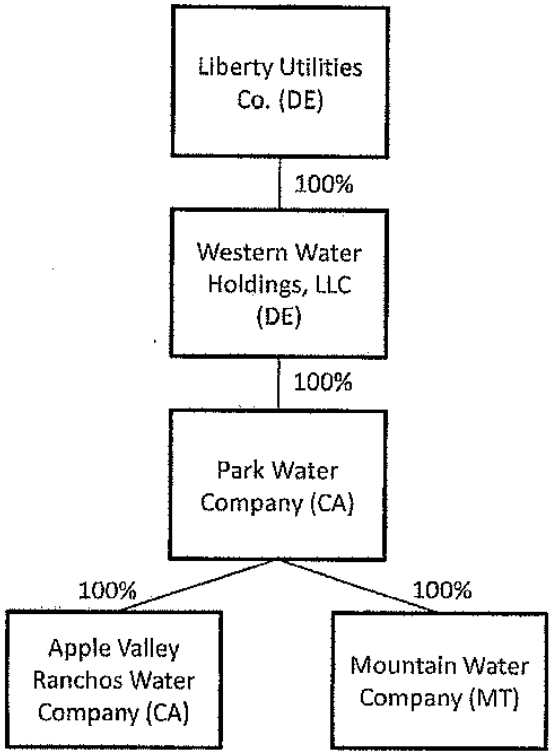

(End of Appendix

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

National Grid USA, National Grid NE Holdings 2 LLC,
Granite State Electric Company d/b/a National Grid,
EnergyNorth Natural Gas, Inc. d/b/a National Grid NH,

- and –

Liberty Energy Utilities Co. and Liberty Energy Utilities (New Hampshire) Corp.

Docket No. DG 11-040

Joint Petition for Authority to Transfer Ownership of Granite State Electric and EnergyNorth Natural Gas, Inc. to Liberty Energy Utilities (New Hampshire) Corp.

SETTLEMENT AGREEMENT – JOINT PETITION FOR AUTHORITY TO TRANSFER OWNERSHIP

April 10, 2012

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STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

National Grid USA, National Grid NE Holdings 2 LLC,
Granite State Electric Company d/b/a National Grid,
EnergyNorth Natural Gas, Inc. d/b/a National Grid NH,

- and –

Liberty Energy Utilities Co. and Liberty Energy Utilities (New Hampshire) Corp.

Docket No. DG 11-040

Joint Petition for Authority to Transfer Ownership of Granite State Electric and EnergyNorth Natural Gas, Inc. to Liberty Energy Utilities (New Hampshire) Corp.

SETTLEMENT AGREEMENT – JOINT PETITION FOR AUTHORITY TO TRANSFER OWNERSHIP

This Settlement Agreement ("Agreement") is entered into as of the ___ day of April, 2012, by and among National Grid USA, National Grid NE Holdings 2 LLC ("National Grid NE") (National Grid USA and National Grid NE are collectively referred to hereinafter as "National Grid"), Granite State Electric Company d/b/a National Grid ("Granite State"), EnergyNorth Natural Gas, Inc. d/b/a National Grid NH ("EnergyNorth"), Liberty Energy Utilities Co. ("Liberty Energy"), Liberty Energy Utilities (New Hampshire) Corp. ("Liberty Energy NH"), the staff ("Staff") of the New Hampshire Public Utilities Commission (the "Commission"), the Office of Consumer Advocate ("OCA"), Pamela Locke, The Way Home, United Steel Workers of America Local 12012-3 ("USWA"), International Brotherhood of Electrical Workers Local 326 ("IBEW"), Granite State Hydropower Association ("GSHA"), and New Hampshire Community Action Association ("NHCAA"). The foregoing are hereinafter referred to collectively as the "Settling Parties and Staff."

I. SUMMARY

This Agreement resolves all issues in the case and constitutes the recommendations by the Settling Parties and Staff for the Commission's approval of:

(1) The transfer of ownership of Granite State and EnergyNorth (collectively, "the Companies") along with other specified conditions;

(2) An Agreement for Granite State that, among other things, includes certain commitments regarding its next base rate case, including a commitment not to seek new distribution rates with a proposed effective date that is sooner than January 1, 2013, and certain commitments relating to information technology, customer service and other operational matters;

(3) An Agreement for EnergyNorth that, among other things, includes a commitment that the test year for its first base rate case after the Closing Date (as defined in footnote 6 in Section V.C.1.a below) will end no sooner than the first to occur of (i) 270 days after seventy percent of the total cost of Transition Services (as defined in Section V.E.1 below) provided under the EnergyNorth Transition Service Agreement (as defined in Section II.B.1 below) are paid or (ii) three years from the date of closing; a plan that provides for the continued replacement of cast iron and bare steel pipe in EnergyNorth's system; and certain commitments relating to information technology, customer service and other operational matters; and

(4) Authorization for Granite State and EnergyNorth to issue new long term debt instruments in order to recapitalize both companies in connection with their acquisition by Liberty Energy NH.

II. BACKGROUND REGARDING PARTIES TO TRANSACTION AND PROPOSED TRANSFER OF CONTROL OF UTILITIES

A. Joint Petitioners and Related Entities

Algonquin Power & Utilities Corp. ("Algonquin") is a publicly traded corporation that is traded on the Toronto Stock Exchange and is incorporated under the laws of Ontario, Canada, with a principal place of business in Oakville, Ontario. Algonquin has two business units: (i) a power generation unit that includes forty-five renewable power generating facilities and nine high-efficiency thermal generating facilities located in six U.S. states and Canada, and (ii) a utility services unit that owns and operates twenty-two regulated utilities located in five states that

provide retail water, sewer and electric utility service. Algonquin has been doing business in New Hampshire since 1998 when its predecessor entity acquired the first of its eight New Hampshire hydroelectric facilities.

Algonquin is one of the largest renewable power companies in Canada. Algonquin owns and operates an approximately $1.1 billion (U.S.) portfolio of renewable power electric generation and utility operations across North America. As of the date of this Agreement, over fifty percent of Algonquin's revenues are generated through its U.S.-based operations. Algonquin acquired its first regulated utility operations in 2001 and since then has acquired twenty-one different water and waste water utilities and one electric utility serving a total of approximately 125,000 customers in the United States.

Liberty Utilities Co. ("Liberty Utilities") is a Delaware corporation and conducts the U.S. regulated utility business of Algonquin.[1] In addition to the acquisition of Granite State and EnergyNorth, Liberty Utilities, through its subsidiaries, is in the process of acquiring gas utilities serving 83,000 customers in three states. Liberty Energy is a Delaware corporation and a wholly owned subsidiary of Liberty Utilities and an indirect subsidiary of Algonquin. Liberty Energy NH is a Delaware corporation that is wholly and directly owned by Liberty Energy. Liberty Energy NH was formed for the purpose of acquiring ownership of the stock of Granite State and EnergyNorth.

National Grid USA is a public utility holding company incorporated in the state of Delaware. It is an indirect, wholly-owned subsidiary of National Grid plc, the parent holding company incorporated in England and Wales. National Grid plc's United States business is conducted through National Grid USA. National Grid USA, in turn, provides electric and natural

[1] Attachment A to this Agreement is an organizational chart showing the Liberty Utilities Family of Companies.

gas service to customers in New England and New York through a number of indirectly owned subsidiaries, including Granite State and EnergyNorth in New Hampshire.

Granite State is a New Hampshire corporation and a public utility as defined in RSA 362:2. It provides retail electric service to approximately 43,000 customers in 21 communities in southern and western New Hampshire. Granite State is directly and wholly owned by National Grid USA, which acquired Granite State as the result of National Grid USA's merger with New England Electric System in 2000.

EnergyNorth is a New Hampshire corporation and a public utility as defined in RSA 362:2. It provides retail gas service to approximately 86,000 customers in 30 communities throughout southern and central New Hampshire and in Berlin, New Hampshire. EnergyNorth is wholly owned by National Grid NE, which itself is indirectly owned by National Grid USA. National Grid USA acquired EnergyNorth as the result of its merger with KeySpan Corporation in 2007.

B. Proposed Transaction

On December 8, 2010, National Grid USA, Liberty Energy, and certain of their respective affiliates entered into two stock purchase agreements, one for the sale and purchase of common stock of Granite State and one for EnergyNorth (collectively, the "Original Agreements"). On January 21, 2011, National Grid USA and Liberty Energy modified the Original Agreements in several limited respects by entering into amended and restated stock purchase agreements for both Granite State (the "GSE Amended and Restated Agreement") and EnergyNorth (the "ENGI Amended and Restated Agreement") (the GSE Amended and Restated Agreement and the ENGI Amended and Restated Agreement are hereinafter referred to collectively as the "Amended and Restated Agreements").

On February 16, 2011, Liberty Energy assigned its rights under the Amended and Restated Agreements to Liberty Energy NH, pursuant to which Liberty Energy NH will acquire the shares of common stock of Granite State and EnergyNorth.

On May 12, 2011, National Grid USA and Liberty Energy NH modified the Amended and Restated Agreements in certain limited respects by entering into letter agreements for both Granite State (the "GSE Letter Agreement", which, together with the GSE Amended and Restated Agreement, is hereinafter referred to as the "GSE Purchase Agreement") and EnergyNorth (the "ENGI Letter Agreement", which, together with the ENGI Amended and Restated Agreement, is hereinafter referred to as the "ENGI Purchase Agreement"). (The GSE Purchase Agreement and the ENGI Purchase Agreement are hereinafter referred to collectively as the "Purchase Agreements".) Specifically, the GSE Letter Agreement and the ENGI Letter Agreement extended the respective termination dates of the GSE Amended and Restated Agreement and the ENGI Amended and Restated Agreements to December 31, 2011 or, alternatively, June 30, 2012 if certain conditions of the closing were not yet fulfilled.[2]

Pursuant to the GSE Purchase Agreement, National Grid USA proposes to sell all of its Granite State shares to Liberty Energy NH (as assignee of Liberty Energy) for the aggregate purchase price of Eighty-Three Million Dollars ($83,000,000) in cash, less the amount of certain existing indebtedness of Granite State, and further adjusted based on Granite State's working capital, capital expenditures, and regulatory assets as of the date of closing.

Pursuant to the ENGI Purchase Agreement, National Grid NE proposes to sell and transfer all of its EnergyNorth shares to Liberty Energy NH (as assignee of Liberty Energy) for the

[2] Specifically, the GSE Letter Agreement and the ENGI Letter Agreement stipulate that, if required regulatory approvals had not become final orders by December 31, 2011, the termination dates of the Amended and Restated Agreements would be extended to June 30, 2012. Because certain required regulatory approvals, including those sought in this docket, had not been finalized as of December 31, 2011, the effective termination dates of the Amended and Restated Agreements is June 30, 2012.

aggregate purchase price of Two Hundred Two Million Dollars ($202,000,000) in cash, adjusted based on EnergyNorth's working capital, environmental remediation costs, capital expenditures, and regulatory assets as of the date of closing.

The Purchase Agreements are each subject to several closing conditions, including obtaining requisite regulatory approvals. The proposed stock transfers are subject to the approval of the Commission, the Federal Energy Regulatory Commission ("FERC"), and the Federal Communications Commission ("FCC"). The stock transfers are also subject to review by the Federal Trade Commission ("FTC") under the Hart-Scott-Rodino Antitrust Improvements Act, and the Committee on Foreign Investment in the United States ("CFIUS") under the Exon-Florio provision of the Defense Production Act of 1950. To date, the proposed stock transfers have been approved by FERC, the FTC has granted early termination of the waiting period under the Hart-Scott-Rodino Antitrust improvements Act, the FCC has granted the license transfer approvals sought relative to Granite State and EnergyNorth, and CFIUS has issued closing letters indicating that there are no unresolved national security claims with respect to the transactions. The Purchase Agreements provide that they will terminate if the stock transfers are not consummated by or on June 30, 2012.

Upon consummation of the stock transfers, Algonquin will indirectly own, and Liberty Energy NH (as assignee of Liberty Energy) will directly own, Granite State and EnergyNorth.

1. Associated Agreements

In connection with the Purchase Agreements, Granite State and/or EnergyNorth will enter into certain agreements, to be effective as of the closing, with National Grid USA, or Algonquin, Liberty Utilities (Canada) Corp., Liberty Utilities, and Liberty Energy NH. Though the Joint

Petitioners (as defined in Section III below) do not seek Commission approval of these agreements, they are described generally below.

To support the operation of Granite State and EnergyNorth during the initial period following the stock transfer, National Grid USA will enter into Transition Service Agreements (collectively, the "TSAs" and individually a "TSA") with Granite State and EnergyNorth, to become effective as of the closing.[3] Under the TSAs, National Grid USA, either directly or through its affiliates, will provide various specified services to Granite State and EnergyNorth following the consummation of the stock transfers until Granite State and/or EnergyNorth notifies National Grid USA that the services provided under the respective TSAs are no longer needed. The TSAs provide for an estimated Transition Period (as defined in Section V.C.1.a below) for the each of the services, which represents the TSA parties' good faith estimate of the time required to transition responsibility for providing each service from National Grid USA to Granite State and/or EnergyNorth, rather than terminating all services simultaneously. Unexecuted final revised versions of the TSAs are attached hereto as Attachment B. Executed copies will be filed with the Commission within 30 days of Closing.

Effective as of the closing, EnergyNorth and Granite State each will enter into Affiliate Services Agreements with Algonquin, Liberty Utilities (Canada) Corp., Liberty Utilities and Liberty Energy NH (collectively, for the purposes of this subsection, the "Service Companies") for the provision of ongoing management, financial, and administrative services. In addition to establishing the services to be provided by each of the Service Companies to EnergyNorth and Granite State, the Affiliate Services Agreements govern, *inter alia*, charging and billing for such services. Copies of the proposed Affiliate Services Agreements are appended hereto as

[3] Copies of the TSAs were attached to the Joint Petition (as defined in Section III below) filed with the Commission on March 4, 2011 seeking approval of the proposed transaction.

Attachment C. EnergyNorth and Granite State each will file with the Commission executed copies of the respective Affiliate Services Agreements within ten (10) days following execution of such agreements pursuant to RSA 366:3.

Effective as of the closing, National Grid USA will enter into a letter agreement with Liberty Energy NH (the "Records Transfer and Retention Agreement") governing, *inter alia*, the transfer of certain records from National Grid USA to Liberty Energy NH and the retention of certain records not so transferred. An unexecuted final version of the Records Transfer and Retention Agreement is attached hereto as Attachment D. Copies of the executed agreement will be filed with the Commission within 30 days of Closing. Furthermore, Granite State, New England Power Company ("NEP"), a subsidiary of National Grid USA, and ISO New England, Inc. will enter into a site agreement ("Site Supplement"), effective as of the closing, governing access to, and the ongoing operation of, six electric substations where NEP and Granite State facilities are co-located. The Site Supplement is incorporated into a Local Service Agreement between NEP and Granite State for transmission service under Schedule 21 – NEP of Section II of the ISO-NE Transmission, Markets and Services Tariff. The Joint Petitioners provided a draft copy of the Site Supplement in a supplemental response to Staff technical session data request Staff TS 3-4. A copy of the final approved Site Supplement will be filed with the Commission within 30 days of Closing.

C. Other Requested Approvals

In addition to seeking the Commission's authorization to transfer the stock of Granite State and EnergyNorth, the two utilities each seek the Commission's authority pursuant to RSA 369:1 to issue a promissory note to Liberty Utilities. Specifically, Granite State seeks authority to issue a promissory note, substantially in the form submitted to the Commission on March 14, 2012, for up

to $20 million. Similarly, EnergyNorth seeks authority to issue a promissory note, substantially in the form submitted to the Commission on March 14, 2012, to Liberty Utilities for up to $90 million.

Granite State and EnergyNorth also seek the Commission's authority for each utility to record a regulatory asset or liability reflecting the fair market valuation as of the date of the stock transfers of their respective pension plans and other post-retirement employment benefits ("OPEBs") to be amortized over the average remaining service period of active employees expected to receive benefits under the plans.

III. PROCEDURAL BACKGROUND

On March 4, 2011, National Grid USA, National Grid NE, Granite State, EnergyNorth, Liberty Energy, and Liberty Energy NH (collectively, the "Joint Petitioners") filed with the Commission a Joint Petition for Authority to Transfer Ownership of Granite State Electric Company and EnergyNorth Natural Gas, Inc. to Liberty Energy Utilities (New Hampshire) Corp. and for Related Approvals (the "Joint Petition"). In support of the Joint Petition, the Joint Petitioners submitted the pre-filed direct testimony of the following witnesses: Ian Robertson; David Pasieka; Timothy F. Horan and David Pasieka (jointly); Andrew Ling, Gaetan Mercier, Daniel Saad, and Kurt Demmer (jointly); William Sherry, Gerald Tremblay and Robert C. Wood (jointly); Gerald Tremblay and David Bronicheski (jointly); and Peter Eichler. The OCA notified the Commission on March 10, 2011 that it would participate in the above-captioned docket on behalf of residential ratepayers consistent with RSA 363:28.

On March 29, 2011, the Commission issued an Order of Notice setting a prehearing conference and technical session for April 20, 2011, requiring that the Order of Notice be published in a newspaper of general circulation pursuant to Puc 203.12, and requiring intervenor

petitions by April 15, 2011. The Joint Petitioners provided notice of the hearing through the publication of the Order of Notice in the Union Leader on April 1, 2011. The following additional parties sought and were granted status as full intervenors: USWA, Pamela Locke, The Way Home, John Martino,[4] GSHA, IBEW, the Business and Industry Association ("BIA"), and NHCAA[5].

Following the prehearing conference held on April 20, 2011, Staff, the Joint Petitioners, OCA, and all other parties appearing at the prehearing conference met in a technical session and agreed upon a proposed schedule to govern the remainder of the proceeding, which the Staff submitted to the Commission by letter dated April 21, 2011. By secretarial letter dated April 25, 2011, the Commission approved the proposed procedural schedule. Since that date, the schedule has undergone various minor revisions.

On June 13 and 14 and September 7 and 8, 2011, technical sessions were held at the Commission to assist in the discovery process regarding the Joint Petitioners' filing. In addition, the Joint Petitioners responded to multiple rounds of data requests from Staff, OCA, and the intervenors and supplemented their responses as additional information became available during the course of the proceeding.

On October 7, 2011, Staff submitted written testimony of Steven E. Mullen, Assistant Director of the Commission's Electric Division, Stephen P. Frink, Assistant Director of the Commission's Gas & Water Division, Amanda O. Noonan, Director of the Commission's Consumer Affairs Division, Randall S. Knepper, Director of the Commission's Safety Division, and Gorham, Gold, Greenwich & Associates, LLC ("G3 Associates"). On the same date, the OCA filed written testimony of consultant Scott J. Rubin, and on October 17, 2011, USWA submitted

[4] Intervenor John Martino withdrew from these proceedings on February 3, 2012.

[5] NHCAA filed a petition for late intervention on May 25, 2011, and the Commission granted the petition by secretarial letter on June 16, 2011.

the written testimony of Mr. Kevin Spottiswood. On October 13, November 9 and 10, and December 7 and 8, 2011, settlement discussions were held at the Commission. As a result of those discussions and subsequent communications, the Settling Parties and Staff have agreed to the terms of this Agreement. The Settling Parties and Staff recommend that the Commission approve this Agreement without modification.

IV. SCOPE OF AGREEMENT

This Agreement constitutes the recommendation of the Settling Parties and Staff with respect to the Commission's approval of the proposed transfer of ownership of EnergyNorth and Granite State to Liberty Energy NH, and related matters. The Settling Parties and Staff agree to this joint submission to the Commission as their proposed resolution of all issues in this docket.

This Agreement shall not be deemed an admission by any of the Settling Parties or Staff that any allegation or contention in these proceedings by the Settling Parties, Staff, or any other party to these proceedings, other than those specifically agreed to herein, is true and valid. This Agreement shall not be construed to represent any concession by any party hereto regarding positions previously taken in this docket. Nor shall this Agreement be deemed to foreclose any Settling Party or Staff from taking any position in the future in any subsequent proceedings, except to the extent that the matters agreed to herein specify a date or time period.

The Settling Parties and Staff agree that all direct testimony and supporting documentation should be admitted as full exhibits for purposes of consideration of this Agreement, and be given the weight the Commission deems appropriate. Agreement to admit all direct testimony without challenge does not constitute agreement by any of the Settling Parties or Staff that the written testimony filed by any other party or Staff is accurate or that the views of the witnesses submitting testimony on behalf of any other party or Staff should be given weight by the Commission.

Moreover, the admission into evidence of any witness's testimony or supporting documentation shall not be deemed in any respect an admission by any party to this Agreement that any allegation or contention in this proceeding is true or false, except that the sworn testimony of any witness shall constitute an admission by such witness. In addition, the resolution of any specific issue in this Agreement does not indicate the Settling Party's or Staff's agreement to such resolution for purposes of any future proceedings.

V. TERMS OF AGREEMENT

The Settling Parties and Staff agree, and therefore recommend to the Commission, that it issue an order as follows:

A. Approval of Stock Transfers

The Settling Parties and Staff agree that the stock transfers, subject to the additional terms and conditions set forth in this Agreement, are "lawful, proper and in the public interest" in accordance with RSA 374:33. The Settling Parties and Staff, therefore, agree that the Commission should authorize National Grid USA and National Grid NE to transfer the stock of Granite State and EnergyNorth, respectively, to Liberty Energy NH, as assignee of Liberty Energy, as contemplated by the Purchase Agreements.

B. Other Approvals Necessary for Implementing the Transfer of Ownership

1. Authority to Issue Promissory Notes

The Settling Parties and Staff agree that Granite State and EnergyNorth should be authorized to issue promissory notes for up to $20 million and $90 million, respectively. The Settling Parties and Staff further agree that issuance of the promissory notes is "consistent with the public good" in accordance with RSA 369:1.

2. Pension/OPEB Fair Value Accounting

Granite State and EnergyNorth shall each be authorized to record a regulatory asset or liability, as the case may be, equal to the amount necessary to adjust its financial statements to reflect the fair value of its pension and OPEBs as required by generally accepted accounting principles and pursuant to Statement of Financial Accounting Standards (SFAS) No. 141, *Business Combinations*. The exact amount of such pension and OPEB asset or liability and the offsetting regulatory asset or liability shall be determined as of the closing date of the acquisition of the utilities by Liberty Energy NH (as assignee of Liberty Energy).

C. Reporting

1. Reporting by the Companies

a. During the Transition Period, the Companies shall submit certain monthly and quarterly reports to Staff describing the status of transition activities and related costs. As used in this Agreement, the term "Transition Period" shall mean the period of time between the Closing Date[6] ("Day 1") and the completion of the last Transition Service under the TSAs other than the Transition Services specified on Attachment L.

b. Monthly reports, consistent with Section V.C.2 below, shall include the following information, separately for each of the Companies:

i. Updated transition timetables;

ii. Costs incurred under the TSAs to date;

iii. Estimated costs for Transition Services over the remainder of the Transition Period;

iv. The percentage of Transition Services completed, calculated pursuant to Section V.D.1.f of this Agreement; and

[6] Closing Date is defined in Section 4.1 of the Purchase Agreements as the date and time at which the closing of the proposed transactions actually occurs.

v. Information technology ("IT") status reports that include forward looking projections regarding the status of implementation of the IT Plan. The term IT Plan and IT Migration Plan shall have the meanings given in Attachment E.

vi. Updated structural organizational charts for the Companies.

c. Quarterly reports shall include the following information:

i. Changes in the Algonquin cost allocation manual;

ii. Changes in the Companies' IT Plan and IT Migration Plan, including updated copies of those sections of the plans affected by the change; and

iii. Financial forecasts, as developed in the ordinary course of business.

d. During the Transition Period, the President of Liberty Energy NH and the CEO of Algonquin will attend quarterly meetings with Staff and OCA to discuss the content of the monthly and quarterly reports.

e. If there are any material changes in the IT Plan in between quarterly reports, the Companies will provide Staff with an interim report outlining these changes as part of its monthly report described in paragraph b of this Section.

2. Reporting by National Grid and the Companies

a. During the Transition Period, National Grid and the Companies will provide a monthly written status report ("Monthly Status Report") to Staff identifying, with respect to the prior month, the Transition Services in use by the Companies, changes to Transition Services required by either or both of the Companies, requests to terminate a Transition Service issued by either or both of the Companies, and confirmation that a Transition Service has been terminated by either or both of the Companies. Such Monthly Status Reports will be submitted within thirty (30) days from the end of the month reported on, and addressed to the attention of the Executive

Director of the Commission with a reference line to Docket No. DG 11-040 and the settlement item the report addresses, with copies to the OCA. Copies of the following shall be included in each Monthly Status Report:

(i) Monthly statements including supporting detail as provided to Granite State and EnergyNorth by National Grid pursuant to the TSAs ("Monthly Statements");

(ii) A report identifying changes in Transition Services requested by Granite State and/or EnergyNorth during the prior month, including Service Transition Notices (as defined in the TSAs, Schedule A Section IV.4.a), Additional Transition Services (see the TSAs Schedule A Section III.I), and the disposition of any requested changes in services provisioned under the TSAs;

(iii) A summary of any material disputes, claims, and adjustments of Monthly Statements in the prior calendar month;

(iv) Copies of minutes of any meetings held between National Grid and Liberty Energy NH, EnergyNorth, or Granite State about Transition Services including complaint escalations (per TSAs Schedule A Section I.7);

(v) When applicable, updated organization charts for National Grid, Liberty Energy NH, EnergyNorth, and/or Granite State transition personnel to reflect any changes in the prior month.

b. Service Transition Notices issued by the Companies in accordance with the TSAs and any corresponding confirmations issued by National Grid to effect the termination of a Transition Service shall be contemporaneously provided to Staff. In the event a Service Transition Notice is cancelled in accordance with the terms of the TSAs by either of the Companies or by National Grid, National Grid and the Companies will provide written certification to Staff of National Grid's confirmation of the cancellation. Staff may request that National Grid and the Companies provide additional information concerning such cancellation.

c. To the extent that National Grid and the Companies agree to add any Transition Services as permitted under the TSAs, National Grid and the Companies will contemporaneously provide to Staff written notice of the added Transition Service with an estimate of associated costs.

d. To the extent that National Grid and Liberty Energy NH and/or the Companies make changes to key personnel affiliated with the implementation of the New Hampshire transactions, including the Service Representatives (as defined in the TSAs, Schedule A Section I.7(a)) identified in the TSAs, National Grid and the Companies will provide forthwith written notice of such changes to Staff.

D. Conditions Agreed to By Liberty Energy and Liberty Energy NH

1. Cost Recovery/Rate Case

a. The Companies shall not seek rate recovery for any transaction costs, which, as used herein refers to financing, legal and regulatory costs incurred in connection with the closing of the transaction; the acquisition premium; or transition costs, which as used herein refers to, temporary costs incurred to effect the transaction.

b. This Agreement shall not constitute an approval of Algonquin's cost allocation methodology. Algonquin's cost allocation methodology will be fully evaluated as part of Granite State's first base rate case after the Closing Date, including whether the Four Factor Utility Methodology allocation factors and weights (rate base/utility plant (50% weight), total customers (40%), non-labor expenses (5%), and labor (5%)) are appropriate. The Companies agree to meet with Staff within six (6) months of closing to discuss Algonquin's cost allocation methodology, and will invite the OCA to attend such meeting.

c. Granite State commits there will be no rate impact from any Internal Revenue Code Section 338(h)(10) election made in connection with the acquisition of Granite State by Liberty Energy NH, as assignee of Liberty Energy.

d. Granite State agrees that in its first base rate case after the Closing Date, it shall not seek rates with a proposed effective date (either as temporary rates or permanent rates)

that is sooner than January 1, 2013. As used in this Section, the "first base rate case" shall not include proceedings at the Commission to consider Vegetation Management Plan ("VMP") or Reliability Enhancement Program ("REP") filings or default energy service filings.

e. The Companies and National Grid agree to comply with the Records Transfer and Retention Agreement attached hereto as Attachment D.

f. EnergyNorth agrees to a Rate Case Stay-Out Period, defined as follows: the test year for its first base rate case after the Closing Date will end no sooner than the first to occur of (i) the third anniversary of the Closing Date or (ii) 270 days after the date on which seventy (70) percent of the cost of the transition services under the EnergyNorth TSA are paid, provided however, that if in any month during the 270 day period the percentage paid drops below seventy percent (70%), then the 270 days will be reset and start running again once the percentage paid reaches seventy percent (70%). As used in this Section, the "first base rate case" shall not include proceedings at the Commission to consider "Exogenous Event" filings (as defined in Section V.D.1.f.ii, below), Cost of Gas ("COG") filings, Local Distribution Adjustment Charge ("LDAC") filings, or Cast Iron/Bare Steel ("CIBS") filings.

i. The EnergyNorth TSA services will be deemed to be seventy percent (70%) paid in the month in which seventy percent (70%) of the total estimated cost of the EnergyNorth TSAs have been paid. The total estimated cost of the EnergyNorth TSAs will be calculated by adding actual TSA payments to date and the estimated costs for Transition Services over the remainder of the Transition Period. The total estimated EnergyNorth TSA costs and timing of those costs are attached hereto as Attachment F, which will be updated and filed monthly in accordance with Section V.C.1.b above.

ii. During the Rate Case Stay-Out Period, EnergyNorth will be allowed to seek adjustment of distribution rates upward or downward resulting from Exogenous Events, as defined below.

1. For any of the events defined as a State Initiated Cost Change, Federally Initiated Cost Change, Regulatory Cost Reassignment, or Externally Imposed Accounting Rule Change, during the Rate Case Stay-Out Period, EnergyNorth will be allowed to seek adjustment of distribution rates upward or downward (to the extent that the revenue impact of such event is not otherwise captured through another rate mechanism that has been approved by the Commission) if the total distribution revenue impact (positive or negative) of all such events exceeds $1,000,000 (Exogenous Events Rate Adjustment Threshold) in any calendar year beginning with 2012.

a. "State Initiated Cost Change" shall mean any externally imposed changes in state or local law or regulatory mandates governing income, revenue, sales, franchise, or property (including capital expenditures required to complete the provision of services required by such mandates) or any new or amended regional, state or locally imposed fees (but excluding the effects of routine annual changes in municipal, county and state property tax rates and revaluations), which impose new obligations, duties or undertakings, or remove existing obligations, duties or undertakings, and which individually decrease or increase distribution costs, revenue, or revenue requirement.

b. "Federally Initiated Cost Change" shall mean any externally imposed changes in the federal tax rates, laws, or regulations governing income, revenue, or sales taxes or any changes in federally imposed fees, which impose new obligations, duties or undertakings, or remove existing obligations, duties or undertakings, and which individually decrease or increase distribution costs, revenue, or revenue requirement.

c. "Regulatory Cost Reassignment" shall mean the reassignment of costs and/or revenues to or away from the EnergyNorth's distribution function by the Commission, FERC, or any other official agency having authority over such matters.

d. "Externally Imposed Accounting Rule Change" shall be deemed to have occurred if the Financial Accounting Standards Board or the Securities and Exchange Commission adopts a rule that requires utilities to use a new accounting rule that is not being utilized by EnergyNorth as of January 1, 2012.

2. No later than March 31 of each year during the Rate Case Stay-Out Period, EnergyNorth shall file with the Commission, Staff, and OCA a Certification of Exogenous Events for the prior calendar year. If, in the prior calendar year, EnergyNorth incurs any changes in distribution costs, revenue, or revenue requirement in excess of the Exogenous Events Rate Adjustment Threshold in connection with any Exogenous Event as defined in Section V.D.1.f.ii, EnergyNorth shall provide specific and sufficient detail supporting each change and the Exogenous Event(s) associated with each change for the Commission, Staff and OCA to assess the proposed Exogenous Event rate

adjustment. If no Exogenous Events causing changes in excess of the Exogenous Events Rate Adjustment Threshold occurred during the prior calendar year, EnergyNorth shall certify that fact in its annual Certification of Exogenous Events. On or before June 1 of each year during the Rate Case Stay-Out Period, the Staff and the OCA may make a filing requesting an Exogenous Event rate decrease or contesting an Exogenous Event rate increase proposed by EnergyNorth. Any adjustments to revenue requirements for Exogenous Events: (1) shall be subject to review and approval as deemed necessary by the Commission; (2) shall be implemented for usage on and after July 1 of that year; and (3) shall be allocated among EnergyNorth's rate classes on a proportional basis based on total distribution revenue by class in effect at the time of the adjustment. Adjustments will be applied as equal percentage changes to each distribution rate component. Any such filings are limited to one per calendar year, provided that any costs incurred or saved due to such Exogenous Events shall be deferred for consolidation in the single filing.

iii. This Section does not prevent EnergyNorth from making COG, LDAC, or CIBS filings. *See* Condition #20 of Attachment J regarding CIBS.

g. In its first base rate case after the Closing Date, Granite State shall not seek recovery for rate case expenses that exceed $300,000 ("Granite State Rate Case Expense Cap"). However, the costs associated with preparing a depreciation study shall be excluded from the calculation of the Granite State Rate Case Expense Cap. Granite State shall also use a Request For Proposal ("RFP") process to hire all third party consultants and outside legal counsel used in the preparation of its first base rate case. Third party consultants hired by Staff for the rate case, the costs of which are borne in whole or in part by Granite State, shall also be excluded from the calculation of the Granite State Rate Case Expense Cap. As used in this Section, the "first base

rate case" shall not include proceedings at the Commission to consider VMP or REP filings or default energy service filings.

h. In its first base rate case after the Closing Date, EnergyNorth shall not seek recovery for rate case expenses that exceed $600,000 ("EnergyNorth Rate Case Expense Cap"). EnergyNorth shall use an RFP process to hire all third party consultants and outside legal counsel used in the preparation of its first base rate case. Third party consultants hired by Staff for the rate case, the costs of which are borne in whole or in party by EnergyNorth, shall be excluded from the EnergyNorth Rate Case Expense Cap. As used in this Section, the "first base rate case" shall not include proceedings at the Commission to consider "Exogenous Event" filings (as defined in Section V.D.1.f.ii above), COG filings, LDAC filings, or CIBS filings.

i. EnergyNorth agrees that it will not seek recovery in its cost-of-gas rate for unaccounted-for gas volumes that exceed 1.28% ("UFG Cap"). The UFG Cap will be applicable beginning with EnergyNorth's September 2013 COG filing. The UFG Cap will continue until the earlier of (i) the completion of EnergyNorth's first rate case, which shall be defined as the effective date of rates approved as a result of that case, or (ii) the filing of EnergyNorth's September 2015 COG filing. For clarity, the UFG Cap shall apply to the recovery and reconciliation of costs incurred between July 1, 2012 and June 30, 2015.

2. Information Technology

a. The Companies agree to continue detailed planning to achieve full implementation of the proposed IT Migration Plan.

b. A fully detailed IT Plan and an associated initial IT Migration Plan, with associated project management milestones, testing provisions and proposed schedule to Day N (as defined in Section V.E.1 below), are defined and provided as Attachments G and H. Any changes

to the Final IT Migration Plan will be done via a defined Change Management Process, and the Companies will notify Commission Staff of any such change, including changes that affect the implementation time and/or IT budget, within fifteen (15) days of the issuance of the Change Management notice. A revised IT Migration Plan ("Final IT Migration Plan") will be provided by August 1, 2012.

c. To ensure the security and integrity of the Liberty Utilities Family of Companies'[7] server infrastructure and data network, a third party security assessment of the Liberty Utilities Family of Companies' network security compliance with the International Organization for Standardization ("ISO") Standard 2700-1 ("Baseline Assessment") will be performed prior to the Closing Date. Any instances of non-compliance with ISO Standard 2700-1 identified by the Baseline Assessment will be resolved before implementation of the applicable element of the IT Plan. Management copies of: (a) the proposed security assessment process, (b) the findings of such an assessment, and (c) the associated actions taken by the parties to remediate the condition will be submitted to Staff under confidential cover pursuant to Commission rules Puc 203.08 and Puc 201.04 prior to the Closing Date.

d. At such time Staff and Liberty Energy NH mutually agree that the IT Migration Plan is fully implemented, the Liberty Utilities Family of Companies will conduct another third party security assessment and resolve any instances of non-compliance with ISO Standard 2700-1 identified by this second security assessment. Any additional hardware or software changes which affect Liberty Energy NH after the second assessment will be subject to the Liberty Utilities Family of Companies' Control Processes for IT Changes which are included in the initial IT Migration Plan attached hereto as Attachment H. Similar to the requirements set

[7] The Liberty Utilities Family of Companies refers to Liberty Utilities (Canada) Corp. and its subsidiaries.

forth above, management copies of: (a) the proposed security assessment process, (b) the findings of such an assessment, and (c) the associated actions taken by the parties to remediate the condition will be submitted to the Commission Staff under confidential cover pursuant to Puc 203.08 and Puc 201.04within 30 days of completing the review.

e. A biennial security assessment of equivalent scope and scale to those envisioned in Sections V.D.2.c through d above will be conducted by the Liberty Utilities Family of Companies and the results submitted to the Commission commencing 12 months following completion of the review set out in V.D.2.d above.

f. All third party vendor contracts entered into after March 1, 2012, will contain a detailed description of the deliverables due under the contract and the cost for each deliverable.

Prior to releasing funds under all vendor contracts, each deliverable will be tested, where applicable, to ensure it meets the contractual requirements. During the transition period, Liberty must show that each deliverable has been thoroughly tested, where applicable, and meets the quality assurance and acceptance standards set forth in Section 4.6 of the IT Plan provided in Attachment G. During the Transition Period, the Companies will undertake annual reviews of all their third party vendors to ensure they are receiving effective and high quality service. Attestation statements to the effect that such testing and review have been done and found acceptable – signed by an authorized representative of the Companies – will be filed annually with Staff, and prior to the sooner of any use of the deliverable by the Companies in their normal operations or release of a third-party vendor from its contractual obligations.

g. The Companies' prudently incurred IT capital investments required to complete the transition of services from National Grid to the Companies, of up to $8,100,000 less depreciation (i.e., net plant in service at the time of the rate filing), are eligible for recovery in

future rate filings. IT capital investments in excess of $8.1 million required to complete the transition of services from National Grid to the Companies are not eligible for recovery in future rate filings, with the exception that IT capital expenditures required to complete the transition of services due to a "State Initiated Cost Change" (as defined in Section V.D.1.f.ii.1.a) or a "Federally Initiated Cost Change" (as defined in Section V.D.1.f.ii.1.b) after the Closing Date shall not be counted against the IT recovery cap.

h. Comprehensive IT testing plans ("Test Plans") that conform to Standard 829 of the Institute of Electrical and Electronics Engineers (IEEE) will be undertaken by the parties as part of the IT Migration Plan set forth above. Copies of the Test Plans will be provided to Staff according to the project milestones set forth in the Final IT Migration Plan. Any subsequent changes to the Test Plans, their requirements, scope, standards and/or tests, which affect the implementation time and/or IT budget, will be reported to Commission Staff within fifteen (15) days of the issuance of the prescribed Change Management Notice. Any findings and recommendations made as a consequence of such testing shall be reported to Commission Staff as part of the Companies' monthly reporting duties.

i. The Liberty Utilities Family of Companies will fully collaborate with Staff and/or Staff's representatives throughout the transition period to ensure an efficient and effective implementation of the IT Migration Plan.

3. Customer Service

a. No later than six months after the Closing Date, the Companies will submit detailed plans that explain how customer service operations and support functions will be operated and maintained after the relevant TSA services are finished.

b. No later than six months after the Closing Date, the Companies will develop and submit a customer service staffing contingency plan that will govern in the event of failures during the cutover from National Grid to the Companies.

c. The Companies will be headquartered in New Hampshire and will have a locally based president for their New Hampshire operations. The Companies will also have local call centers as well as walk-in customer service centers. To ensure local management authority in emergency situations, the Liberty NH president shall have at least $250,000 in spending authority and the vice president of operations shall have at least $100,000 in spending authority.

d. Granite State commits to answering eighty percent (80%) of calls to its call centers within 20 seconds. EnergyNorth commits to answering eighty percent (80%) of calls to its call centers within 30 seconds.

i. For purposes of this Section, the timing of a call answered is measured from when the call leaves the automated menu system and enters the queue to be "live answered" by a customer service representative. However, a call that never leaves the automated menu system is included in the number of calls for purposes of the monthly and annual reported results.

ii. The Companies shall provide monthly reports within 21 days of the end of the month reported, in the form attached hereto as Attachment I, of call answering results.

iii. During the period following the cutover of call center services and continuing through Day N and 365 days thereafter, the Companies shall work to identify the root cause of any failure to achieve the call answer time metrics set forth above. If the Companies have reason to believe that the root cause relates to National Grid's failure to

comply with its obligations under the TSAs or a system, database, process and/or procedure error that is attributable to National Grid, they shall request that National Grid cooperate with them in determining the root cause of the failure to achieve such metrics. National Grid agrees to comply with such request.

iv. The Companies' compliance with this Section will be determined on a yearly basis by aggregating all the calls for the 12 month calendar year period.

v. Notwithstanding the above, if Staff or the OCA is not satisfied with the performance of the Companies at any time following notice of cutover of call center services to the Companies and believes customer service is being materially compromised by poor performance, Staff or the OCA may request the Commission to open an investigation to determine whether additional actions should be taken by the Commission to address the Companies' service quality performance. Such actions may include, but shall not be limited to, the establishment of service quality performance standards for the Companies with financial penalties associated with future performance, if the Commission deems appropriate.

e. The Companies agree to conduct a statistically valid annual residential customer satisfaction survey and report the results to the Commission annually, no later than one month following the availability of survey results. The Companies will select a sample size that yields an error rate of no more than plus or minus two and a half percent (2.5%) with a ninety five percent (95%) confidence rate.

i. In order to ensure a meaningful comparison between National Grid's current customer satisfaction survey for Granite State and Liberty Utilities (Canada) Corp.'s customer satisfaction survey, Granite State and EnergyNorth commit to

undertaking a survey of their residential customers using Liberty Utilities (Canada) Corp.'s own format within 3 months of the Closing Date ("Baseline Customer Satisfaction Survey"). Prior to conducting this survey, Granite State and EnergyNorth will meet with Staff within 45 days of the Closing Date to discuss the design and format of Liberty Utilities (Canada) Corp.'s customer satisfaction survey, the objectives of the survey and whether it should be modified in any way.

ii. The Companies commit to maintaining a customer satisfaction percentage that is no lower than the Baseline Customer Satisfaction Survey satisfaction percentage. Should the Baseline Customer Satisfaction Survey satisfaction percentage be lower than eighty percent (80%), the Companies agree to provide the Commission with an action plan for improving customer satisfaction levels. The plan shall be provided no later than 90 days following the availability of the survey results and shall be provided annually until such time as subsequent Customer Satisfaction Survey satisfaction percentages exceed eighty percent (80%).

f. The Companies commit to allocate the equivalent of one full time employee to low-income initiatives, which shall include but are not limited to: providing specialized enrollment and education services; responding to customer requests through early intervention; crisis bill payment management; outreach and education including the activities described in paragraphs g.iv, g.v, and g.viii of this Section; and maintaining strong partnerships with human service agencies.

g. The Companies agree to maintain the following low-income initiatives:

i. Maintain Granite State's participation in the statewide Electric Assistance Program ("EAP"), including maintaining Granite State's position as a member on the EAP Advisory Board;

ii. Maintain at least the fiscal year 2011 funding for the NH "Neighbor Helping Neighbor" customer bill assistance program;

iii. Maintain at least the fiscal year 2011 funding for EnergyNorth's low income "R-4" gas discount rate;

iv. Conduct at a minimum the current level of outreach and education efforts to enroll low-income customers in EnergyNorth's low income "R-4" gas discount rate;

v. Continue to meet with NH Legal Assistance no less frequently than annually to discuss EnergyNorth's outreach efforts regarding its low-income "R-4" gas discount rate and its collection practices and activities;

vi. Continue participation in the statewide "Core" electric and natural gas energy efficiency programs, including the low income energy efficiency programs;

vii. Maintain the NH Community Action Program's right of first refusal to provide energy efficiency services to the Companies' low income energy efficiency programs; and

viii. Calling campaign in the early fall, targeting customers eligible for federal low income home energy assistance ("LIHEAP").

h. During the Transition Period, the Companies and National Grid commit to working together to identify the root cause of any failure to achieve the Performance Metrics set forth in Attachments N and O. During the period from Day N and 365 days thereafter, the

Companies shall work to identify the root cause of any failure to achieve the Performance Metrics (as defined in Section E.3.c. below) in Attachment N. If the Companies have reason to believe that the root cause relates to National Grid's failure to comply with its obligations under the TSAs or a system, database, process and/or procedure error that is attributable to National Grid, they shall request that National Grid cooperate with them in determining the root cause of the failure to achieve such metrics. National Grid agrees to comply with such request.

i. During the transition period and the period Day N plus 365 days thereafter, the Companies shall provide National Grid with all information necessary for National Grid to file its monthly performance reports.

j. The Companies will provide National Grid with information relevant to the performance metrics, and will maintain the National Grid performance metrics in Attachment N following the termination of each associated transition service and through Day N plus 365 days thereafter.

4. Safety

a. The Companies will ensure back-office familiarity with systems used to assess/handle outages, including local outage management personnel and systems, as well as periodic in-house emergency response training and drills. The Companies will provide Staff with copies of training and drill materials within six months of the Closing Date.

b. The Companies commit to implementing by January 2014 and maintaining remote readable computer access during emergency events for designated members of Commission Staff to enable access to outage management system ("OMS") display screens, including information that is not typically available to the public. The Companies further commit to developing its OMS capability to display Estimated Restoration Times ("ERTs") by location of

outages and number of customers affected. An update of the status of OMS development will be provided in Granite State Electric's first base rate case after Closing.

c. The Companies agree to appoint an Emergency Liaison who, in the event the Liberty Energy NH Emergency Operations Center opens, will provide designated Staff with Emergency Response Updates four times daily. For purposes of this Section, the term Emergency Response Updates means crew reports, outage reports by town, and outage reports by circuit within towns.

d. The Companies commit to continuing their participation in regional mutual assistance networks.

e. See Attachment J for a detailed list of additional safety commitments by the Companies.

5. Operations

a. Granite State agrees that the REP and VMP conditions established in Docket No. DG 06-107 and set forth in Attachment K should be approved by the Commission as renewed commitments undertaken by Granite State in this transaction.

b. Granite State commits to undertake all reasonable efforts to maintain Granite State's practice of operating energy efficiency programs within budget and achieving kWh savings.

c. Concurrently with approval of this Settlement, the Staff and the Companies request the Commission close Docket No. DE 10-142 (Granite State's Least Cost Integrated Resource Plan ("LCIRP")). Granite State agrees that it shall file a new LCIRP within six months of Commission's Order approving this transaction and closing Docket No. DE 10-142.

d. The Companies agree to review the current levels of their energy efficiency budgets in the "Core" Electric and Gas Energy Efficiency dockets to determine whether, and to what extent, these budgets, including the low income budget, may be increased in order to provide energy efficiency services to more customers. As part of their next Core filing, the Companies will include a report summarizing the results of this review.

6. Financial

Liberty Utilities agrees to guarantee each of its New Hampshire subsidiaries access to the following minimum capital amounts under its January 18, 2012 Short-Term Revolving Credit Facility: EnergyNorth $18,867,000; Granite State $2,731,000. Future renewals of that facility or any new short-term facilities will be at favorable terms and conditions that are no more costly than comparable commercial credit facilities.

7. Transition

Liberty Utilities (Canada) Corp shall maintain a fully dedicated senior executive to be responsible for transition activities associated with all of Liberty Utilities Co.'s acquisitions. This individual will be the head of Liberty Utilities (Canada) Corp.'s Project Management Office ("PMO"). The PMO's responsibilities shall include providing leadership, oversight and control of any projects related to the integration of new acquisitions. The PMO shall report directly to the President of Liberty Utilities (Canada) Corp., and shall be responsible for approving project charters and plans to ensure they conform to Liberty Utilities (Canada) Corp.'s overall business strategy and commitments. The PMO shall also track and audit ongoing transition project plans to ensure the transition projects are on target for success. Throughout the transition, the PMO will hold periodic briefing sessions with transition team leads to ensure the project(s) are on target for

success. Updates based on the PMO briefings will be provided in the quarterly reports provided pursuant to Section V.C.1.c above.

8. Affiliate Requirements

The Companies shall comply with the Commission's Affiliate Transactions Rules (Puc Chapter 2100), and more specifically Granite State and EnergyNorth shall not purchase or offer to purchase energy, capacity and/or services from any of their competitive affiliates (including hydroelectric generating or gas facilities owned directly or indirectly by Algonquin Power Co., its successors or assigns) on terms more favorable than those offered to or available to any non-affiliated suppliers, including independently owned hydroelectric generating facilities in New Hampshire.

E. <u>Conditions Agreed to by National Grid</u>

1. National Grid has agreed to provide certain transition services (each, a "Transition Service" and collectively, "Transition Services") to the Companies pursuant to the terms and conditions of the TSAs. The TSAs provide that National Grid will perform each Transition Service from the Closing Date to such date that Liberty Energy achieves the capability to perform such Transition Service without assistance from National Grid (each, an "Individual TSA Transition Period"). With regard to all Transition Services other than the Transition Services indentified in Attachment L (collectively, the "Attachment L Transition Services"),[8] the date on which each Individual TSA Transition Period has terminated is hereinafter referred to as "Individual Day N." The date on which all Transition Services have transferred from National Grid to Liberty Energy is hereinafter referred to as "Day N." (If, from time to time, National Grid provides additional Transition Services to the Companies that National Grid believes to be on-

[8] The Transition Services identified in Attachment L tend to deal with consulting services that may be utilized on an as-needed basis and may continue to be used by the Companies following the Transition Period.

going, as-needed consulting-type services, it may seek Staff's agreement to add such additional Transition Services to Attachment L, in which event they shall also be excluded from the determination of Day N and shall be included in the list of Attachment L Transition Services.)

2. As further described in Section V.E.6 below, within five (5) business days following the Closing Date, National Grid will deposit Twenty-Eight Million Five Hundred Thousand Dollars ($28,500,000) (the "Escrow Funds") by wire transfer of immediately available funds into a segregated, interest-bearing escrow account ("Escrow Account") established by National Grid and administered by an escrow agent ("Agent") deemed acceptable to both National Grid and Staff. Such Escrow Funds will be held for the purposes of securing the provision of Transition Services by National Grid as described herein.

3. The Escrow Funds will be segregated into three "pools" as follows:

a. Thirteen Million Five Hundred Thousand Dollars ($13,500,000) of the Escrow Funds ("Pool A Escrow Funds") will be eligible for release to National Grid in increments at prescribed 3-month intervals following Day 1 and continuing until Day N. To effect release of the Pool A Escrow Funds, the Companies and National Grid will submit jointly to Staff within sixty (60) days after the end of each three-month interval a written attestation (each, a "TSA Transfer Certification") that the Transition Services identified in the TSA Transfer Certification have been fully transferred pursuant to the terms of the TSAs. The Companies and National Grid shall provide a copy to the OCA of the cover letter enclosing each TSA Transfer Certification.

Upon receipt of each TSA Transfer Certification, Staff will confirm within thirty (30) days in a letter to the Companies and National Grid, with copies provided to the OCA, that the Transition Services described in the TSA Transfer Certification have been fully transferred in accordance with the terms of the TSAs and, upon Staff's confirmation, the Agent shall release to

National Grid Pool A Escrow Funds on a pro-rata basis, based on the cumulative number of Transition Services that have been fully transferred to Liberty Energy and/or its affiliates. If Staff determines that any of the Transition Services have not been so transferred, it shall provide the Companies and National Grid a detailed written explanation of the basis for that determination, with copies to the OCA. The associated Pool A Escrow Funds shall be held for release to National Grid as part of the next submission of a TSA Transfer Certification submitted by the Companies and National Grid upon a determination by Staff that such service has been so transferred. Notwithstanding the foregoing, One Million Five Hundred Thousand Dollars ($1,500,000) of Pool A Escrow Funds will be held in reserve until confirmation by Staff that all Transition Services (other than Attachment L Transition Services) are completed. All remaining Pool A Escrow Funds will be released to National Grid concurrently with the final release payment of the Pool A Escrow Funds to National Grid; National Grid's continued provision after Day N of any of the Attachment L Transition Services shall not preclude the release of the remaining Pool A Escrow Funds to National Grid. The sliding scale set forth in Attachment M is a sample calculation. All calculations under this provision shall include adjustments as appropriate for any changes in the number of Transition Services provided.

b. Five Million Dollars ($5,000,000) of the Escrow Funds ("Pool B Escrow Funds") will be eligible for release to National Grid at such time as the Companies and National Grid submit jointly a written attestation ("Day N Certification") to Staff that all Transition Services provided under the TSAs other than the Attachment L Transition Services have been transferred (i.e., that Day N has occurred). National Grid's continued provision after Day N of any of the Attachment L Transition Services shall not preclude the release of the Pool B Escrow Funds to National Grid. The Pool B Escrow Funds will be released to National Grid no earlier than 90

days and no later than 120 days after the Companies and National Grid jointly submit the Day N Certification to Staff. The Companies and National Grid shall provide to the OCA a copy of the cover letter enclosing the Day N Certification.

c. Ten Million Dollars ($10,000,000) of the Escrow Funds ("Pool C Escrow Funds") will be held by the Agent and reserved for administering the prescribed performance metrics appended as Attachment N ("Customer Service Performance Metrics") and Attachment O ("Safety Performance Metrics") to this Agreement. (The Customer Service Performance Metrics and the Safety Performance Metrics are collectively referred to herein as "Performance Metrics" and individually as a "Performance Metric".) The intent of the Performance Metrics is to ensure (i) that National Grid achieves and maintains certain specified performance levels when providing Transition Services during the Individual TSA Transition Periods, and (ii) that the continued performance of such services by Liberty Energy following the termination of each Individual TSA Transition Period is not rendered defective as a result of any system, database, data, process and/or procedure error that is directly attributable to National Grid. Unless otherwise specified, the Performance Metrics will be monitored beginning on Day 1 and continuing through Day N and 365 days thereafter.

i. Customer Service Performance Metrics. As noted above, the Customer Service Performance Metrics are appended to this Agreement as Attachment N. In addition to the Customer Service Performance Metrics set forth in Attachment N, the volume of calls from EnergyNorth and Granite State customers to the Companies' call center will continue to be reported to the Staff on a monthly basis as part of the call answering report. If the EnergyNorth customer call volume in a given month exceeds the prior month by twenty percent (20%), National Grid will provide a written explanation to

Staff within 10 days of the filing of the call answering report with the Commission. If the Granite State customer call volume in a given month exceeds the prior month by twenty five (25%), National Grid will provide a written explanation to Staff within 10 days of the filing of the call answering report with the Commission. If the written explanation provided by National Grid indicates that the call volume increase is related to problems occurring in the operation of the affected Company's respective distribution systems or billing and customer service systems, Staff may initiate a review and National Grid, Liberty Energy, and the affected Company shall cooperate fully with the Staff's review. National Grid shall not be deemed to have failed to achieve this metric if call volumes were materially affected by a Major Storm Event[9] or other event beyond National Grid's reasonable control, third party acts, or calls that are otherwise not related to problems occurring in the operation of the utilities' respective distribution systems or billing and customer service systems.

If either of the Companies fails to achieve a Customer Service Performance Metric, a report will be filed with Staff within 21 days following the end of the month in which the failure occurred. Within 10 days of the submission to Staff of the report identifying such failure, National Grid and the affected Company shall jointly provide Staff a written explanation of the reason for the failure to achieve the relevant Customer Service Performance Metric. A copy of this written explanation shall be provided to the OCA.

If a decline in performance level or failure to achieve a particular Customer Service Performance Metric triggers a Staff review and/or a set-aside as described in Attachment N, the written explanation described above shall also include, if applicable, the

[9] A "Major Storm Event" is defined as a severe weather event or events causing 30 concurrent troubles and fifteen percent (15%) of customers interrupted or 45 concurrent troubles.

proposed remedy for the failure to achieve the Customer Service Performance Metric, including a good faith estimate of the cost of the proposed remedy. To the extent that a decline in performance levels for a particular Customer Service Performance Metric in a given month triggers Staff review and/or a set-aside, National Grid will continue to report on a monthly basis. If the Customer Service Performance Metric failure continues in consecutive months as a result of the same event or circumstances, National Grid will not be subject to additional set-asides in connection with such event or circumstances. A continued decline in performance of Customer Service Performance Metrics, however, may be taken into account in determining the remedial action to be taken and/or the amount of any penalty to be imposed in accordance with the procedure set forth below.

With respect to any failure to achieve a particular Customer Service Performance Metric under this subsection for which Staff determines that a review is necessary, Staff will expeditiously review the specific circumstances of the failure to meet the relevant Customer Service Performance Metric to determine the reasons for such failure, the severity or significance of the impact of such failure, and whether such failure is directly attributable to National Grid. National Grid, Liberty Energy, and the affected Company shall cooperate fully with the Staff's review. Staff shall memorialize the findings of this review in a report provided to the affected Company, National Grid and the OCA. Upon the initiation of any such review by the Staff, $250,000 of the Pool C Escrow Funds will be earmarked and set aside for National Grid's potential liability, which may consist of remedial funds and/or a penalty as described below. To the extent necessary, National Grid, Liberty Energy, and the affected Company may begin implementation of a proposed remedy prior to the conclusion of Staff's review, and such implementation shall

not constitute an admission of fault or liability. If Staff determines that the failure to achieve a particular Customer Service Performance Metric is a result of (1) National Grid's failure to comply with its obligations under the TSAs or (2) a system, database, data, process and/or procedure error that is attributable to National Grid, it shall either accept National Grid's proposed remedy or propose such changes as it reasonably determines are necessary. Such funds as are reasonably determined appropriate by Staff to remedy the identified deficiency will be drawn from the Pool C Escrow Funds and used by National Grid to implement the remedy. The amount of such remedial funds is not intended to be limited to a maximum of $250,000. In determining the amount of Pool C Escrow Funds to be applied for remedial purposes, the Staff shall consider (i) National Grid's relative culpability for the failure to achieve the relevant Customer Service Performance Metric, and (ii) the most cost-effective remedy to address the specific performance issue (with due consideration to the short-term nature of Transition Services).

Upon determination that National Grid is at fault, and costs are incurred in the implementation of a remedy prior to the conclusion of the Staff's review, a corresponding amount shall be transferred from the Pool C Escrow Funds to National Grid after approval by Staff. If National Grid disputes Staff's determination, it may seek a resolution of the dispute by the Commission. Any such dispute shall be treated as an adjudicative proceeding before the Commission.

If Staff's review includes a determination that it is appropriate to assess a penalty against National Grid as a result of a material failure to achieve a particular Customer Service Performance Metric under this subsection, it shall report its finding to the Commission, with copies to the OCA, for a determination of the appropriate amount of

the penalty to be assessed. The Commission shall consider, among other relevant factors, (i) National Grid's relative culpability for the failure to achieve the relevant Customer Service Performance Metric; (ii) the harm, if any, to customers of the Companies directly resulting from the failure to achieve a particular Performance Metric; (iii) the degree to which National Grid or the Companies failed to achieve a particular Customer Service Performance Metric; and (iv) Commission precedent with regard to the magnitude of fines levied against New Hampshire utilities for similar performance issues. No penalty assessed against National Grid for a material failure to meet a Customer Service Performance Metric shall exceed $250,000. Any such penalty determination shall be treated as an adjudicative proceeding before the Commission.

National Grid's failure to meet a particular Customer Service Performance Metric shall be excused to the extent that such failure is caused by circumstances beyond its reasonable control, including but not limited to extraordinary events that are external to National Grid and the actions/inactions of Liberty Energy and/or any of its affiliates. However, failure to achieve the Bill Accuracy, Bills with Exceptions, and Emergency Response – Major Storm Customer Service Performance Metrics, as listed in Attachment N shall not be excused by reason of a Major Storm Event.

ii. Safety Performance Metrics. As noted above, the Safety Performance Metrics are appended to this Agreement as Attachment O. If either of the Companies fails to achieve a Safety Performance Metric measurement as set forth on Attachment O, within 15 days of such failure or notification by Staff of such failure, National Grid and the affected Company shall jointly provide Staff a written explanation of

the reason for the failure to achieve the relevant Safety Performance Metric measurement. A copy of this written explanation shall be provided to the OCA.

If the written explanation indicates that the failure to achieve a Safety Performance Metric measurement is or may be directly attributable to National Grid, Staff may initiate a review if it determines that such a review is necessary. If Staff determines that such a review is necessary, Staff will expeditiously review the specific circumstances of the failure to achieve the relevant Safety Performance Metric measurement to determine the reasons for such failure, the severity or significance of the impact of such failure, and whether such failure is directly attributable to National Grid. National Grid, Liberty Energy, and the affected Company shall cooperate fully with the Staff's review. Staff shall memorialize the findings of this review in a report provided to the affected Company, National Grid and the OCA. Upon the initiation of any such review by the Staff, $250,000 of the Pool C Escrow Funds will be earmarked and set aside for National Grid's potential liability, which may consist of remedial funds and/or a penalty as described below.

To the extent necessary, National Grid, Liberty Energy, and the affected Company may begin implementation of a proposed remedy prior to the conclusion of Staff's review, and such implementation shall not constitute an admission of fault or liability. If Staff determines that the failure to achieve a particular Safety Performance Metric is a result of (1) National Grid's failure to comply with its obligations under the TSAs or (2) a system, database, data, process and/or procedure error that is attributable to National Grid, it shall either accept National Grid's proposed remedy or propose such changes as it reasonably determines are necessary. Such funds as are reasonably determined appropriate by Staff to remedy the identified deficiency will be drawn from the

Pool C Escrow Funds and used by National Grid to implement the remedy. The amount of such remedial funds is not intended to be limited to a maximum of $250,000. In determining the amount of Pool C Escrow Funds to be applied for remedial purposes, the Staff shall consider (i) National Grid's relative culpability for the failure to achieve the relevant Safety Performance Metric, and (ii) the most cost-effective remedy to address the specific performance issue (with due consideration to the short-term nature of Transition Services).

Upon determination that National Grid is at fault, and costs are incurred in the implementation of a remedy prior to the conclusion of the Staff's review, a corresponding amount shall be transferred from the Pool C Escrow Funds to National Grid after approval by Staff. If National Grid disputes Staff's determination, it may seek a resolution of the dispute by the Commission. Any such dispute shall be treated as an adjudicative proceeding before the Commission.

If Staff's review includes a determination that it is appropriate to assess a penalty against National Grid as a result of a material failure to achieve a particular Safety Performance Metric measurement under this subsection, it shall report its finding to the Commission, with copies to the OCA, for a determination of the appropriate amount of the penalty to be assessed. The Commission shall consider, among other relevant factors, (i) National Grid's relative culpability for the failure to achieve the relevant Safety Performance Metric measurement; (ii) the harm, if any, to customers of the affected Company directly resulting from the failure to achieve a particular Safety Performance Metric measurement; and (iii) the degree to which National Grid or the affected Company failed to achieve a particular Safety Performance Metric measurement. No penalty

assessed against National Grid for a material failure to meet a Safety Performance Metric measurement shall exceed $250,000. Any such penalty determination shall be treated as an adjudicative proceeding before the Commission.

National Grid's failure to meet a particular Safety Performance Metric measurement shall be excused to the extent that such failure is caused by circumstances beyond its reasonable control, including but not limited to extraordinary events that are external to National Grid and the actions/inactions of Liberty Energy and/or any of Liberty Energy's affiliates. However, failure to achieve the Safety Performance Metrics measurements contained in Attachment O shall not be excused by reason of a Major Storm Event or Large Scale System Wide Outage as defined in Attachment O.

iii. Release of Pool C Escrow Funds. This subsection applies to all Performance Metrics. If, at one hundred eighty (180) days after Day N, there are no unresolved or uncorrected performance failures outstanding, Staff will confirm this in a letter provided to the Companies and National Grid and copied to the OCA and the Agent shall release twenty-five percent (25%) of the non-earmarked Pool C Escrow Funds to National Grid. The balance of Pool C Escrow Funds thereafter shall be held until 365 days following Day N at which time it shall be released in full to National Grid; provided, however, that if any failure to achieve any Performance Metric shall have occurred prior to the conclusion of the 365 days and the disposition of such matter shall not have been finally resolved, a portion of the Pool C Escrow Funds in an amount equal to $250,000 for each such pending matter shall continue to be held in escrow until such matter has been finally resolved, after which time any residual Pool C Escrow Funds shall be promptly released to National Grid.

5. *Partial Terminations*: Partially completed Transition Services are not considered completed for purposes of releasing any Escrow Funds.

6. *Administration of Escrow Funds*

a. Escrow Account: National Grid will establish the Escrow Account for purposes of administering the Escrow Funds as contemplated by this Agreement. Once the Agent has been selected, National Grid shall enter into an appropriate escrow agreement (the "Escrow Agreement") with the selected Agent. The Agent shall hold, safeguard, administer and disburse the Escrow Funds upon written certification of Staff as described in Section 3.a above, and in accordance with the terms of this Agreement and the Escrow Agreement. A copy of the Escrow Agreement shall be filed with the Commission upon execution.

b. Disposition of Escrow Funds: The Agent will hold the Escrow Funds in its possession pending any authorized release of the Escrow Funds to National Grid as described herein. The certification by Staff that certain conditions have been met related to the release of Escrow Funds shall not be considered an adjudicatory proceeding except as provided herein. No third parties shall have a right to participate as a party in interest with regard to any such certification unless authorized by the Commission.

c. Interest: All interest accruing on the funds deposited in the Escrow Account shall be for the benefit of National Grid. National Grid shall receive quarterly interest payments in an amount equal to the accrued interest on the Escrow Account.

d. Escrow Fees: Any fees associated with the maintenance of the Escrow Funds shall not be taken from the principal amount in the Escrow Account.

e. Escrow Statements: Copies of the monthly statements provided by the Escrow Agent to National Grid shall be provided simultaneously to Staff.

F. Acquisition Premium

Neither Granite State nor EnergyNorth shall seek to recover through rates any acquisition premium on its respective books or those of any affiliated entity that results from the acquisition of their stock by Liberty Energy NH. To the extent that any portion of the acquisition premium is required for financial accounting purposes to be reflected on the books of either utility it shall be reflected "below the line" for ratemaking purposes.

G. Consultant Costs

If the Commission engages a consultant or other outside contractor for purposes of implementing the terms of this Agreement or otherwise overseeing the transactions contemplated by this agreement, the costs of any such consultant or outside contractor shall not be assessed to National Grid or its affiliates.

VI. GENERAL PROVISIONS

1. The signatories to this Agreement agree and recommend that, based upon information provided by the Joint Petitioners in this proceeding and the commitments contained in this Agreement, the Commission find that the proposed transaction is lawful, proper and in the public interest, and should be approved by the Commission.

2. This Agreement is expressly conditioned upon the Commission's acceptance of all its terms, without change or condition. If the Commission does not accept this Agreement in its entirety, without change or condition, or if the Commission makes any findings other than those expressly contained in this Agreement, and the Staff or any of the Settling Parties notifies the Commission within ten business days of its disagreement with any such changes, conditions or findings, the Agreement shall be deemed to be withdrawn, in which event it shall be deemed to be null and void and without effect, and shall not constitute any part of the record in this proceeding,

shall not be relied upon by Staff or any party to this proceeding or by the Commission for any other purpose.

3. The rights conferred and obligations imposed on any party by this Agreement shall be binding on or inure to the benefit of their respective successors in interest or assignees as if such successor or assignee itself was a party hereto.

4. The discussions that produced this Agreement have been conducted on the understanding that all offers of settlement and settlement discussions relating to this docket were and shall continue to be privileged and confidential, shall not be admissible as evidence in this proceeding, shall be without prejudice to the position of any party or participant representing any such offer or participating in any such discussion, and are not to be used in connection with any future proceeding or otherwise.

This Agreement represents a resolution of the matters specified herein only. The Settling Parties and Staff agree that the Commission's approval of this Agreement will not constitute continuing approval of, or precedent for, any particular principle or issue other than those specified herein, but such acceptance does constitute a determination that the terms set forth herein in their totality are just and reasonable and consistent with the public interest.

This Agreement may be executed in multiple counterparts, which together shall constitute one agreement.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF, the signatories below have executed this Agreement, each being fully authorized to do so, as of the day and year written below.

LIBERTY ENERGY UTILITIES CO. and
Liberty Energy Utilities (New Hampshire) Corp.
By their Attorney

Date: April 10, 2012

By:_____
Shannon P. Coleman

NATIONAL GRID USA,
National Grid NE Holdings 2 LLC,
Granite State Electric Company, and
EnergyNorth Natural Gas, Inc.
By their Attorneys

Date: April , 2012

By:_____
Celia B. O'Brien

Date: April , 2012

By:_____
Steven V. Camerino
McLane, Graf, Raulerson & Middleton, PA

STAFF OF THE NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION
By its Attorney

Date: April , 2012

By:_____
Lynn Fabrizio

OFFICE OF CONSUMER ADVOCATE
By its Attorney

Date: April , 2012

By:_____
Rorie E. Hollenberg

[SIGNATURES CONTINUE ON NEXT PAGE]

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LIBERTY ENERGY UTILITIES CO. and
Liberty Energy Utilities (New Hampshire) Corp.
By their Attorney

Date: April , 2012

By:_____
Shannon P. Coleman

NATIONAL GRID USA,
National Grid NE Holdings 2 LLC,
Granite State Electric Company, and
EnergyNorth Natural Gas, Inc.
By their Attorneys

Date: April 10, 2012

By: Celia B. O'Brien
Celia B. O'Brien

Date: April 10, 2012

By:_____
Steven V. Camerino
McLane, Graf, Raulerson & Middleton, PA

STAFF OF THE NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION
By its Attorney

Date: April , 2012

By:_____
Lynn Fabrizio

OFFICE OF CONSUMER ADVOCATE
By its Attorney

Date: April , 2012

By:_____
Rorie E. Hollenberg

[SIGNATURES CONTINUE ON NEXT PAGE]

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LIBERTY ENERGY UTILITIES CO. and
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By their Attorney

Date: April , 2012

By:_____
Shannon P. Coleman

NATIONAL GRID USA,
National Grid NE Holdings 2 LLC,
Granite State Electric Company, and
EnergyNorth Natural Gas, Inc.
By their Attorneys

Date: April , 2012

By:_____
Celia B. O'Brien

Date: April , 2012

By:_____
Steven V. Camerino
McLane, Graf, Raulerson & Middleton, PA

STAFF OF THE NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION
By its Attorney

Date: April 10, 2012

By: Lynn Fabrizio
Lynn Fabrizio

OFFICE OF CONSUMER ADVOCATE
By its Attorney

Date: April , 2012

By:_____
Rorie E. Hollenberg

[SIGNATURES CONTINUE ON NEXT PAGE]

IN WITNESS WHEREOF, the signatories below have executed this Agreement, each being fully authorized to do so, as of the day and year written below.

LIBERTY ENERGY UTILITIES CO. and
Liberty Energy Utilities (New Hampshire) Corp.
By their Attorney

Date: April , 2012

By:_____
Shannon P. Coleman

NATIONAL GRID USA,
National Grid NE Holdings 2 LLC,
Granite State Electric Company, and
EnergyNorth Natural Gas, Inc.
By their Attorneys

Date: April , 2012

By:_____
Celia B. O'Brien

Date: April , 2012

By:_____
Steven V. Camerino
McLane, Graf, Raulerson & Middleton, PA

STAFF OF THE NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION
By its Attorney

Date: April , 2012

By:_____
Lynn Fabrizio

OFFICE OF CONSUMER ADVOCATE
By its Attorney

Date: April 10, 2012

By: R E Hollenberg
Rorie E. Hollenberg

[SIGNATURES CONTINUE ON NEXT PAGE]

THE WAY HOME
By its Attorney

PAMELA LOCKE
By her Attorney

Date: April 10, 2012

By: Alan Linder
Alan Linder
Daniel Feltes
New Hampshire Legal Assistance

NEW HAMPSHIRE COMMUNITY ACTION ASSOCIATION
By their Attorney

Date: April , 2012

By:_____
Dana Nute

UNITED STEEL WORKERS OF AMERICA LOCAL 12012-3
By its Attorney

Date: April , 2012

By:_____
Shawn Sullivan

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS LOCAL 326

Date: April , 2012

By:_____
James Simpson

GRANITE STATE HYDROPOWER ASSOCIATION
By its Attorney

Date: April , 2012

By:_____
Howard M. Moffett
Orr & Reno, P.A.

THE WAY HOME
By its Attorney

PAMELA LOCKE
By her Attorney

Date: April , 2012

By:_____
Alan Linder
Daniel Feltes
New Hampshire Legal Assistance

NEW HAMPSHIRE COMMUNITY ACTION ASSOCIATION
By their Attorney

Date: April 10, 2012

By:_____ 4-10-11
Dana Nute

UNITED STEEL WORKERS OF AMERICA LOCAL 12012-3
By its Attorney

Date: April , 2012

By:_____
Shawn Sullivan

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Date: April , 2012

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Date: April 10, 2012 By: 
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By its Attorney

Date: April , 2012 By:_____
Howard M. Moffett
Orr & Reno, P.A.

THE WAY HOME
By its Attorney

PAMELA LOCKE
By her Attorney

Date: April , 2012

By:_____
Alan Linder
Daniel Feltes
New Hampshire Legal Assistance

NEW HAMPSHIRE COMMUNITY ACTION ASSOCIATION
By their Attorney

Date: April , 2012

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Dana Nute

UNITED STEEL WORKERS OF AMERICA LOCAL 12012-3
By its Attorney

Date: April , 2012

By:_____
Shawn Sullivan

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS LOCAL 326

Date: April , 2012

By:_____
James Simpson

GRANITE STATE HYDROPOWER ASSOCIATION
By its Attorney

Date: April 10, 2012

By: Howard M Moffett
Howard M. Moffett
Orr & Reno, P.A.

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

November 26, 2002

CERTIFIED MAIL

Mr. Michael A. Gershon
Lloyd, Gosselink, Blevins, Rochelle,
Baldwin & Townsend, P.C.
111 Congress Avenue, Suite 1800
Austin, Texas 78701

Re: Application No. 34040-K; Application from Algonquin Water Resources of America to Report the Purchase and Transfer of the Stock of Tall Timbers Utility Company, Inc., Sewer Certificate of Convenience and Necessity (CCN) No. 20694 in Smith County

Dear Mr. Gershon:

We received the final closing letter for the application referenced above on November 20, 2002. Per this information, we understand the stock transfer was completed on November 5, 2002. This confirms that Algonquin Water Resources of America is now 100% stockholder of Tall Timbers Utility Company, Inc., CCN No. 20694 in Smith County.

The application is now closed and a copy of this information has been placed in the official file. The following changes will be reflected in our records:

Utility Name:	Tall Timbers Utility Company, Inc.
New Stockholders:	Algonquin Water Resources of America
Responsible Person:	No change
Address:	No change
Telephone:	No change

If you have any questions, please contact Ms. Tammy Benter by phone at 512/239-6136, or if by correspondence include MC 153 in the letterhead address.

Sincerely,

Michelle Abrams

Michelle Abrams, Team Leader
Utilities & Districts Section
Water Supply Division

MA/TB/ac

cc: TCEQ Region 5 Office

LLOYD, GOSSELINK, BLEVINS, ROCHELLE,
BALDWIN & TOWNSEND, P. C.
ATTORNEYS AT LAW

111 CONGRESS AVENUE
SUITE 1800
AUSTIN, TEXAS 78701

Mr. Gershon's Direct Line: (512) 322-5872
Email: mgershon@lglawfirm.com

TELEPHONE (512) 322-5800
TELECOPIER (512) 472-0532
www.lglawfirm.com

December 3, 2002

Mr. Trevor T. Hill
Algonquin Water Resources of America, Inc.
P.O. Box 731
Carefree, Arizona 85377

Re: TCEQ Approval of AWRA's Application for Stock Transfer--Tall Timbers Utility Company (2005-01)

Dear Mr. Hill:

Attached please find final confirmation from the TCEQ Utilities and Districts Section regarding the Tall Timbers Utility Co. acquisition, received via mail today. This confirmation memorializes our timely filing of the *Notice that Transaction is Complete*, pursuant to §291.111(f), and advises that TCEQ's files have been updated to reflect the new ownership and contact information.

Please recognize in this letter that TCEQ's records of the responsible person and contact information remain unchanged, as we advised in our Application. In the event that management changes, or the contact information changes, please note that TCEQ should be advised of the new information.

If you have any questions, comments, or requests, please let me know. Thank you.

Sincerely,

Michael A. Gershon

MAG:daa

Attachment
cc: Martin C. Rochelle, Esq., *of the firm*
Lambeth Townsend, Esq., *of the firm*
Ms. Pat L. Seward, *of the firm*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

November 26, 2002

CERTIFIED MAIL

Mr. Michael A. Gershon
Lloyd, Gosselink, Blevins, Rochelle,
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111 Congress Avenue, Suite 1800
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New Stockholders:	Algonquin Water Resources of America
Responsible Person:	No change
Address:	No change
Telephone:	No change

If you have any questions, please contact Ms. Tammy Benter by phone at 512/239-6136, or if by correspondence include MC 153 in the letterhead address.

Sincerely,

Michelle Abrams

Michelle Abrams, Team Leader
Utilities & Districts Section
Water Supply Division

MA/TB/ac

cc: TCEQ Region 5 Office

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_58 Please provide a copy of the AEP Tax Allocation Agreement.

RESPONSE

The Joint Applicants object to this request on the basis that it seeks information that is outside the scope of this proceeding and that is neither relevant to this proceeding or calculated to lead to the discovery of admissible evidence. In support of this objection the Joint Applicants state that information concerning the AEP Tax Allocation Agreement has nothing to do with the Commission's inquiry into this matter, which, pursuant to KRS 278.020(6) and (7), is whether Liberty has the financial, technical, and managerial abilities to provide reasonable service and that the proposed acquisition is in accordance with law, for a proper purpose, and consistent with the public interest.

Respondent: Counsel

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_59 Please provide a copy of the Liberty Tax Allocation Agreement.
a. Indicate if the Liberty Tax Allocation Agreement has a provision similar to that of the AEP Tax Allocation Agreement whereby Liberty reimburses the members of the affiliate consolidated group for the income tax effect of taxable losses, thereby reducing or eliminating any net operating loss carryforward ADIT.
b. Indicate if Liberty files a consolidated US federal income tax return. If so, indicate if Kentucky Power will be a member of the affiliate consolidated group.

RESPONSE

a.-b. Liberty does not have a tax allocation agreement in place. After the proposed transaction, Kentucky Power would be a member in Liberty Utilities (America) Co. & Subs consolidated group for U.S. federal income tax purposes.

Witness: Michael McCuen

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_60 Refer to the Direct Testimony of Mr. Eichler at 29 wherein he states: "Subject to the Commission's own views and findings, public interest in the context of a utility acquisition is first and foremost a function of the impact on customers. This includes customer rates paid for service."

a. Please provide all citations in the Joint Application and/or accompanying Direct Testimony that quantify the impact of the Liberty acquisition on customer rates. If none, then so state.
b. Please provide a copy of all analyses, studies, and comparative data to demonstrate the effect on customer rates for the number of forecast years available if the Liberty acquisition is approved and closes. Provide a copy of all Excel and/or other files in live format with all formulas intact and a copy of all other source documents relied on for your response. If none, then so state.
c. Please provide a copy of all analyses, studies, and comparative data to demonstrate the effect on customer rates for the number of forecast years available if the Liberty acquisition is not approved and/or is approved, but does not close. Provide a copy of all Excel and/or other files in live format with all formulas intact and a copy of all

RESPONSE

a. Since the acquisition process itself will not result in any impact on customer rates, there was no impact for Liberty to cite.
b. This type of analysis was not applicable based on the reasoning provided in (a).
c. The contemplated scenarios would give Kentucky Power no basis to recover any costs from Kentucky customers. As such, the Joint Applicants had no reason to conduct the associated analysis.

Witness: Peter Eichler

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_61 Please provide the following estimated amounts for the forecast years available, including, but not limited to, a copy of all Excel and/or other files in live format with all formulas intact and a copy of all other source documents relied on for your response:

a. Kentucky Power and Kentucky Transco non-fuel operation and maintenance expense by function and account, administrative and general expense by account, and other operating expenses by account and type of expense if the Liberty acquisition does not close. Separate the expenses into Kentucky Power and Kentucky Transco directly-incurred expenses and indirectly-incurred expenses charged by AEPSC to each of the acquired companies.

b. Kentucky Power and Kentucky Transco non-fuel operation and maintenance expense by function and account, administrative and general expense by account, and other operating expenses by account and type of expense if the Liberty acquisition closes. Separate the expenses into Kentucky Power and Kentucky Transco directly-incurred expenses, indirectly-incurred expenses charged by AEPSC to Kentucky Power and Kentucky Transco pursuant to the Transition Services Agreement, and indirectly-incurred expenses charged by Liberty and other Liberty affiliates' to Kentucky Power and Kentucky Transco.

RESPONSE

a. There are no documents responsive to this request.

b. There are no documents responsive to this request.

Witness: Brian West

Witness: Peter Eichler

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_62 Refer to the Direct Testimony of Mr. Eichler at 38 herein he states:
At this point, however, we expect that in addition to approximately 350 existing Kentucky Power positions that will transition to Liberty, upwards of another 100 positions will be required to staff the new organization under Liberty's management. For clarity, these positions are not incremental to those providing services today, but rather are replacements for positions that currently provide services from other locations.
Please provide Liberty's analyses of the local and other Liberty affiliate staffing and related costs that will be incurred to replace the centralized services presently provided by AEPSC, including, but not limited to PowerPoint presentations, Excel spreadsheets in live format with all formulas intact, payroll costs, other overhead costs, including benefits and payroll taxes, additional rent expense, and utilities expense, etc. In addition, map the present AEPSC, AEP Transco and local Kentucky Power and Kentucky Transco organizations, functions, and staffing to the planned Liberty by (entity and location) and local Kentucky Power and Kentucky Transco organizations, functions, and staffing.

RESPONSE

Refer to the confidential attachment in response to Staff 1-19 (JA_R_STAFF_1_19_ConfidentialAttachment_Liberty KY new jobs 3.xls) for the analysis of jobs Liberty expects to bring to Kentucky to perform the duties currently performed by AEPSC. Liberty expects to replace other AEPSC corporate costs with the existing staff and systems in place supporting the Liberty organization. We expect to use space in existing facilities and leverage existing fleet for field based supervisory roles.

The analysis maps the employees based on AEPSC functional groupings and the positions that are expected to be in Kentucky, to the degree possible with local market conditions.

Witness: Peter Eichler

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_63 Identify each Liberty entity that will provide services and charge costs to the acquired companies and describe the specific services that each entity will provide to each acquired company.

RESPONSE

Algonquin Power & Utilities Corp., Liberty Utilities (Canada) Corp., Liberty Utilities Co., and Liberty Utilities Service Corp. (which will employ all the employees of Kentucky Power Company) will each charge costs to Kentucky Power. Please refer to Staff 1-17 for the results of application of the Cost Allocation Manual associated with this transaction and the response to AG 1-40 for a copy of the Cost Allocation Manual.

Witness: Peter Eichler

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_64 Refer to the Direct Testimony of Mr. Eichler at 6 wherein he states: *Liberty will bring a strategic focus to Kentucky Power as Kentucky Power's size makes it important in Liberty's portfolio. Although in AEP's footprint it is among the smallest utilities, Kentucky Power would be among the largest in Liberty's portfolio and would receive the commensurate share of managerial attention and resources.*

a. Please provide a copy of the most recent actual financial statements (balance sheet, income statement, and statement of cash flows) and forecast financial statements for all years available for Liberty without Kentucky Power (standalone) at the same level of detail as the line items on the income statement and balance sheet reflected in the FERC Form 1.

b. Please provide a copy of the proforma (based on most recent actual Liberty and Kentucky Power) financial statements and forecast financial statements for all years available for Liberty with Kentucky Power (consolidated) at the same level of detail as the line items on the income statement and balance sheet reflected in the FERC Form 1.

RESPONSE

a. Please see response to Staff 1-09.

b. There are no documents responsive to the request for forecasted financials for the consolidated Liberty / Kentucky Power entity.

Witness: Peter Eichler

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_65 Please provide a copy of all analyses developed by or for Algonquin and/or Liberty to value each of the acquired companies, including all Excel workbooks in live format and with all formulas intact.

RESPONSE

Liberty objects to this request on the basis that it seeks information that is outside the scope of this proceeding and that is neither relevant to this proceeding or calculated to lead to the discovery of admissible evidence. In support of this objection Liberty states that information concerning the method by which Liberty valued Kentucky Power has nothing to do with the Commission's inquiry into this matter, which, pursuant to KRS 278.020(6) and (7), is whether Liberty has the financial, technical, and managerial abilities to provide reasonable service and that the proposed acquisition is in accordance with law, for a proper purpose, and consistent with the public interest.

Please see response to KPSC 1-68.

While Liberty did not value each of the acquired companies separately, the total valuation can be allocated to each acquired company based on asset value. Using December 31, 2020 (the last audited year end book value), the total asset valuation for Kentucky Power would be $2.7Bn and for Kentucky Transco based on the FERC Form 1 was $158Mn.

Witness: Peter Eichler

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_66 Describe in detail Algonquin and Liberty's (by entity) planned financing to fund the acquisition of the acquired companies (by entity).

RESPONSE

Please see response to Staff 1-23.

Witness: Michael Mosindy

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_67 Please provide a copy of all analyses developed by or for Algonquin and/or Liberty to develop, study, and/or evaluate the financing to acquire each of the acquired companies, including all Excel workbooks in live format and with all formulas intact.

RESPONSE

Please see response to Staff 1-23.

Witness: Michael Mosindy

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_68 Refer to the Direct Testimony of Mr. Eichler at 30 wherein he states: *To ensure this critical outcome, professionals from Liberty, Kentucky Power, and AEPSC have been engaged in transition and separation planning activities since October 27 – the day after the proposed transaction's announcement.*

a. Identify and describe each of the professional teams engaged in the transition and separation planning activities.

b. Please provide a copy of all transition and separation planning documents, including overviews, goals and objectives overall and for each team and each functional area, task assignments and functions for each team and each functional area, status reports overall and for each team and each functional area, and all assessments of costs and savings developed by and/or considered overall and by each team and each functional area.

RESPONSE

a. Please refer to Transition Service Agreement provided as an exhibit the Stock Purchase Agreement (Exhibit 5 to the Application) and JA_R_KIUC_1_68_ConfidentialAttachment1 for a description of the AEP and Kentucky Power functions involved in the transition and separation activities.

Please see below for a description of the Liberty functions involved in the transition and separation activities.

Team	Description – Develop cutover and post-close plan for:
Finance	Accounting, financial reporting, budgeting, treasury activities, tax and accounts payable
HR	Compensation & benefits, payroll, recruiting/ talent management, labor relations, learning & development and internal comms
Supply Chain	Procurement, fleet, warehousing & inventory and facilities mgt.
Distribution	Electric distribution employees, assets and processes

Transmission	Electric transmission employees, assets and processes
Generation	Big Sandy employees, assets and processes
Commercial Operations	Fuel procurement, load forecasting and PJM settlements
IT	Establish network connectivity to Liberty and migrate from AEP to Liberty IT applications and manage cybersecurity
Risk & Compliance	Integration of activities into Liberty risk management and compliance processes; insurance
Regulatory & Legal	Legal and Regulatory employees, processes and ongoing litigation and rate activity
Customer	Customer care, billing, credit & collections

b. AEP objects to this request on the basis that it seeks information that is outside the scope of this proceeding and that is neither relevant to this proceeding nor calculated to lead to the discovery of admissible evidence. AEP further objects on the basis that the request is overly broad and unduly burdensome in that it is unbound in scope or duration and seeks voluminous, preliminary, and draft documents and information regarding activities that are currently underway.

Witness: Stephan T. Haynes

Witness: Peter Eichler

JA_R_KIUC_1_68_PublicAttachment1 has been redacted in its entirety.

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_69 Describe the present AEP and Kentucky Power generation dispatch, transmission operations center, and distribution operations center, including the physical locations, specific functions, staffing, and functions performed and/or managed at each location.

RESPONSE

Distribution Operations
The Kentucky Distribution Dispatch Center (DDC) has the overall responsibility for continual real time monitoring, coordination, safe and reliable operation for Kentucky Power distribution electrical facilities operated below 40kV. This includes establishing and administering the operating procedures and policies. In addition, the Kentucky DDC is responsible for the dispatching of outages and the safe and timely restoration of customers..

The Kentucky DDC is located at the Robert E. Matthews Service Center, 12333 Kevin Avenue, Ashland, KY, 41102 . For business continuity purposes, all dispatch functions can be transferred to a backup centers located at the Paintsville Training Center, 408 Teays Branch Road, Paintsville, KY, 41240 or the Appalachian Power Company DDC located at 40 Franklin Road SW, Roanoke, VA, 24011. These locations do have work stations to allow a limited number of Kentucky DDC employees to travel and take over all dispatch functions. In addition, we have the capability to have all trouble dispatch functions (non SCADA) to be performed at the employee's home.

The Kentucky DDC's current staff consists of the following: (1) Manager, (1) Distribution Dispatch Energy Control Coordinator, (1) Distribution Dispatch Trouble Coordinator, (6) Energy Control Dispatchers and (3) Trouble Dispatchers.

Transmission Operations
The AEP Service Company will own Transmission Operations (TOP) real time operational responsibility for all sub-transmission and transmission facilities operated by Liberty in Kentucky. The responsibility will include operation services covered under the NERC and PJM definitions of (Real Time Monitoring and Control and Real Time Assessments). The defined real time operational services responsibilities include: 1. Monitor, Operate and Dispatch Transmission System, 2. Routine and Emergency Switching Instructions, 3. Operational Modeling Data, 4. Supervisory Control and Data Acquisition (SCADA), 5. Coordination with PJM, 6. Service Restoration, 7.

Interruption/Outage Analysis, 8. Weather Monitoring and Alerts, 9. EMS Support, and 10. Applicable Reliability Standards.

The two AEP Transmission Control Centers responsible for the real time operational services are located at:

New Albany Control Center 8400 SMITHS MILL ROAD, NEW ALBANY, OH 43054	AEP Roanoke Transmission Dispatch 40 FRANKLIN ROAD SW, ROANOKE, VA 24011

Per NERC standard requirements a Back Up Control Center for both control centers is located at 1 RIVERSIDE PLAZA, COLUMBUS, OH 43215.

The Energy Delivery Operations NERC certified and AEP qualified staff working from the two facilities consists of: (2) Manager, (3) Supervisors, (1) Technologist, (6) Transmission Dispatch Coordinator / Schedulers, (16) Dispatchers, (1) SCC Operations Specialist, (10) SCC Reliability Coordinators.
Note: The staff listed above supports AEP assets operated within the PJM. Real Time Operations Technology and Real Time Transmission Operations Support staff also works from the New Albany Transmission Control Center.

Generation Dispatch
AEP Service Corporation (AEPSC), acting on behalf of Kentucky Power, offers all of Kentucky Power's available generation resources into the PJM energy and ancillary markets on a daily basis. AEPSC submits all required unit offers and data in accordance with PJM protocols and works with the appropriate generation personnel at each plant to maintain the most up-to-date unit capabilities and parameters. Dispatch requirements are established by PJM based on its unit commitment and dispatch process while power plant personnel and AEPSC work together to comply with those requirements.
The Real Time Market Operations (RTMO) team responsible for coordinating dispatch of Kentucky Power generation consists of: (4) Managers, (5) Supervisors and (17) RTMO employees. These employees support real-time dispatch for all AEP operating companies, including Kentucky Power.
Generation Dispatch operations subject to NERC/CIP security requirements are conducted at two sites:

AEP Headquarters 1 Riverside Plaza Columbus, OH 43215	Dolan Laboratory 4001 Bixby Road Groveport, OH 43125

Witness: Brian K. West

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_70 Describe the planned future Liberty and Kentucky Power/Kentucky Transco generation dispatch, operation, and maintenance; transmission operations and maintenance, including any operations/dispatch center; and distribution operations and maintenance, including any operations/dispatch center; including the physical locations, specific functions, and staffing. Identify all changes from the present status, new locations or contracts with other entities to perform such functions, and the costs of the future operations compared to the cost of the present AEP and Kentucky Power/Kentucky Transco operations.

RESPONSE

Liberty's plans for Kentucky Power are organized into 3 phases, currently under development, and in progress:

- Phase 1: Immediate steps necessary to maintain the status quo;
- Phase 2: Delivery of key actions that will result in opportunities for efficiency and improved effectiveness between Liberty and future Kentucky Power operations;
- Phase 3: Liberty integrates Kentucky Power fully into Liberty utilizing subject matter experts (SME) from across Liberty and onto Liberty's continually developing infrastructure, practices, and processes.

In all cases, Liberty's plans include completing a comprehensive review of the critical processes, practices, systems, resources, and infrastructure that will be necessary to seamlessly transition Kentucky Power's operations into Liberty while ensuring safe and reliable service to the customers of Kentucky Power.

All Generation dispatch/ operation, and maintenance will continue to operate as it had prior to the acquisition, but under Liberty leadership. Similarly, Transmission and Distribution operations/ maintenance will also operate as it did prior to the acquisition, but under Liberty leadership.
Liberty will utilize Transition Service Agreements (TSAs) to ensure all business functions continue to be operational on Day 1. They will also provide Liberty the necessary time to carefully transition operational functions that require major changes to infrastructure, technology, or that require key additions to staffing. The TSAs will be

structured around each function's specific requirements so that Liberty is able to transition Kentucky operations and exit the TSAs as soon as it is ready.

Operational functions considered in the TSA include: Transmission Operations, Transmission Telecom, and Transmission Planning plus the associated IT and OT systems required within each function for both Distribution and Transmission. During the TSA period, AEP will continue to operate the Transmission grid in Kentucky Power working directly with PJM, coordinating with the Kentucky Power Field services, and working directly with the Kentucky Power Distribution Dispatch Center. The Distribution Dispatch Center will initially remain as is, utilizing Kentucky Power employees supported by a TSA for enabling use of AEP's systems.

Liberty will adopt all existing AEP operating practices and processes, ensure all teams continue to have access to operating systems necessary to complete their roles, and ensure that the business processes are established to ensure that Liberty is involved throughout.

Transmission Operations will be the subject of a contract between Liberty and AEP whereby AEP will continue to provide this service to Liberty for a mutually agreed upon period.

Liberty will also be leveraging its enterprise expertise in the electric utility industry in its plans. This includes the following, although not exhaustive, which is a reflection of some of the internal capabilities Liberty plans to utilize in the transition:

- Transmission, Distribution, and Generation resources based across our service territories, but primarily located in Missouri, Kansas, Oklahoma, and Arkansas
- Kodiak Electric Training Center in Joplin, Missouri
- Distribution Control Center in Londonderry, New Hampshire
- Transmission System Operations Center in Joplin, Missouri
- Strong working relationship with SPP, a neighboring RTO
- Centralized Operational Services structure for centers of excellence
- Electric Modality Teams comprised of Subject Matter Experts (SME) from all Liberty regions for Best Practices, Process, and Standards Development
- NERC, Compliance, and Cyber/ Physical Security Services
- Operational Technology & IT Enterprise Solutions

Witness: Drew Landoll

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_71 Please provide a template for all AEP accounting journal entries (debit and credit) on the date of closing, including, but not limited to, all balance sheet entries, including cash, financing, and benefit plans assets and liabilities; and all income statement entries, including gains and losses; and tax entries.

RESPONSE

Joint Applicants object to this request on the basis that it seeks information that is outside the scope of this proceeding and that is neither relevant to this proceeding nor calculated to lead to the discovery of admissible evidence. Joint Applicants further object to this request to the extent it seeks to require Joint Applicants to prepare documents that they have not previously created. Subject to and without waiving the foregoing objection the Joint Applicants state: the requested journal entries have not been prepared; therefore, Joint Applicants have no documents responsive to this request.

Witness: Allyson L. Keaton

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_72 Please provide a template for all Kentucky Power accounting journal entries (debit and credit) on the date of closing, including, but not limited to, all balance sheet entries, including cash, financing, and benefit plans assets and liabilities; and all income statement entries, including gains and losses; and tax entries.

RESPONSE

Joint Applicants object to this request to the extent it seeks to require Joint Applicants to prepare documents that they have not previously created. Subject to and without waiving the foregoing objection the Joint Applicants state: the requested journal entries have not been prepared; therefore, Joint Applicants have no documents responsive to this request.

Witness: Allyson L. Keaton

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_73 Please provide a template for all Kentucky Transco accounting journal entries (debit and credit) on the date of closing, including, but not limited to, all balance sheet entries, including cash, financing, and benefit plan assets and liabilities; and all income statement entries, including gains and losses; and tax entries.

RESPONSE

Joint Applicants object to this request on the basis that it seeks information that is outside the scope of this proceeding and that is neither relevant to this proceeding nor calculated to lead to the discovery of admissible evidence. Joint Applicants further object to this request to the extent it seeks to require Joint Applicants to prepare documents that they have not previously created. Subject to and without waiving the foregoing objection the Joint Applicants state: the requested journal entries have not been prepared; therefore, Joint Applicants have no documents responsive to this request.

Witness: Allyson L. Keaton

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_74 Identify all commitments offered by Liberty to protect customers from potential cost increases due to the following:

a. Loss of economies of scale due to AEPSC provision of centralized services to Kentucky Power and Kentucky Transco.

b. Loss of benefits, including economies and/or other savings and revenues, due to the termination of AEP intercompany agreements, including, but not limited to, the AEP Credit, Inc. agreement to purchase Kentucky Power's receivables on a daily basis and the AEP Tax Allocation Agreement.

c. Increase in local employment in lieu of AEPSC provision of centralized services.

RESPONSE

a.-c. While Liberty does not expect any of the hypothetical scenarios implied in the question to materialize, the Company would not be able to pass the costs described onto customers without the Commission's explicit approval in any case. Liberty is willing to agree to reasonable regulatory commitments, such as those agreed to and set forth in response to Staff 1-02. However, the reasonableness of any commitment is highly fact specific and may be impacted by other factors, including obligations and the testimony of the parties in this case. Accordingly, additional commitments are best considered in totality, such as in discussions of a global settlement or through a final order of the Commission. Liberty believes it would be premature to make commitments in addition to those set forth in Staff 1-02 at this time.

Witness: Peter Eichler

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_75 Please confirm that Liberty will commit to competitively bid and source new generation and purchased power resources to meet its load requirements. If denied, then explain why Liberty is unwilling to make this commitment.

RESPONSE

Liberty will evaluate the most prudent course of action specific to each generation and power resource. The first step in identifying future generation projects will be through robust integrated resource modeling. In Kentucky, Liberty will engage in supply side planning consistent with least cost integrated resource planning requirements. Whether to competitively bid a specific project will require a more detailed understanding of all the supply needs of Kentucky Power. Thus, it is premature to conclude at this time that every project should be competitively bid.

Witness: Peter Eichler

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_76 1. Refer to various presentations wherein Algonquin and Liberty have discussed their "playbook" for extracting value from the acquisitions of Kentucky Power and Kentucky Transco.

a. Confirm that Algonquin and Liberty have publicly identified the following "plays" that it will run from the Algonquin/Liberty "playbook," including the following:

i. "Greening the Fleet" through significant ***rate base*** investments in renewables (Analyst/Investor Day 12.14.21 transcript).

ii. Improving the reliability and resiliency of the system through significant rate base investments.

iii. Abandoning AEP's use of historic test years and transitioning to forecast test years.

iv. Sharply increasing the common equity (equity ratio) used to finance rate base compared to AEP's historic levels.

v. Seeking additional revenues through riders (see Analyst/Investor Day 12.14.21 transcript).

b. Identify and describe all other "plays" that Algonquin and Liberty plan to run in order to extract value from the acquisitions of Kentucky Power and Kentucky Transco.

RESPONSE

As a general matter, it is important to note that Liberty's references to the items discussed below have been made in an attempt to balance customer affordability and provide benefits to customers, and implicit in all statements is that any projects or investment opportunities will be the subject to the approval of the KPSC.

a.

i. Liberty acknowledges that "Greening the Fleet" initiatives give rise to significant upfront investments. However, as was the case in Liberty's Central Region, investments of approximately $600 million in renewable energy resulted in estimated customer savings of $125 million over 20 years. Given the KPSC's order to retire Mitchell for ratemaking purposes by 2028, Liberty sees similar opportunity to provide customer savings while making investments in Kentucky Power. Liberty at all times has assumed that any such investment will be the

subject of scrutiny and discussion by affected stakeholders and will be subject to the approval of the KPSC.

ii. In the course of its due diligence work, Liberty established that Kentucky Power's ratio of annual capital additions to depreciation expense is substantially below those of other large utilities and is substantially below the 2.0 multiple that is seen in the industry as a minimal measure of capital replenishment for a power utility. At the same time, Liberty's due diligence work saw that Kentucky Power's reliability is substantially below the industry standards and aside from the most recent year, has shown a declining trend. Assessing these two observations in tandem, Liberty made a working assumption that capital underinvestment is a driver behind Kentucky Power's reliability performance, and is an area Liberty intends to explore further. -

iii. Liberty believes that future test years allow utility operators to better manage costs in accordance with those allowed by regulatory agencies. Since future test years are permitted in Kentucky, Liberty plans to utilize this approach.

iv. Please see response to KIUC 1-42.

v. Confirmed, to the extent additional riders that provide both shareholder and customer benefits are identified, Liberty will seek utilization of such riders. Historically, it has been Liberty's experience that riders can provide benefits to both customers and shareholders by reducing volatility of costs, smoothing out capital expenditures, and helping with affordability.

b. Liberty will plan to operate Kentucky Power as a prudent operator of utilities as it does within its current portfolio and believes that value will only be achieved by balancing the needs of the customer base with shareholders; and therefore, if any initiatives are identified, it is Liberty's intent to discuss them with key stakeholders (including intervenor groups) to seek input.

Witness: Peter Eichler

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_77 In a December 14, 2021 presentation by Algonquin, Chief Operating Officer Anthony Johnston referred to "bringing on an estimated $2.2 billion of rate base" at the "close" of the acquisitions of Kentucky Power and Kentucky Transco in "mid-2022." This $2.2 billion figure was also cited in Algonquin's October 26, 2021 investor presentation.

a. Please provide the calculation of the $2.2 billion in rate base separated between Kentucky Power and Kentucky Transco, and with Kentucky Power separated into base, environmental surcharge, retirement rider (Big Sandy), and each other rider with rate base, if any.
b. Confirm that Liberty agreed to pay AEP $2.846 billion, including the assumption of $1.221 billion in debt. Confirm this statement means that Liberty will pay AEP $1.625 billion for its equity ownership in the acquired companies. If this is not correct, then provide a corrected statement and explain why the assertion in the question was incorrect.
c. Provide all reasons why Algonquin is willing to pay $2.846 billion for $2.2 billion in rate base.
d. Explain how Algonquin plans to recover the $646 million premium over the estimated rate base.

RESPONSE

a. See attached excel DR_KIUC 1-77 for rate base calculation. The $2.2Bn of rate base is an estimate at closing. There are no documents responsive to the request for a breakdown of rate base between base, environmental surcharge, retirement rider or other riders, however, rate base split between Kentucky Power and Kentucky Transco has been attached.

b. Confirmed.

c. In most merger and acquisition transactions, a premium is typically paid to the sellers of its business. This is in recognition of the scarcity of the assets being acquired, the skilled labor associated with the business, and other intangible factors. Liberty, as well as many other utility companies, have paid amounts above the book value of the acquired companies in recent history.

d. Liberty does not plan to recover the premium over the estimated rate base, and is not seeking to recover any such amounts from customers.

Witness: Peter Eichler

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_78 Refer to the Stock Purchase Agreement at 4.13 NSR Consent Decree.
a. Provide a copy of the NSR Consent Decree.
b. Identify all provisions of the NSR Consent Decree that specifically relate to the Mitchell Interest and Big Sandy and that are separate and distinct from AEP systemwide compliance commitments.

RESPONSE

a. Please see JA_R_KIUC_1_78_Attachment1 for the NSR Consent Decree and the six modifications.
b. The following paragraphs of the Consent Decree that impose specific obligations on Mitchell and Big Sandy:
¶68 – NOx controls at Big Sandy and Mitchell
¶69 – NOx controls at Big Sandy
¶87 – SO2 controls at Big Sandy and Mitchell
¶90 – SO2 controls at Big Sandy

Witness: Stephan T. Haynes

IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF OHIO
EASTERN DIVISION

UNITED STATES OF AMERICA Plaintiff, and STATE OF NEW YORK, ET AL., Plaintiff-Intervenors, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Terence P. Kemp Civil Action No C2-99-1250 (Consolidated with C2-99-1182)

UNITED STATES OF AMERICA Plaintiff, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	JUDGE GREGORY L. FROST Magistrate Judge Norah McCann King Civil Action No C2-05-360

OHIO CITIZEN ACTION, ET AL.,

Plaintiffs,

v.

AMERICAN ELECTRIC POWER SERVICE CORP., ET AL.,

Defendants.

JUDGE GREGORY L. FROST
Magistrate Judge Norah McCann King

Civil Action No. C2-04-1098

CONSENT DECREE

TABLE OF CONTENTS

WHEREAS, the following complaints have been filed against American Electric Power Service Corporation, Indiana Michigan Power Company, Ohio Power Company, Appalachian Power Company, Cardinal Operating Company, and Columbus Southern Power Company in the above-captioned cases, *United States, et al. v. American Electric Power Service Corp., et al.*, Civil Action Nos. C2-99-1182 and C2-99-1250 ("*AEP I*") and *United States, et al. v. American Electric Power Service Corp., et al.*, Civil Action Nos. C2-04-1098 and C2-05-360 ("*AEP II*"):

(a) the United States of America ("United States"), on behalf of the United States Environmental Protection Agency ("EPA"), filed initial complaints on November 3, 1999 and April 8, 2005, and filed amended complaints on March 3, 2000 and September 17, 2004, pursuant to Sections 113(b), 165, and 167 of the Clean Air Act (the "Act"), 42 U.S.C. §§ 7413, 7475, and 7477;

(b) the States of New York, Connecticut, New Jersey, Vermont, New Hampshire, Maryland, and Rhode Island, and the Commonwealth of Massachusetts, after their motion to intervene was granted, filed initial complaints on December 14, 1999 and November 18, 2004, and filed amended complaints on April 5, 2000, September 24, 2002, and September 17, 2004, pursuant to Section 304 of the Act, 42 U.S.C. § 7604; and

(c) Ohio Citizen Action, Citizens Action Coalition of Indiana, Hoosier Environmental Council, Valley Watch, Inc., Ohio Valley Environmental Coalition, West Virginia Environmental Council, Clean Air Council, Izaak Walton League of America, United States Public Interest Research Group, National Wildlife Federation, Indiana Wildlife Federation, League of Ohio Sportsmen, Sierra Club, and Natural Resources Defense Council,

Inc. filed an initial complaint on November 19, 1999, and filed amended complaints on January 1, 2000 and September 16, 2004, pursuant to Section 304 of the Act, 42 U.S.C. § 7604;

WHEREAS, the complaints filed against Defendants in *AEP I* and *AEP II* sought injunctive relief and the assessment of civil penalties for alleged violations of, *inter alia*, the:

(a) Prevention of Significant Deterioration and Nonattainment New Source Review provisions in Part C and D of Subchapter I of the Act, 42 U.S.C. §§ 7470-7492, 7501-7515; and

(b) federally-enforceable state implementation plans developed by Indiana, Ohio, Virginia, and West Virginia;

WHEREAS, EPA issued notices of violation ("NOVs") to Defendants with respect to such allegations on November 2, 1999, November 22, 1999, and June 18, 2004;

WHEREAS, EPA provided Defendants and the States of Indiana, Ohio, and West Virginia, and the Commonwealth of Virginia, with actual notice pertaining to Defendants' alleged violations, in accordance with Section 113(a)(1) and (b) of the Act, 42 U.S.C. § 7413(a)(1) and (b);

WHEREAS, in their complaints, the United States, the States, and Citizen Plaintiffs (collectively, the "Plaintiffs") alleged, *inter alia,* that Defendants made major modifications to major emitting facilities, and failed to obtain the necessary permits and install the controls necessary under the Act to reduce sulfur dioxide, nitrogen oxides, and/or particulate matter emissions, and further alleged that such emissions damage human health and the environment;

WHEREAS, the Plaintiffs' complaints state claims upon which relief can be granted against Defendants under Sections 113, 165, and 167 of the Act, 42 U.S.C. §§ 7413, 7475, and 7477, and 28 U.S.C. § 1355;

WHEREAS, Defendants have denied and continue to deny the violations alleged in the complaints and NOVs, maintain that they have been and remain in compliance with the Act and are not liable for civil penalties or injunctive relief, and state that they are agreeing to the obligations imposed by this Consent Decree solely to avoid the costs and uncertainties of litigation and to improve the environment;

WHEREAS, Defendants have installed and operated SCR technology on several Units in the AEP Eastern System, as those terms are defined herein, during the five (5) month ozone season to achieve emission reductions in compliance with the NO_x SIP Call;

WHEREAS, the Plaintiffs and Defendants anticipate that this Consent Decree, including the installation and operation of pollution control technology and other measures adopted pursuant to this Consent Decree, will achieve significant reductions of emissions from the AEP Eastern System and thereby significantly improve air quality;

WHEREAS, the liability phase of *AEP I* was tried on July 6-7, 2005, and July 11-12, 2005, and no decision has been rendered;

WHEREAS, the Parties have agreed, and the Court by entering this Consent Decree finds, that this Consent Decree has been negotiated in good faith and at arm's length; that this settlement is fair, reasonable, and in the public interest, and consistent with the goals of the Act; and that entry of this Consent Decree without further litigation is the most appropriate means of resolving this matter;

NOW, THEREFORE, without any admission by Defendants, and without adjudication of the violations alleged in the complaints or the NOVs, it is hereby ORDERED, ADJUDGED, AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over this action, the subject matter herein, and the Parties consenting hereto, pursuant to 28 U.S.C. §§ 1331, 1345, 1355, and 1367, Sections 113, 167, and 304 of the Act, 42 U.S.C. §§ 7413, 7477, and 7604. Solely for the purposes of this Consent Decree, venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), and under 28 U.S.C. § 1391(b) and (c). Solely for the purposes of this Consent Decree and the underlying complaints, and for no other purpose, Defendants waive all objections and defenses that they may have to the Court's jurisdiction over this action, to the Court's jurisdiction over Defendants, and to venue in this District. Defendants shall not challenge the terms of this Consent Decree or this Court's jurisdiction to enter and enforce this Consent Decree. Solely for the purposes of the complaints filed by the Plaintiffs in this matter and resolved by the Consent Decree, for the purposes of entry and enforcement of this Consent Decree, and for no other purpose, Defendants waive any defense or objection based on standing. Except as expressly provided for herein, this Consent Decree shall not create any rights in or obligations of any party other than the Plaintiffs and Defendants. Except as provided in Section XXV (Public Comment) of this Consent Decree, the Parties consent to entry of this Consent Decree without further notice. To facilitate entry of this Consent Decree, upon the Date of Lodging of this Consent Decree the Parties shall file a Joint Motion to Consolidate *AEP I* and *AEP II* so that *AEP II* is consolidated into *AEP I*.

II. APPLICABILITY

2. Upon entry, the provisions of the Consent Decree shall apply to and be binding upon and inure to the benefit of Plaintiffs and Defendants, and their respective successors and assigns, and upon their officers, employees, and agents, solely in their capacities as such.

3. Defendants shall be responsible for providing a copy of this Consent Decree to all vendors, suppliers, consultants, contractors, agents, and any other company or other organization retained to perform any of the work required by this Consent Decree. Notwithstanding any retention of contractors, subcontractors, or agents to perform any work required under this Consent Decree, Defendants shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. For this reason, in any action to enforce this Consent Decree, Defendants shall not assert as a defense the failure of their officers, directors, employees, servants, agents, or contractors to take actions necessary to comply with this Consent Decree, unless Defendants establish that such failure resulted from a Force Majeure Event, as defined in Paragraph 158 of this Consent Decree.

III. DEFINITIONS

Every term expressly defined by this Consent Decree shall have the meaning given to that term by this Consent Decree and, except as otherwise provided in this Consent Decree, every other term used in this Consent Decree that is also a term under the Act or the regulations implementing the Act shall mean in this Consent Decree what such term means under the Act or those implementing regulations.

4. A "1-hour Average NO_x Emission Rate" for a re-powered gas-fired, electric generating unit means, and shall be expressed as, the average concentration in parts per million

("ppm") by dry volume, corrected to 15% O_2, as averaged over one (1) hour. In determining the 1-Hour Average NO_x Emission Rate, Defendants shall use CEMS in accordance with applicable reference methods specified in 40 C.F.R. Part 60 to calculate the emissions for each 15-minute interval within each clock hour, except as provided in this Paragraph. Compliance with the 1-Hour Average NO_x Emission Rate shall be shown by averaging all 15-minute CEMS interval readings within a clock hour, except that any 15-minute CEMS interval that contains any part of a startup or shutdown shall not be included in the calculation of that 1-Hour average. A minimum of two 15-minute CEMS interval readings within a clock hour, not including startup or shutdown intervals, is required to determine compliance with the 1-Hour average NO_x Emission Rate. All emissions recorded by CEMS shall be reported in 1-Hour averages.

5. A "30-Day Rolling Average Emission Rate" for a Unit means, and shall be expressed as, a lb/mmBTU and calculated in accordance with the following procedure: first, sum the total pounds of the pollutant in question emitted from the Unit during an Operating Day and the previous twenty-nine (29) Operating Days; second, sum the total heat input to the Unit in mmBTU during the Operating Day and the previous twenty-nine (29) Operating Days; and third, divide the total number of pounds of the pollutant emitted during the thirty (30) Operating Days by the total heat input during the thirty (30) Operating Days. A new 30-Day Rolling Average Emission Rate shall be calculated for each new Operating Day. Each 30-Day Rolling Average Emission Rate shall include all emissions that occur during all periods of startup, shutdown, and Malfunction within an Operating Day, except as follows:

a. Emissions and BTU inputs that occur during a period of Malfunction shall be excluded from the calculation of the 30-Day Rolling Average Emission

Rate if Defendants provide notice of the Malfunction to EPA in accordance with Paragraph 159 in Section XIV (Force Majeure) of this Consent Decree;

b. Emissions of NO_x and BTU inputs that occur during the fifth and subsequent Cold Start Up Period(s) that occur at a given Unit during any 30-day period shall be excluded from the calculation of the 30-Day Rolling Average Emission Rate if inclusion of such emissions would result in a violation of any applicable 30-Day Rolling Average Emission Rate and Defendants have installed, operated, and maintained the SCR in question in accordance with manufacturers' specifications and good engineering practices. A "Cold Start Up Period" occurs whenever there has been no fire in the boiler of a Unit (no combustion of any Fossil Fuel) for a period of six (6) hours or more. The NO_x emissions to be excluded during the fifth and subsequent Cold Start Up Period(s) shall be the lesser of (i) those NO_x emissions emitted during the eight (8) hour period commencing when the Unit is synchronized with a utility electric distribution system and concluding eight (8) hours later, or (ii) those NO_x emissions emitted prior to the time that the flue gas has achieved the minimum SCR operational temperature specified by the catalyst manufacturer; and

c. For SO_2, shall include all emissions and BTUs commencing from the time the Unit is synchronized with a utility electric distribution system through

the time that the Unit ceases to combust fossil fuel and the fire is out in the boiler.

6. A "30-Day Rolling Average Removal Efficiency" means, for SO_2, at a Unit other than Conesville Unit 5 and Conesville Unit 6, the percent reduction in the mass of SO_2 achieved by a Unit's FGD system over a 30-Operating Day period and shall be calculated as follows: step one, sum the total pounds of SO_2 emitted as measured at the outlet of the FGD system for the Unit during the current Operating Day and the previous twenty-nine (29) Operating Days as measured at the outlet of the FGD system for that Unit; step two, sum the total pounds of SO_2 delivered to the inlet of the FGD system for the Unit during the current Operating Day and the previous twenty-nine (29) Operating Days as measured at the inlet to the FGD system for that Unit; step three, subtract the outlet SO_2 emissions calculated in step one from the inlet SO_2 emissions calculated in step two; step four, divide the remainder calculated in step three by the inlet SO_2 emissions calculated in step two; and step five, multiply the quotient calculated in step four by 100 to express as a percentage of removal efficiency. A new 30-day Rolling Average Removal Efficiency shall be calculated for each new Operating Day, and shall include all emissions that occur during all periods within each Operating Day except that emissions that occur during a period of Malfunction may be excluded from the calculation if Defendants provide Notice of the Malfunction to Plaintiffs in accordance with Section XIV (Force Majeure) and it is determined to be a Force Majeure Event pursuant to that Section.

7. "AEP Eastern System" means, solely for purposes of this Consent Decree, the following coal-fired, electric steam generating Units (with the nominal nameplate net capacity of each Unit):

a. Amos Unit 1 (800 MW), Amos Unit 2 (800 MW), and Amos Unit 3 (1300 MW) located in St. Albans, West Virginia;

b. Big Sandy Unit 1 (260 MW) and Big Sandy Unit 2 (800 MW) located in Louisa, Kentucky;

c. Cardinal Unit 1 (600 MW), Cardinal Unit 2 (600 MW), and Cardinal Unit 3 (630 MW) located in Brilliant, Ohio;

d. Clinch River Unit 1 (235 MW), Clinch River Unit 2 (235 MW), and Clinch River Unit 3 (235 MW) located in Carbo, Virginia;

e. Conesville Unit 1 (125 MW), Conesville Unit 2 (125 MW), Conesville Unit 3 (165 MW), Conesville Unit 4 (780 MW), Conesville Unit 5 (375 MW), and Conesville Unit 6 (375 MW) located in Conesville, Ohio;

f. Gavin Unit 1 (1300 MW) and Gavin Unit 2 (1300 MW) located in Cheshire, Ohio;

g. Glen Lyn Unit 5 (95 MW) and Glen Lyn Unit 6 (240 MW) located in Glen Lyn, Virginia;

h. Kammer Unit 1 (210 MW), Kammer Unit 2 (210 MW), and Kammer Unit 3 (210 MW) located in Moundsville, West Virginia;

i. Kanawha River Unit 1 (200 MW) and Kanawha River Unit 2 (200 MW) located in Glasgow, West Virginia;

j. Mitchell Unit 1 (800 MW) and Mitchell Unit 2 (800 MW) located in Moundsville, West Virginia;

k. Mountaineer Unit 1 (1300 MW) located in New Haven, West Virginia;

l. Muskingum River Unit 1 (205 MW), Muskingum River Unit 2 (205 MW), Muskingum River Unit 3 (215 MW), Muskingum River Unit 4 (215 MW), and Muskingum River Unit 5 (585 MW) located in Beverly, Ohio;

m. Picway Unit 9 (100 MW) located in Lockbourne, Ohio;

n. Rockport Unit 1 (1300 MW) and Rockport Unit 2 (1300 MW) located in Rockport, Indiana;

o. Sporn Unit 1 (150 MW), Sporn Unit 2 (150 MW), Sporn Unit 3 (150 MW), Sporn Unit 4 (150), and Sporn Unit 5 (450 MW) located in New Haven, West Virginia; and

p. Tanners Creek Unit 1 (145 MW), Tanners Creek Unit 2 (145 MW), Tanners Creek Unit 3 (205 MW), and Tanners Creek Unit 4 (500 MW) located in Lawrenceburg, Indiana.

8. "Boiler Island" means: a Unit's (a) fuel combustion system (including bunker, coal pulverizers, crusher, stoker, and fuel burners); (b) combustion air system; (c) steam generating system (firebox, boiler tubes, and walls); and (d) draft system (excluding the stack), all as further described in "Interpretation of Reconstruction," by John B. Rasnic, U.S. EPA (November 25, 1986) and attachments thereto.

9. "CEMS" or "Continuous Emission Monitoring System" means, for obligations involving NO_x and SO_2 under this Consent Decree, the devices defined in 40 C.F.R. § 72.2 and installed and maintained as required by 40 C.F.R. Part 75.

10. "Citizen Plaintiffs" means, collectively, Ohio Citizen Action, Citizens Action Coalition of Indiana, Hoosier Environmental Council, Ohio Valley Environmental Coalition,

West Virginia Environmental Council, Clean Air Council, Izaak Walton League of America, United States Public Interest Research Group, National Wildlife Federation, Indiana Wildlife Federation, League of Ohio Sportsmen, Sierra Club, and Natural Resources Defense Council, Inc.

11. "Clean Air Act" or "Act" means the federal Clean Air Act, 42 U.S.C. §§ 7401-7671q, and its implementing regulations.

12. "Clean Air Interstate Rule" or "CAIR" means the regulations promulgated by EPA on May 12, 2005, at 70 Fed. Reg. 25,161, which are entitled, "Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to NO_x SIP Call; Final Rule," and any subsequent amendments to that regulation, and any applicable, federally-approved state implementation plan or the federal implementation plan to implement CAIR.

13. "Consent Decree" or "Decree" means this Consent Decree and the appendices attached hereto, which are incorporated into this Consent Decree.

14. "Continuously Operate" or "Continuous Operation" means that when an SCR, FGD, ESP, or Other NO_x Pollution Controls are used at a Unit, except during a Malfunction, they shall be operated at all times such Unit is in operation, consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for such equipment and the Unit so as to minimize emissions to the greatest extent practicable.

15. "Date of Entry" means the date this Consent Decree is approved or signed by the United States District Court Judge; provided, however, that if the Parties' Joint Motion to Consolidate, as specified in Paragraph 1, is denied or not decided, then the "Date of Entry"

means the date that the last of the two United States District Court Judges hearing these cases approves or signs this Consent Decree.

16. "Date of Lodging" means the date this Consent Decree is filed for lodging with the Clerk of the Court for the United States District Court for the Southern District of Ohio.

17. "Day" means, unless otherwise specified, calendar day.

18. "Defendants" or "AEP" means American Electric Power Service Corporation, Kentucky Power Company d/b/a American Electric Power, Indiana Michigan Power Company d/b/a American Electric Power, Ohio Power Company d/b/a American Electric Power, Cardinal Operating Company and its owners (Ohio Power and Buckeye Power, Inc.), Appalachian Power Company d/b/a American Electric Power, and Columbus Southern Power Company d/b/a American Electric Power.

19. "Eastern System-Wide Annual Tonnage Limitation" means the limitations, as specified in this Consent Decree, on the number of tons of the air pollutants that may be emitted from the AEP Eastern System during the relevant calendar year (i.e., January 1 through December 31), and shall include all emissions of the air pollutants emitted during all periods of startup, shutdown, and Malfunction, except that emissions that occur during a period of Malfunction may be excluded from the calculation if Defendants provide Notice of the Malfunction to Plaintiffs in accordance with Section XIV (Force Majeure) and it is determined to be a Force Majeure Event pursuant to that Section.

20. "Emission Rate" means the number of pounds of pollutant emitted per million BTU of heat input ("lb/mmBTU"), measured in accordance with this Consent Decree.

21. "EPA" means the United States Environmental Protection Agency.

22. "ESP" means electrostatic precipitator, a pollution control device for the reduction of PM.

23. "Environmental Mitigation Project" means a project funded or implemented by Defendants as a remedial measure to mitigate alleged damage to human health or the environment, including National Parks or Wilderness Areas, claimed to have been caused by the alleged violations described in the complaints or to compensate Plaintiffs for costs necessitated as a result of the alleged damages.

24. "Existing Unit" means a Unit that commenced operation prior to the Date of Lodging of this Consent Decree.

25. "Flue Gas Desulfurization System," or "FGD," means a pollution control device with one or more absorber vessels that employs flue gas desulfurization technology for the reduction of SO_2.

26. "Fossil Fuel" means any hydrocarbon fuel, including coal, petroleum coke, petroleum oil, or natural gas.

27. An "Improved Unit" for NO_x means an AEP Eastern System Unit equipped with an SCR or scheduled under this Consent Decree to be equipped with an SCR, or required to be Retired, Retrofitted, or Re-powered. A Unit may be an Improved Unit for one pollutant without being an Improved Unit for another. Any Other Unit in the AEP Eastern System can become an Improved Unit for NO_x if it is equipped with an SCR and the requirement to Continuously Operate such SCR is incorporated into a federally-enforceable non-Title V permit or site-specific amendment to the state implementation plan and the Title V Permit applicable to that Unit.

28. An "Improved Unit" for SO_2 means an AEP Eastern System Unit equipped with an FGD or scheduled under this Consent Decree to be equipped with an FGD, or required to be Retired, Retrofitted, or Re-powered. A Unit may be an Improved Unit for one pollutant without being an Improved Unit for another. Any Other Unit in the AEP Eastern System can become an Improved Unit for SO_2 if it is equipped with an FGD and the requirement to Continuously Operate such FGD is incorporated into a federally-enforceable non-Title V permit or site-specific amendment to the state implementation plan and the Title V Permit applicable to that Unit.

29. "KW" means kilowatt or one thousand watts.

30. "lb/mmBTU" means one pound per million British thermal units.

31. "Malfunction" means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not Malfunctions.

32. "MW" means a megawatt or one million watts.

33. "NSR Permit" means a preconstruction permit issued by the permitting authority pursuant to Parts C or D of Subchapter I of the Clean Air Act.

34. "National Ambient Air Quality Standards" or "NAAQS" means national ambient air quality standards that are promulgated pursuant to Section 109 of the Act, 42 U.S.C. § 7409.

35. "New and Newly Permitted Unit" means a Unit that commenced operation after the Date of Lodging of this Consent Decree, and that has been issued a final NSR Permit for SO_2 and NO_x that includes applicable Best Available Control Technology ("BACT") and/or Lowest

Achievable Emission Rate ("LAER") limitations, as those terms are respectively defined at 42 U.S.C. §§ 7479(3), 7501(3).

36. "Nonattainment NSR" means the nonattainment area New Source Review program within the meaning of Part D of Subchapter I of the Act, 42 U.S.C. §§ 7501-7515, and its regulations, 40 C.F.R. Part 51.

37. "NO_x" means oxides of nitrogen, measured in accordance with the provisions of this Consent Decree.

38. "NO_x Allowance" means an authorization to emit a specified amount of NO_x that is allocated or issued under an emissions trading or marketable permit program of any kind that has been established under the Clean Air Act or a state implementation plan.

39. "NO_x CAIR Allocations" means the number of NO_x Allowances allocated to the AEP Eastern System Units pursuant to the Clean Air Interstate Rule, excluding any NO_x Allowances awarded by Indiana, Kentucky, Ohio, West Virginia, and Virginia to an AEP Eastern System Unit from the "compliance supplement pool," as that phrase is defined at 40 C.F.R. § 96.143, in a federally-approved state implementation plan, or federal implementation plan to implement CAIR.

40. "Operating Day" means any day on which a Unit fires Fossil Fuel.

41. "Other NO_x Pollution Controls" means the measures identified in the table in Paragraph 69 that will achieve reductions in NO_x emissions at the Units specified therein.

42. "Other SO_2 Measures" means the measures identified in Paragraph 90 that will achieve reductions in SO_2 emissions at the Units specified therein.

43. "Other Unit" means any Unit of the AEP Eastern System that is not an Improved Unit for the pollutant in question.

44. "Operational or Ownership Interest" means part or all of Defendants' legal or equitable operational or ownership interests in any Unit in the AEP Eastern System.

45. "Parties" means the United States, the States, the Citizen Plaintiffs, and Defendants. "Party" means one of the Parties.

46. "Plaintiffs" means the United States, the States, and the Citizen Plaintiffs.

47. "Plant-Wide Annual Rolling Tonnage Limitation for SO_2 at Clinch River" means the sum of the tons of SO_2 emitted during all periods of operation from the Clinch River plant, including, without limitation, all SO_2 emitted during periods of startup, shutdown, and Malfunction, in the most recent month and the previous eleven (11) months. A new Annual Rolling Average Tonnage Limitation for years 2010 through 2014, and for 2015 and continuing thereafter, shall be calculated in accordance with Paragraph 88.

48. "Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer" means the sum of the tons of SO_2 emitted during all periods of operation from the Kammer plant, including, without limitation, all SO_2 emitted during periods of startup, shutdown, and Malfunction, during the relevant calendar year (i.e., January 1 through December 31). A new Plant-Wide Annual Tonnage Limitation shall be calculated for each new calendar year.

49. "PM" means particulate matter, as measured in accordance with the provisions of this Consent Decree.

50. "PM CEMS" or "PM Continuous Emission Monitoring System" means the equipment that samples, analyzes, measures, and provides, by readings taken at frequent intervals, an electronic or paper record of PM emissions.

51. "PM Emission Rate" means the number of pounds of PM emitted per million BTU of heat input (lb/mmBTU), as measured in annual stack tests in accordance with EPA Method 5, 5B, or 17, 40 C.F.R. Part 60, including Appendix A.

52. "Project Dollars" means Defendants' expenditures and payments incurred or made in carrying out the Environmental Mitigation Projects identified in Section VIII (Environmental Mitigation Projects) of this Consent Decree to the extent that such expenditures or payments both: (a) comply with the requirements set forth in Section VIII (Environmental Mitigation Projects) and Appendix A of this Consent Decree, and (b) constitute Defendants' direct payments for such projects, or Defendants' external costs for contractors, vendors, and equipment.

53. "PSD" means Prevention of Significant Deterioration within the meaning of Part C of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470-7492, and its regulations, 40 C.F.R. Part 52.

54. "Re-power" means either (1) the replacement of an existing pulverized coal boiler through the construction of a new circulating fluidized bed ("CFB") boiler or other technology of equivalent environmental performance that at a minimum achieves and maintains a 30-Day Rolling Average Emission Rate not greater than 0.100 lb/mmBTU or a 30-Day Rolling Average Removal Efficiency of at least ninety-five percent (95%) for SO_2 and a 30-Day Rolling Average Emission Rate not greater than 0.070 lb/mmBTU for NO_x; or (2) the modification of

such Unit, or removal and replacement of Unit components, such that the modified or replaced Unit generates electricity through the use of new combined cycle combustion turbine technology fueled by natural gas containing no more than 0.5 grains of sulfur per 100 standard cubic feet of natural gas, and at a minimum, achieves a 1-hour Average NO_x Emission Rate not greater than 2.0 ppm.

55. "Retire" means that Defendants shall: (a) permanently shut down and cease to operate the Unit; and (b) comply with any state and/or federal requirements applicable to that Unit. Defendants shall amend any applicable permits so as to reflect the permanent shutdown status of such Unit.

56. "Retrofit" means that the Unit must install and Continuously Operate both an SCR and an FGD. For the 600 MW listed in the table in Paragraph 68 and 87, "Retrofit" means that the Unit must meet a federally-enforceable 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU for NO_x and a 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU for SO_2, measured in accordance with the requirements of this Consent Decree.

57. "Selective Catalytic Reduction System" or "SCR" means a pollution control device that employs selective catalytic reduction technology for the reduction of NO_x emissions.

58. "Selective Non-Catalytic Reduction" means a pollution control device for the reduction of NO_x emissions that utilizes ammonia or urea injection into the boiler.

59. "SO_2" means sulfur dioxide, as measured in accordance with the provisions of this Consent Decree.

60. "SO_2 Allowance" means "allowance" as defined at 42 U.S.C. § 7651a(3): "an authorization, allocated to an affected unit by the Administrator of EPA under Subchapter IV of the Act, to emit, during or after a specified calendar year, one ton of sulfur dioxide."

61. "SO_2 Allocations" means the number of SO_2 Allowances allocated to the AEP Eastern System Units.

62. "Super-Compliant NO_x Allowance" means an allowance attributable to reductions beyond the requirements of this Consent Decree as determined in accordance with Paragraph 80.

63. "Super-Compliant SO_2 Allowance" means an allowance attributable to reductions beyond the requirements of this Consent Decree as determined in accordance with Paragraph 98.

64. "States" means the States of Connecticut, Maryland, New Hampshire, New Jersey, New York, Rhode Island, and Vermont, and the Commonwealth of Massachusetts.

65. "Title V Permit" means the permit required for Defendants' major sources under Subchapter V of the Act, 42 U.S.C. §§ 7661-7661e.

66. "Unit" means collectively, the coal pulverizer, stationary equipment that feeds coal to the boiler, the boiler that produces steam for the steam turbine, the steam turbine, the generator, the equipment necessary to operate the generator, steam turbine, and boiler, and all ancillary equipment, including pollution control equipment. An electric steam generating station may comprise one or more Units.

IV. NO_x EMISSION REDUCTIONS AND CONTROLS

A. Eastern System-Wide Annual Tonnage Limitations for NO_x.

67. Notwithstanding any other provisions of this Consent Decree, except Section XIV (Force Majeure), during each calendar year specified in the table below, all Units in the AEP

Eastern System, collectively, shall not emit NO_x in excess of the following Eastern System-Wide Annual Tonnage Limitations:

Calendar Year	**Eastern System-Wide Annual Tonnage Limitations for NO_x**
2009	96,000 tons
2010	92,500 tons
2011	92,500 tons
2012	85,000 tons
2013	85,000 tons
2014	85,000 tons
2015	75,000 tons
2016, and each year thereafter	72,000 tons

B. NO_x Emission Limitations and Control Requirements.

68. No later than the dates set forth in the table below, Defendants shall install and Continuously Operate SCR on each Unit identified therein, or, if indicated in the table, Retire, Retrofit, or Re-power such Unit:

Unit	**NO_x Pollution Control**	**Date**
Amos Unit 1	SCR	January 1, 2008
Amos Unit 2	SCR	January 1, 2009
Amos Unit 3	SCR	January 1, 2008
Big Sandy Unit 2	SCR	January 1, 2009
Cardinal Unit 1	SCR	January 1, 2009
Cardinal Unit 2	SCR	January 1, 2009

Unit	**NO_x Pollution Control**	**Date**
Cardinal Unit 3	SCR	January 1, 2009
Conesville Unit 1	Retire, Retrofit, or Re-power	Date of Entry of this Consent Decree
Conesville Unit 2	Retire, Retrofit, or Re-power	Date of Entry of this Consent Decree
Conesville Unit 3	Retire, Retrofit, or Re-power	December 31, 2012
Conesville Unit 4	SCR	December 31, 2010
Gavin Unit 1	SCR	January 1, 2009
Gavin Unit 2	SCR	January 1, 2009
Mitchell Unit 1	SCR	January 1, 2009
Mitchell Unit 2	SCR	January 1, 2009
Mountaineer Unit 1	SCR	January 1, 2008
Muskingum River Units 1-4	Retire, Retrofit, or Re-power	December 31, 2015
Muskingum River Unit 5	SCR	January 1, 2008
Rockport Unit 1	SCR	December 31, 2017
Rockport Unit 2	SCR	December 31, 2019
Sporn Unit 5	Retire, Retrofit, or Re-power	December 31, 2013
A total of at least 600 MW from the following list of Units: Sporn Units 1-4, Clinch River Units 1-3, Tanners Creek Units 1-3, and/or Kammer Units 1-3	Retire, Retrofit, or Re-power	December 31, 2018

69. Other NO_x Pollution Controls. No later than the dates set forth in the table below, Defendants shall Continuously Operate the Other NO_x Pollution Controls on the Units identified therein:

Unit	**Other NO_x Pollution Controls**	**Date**
Big Sandy Unit 1	Low NO_x Burners	Date of Entry
Glen Lyn Units 5 and 6	Low NO_x Burners	Date of Entry
Clinch River Units 1, 2, and 3	Low NO_x Burners, and Selective Non-catalytic Reduction	For Low NO_x Burners, Date of Entry, and, for Selective Non-Catalytic Reduction, December 31, 2009
Conesville Units 5 and 6	Low NO_x Burners	Date of Entry
Kammer Units 1, 2, and 3	Overfire Air	Date of Entry
Kanawha River Units 1 and 2	Low NO_x Burners	Date of Entry
Picway Unit 9	Low NO_x Burners	Date of Entry
Tanners Creek Units 1, 2, and 3	Low NO_x Burners	Date of Entry
Tanners Creek Unit 4	Overfire Air	Date of Entry

C. General Provisions for Use and Surrender of NO_x Allowances.

70. Except as may be necessary to comply with this Section and Section XIII (Stipulated Penalties), Defendants may not use NO_x Allowances to comply with any requirement of this Consent Decree, including by claiming compliance with any emission limitation or Eastern System-Wide Annual Tonnage Limitation required by this Decree, by using, tendering,

or otherwise applying NO_x Allowances to achieve compliance or offset any emissions above the limits specified in this Consent Decree.

71. As required by this Section IV of this Consent Decree, Defendants shall surrender NO_x Allowances that would otherwise be available for sale, trade, or transfer as a result of actions taken by Defendants to comply with the requirements of this Consent Decree.

72. NO_x Allowances allocated to the AEP Eastern System may be used by Defendants to meet their own federal and/or state Clean Air Act regulatory requirements for the Units included in the AEP Eastern System. Subject to Paragraph 70, nothing in this Consent Decree shall prevent Defendants from purchasing or otherwise obtaining NO_x Allowances from another source for purposes of complying with their own federal and/or state Clean Air Act requirements to the extent otherwise allowed by law.

73. The requirements in this Consent Decree pertaining to Defendants' use and surrender of NO_x Allowances are permanent injunctions not subject to any termination provision of this Consent Decree. These provisions shall survive any termination of this Consent Decree.

D. Use of Excess NO_x Allowances.

74. Calculation of Unrestricted and Restricted NO_x Allowances. On an annual basis, beginning in 2009, Defendants shall calculate the difference between the NO_x CAIR Allocations for the Units in the AEP Eastern System for that year and the annual Eastern System-Wide Tonnage Limitations for NO_x for that calendar year. This difference represents the total Excess NO_x Allowances for that calendar year. For purposes of this Consent Decree, for each year commencing in 2009 and ending in 2015, forty-two percent (42%) of the Excess NO_x Allowances shall be Unrestricted Excess NO_x Allowances and fifty-eight percent (58%) shall be

Restricted Excess NO_x Allowances. Commencing in 2016, and continuing thereafter, all Excess NO_x Allowances shall be Restricted Excess NO_x Allowances.

75. Use and Surrender of Unrestricted Excess NO_x Allowances. For each calendar year commencing in 2009 and ending in 2015, Defendants may use Unrestricted Excess NO_x Allowances in any manner authorized by law. No later than March 1, 2016, Defendants must surrender, or transfer to a non-profit third party selected by Defendants for surrender, all unused Unrestricted Excess NO_x Allowances subject to surrender accumulated during the period from 2009 through 2015.

76. Use and Surrender of Restricted Excess NO_x Allowances. Beginning in calendar year 2009, and for each calendar year thereafter, Defendants shall calculate the difference between the number of any Restricted Excess NO_x Allowances and the number of NO_x Allowances that is equal to the amount of actual NO_x emissions from: (a) any New and Newly Permitted Unit as defined in this Consent Decree, and (b) the following five natural-gas plants but only up to a cumulative total of 1200 tons of NO_x in any single year: Ceredo Generating Station located near Ceredo, West Virginia, with a nominal generating capacity of 505 megawatts; Waterford Energy Center located in southeastern Ohio, with a nominal generating capacity of 821 megawatts; Darby Electric Generating Station located near Columbus, Ohio, with a nominal generating capacity of 480 megawatts; Lawrenceburg Generating Station located in Lawrenceburg, Indiana, with a generating capacity of 1,096 megawatts; and a natural gas-fired power plant under construction near Dresden, Ohio, with a nominal generating capacity of 580 megawatts. This difference shall be the amount of Restricted Excess NO_x Allowances

potentially subject to surrender in 2016. During calendar years 2009 through 2015, Defendants may accumulate Restricted Excess NO_x Allowances potentially subject to surrender in 2016.

77. NO_x Allowances from Renewable Energy. Beginning in calendar year 2009, and for each calendar year thereafter, Defendants may subtract from the number of Restricted Excess NO_x Allowances potentially subject to surrender, a number of allowances calculated in accordance with this Paragraph. To calculate such number, Defendants shall use the following method: multiply 0.0002 by the sum of (a) the actual annual generation in MWH/year generated from solar or wind power projects first owned or operated by Defendants after the Date of Lodging of this Consent Decree, and (b) the actual annual generation in MWH/year purchased by Defendants from solar or wind power projects in any year after the Date of Lodging of this Consent Decree. Such figure so calculated shall be subtracted from the number of Restricted Excess NO_x Allowances potentially subject to surrender each year. The remainder shall be the Restricted Excess NO_x Allowances subject to surrender.

78. Defendants may, solely at their discretion, use Restricted Excess NO_x Allowances at a New and Newly Permitted Unit for which Defendants have received a final NSR Permit from the permitting agency even if the NSR Permit has been appealed but not stayed during the permit appeal process. If Defendants use Restricted Excess NO_x Allowances at such New and Newly Permitted Unit, and the emissions from such New and Newly Permitted Unit are greater than what such Unit is permitted to emit after final adjudication of the appeal process, Defendants shall, within thirty (30) days of such final adjudication, retire an amount of NO_x Allowances equal to the number of tons of NO_x actually emitted that exceeded the finally adjudicated permit limit.

79. No later than March 1, 2016, the total number of Restricted Excess NO_x Allowances subject to surrender accumulated during 2009 through 2015 as calculated in accordance with Paragraphs 74, 76, and 77, shall be surrendered or transferred to a non-profit third party selected by Defendants for surrender, pursuant to Subsection F, below. Beginning in calendar year 2016, and for each calendar year thereafter, the total number of Restricted Excess NO_x Allowances subject to surrender for that year calculated in accordance with Paragraph 74, 76 and 77, shall be surrendered, or transferred to a non-profit third party selected by Defendants for surrender, by March 1 of the following calendar year.

E. Super-Compliant NO_x Allowances.

80. In each calendar year beginning in 2009, and continuing thereafter, Defendants may use in any manner authorized by law any NO_x Allowances made available in that year as a result of maintaining actual NO_x emissions from the AEP Eastern System below the Eastern System-Wide Annual Tonnage Limitations for NO_x under this Consent Decree for each calendar year. Defendants shall timely report the generation of such Super-Compliant NO_x Allowances in accordance with Section XI (Periodic Reporting) and Appendix B of this Consent Decree.

F. Method for Surrender of Excess NO_x Allowances.

81. For purposes of this Consent Decree, the "surrender" of Excess Restricted or Unrestricted Excess NO_x Allowances subject to surrender means permanently surrendering to EPA NO_x Allowances from the accounts administered by EPA so that such NO_x Allowances can never be used thereafter to meet any compliance requirement under the Clean Air Act, a state implementation plan, or this Consent Decree.

82. For all Restricted or Unrestricted Excess NO_x Allowances subject to surrender required to be surrendered to EPA in Paragraphs 79 and 75, above, Defendants or the third party recipient(s) (as the case may be) shall first submit a NO_x Allowance transfer request form to EPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of such NO_x Allowances to the EPA Enforcement Surrender Account or to any other EPA account that EPA may direct in writing. As part of submitting these transfer requests, Defendants or the third party recipient(s) shall irrevocably authorize the transfer of these NO_x Allowances and identify – by name of account and any applicable serial or other identification numbers or station names – the source and location of the NO_x Allowances being surrendered.

83. If any NO_x Allowances required to be surrendered under this Consent Decree are transferred directly to a non-profit third party, Defendants shall include a description of such transfer in the next report submitted to EPA as required by Section XI (Periodic Reporting) of this Consent Decree. Such report shall: (a) identify the non-profit third party recipient(s) of the NO_x Allowances and list the serial numbers of the transferred NO_x Allowances; and (b) include a certification by the third party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the NO_x Allowances and will not use any of the NO_x Allowances to meet any obligation imposed by any environmental law. No later than the second periodic report due after the transfer of any NO_x Allowances, Defendants shall include a statement that the third party recipient(s) surrendered the NO_x Allowances for permanent surrender to EPA in accordance with the provisions of Paragraph 82 within one (1) year after Defendants transferred the NO_x Allowances to them. Defendants shall not have complied with the NO_x Allowance

surrender requirements of this Paragraph until all third party recipient(s) have actually surrendered the transferred NO_x Allowances to EPA.

G. Reporting Requirements for NO_x Allowances.

84. Defendants shall comply with the reporting requirements for NO_x Allowances as described in Section XI (Periodic Reporting) and Appendix B.

H. General NO_x Provisions.

85. To the extent a NO_x Emission Rate is required under this Consent Decree, Defendants shall use CEMS in accordance with the reference methods specified in 40 C.F.R. Part 75 to determine such Emission Rate.

V. SO_2 EMISSION REDUCTIONS AND CONTROLS

A. Eastern System-Wide Annual Tonnage Limitations for SO_2.

86. Notwithstanding any other provisions of this Consent Decree, except Section XIV (Force Majeure), during each calendar year specified in the table below, all Units in the AEP Eastern System, collectively, shall not emit SO_2 in excess of the following Eastern System-Wide Annual Tonnage Limitations:

Calendar Year	**Eastern System-Wide Annual Tonnage Limitations for SO_2**
2010	450,000 tons
2011	450,000 tons
2012	420,000 tons
2013	350,000 tons
2014	340,000 tons

Calendar Year	**Eastern System-Wide Annual Tonnage Limitations for SO_2**
2015	275,000 tons
2016	260,000 tons
2017	235,000 tons
2018	184,000 tons
2019, and each year thereafter	174,000 tons

B. SO_2 Emission Limitations and Control Requirements.

87. No later than the dates set forth in the table below, Defendants shall install and Continuously Operate an FGD on each Unit identified therein, or, if indicated in the table, Retire, Retrofit, or Re-power such Unit:

Unit	**SO_2 Pollution Control**	**Date**
Amos Units 1 and 3	FGD	December 31, 2009
Amos Unit 2	FGD	December 31, 2010
Big Sandy Unit 2	FGD	December 31, 2015
Cardinal Units 1 and 2	FGD	December 31, 2008
Cardinal Unit 3	FGD	December 31, 2012
Conesville Units 1 and 2	Retire, Retrofit, or Re-power	Date of Entry
Conesville Unit 3	Retire, Retrofit, or Re-power	December 31, 2012
Conesville Unit 4	FGD	December 31, 2010
Conesville Unit 5	Upgrade existing FGD and meet a 95% 30-day Rolling Average Removal Efficiency	December 31, 2009

Unit	SO_2 Pollution Control	Date
Conesville Unit 6	Upgrade existing FGD and meet a 95% 30-day Rolling Average Removal Efficiency	December 31, 2009
Gavin Units 1 and 2	FGD	Date of Entry
Mitchell Units 1 and 2	FGD	December 31, 2007
Mountaineer Unit 1	FGD	December 31, 2007
Muskingum River Units 1-4	Retire, Retrofit, or Re-power	December 31, 2015
Muskingum River Unit 5	FGD	December 31, 2015
Rockport Unit 1	FGD	December 31, 2017
Rockport Unit 2	FGD	December 31, 2019
Sporn Unit 5	Retire, Retrofit, or Re-power	December 31, 2013
A total of at least 600 MW from the following list of Units: Sporn Units 1-4, Clinch River Units 1-3, Tanners Creek Units 1-3, and/or Kammer Units 1-3	Retire, Retrofit, or Re-power	December 31, 2018

88. Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River. Beginning on January 1, 2010, and continuing through December 31, 2014, Defendants shall limit their total annual SO_2 emissions at the Clinch River plant to a Plant-Wide Annual Rolling Average Tonnage Limitation of 21,700 tons. Beginning on January 1, 2015, and continuing thereafter, Defendants shall limit their total annual SO_2 emissions at the Clinch River plant to a Plant-Wide Annual Rolling Average Tonnage Limitation of 16,300 tons. For purposes of calculating the Plant-Wide Annual Rolling Average Tonnage Limitation that begins in 2010, Defendants shall use the period beginning January 1, 2010 through December 31, 2010 to

establish the initial annual period that is subject to the Plant-Wide Annual Rolling Average Tonnage Limitation for 2010 through 2014. Defendants shall then calculate a new Plant-Wide Annual Rolling Average Tonnage Limitation each month thereafter through December 31, 2014, by averaging the most recent month with the previous eleven (11) months. For purposes of calculating the Plant-Wide Annual Rolling Average Tonnage Limitation that begins in 2015, Defendants shall use the period beginning January 1, 2015 through December 31, 2015 to establish the initial annual period that is subject to the Plant-Wide Annual Average Rolling Tonnage Limitation for 2015. Defendants shall then calculate a new Plant-Wide Annual Rolling Average Tonnage Limitation each month thereafter by averaging the most recent month with the previous eleven (11) months.

89. Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer. Beginning on January 1, 2010, and continuing annually thereafter, Defendants shall limit their total annual SO_2 emissions at the Kammer plant to a Plant-Wide Annual Tonnage Limitation of 35,000 tons.

90. Other SO_2 Measures. No later than the dates set forth in the table below, Defendants shall comply with the limit on coal sulfur content for such Units, at all times that the Units are in operation:

Unit	**Other SO_2 Measures**	**Date**
Big Sandy Unit 1	Units can only burn coal with a sulfur content no greater than 1.75 lb/mmBTU on an annual average basis	Date of Entry
Glen Lyn Units 5 and 6	Units can only burn coal with a sulfur content no greater than 1.75 lb/mmBTU on an annual average basis.	Date of Entry

Unit	Other SO_2 Measures	Date
Kanawha River Units 1 and 2	Units can only burn coal with a sulfur content no greater than 1.75 lb/mmBTU on an annual average basis	Date of Entry
Tanners Creek Units 1, 2, and 3	Units can only burn coal with a sulfur content no greater than 1.2 lb/mmBTU on an annual average basis	Date of Entry
Tanners Creek Unit 4	Unit can only burn coal with a sulfur content no greater than 1.2 % on an annual average basis	Date of Entry

C. Use and Surrender of SO_2 Allowances.

91. Defendants may use SO_2 Allowances allocated to the AEP Eastern System by the Administrator of EPA under the Act, or by any state under its state implementation plan, to meet their own federal and/or state regulatory requirements for the Units included in the AEP Eastern System. Subject to Paragraph 92, nothing in this Consent Decree shall prevent Defendants from purchasing or otherwise obtaining SO_2 Allowances from another source for purposes of complying with their own federal and/or state Clean Air Act requirements to the extent otherwise allowed by law.

92. Except as may be necessary to comply with this Section and Section XIII (Stipulated Penalties), Defendants may not use any SO_2 Allowances to comply with any requirement of this Consent Decree, including by claiming compliance with any emission limitation, Eastern System-Wide Annual Tonnage Limitations, Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River, or Plant-Wide Annual Tonnage Limitation

for SO_2 at Kammer required by this Consent Decree by using, tendering, or otherwise applying SO_2 Allowances to achieve compliance or offset any emissions above the limits specified in this Consent Decree.

93. On an annual basis beginning in 2010, and continuing thereafter, Defendants shall calculate the number of Excess SO_2 Allowances by subtracting the number of SO_2 Allowances equal to the annual Eastern System-Wide Tonnage Limitations for SO_2 for each calendar year times the applicable allowance surrender ratio from the annual SO_2 Allocations for all Units within the AEP Eastern System for the same calendar year. Defendants shall surrender, or transfer to a non-profit third party selected by Defendants for surrender, all Excess SO_2 Allowances that have been allocated to the AEP Eastern System for the specified calendar year by the Administrator of EPA under the Act or by any state under its state implementation plan. Defendants shall make the surrender of SO_2 Allowances required by this Paragraph to EPA by March 1 of the immediately following calendar year.

D. Method for Surrender of Excess SO_2 Allowances.

94. For purposes of this Subsection, the "surrender" of Excess SO_2 Allowances means permanently surrendering allowances from the accounts administered by EPA so that such allowances can never be used thereafter to meet any compliance requirement under the Clean Air Act, a state implementation plan, or this Consent Decree.

95. If any SO_2 Allowances required to be surrendered under this Consent Decree are transferred directly to a non-profit third party, Defendants shall include a description of such transfer in the next report submitted to EPA pursuant to Section XI (Periodic Reporting) of this Consent Decree. Such report shall: (i) identify the non-profit third party recipient(s) of the SO_2

Allowances and list the serial numbers of the transferred SO_2 Allowances; and (ii) include a certification by the third party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the allowances and will not use any of the SO_2 Allowances to meet any obligation imposed by any environmental law. No later than the second periodic report due after the transfer of any SO_2 Allowances, Defendants shall include a statement that the third party recipient(s) surrendered the SO_2 Allowances for permanent surrender to EPA in accordance with the provisions of Paragraph 96 within one (1) year after Defendants transferred the SO_2 Allowances to them. Defendants shall not have complied with the SO_2 Allowance surrender requirements of this Paragraph until all third party recipient(s) have actually surrendered the transferred SO_2 Allowances to EPA.

96. For all SO_2 Allowances surrendered to EPA, Defendants or the third party recipient(s) (as the case may be) shall first submit an SO_2 Allowance transfer request form to EPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of such SO_2 Allowances to the EPA Enforcement Surrender Account or to any other EPA account that EPA may direct in writing. As part of submitting these transfer requests, Defendants or the third party recipient(s) shall irrevocably authorize the transfer of these SO_2 Allowances and identify -- by name of account and any applicable serial or other identification numbers or station names -- the source and location of the SO_2 Allowances being surrendered.

97. The requirements in this Consent Decree pertaining to Defendants' surrender of SO_2 Allowances are permanent injunctions not subject to any termination provision of this Decree. These provisions shall survive any termination of this Consent Decree in whole or in part.

E. Super-Compliant SO_2 Allowances.

98. In each calendar year beginning in 2010, and continuing thereafter, Defendants may use in any manner authorized by law any SO_2 Allowances made available in that year as a result of maintaining actual SO_2 emissions from the AEP Eastern System below the Eastern System-Wide Annual Tonnage Limitations for SO_2 under this Consent Decree for each calendar year. Defendants shall timely report the generation of such Super-Compliant SO_2 Allowances in accordance with Section XI (Periodic Reporting) and Appendix B of this Consent Decree.

F. Reporting Requirements for SO_2 Allowances.

99. Defendants shall comply with the reporting requirements for SO_2 Allowances as described in Section XI (Periodic Reporting) and Appendix B.

G. General SO_2 Provisions.

100. To the extent an Emission Rate or 30-Day Rolling Average Removal Efficiency for SO_2 is required under this Consent Decree, Defendants shall use CEMS in accordance with the reference methods specified in 40 C.F.R. Part 75 to determine such Emission Rate or Removal Efficiency.

101. Notwithstanding Paragraphs 6 and 100, the 30-Day Rolling Average Removal Efficiency for SO_2 at Conesville Unit 5 and Conesville Unit 6 shall be determined in accordance with Appendix C.

VI. PM EMISSION REDUCTIONS AND CONTROLS

A. Optimization of Existing ESPs.

102. Beginning thirty (30) days after the Date of Entry, and continuing thereafter, Defendants shall Continuously Operate each ESP on Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5 to maximize PM emission reductions at all times when the Unit is in

operation, provided that such operation of the ESP is consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for the ESP. Defendants shall, at a minimum, to the extent reasonably practicable: (a) fully energize each section of the ESP for each unit, and repair any failed ESP section at the next planned Unit outage (or unplanned outage of sufficient length); (b) operate automatic control systems on each ESP to maximize PM collection efficiency; (c) maintain power levels delivered to the ESPs, consistent with manufacturers' specifications, the operational design of the Unit, and good engineering practices; and (d) inspect for and repair during the next planned Unit outage (or unplanned outage of sufficient length) any openings in ESP casings, ductwork, and expansion joints to minimize air leakage.

B. PM Emission Rate and Testing.

103. No later than the dates specified in the table below, Defendants shall Continuously Operate each Unit specified therein to achieve and maintain a PM Emission Rate no greater than 0.030 lb/mmBTU:

Unit	**Date to Achieve and Maintain PM Emission Rate**
Cardinal Unit 1	December 31, 2009
Cardinal Unit 2	December 31, 2009
Muskingum River Unit 5	December 31, 2012

104. On or before the date established by this Consent Decree for Defendants to achieve and maintain 0.030 lb/mmBTU at Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5, Defendants shall conduct a performance test for PM that demonstrates compliance with the PM Emission Rate required by this Consent Decree. Within forty-five (45) days of each such performance test, Defendants shall submit the results of the performance test to Plaintiffs pursuant to Section XVIII (Notices) of this Consent Decree.

C. PM Emissions Monitoring.

105. Beginning in calendar year 2010 for Cardinal Unit 1 and Cardinal Unit 2, and calendar year 2013 for Muskingum River Unit 5, and continuing in each calendar year thereafter, Defendants shall conduct a stack test for PM on each stack servicing Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5. The annual stack test requirement imposed by this Paragraph may be satisfied by stack tests conducted by Defendants as required by their permits from the State of Ohio for any year that such stack tests are required under the permits.

106. The reference methods and procedures for determining compliance with PM Emission Rates shall be those specified in 40 C.F.R. Part 60, Appendix A, Method 5, 5B, or 17, or an alternative method that is promulgated by EPA, requested for use herein by Defendants, and approved for use herein by EPA. Use of any particular method shall conform to the EPA requirements specified in 40 C.F.R. Part 60, Appendix A and 40 C.F.R. § 60.48Da(b) and (e), or any federally-approved method contained in the Ohio State Implementation Plan. Defendants shall calculate the PM Emission Rates from the stack test results in accordance with 40 C.F.R. § 60.8(f). The results of each PM stack test shall be submitted to EPA within forty-five (45) days of completion of each test.

D. Installation and Operation of PM CEMS.

107. Defendants shall install, calibrate, operate, and maintain PM CEMS, as specified below. Each PM CEMS shall comprise a continuous particle mass monitor measuring particulate matter concentration, directly or indirectly, on an hourly average basis and a diluent monitor used to convert the concentration to units of lb/mmBTU. Defendants shall maintain, in an electronic database, the hourly average emission values produced by all PM CEMS in lb/mmBTU. Defendants shall use reasonable efforts to keep each PM CEMS running and producing data whenever any Unit served by the PM CEMS is operating.

108. No later than December 31, 2011, Defendants shall submit to EPA pursuant to Section XII (Review and Approval of Submittals) of this Consent Decree: (a) a plan for the installation and certification of each PM CEMS, and (b) a proposed Quality Assurance/Quality Control ("QA/QC") protocol that shall be followed in calibrating such PM CEMS. In developing both the plan for installation and certification of the PM CEMS and the QA/QC protocol, Defendants shall use the criteria set forth in 40 C.F.R. Part 60, Appendix B, Performance Specification 11, and Appendix F, Procedure 3. Following approval by EPA of the protocol, Defendants shall thereafter operate each PM CEMS in accordance with the approved protocol.

109. No later than the dates specified below, Defendants shall install, certify, and operate PM CEMS on the stacks or common stacks for Cardinal Unit 1, Cardinal Unit 2, and a third Unit, as further described in Paragraph 110:

Stack	Date to Commence Operation of PM CEMS
Cardinal Unit 1	December 31, 2012
Cardinal Unit 2	December 31, 2012
Unit to be identified pursuant to Paragraph 110	December 31, 2012

110. No later than December 31, 2011, Defendants shall identify, subject to Plaintiffs' approval, the third Unit required by Paragraph 109.

111. No later than ninety (90) days after Defendants begin operation of the PM CEMS, Defendants shall conduct tests of each PM CEMS to demonstrate compliance with the PM CEMS installation and certification plan submitted to and approved by EPA.

112. Demonstration that PM CEMS are Infeasible. Defendants shall operate the PM CEMS for at least two (2) years on each of the Units specified in Paragraphs 109 and 110. After two (2) years of operation, Defendants may attempt to demonstrate that it is infeasible to continue operating PM CEMS. As part of such demonstration, Defendants shall submit an alternative PM monitoring plan for review and approval by EPA. The plan shall explain the basis for stopping operation of the PM CEMS and propose an alternative PM monitoring plan. If the United States disapproves the alternative PM monitoring plan, or if the United States rejects Defendants' claim that it is infeasible to continue operating PM CEMS, such disagreement is subject to Section XV (Dispute Resolution).

113. "Infeasible to Continue Operating PM CEMS" Standard. Operation of a PM CEMS shall be considered no longer feasible if: (a) the PM CEMS cannot be kept in proper

condition for sufficient periods of time to produce reliable, adequate, or useful data consistent with the QA/QC protocol, or (b) Defendants demonstrate that recurring, chronic, or unusual equipment adjustment or servicing needs in relation to other types of continuous emission monitors cannot be resolved through reasonable expenditures of resources. If EPA determines that Defendants have demonstrated pursuant to this Paragraph that operation is no longer feasible, Defendants shall be entitled to discontinue operation of and remove the PM CEMS.

114. PM CEMS Operations Will Continue During Dispute Resolution or Proposals for Alternative Monitoring. Until EPA approves an alternative monitoring plan, or until the conclusion of any proceeding under Section XV (Dispute Resolution), Defendants shall continue to operate the PM CEMS. If EPA has not issued a decision regarding an alternative monitoring plan within 120 days, Defendants may initiate action under Section XV (Dispute Resolution).

E. PM Reporting.

115. Defendants shall comply with the reporting requirements for PM as described in Section XI (Periodic Reporting) and Appendix B.

F. General PM Provisions.

116. Although stack testing shall be used to determine compliance with the PM Emission Rate established by this Consent Decree, data from the PM CEMS shall be used, at a minimum, to monitor progress in reducing PM emissions.

VII. PROHIBITION ON NETTING CREDITS OR OFFSETS FROM REQUIRED CONTROLS

117. Emission reductions that result from actions required to be taken by Defendants after the Date of Entry of this Consent Decree to comply with the requirements of this Consent Decree shall not be considered as a creditable contemporaneous emission decrease for the purpose of obtaining a netting credit or offset under the Clean Air Act's Nonattainment NSR and PSD programs.

118. Nothing in this Consent Decree is intended to preclude the emission reductions generated under this Consent Decree from being considered by a State or EPA as creditable contemporaneous emission decreases for the purpose of attainment demonstrations submitted pursuant to § 110 of the Act, 42 U.S.C. § 7410, or in determining impacts on NAAQS, PSD increment, or air quality related values, including visibility, in a Class I area.

VIII. ENVIRONMENTAL MITIGATION PROJECTS

119. Defendants shall implement the Environmental Mitigation Projects ("Projects") described in Appendix A to this Consent Decree and fund the categories of Projects described in Subsection B, below, in compliance with the approved plans and schedules for such Projects and other terms of this Consent Decree. In funding and/or implementing all such Projects in Appendix A and Subsection B, Defendants shall expend moneys and/or implement Projects valued at no less than $36 million for the Projects identified in Appendix A and $24 million for the payments to the States to fund Projects within the categories set forth in Subsection B. Defendants shall fund and/or implement such Projects over a period of no later than five (5) years from the Date of Entry. Defendants may propose establishing one or more qualified settlement funds within the meaning of Treas. Reg. §1.468B-1 in conjunction with one or more

Mitigation Projects. Any such trust would be established pursuant to a trust agreement in a form to be mutually agreed upon by the affected Parties. Nothing in the foregoing is intended by the United States to be a determination or opinion regarding whether such trust would meet the requirements of Treas. Reg. §1.468B-1 or is otherwise appropriate.

A. Requirements for Projects Described in Appendix A ($36 million).

120. Defendants shall maintain, and present to EPA upon request, all documents to substantiate the Project Dollars expended to implement the Projects described in Appendix A, and shall provide these documents to EPA within thirty (30) days of a request for the documents.

121. All plans and reports prepared by Defendants pursuant to the requirements of this Section of the Consent Decree and required to be submitted to EPA shall be publicly available from Defendants without charge.

122. Defendants shall certify, as part of each plan submitted to EPA for any Project, that Defendants are not otherwise required by law to perform the Project described in the plan, that Defendants are unaware of any other person who is required by law to perform the Project, and that Defendants will not use any Project, or portion thereof, to satisfy any obligations that it may have under other applicable requirements of law, including any applicable renewable portfolio standards.

123. Defendants shall use good faith efforts to secure as much benefit as possible for the Project Dollars expended, consistent with the applicable requirements and limits of this Consent Decree.

124. If Defendants elect (where such an election is allowed) to undertake a Project by contributing funds to another person or entity that will carry out the Project in lieu of Defendants, but not including Defendants' agents or contractors, that person or instrumentality

must, in writing: (a) identify its legal authority for accepting such funding; and (b) identify its legal authority to conduct the Project for which Defendants contribute the funds. Regardless of whether Defendants elect (where such election is allowed) to undertake a Project by itself or to do so by contributing funds to another person or instrumentality that will carry out the Project, Defendants acknowledge that they will receive credit for the expenditure of such funds as Project Dollars only if Defendants demonstrate that the funds have been actually spent by either Defendants or by the person or instrumentality receiving them, and that such expenditures met all requirements of this Consent Decree.

125. Defendants shall comply with the reporting requirements for Appendix A Projects as described in Section XI (Periodic Reporting) and Appendix B.

126. Within sixty (60) days following the completion of each Project required under this Consent Decree (including any applicable periods of demonstration or testing), Defendants shall submit to the United States a report that documents the date that the Project was completed, Defendants' results of implementing the Project, including the emission reductions or other environmental benefits achieved, and the Project Dollars expended by Defendants in implementing the Project.

B. Mitigation Projects to be Conducted by the States ($24 million).

127. The States, by and through their respective Attorneys General, shall jointly submit to Defendants Projects within the categories identified in this Subsection B for funding in amounts not to exceed $4.8 million per calendar year for no less than five (5) years following the Date of Entry of this Consent Decree beginning as early as calendar year 2008. The funds for these Projects will be apportioned by and among the States, and Defendants shall not have approval rights for the Projects or the apportionment. Defendants shall pay proceeds as

designated by the States in accordance with the Projects submitted for funding each year within seventy-five (75) days after being notified in writing by the States. Notwithstanding the $4.8 million and 5-year limitation above, if the total costs of the projects submitted in any one or more years are less than $4.8 million, the difference between that amount and $4.8 million will be available for funding by Defendants of new or previously submitted projects in the following years, except that all amounts not designated by the States within ten (10) years after the Date of Entry of this Consent Decree shall expire.

128. Categories of Projects. The States agree to use money funded by Defendants to implement Projects that pertain to energy efficiency and/or pollution reduction. Such projects may include, but are not limited by, the following:

a. Retrofitting land and marine vehicles (e.g., automobiles, off-road and on-road construction and other vehicles, trains, ferries) and transportation terminals and ports, with pollution control devices, such as particulate matter traps, computer chip reflashing, and battery hybrid technology;

b. Truck-stop and marine port electrification;

c. Purchase and installation of photo-voltaic cells on buildings;

d. Projects to conserve energy use in new and existing buildings, including appliance efficiency improvement projects, weatherization projects, and projects intended to meet EPA's Green Building guidelines (see http://www.epa.gov/greenbuilding/pubs/enviro-issues.htm) and/or the Leadership in Energy and Environmental Design (LEED) Green Building Rating System (see http://www.usgbc.org/DisplayPage.aspx?CategoryID=19), and projects to

collect information in rental markets to assist in design of efficiency and conservation programs;

e. Construction associated with the production of energy from wind, solar, and biomass;

f. "Buy back" programs for dirty old motors (e.g., automobile, lawnmowers, landscape equipment);

g. Programs to remove and/or replace oil-fired home heating equipment to allow use of ultra-low sulfur oil, and outdoor wood-fired boilers;

h. Purchase and retirement of SO_2 and NO_x allowances; and

i. Funding program to improve modeling of mobile source sector.

IX. CIVIL PENALTY

129. Within thirty (30) days after the Date of Entry, Defendants shall pay to the United States a civil penalty in the amount of $15,000,000. The civil penalty shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing USAO File Number 1999v01542 and DOJ Case Number 90-5-2-1-06893 and the civil action case name and consolidated case numbers of this action. The costs of such EFT shall be Defendants' responsibility. Payment shall be made in accordance with instructions provided to Defendants by the Financial Litigation Unit of the U.S. Attorney's Office for the Southern District of Ohio. Any funds received after 2:00 p.m. EDT shall be credited on the next business day. At the time of payment, Defendants shall provide notice of payment, referencing the USAO File Number, the DOJ Case Number, and the civil action case name and consolidated case numbers, to the Department of Justice and to EPA in accordance with Section XVIII (Notices) of this Consent Decree.

130. Failure to timely pay the civil penalty shall subject Defendants to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render Defendants liable for all charges, costs, fees, and penalties established by law for the benefit of a creditor or of the United States in securing payment.

131. Payment made pursuant to this Section is a penalty within the meaning of Section 162(f) of the Internal Revenue Code, 26 U.S.C. § 162(f), and is not a tax-deductible expenditure for purposes of federal law.

X. RESOLUTION OF CIVIL CLAIMS AGAINST DEFENDANTS

A. Resolution of the United States' Civil Claims.

132. Claims Based on Modifications Occurring Before the Date of Lodging of this Consent Decree. Entry of this Decree shall resolve all civil claims of the United States against Defendants that arose from any modifications commenced at any AEP Eastern System Unit prior to the Date of Lodging of this Consent Decree, including but not limited to, those modifications alleged in the Notices of Violation and complaints filed in *AEP I* and *AEP II*, under any or all of: (a) Parts C or D of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470-7492, 7501-7515; (b) Section 111 of the Clean Air Act, 42 U.S.C. § 7411, and 40 C.F.R. § 60.14; (c) the federally-approved and enforceable Indiana State Implementation Plan, Kentucky State Implementation Plan, Ohio State Implementation Plan, Virginia State Implementation Plan, and West Virginia State Implementation Plan; or (d) Sections 502(a) and 504(a) of Title V of the Clean Air Act, 42 U.S.C §§ 7611(a) and 7611(c), but only to the extent that such claims are based on Defendants' failure to obtain an operating permit that reflects applicable requirements imposed under Parts C or D of Subchapter I, or Section 111 of the Clean Air Act.

133. Claims Based on Modifications after the Date of Lodging of This Consent Decree. Entry of this Consent Decree also shall resolve all civil claims of the United States against Defendants that arise based on a modification commenced before December 31, 2018, or solely for Rockport Unit 2, before December 31, 2019, for all pollutants, except Particulate Matter, regulated under Parts C or D of Subchapter I of the Clean Air Act, and under regulations promulgated thereunder, as of the Date of Lodging of this Consent Decree, and:

a. where such modification is commenced at any AEP Eastern System Unit after the Date of Lodging of this Consent Decree; or

b. where such modification is one this Consent Decree expressly directs Defendants to undertake.

The term "modification" as used in this Paragraph shall have the meaning that term is given under the Clean Air Act and under the regulations in effect as of the Date of Lodging of this Consent Decree, as alleged in the complaints in *AEP I* and *AEP II*.

134. Reopener. The resolution of the United States' civil claims against Defendants, as provided by this Subsection A, is subject to the provisions of Subsection B of this Section.

B. Pursuit by the United States of Civil Claims Otherwise Resolved by Subsection A.

135. Bases for Pursuing Resolved Claims for the AEP Eastern System. If Defendants violate: (a) the Eastern System-Wide Annual Tonnage Limitations for NO_x required pursuant to Paragraph 67; (b) the Eastern System-Wide Annual Tonnage Limitations for SO_2 required pursuant to Paragraph 86; or (c) operate a Unit more than ninety (90) days past a date established in this Consent Decree without completing the required installation, upgrade, or commencing Continuous Operation of any emission control device required pursuant to Paragraphs 68, 69, 87, 102, and 103 then the United States may pursue any claim at any AEP Eastern System Unit that is otherwise resolved under Subsection A (Resolution of United States' Civil Claims), subject to (a) and (b) below.

a. For any claims based on modifications undertaken at any Unit in the AEP Eastern System that is not an Improved Unit for the pollutant in question, claims may be pursued only where the modification(s) on which such claim is based was commenced within the five (5) years preceding the violation or failure specified in this Paragraph.

b. For any claims based on modifications undertaken at an Improved Unit, claims may be pursued only where the modification(s) on which such claim is based was commenced: (1) after the Date of Lodging of this Consent Decree and (2) within the five (5) years preceding the violation or failure specified in this Paragraph.

136. Additional Bases for Pursuing Resolved Claims for Modifications at an Improved Unit. Solely with respect to an Improved Unit, the United States may also pursue claims arising

from a modification (or collection of modifications) at an Improved Unit that has otherwise been resolved under Subsection A (Resolution of the United States' Civil Claims) if the modification (or collection of modifications) at the Improved Unit on which such claim is based (a) was commenced after the Date of Lodging of this Consent Decree and (b) individually (or collectively) increased the maximum hourly emission rate of that Unit for NO_x or SO_2 (as measured by 40 C.F.R. § 60.14 (b) and (h)) by more than ten percent (10%).

137. Any Other Unit can become an Improved Unit for NO_x if (a) it is equipped with an SCR, and (b) the operation of such SCR is incorporated into a federally-enforceable non-Title V permit or site-specific amendment to the state implementation plan and incorporated into a Title V permit applicable to that Unit. Any Other Unit can become an Improved Unit for SO_2 if (a) it is equipped with an FGD, and (b) the operation of such FGD is incorporated into a federally-enforceable non-Title V permit or site-specific amendment to the state implementation plan and incorporated into a Title V permit applicable to that Unit.

138. Additional Bases for Pursuing Resolved Claims for Modifications at Other Units.

a. Solely with respect to Other Units, i.e., a Unit that is not an Improved Unit under the terms of this Consent Decree, the United States may also pursue claims arising from a modification (or collection of modifications) at an Other Unit that has otherwise been resolved under Subsection A (Resolution of the United States' Civil Claims), if the modification (or collection of modifications) at the Other Unit on which the claim is based was commenced within the five (5) years preceding any of the following events:

1. a modification (or collection of modifications) at such Other Unit commenced after the Date of Lodging of this Consent Decree increases the maximum hourly

emission rate for such Other Unit for the relevant pollutant (NO_x or SO_2) (as measured by 40 C.F.R. § 60.14(b) and (h));

2. the aggregate of all Capital Expenditures made at such Other Unit exceed $125/KW on the Unit's Boiler Island (based on the generating capacities identified in Paragraph 7) during the period from the Date of Entry of this Consent Decree through December 31, 2015. (Capital Expenditures shall be measured in calendar year 2007 constant dollars, as adjusted by the McGraw-Hill Engineering News-Record Construction Cost Index); or

3. a modification (or collection of modifications) at such Other Unit commenced after the Date of Lodging of this Consent Decree results in an emissions increase of NO_x and/or SO_2 at such Other Unit, and such increase: (i) presents, by itself, or in combination with other emissions or sources, "an imminent and substantial endangerment" within the meaning of Section 303 of the Act, 42 U.S.C. §7603; (ii) causes or contributes to violation of a NAAQS in any Air Quality Control Area that is in attainment with that NAAQS; (iii) causes or contributes to violation of a PSD increment; or (iv) causes or contributes to any adverse impact on any formally-recognized air quality and related values in any Class I area. The introduction of any new or changed NAAQS shall not, standing alone, provide the showing needed under Subparagraphs (3)(ii) or (3)(iii) of this Paragraph, to pursue any claim for a modification at an Other Unit resolved under Subparagraph A of this Section.

b. Solely with respect to Other Units at the plant listed below, the United States may also pursue claims arising from a modification (or collection of modifications) at such Other Units commenced after the Date of Lodging of this Consent Decree if such modification (or collection of modifications) results in an emissions increase of SO_2 at such Other Unit, and such increase causes the emissions at the plant at issue to exceed the Plant-Wide Annual Rolling

Average Tonnage Limitation for SO_2 at Clinch River listed in the table below for year 2010-2014 and/or 2015 and beyond:

Plant	Year	SO_2 Tons Limit
Clinch River	2010 - 2014	21,700
Clinch River	2015 and each year thereafter	16,300

C. Resolution of Past Claims of the States and Citizen Plaintiffs and Reservation of Rights.

139. The States and Citizen Plaintiffs agree that this Consent Decree resolves all civil claims that have been alleged in their respective complaints or could have been alleged against Defendants prior to the Date of Lodging of this Consent Decree for violations of: (a) Parts C or D of Subchapter I of the Clean Air Act, 42 U.S.C. §§ 7470-7492, 7501-7515, and (b) Section 111 of the Act, 42 U.S.C. § 7411, and 40 C.F.R § 60.14, at Units within the AEP Eastern System.

140. The States and Citizen Plaintiffs expressly do not join in giving the Defendants the covenant provided by the United States through Paragraph 133 of this Consent Decree, do not release any claims under the Clean Air Act and its implementing regulations arising after the Date of Lodging of this Consent Decree, and reserve their rights, if any, to bring any actions against the Defendants pursuant to 42 U.S.C. § 7604 for any claims arising after the Date of Lodging of this Consent Decree.

141. Notwithstanding Paragraph 140, the States and Citizen Plaintiffs release Defendants from any civil claim that may arise under the Clean Air Act for Defendants' performance of activities that this Consent Decree expressly directs Defendants to undertake,

except to the extent that such activities would cause a significant increase in the emission of a criteria pollutant other than SO_2, NO_x, or PM.

142. Retention of Authority Regarding NAAQS Exceedences. Nothing in this Consent Decree shall be construed to affect the authority of the United States or any state under applicable federal statutes or regulations and applicable state statutes or regulations to impose appropriate requirements or sanctions on any Unit in the AEP Eastern System, including, but not limited to, the Units at the Clinch River plant, if the United States or a state determines that emissions from any Unit in the AEP Eastern System result in violation of, or interfere with the attainment and maintenance of, any ambient air quality standard.

XI. PERIODIC REPORTING

143. Beginning on March 31, 2008, and continuing annually thereafter on March 31 until termination of this Consent Decree, and in addition to any other express reporting requirement in this Consent Decree, Defendants shall submit to the Unites States, the States, and the Citizen Plaintiffs a progress report in compliance with Appendix B of this Consent Decree.

144. In any periodic progress report submitted pursuant to this Section, Defendants may incorporate by reference information previously submitted under their Title V permitting requirements, provided that Defendants attach the Title V permit report, or the relevant portion thereof, and provide a specific reference to the provisions of the Title V permit report that are responsive to the information required in the periodic progress report.

145. In addition to the progress reports required pursuant to this Section, Defendants shall provide a written report to the United States, the States, and the Citizen Plaintiffs of any violation of the requirements of this Consent Decree within fifteen (15) days of when Defendants knew or should have known of any such violation. In this report, Defendants shall explain the

cause or causes of the violation and all measures taken or to be taken by Defendants to prevent such violations in the future.

146. Each report shall be signed by Defendants' Vice President of Environmental Services or his or her equivalent or designee of at least the rank of Vice President, and shall contain the following certification:

> This information was prepared either by me or under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my evaluation, or the direction and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, I hereby certify under penalty of law that, to the best of my knowledge and belief, this information is true, accurate, and complete. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.

147. If any SO_2 or NO_x Allowances are surrendered to any third party pursuant to this Consent Decree, the third party's certification pursuant to Paragraphs 83 and 95 shall be signed by a managing officer of the third party and shall contain the following language:

> I certify under penalty of law that, _____ [name of third party] will not sell, trade, or otherwise exchange any of the allowances and will not use any of the allowances to meet any obligation imposed by any environmental law. I understand that there are significant penalties for submitting false, inaccurate, or incomplete information to the United States.

XII. REVIEW AND APPROVAL OF SUBMITTALS

148. Defendants shall submit each plan, report, or other submission required by this Consent Decree to the Plaintiffs specified, whenever such a document is required to be submitted for review or approval pursuant to this Consent Decree. The Plaintiff(s) to whom the report is submitted, as required, may approve the submittal or decline to approve it and provide written comments explaining the bases for declining such approval as soon as reasonably practicable. Such Plaintiff(s) will endeavor to coordinate their comments into one document when explaining their bases for declining such approval. Within sixty (60) days of receiving written comments from any of the Plaintiff(s), Defendants shall either: (a) revise the submittal consistent with the written comments and provide the revised submittal to the Plaintiff(s); or (b) submit the matter for dispute resolution, including the period of informal negotiations, under Section XV (Dispute Resolution) of this Consent Decree.

149. Upon receipt of Plaintiffs' or Plaintiff's (as the case may be) final approval of the submittal, or upon completion of the submittal pursuant to dispute resolution, Defendants shall implement the approved submittal in accordance with the schedule specified therein.

XIII. STIPULATED PENALTIES

150. For any failure by Defendants to comply with the terms of this Consent Decree, and subject to the provisions of Sections XIV (Force Majeure) and XV (Dispute Resolution), Defendants shall pay, within thirty (30) days after receipt of written demand to Defendants by the United States, the following stipulated penalties to the United States:

Consent Decree Violation	**Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)**
a. Failure to pay the civil penalty as specified in Section IX (Civil Penalty) of this Consent Decree	$10,000 per day
b. Failure to comply with any applicable 30-Day Rolling Average Emission Rate, 30-Day Rolling Average Removal Efficiency, Emission Rate for PM, or Other SO_2 Measures where the violation is less than 5% in excess of the limits set forth in this Consent Decree	$2,500 per day per violation
c. Failure to comply with any applicable 30-Day Rolling Average Emission Rate, 30-Day Rolling Average Removal Efficiency, Emission Rate for PM, or Other SO_2 Measures where the violation is equal to or greater than 5% but less than 10% in excess of the limits set forth in this Consent Decree	$5,000 per day per violation
d. Failure to comply with any applicable 30-Day Rolling Average Emission Rate, 30-Day Rolling Average Removal Efficiency, Emission Rate for PM, or Other SO_2 Measures where the violation is equal to or greater than 10% in excess of the limits set forth in this Consent Decree	$10,000 per day per violation

Consent Decree Violation	**Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)**
e. Failure to comply with the Eastern System-Wide Annual Tonnage Limitation for SO_2	$5,000 per ton for the first 1000 tons, and $10,000 per ton for each additional ton above 1000 tons, plus the surrender, pursuant to the procedures set forth in Paragraphs 95 and 96, of SO_2 Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
f. Failure to comply with the Plant-Wide Annual Rolling Tonnage Limitation for SO_2 at Clinch River	$40,000 per ton, plus the surrender, pursuant to the procedures set forth in Paragraphs 95 and 96, of SO_2 Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
g. Failure to comply with the Eastern System-Wide Annual Tonnage Limitation for NO_x	$5,000 per ton for the first 1000 tons, and $10,000 per ton for each additional ton above 1000 tons, plus the surrender, pursuant to the procedures set forth in Paragraphs 82 and 83, of NO_x Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
h. Failure to install, commence operation, or Continuously Operate a pollution control device required under this Consent Decree	$10,000 per day per violation during the first 30 days, $32,500 per day per violation thereafter
i. Failure to Retire, Retrofit, or Re-power a Unit by the date specified in this Consent Decree	$10,000 per day per violation during the first 30 days, $32,500 per day per violation thereafter

Consent Decree Violation	**Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)**
j. Failure to install or operate CEMS as required in this Consent Decree	$1,000 per day per violation
k. Failure to conduct performance tests of PM emissions, as required in this Consent Decree	$1,000 per day per violation
l. Failure to apply for any permit required by Section XVI (Permits)	$1,000 per day per violation
m. Failure to timely submit, modify, or implement, as approved, the reports, plans, studies, analyses, protocols, or other submittals required in this Consent Decree	$750 per day per violation during the first ten days, $1,000 per day per violation thereafter
n. Using NO_x Allowances except as permitted by Paragraphs 75, 76, and 78	The surrender of NO_x Allowances in an amount equal to four times the number of NO_x Allowances used in violation of this Consent Decree
o. Failure to surrender NO_x Allowances as required by Paragraphs 75 and 79	(a) $32,500 per day plus (b) $7,500 per NO_x Allowance not surrendered
p. Failure to surrender SO_2 Allowances as required by Paragraph 93	(a) $32,500 per day plus (b) $1,000 per SO_2 Allowance not surrendered
q. Failure to demonstrate the third party surrender of an SO_2 Allowance or NO_x Allowance in accordance with Paragraphs 95-96 and 82-83.	$2,500 per day per violation
r. Failure to implement any of the Environmental Mitigation Projects described in Appendix A in compliance with Section VIII (Environmental Mitigation Projects) of this Consent Decree	The difference between the cost of the Project, as identified in Appendix A, and the dollars Defendants spent to implement the Project

Consent Decree Violation	**Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)**
s. Failure to fund an Environmental Mitigation Project, as submitted by the States, in compliance with Section VIII (Environmental Mitigation Projects) of this Consent Decree	$1,000 per day per violation during the first 30 days, $5,000 per day per violation thereafter
t. Failure to Continuously Operate required Other NO_x Pollution Controls required in Paragraph 69	$10,000 per day during the first 30 days, and $32,500 each day thereafter
u. Failure to comply with the Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer	$40,000 per ton, plus the surrender, pursuant to the procedures set forth in Paragraphs 95 and 96 of SO_2 Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
v. Any other violation of this Consent Decree	$1,000 per day per violation

151. Violation of an Emission Rate or 30-Day Rolling Average Removal Efficiency that is based on a 30-Day Rolling Average is a violation on every day on which the average is based. Where a violation of a 30-Day Rolling Average Emission Rate or 30-Day Rolling Average Removal Efficiency (for the same pollutant and from the same source) recurs within periods of less than thirty (30) days, Defendants shall not pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

152. All stipulated penalties shall begin to accrue on the day after the performance is due or on the day a violation occurs, whichever is applicable, and shall continue to accrue until performance is satisfactorily completed or until the violation ceases, whichever is applicable. Nothing in this Consent Decree shall prevent the simultaneous accrual of separate stipulated penalties for separate violations of this Consent Decree.

153. Defendants shall pay all stipulated penalties to the United States within thirty (30) days of receipt of written demand to Defendants from the United States, and shall continue to make such payments every thirty (30) days thereafter until the violation(s) no longer continues, unless Defendants elect within twenty (20) days of receipt of written demand to Defendants from the United States to dispute the accrual of stipulated penalties in accordance with the provisions in Section XV (Dispute Resolution) of this Consent Decree.

154. Stipulated penalties shall continue to accrue as provided in accordance with Paragraph 152 during any dispute, with interest on accrued stipulated penalties payable and calculated at the rate established by the Secretary of the Treasury, pursuant to 28 U.S.C. § 1961, but need not be paid until the following:

a. If the dispute is resolved by agreement, or by a decision of Plaintiffs pursuant to Section XV (Dispute Resolution) of this Consent Decree that is not appealed to the Court, accrued stipulated penalties agreed or determined to be owing, together with accrued interest, shall be paid within thirty (30) days of the effective date of the agreement or of the receipt of Plaintiffs' decision;

b. If the dispute is appealed to the Court and Plaintiffs prevail in whole or in part, Defendants shall, within sixty (60) days of receipt of the Court's decision or order, pay all accrued stipulated penalties determined by the Court to be owing, together with interest accrued on such penalties determined by the Court to be owing, except as provided in Subparagraph c, below;

c. If the Court's decision is appealed by any Party, Defendants shall, within fifteen (15) days of receipt of the final appellate court decision, pay all accrued stipulated penalties determined to be owing, together with interest accrued on such stipulated penalties determined to be owing by the appellate court.

Notwithstanding any other provision of this Consent Decree, the accrued stipulated penalties agreed by the Plaintiffs and Defendants, or determined by the Plaintiffs through Dispute Resolution, to be owing may be less than the stipulated penalty amounts set forth in Paragraph 150.

155. All stipulated penalties shall be paid in the manner set forth in Section IX (Civil Penalty) of this Consent Decree.

156. Should Defendants fail to pay stipulated penalties in compliance with the terms of this Consent Decree, the United States shall be entitled to collect interest on such penalties, as provided for in 28 U.S.C. § 1961.

157. The stipulated penalties provided for in this Consent Decree shall be in addition to any other rights, remedies, or sanctions available to Plaintiffs by reason of Defendants' failure to comply with any requirement of this Consent Decree or applicable law, except that for any violation of the Act for which this Consent Decree provides for payment of a stipulated penalty, Defendants shall be allowed a credit for stipulated penalties paid against any statutory penalties also imposed for such violation.

XIV. FORCE MAJEURE

158. For purposes of this Consent Decree, including, but not limited to, Paragraphs 67 and 86, a "Force Majeure Event" shall mean an event that has been or will be caused by circumstances beyond the control of Defendants or any entity controlled by Defendants that delays compliance with any provision of this Consent Decree or otherwise causes a violation of any provision of this Consent Decree despite Defendants' best efforts to fulfill the obligation. "Best efforts to fulfill the obligation" include using best efforts to anticipate any potential Force Majeure Event and to address the effects of any such event (a) as it is occurring and (b) after it has occurred, such that the delay or violation is minimized to the greatest extent possible.

159. Notice of Force Majeure Events. If any event occurs or has occurred that may delay compliance with or otherwise cause a violation of any obligation under this Consent Decree, as to which Defendants intend to assert a claim of Force Majeure, Defendants shall notify the Plaintiffs in writing as soon as practicable, but in no event later than twenty-one (21) business days following the date Defendants first knew, or by the exercise of due diligence should have known, that the event caused or may cause such delay or violation. In this notice, Defendants shall reference this Paragraph of this Consent Decree and describe the anticipated length of time that the delay or violation may persist, the cause or causes of the delay or violation, all measures taken or to be taken by Defendants to prevent or minimize the delay or violation, the schedule by which Defendants propose to implement those measures, and Defendants' rationale for attributing a delay or violation to a Force Majeure Event. Defendants shall adopt all reasonable measures to avoid or minimize such delays or violations. Defendants shall be deemed to know of any circumstance which Defendants or any entity controlled by Defendants knew or should have known.

160. Failure to Give Notice. If Defendants materially fail to comply with the notice requirements of this Section, the Plaintiffs may void Defendants' claim for Force Majeure as to the specific event for which Defendants have failed to comply with such notice requirement.

161. Plaintiffs' Response. The Plaintiffs shall notify Defendants in writing regarding Defendants' claim of Force Majeure as soon as reasonably practicable. If the Plaintiffs agree that a delay in performance has been or will be caused by a Force Majeure Event, the Parties shall stipulate to an extension of deadline(s) for performance of the affected compliance requirement(s) by a period equal to the delay actually caused by the event, or the extent to which Defendants may be relieved of stipulated penalties or other remedies provided under the terms of this Consent Decree. Such agreement shall be reduced to writing, and signed by all Parties. If the agreement results in a material change to the terms of this Consent Decree, an appropriate modification shall be made pursuant to Section XXII (Modification). If such change is not material, no modification of this Consent Decree shall be required.

162. Disagreement. If Plaintiffs do not accept Defendants' claim of Force Majeure, or if the Plaintiffs and Defendants cannot agree on the length of the delay actually caused by the Force Majeure Event, or the extent of relief required to address the delay actually caused by the Force Majeure Event, the matter shall be resolved in accordance with Section XV (Dispute Resolution) of this Consent Decree.

163. Burden of Proof. In any dispute regarding Force Majeure, Defendants shall bear the burden of proving that any delay in performance or any other violation of any requirement of this Consent Decree was caused by or will be caused by a Force Majeure Event. Defendants shall also bear the burden of proving that Defendants gave the notice required by this Section and the burden of proving the anticipated duration and extent of any delay(s) attributable to a

Force Majeure Event. An extension of one compliance date based on a particular event may, but will not necessarily, result in an extension of a subsequent compliance date.

164. Events Excluded. Unanticipated or increased costs or expenses associated with the performance of Defendants' obligations under this Consent Decree shall not constitute a Force Majeure Event.

165. Potential Force Majeure Events. The Parties agree that, depending upon the circumstances related to an event and Defendants' response to such circumstances, the kinds of events listed below are among those that could qualify as Force Majeure Events within the meaning of this Section: construction, labor, or equipment delays; Malfunction of a Unit or emission control device; unanticipated coal supply or pollution control reagent delivery interruptions; acts of God; acts of war or terrorism; and orders by a government official, government agency, other regulatory authority, or a regional transmission organization, acting under and authorized by applicable law, that directs Defendants to operate an AEP Eastern System Unit in response to a local or system-wide (state-wide or regional) emergency (which could include unanticipated required operation to avoid loss of load or unserved load). Depending upon the circumstances and Defendants' response to such circumstances, failure of a permitting authority to issue a necessary permit in a timely fashion may constitute a Force Majeure Event where the failure of the permitting authority to act is beyond the control of Defendants and Defendants have taken all steps available to it to obtain the necessary permit, including, but not limited to: submitting a complete permit application; responding to requests for additional information by the permitting authority in a timely fashion; and accepting lawful permit terms and conditions after expeditiously exhausting any legal rights to appeal terms and conditions imposed by the permitting authority.

166. As part of the resolution of any matter submitted to this Court under Section XV (Dispute Resolution) of this Consent Decree regarding a claim of Force Majeure, the Plaintiffs and Defendants by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay agreed to by the Plaintiffs or approved by the Court. Defendants shall be liable for stipulated penalties for their failure thereafter to complete the work in accordance with the extended or modified schedule (provided that Defendants shall not be precluded from making a further claim of Force Majeure with regard to meeting any such extended or modified schedule).

XV. DISPUTE RESOLUTION

167. The dispute resolution procedure provided by this Section shall be available to resolve all disputes arising under this Consent Decree, provided that the Party invoking such procedure has first made a good faith attempt to resolve the matter with the other Parties.

168. The dispute resolution procedure required herein shall be invoked by one Party giving written notice to the other Parties advising of a dispute pursuant to this Section. The notice shall describe the nature of the dispute and shall state the noticing Party's position with regard to such dispute. The Parties receiving such a notice shall acknowledge receipt of the notice, and the Parties in dispute shall expeditiously schedule a meeting to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

169. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations among the disputing Parties. Such period of informal negotiations shall not extend beyond thirty (30) days from the date of the first meeting among the disputing Parties' representatives unless they agree in writing to shorten or extend

this period. During the informal negotiations period, the disputing Parties may also submit their dispute to a mutually agreed upon alternative dispute resolution (ADR) forum if the Parties agree that the ADR activities can be completed within the 30-day informal negotiations period (or such longer period as the Parties may agree to in writing).

170. If the disputing Parties are unable to reach agreement during the informal negotiation period, the Plaintiffs shall provide Defendants with a written summary of their position regarding the dispute. The written position provided by Plaintiffs shall be considered binding unless, within forty-five (45) days thereafter, Defendants seek judicial resolution of the dispute by filing a petition with this Court. The Plaintiffs may respond to the petition within forty-five (45) days of filing. In their initial filings with the Court under this Paragraph, the disputing Parties shall state their respective positions as to the applicable standard of law for resolving the particular dispute.

171. The time periods set out in this Section may be shortened or lengthened upon motion to the Court of one of the Parties to the dispute, explaining the Party's basis for seeking such a scheduling modification.

172. This Court shall not draw any inferences nor establish any presumptions adverse to any disputing Party as a result of invocation of this Section or the disputing Parties' inability to reach agreement.

173. As part of the resolution of any dispute under this Section, in appropriate circumstances the disputing Parties may agree, or this Court may order, an extension or modification of the schedule for the completion of the activities required under this Consent Decree to account for the delay that occurred as a result of dispute resolution. Defendants shall be liable for stipulated penalties for their failure thereafter to complete the work in accordance

with the extended or modified schedule, provided that Defendants shall not be precluded from asserting that a Force Majeure Event has caused or may cause a delay in complying with the extended or modified schedule.

174. The Court shall decide all disputes pursuant to applicable principles of law for resolving such disputes. In their initial filings with the Court under Paragraph 170, the disputing Parties shall state their respective positions as to the applicable standard of law for resolving the particular dispute.

XVI. PERMITS

175. Unless expressly stated otherwise in this Consent Decree, in any instance where otherwise applicable law or this Consent Decree requires Defendants to secure a permit to authorize construction or operation of any device contemplated herein, including all preconstruction, construction, and operating permits required under state law, Defendants shall make such application in a timely manner. Defendants shall provide Notice to Plaintiffs under Section XVIII (Notices), for each Unit that Defendants submit an application for any permit described in this Paragraph 175.

176. Notwithstanding the previous Paragraph, nothing in this Consent Decree shall be construed to require Defendants to apply for or obtain a PSD or Nonattainment NSR permit for physical changes in, or changes in the method of operation of, any AEP Eastern System Unit that would give rise to claims resolved by Paragraph 132 and 133, subject to Paragraphs 134 through 138, or Paragraphs 139 and 141 of this Consent Decree.

177. When permits are required as described in Paragraph 175, Defendants shall complete and submit applications for such permits to the appropriate authorities to allow time for all legally required processing and review of the permit request, including requests for additional

information by the permitting authorities. Any failure by Defendants to submit a timely permit application for any Unit in the AEP Eastern System shall bar any use by Defendants of Section XIV (Force Majeure) of this Consent Decree, where a Force Majeure claim is based on permitting delays.

178. Notwithstanding the reference to Title V permits in this Consent Decree, the enforcement of such permits shall be in accordance with their own terms and the Act. The Title V permits shall not be enforceable under this Consent Decree, although any term or limit established by or under this Consent Decree shall be enforceable under this Consent Decree regardless of whether such term or limit has or will become part of a Title V permit, subject to the terms of Section XXVI (Conditional Termination of Enforcement Under Decree) of this Consent Decree.

179. Within three (3) years from the Date of Entry of this Consent Decree, and in accordance with federal and/or state requirements for modifying or renewing a Title V permit, Defendants shall amend any applicable Title V permit application, or apply for amendments to their Title V permits, to include a schedule for any Unit-specific performance, operational, maintenance, and control technology requirements established by this Consent Decree including, but not limited to, required emission rates or other limitations. For Units subject to a requirement to Retire, Retrofit, or Re-power, Defendants shall apply to modify, renew, or obtain any applicable Title V permit to include a schedule for any Unit-specific performance, operation, maintenance, and control technology requirements established by this Consent Decree including, but not limited to, required emission rates or other limitations, within (12) twelve months of making such election to Retire, Retrofit, or Re-power.

180. Within one (1) year from commencement of operation of each pollution control device to be installed, upgraded, and/or operated under this Consent Decree, Defendants shall apply to include the requirements and limitations enumerated in this Consent Decree into federally-enforceable non-Title V permits and/or site-specific amendments to the applicable state implementation plans to reflect all new requirements applicable to each Unit in the AEP Eastern System, the Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River, and the Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer.

181. Defendants shall provide the United States with a copy of each application for a federally-enforceable non-Title V permit or amendment to a state implementation plan, as well as a copy of any permit proposed as a result of such application, to allow for timely participation in any public comment period.

182. Prior to termination of this Consent Decree, Defendants shall obtain enforceable provisions in their Title V permits for the AEP Eastern System that incorporate (a) any Unit-specific requirements and limitations of this Consent Decree, such as performance, operational, maintenance, and control technology requirements, (b) the Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River and the Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer, and (c) the Eastern System-Wide Annual Tonnage Limitations for SO_2 and NO_x. If Defendants do not obtain enforceable provisions for the Eastern System-Wide Annual Tonnage Limitations for SO_2 and NO_x in such Title V permits, then the requirements in Paragraphs 86 and 67 shall remain enforceable under this Consent Decree and shall not be subject to termination.

183. If Defendants sell or transfer to an entity unrelated to Defendants ("Third-Party Purchaser") part or all of Defendants' Ownership Interest in a Unit in the AEP Eastern System,

Defendants shall comply with the requirements of Section XIX (Sales or Transfers of Operational or Ownership Interests) with regard to that Unit prior to any such sale or transfer unless, following any such sale or transfer, Defendants remain the holder of the Title V permit for such facility.

XVII. INFORMATION COLLECTION AND RETENTION

184. Any authorized representative of the United States, including attorneys, contractors, and consultants, upon presentation of credentials, shall have a right of entry upon the premises of any facility in the AEP Eastern System at any reasonable time for the purpose of:

a. monitoring the progress of activities required under this Consent Decree;

b. verifying any data or information submitted to the United States in accordance with the terms of this Consent Decree;

c. obtaining samples and, upon request, splits of any samples taken by Defendants or their representatives, contractors, or consultants; and

d. assessing Defendants' compliance with this Consent Decree.

185. Defendants shall retain, and instruct their contractors and agents to preserve, all non-identical copies of all records and documents (including records and documents in electronic form) now in their or their contractors' or agents' possession or control (with the exception of their contractors' copies of field drawings and specifications), and that directly relate to Defendants' performance of their obligations under this Consent Decree until six (6) years following completion of performance of such obligations. This record retention requirement shall apply regardless of any corporate document retention policy to the contrary.

186. All information and documents submitted by Defendants pursuant to this Consent Decree shall be subject to any requests under applicable law providing public disclosure of

documents unless (a) the information and documents are subject to legal privileges or protection or (b) Defendants claim and substantiate in accordance with 40 C.F.R. Part 2 that the information and documents contain confidential business information.

187. Nothing in this Consent Decree shall limit the authority of EPA to conduct tests and inspections at Defendants' facilities under Section 114 of the Act, 42 U.S.C. § 7414, or any other applicable federal or state laws, regulations, or permits.

XVIII. NOTICES

188. Unless otherwise provided herein, whenever notifications, submissions, or communications are required by this Consent Decree, they shall be made in writing and addressed as follows:

As to the United States:

Chief, Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, DC 20044-7611
DJ# 90-5-2-1-06893

and

Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [Mail Code 2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

and

Air Enforcement & Compliance Assurance Branch
U.S. EPA Region V
77 W. Jackson St.
Mail Code AE17J
Chicago, IL 60604

and

Air Protection Division Director
U.S. EPA Region III
1650 Arch Street
Philadelphia, PA 19103

As to the State of Connecticut:

Office of the Attorney General
Environmental Department
P.O. Box 120
Hartford, Connecticut
06141-0120

As to the State of Maryland:

Frank Courtright
Program Manager
Air Quality Compliance Program
Maryland Department of the Environment
1800 Washington Blvd.
Baltimore, Maryland 21230
fcourtright@mde.state.md.us

As to the Commonwealth of Massachusetts:

Frederick D. Augenstern, Assistant Attorney General
Office of the Attorney General
1 Ashburton Place, 18th floor
Boston, Massachusetts 02108
fred.augenstern@state.ma.us

and

Douglas Shallcross, Esquire
Department of Environmental Protection
Office of General Counsel
1 Winter Street
Boston, Massachusetts 02108
Douglas.Shallcross@state.ma.us

As to the State of New Hampshire:

Director, Air Resources Division
New Hampshire Department of Environmental Services
29 Hazen Dive
Concord, New Hampshire 03302-0095

As to the State of New Jersey:

Kevin P. Auerbacher
Section Chief
Environmental Enforcement Section
R.J. Hughes Justice Complex
25 Market Street
P.O. Box 093
Trenton, New Jersey 08625-0093

As to the State of New York:

Robert Rosenthal
Assistant Attorney General
New York State Attorney General's Office
The Capitol
Albany, New York 12224

As to the State of Rhode Island:

Tricia K. Jedele
Special Assistant Attorney General
150 South Main Street
Providence, RI 02903
(401) 274-4400, Ext. 2400
tjedele@riag.ri.gov

As to the State of Vermont:

Environmental Division
Office of the Attorney General
109 State Street
Montpelier, Vermont 05609-1001

and

Director
Air Pollution Control Division
Department of Environmental Conservation
Agency of Natural Resources
Building 3 South
103 South Main Street
Waterbury, Vermont 05671-0402

As to the Citizen Plaintiffs:

Nancy S. Marks
Natural Resources Defense Council, Inc.
40 West 20th Street
New York, New York 10011
(212) 727-4414
nmarks@nrdc.org

and

Albert F. Ettinger
Environmental Law and Policy Center
35 East Wacker Dr. Suite 1300
Chicago, Illinois 60601-2110
(312) 673-6500
aettinger@elpc.org

As to Defendants:

Vice President, Environmental Services
American Electric Power Service Corporation
1 Riverside Plaza
Columbus, OH 43215
jmmcmanus@aep.com

and

General Counsel
American Electric Power
1 Riverside Plaza
Columbus, OH 43215
jbkeane@aep.com

189. All notifications, communications, or submissions made pursuant to this Section shall be sent as follows: (a) by overnight mail or overnight delivery service to the United States;

and (b) by electronic mail to all Plaintiffs, if practicable, but if not practicable, then by overnight mail or overnight delivery service to the States and Citizen Plaintiffs. All notifications, communications, and transmissions sent by overnight delivery service shall be deemed submitted on the date they are delivered to the delivery service.

190. Any Party may change either the notice recipient or the address for providing notices to it by serving all other Parties with a notice setting forth such new notice recipient or address.

XIX. SALES OR TRANSFERS OF OPERATIONAL OR OWNERSHIP INTERESTS

191. If Defendants propose to sell or transfer an Operational or Ownership Interest to an entity unrelated to Defendants ("Third Party"), they shall advise the Third Party in writing of the existence of this Consent Decree prior to such sale or transfer, and shall send a copy of such written notification to the Plaintiffs pursuant to Section XVIII (Notices) of this Consent Decree at least sixty (60) days before such proposed sale or transfer.

192. No sale or transfer of an Operational or Ownership Interest shall take place before the Third Party and Plaintiffs have executed, and the Court has approved, a modification pursuant to Section XXII (Modification) of this Consent Decree making the Third Party a party to this Consent Decree and jointly and severally liable with Defendants for all the requirements of this Decree that may be applicable to the transferred or purchased Interests.

193. This Consent Decree shall not be construed to impede the transfer of any Interests between Defendants and any Third Party so long as the requirements of this Consent Decree are met. This Consent Decree shall not be construed to prohibit a contractual allocation – as between Defendants and any Third Party – of the burdens of compliance with this Decree,

provided that both Defendants and such Third Party shall remain jointly and severally liable for the obligations of the Consent Decree applicable to the transferred or purchased Interests.

194. If the Plaintiffs agree, the Plaintiffs, Defendants, and the Third Party that has become a party to this Consent Decree pursuant to Paragraph 192, may execute a modification that relieves Defendants of liability under this Consent Decree for, and makes the Third Party liable for, all obligations and liabilities applicable to the purchased or transferred Interests. Notwithstanding the foregoing, however, Defendants may not assign, and may not be released from, any obligation under this Consent Decree that is not specific to the purchased or transferred Interests, including the obligations set forth in Section VIII (Environmental Mitigation Projects), Paragraphs 86 and 67, and Section IX (Civil Penalty).

195. Defendants may propose and Plaintiffs may agree to restrict the scope of joint and several liability of any purchaser or transferee for any AEP Eastern System obligations to the extent such obligations may be adequately separated in an enforceable manner using the methods provided by or approved under Section XVI (Permits).

196. Paragraphs 191-195 of this Consent Decree do not apply if an Interest is sold or transferred solely as collateral security in order to consummate a financing arrangement (not including a sale-leaseback), so long as Defendants: (a) remain the operator (as that term is used and interpreted under the Clean Air Act) of the subject AEP Eastern System Unit(s); (b) remain

subject to and liable for all obligations and liabilities of this Consent Decree; and (c) supply Plaintiffs with the following certification within thirty (30) days of the sale or transfer:

> "Certification of Change in Ownership Interest Solely for Purpose of Consummating Financing. We, the Chief Executive Officer and General Counsel of American Electric Power ("AEP"), hereby jointly certify under Title 18 U.S.C. Section 1001, on our own behalf and on behalf of AEP, that any change in AEP's Ownership Interest in any AEP Eastern System Unit that is caused by the sale or transfer as collateral security of such Ownership Interest in such Unit(s) pursuant to the financing agreement consummated on [insert applicable date] between AEP and [insert applicable entity]: a) is made solely for the purpose of providing collateral security in order to consummate a financing arrangement; b) does not impair AEP's ability, legally or otherwise, to comply timely with all terms and provisions of the Consent Decree entered in *United States, et al. v. American Electric Power Service Corp., et al.*, Civil Action No. C2-99-1250 ("AEP I") and *United States, et al. v. American Electric Power Service Corp., et al.*, Civil Action Nos. C2-04-1098 and C2-05-360 ("AEP II"); c) does not affect AEP's operational control of any Unit covered by that Consent Decree in a manner that is inconsistent with AEP's performance of its obligations under the Consent Decree; and d) in no way affects the status of AEP's obligations or liabilities under that Consent Decree."

XX. EFFECTIVE DATE

197. The effective date of this Consent Decree shall be the Date of Entry.

XXI. RETENTION OF JURISDICTION

198. The Court shall retain jurisdiction of this case after the Date of Entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to take any action necessary or appropriate for its interpretation, construction, execution, modification, or adjudication of disputes. During the term of this Consent Decree, any Party to this Consent Decree may apply to the Court for any relief necessary to construe or effectuate this Consent Decree.

XXII. MODIFICATION

199. The terms of this Consent Decree may be modified only by a subsequent written agreement signed by the Plaintiffs and Defendants. Where the modification constitutes a material change to any term of this Decree, it shall be effective only upon approval by the Court.

XXIII. GENERAL PROVISIONS

200. This Consent Decree is not a permit. Compliance with the terms of this Consent Decree does not guarantee compliance with all applicable federal, state, or local laws or regulations. The limitations and requirements set forth herein do not relieve Defendants from any obligation to comply with other state and federal requirements under the Clean Air Act at any Units covered by this Consent Decree, including the Defendants' obligation to satisfy any state modeling requirements set forth in a state implementation plan.

201. This Consent Decree does not apply to any claim(s) of alleged criminal liability.

202. In any subsequent administrative or judicial action initiated by any of the Plaintiffs for injunctive relief or civil penalties relating to the facilities covered by this Consent Decree, Defendants shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim preclusion, or claim splitting, or any other defense based upon the contention that the claims raised by any of the Plaintiffs in the subsequent proceeding were brought, or should have been brought, in the instant case; provided, however, that nothing in this Paragraph affects the validity of Paragraphs Paragraph 132 and 133, subject to Paragraphs 134 through 138, or Paragraphs 139 and 141.

203. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve Defendants of their obligation to comply with all applicable federal, state, and local laws and regulations. Subject to the provisions in Section X (Resolution of Civil

Claims Against Defendants), nothing contained in this Consent Decree shall be construed to prevent or limit the rights of the Plaintiffs to obtain penalties or injunctive relief under the Act or other federal, state, or local statutes, regulations, or permits.

204. At any time prior to termination of this Consent Decree, Defendants may request approval from Plaintiffs to implement other control technology for SO_2 or NO_x than what is required by this Consent Decree. In seeking such approval, Defendants must demonstrate that such alternative control technology is capable of achieving pollution reductions equivalent to an FGD (for SO_2) or SCR (for NO_x) at the Units in the AEP Eastern System at which Defendants seek approval to implement such other control technology for SO_2 or NO_x. Approval of such a request is solely at the discretion of the Plaintiffs.

205. Nothing in this Consent Decree is intended to, or shall, alter or waive any applicable law (including but not limited to any defenses, entitlements, challenges, or clarifications related to the Credible Evidence Rule, 62 Fed. Reg. 8314 (Feb. 24, 1997)) concerning the use of data for any purpose under the Act generated either by the reference methods specified herein or otherwise.

206. Each limit and/or other requirement established by or under this Consent Decree is a separate, independent requirement.

207. Performance standards, emissions limits, and other quantitative standards set by or under this Consent Decree must be met to the number of significant digits in which the standard or limit is expressed. For example, an Emission Rate of 0.100 is not met if the actual Emission Rate is 0.101. Defendants shall round the fourth significant digit to the nearest third significant digit, or the third significant digit to the nearest second significant digit, depending upon whether the limit is expressed to three or two significant digits. For example, if an actual

Emission Rate is 0.1004, that shall be reported as 0.100, and shall be in compliance with an Emission Rate of 0.100, and if an actual Emission Rate is 0.1005, that shall be reported as 0.101, and shall not be in compliance with an Emission Rate of 0.100. Defendants shall report data to the number of significant digits in which the standard or limit is expressed.

208. This Consent Decree does not limit, enlarge, or affect the rights of any Party to this Consent Decree as against any third parties.

209. This Consent Decree constitutes the final, complete, and exclusive agreement and understanding among the Parties with respect to the settlement embodied in this Consent Decree, and supersedes all prior agreements and understandings among the Parties related to the subject matter herein. No document, representation, inducement, agreement, understanding, or promise constitutes any part of this Consent Decree or the settlement it represents, nor shall they be used in construing the terms of this Consent Decree.

210. Except for Citizen Plaintiffs, each Party to this action shall bear its own costs and attorneys' fees. Defendants shall reimburse the Citizen Plaintiffs' attorneys' fees and costs, pursuant to 42 U.S.C. § 7604(d), and the agreement between counsel for Defendants and Citizen Plaintiffs within thirty (30) days of the Date of Entry of this Consent Decree.

XXIV. SIGNATORIES AND SERVICE

211. Each undersigned representative of the Parties certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind to this document the Party he or she represents.

212. This Consent Decree may be signed in counterparts, and such counterpart signature pages shall be given full force and effect.

213. Each Party hereby agrees to accept service of process by mail with respect to all matters arising under or relating to this Consent Decree and to waive the formal service requirements set forth in Rule 4 of the Federal Rules of Civil Procedure and any applicable Local Rules of this Court including, but not limited to, service of a summons.

XXV. PUBLIC COMMENT

214. The Parties agree and acknowledge that final approval by the United States and the entry of this Consent Decree is subject to the procedures of 28 C.F.R. § 50.7, which provides for notice of lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper, or inadequate. The Defendants shall not oppose entry of this Consent Decree by this Court or challenge any provision of this Consent Decree unless the United States has notified the Defendants, in writing, that the United States no longer supports entry of the Consent Decree.

XXVI. CONDITIONAL TERMINATION OF ENFORCEMENT UNDER DECREE

215. Termination as to Completed Tasks. As soon as Defendants complete a construction project or any other requirement of this Consent Decree that is not ongoing or recurring, Defendants may, by motion to this Court, seek termination of the provision or provisions of this Consent Decree that imposed the requirement.

216. Conditional Termination of Enforcement Through the Consent Decree. After Defendants:

a. have successfully completed construction, and have maintained Continuous Operation, of all pollution controls as required by this Consent Decree;

b. have obtained final Title V permits (i) as required by the terms of this Consent Decree; (ii) that cover all Units in this Consent Decree; and (iii) that include as enforceable permit terms all of the Unit performance and other requirements specified in this Consent Decree; and

c. certify that the date is later than December 31, 2022;

then Defendants may so certify these facts to the Plaintiffs and this Court. If the Plaintiffs do not object in writing with specific reasons within forty-five (45) days of receipt of Defendants' certification, then, for any Consent Decree violations that occur after the filing of notice, the Plaintiffs shall pursue enforcement of the requirements contained in the Title V permit through the applicable Title V permit and not through this Consent Decree.

217. Resort to Enforcement under this Consent Decree. Notwithstanding Paragraph 216, if enforcement of a provision in this Consent Decree cannot be pursued by a Party under the applicable Title V permit, or if a Consent Decree requirement was intended to be part of a Title V Permit and did not become or remain part of such permit, then such requirement may be enforced under the terms of this Consent Decree at any time.

XXVII. FINAL JUDGMENT

218. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment among the Parties.

IT IS SO ORDERED, this 10th day of December, 2007.

EDMUND A. SARGUS, JR.
UNITED STATES DISTRICT JUDGE

Signature Page for Consent Decree in:

United States et al.
v.
American Electric Power Service Corp., et al.

FOR THE UNITED STATES:

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Acting Assistant Attorney General
Environmental and Natural Resources Division
United States Department of Justice

W. BENJAMIN FISHEROW
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THOMAS A. BENSON
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DEBORAH BEHLES
MYLES E. FLINT, II
Trial Attorneys
LESLIE B. BELLAS
By Special Appointment as a Department of Justice
Attorney
Environmental Enforcement Section
Environmental and Natural Resources Division

Signature Page for Consent Decree in:

United States of America
v.
American Electric Power Service Corp., et al.

FOR THE UNITED STATES OF AMERICA:

GREGORY G. LOCKHART
United States Attorney
Southern District of Ohio

MARK D'ALESSANDRO
Assistant United States Attorney
Southern District of Ohio
United States Department of Justice

Signature Page for Consent Decree in:

United States et al.
v.
American Electric Power Service Corp., et al.

FOR THE UNITED STATES:

GRANTA Y. NAKAYAMA
Assistant Administrator
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

WALKER B. SMITH
Director, Office of Civil Enforcement
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

ADAM M. KUSHNER
Acting Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency

ILANA S. SALTZBART
EDWARD MESSINA
Attorney-Advisor

Signature Page for Consent Decree in:

United States et al.
v.
American Electric Power Service Corp., et al.

MARY A. GADE
Regional Administrator
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ROBERT A. KAPLAN
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STEPHEN ROTHBLATT
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SABRINA ARGENTIERI
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Signature Page for Consent Decree in:

United States et al.,
v.
American Electric Power Service Corp., et al.

Donald S. Welsh

DONALD S. WELSH
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Margaret Bottenson

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Donna L. Mastro

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Douglas J. Snyder

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Signature Page for Consent Decree in:

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FOR THE STATE OF CONNECTICUT:

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Assistant Attorney General

JOSE A. SUAREZ
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Signature Page for Consent Decree in:

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DOUGLAS F. GANSLER
Attorney General of Maryland

MATTHEW ZIMMERMAN
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United States et al.
v.
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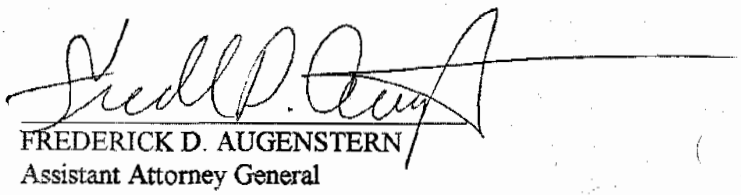
FOR THE COMMONWEALTH OF MASSACHUSETTS:

MARTHA COAKLEY
ATTORNEY GENERAL



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Signature Page for Consent Decree in:

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v.
American Electric Power Service Corp., et al.

FOR THE STATE OF NEW HAMPSHIRE:

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Signature Page for Consent Decree in:

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FOR THE STATE OF NEW JERSEY:

Very Truly Yours,

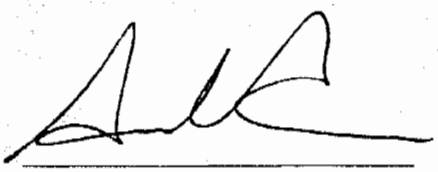
ANNE MILGRAM
ATTORNEY GENERAL OF NEW JERSEY

By: 
Jon C. Martin
Deputy Attorney General

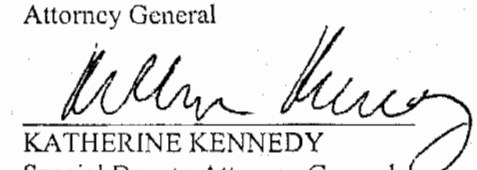
Signature Page for Consent Decree in:

United States et al.
v.
American Electric Power Service Corp., et al.

FOR THE STATE OF NEW YORK:



ANDREW M. CUOMO
Attorney General



KATHERINE KENNEDY
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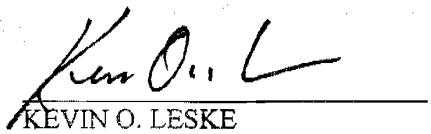
Signature Page for Consent Decree in:

United States, et al.
v.
American Electric Power Service Corp., et al.

FOR THE STATE OF VERMONT:

WILLIAM H. SORRELL
ATTORNEY GENERAL
STATE OF VERMONT



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Signature Page for Consent Decree in:

United States et al.
v.
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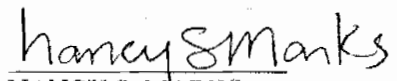
FOR CITIZEN PLAINTIFFS:



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For Citizen Plaintiffs Sierra Club and
Natural Resources Defense Council, Inc.

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United States et al.
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American Electric Power Service Corp., et al.

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For Citizen Plaintiffs Ohio Citizen Action,
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Hoosier Environmental Council,
Ohio Valley Environmental Coalition,
West Virginia Environmental Council,
Clean Air Council,
Izaak Walton League of America,
United States Public Interest Research Group,
National Wildlife Federation,
Indiana Wildlife Federation
and League of Ohio Sportsmen

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FOR CITIZEN PLAINTIFFS:

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Signature Page for Consent Decree in:

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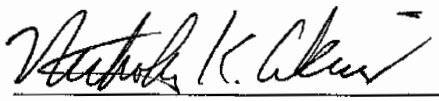
FOR DEFENDANTS AMERICAN ELECTRIC POWER SERVICE CORPORATION, ET AL.:



NICHOLAS K. AKINS
Executive Vice President – Generation

APPENDIX A
ENVIRONMENTAL MITIGATION PROJECTS

In compliance with and in addition to the requirements in Section VIII of this Consent Decree (Environmental Mitigation Projects), Defendants shall comply with the requirements of this Appendix to ensure that the benefits of the $36 million in federally directed Environmental Mitigation Projects are achieved.

I. National Parks Mitigation

A. Within 45 days from the Date of Entry, Defendants shall pay to the National Park Service the sum of $2 million to be used in accordance with the Park System Resource Protection Act, 16 U.S.C. § 19jj, for the restoration of land, watersheds, vegetation, and forests using adaptive management techniques designed to improve ecosystem health and mitigate harmful effects from air pollution. This may include reforestation or restoration of native species and acquisition of equivalent resources and support for collaborative initiatives with state and local agencies and other stakeholders to develop plans to assure resource protection over the long-term. Projects will focus on one or more of the following Class I areas alleged in the underlying action to have been injured by emissions from Defendants facilities: Shenandoah National Park, Mammoth Cave National Park, and Great Smoky Mountains National Park.

B. Payment of the amount specified in the preceding paragraph shall be made to the Natural Resource Damage and Assessment Fund managed by the United States Department of the Interior. Instructions for transferring funds will be provided to the Defendants by the National Park Service. Notwithstanding Section I.A of this Appendix, payment of funds by Defendants is not due until ten (10) days after receipt of payment instructions.

C. Upon payment of the required funds into the Natural Resource Damage and Assessment Fund, Defendants shall have no further responsibilities regarding the implementation of any project selected by the National Park Service in connection with this provision of the Consent Decree.

II. Overall Environmental Mitigation Project Schedule and Budget

A. Within 120 days of the Date of Entry, as further described below, Defendants shall submit plans to EPA for review and approval for completing the remaining $34 million in federally directed Environmental Mitigation Projects specified in this Appendix over a period of not more than five (5) years from the Date of Entry. EPA will consult with the Citizen Plaintiffs, through their counsel, prior to approving or commenting on any proposed plan. The Parties agree that Defendants are entitled to spread their payments for Environmental Mitigation Projects evenly over the five-year period commencing upon the Date of Entry. Defendants are not, however, precluded from accelerating payments to better effectuate a proposed mitigation plan, provided however, Defendants shall not be

entitled to any reduction in the nominal amount of the required payments by virtue of the early expenditures. EPA may, but is not required to, approve a proposed Project budget that results in a back-loading of some expenditures. EPA shall determine prior to approval that all Projects are consistent with federal law.

B. Defendants may, at their election, consolidate the plans required by this Appendix into a single plan.

C. In addition to the requirements set forth below, Defendants shall submit within 120 days of the Date of Entry, a summary-level budget and Project time-line that covers all of the Projects proposed.

D. Beginning March 31, 2008, and continuing on March 31 of each year thereafter until completion of each Project (including any applicable periods of demonstration or testing), Defendants shall provide the United States and Citizen Plaintiffs with written reports detailing the progress of each Project, including Project Dollars.

E. Within 60 days following the completion of each Project required under Appendix A, Defendants shall submit to the United States and Citizen Plaintiffs a report that documents the date that the Project was completed, the results of implementing the Project, including the emission reductions or other environmental benefits achieved, and the Project Dollars expended by Defendants in implementing the Project.

F. Upon approval of the plans required by this Appendix by EPA, Defendants shall complete the Environmental Mitigation Projects according to the approved plans. Nothing in this Consent Decree shall be interpreted to prohibit Defendants from completing Environmental Mitigation Projects before the deadlines specified in the schedule of an approved plan.

III. Acquisition and Restoration of Ecologically Significant Areas in Indiana, Kentucky, North Carolina, Ohio, Pennsylvania, Virginia, and West Virginia

A. Within 120 days of the Date of Entry, and on each anniversary of the initial submission for the following four (4) years, Defendants shall submit a plan to EPA for review and approval, in consultation with the Citizen Plaintiffs, for acquisition and/or restoration of ecologically significant areas in Indiana, Kentucky, North Carolina, Ohio, Pennsylvania, Virginia, and West Virginia ("Land Acquisition and Restoration"). Defendants shall spend no less than a total of $10 million in Project Dollars on Land Acquisition and Restoration over the five year period provided under this Appendix for completion of federally directed Environmental Mitigation Projects.

B. Defendants' proposed plan shall:

1. Describe the proposed Land Acquisition and Restoration projects in sufficient detail to allow the reader to ascertain how each proposed action meets the requirements set out below. For purposes of this Appendix and Section VIII (Environmental Mitigation Projects) of this Consent Decree, land acquisition means purchase of interests in land, including fee ownership, easements, or other restrictions that run with the land that provide for perpetual protection of the acquired land. Restoration may include, by way of illustration, direct reforestation (particularly of tree species that may be affected by acidic deposition) and soil enhancement. Any restoration action must also incorporate the acquisition of an interest in the restored lands sufficient to ensure perpetual protection of the restored land. Any proposal for acquisition of land must identify fully all owners of the interests in the land. Every proposal for acquisition of land must identify the ultimate holder of the interests to be acquired and provide a basis for concluding that the proposed holder of title is appropriate for long-term protection of the ecological or environmental benefits sought to be achieved through the acquisition.

2. Describe generally the ecological significance of the area to be acquired or restored. In particular, identify the environmental/ecological benefits expected as a result of the proposed action. In proposing areas for acquisition and restoration, Defendants shall focus on those areas that are in most need of conservation action or that promise the greatest conservation return on investment.

3. Describe the expected cost of the Land Acquisition and Restoration, including the fair market value of any areas to be acquired.

4. Identify any person or entity other than Defendants that will be involved in the land acquisition or restoration action. Defendants shall describe the third-party's role in the action and the basis for asserting that such entity is able and suited to perform the intended role. For purposes of this Section of the Appendix, third-parties shall only include non-profits; federal, state, and local agencies; or universities. Any proposed third-party must be legally authorized to perform the proposed action or to receive Project Dollars.

5. Include a schedule for completing and funding each portion of the project.

C. Performance - Upon approval of the plan by EPA, after consultation with the Citizen Plaintiffs, Defendants shall complete the Land Acquisition and Restoration project according to the approved plan and schedule.

IV. Nitrogen Impact Mitigation in the Chesapeake Bay

A. Within 120 days of Date of Entry, Defendants shall submit a plan to EPA for review and approval, in consultation with the Citizen Plaintiffs, for the mitigation of adverse impacts on the Chesapeake Bay associated with nitrogen ("Chesapeake Bay Mitigation Project"). Defendants shall spend no less than a total of $3 million in Project Dollars on the Chesapeake Bay Mitigation Project.

B. Defendant's proposed plan shall:

1. Describe proposed Project(s) that reduce nitrogen loading in the Chesapeake Bay or otherwise mitigate the adverse effects of nitrogen in the Chesapeake Bay. Projects that may be approved include, by way of illustration, creation of forested stream buffers on agricultural land or other land cover to establish a "buffer zone" to keep livestock out of the adjoining waterway and to filter runoff before it enters the waterway.

2. Describe generally the expected environmental benefit of the proposed Chesapeake Bay Mitigation Project. The key criteria for selection of components of the Project are the magnitude of the expected ecological/environmental benefit(s) in relation to the cost and the relative permanence of the expected benefit(s). Expected loadings benefits should be quantified to the extent practicable.

3. Describe the expected cost of each element of the Chesapeake Bay Mitigation Project, including the fair market value of any interests in land to be acquired.

4. Identify any person or entity other than Defendants that will be involved in any aspect of the Chesapeake Bay Mitigation Project. Defendants shall describe the third-party's role in the action and the basis for asserting that such entity is able and suited to perform the intended role. For purposes of this Section of the Appendix, third-parties shall only include non-profits; federal, state, and local agencies; or universities. Any proposed third-party must be legally authorized to perform the proposed action or to receive Project Dollars.

5. Include a schedule for completing and funding each portion of the Project.

C. Performance - Upon approval of the plan for Chesapeake Bay Mitigation by EPA, Defendants shall complete the Project according to the approved plan and schedule.

V. Mobile Source Emission Reduction Projects

A. Within 120 days of the Date of Entry, Defendants shall submit a plan to EPA for review and approval, in consultation with the Citizen Plaintiffs, for the completion of Projects to reduce emissions from Defendants' fleet of barge tugboats on the Ohio River, diesel trains at or near power plants, Defendants' fleet of motor vehicles in certain eastern states, and/or truck stops in certain eastern states ("Mobile Source Projects"). Defendants shall spend no less than a total of $21 million in Project Dollars on one or more of the three Mobile Source Projects specified in this Section, in accordance with the plans for such Projects approved by EPA, after consultation with the Citizen Plaintiffs. The key criteria for selection of components of the Mobile Source Projects are the magnitude of the expected environmental benefit(s) in relation to the cost.

B. Diesel Tug/Train Project

1. Defendants are among the leading barge operators in the country, with operations on the Ohio River, the Mississippi River, and the Gulf Coast. Barges are propelled by tugboats, which generally use a type of marine diesel fuel known as No. 2 distillate fuel oil. Tugboats that switch to ultra-low sulfur diesel fuel ("ULSD") reduce emissions of NO_X, PM, volatile organic compounds ("VOCs"), and other air pollutants. All marine diesel fuel must be ULSD by June 1, 2012, pursuant to EPA's Nonroad Diesel Rule (see "Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuels; Final Rule," 69 Fed. Reg. 38,958 (June 29, 2004)). Defendants also receive coal by diesel trains.

2. As part of the plan for Mobile Source Projects, Defendants may elect to achieve accelerated emission reductions from their tugboat fleet on the Ohio River ("Ohio River Tug Fleet") and/or their diesel powered trains used at or near their power plants, as one of the three possible mobile source Projects under this Consent Decree ("Diesel Tug/Train Project").

3. The Diesel Tug/Train Project shall require one or more of the following:

a. The accelerated retrofitting or re-powering of Tugs with engines that require the use of ULSD. Selection of this Project is expressly conditioned upon identification of satisfactory technology and an agreement between EPA and Defendants on how to credit Project Dollars towards this project.

b. The retrofitting or repowering of the marine engines in the Ohio River Tug Fleet with diesel oxidation catalysts ("DOCs"), diesel particulate filters ("DPFs"), or other equivalent advanced technologies that reduce emissions of PM and VOCs from marine engines in tugboats (collectively "DOC/DPFs"). Defendants shall only install DOCs/DPFs that have received applicable approvals or

verifications, if any, from the relevant regulatory agencies for reducing emissions from tugboat engines. Defendants must maintain any DOCs/DPFs installed as part of the Tug Project for the useful life of the equipment (as defined in the proposed Plan), even after the completion of the Tug Project. Project Dollars may be spent on DOCs/DPFs within 5 years of the Date of Entry, in accordance with the approved schedule for the mitigation projects in this Appendix.

c. The accelerated use of ULSD for the Ohio River Tug Fleet, from the Date of Entry through January 1, 2012. Notwithstanding any other provision of this Consent Decree, including this Appendix, Defendants shall only receive credit for the incremental cost of ULSD as compared to the cost of the fuel Defendants would otherwise utilize.

d. Emission reduction measures for diesel powered trains. Such measures may include retro-fitting with, or conversion to, Multiple Diesel Engine GenSets that are EPA Tier III Off-Road certified; Diesel Electric Hybrid; Anti-idling controls/strategies and Auto Shut-Off capabilities. Selection of this Project is expressly conditioned upon identification of satisfactory technology and an agreement between EPA and Defendants on how to credit Project Dollars towards this project.

4. The proposed plan for the Diesel Tug/Train Project shall:

a. Describe the expected cost of the project, including the costs for any equipment, material, labor costs, and the proposed method for accounting for the cost of each element of the Diesel Tug/Train Project, including the incremental cost of ULSD.

b. Describe generally the expected environmental benefit of the project, including any expected fuel efficiency improvements and quantify emission reductions expected.

c. Include a schedule for completing each portion of the Diesel Tug/Train Project.

5. Performance - Upon approval of the Diesel Tug/Train Project plan by EPA, Defendants shall complete the project according to the approved plan and schedule.

C. Hybrid Vehicle Fleet Project

1. AEP has a fleet of approximately 11,000 motor vehicles in the eleven states where it operates, including vehicles in Indiana, Ohio, Michigan, Virginia, West Virginia, and Kentucky. These motor vehicles are generally powered by conventional diesel or gasoline engines and include vehicles such as diesel "bucket" trucks. The use of hybrid engine technologies in Defendants' motor vehicles, such as diesel-electric engines, will improve fuel efficiency and reduce emissions of NO_X, PM, VOCs, and other air pollutants.

2. As part of the plan for Mobile Source Projects, Defendants may elect to spend Project Dollars on the replacement of conventional motor vehicles in their fleet with newly manufactured Hybrid Vehicles ("Hybrid Vehicle Fleet Project").

3. The proposed plan for the Hybrid Vehicle Fleet Project shall:

   a. Propose the replacement of conventional gasoline or diesel powered motor vehicles (such as bucket trucks) with Hybrid Vehicles. For purposes of this subsection of this Appendix, "Hybrid Vehicle" means a vehicle that can generate and utilize electric power to reduce the vehicle's consumption of fossil fuel. Any Hybrid Vehicle proposed for inclusion in the Hybrid Fleet Project shall meet all applicable engine standards, certifications, and/or verifications.

   b. Provide for Hybrid Vehicles replacement in that portion of Defendants' fleet in Indiana, Ohio, Michigan, West Virginia, Virginia, and/or Kentucky. Notwithstanding any other provision of this Consent Decree, including this Appendix, Defendants shall only receive credit toward Project Dollars for the incremental cost of Hybrid Vehicles as compared to the cost of a newly manufactured, similar motor vehicle.

   c. Prioritize the replacement of diesel-powered vehicles in Defendants' fleet.

   d. Provide a method to account for the costs of the Hybrid Vehicles, including the incremental costs of such vehicles as compared to conventional gasoline or diesel motor vehicles.

   e. Certify that Defendants will use the Hybrid Vehicles for their useful life (as defined in the proposed plan).

   f. Include a schedule for completing each portion of the Project.

g. Describe generally the expected environmental benefits of the Project, including any fuel efficiency improvements, and quantify emission reductions expected.

4. Performance - Upon approval by EPA of the plan for the Hybrid Vehicle Fleet Project, after consultation with the Citizen Plaintiffs, Defendants shall complete the Project according to the approved plan.

D. Truck Stop Electrification

1. Long-haul truck drivers typically idle their engines at night at rest areas to supply heat or cooling in their sleeper cab compartments, and to maintain vehicle battery charge while electrical appliances such as televisions, computers, and microwaves are in use. Modifications to rest areas to provide parking spaces with electrical power, heat, and air conditioning will allow truck drivers to turn their engines off. Truck stop electrification reduces idling time and therefore reduces diesel fuel usage, and thus reduces emissions of PM, NO_x, and VOCs.

2. As part of the plan for Mobile Source Projects, Defendants may elect to achieve emission reductions by truck stop electrification, which shall include, where necessary, techniques and infrastructure needed to support such a program ("Truck Stop Electrification Project").

3. The proposed plan for the Truck Stop Electrification Project shall:

a. Identify truck stops in one or more of the following States for Electrification: Ohio, Indiana, Kentucky, North Carolina, Pennsylvania, West Virginia, and Virginia. EPA may give preference to electrification Projects that are co-located, if possible, along the same transportation corridor.

b. Describe the level of expected usage of the planned electrification facilities, air quality in the vicinity of the proposed Projects, proximity of the proposed Project to population centers, and whether the owner or some other entity is willing to pay for some portion of the work.

c. Provide for the construction of truck stop electrification stations with established technologies and equipment.

d. Account for hardware procurement and installation costs at the recipient truck stops.

e. Include a schedule for completing each portion of the Project.

f. Describe generally the expected environmental benefits of the Project and quantify emission reductions expected.

4. Performance - Upon approval of the plan for the Truck Stop Electrification Project by EPA, after consultation with the Citizen Plaintiffs, Defendants shall complete the Project according to the approved plan.

APPENDIX B

REPORTING REQUIREMENTS

I. Annual Reporting Requirements

In accordance with the dates specified below, for periods on and after the Date of Entry, Defendants shall submit annual reports to the United States, the States, and the Citizen Plaintiffs, electronically and in hard copy, as required by Paragraph 143 and certified as required by Paragraph 146. In such annual reports, Defendants shall include the following information:

A. Eastern System-Wide Annual Tonnage Limitations for SO_2 and NO_x

Beginning on March 31, 2010, for the Eastern System-Wide Annual Tonnage Limitations for NO_x, and March 31, 2011, for the Eastern System-Wide Annual Tonnage Limitations for SO_2, and annually thereafter, Defendants shall report the following information: (a) the total actual annual tons of the pollutant emitted from each Unit (or for Units vented to a common stack, from each combined stack) within the AEP Eastern System, as defined in Paragraph 7, during the prior calendar year; (b) the total actual annual tons of the pollutant emitted from the AEP Eastern System during the prior calendar year; (c) the difference, if any, between the applicable Eastern System-Wide Annual Tonnage Limitation for the pollutant in that calendar year and the amount reported in subparagraph (b); and (d) the annual average emission rate, expressed as a lb/mmBTU for NO_x, for each Unit within the AEP Eastern System and for the entire AEP Eastern System during the prior calendar year. Data reported pursuant to this subsection shall be based upon the CEMS data submitted to the Clean Air Markets Division.

B. Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River

Beginning on March 31, 2011, and continuing annually thereafter, Defendants shall report: (a) the actual tons of SO_2 emitted from all Units at the Clinch River plant on an annual rolling average basis as defined in Paragraphs 47 and 88 for the prior calendar year; and (b) the applicable Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at the Clinch River plant for the prior calendar year. For calendar years other than 2010 and 2015, Defendants shall also report the 12-month rolling average emissions for each month.

C. Plant-Wide Tonnage Limitation for SO_2 at Kammer

Beginning on March 31, 2011, and continuing annually thereafter, Defendants shall report: (a) the actual tons of SO_2 emitted from all Units at the Kammer plant as specified in Paragraph 48 for the prior calendar year; and (b) the Plant-Wide Tonnage Limitation for SO_2 at the Kammer plant for that calendar year.

D. Reporting Requirements for Excess NO_x Allowances

1. Reporting Requirements for Unrestricted Excess NO_x Allowances

Beginning on March 31, 2010, and continuing annually through March 31, 2016, Defendants shall report the number of Unrestricted Excess NO_x Allowances available each year between 2009 through 2015, and how or whether such allowances were used so that Defendants account for each Unrestricted Excess NO_x Allowance for each year during 2009 through 2015. No later than March 31, 2016, Defendants shall report: (a) the cumulative number of unused Unrestricted Excess NO_x Allowances subject to surrender pursuant to Paragraph 75 and calculated pursuant to Paragraph 74, and (b) the total number of unused Unrestricted Excess NO_x Allowances that they surrendered.

2. Reporting Requirements for Restricted Excess NO_x Allowances

a. Beginning on March 31, 2010, and continuing annually through March 31, 2016, Defendants shall report: (a) the number of Restricted Excess NOx Allowances available each year between 2009 through 2015; (b) the actual emissions from any New and Newly Permitted Unit during each year; (c) the actual NOx emissions from the five natural gas plants listed in Paragraph 76 during each year; (d) the amount, if any, of Restricted Excess NOx Allowances that are not subject to surrender each year because of Defendants' investment in renewable energy as defined in Paragraph 77 and the data supporting Defendants' calculation; and (e) the difference between the cumulative total of Restricted Excess NO_x Allowances available from each year and any prior year and the actual emissions reported under (b) and (c), above, for that year and any Restricted Excess NO_x Allowances not subject to surrender reported under (d), above. No later than March 31, 2016, Defendants shall report: (a) the cumulative number of unused Restricted Excess NO_x Allowances subject to surrender calculated pursuant to Paragraphs 76 and 77, and (b) the total number of unused Restricted Excess NO_x Allowances that they surrendered.

b. No later than March 31, 2017, and continuing annually thereafter, Defendants shall report: (a) the number of Restricted Excess NO_x Allowances available in the prior year; (b) the actual emissions from any New and Newly Permitted Unit during such year; (c) the actual emissions from the five natural gas plants listed in Paragraph 76 during such year; (d) the amount, if any, of Restricted Excess NO_x Allowances that are not subject to surrender for such year because of Defendants' investment in renewable energy as defined in Paragraph 77 and the data supporting Defendants' calculation; (e) the number of Restricted Excess NO_x Allowances subject to surrender for such year calculated pursuant to Paragraphs 76 and 77; and (f) the total number of unused Restricted Excess NO_x Allowances that they surrendered for such year.

E. Reporting Requirements for Excess SO_2 Allowances

Beginning on March 31, 2011, and continuing annually thereafter, Defendants shall report: (a) the number of Excess SO_2 Allowances subject to surrender calculated pursuant to Paragraph 93, and (b) the total number of Excess SO_2 Allowances that they surrendered.

F. Continuous Operation of Pollution Controls required by Paragraphs 68, 69, 87, and 102

On March 31 of the year following Defendants' obligation pursuant to this Consent Decree to commence Continuous Operation of an SCR, FGD, ESP, or Additional NO_x Pollution Controls, Defendants shall report the date that they commenced Continuous Operation of each such pollution control as required by this Consent Decree. Beginning on March 31, 2008, and continuing annually thereafter, Defendants shall report, for any SCR, FGD, ESP, or Additional NO_x Pollution Controls required to Continuously Operate during that year, the duration of any period during which that pollution control did not Continuously Operate, including the specific dates and times that such pollution control did not operate, the reason why Defendants did not Continuously Operate such pollution control, and the measures taken to reduce emissions of the pollutant controlled by such pollution control.

G. Installation of SO_2 and NO_x Pollution Controls

Beginning on March 31, 2008, and continuing annually thereafter, Defendants shall report on the progress of construction of NO_x and SO_2 pollution controls required by this Consent Decree including: (1) if construction is not underway, any available information concerning the construction schedule, including the dates of any major contracts executed during the prior calendar year, and any major components delivered during the prior calendar year; (2) if construction is underway, the estimated percent of installation as of the end of the prior calendar year, the current estimated construction completion date, and a brief description of completion of significant milestones during the prior calendar year, including a narrative description of the current construction status (e.g. foundations completed, absorber installation proceeding all material on-site, new stack erection completed, etc.); and (3) once construction is complete, the dates the equipment was placed in service and any acceptance testing was performed during the prior calendar year.

H. Installation and Operation of PM CEMS

Beginning on March 31, 2013, for Cardinal Units 1 and 2 and a third Unit identified pursuant to Paragraph 110, and continuing annually thereafter for all periods of operation of PM CEMS as required by this Consent Decree, Defendants shall report the data recorded by the PM CEMS, expressed in lb/mmBTU on a 3-hour rolling average basis in electronic format for the prior calendar year, in accordance with Paragraph 107.

I. Other SO_2 Measures

Commencing in the first annual report Defendants submit pursuant to Paragraph 143, and continuing annually thereafter, Defendants shall submit all data necessary to determine Defendants' compliance with the annual average coal content specified in the table in Paragraph 90.

J. 1-Hour Average NO_x Emission Rate and 30-Day Rolling Average Emission Rates for SO_2 and NO_x

1. Beginning on March 31 of the year following Defendants' obligation pursuant to this Consent Decree to first comply with an applicable 1-Hour Average NO_x Emission Rate and/or 30-Day Rolling Average Emission Rate for SO_2 and NO_x, and continuing annually thereafter, Defendants shall report all 1-Hour Average Emission Rate results and/or 30-Day Rolling Average Emission Rate results to determine compliance with such emission rate, as defined in Paragraph 4 or 5, as appropriate. Defendants shall also report: (a) the date and time that the Unit initially combusts any fuel after shutdown; (b) the date and time after startup that the Unit is synchronized with a utility electric distribution system; (c) the date and time that the fire is extinguished in a Unit; and (d) for the fifth and subsequent Cold Start Up Period that occurs within any 30-Day period, the earlier of the date and time that is either (i) eight hours after the unit is synchronized with a utility electric distribution system, or (ii) the flue gas has reached the SCR operational temperature range specified by the catalyst manufacturer.

2. Within the first report that identifies a 1-Hour Average NO_x Emission Rate or 30-Day Rolling Average Emission Rate for SO_2 or NO_x, Defendants shall include at least five (5) example calculations (including hourly CEMS data in electronic format for the calculation) used to determine the 1-Hour Average NO_x Emission Rate and the 30-Day Rolling Average Emission Rate for SO_2 or NO_x for five (5) randomly selected days. If at any time Defendants change the methodology used in determining the 1-Hour Average NO_x Emission Rate or the 30-Day Rolling Average Emission Rate for SO_2 or NO_x, Defendants shall explain the change and the reason for using the new methodology.

K. 30-Day Rolling Average Removal Efficiency for SO_2

1. Beginning on March 31 of the year following Defendants' obligation pursuant to this Consent Decree to first comply with a 30-Day Rolling Average Removal Efficiency, and continuing annually thereafter, Defendants shall report all 30-Day Rolling Average Removal Efficiency results to determine compliance with such removal efficiency as defined in Paragraph 6 or, for Conesville Units 5 and 6, as specified in Appendix C.

2. Within the first report that identifies a 30-Day Rolling Average Removal Efficiency for SO_2, Defendants shall include at least five (5) example calculations (including hourly CEMS data in electronic format for the calculation) used to determine the 30-Day Rolling Average Removal Efficiency for five (5) randomly selected days. If

at any time Defendants change the methodology used in determining the 30-Day Rolling Average Removal Efficiency, Defendants shall explain the change and the reason for using the new methodology.

L. PM Emission Rates

Beginning on March 31, 2010, for Cardinal Units 1 and 2, and beginning on March 31, 2013 for Muskingum River Unit 5, and continuing annually thereafter, Defendants shall report the PM Emission Rate as defined in Paragraph 51, for Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5. For all such Units, Defendants shall attach a copy of the executive summary and results of any stack test performed during the calendar year covered by the annual report.

M. Environmental Mitigation Projects

1. Mitigation Projects to be Conducted by the States

Defendants shall report the disbursement of funds as required in Paragraph 127 of the Consent Decree in the next annual progress report that Defendants submit pursuant to Paragraph 143 following such disbursement of funds.

2. Appendix A Projects

Beginning March 31, 2008, and continuing on March 31 of each year thereafter until completion of each Project (including any applicable periods of demonstration or testing), Defendants shall provide the United States and Citizen Plaintiffs with written reports detailing the progress of each Project, including Project Dollars.

N. Other Unit becoming an Improved Unit

If Defendants decide to make an Other Unit an Improved Unit, Defendants shall so state in the next annual progress report they submit pursuant to Paragraph 143 after making such decision, and comply with the reporting requirements specified in Section I.G of this Appendix and any other reporting or notice requirements in accordance with the Consent Decree.

II. Deviation Reports

Beginning March 31, 2008, and continuing annually thereafter, Defendants shall report a summary of all deviations from the requirements of the Consent Decree that occurred during the prior calendar year, identifying the date and time that the deviation occurred, the date and time the deviation was corrected, the cause and any corrective actions taken for each deviation, if necessary, and the date that the deviation was initially reported under Paragraph 145. In addition to any express requirements in Section I, above, or in the Consent Decree, such deviations required to be reported include, but are not limited to, the following requirements: the 1-Hour Average NO_x Emission Rate, the

30-Day Rolling Average Emission Rates for SO_2 and NO_x, the 30-Day Rolling Average Removal Efficiency for SO_2, and the PM Emission Rate.

III. Submissions Pending Review

In each annual report Defendants submit pursuant to Paragraph 143, Defendants shall include a list of all plans or submissions made pursuant to this Consent Decree during the calendar year covered by the annual report, the date(s) such plans or submissions were submitted to one or more Plaintiffs for review and/or approval, and shall identify which, if any, are still pending review and approval by Plaintiffs upon the date of submission of the annual report.

IV. Other Information Necessary To Determine Compliance

To the extent that information not expressly identified above is necessary to determine Defendants' compliance with the requirements of this Consent Decree during a reporting period, and has not otherwise been submitted in accordance with the provisions of the Consent Decree, Defendants shall provide such information as part of the annual report required pursuant to Section XI of the Consent Decree.

at any time Defendants change the methodology used in determining the 30-Day Rolling Average Removal Efficiency, Defendants shall explain the change and the reason for using the new methodology.

L. PM Emission Rates

Beginning on March 31, 2010, for Cardinal Units 1 and 2, and beginning on March 31, 2013 for Muskingum River Unit 5, and continuing annually thereafter, Defendants shall report the PM Emission Rate as defined in Paragraph 51, for Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5. For all such Units, Defendants shall attach a copy of the executive summary and results of any stack test performed during the calendar year covered by the annual report.

M. Environmental Mitigation Projects

1. Mitigation Projects to be Conducted by the States

Defendants shall report the disbursement of funds as required in Paragraph 127 of the Consent Decree in the next annual progress report that Defendants submit pursuant to Paragraph 143 following such disbursement of funds.

2. Appendix A Projects

Beginning March 31, 2008, and continuing on March 31 of each year thereafter until completion of each Project (including any applicable periods of demonstration or testing), Defendants shall provide the United States and Citizen Plaintiffs with written reports detailing the progress of each Project, including Project Dollars.

N. Other Unit becoming an Improved Unit

If Defendants decide to make an Other Unit an Improved Unit, Defendants shall so state in the next annual progress report they submit pursuant to Paragraph 143 after making such decision, and comply with the reporting requirements specified in Section I.G of this Appendix and any other reporting or notice requirements in accordance with the Consent Decree.

II. Deviation Reports

Beginning March 31, 2008, and continuing annually thereafter, Defendants shall report a summary of all deviations from the requirements of the Consent Decree that occurred during the prior calendar year, identifying the date and time that the deviation occurred, the date and time the deviation was corrected, the cause and any corrective actions taken for each deviation, if necessary, and the date that the deviation was initially reported under Paragraph 145. In addition to any express requirements in Section I, above, or in the Consent Decree, such deviations required to be reported include, but are not limited to, the following requirements: the 1-Hour Average NO_x Emission Rate, the

30-Day Rolling Average Emission Rates for SO_2 and NO_x, the 30-Day Rolling Average Removal Efficiency for SO_2, and the PM Emission Rate.

III. Submissions Pending Review

In each annual report Defendants submit pursuant to Paragraph 143, Defendants shall include a list of all plans or submissions made pursuant to this Consent Decree during the calendar year covered by the annual report, the date(s) such plans or submissions were submitted to one or more Plaintiffs for review and/or approval, and shall identify which, if any, are still pending review and approval by Plaintiffs upon the date of submission of the annual report.

IV. Other Information Necessary To Determine Compliance

To the extent that information not expressly identified above is necessary to determine Defendants' compliance with the requirements of this Consent Decree during a reporting period, and has not otherwise been submitted in accordance with the provisions of the Consent Decree, Defendants shall provide such information as part of the annual report required pursuant to Section XI of the Consent Decree.

APPENDIX C

MONITORING STRATEGY AND CALCULATION OF THE 30-DAY ROLLING AVERAGE REMOVAL EFFICIENCY FOR CONESVILLE UNITS 5 AND 6

I. Monitoring Strategy

1. The SO_2 monitoring system for Conesville Units 5 & 6 will consist of two separate FGD inlet monitors in each of the two FGD inlet ducts for each Unit, and one FGD outlet monitor in the combined flow from the outlets of the FGD modules for each Unit, prior to the common stack.

2. Due to space constraints and potential interferences, monitors are currently located in the inlet duct for one FGD module on each Unit and at the combined outlet from both FGD modules for each Unit prior to entering the stack using best engineering judgment.

3. On or before December 31, 2008, Defendants shall submit a monitoring plan to EPA for approval that will propose where to site and install an additional inlet monitor in each of the unmonitored FGD inlet ducts for each Unit, and include a requirement that Defendants submit a complete certification application for the Conesville Units 5 & 6 monitoring system to EPA and the state permitting authority.

4. The Monitoring Plan will incorporate the applicable procedures and quality assurance testing found in 40 C.F.R. Part 75, subject to the following:

   a. The PS-2 siting criteria will not be applied to these monitoring systems; however, the majority of the procedures in Section 8.1.3.2 of PS-2 will be followed. Sampling of at least nine (9) sampling points selected in accordance with PS-1 will be performed prior to the initial RATA. If the resultant SO_2 emission rates for any single sampling point calculated in accordance with Equation 19.7 are all within 10% or 0.02 lb/mmBtu of the mean of all nine (9) sampling points, the alternative traverse point locations (0.4, 1.2, and 2.0 meters from the duct wall) will be representative and may be used for all subsequent RATAs.

   b. The required relative accuracy test audit will be performed in accordance with the procedures of 40 C.F.R. Part 75, except that the calculations will be performed on an SO_2 emission rate basis (i.e., lb/mmBtu).

   c. The criteria for passing the relative accuracy test audit will be the same criteria that 40 C.F.R. Part 75 requires for relative accuracy or alternative performance specification as provided for NO_x emission rates.

d. "Diluent capping" (i.e., 5% CO_2) will be applied to the SO_2 emission rate for any hours where the measured CO_2 concentration rounds to zero.

e. Results of quality assurance testing, data gathered by the inlet and outlet monitoring systems, and the resultant 30-day Rolling Average Removal Efficiencies for these monitoring systems are not required to be reported in the quarterly reports submitted to EPA's Clean Air Markets Division for purposes of 40 C.F.R. Part 75. Results will be maintained at the facility and available for inspection, and the 30-day Rolling Average Removal Efficiency will be reported in accordance with the requirements of the Consent Decree and Appendix B. Equivalent data retention and reporting requirements will be incorporated into the applicable permits for these Units.

f. Missing Data Substitution of 40 C.F.R Part 75 will not be implemented.

g. Initial performance testing will be performed before the effective date of the 30-Day Rolling Average Removal Efficiency requirements, and the results will be reported to Plaintiffs as part of the annual report submitted in accordance with Appendix B.

II. Calculation of 30-Day Rolling Average Removal Efficiency

1. Removal efficiency shall be calculated by the equation:

$$[SO_2 \text{ emission rate}_{\text{Inlet}} - SO_2 \text{ emission rate}_{\text{Outlet}}] / SO_2 \text{ emission rate}_{\text{Inlet}} * 100$$

2. Inlet and outlet emission rates shall be calculated using the methodology specified in 40 C.F.R. Part 60 Appendix B – Method 19. Inlet emission rates will be based on the average of the valid recorded values calculated for each of the inlet FGD monitors at each Unit. Measurements are made on a wet basis, so Equation 19.7 will be utilized to determine the hourly SO_2 emission rate at each location. To make the conversion between the measured wet SO_2 and CO_2 concentrations and an emission rate in pounds per million BTU, an electronic Data System will perform Equation 19.7 using the SO_2 ppm conversion factor from Table 19-1 of Method 19 and the Fc factor for the applicable fuel (currently bituminous coal) in Table 19-2 of Method 19. The resulting equation will be:

$$\text{Emission rate (lb } SO_2/\text{mmBtu)} = 1.660 \times 10^{-7} * SO_2 \text{ (in ppm)} * Fc * 100 / CO_2 \text{ (in \%)}$$

3. The electronic data system will calculate the hourly average SO_2 and CO_2 concentration in accordance with 40 C.F.R. Part 75 quality control/quality assurance requirements and will compute and retain these SO_2 emission rates for every operating hour meeting the minimum data capture requirements in accordance with 40 C.F.R. Part 75. Prior to the

calculation of the SO_2 emission rate, hourly SO_2 and CO_2 concentrations will be rounded to the nearest tenth (i.e., 0.1 ppm or 0.1 % CO_2) and the resulting SO_2 emission rate will be rounded to the nearest thousandth (i.e., 0.001 lb/mmBtu).

4. From these hourly SO_2 emission rates, SO_2 removal efficiencies will be calculated for each hour when the Unit is firing fossil fuel, and the hourly SO_2 and CO_2 monitors meet the QA/QC requirements of Part 75. Hourly SO_2 removal efficiencies will be computed by taking the hourly inlet SO_2 emission rate minus the outlet SO_2 emission rate, dividing the result by inlet SO_2 emission rate and multiplying by 100. The resulting removal efficiency will be rounded to the nearest tenth (i.e., 95.1%). Daily SO_2 removal efficiencies will be calculated by taking the sum of Hourly SO_2 removal efficiencies and dividing by the number of valid monitored hours for each Operating Day. The resulting daily removal efficiencies will be rounded to the nearest tenth (i.e., 95.1%).

5. The 30-Day Rolling Average Removal Efficiency will be computed by taking the current Operating Day's daily SO_2 removal efficiency (as described in Paragraph 4 of this Appendix C) plus the previous 29 Operating Days' daily SO_2 removal efficiency, and dividing the sum by 30. In the event that a daily SO_2 removal efficiency is not available for an Operating Day, Defendants shall exclude that Operating Day from the calculation of the 30-Day Rolling Average Removal Efficiency. The resulting 30-day Rolling Average Removal Efficiency will be rounded to the nearest tenth of a percent (i.e., a value of 95.04% rounds down to 95.0%, and a value of 95.05% rounds up to 95.1%).

IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF OHIO
EASTERN DIVISION

UNITED STATES OF AMERICA Plaintiff, and STATE OF NEW YORK, ET AL., Plaintiff-Intervenors, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Terence P. Kemp Civil Action No C2-99-1250 (Consolidated with C2-99-1182)

UNITED STATES OF AMERICA Plaintiff, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	JUDGE GREGORY L. FROST Magistrate Judge Norah McCann King Civil Action No C2-05-360

OHIO CITIZEN ACTION, ET AL., Plaintiffs, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	JUDGE GREGORY L. FROST Magistrate Judge Norah McCann King Civil Action No. C2-04-1098

JOINT MODIFICATION TO CONSENT DECREE WITH ORDER MODIFYING CONSENT DECREE

WHEREAS On December 10, 2007, this Court entered a Consent Decree in the above-captioned matters.

WHEREAS Paragraph 199 of the Consent Decree provides that the terms of the Consent Decree may be modified only by a subsequent written agreement signed by the Plaintiffs and Defendants. Material modifications shall be effective only upon written approval by the Court.

WHEREAS pursuant to Paragraph 87 of the Consent Decree, by no later than December 31, 2009, American Electric Power is required, *inter alia*, to install and continuously operate a Flue Gas Desulfurization System (FGD) on Amos Unit 1.

WHEREAS pursuant to Paragraph 87 of the Consent Decree, by no later than December 31, 2010, American Electric Power is required, *inter alia*, to install and continuously operate a FGD on Amos Unit 2.

WHEREAS American Electric Power has requested to modify the schedules for the installation and continuous operation of the FGD at Amos Units 1 from December 31, 2009 to December 31, 2010 and for the installation and continuous operation of the FGD at Amos Unit 2 from December 31, 2010 to April 1, 2010.

WHEREAS Amos Unit 2 was shutdown on October 19, 2009 and shall remain shutdown until it is restarted with the FGD.

WHEREAS the Plaintiffs have agreed to American Electric Power's requested modification in exchange for American Electric Power agreeing to comply with an enforceable combined annual cap for the calendar year 2010 at Amos Units 1 and 2 of 32,005 tons of Sulfur Dioxide (SO_2).

WHEREAS all Parties have obtained the necessary approvals to modify the schedule for the installation and continuous operation of the FGDs at Amos Units 1 and 2, and for the enforceable combined annual cap for the calendar year 2010 at Amos Units 1 and 2 of 32,005 tons of SO_2.

For good cause shown, the Parties hereby seek to modify the Consent Decree in this matter, and move that the Court sign and enter the following Order:

1. Modify the dates for installing and continuously operating FGD's at Amos Unit 1 and Amos Unit 2, as listed in the table in Paragraph 87 of the Consent Decree as follows:

87. No later than the dates set forth in the table below, Defendants shall install and Continuously Operate an FGD on each Unit identified therein, or, if indicated in the table, Retire, Retrofit, or Re-power such Unit:

Unit	SO_2 Pollution Control	Date	Modified Date
Amos Unit ~~1~~ 2	FGD	~~December 31, 2009~~	April 2, 2010
Amos Unit ~~2~~ 1	FGD	December 31, 2010	

The remainder of the table in Paragraph 87 of the Consent Decree shall remain the same.

2. Modify Section V (SO_2 Emission Reductions and Controls), to insert Paragraph 88B as follows:

88B. Calendar Year 2010 Combined Annual Cap for Amos Units 1 and 2.

For the calendar year 2010 Defendants shall limit their combined annual SO_2 emissions from Amos Units 1 and 2 to 32,005 tons of SO_2.

3. Modify Section XIII (Stipulated Penalties), by adding item w to the table of "Stipulated Penalties" as follows:

Consent Decree Violation	Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)
w. Failure to comply with the year 2010 combined annual cap for Amos Units 1 and 2	$5,000 per ton for the first 1000 tons, and $10,000 per ton for each additional ton above 1000 tons

4. Except as specifically provided in this Order, all other terms and conditions of the Consent Decree remain unchanged and in full effect.

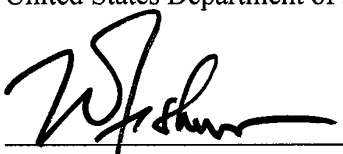
SO ORDERED, THIS _____ DAY OF _____, 2010.

_____
HONORABLE EDMUND A. SARGUS, JR.
UNITED STATES DISTRICT COURT JUDGE

Respectfully submitted,

FOR THE UNITED STATES OF AMERICA:

IGNACIA S. MORENO
Assistant Attorney General
Environmental and Natural Resources Division
United States Department of Justice



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IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF OHIO
EASTERN DIVISION

UNITED STATES OF AMERICA Plaintiff, and STATE OF NEW YORK, ET AL., Plaintiff-Intervenors, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Consolidated Cases: Civil Action No. C2-99-1182 Civil Action No. C2-99-1250 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Terence P. Kemp
OHIO CITIZEN ACTION, ET AL., Plaintiffs, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	
UNITED STATES OF AMERICA Plaintiff, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Norah McCann King Civil Action No C2-05-360

JOINT MODIFICATION TO CONSENT DECREE WITH ORDER MODIFYING CONSENT DECREE

WHEREAS On December 10, 2007, this Court entered a Consent Decree in the above-captioned matters.

WHEREAS Paragraph 199 of the Consent Decree provides that the terms of the Consent Decree may be modified only by a subsequent written agreement signed by the Plaintiffs and Defendants. Material modifications shall be effective only upon written approval by the Court.

WHEREAS pursuant to Paragraph 87 of the Consent Decree (Docket # 363), as modified by a Joint Modification to Consent Decree With Order Modifying Consent Decree filed on April 5, 2010 (Docket # 371), no later than December 31, 2010, American Electric Power is required, *inter alia*, to install and continuously operate a Flue Gas Desulfurization System (FGD) on Amos Unit 1.

WHEREAS American Electric Power has requested to modify the schedule for the installation and continuous operation of the FGD at Amos Units 1 from December 31, 2010 to February 15, 2011.

WHEREAS Amos Unit 1 was shutdown on September 3, 2010 and shall remain shutdown until it is restarted with the FGD.

WHEREAS all the Parties have obtained the necessary approvals to modify the schedule for the installation and continuous operation of the FGD at Amos Unit 1.

For good cause shown, the Parties hereby seek to modify the Consent Decree in this matter, and move that the Court sign and enter the following Order:

1. Modify the date for installing and continuously operating an FGD at Amos Unit 1

as listed in the table in Paragraph 87 of the Consent Decree as follows:

87. No later than the dates set forth in the table below, Defendants shall install and Continuously Operate an FGD on each Unit identified therein, or, if indicated in the table, Retire, Retrofit, or Re-power such Unit:

Unit	**SO_2 Pollution Control**	**Date**	**Modified Date**
Amos Unit 1	FGD	~~December 31, 2010~~	February 15, 2011

The remainder of the table in Paragraph 87 of the Consent Decree shall remain the same.

2. Defendants shall not operate Amos Unit 1 until the FGD referenced in Paragraph 87 of the Consent Decree is installed and operating.

3. Except as specifically provided in this Order, all other terms and conditions of the Consent Decree remain unchanged and in full effect.

SO ORDERED, THIS 28th DAY OF December, 2010.

E A S Jr.

HONORABLE EDMUND A. SARGUS, JR.
UNITED STATES DISTRICT COURT JUDGE

Respectfully submitted,

FOR THE UNITED STATES OF AMERICA:

IGNACIA S. MORENO
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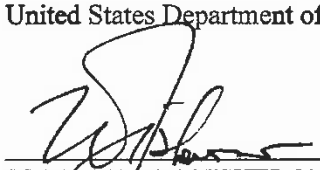
United States Department of Justice



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IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF OHIO
EASTERN DIVISION

UNITED STATES OF AMERICA Plaintiff, and STATE OF NEW YORK, ET AL., Plaintiff-Intervenors, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Consolidated Cases: Civil Action No. C2-99-1182 Civil Action No. C2-99-1250 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Terence P. Kemp
OHIO CITIZEN ACTION, ET AL., Plaintiffs, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	
UNITED STATES OF AMERICA Plaintiff, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Norah McCann King Civil Action No. C2-05-360 Civil Action No. C2-04-1098

ORDER ENTERING THIRD JOINT MODIFICATION TO CONSENT DECREE

This matter is before the Court on Plaintiff the United States of America's Motion to Approve the Third Joint Modification of the Consent Decree. (Doc. No. 547.) For the reasons set forth within Plaintiff's motion, the Court **GRANTS** the motion and **ENTERS** the Third Joint Modification to Consent Decree, which is attached hereto.

This Order renders moot Defendants' Application for Judicial Interpretation of the Consent Decree (Doc. No. 528) and Defendants' Motion to Strike (Doc. No. 539). These two motions are therefore **DENIED AS MOOT**.

IT IS SO ORDERED this 14th day of MAY, 2013.

EDMUND A. SARGUS, JR.
UNITED STATES DISTRICT COURT JUDGE

IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF OHIO
EASTERN DIVISION

UNITED STATES OF AMERICA Plaintiff, and STATE OF NEW YORK, ET AL., Plaintiff-Intervenors, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Consolidated Cases: Civil Action No. C2-99-1182 Civil Action No. C2-99-1250 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Terence P. Kemp
OHIO CITIZEN ACTION, ET AL., Plaintiffs, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Civil Action No. C2-04-1098 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Norah McCann King
UNITED STATES OF AMERICA Plaintiff, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Civil Action No. C2-05-360 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Norah McCann King

THIRD JOINT MODIFICATION TO CONSENT DECREE WITH ORDER MODIFYING CONSENT DECREE

WHEREAS On December 10, 2007, this Court entered a Consent Decree in the above-captioned matters (Case No. 99-1250, Docket # 363; Case No. 99-1182, Docket # 508).

WHEREAS Paragraph 199 of the Consent Decree provides that the terms of the Consent Decree may be modified only by a subsequent written agreement signed by the Plaintiffs and Defendants. Material modifications shall be effective only upon written approval by the Court.

WHEREAS pursuant to Paragraph 87 of the Consent Decree, as modified by a Joint Modification to Consent Decree With Order Modifying Consent Decree, filed on April 5, 2010 (Case No. 99-1250, Docket # 371), and as modified by a second Joint Modification to Consent Decree With Order Modifying Consent Decree, filed on December 28, 2010 (Case No. 99-1250, Docket # 372), the Defendants are required, *inter alia*, to install and continuously operate a Flue Gas Desulfurization System (FGD) no later than December 31, 2015 on Big Sandy Unit 2, December 31, 2015 on Muskingum River Unit 5, December 31, 2017 on Rockport Unit 1, and December 31, 2019 on Rockport Unit 2.

WHEREAS, on October 31, 2012, the Defendants filed an Application for Judicial Interpretation of Consent Decree in Case No. 99-1182 (Docket # 528) and the related cases.

WHEREAS, the United States, the States and Citizen Plaintiffs filed a Memorandum in Opposition (Case No. 99-1182, Docket # 534), and Citizen Plaintiffs filed a Supplemental Memorandum in Opposition (Case No. 99-1250, Docket # 381) to the Defendants' Application.

WHEREAS all Parties made additional filings and the Application was scheduled for a hearing on December 17, 2012.

WHEREAS, the Parties have engaged in settlement discussions and have reached

agreement on a modification to the Consent Decree as set forth herein.

WHEREAS, the Parties have agreed, and this Court by entering this Third Joint Modification finds, that this Third Joint Modification has been negotiated in good faith and at arm's length; that this settlement is fair, reasonable, and in the public interest, and consistent with the goals of the Clean Air Act, 42 U.S.C. §7401, *et seq*.; and that entry of this Third Joint Modification without further litigation is the most appropriate means of resolving this matter.

WHEREAS, the Parties agree and acknowledge that final approval of the United States and entry of this Third Joint Modification is subject to the procedures set forth in 28 CFR § 50.7, which provides for notice of this Third Joint Modification in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Third Joint Modification is inappropriate, improper, or inadequate. No Party will oppose entry of this Third Joint Modification by this Court or challenge any provision of this Third Joint Modification unless the United States has notified the Parties, in writing, that the United States no longer supports entry of the Third Joint Modification.

NOW THEREFORE, for good cause shown, without admission of any issue of fact or law raised in the Application or the underlying litigation, the Parties hereby seek to modify the Consent Decree in this matter, and upon the filing of a Motion to Enter by the United States, move that the Court sign and enter the following Order:

1. Add a definition of "Cease Burning Coal" as new Paragraph 8A of the Consent Decree as follows:

8A. "Cease Burning Coal" means that Defendants shall permanently cease burning coal for purposes of generating electricity from a Unit, and shall submit all necessary notifications or

requests for permit amendments to reflect the permanent cessation of coal firing at the Unit.

2. Modify the definition of "Continuously Operate" in Paragraph 14 of the Consent Decree as follows:

14. "Continuously Operate" or "Continuous Operation" means that when an SCR, FGD, DSI, ESP, or Other NOx Pollution Controls are used at a Unit, except during a Malfunction, they shall be operated at all times such Unit is in operation, consistent with the technological limitations, manufacturer's specifications, and good engineering and maintenance practices for such equipment and the Unit so as to minimize emissions to the greatest extent practicable.

3. Add a new definition of "Dry Sorbent Injection" or "DSI" as new Paragraph18A of the Consent Decree as follows:

18A. "Dry Sorbent Injection" or "DSI" means a pollution control system in which a sorbent is injected into the flue gas path prior to the particulate pollution control device for the purpose of reducing SO_2 emissions. For purposes of the DSI systems required to be installed at the Rockport Units only, the DSI systems shall utilize a sodium based sorbent and be designed to inject at least 10 tons per hour of a sodium based sorbent. Defendants may utilize a different sorbent at the Rockport Units provided they obtain prior approval from Plaintiffs pursuant to Paragraph 148 of the Consent Decree.

4. Modify the definition of "Improved Unit" in Paragraph 28 of the Consent Decree as follows:

28. An "Improved Unit" for SO_2 means an AEP Eastern System Unit equipped with an FGD or scheduled under this Consent Decree to be equipped with an FGD, or required to be Retired, Retrofitted, Re-Powered, or Refueled.

The remainder of Paragraph 28 shall remain the same.

5. Add a definition of "Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport" as new Paragraph 48A of the Consent Decree, as follows:

48A. "Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport" means the sum of the tons of SO_2 emitted during all periods of operation from the Rockport Plant, including, without limitation, all SO_2 emitted during periods of startup, shutdown, and Malfunction, during the relevant calendar year (*i.e.*, January 1 – December 31).

6. Add a definition of "Refuel" as new Paragraph 53A of the Consent Decree, as follows:

53A. "Refuel" means, solely for purposes of this Consent Decree, the modification of a unit as necessary such that the modified unit generates electricity solely through the combustion of natural gas rather than coal, including the installation and Continuous Operation of the NO_x controls required by Section IV of this Consent Decree. Nothing herein shall prevent the reuse of any equipment at any existing unit or new emissions unit, provided that AEP applies for, and obtains, all required permits, including, if applicable, a PSD or Nonattainment NSR permit.

7. Modify the definition of "Retrofit" in Paragraph 56 of the Consent Decree as follows:

56. "Retrofit" means that the Unit must install and Continuously Operate both an SCR and an FGD, as defined in the Consent Decree. For purposes of the requirements in Paragraph 87 for the Rockport Units, "Retrofit" also means that the Unit will be equipped with a post-combustion wet- or dry-FGD system with a control technology vendor guaranteed design removal efficiency of 98% or more, and subject upon installation to a 30-Day Rolling Average Emissions Rate of 0.100 lb/mmBTU for SO_2, if the Unit burns coal with an uncontrolled SO_2 emissions rate of 3.0 lb/mmBTU or higher, or a 30-day Rolling Average Emission Rate of 0.060 lb/mmBTU if the

Unit burns coal with an uncontrolled SO_2 emissions rate below 3.0 lb/mmBTU. For the 600 MW listed in the table in Paragraph 68 and 87, "Retrofit" means that the Unit must meet a federally-enforceable 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU for NOx and a 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU for SO2, measured in accordance with the requirements of this Consent Decree.

8. Modify the Eastern System-Wide Annual Tonnage Limitations for SO_2 in the table in Paragraph 86 of the Consent Decree as follows:

86. Notwithstanding any other provision of this Consent Decree, except Section XIV (Force Majeure), during each calendar year specified in the table below, all Units in the AEP Eastern System, collectively, shall not emit SO_2 in excess of the following Eastern System-Wide Annual Tonnage Limitations:

Calendar Year(s)	**Eastern System-Wide Annual Tonnage Limitations for SO_2**	**Modified Eastern System-Wide Annual Tonnage Limitations for SO_2**
2016	~~260,000 tons~~	145,000 tons
2017	~~235,000 tons~~	145,000 tons
2018	~~184,000 tons~~	145,000 tons
2019~~, and each year thereafter~~ - 2021	~~174,000 tons~~	113,000 tons per year
2022 - 2025	~~174,000 tons~~	110,000 tons per year
2026 - 2028	~~174,000 tons~~	102,000 tons per year
2029, and each year thereafter	~~174,000 tons~~	94,000 tons per year

The remainder of the table in Paragraph 86 shall remain the same.

9. Modify the SO_2 pollution control requirements and compliance dates listed in the

table in Paragraph 87 of the Consent Decree for Big Sandy Unit 2, Muskingum River Unit 5, Rockport Units 1 and 2, and Tanners Creek Unit 4 as follows:

87. No later than the dates set forth in the table below, Defendants shall install and Continuously Operate an FGD on each Unit identified therein, or, if indicated in the table, Retire, Retrofit, ~~or~~ Re-power, or Refuel such Unit:

Unit	**SO_2 Pollution Control**	**Modified SO_2 Pollution Control**	**Date**	**Modified Date**
Big Sandy Unit 2	~~FGD~~	Retrofit, Retire, Re-power, or Refuel	December 31, 2015	NA
Muskingum River Unit 5	~~FGD~~	Cease Burning Coal and Retire Or Cease Burning Coal and Refuel	~~December 31, 2015~~	December 15, 2015 December 31, 2015, unless the Refueling project is not completed in which case the unit will be taken out of service no later than December 31, 2015 and will not restart until the Refueling project is completed. The Refueling project must be completed by June 30, 2017.
First Rockport Unit	~~FGD~~	Dry Sorbent Injection, and Retrofit, Retire, Re-power, or Refuel	~~December 31, 2017~~	April 16, 2015 December 31, 2025.
Second Rockport Unit	~~FGD~~	Dry Sorbent Injection, and	~~December 31, 2019~~	April 16, 2015 and

Unit	SO_2 Pollution Control	Modified SO_2 Pollution Control	Date	Modified Date
		Retrofit, Retire, Re-power, or Refuel		December 31, 2028.
Tanners Creek Unit 4	NA	Retire or Refuel	NA	June 1, 2015

The remainder of the table in Paragraph 87 of the Consent Decree shall remain the same, including the Joint Modifications previously made to the compliance deadlines for Amos Units 1 and 2.

10. Add a new Paragraph 89A establishing the Plant-Wide Annual Tonnage Limitations for SO_2 at Rockport, as follows:

89A. For each of the calendar years set forth in the table below, Defendants shall limit their total annual SO_2 emissions from Rockport Units 1 and 2 to Plant-Wide Annual Tonnage Limitations for SO_2 as follows:

Calendar Years	Plant-Wide Annual Tonnage Limitations for SO_2
2016 - 2017	28,000 tons per year
2018 - 2019	26,000 tons per year
2020 - 2025	22,000 tons per year
2026 - 2028	18,000 tons per year
2029, and each year thereafter	10,000 tons per year

11. Modify Paragraph 92 of the Consent Decree as follows:

92. Except as may be necessary to comply with this Section and Section XIII (Stipulated Penalties), Defendants may not use any SO_2 Allowances to comply with any requirements of this

Consent Decree, including by claiming compliance with any emission limitation, Eastern System-Wide Annual Tonnage Limitation, Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River, Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer, or Plant-Wide Annual Tonnage Limitations for SO_2 at Rockport required by this Consent Decree by using, tendering, or otherwise applying SO_2 Allowances to achieve compliance or offset any emission above the limits specified in this Consent Decree.

12. Modify Paragraph 100 of the Consent Decree as follows:

100. To the extent an Emission Rate, 30-Day Rolling Average Removal Efficiency, Eastern System-Wide Annual Tonnage Limitation, or Plant-Wide Annual Tonnage Limitation for SO_2 is required under this Consent Decree, Defendants shall use CEMS in accordance with the reference methods specified in 40 C.F.R. Part 75 to determine the Emission Rate or annual emissions.

13. Modify Paragraph 104 of the Consent Decree as follows:

104. On or before the date established by this Consent Decree for Defendants to achieve and maintain 0.030 lb/mmBTU at Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5, Defendants shall conduct a performance test for PM that demonstrates compliance with the PM Emission Rate required by this Consent Decree. Within forty-five (45) days of each such performance test, Defendants shall submit the results of the performance test to Plaintiffs pursuant to Section XVIII (Notices) of this Consent Decree. On and after the date that Muskingum River Unit 5 complies with the requirement to Cease Burning Coal pursuant to Paragraph 87 of this Consent Decree, Defendants shall no longer be obligated to comply with the performance testing requirements for Muskingum River Unit 5 contained in this Paragraph.

14. Modify Paragraph 105 of the Consent Decree as follows:

105. Beginning in calendar year 2010 for Cardinal Unit 1 and Cardinal Unit 2, and calendar year 2013 for Muskingum River Unit 5, and continuing in each calendar year thereafter, Defendants shall conduct a stack test for PM on each stack servicing Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5. The annual stack test requirement imposed by this Paragraph may be satisfied by stack tests conducted by Defendants as required by their permits from the State of Ohio for any year that such stack tests are required under the permits. On and after the date that Muskingum River Unit 5 complies with the requirement to Cease Burning Coal pursuant to Paragraph 87 of this Consent Decree, Defendants shall no longer be obligated to comply with the stack testing requirements for Muskingum River Unit 5 contained in this Paragraph.

15. Modify Paragraph 119 of the Consent Decree as follows:

119. Defendants shall implement the Environmental Mitigation Projects described in Appendix A to this Consent Decree, shall fund the categories of Projects described in Subsection B, below, and shall implement the Citizen Plaintiffs' Renewable Energy Project and Citizen Plaintiffs' Mitigation Projects described in Subsection C, below, (collectively, the "Projects") in compliance with the approved plans and schedules for such Projects and other terms of this Consent Decree.

The remainder of Paragraph 119 shall remain the same.

16. Add a new Subsection C after Paragraph 128 of the Consent Decree as follows:

C. Citizen Plaintiffs' Renewable Energy Project and Citizen Plaintiffs' Mitigation Projects.

128A. Citizen Plaintiffs' Renewable Energy Project. Defendants shall implement a renewable

energy project as described below during the period from 2013 through 2019.

a. If, during the period from 2013-2015, a renewable energy production tax credit of at least 2.2 cents/kwh for ten years is available for new wind electricity production facilities upon which construction is commenced within one year or more after enactment of the tax credit (or an alternative tax benefit is available that provides sufficient economic value so that the levelized cost to customers does not exceed the weighted average cost of any existing contracts with Indiana Michigan Power Company ("I&M") for 50 MW or greater of wind capacity, adjusted for inflation) I&M will secure 200 MW of new wind energy capacity from facilities located in Indiana or Michigan that qualify for the production tax credit or alternative tax benefit within two years after enactment. For the avoidance of doubt, so long as the energy production tax credit contained in the American Taxpayer Relief Act of 2012 allows projects that have commenced construction by December 31, 2013, and that are placed in service by December 31, 2014, to qualify for the energy production tax credit provided in that Act, then I&M shall be obligated to secure new renewable energy purchase agreements for 200 MW of new wind energy capacity.

b. If a renewable energy production tax credit or alternative tax benefit as described in subparagraph a., above, is not available during 2013-2015, but becomes available during 2016-2019 for new wind electricity production facilities on which construction is commenced within one year or more after the production tax credit or alternative tax benefit is enacted, I&M will use commercially reasonable efforts to secure 200 MW of new wind energy capacity from facilities located in Indiana or Michigan that qualify for the production tax credit or alternative tax benefit within two years after enactment.

c. If a renewable energy production tax credit or alternative tax benefit as described in subparagraph a., above, is not available during the period from 2013 – 2019 for new wind electricity production facilities on which construction is commenced within one year or more after the production tax credit or alternative tax benefit is enacted, I&M shall be relieved of its obligations to secure new wind energy capacity under this Paragraph 119A.

128B. Citizen Plaintiffs' Mitigation Projects. I&M will provide $2.5 million in mitigation funding as directed by the Citizen Plaintiffs for projects in Indiana that include diesel retrofits, health and safety home repairs, solar water heaters, outdoor wood boilers, land acquisition projects, and small renewable energy projects (less than 0.5 MW) located on customer premises that are eligible for net metering or similar interconnection arrangements on or before December 31, 2014. I&M shall make payments to fund such Projects within seventy-five (75) days after being notified by the Citizen Plaintiffs in writing of the nature of the Project, the amount of funding requested, the identity and mailing address of the recipient of the funds, payment instructions, including taxpayer identification numbers and routing instructions for electronic payments, and any other information necessary to process the requested payments. Defendants shall not have approval rights for the Projects or the amount of funding requested, but in no event shall the cumulative amount of funding provided pursuant to this Paragraph 128B exceed $2.5 million.

17. Modify Paragraph 127 of the Consent Decree as follows:

127. The States, by and through their respective Attorneys General, shall jointly submit to Defendants Projects within the categories identified in this Subsection B for funding in amounts not to exceed $4.8 million per calendar year for no less than five (5) years following the Date of Entry of this Consent Decree beginning as early as calendar year 2008, and for an additional

amount not to exceed $6.0 million in 2013. The funds for these Projects will be apportioned by and among the States, and Defendants shall not have approval rights for the Projects or the apportionment. Defendants shall pay proceeds as designated by the States in accordance with the Projects submitted for funding each year within seventy-five (75) days after being notified by the States in writing. Notwithstanding the maximum annual funding limitations above, if the total costs of the projects submitted in any one or more years is less than the maximum annual amount, the difference between the amount requested and the maximum annual amount for that year will be available for funding by the Defendants of new and previously submitted projects in the following years, except that all amounts not requested by and paid to the States within eleven (11) years after the Date of Entry of this Consent Decree shall expire.

18. Modify Paragraph 133 of the Consent Decree as follows:

133. Claims Based on Modifications after the Date of Lodging of This Consent Decree. Entry of this Consent Decree shall resolve all civil claims of the United States against Defendants that arise based on a modification commenced before December 31, 2018, or, solely for the first Rockport Unit, before December 31, 2025, or, solely for the second Rockport Unit, before December 31, 2028, for all pollutants, except Particulate Matter, regulated under Parts C or D of Subchapter I of the Clean Air Act, and under regulations promulgated thereunder, as of the Date of Lodging of this Consent Decree, and:

a. where such modification is commenced at any AEP Eastern System Unit after the Date of Lodging of this Consent Decree; or

b. where such modification is one this Consent Decree expressly directs Defendants to undertake.

The remainder of Paragraph 133 shall remain the same.

19. Modify the table in Paragraph 150 of the Consent Decree as follows:

Consent Decree Violation	**Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)**
x. Failure to comply with the Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport	$40,000 per ton, plus the surrender, pursuant to the procedures set forth in Paragraphs 95 and 96, of SO_2 Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
y. Failure to fund a Citizen Plaintiffs' Mitigation Project as required by Paragraph 119B of this Consent Decree	$1,000 per day per violation during the first 30 days, $5,000 per day per violation thereafter
z. Failure to implement the Citizen Plaintiffs' Renewable Energy Project required by Paragraph 128A of this Consent Decree	$10,000 per day per violation during the first 30 days, $32,500 per day per violation thereafter

The remainder of the table in Paragraph 150 shall remain the same.

20. In addition to the requirements reflected in Appendix B (Reporting Requirements) to the Consent Decree, Defendants shall include in their Annual Report to Plaintiffs the following information:

O. Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport

Beginning on March 31, 2017, and continuing annually thereafter, Defendants shall report: (a) the actual tons of SO_2 emitted from Units 1 and 2 at the Rockport Plant for the prior calendar year; (b) the Plant-Wide Annual Tonnage Limitation for SO_2 at the Rockport Plant for the prior calendar year as set forth in Paragraph 89A of the Consent Decree; and (c) for the annual reports for calendar years 2015 – 2028, Defendants shall report the daily average SO_2 emissions from the Rockport Plant expressed in lb/mmBTU, and the daily sorbent deliveries to the Rockport Plant by weight.

P. Citizen Plaintiffs' Renewable Energy Project

Beginning on March 31, 2014, and continuing each year thereafter until completion of the Citizen Plaintiffs' Renewable Energy Project, Defendants shall include a written report detailing the progress of the implementation of the Citizen Plaintiffs' Renewable Energy Project required by Paragraph 119A of the Consent Decree.

Q. Citizen Plaintiffs' Mitigation Projects

Beginning on March 31, 2013, and continuing each year until March 31, 2015, Defendants shall include a written report detailing the progress of implementation of the Citizen

Plaintiffs' Mitigation Projects required by Paragraph 119B of the Consent Decree.

R. By March 31, 2015, Defendants shall notify Plaintiffs of their intent to Retire or Refuel Muskingum River 5.

S. By March 31, 2024, Defendants shall notify Plaintiffs of their decision to Retrofit, Retire, Re-Power or Refuel the first Rockport Unit. If Defendants elect to Retrofit the Unit, Defendants shall provide with such notification, information regarding the removal efficiency guarantee requested from and obtained from the control technology vendor and the sulfur content of the fuel used to design the FGD, including any non-confidential information regarding the SO_2 control technology filed by Defendants with the public utility regulator.

T. By March 31, 2027, Defendants shall notify Plaintiffs of their decision to Retrofit, Retire, Re-power or Refuel the second Rockport Unit. If Defendants elect to Retrofit the Unit, Defendants shall provide with such notification, information regarding the removal efficiency guarantee requested from and obtained from the control technology vendor and the sulfur content of the fuel used to design the FGD, including any non-confidential information regarding the SO_2 control technology filed by Defendants with the public utility regulator.

U. If Defendants elect to Retrofit one or both of the Rockport Units, beginning in the annual reports submitted for calendar years 2026 and/or 2029, as applicable, Defendants shall report a 30-Day Rolling Average SO_2 Emission Rate for the Unit(s) that is (are) Retrofit in accordance with Paragraph 5 of the Consent Decree. In addition, Defendants shall report a 30-Day Rolling Average Uncontrolled Emission Rate for SO_2 for the Unit(s) that is(are) Retrofit based on daily as burned coal sampling and analysis or an inlet SO_2 CEMs upstream of the FGD.

The remainder of Appendix B shall remain the same.

21. Except as specifically provided in this Order, all other terms and conditions of the Consent Decree remain unchanged and in full effect.

SO ORDERED, THIS 14th DAY OF May, 2013.

HONORABLE EDMUND A. SARGUS, JR.
UNITED STATES DISTRICT COURT JUDGE

Respectfully submitted,

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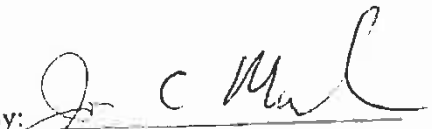
By: 
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[1] Environment America is the same entity that signed on to the original Consent Decree as United States Public Interest Research Group.

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IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF OHIO
EASTERN DIVISION

UNITED STATES OF AMERICA Plaintiff, and STATE OF NEW YORK, ET AL., Plaintiff-Intervenors, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Consolidated Cases: Civil Action No. C2-99-1182 Civil Action No. C2-99-1250 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Terence P. Kemp
OHIO CITIZEN ACTION, ET AL., Plaintiffs, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Civil Action No. C2-04-1098 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Norah McCann King
UNITED STATES OF AMERICA Plaintiff, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Civil Action No. C2-05-360 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Norah McCann King

FOURTH JOINT MODIFICATION TO CONSENT DECREE

WHEREAS, on December 10, 2007, this Court entered a Consent Decree in the above-captioned matters (Case No. 99-1250, Docket # 363; Case No. 99-1182, Docket # 508), as subsequently modified by a Joint Modification entered on April 5, 2010 (Case No. 99-1250, Docket # 371), a Second Joint Modification entered on December 28, 2010 (Case No. 99-1250, Docket # 373), and a Third Joint Modification entered on May 14, 2013 (Case No. 99-1182, Docket # 548).

WHEREAS, Section XIX of the Consent Decree details requirements for advance notice and modification of the Consent Decree prior to the sale or transfer of any Operational or Ownership Interest in a Unit subject to the terms of the Consent Decree to a Third Party.

WHEREAS, Paragraph 191 of the Consent Decree provides that a selling or transferring Defendant must advise a Third Party purchaser in writing of the existence of the Consent Decree, and send a copy of such notification to the Plaintiffs at least 60 days prior to the sale or transfer.

WHEREAS, on April 14, 2016, the Defendants notified Plaintiffs that they were exploring the potential transfer of an Operational or Ownership Interest in the Gavin Units to a Third Party, and Defendants provided a copy of the Consent Decree to all potential buyers.

WHEREAS the Defendants have complied with the notice provisions of Paragraph 191 of the Consent Decree.

WHEREAS Paragraph 192 of the Consent Decree provides that no sale or transfer of an Operational or Ownership Interest shall take place before the Third Party purchaser and the Plaintiffs have executed, and the Court has approved, a modification of the Consent Decree that makes the Third Party purchaser a party to the Consent Decree and jointly and severally liable

with Defendants for all the requirements of the Decree that may be applicable to the transferred or purchased interests.

WHEREAS Paragraph 193 of the Consent Decree further provides that the Consent Decree is not to be construed to impede the transfer of any Operational or Ownership Interests between Defendants and any Third Party so long as the requirements of the Consent Decree are met, and that the Consent Decree is not to be construed to prohibit a contractual allocation as between a Defendant and a Third Party purchaser of the burdens of compliance with the Consent Decree, provided that such Defendant and Third Party purchaser remain jointly and severally liable for Consent Decree obligations applicable to the transferred or purchased interests.

WHEREAS, Defendant AEP Generation Resources Inc. (as successor in interest to Defendant Ohio Power Company dba/ American Electric Power) has agreed to sell the Gavin Units to Gavin Buyer and Gavin Buyer has agreed to buy the Gavin Units. Gavin Buyer has contractually agreed to assume the obligations of, and to be bound by the terms and conditions of the Consent Decree as they relate to the Gavin Units.

WHEREAS, all Parties desire to modify the terms of the Consent Decree to allow Gavin Buyer to assume the obligations of the Consent Decree, as amended by the First, Second, and Third Modifications, related to the Gavin Units as set forth herein.

WHEREAS, Paragraph 198 of the Consent Decree specifies that the Court retains continuing jurisdiction for purposes of enforcing and modifying the Consent Decree.

WHEREAS, Paragraph 199 of the Consent Decree provides that the Consent Decree may be modified only by a subsequent written agreement signed by the Plaintiffs and Defendants, and that any material modification of the Consent Decree shall be effective only upon approval of the Court.

NOW THEREFORE, the Parties hereby seek to modify the Consent Decree in this matter, and move that the Court sign and enter the following Order:

AMENDED CONSENT DECREE PROVISIONS

1. The Parties agree and the Court finds that the Consent Decree, as previously modified, shall remain in full force and effect in accordance with its terms, except as set forth below, and that the modifications herein shall become effective upon the Gavin Closing Date.

2. The following definitions shall be added to or modified in Section III of the Consent Decree.

a. A definition of "AEP" shall be added and means American Electric Power Service Corporation, Kentucky Power Company dba/American Electric Power, Indiana Michigan Power Company dba/American Electric Power, AEP Generation Resources Inc., successor in interest to Ohio Power Company dba/American Electric Power and Columbus Southern Power Company dba/American Electric Power, Appalachian Power Company dba/American Electric Power, and Cardinal Operating Company and its owners (AEP Generation Resources Inc. and Buckeye Power, Inc.) and their respective successors and assigns.

b. A definition of "Gavin Buyer" shall be added and means Gavin Power, LLC, a Delaware limited liability company, whose principal place of business is 7397 N. State Route 7, Cheshire, OH 45620.

c. A definition of "Gavin Closing Date" shall be added and means the date on which the closing of the sale of the Gavin Units to Gavin Buyer occurs.

d. A definition of "Gavin Units" shall be added and means Gavin Unit 1 (1300 MW) and Gavin Unit 2 (1300 MW) located in Cheshire, Ohio.

e. The definition of "Defendants" in Paragraph 18 shall be modified as follows: "Defendants" means AEP and Gavin Buyer.

f. The definition of "Operational or Ownership Interest" in Paragraph 44 shall be modified by restating the definition as follows: "with respect to AEP, part or all of AEP's legal or equitable operational or ownership interest in any Unit in the AEP Eastern System other than the Gavin Units, and, with respect to Gavin Buyer, part or all of Gavin Buyer's legal or equitable operational or ownership interest in the Gavin Units."

3. Effective on the Gavin Closing Date, Gavin Buyer hereby assumes, and will be responsible for all obligations and liabilities imposed by the terms and conditions of the Consent Decree with respect to the Gavin Units, and those obligations and liabilities shall apply to and be enforceable against Gavin Buyer jointly and severally with AEP, to the same extent as if Gavin Buyer were specifically identified and/or named in those provisions of the Consent Decree.

4. The requirements of the Consent Decree that are applicable to the Gavin Units, and for which the Gavin Buyer and AEP will be jointly liable pursuant to paragraph 192 of the Consent Decree, include, but are not limited to: the NOx emission reduction obligations in Paragraphs 67 and 68, the SO_2 emission reduction obligations in Paragraphs 86 and 87, the allowance surrender provisions in Paragraphs 70 through 73, 81 through 83, and 91 through 97, reporting of any violations in accordance with Section XI of the Consent Decree, satisfying any claim for stipulated penalties in accordance with Section XIII of the Consent Decree, complying with the requirements of Section XIV for any Force Majeure Events, pursuing resolution of any disputes in accordance with Section XV of the Consent Decree, complying with the requirements related to Permits under Section XVI of the Consent Decree, complying with the Information Collection and Retention

requirements of Section XVII of the Consent Decree, and complying with the requirements of Section XIX of the Consent Decree related to Sales or Transfers on and after the Closing Date, all as they relate specifically to the Gavin Units.

5. Gavin Buyer shall not be responsible for any portion of the Civil Penalty provided for in Section IX of the Consent Decree, which the United States acknowledges has been paid in full. Gavin Buyer shall not be responsible for the Environmental Mitigation Projects set forth in Section VIII of the Consent Decree, including the Projects set forth in Appendix A, the Projects to be Conducted by the States set forth in Subsection B, as modified in the Third Joint Modification, or the Citizen Plaintiffs Renewable Energy and Mitigation Projects set forth in Subsection C in the Third Joint Modification, which the Citizen Plaintiffs acknowledge have been satisfied in full.

6. Gavin Buyer and AEP shall cooperate to accurately and timely fulfill the reporting obligations set forth in Paragraph 143 and Appendix B to the Consent Decree. Both AEP and Gavin Buyer shall comply with the certification requirements of Paragraph 146 of the Consent Decree with respect to the information each provides that is incorporated into such reports.

7. Paragraph 188 of the Consent Decree is modified by updating the information required in order to provide required notices under the Consent Decree:

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8. A new Paragraph 196A shall be inserted and read as follows: "With respect to any Gavin Unit, Paragraphs 191-195 of this Consent Decree do not apply if an Interest is sold or transferred solely as collateral security in order to consummate a financing arrangement (not including a sale-leaseback), so long as Gavin Buyer: (a) remains the operator (as that term is used and interpreted under the Clean Air Act) of the subject Gavin Units; (b) remains subject to and liable for all obligations and liabilities of this Consent Decree; and (c) supplies Plaintiffs with the following certification within thirty (30) days of the sale or transfer:

> "Certification of Change in Ownership Interest Solely for Purpose of Consummating Financing. I, the authorized officer with primary operational responsibility for the Gavin Units, hereby certify under Title 18 U.S.C. Section 1001, on my own behalf and on behalf of Gavin Buyer, that any change in Gavin Buyer's Ownership Interest in any Gavin Unit that is caused by the sale or transfer as collateral security of such Ownership Interest in such Unit(s) pursuant to the financing agreement consummated on [insert applicable date]

between Gavin Buyer and [insert applicable entity]: a) is made solely for the purpose of providing collateral security in order to consummate a financing arrangement; b) does not impair Gavin Buyer's ability, legally or otherwise, to comply timely with all terms and provisions of the Consent Decree entered in *United States, et al. v. American Electric Power Service Corp., et al.*, Civil Action No. C2-99-1250 ("AEP I") and *United States, et al. v. American Electric Power Service Corp., et al*., Civil Action Nos. C2-04-1098 and C2-05-360 ("AEP II"); c) does not affect Gavin Buyer's operational control of any Gavin Unit covered by that Consent Decree in a manner that is inconsistent with Gavin Buyer's performance of its obligations under the Consent Decree; and d) in no way affects the status of Gavin Buyer's obligations or liabilities under that Consent Decree."

9. Paragraph 199 shall be modified to read as follows: "The terms of this Consent Decree that pertain to any rights, obligations or liabilities related to AEP or the AEP Eastern System Units other than the Gavin Units may be modified only by a subsequent written agreement signed by Plaintiffs and AEP. The terms of this Consent Decree that pertain to any rights, obligations or liabilities related to Gavin Buyer or the Gavin Units may be modified only by a subsequent written agreement signed by Plaintiffs, AEP, and Gavin Buyer. Provided, however, no provision of this Consent Decree, including Sections XIX and XXII or this Paragraph 199, shall be interpreted to require Gavin Buyer to consent to any modification that relates solely to AEP or the AEP Eastern System Units (other than the Gavin Units), or to require AEP to consent to any modification that relates solely to the sale, transfer or change of control of the Gavin Units. Where a modification constitutes a material change to any term of this Decree, it shall be effective only upon approval by the Court."

10. Within 20 Days after the Gavin Closing Date, Gavin Buyers shall notify the Plaintiffs in accordance with Section XVIII (Notices) of the Consent Decree that the closing has occurred as anticipated.

11. This Fourth Joint Modification may be executed in several counterparts, each of which shall be considered an original.

12. Except as specifically provided in this Order, all other terms and conditions of the Consent Decree remain unchanged and in full effect.

SO ORDERED, THIS ___ DAY OF _____, 2017.

_____
HONORABLE EDMUND A. SARGUS, JR.
UNITED STATES DISTRICT JUDGE

SIGNATURE PAGE FOR THE
FOURTH JOINT MODIFICATION OF THE CONSENT DECREE

in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

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Civil Action No. 99-CV-1182 and consolidated cases

FOR THE STATE OF VERMONT

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SIGNATURE PAGE FOR THE
FOURTH JOINT MODIFICATION OF THE CONSENT DECREE

in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

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in

United States v. American Electric Power Service Corp., et al.
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FOR OHIO CITIZEN ACTION, CITIZENS ACTION COALITION OF INDIANA, HOOSIER ENVIRONMENTAL COUNCIL, OHIO VALLEY ENVIRONMENTAL COALITION, WEST VIRGINIA ENVIRONMENTAL COUNCIL, CLEAN AIR COUNCIL, IZAAK WALTON LEAGUE OF AMERICA, ENVIRONMENT AMERICA, NATIONAL WILDLIFE FEDERATION, INDIANA WILDLIFE FEDERATION, AND LEAGUE OF OHIO SPORTSMEN

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SIGNATURE PAGE FOR THE
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in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

FOR THE AEP COMPANIES

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FOURTH JOINT MODIFICATION OF THE CONSENT DECREE

in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

FOR GAVIN POWER LLC

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Karl A. Karg
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IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF OHIO
EASTERN DIVISION

UNITED STATES OF AMERICA Plaintiff, and STATE OF NEW YORK, ET AL., Plaintiff-Intervenors, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Consolidated Cases: Civil Action No. 2:99-CV-1182 Civil Action No. 2:99-CV-1250 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Terence P. Kemp
OHIO CITIZEN ACTION, ET AL., Plaintiffs, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Civil Action No. 2:04-CV-1098 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Norah McCann King
UNITED STATES OF AMERICA Plaintiff, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Civil Action No. 2:05-CV-360 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Norah McCann King

AGREED ENTRY APPROVING FOURTH JOINT MODIFICATION TO CONSENT DECREE

The attached Fourth Joint Modification is filed to comply with Paragraph 192 of the Consent Decree entered in this matter on December 10, 2007, to facilitate the transfer of the Gavin Plant to Gavin Power LLC, and add Gavin Power, LLC as a party to the Consent Decree according to the terms of the Fourth Joint Modification.

By agreement, evidenced by the signatures of all parties, it is respectfully requested that the court enter this Fourth Joint Modification promptly.

IT IS SO ORDERED.

Date: 1-23-2017

HONORABLE EDMUND A. SARGUS, JR.
UNITED STATES DISTRICT JUDGE

AGREED:

FOR THE UNITED STATES

/s/ John C. Cruden, per authority
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Environment and Natural Resources Division
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/s/ Myles E. Flint, II, per authority
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Susan Shinkman
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/s/ Phillip A. Brooks, per authority
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/s/ Sabrina Argentieri, per authority
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FOR NATURAL RESOURCES DEFENSE COUNCIL, INC.

/s/ Nancy S. Marks, per authority

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FOR SIERRA CLUB

/s/ Kristin Henry, per authority

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FOR OHIO CITIZEN ACTION, CITIZENS ACTION COALITION OF INDIANA, HOOSIER ENVIRONMENTAL COUNCIL, OHIO VALLEY ENVIRONMENTAL COALITION, WEST VIRGINIA ENVIRONMENTAL COUNCIL, CLEAN AIR COUNCIL, I ZAAK WALTON LEAGUE OF AMERICA, ENVIRONMENT AMERICA, NATIONAL WILDLIFE FEDERATION, INDIANA WILDLIFE FEDERATION, AND LEAGUE OF OHIO SPORTSMEN

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FOR AMERICAN ELECTRIC POWER & SERVICE CORP., APPALACHIAN POWER CO., CARDINAL OPERATING COMPANY, CENTRAL OPERATING COMPANY, MICHIGAN POWER CO., AND OHIO POWER COMPANY

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FOR GAVIN POWER LLC

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/s/ Karl A. Karg, per authority
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IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF OHIO
EASTERN DIVISION

UNITED STATES OF AMERICA Plaintiff, and STATE OF NEW YORK, ET AL., Plaintiff-Intervenors, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Consolidated Cases: Civil Action No. C2-99-1182 Civil Action No. C2-99-1250 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Kimberly A. Jolson
OHIO CITIZEN ACTION, ET AL., Plaintiffs, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Civil Action No. C2-04-1098 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Kimberly A. Jolson
UNITED STATES OF AMERICA Plaintiff, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Civil Action No. C2-05-360 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Kimberly A. Jolson

ORDER

This matter came before the Court on the Parties' Joint Motion to Enter the Fifth Joint Modification of Consent Decree (ECF No.). Having reviewed the submissions of all Parties and being fully advised of the positions therein, the Court hereby **GRANTS** the Joint Motion and **ORDERS** that the following Paragraphs of the Consent Decree entered in this case are modified as set forth herein.

IT IS SO ORDERED.

7-17-2019
DATE

EDMUND A. SARGUS, JR.
CHIEF UNITED STATES DISTRICT JUDGE

FIFTH JOINT MODIFICATION TO
CONSENT DECREE WITH ORDER MODIFYING CONSENT DECREE

WHEREAS, On December 10, 2007, this Court entered a Consent Decree in the above-captioned matters (Case No. 99-1250, Docket # 363; Case No. 99-1182, Docket # 508).

WHEREAS, Paragraph 199 of the Consent Decree provides that the terms of the Consent Decree may be modified only by a subsequent written agreement signed by the Plaintiffs and Defendants. Material modifications shall be effective only upon written approval by the Court.

WHEREAS, pursuant to Paragraph 87 of the Consent Decree (Case No. 99-1250, Docket # 363), as modified by a Joint Modification to Consent Decree With Order Modifying Consent Decree filed on April 5, 2010 (Case No. 99-1250, Docket # 371), as modified by a Second Joint Modification to Consent Decree with Order Modifying Consent Decree filed on December 28, 2010 (Case No. 99-1250, Docket # 372), as modified by a Third Joint Modification With Order Modifying Consent Decree filed on May 14, 2013 (Case No. 99-1182, Docket # 548), and as modified by an Agreed Entry Approving Fourth Joint Modification to Consent Decree filed on January 23, 2017 (Case No. 99-1182, Docket # 553), no later than December 31, 2025, the American Electric Power (AEP) Defendants are required, *inter alia*, to install and continuously operate a Flue Gas Desulfurization (FGD) system on, or Retire, Refuel, or Re-Power one Unit at the Rockport Plant, and no later than December 31, 2028, the AEP Defendants are required to install and continuously operate a FGD system on, or Retire, Refuel, or Re-Power the second Unit at the Rockport Plant.

WHEREAS, the AEP Defendants filed a Motion for Fifth Modification of Consent Decree in Case No. 99-1182 on July 21, 2017 (Case No. 99-1182, Docket # 555) and in the related cases seeking to further modify the provisions of Paragraph 87 and make other changes.

WHEREAS, the United States, the States, and Citizen Plaintiffs filed memoranda in

opposition to the motion by the AEP Defendants (Case No. 99-1182, Docket # 571 and 572, and Case No. 99-1250, Docket # 405) on September 1, 2017.

WHEREAS, the Parties made additional supplemental filings and engaged in settlement discussions and have reached agreement on a modification to the Consent Decree as set forth herein.

WHEREAS, the Parties have agreed, and this Court by entering this Fifth Joint Modification finds, that this Fifth Joint Modification has been negotiated in good faith and at arm's length; that this settlement is fair, reasonable, and in the public interest, and consistent with the goals of the Clean Air Act, 42 U.S.C. §7401, *et seq.*; and that entry of this Fifth Joint Modification without further litigation is the most appropriate means of resolving this matter.

WHEREAS, the Parties agree and acknowledge that final approval of the United States and entry of this Fifth Joint Modification is subject to the procedures set forth in 28 CFR § 50.7, which provides for notice of this Fifth Joint Modification in the *Federal Register*, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Fifth Joint Modification is inappropriate, improper, or inadequate. No Party will oppose entry of this Fifth Joint Modification by this Court or challenge any provision of this Fifth Joint Modification unless the United States has notified the Parties, in writing, that the United States no longer supports entry of the Fifth Joint Modification.

NOW THEREFORE, for good cause shown, without admission of any issue of fact or law raised in the Motion or the underlying litigation, the Parties hereby seek to modify the Consent Decree in this matter, and upon the filing of a Motion to Enter by the United States, move that the Court sign and enter the following Order:

Modify the provisions of the Consent Decree, as amended by the first four modifications, as follows:

Add a new Paragraph 5A that states:

5A. A "30-Day Rolling Average Emission Rate" for Rockport means, and shall be expressed as, lb/mmBTU and calculated in accordance with the following procedure: first, sum the total pounds of the pollutant in question emitted from the combined Rockport stack during a Day which is an Operating Day for either or both Rockport Units, and the previous twenty-nine (29) such Days; second, sum the total heat input to both Rockport Units in mmBTU during the Day which was an Operating Day for either or both Rockport Units, and the previous twenty-nine (29) such Days; and third, divide the total number of pounds of the pollutant emitted during the thirty (30) Days which were Operating Days for either or both Rockport Units by the total heat input during the thirty such Days. A new 30-Day Rolling Average Emission Rate shall be calculated for each new Day which is an Operating Day for either or both Rockport Units. Each 30-Day Rolling Average Emission Rate shall include all emissions that occur during all periods of startup, shutdown, and Malfunction within an Operating Day, except as follows:

a. Emissions and BTU inputs from both Rockport Units that occur during a period of Malfunction at either Rockport Unit shall be excluded from the calculation of the 30-Day Rolling Average Emission Rate if Defendants provide notice of the Malfunction to EPA in accordance with Paragraph 159 in Section XIV (Force Majeure) of this Consent Decree;

b. Emissions of NOx and BTU inputs from both Rockport Units that occur during the fifth and subsequent Cold Start Up Period(s) that occur at a single Rockport Unit during any 30-Day period shall be excluded from the calculation of the 30-Day Rolling Average Emission Rate if inclusion of such emissions would result in a

violation of any applicable 30-Day Rolling Average Emission Rate and Defendants have installed, operated, and maintained the SCR at the Unit in question in accordance with manufacturers' specifications and good engineering practices. A "Cold Start Up Period" occurs whenever there has been no fire in the boiler of a Unit (no combustion of any Fossil Fuel) for a period of six (6) hours or more. The NOx emissions to be excluded during the fifth and subsequent Cold Start Up Period(s) at a single unit shall be the lesser of (i) those NOx emissions emitted during the eight (8) hour period commencing when the Unit is synchronized with a utility electric distribution system and concluding eight (8) hours later, or (ii) those NOx emissions emitted prior to the time that the flue gas has achieved the minimum SCR operational temperature specified by the catalyst manufacturer; and

c. For SO_2, shall include all emissions and BTUs commencing from the time a single Rockport Unit is synchronized with a utility electric distribution system through the time that both Rockport Units cease to combust fossil fuel and the fire is out in both boilers.

Paragraph 14 is replaced in its entirety and now reads as follows:

14. "Continuously Operate" or "Continuous Operation" means that when an SCR, FGD, DSI, Enhanced DSI, ESP or other NOx Pollution Controls are used at a Unit, except during a Malfunction, they shall be operated at all times such Unit is in operation, consistent with the technological limitations, manufacturers' specifications, and good engineering and maintenance practices for such equipment and the Unit so as to minimize emissions to the greatest extent practicable.

Add a new Paragraph 20A that states:

20A. "Enhanced Dry Sorbent Injection" or "Enhanced DSI" means a pollution control system in which a dry sorbent is injected into the flue gas prior to the NOx and particulate matter controls in order to provide additional mixing and improved SO_2 removal as compared to Dry Sorbent Injection.

Paragraph 67 is replaced in its entirety and now reads as follows:

67. Notwithstanding any other provisions of this Consent Decree, except Section XIV (Force Majeure), during each calendar year specified in the table below, all Units in the AEP Eastern System, collectively, shall not emit NOx in excess of the following Eastern System-Wide Annual Tonnage Limitations:

Calendar Year	**Eastern System-Wide Annual Tonnage Limitations for NOx**
2009	96,000 tons
2010	92,500 tons
2011	92,500 tons
2012	85,000 tons
2013	85,000 tons
2014	85,000 tons
2015	75,000 tons
2016-2017	72,000 tons per year
2018-2020	62,000 tons per year
2021-2028	52,000 tons per year
2029 and each year thereafter	44,000 tons per year

Paragraph 68 is replaced in its entirety and now reads as follows:

68. No later than the dates set forth in the table below, Defendants shall install and

Continuously Operate SCR on each Unit identified therein, or, if indicated in the table, Retire, Retrofit, or Re-Power such Unit:

Unit	NOx Pollution Control	Date
Amos Unit 1	SCR	January 1, 2008
Amos Unit 2	SCR	January 1, 2009
Amos Unit 3	SCR	January 1, 2008
Big Sandy Unit 2	SCR	January 1, 2009
Cardinal Unit 1	SCR	January 1, 2009
Cardinal Unit 2	SCR	January 1, 2009
Cardinal Unit 3	SCR	January 1, 2009
Conesville Unit 1	Retire, Retrofit, or Re-Power	Date of Entry of this Consent Decree
Conesville Unit 2	Retire, Retrofit, or Re-Power	Date of Entry of this Consent Decree
Conesville Unit 3	Retire, Retrofit, or Re-Power	December 31, 2012
Conesville Unit 4	SCR	December 31, 2010
Gavin Unit 1	SCR	January 1, 2009
Gavin Unit 2	SCR	January 1, 2009
Mitchell Unit 1	SCR	January 1, 2009
Mitchell Unit 2	SCR	January 1, 2009
Mountaineer Unit 1	SCR	January 1, 2008
Muskingum River Units 1-4	Retire, Retrofit, or Re-Power	December 31, 2015
Muskingum River Unit 5	SCR	January 1, 2008
Rockport Unit 1	SCR	December 31, 2017
Rockport Unit 2	SCR	June 1, 2020
Sporn Unit 5	Retire, Retrofit, or Re-Power	December 31, 2013
A total of at least 600 MW from the following list of Units: Sporn Units 1-4, Clinch River units 1-3, Tanners Creek Units 1-3 and/or Kammer Units 1-3	Retire, Retrofit, or Re-Power	December 31, 2018

Add a new Paragraph 68A that reads as follows:

68A. 30-Day Rolling Average NO_x Emission Rate at Rockport. Beginning on the thirtieth Day which is an Operating Day for either one or both Rockport Units in calendar year 2021, average

NOx emissions from the Rockport Units shall be limited to 0.090 lb/mmBTU on a 30-day Rolling Average Basis at the combined stack for the Rockport Units. Emissions shall be calculated in accordance with the provisions of Paragraph 5A and reported in accordance with the requirements of Paragraph J in Appendix B.

Add a new Paragraph 68B that reads as follows:

68B. Informational NOx Monitoring. During the ozone seasons (May 1 – September 30) in each of calendar years 2019 and 2020, prior to the effective date of the 30-Day Rolling Average NOx Rate at the Rockport Units in Paragraph 68A, the AEP Defendants shall provide an estimate of the 30-day rolling average NOx emissions from Rockport Unit 1, based on NOx concentrations and percent CO_2 measured at an uncertified NOx monitor in the duct from Unit 1 before the flue gases from Rockport Units 1 and 2 combine at the common stack. Hourly NOx rates shall be calculated for each hour for which valid data is available, using the following equation:

NOx lb/mmBtu = $[(1.194 \times 10^{-7}) \times$ NOx ppm x 1840 scf CO_2 per mmBtu x 100$]/\%$ CO_2

The monitor shall be calibrated daily and maintained in accordance with good engineering and maintenance practices. If valid NOx or CO_2 data is not available for any hour, that hour shall not be used in the calculation of the informational data provided to Plaintiffs, including periods of monitor downtime, calibrations, and maintenance. For informational purposes only, NOx emission rate data for Rockport Unit 1 on a 30-Day Rolling Average Basis for May – June shall be reported to Plaintiffs by July 30, and NOx emission rate data for Rockport Unit 1 on a 30-Day Rolling Average Basis for July – September shall be reported to Plaintiffs by October 30. Nothing in this Paragraph shall be construed to establish a Unit-specific NOx Emission Rate for Rockport Unit 1, and these interim reporting obligations are not required to be incorporated into the Title V permit for the Rockport Plant.

Paragraph 86 is replaced in its entirety and now reads as follows:

86. Notwithstanding any other provisions of this Consent Decree, except Section XIV (Force Majeure), during each calendar year specified in the table below, all Units in the AEP Eastern System, collectively, shall not emit SO_2 in excess of the following Eastern System-Wide Annual Tonnage Limitations:

Calendar Year	**Eastern System-Wide Annual Tonnage Limitations for SO2**
2010	450,000 tons
2011	450,000 tons
2012	420,000 tons
2013	350,000 tons
2014	340,000 tons
2015	275,000 tons
2016	145,000 tons
2017	145,000 tons
2018	145,000 tons
2019-2020	113,000 tons per year
2021-2028	94,000 tons per year
2029, and each year thereafter	89,000 tons per year

Paragraph 87 is replaced in its entirety and now reads as follows:

87. No later than the dates set forth in the table below, Defendants shall install and Continuously Operate an FGD, Dry Sorbent Injection, or Enhanced Dry Sorbent Injection system on each Unit identified therein, or, if indicated in the table, Cease Burning Coal, Retire,

Retrofit, Re-power, or Refuel such Unit:

Unit	SO_2 Pollution Control	Date
Amos Unit 1	FGD	February 15, 2011
Amos Unit 2	FGD	April 2, 2010
Amos Unit 3	FGD	December 31, 2009
Big Sandy Unit 2	Retrofit, Retire, Re-Power or Refuel	December 31, 2015
Cardinal Units 1 and 2	FGD	December 31, 2008
Cardinal Unit 3	FGD	December 31, 2012
Conesville Units 1 and 2	Retire, Retrofit, or Re-power	Date of Entry
Conesville Unit 3	Retire, Retrofit, or Re-power	December 31, 2012
Conesville Unit 4	FGD	December 31, 2010
Conesville Unit 5	Upgrade existing FGD and meet a 95% 30-day Rolling Average Removal Efficiency	December 31, 2009
Conesville Unit 6	Upgrade existing FGD and meet a 95% 30-day Rolling Average Removal Efficiency	December 31, 2009
Gavin Units 1 and 2	FGD	Date of Entry
Mitchell Units 1 and 2	FGD	December 31, 2007
Mountaineer Unit 1	FGD	December 31, 2007
Muskingum River Units 1-4	Retire, Retrofit, or Re-power	December 31, 2015
Muskingum River Unit 5	Cease Burning Coal and Retire Or Cease Burning Coal and Refuel	December 15, 2015 December 31, 2015, unless the Refueling project is not completed in which case the Unit

Unit	SO_2 Pollution Control	Date
		will be taken out of service no later than December 31, 2015, and will not restart until the Refueling project is completed. The refueling project must be completed by June 30, 2017.
Rockport Unit 1	Dry Sorbent Injection and Enhanced DSI, and beginning in calendar year 2021 meet an Emission Rate of 0.15 lb/mmBTU of SO_2 on a 30-Day Rolling Average Basis at the Rockport combined stack And Retrofit, Refuel, or Re-Power, but must satisfy the provisions of Paragraphs 133 and 140	April 16, 2015 December 31, 2020 December 31, 2028
Rockport Unit 2	Dry Sorbent Injection and Enhanced DSI, and beginning in calendar year 2021 meet an Emission Rate of 0.15 lb/mmBTU of SO_2 on a 30-Day Rolling Average Basis at the Rockport combined stack	April 16, 2015 June 1, 2020
Sporn Unit 5	Retire, Retrofit, or Re-power	December 31, 2013
A total of at least 600 MW from the following list of Units: Sporn Units 1-4, Clinch River Units 1-3,	Retire, Retrofit, or Re-power	December 31, 2018

Unit	SO_2 Pollution Control	Date
Tanners Creek Units 1-3, and/or Kammer Units 1-3		

Paragraph 89A is replaced in its entirety and now reads as follows:

89A. Plant-Wide Annual Tonnage Limitation and 30-Day Rolling Average Emission Rate for SO_2 at Rockport. For each of the calendar years set forth in the table below, AEP Defendants shall limit their total annual SO_2 emissions from Rockport Units 1 and 2 to the Plant-Wide Annual Tonnage Limitation for SO_2 as follows:

Calendar Years	Plant-Wide Annual Tonnage Limitation for SO2
2016-2017	28,000 tons per year
2018-2019	26,000 tons per year
2020	22,000 tons per year
2021-2028	10,000 tons per year
2029, and each year thereafter	5,000 tons per year

In addition to the Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport, beginning on the thirtieth Day which is an Operating Day for either or both Rockport Units in calendar year 2021, SO_2 emissions from the Rockport Units shall be limited to 0.15 lb/mmBTU on a 30-Day Rolling Average Basis at the Rockport combined stack (30-Day Rolling Average Emission Rate for SO_2 at Rockport). Emissions shall be calculated in accordance with the provisions of Paragraph 5A and reported in accordance with the requirements of Paragraph J in Appendix B. Nothing in this Consent Decree shall be construed to prohibit the AEP Defendants from further optimizing the Enhanced DSI system, utilizing alternative sorbents, or upgrading the SO_2 removal technology at

the Rockport Units so long as the Units maintain compliance with the 30-day Rolling Average Emission Rate for SO_2 at Rockport and the 30-day Rolling Average Emission Rate for NO_x at Rockport.

Paragraph 127 is replaced in its entirety and now reads as follows:

127. The States, by and through their respective Attorneys General, shall jointly submit to Defendants Projects within the categories identified in this Subsection B for funding in amounts not to exceed $4.8 million per calendar year for no less than five (5) years following the Date of Entry of this Consent Decree beginning as early as calendar year 2008, and for an additional amount not to exceed $6.0 million in 2013. The funds for these Projects will be apportioned by and among the States, and Defendants shall not have approval rights for the Projects or the apportionment. Defendants shall pay proceeds as designated by the States in accordance with the Projects submitted for funding each year within seventy-five (75) days after being notified by the States in writing. Notwithstanding the maximum annual funding limitations above, if the total costs of the projects submitted in any one or more years is less than the maximum annual amount, the difference between the amount requested and the maximum annual amount for that year will be available for funding by the Defendants of new and previously submitted projects in the following years, except that all amounts not requested by and paid to the States within eleven (11) years after the Date of Entry of this Consent Decree shall expire.

Pursuant to the Fifth Joint Modification Indiana Michigan Power Company ("I&M") will provide as restitution or as funds to come into compliance with the law $4 million in additional funding for the States to support projects identified in Section VIII, Subsection B during the period from 2019 through 2021. I&M shall provide the funding within seventy-five (75) days of receipt of a written request for payment and in accordance with instructions from counsel for the States.

Paragraph 128B is replaced in its entirety and now reads as follows:

128B. Citizen Plaintiffs' Mitigation Projects. I&M will provide $2.5 million in mitigation funding as directed by the Citizen Plaintiffs for projects in Indiana that include diesel retrofits, health and safety home repairs, solar water heaters, outdoor wood boilers, land acquisition projects, and small renewable energy projects (less than 0.5 MW) located on customer premises that are eligible for net metering or similar interconnection arrangements on or before December 31, 2014. I&M shall make payments to fund such Projects within seventy-five (75) days after being notified by the Citizen Plaintiffs in writing of the nature of the Project, the amount of funding requested, the identity and mailing address of the recipient of the funds, payment instructions, including taxpayer identification numbers and routing instructions for electronic payments, and any other information necessary to process the requested payments. Defendants shall not have approval rights for the Projects or the amount of funding requested, but in no event shall the cumulative amount of funding provided pursuant to this Paragraph 128B exceed $2.5 million.

In addition to the $2.5 million provided in 2014, pursuant to the Fifth Joint Modification I&M will provide as restitution or as funds to come into compliance with the law $3.5 million in funding for Citizen Plaintiffs to support projects that will promote energy efficiency, distributed generation, and pollution reduction measures for nonprofits, governmental entities, low income residents and/or other entities selected by Citizen Plaintiffs. I&M shall provide the $3.5 million in funding within seventy-five (75) days of the Date of Entry of the Fifth Joint Modification of the Consent Decree by the Court in accordance with instructions from counsel for Citizen Plaintiffs.

Paragraph 133 is replaced in its entirety and now reads as follows:

133. Claims Based on Modifications after the Date of Lodging of This Consent Decree. Entry of this Consent Decree shall resolve all civil claims of the United States against Defendants that

arise based on a modification commenced before December 31, 2018, or, solely for Rockport Unit 1, before December 31, 2028, or, solely for Rockport Unit 2, before June 1, 2020, for all pollutants, except Particulate Matter, regulated under Parts C or D of Subchapter I of the Clean Air Act, and under regulations promulgated thereunder, as of the Date of Lodging of this Consent Decree, and:

a. where such modification is commenced at any AEP Eastern System Unit after the Date of Lodging of the original Consent Decree; or

b. where such modification is one this Consent Decree expressly directs Defendants to undertake.

With respect to Rockport Unit 1, the United States agrees that the AEP Defendants' obligation to Retrofit, Re-Power, or Refuel Rockport Unit 1 would be satisfied if, by no later than December 31, 2028, the AEP Defendants Retrofit Rockport Unit 1 by installing and commencing continuous operation of FGD technology consistent with the definition in Paragraph 56 of the Third Joint Modification of the Consent Decree, Re-Power the Unit consistent with the definition in Paragraph 54 of the Consent Decree, or Refuel the Unit consistent with the provisions of Paragraph 53A of the Third Joint Modification of the Consent Decree. If the AEP Defendants elect to Retire Rockport Unit 1 by December 31, 2028, that would also satisfy the requirements of this Paragraph and fulfill the AEP Defendants' obligations with regard to Rockport Unit 1 under this Consent Decree. The term "modification" as used in this paragraph shall have the meaning that term is given under the Clean Air Act and under the regulations in effect as of the Date of Lodging of this Consent Decree, as alleged in the complaints in *AEP I* and *AEP II*.

Paragraph 140 is replaced in its entirety and now reads as follows:

140. With respect to the States and Citizen Plaintiffs, except as specifically set forth in this Paragraph, the States and Citizen Plaintiffs expressly do not join in giving the Defendants the

covenant provided by the United States in Paragraph 133 of this Consent Decree, do not release any claims under the Clean Air Act and its implementing regulations arising after the Date of Lodging of the original Consent Decree, and reserve their rights, if any, to bring any actions against Defendants pursuant to 42 U.S.C. §7604 for any claims arising after the Date of the Lodging of the original Consent Decree. AEP, the States, and Citizen Plaintiffs also recognize that I&M informed state regulators in its most recent base rate proceedings that the most realistic date through which Rockport Unit 1 can be expected to be in operation with any reasonable degree of certainty is December 2028, and the Indiana Utility Regulatory Commission and the Michigan Public Service Commission have approved depreciation rates for I&M's share of Rockport Unit 1 to be consistent with the retirement of Unit 1 in December 2028. Notwithstanding the existence of any other compliance options in Paragraphs 87 and 133, AEP Defendants must Retire Rockport Unit 1 by no later than December 31, 2028. AEP Defendants and the States and Citizen Plaintiffs agree that Paragraph 140 prevails in any conflict between it and Paragraphs 87 and/or 133.

a. On or before March 31, 2025, AEP Defendants shall submit to PJM Interconnection, LLC, or any other regional transmission organization with jurisdiction over the Rockport Units, notification of the planned retirement of Rockport Unit 1 by no later than December 31, 2028, and a request for such regional transmission organization to evaluate and identify any reliability concerns associated with such retirement.

Paragraph 180 is replaced in its entirety and now reads as follows:

180. Within one (1) year from commencement of operation of each pollution control device to be installed, upgraded, and/or operated under this Consent Decree, Defendants shall apply to include the requirements and limitations enumerated in this Consent Decree into federally-enforceable non-Title V permits and/or site-specific amendments to the applicable state

implementation plans to reflect all new requirements applicable to each Unit in the AEP Eastern System, the Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River, the Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer, and the Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport.

Paragraph 182 is replaced in its entirety and now reads as follows:

182. Prior to termination of this Consent Decree, Defendants shall obtain enforceable provisions in their Title V permits for the AEP Eastern System that incorporate (a) any Unit-specific requirements and limitations of this Consent Decree, such as performance, operational, maintenance, and control technology requirements, (b) the Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River, the Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer, and the Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport, and (c) the Eastern System-Wide Annual Tonnage Limitations for SO_2 and NO_x. If Defendants do not obtain enforceable provisions for the Eastern System-Wide Annual Tonnage Limitations for SO_2 and NO_x in such Title V permits, then the requirements in Paragraphs 86 and 67 shall remain enforceable under this Consent Decree and shall not be subject to termination.

Paragraph 188 is modified as follows to update the information required in order to provide required notices under the Consent Decree:

188.

As to the United States:

Case Management Unit
Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, DC 20044-7611
DJ# 90-5-2-1-06893
eescdcopy.enrd@usdoj.gov

Phillip Brooks
Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [Mail Code 2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460
Brooks.phillip@epa.gov

Sara Breneman
Air Enforcement & Compliance Assurance Branch
U.S. EPA Region 5
77 W. Jackson Blvd.
Mail Code AE-18J
Chicago, IL 60604
Breneman.sara@epa.gov

and

Carol Amend, Branch Chief
Air, RCRA & Toxics Branch (3ED20)
Enforcement & Compliance Assurance Division
U.S. EPA, Region 3
1650 Arch Street
Philadelphia, PA 19103-2029
Amend.carol@epa.gov

For all notices to EPA, Defendants shall register for the CDX electronic system and upload such notices at https://cdx.gov/epa-home.asp.

As to the State of Connecticut:

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Office of the Attorney General
Environment Department
55 Elm Street
P.O. Box 120
Hartford, CT 06141-0120
Lori.dibella@ct.gov

As to the State of Maryland:

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Program Manager
Air Quality Compliance Program

Maryland Department of the Environment
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fcourtright@mde.state.md.us

and

Matthew Zimmerman
Assistant Attorney General
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mzimmerman@mde.state.md.us

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Office of the Attorney General
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Boston, Massachusetts 02108
Christophe.courchesne@state.ma.us

As to the State of New Hampshire:

Director, Air Resources Division
New Hampshire Department of Environmental Services
29 Hazen Dive
Concord, New Hampshire 03302-0095

and

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Senior Assistant Attorney General
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Concord, New Hampshire 03301
Allen.brooks@doj.nh.gov

As to the State of New Jersey:

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Environmental Enforcement
Dept. of Law & Public Safety
Division of Law
R.J. Hughes Justice Complex
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and

Shannon Fisk
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As to Gavin Buyer:

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karl.karg@lw.com

and

Alexandra Farmer
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Washington, DC 20004
alexandra.farmer@kirkland.com

Add a new Paragraph 205A that reads as follows:

205A. 26 U.S.C. Section 162(f)(2)(A)(ii) Identification. For purposes of the identification requirement of Section 162(f)(2)(A)(ii) of the Internal Revenue Code, 26 U.S.C. § 162(f)(2)(A)(ii), with respect to obligations incurred under this Fifth Joint Modification, performance of Section II (Applicability), Paragraph 3; Section IV (NO_x Emission Reductions and Controls), Paragraphs 67, 68, 68A, and 68B; Section V (SO_2 Emission Reductions and Controls), Paragraphs 86, 87, and 89A; Section VII (Prohibition on Netting Credits or Offsets from Required Controls), Paragraph 117; Section XI (Periodic Reporting), Paragraphs 143 – 147; Section XII (Review and Approval of Submittals), Paragraphs 148 and 149 (except with respect to dispute resolution); Section XVI (Permits), Paragraphs 175, 177, 179, and 180 – 183; Section XVII (Information Collection and Retention), Paragraphs 184 and 185; Section XXIII (General Provisions), Paragraph 207; and Appendix B; is restitution or required to come into compliance with law.

Modify Appendix B (Reporting Requirements) as follows:

Section I Paragraph O is replaced in its entirety and now reads as follows:

O. Plant-Wide Annual Tonnage Limitation and Emission Rate for SO_2 at Rockport.

Beginning March 31, 2017, and continuing annually thereafter, Defendants shall report: (a) the actual tons of SO_2 emitted from Units 1 and 2 at the Rockport Plant for the prior calendar year; (b) the Plant-Wide Annual Tonnage Limitation for SO_2 at the Rockport Plant for the prior calendar year as set forth in Paragraph 89A of the Consent Decree; and (c) for the annual reports for calendar years 2015 - 2020, Defendants shall report the daily sorbent deliveries to the Rockport Plant by weight. Beginning in calendar year 2021, the annual reports shall report the 30-day rolling average SO_2 Emissions Rate at the Rockport stack as required under Section I, Paragraph J of Appendix B, and reporting of daily sorbent deliveries will no longer be required.

Section I Paragraph S. is replaced in its entirety and now reads as follows:

S. Notification of Retirement of Rockport Unit 1.

AEP Defendants shall provide to the Plaintiffs a copy of the notification submitted to PJM Interconnection, LLC, or any other regional transmission organization pursuant to Paragraph 140.a, and a copy of any response received from PJM Interconnection, LLC, or any other the regional transmission organization.

Delete Paragraphs T and U from Section I of Appendix B.

Except as specifically provided in this Order, all other terms and conditions of the Consent Decree remain unchanged and in full effect.

SO ORDERED, THIS 17th DAY OF July, 2019.

HONORABLE EDMUND A. SARGUS, JR.
UNITED STATES DISTRICT JUDGE

SIGNATURE PAGE FOR THE
FIFTH JOINT MODIFICATION OF THE CONSENT DECREE

in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

FOR THE UNITED STATES

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Office of Civil Enforcement
United States Environmental Protection Agency

Phillip A. Brooks
Director, Air Enforcement Division
Office of Civil Enforcement
United States Environmental Protection Agency

Sabrina Argentieri
Attorney-Advisor
Office of Civil Enforcement
Civil Enforcement Division
United States Environmental Protection Agency

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Civil Action No. 99-CV-1182 and consolidated cases

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By: _____
MATTHEW ZIMMERMAN
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SIGNATURE PAGE FOR THE
FIFTH JOINT MODIFICATION OF THE CONSENT DECREE

in

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Civil Action No. 99-CV-1182 and consolidated cases

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Civil Action No. 99-CV-1182 and consolidated cases

FOR THE STATE OF NEW JERSEY

GURBIR S. GREWAL
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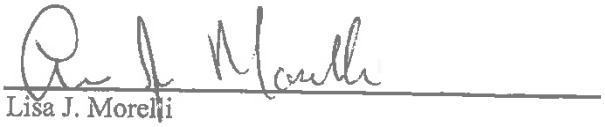

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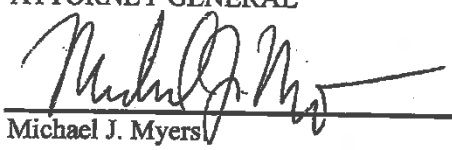
FOR THE STATE OF NEW YORK

LETITIA JAMES
ATTORNEY GENERAL



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Environmental Protection Bureau
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Albany, NY 12224

SIGNATURE PAGE FOR THE
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Civil Action No. 99-CV-1182 and consolidated cases

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in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

FOR NATURAL RESOURCES DEFENSE COUNCIL, INC.

Nancy S Marks

Nancy S. Marks
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SIGNATURE PAGE FOR THE
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in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

FOR SIERRA CLUB

Kristin A. Henry

Kristin Henry
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SIGNATURE PAGE FOR THE
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in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

FOR OHIO CITIZEN ACTION, CITIZENS ACTION COALITION OF INDIANA, HOOSIER ENVIRONMENTAL COUNCIL, OHIO VALLEY ENVIRONMENTAL COALITION, WEST VIRGINIA ENVIRONMENTAL COUNCIL, CLEAN AIR COUNCIL, IZAAK WALTON LEAGUE OF AMERICA, ENVIRONMENT AMERICA, NATIONAL WILDLIFE FEDERATION, INDIANA WILDLIFE FEDERATION, AND LEAGUE OF OHIO SPORTSMEN

Margrethe Kearney
Environmental Law and Policy Center
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SIGNATURE PAGE FOR THE
FIFTH JOINT MODIFICATION OF THE CONSENT DECREE

in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

FOR THE AEP COMPANIES

David M. Feinberg
American Electric Power
1 Riverside Plaza
Columbus, OH 43215

IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF OHIO
EASTERN DIVISION

UNITED STATES OF AMERICA Plaintiff, and STATE OF NEW YORK, ET AL., Plaintiff-Intervenors, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Consolidated Cases: Civil Action No. C2-99-1182 Civil Action No. C2-99-1250 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Kimberly A. Jolson
OHIO CITIZEN ACTION, ET AL., Plaintiffs, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Civil Action No. C2-04-1098 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Kimberly A. Jolson
UNITED STATES OF AMERICA Plaintiff, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Civil Action No. C2-05-360 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Kimberly A. Jolson

SIXTH JOINT MODIFICATION TO CONSENT DECREE

WHEREAS, On December 10, 2007, this Court entered a Consent Decree in the above-captioned matters (Case No. 99-1250, Docket # 363; Case No. 99-1182, Docket # 508).

WHEREAS, Paragraph 199 of the Consent Decree provides that the terms of the Consent Decree may be modified only by a subsequent written agreement signed by the Plaintiffs and Defendants. Material modifications shall be effective only upon written approval by the Court.

WHEREAS, the Consent Decree has been modified five times, see Joint Modification to Consent Decree With Order Modifying Consent Decree filed on April 5, 2010 (Case No. 99-1250, Docket # 371), Second Joint Modification to Consent Decree with Order Modifying Consent Decree filed on December 28, 2010 (Case No. 99-1250, Docket # 372), Third Joint Modification With Order Modifying Consent Decree filed on May 14, 2013 (Case No. 99-1182, Docket # 548), Agreed Entry Approving Fourth Joint Modification to Consent Decree filed on January 23, 2017 (Case No. 99-1182, Docket # 553), and Fifth Joint Modification to Consent Decree with Order Modifying the Consent Decree filed on July 17, 2019 (Case 99-1182, Docket Entry # 606).

WHEREAS, the Parties have agreed to a sixth joint modification of the Consent Decree that modifies Section XVIII (Notices) and Appendix A of the Consent Decree.

WHEREAS, Section XVIII (Notices) is modified to allow notifications, submissions, and communications to be submitted electronically.

WHEREAS, Appendix A Environmental Mitigation Projects requires, *inter alia*, American Electric Power (AEP) to perform Mobile Source Emission Reduction Projects which include a Diesel Tug/Train Project, a Hybrid Vehicle Fleet Project, and a Truck Stop Electrification Project.

WHEREAS, AEP, due to unexpected difficulties in implementation, has requested the ability to expand the types of Mobile Source Emission Reduction Projects included in Appendix A.

WHEREAS, the Parties have agreed to expand the Mobile Source Emission Reduction Projects to include Bus Replacement Projects.

WHEREAS, the Parties agree that this Sixth Joint Modification is a non-material modification that, pursuant to Paragraph 199, does not require written approval by the Court.

NOW THEREFORE, the Parties hereby modify the Consent Decree, as amended by the first five modifications, as follows:

I. Replace Section XVIII (Notices) with the following:

XVIII. NOTICES

188. Unless otherwise provided herein, whenever notifications, submissions, or communications are required by this Consent Decree, they shall be made in the manner specified herein.

As to the United States:

As to DOJ:

By email:

Chief, Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
eescdcopy.enrd@usdoj.gov
Referencing DJ# 90-5-2-1-06893 in the subject line of the email

As to U.S. EPA:

By uploading an electronic version of the submission to the cdx system at: https://cdx.epa.gov.

And by email to:

r5ardreporting@epa.gov

willard.erinm@epa.gov

And, unless otherwise agreed in writing by the submitter and EPA, a hard copy shall be sent to one of the following addresses for overnight delivery:

By U.S. Mail:

Director, Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency Mail Code 2242A
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Or by commercial delivery service:

Air Enforcement Division
Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios South Building, Room 1119
1200 Pennsylvania Avenue, NW
Washington, DC 20004

As to the States:

As to the State of Connecticut:

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Environment Department
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As to the State of Maryland:

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As to the State of New Jersey:

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Environmental Enforcement
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and

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As to AEP:

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As to Gavin Buyer:

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karl.karg@lw.com

and

Alexandra Farmer
Kirkland & Ellis LLP
1301 Pennsylvania Avenue, N.W.
Washington, DC 20004
alexandra.farmer@kirkland.com

189. All notifications, communications, or submissions made pursuant to this Section shall be made by electronic filing and email delivery to all Parties if practicable, but if not practicable, then by overnight mail or delivery to the addresses set forth above. EPA may waive the requirement to submit a hard copy by overnight delivery, upon receipt of a written request from the submitter, by email or other means in writing. All notifications, communications, and transmissions sent by overnight delivery service shall be deemed submitted on the date they are delivered to the delivery service.

190. Any Party may change either the notice recipient or the address for providing notices to it by serving all other Parties with a notice setting forth such new notice recipient or address.

II. Modify Appendix A (Environmental Mitigation Projects) as follows:

Appendix A, Section V, Paragraph A, 7th line is amended by replacing "three" with "four".

Appendix A, Section V, the following Paragraphs are added:

E. **Bus Replacement Projects**

1. AEP shall facilitate the replacement of existing public school and transit buses with new, more energy-efficient buses and thereby reduce emissions of NOx and PM. AEP shall maximize the environmental benefits of the project and shall seek and prioritize bus replacements with the greatest potential emissions reductions.

2. AEP shall submit a plan to EPA for review and approval, in consultation with the Citizen Plaintiffs, for the implementation of the Bus Replacement Projects. Upon approval of the plan by EPA, AEP shall implement the plan. The plan shall include:

a. A description of how the Bus Replacement Project will be implemented, including how opportunities for bus replacement will be communicated to local communities and school districts;

b. A calculation of the maximum amount of Project Dollar credits that would be available per vehicle and per fueling infrastructure installation, based upon the class and size of the Eligible vehicle that was replaced and the cost of a New vehicle of the same class and size, and a fueling installation capable of supporting the New vehicle(s);

c. A timeline for initial and subsequent solicitations of applications from local communities and school districts to participate in the project, with the project to be completed within five years of the date of filing of this Sixth Joint Modification;

d. A description of the anticipated environmental benefits of the project, including an estimate of the emission reductions expected to be realized per vehicle, and the methodology and any calculations used in the derivation of such expected benefits; and

e. A commitment to require each Bus Replacement Project participant to certify that the criteria for eligibility set forth in Paragraphs 4 - 7 for each School Bus Replacement Project, or that the criteria set forth in Paragraphs 8 - 11 for each Transit Bus Replacement Project, as applicable, will be met.

3. As part of the periodic reports required by Section XI (Periodic Reporting) of the Consent Decree, AEP shall provide an update on the Bus Replacement Project. These reports shall continue until the conclusion of the Bus Replacement Project. The update shall address the steps taken by AEP during the reporting period related to the Bus Replacement Project, including the vehicles replaced, the fueling infrastructure installed, and the Project Dollars proposed to be credited for and actual cost of each vehicle and/or fueling installation completed during the prior year.

School Bus Replacement Project

4. To be eligible to participate in the Bus Replacement Projects, the public school district must be located in Indiana, Kentucky, North Carolina, Ohio, Pennsylvania, Virginia or West Virginia, and own the Eligible Buses that will be replaced as part of this Project with the following exceptions:

a. Public school districts may apply with state-owned buses as long as they receive an authorized letter from the state agency that owns the buses allowing the school district to acquire New School Bus(es) and scrap the Eligible School Bus(es);

b. Third-party school bus contractors who own the Eligible School Bus(es) serving public school districts are eligible to participate in the program, however third-party school bus contractors who lease the proposed bus(es) to be replaced are only eligible if the remaining lease on the vehicle equals or exceeds three years; and

c. Buses owned by Federal agencies are not eligible.

5. An Eligible School Bus is a bus that meets all of the following criteria:

a. Is primarily used for the purpose of transporting 10 or more pre-primary, primary, or secondary school students to schools or homes;

b. Is rated Class 3-8, as defined by the Department of Transportation's vehicle service classifications;

c. Has a Gross Vehicle Weight Rating (GVWR) of at least 10,001 pounds;

d. Has accumulated at least 10,000 miles transporting students during at least one of the three prior calendar years, or has been in use for at least three days per week transporting students during the current school year;

e. Is operated within the following States: Indiana, Kentucky, North Carolina, Ohio, Pennsylvania, Virginia or West Virginia;

f. Has a diesel-powered engine with a model year of 1996-2009 or older; and

g. Is able to start, move in all directions and have all operational parts.

6. For a replacement to be considered eligible, the New School Bus must

a. Be model year 2019 or later;

b. Operate in the same manner and over similar routes as the original school bus;

c. Meet all applicable engine standards, certifications, and/or verifications and shall be retained and operated for its useful life; and

d. Meet Federal safety standards and required warranties.

7. For the school bus replacement to be considered eligible, the school district must provide to AEP, and AEP must retain and provide to the Plaintiffs in AEP's annual report, documentation that each diesel bus that is being replaced is scrapped or rendered permanently disabled within 90 days of being replaced. More specifically:

a. The preferred scrapping method is cutting a three-inch by three-inch hole in the engine block (the part of the engine containing the cylinders).

b. Disabling the chassis should be completed by cutting through the frame/frame rails on each side at a point located between the front and rear axles.

c. A signed certificate of destruction and digital photos of the engine tag (showing serial number, engine family number, and engine model year), the destroyed engine block, and cut frame rails or other cut structural components, or other evidence of destruction, as applicable, shall be provided.

d. Equipment and vehicle components that are not part of the engine or chassis may be salvaged from the unit being replaced (e.g. plow blades, shovels, seats, tires, etc.).

Transit Bus Replacement Project

8. To be eligible to participate in the Bus Replacement Project, the transit bus system must be located in Indiana, Kentucky, North Carolina, Ohio, Pennsylvania, Virginia or West Virginia, and the participant must own the Eligible Transit Bus(es) that will be replaced as part of this Project.

9. An Eligible Transit Bus is a bus that meets all of the following criteria:

a. Is primarily used for public transportation for people in the transit bus system;

b. Is rated Class 3-8, as defined by the Department of Transportation's vehicle service classifications;

c. Has a Gross Vehicle Weight Rating (GVWR) of at least 10,001 pounds;

d. Has accumulated at least 10,000 miles transporting people during at least one of the three prior calendar years;

e. Is operated within Indiana, Kentucky, North Carolina, Ohio, Pennsylvania, Virginia or West Virginia;

f. Has a diesel-powered engine with a model year of 1996-2009 or older; and

g. Is able to start, move in all directions and have all operational parts.

10. For a replacement to be considered eligible, the New Transit Bus must:

a. Be model year 2019 or later;

b. Operate in the same manner and over similar routes as the original bus;

c. Meet all applicable engine standards, certifications, and/or verifications and shall be retained and operated for its useful life; and

d. Meet Federal safety standards and required warranties.

11. For the replacement to be considered eligible, the transit district must provide to AEP, and AEP must retain and provide to the Plaintiffs in AEP's annual report, documentation that each diesel bus that is being replaced is scrapped or rendered

permanently disabled within 90 days of being replaced, as set forth in Paragraph E.7., above.

All other terms and conditions of the Consent Decree remain unchanged and in full effect.

SIGNATURE PAGE FOR THE
SIXTH JOINT MODIFICATION OF THE CONSENT DECREE

in

United States v. American Electric Power Service Corp., et al.
Civil Action No. 99-CV-1182 and consolidated cases

FOR THE UNITED STATES

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FOR THE UNITED STATES

EVAN BELSER

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Sabrina Argentieri

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FOR THE STATE OF CONNECTICUT

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By:

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GURBIR S. GREWAL
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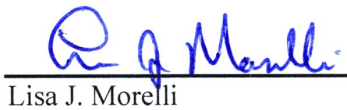

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FOR THE STATE OF NEW YORK

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FOR THE STATE OF RHODE ISLAND

PETER F. NERONHA
ATTORNEY GENERAL

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FOR NATURAL RESOURCES DEFENSE COUNCIL, INC.

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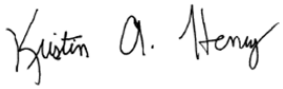
FOR SIERRA CLUB



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FOR OHIO CITIZEN ACTION, CITIZENS ACTION COALITION OF INDIANA, HOOSIER ENVIRONMENTAL COUNCIL, OHIO VALLEY ENVIRONMENTAL COALITION, WEST VIRGINIA ENVIRONMENTAL COUNCIL, CLEAN AIR COUNCIL, IZAAK WALTON LEAGUE OF AMERICA, ENVIRONMENT AMERICA, NATIONAL WILDLIFE FEDERATION, INDIANA WILDLIFE FEDERATION, AND LEAGUE OF OHIO SPORTSMEN

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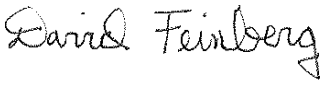
FOR THE AEP COMPANIES



David M. Feinberg
American Electric Power
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FOR GAVIN POWER LLC

William Lee Davis
Gavin Power, LLC
7397 N. St Rt #7
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American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_79 Please provide a copy of the Seller's Disclosure Letter.

RESPONSE

Please see Joint Exhibit 5 to the Application for the requested information.

Witness: Stephan T. Haynes

American Electric Power Company, Inc.
Kentucky Power Company
Liberty Utilities Co.
KPSC Case No. 2021-00481
KIUC's First Set of Data Requests
Dated January 13, 2022

DATA REQUEST

KIUC 1_80 Refer to the Stock Purchase Agreement at 4.16 Existing Debt Agreements; Senior Notes.

a. Indicate which of the Kentucky Power debt issuances are subject to so-called "make-whole" provisions.

i. Provide an estimate of the fees and make-whole costs that will be incurred by issue in live Excel format with all formulas intact if the debt must be pre-paid prior to its scheduled maturity.

ii. Indicate how Kentucky Power will record the fees and make-whole costs.

iii. Indicate whether Liberty will reimburse Kentucky Power for such fees and make whole costs.

iv. Confirm that Liberty will not seek recovery of such fees and make whole costs from customers if they are incurred.

b. Indicate which of the Kentucky Transco debt issuances are subject to so-called "make-whole" provisions.

i. Provide an estimate of the fees and make-whole costs that will be incurred by issue in live Excel format with all formulas intact if the debt must be pre-paid prior to its scheduled maturity.

ii. Indicate how Kentucky Transco will record the fees and make-whole costs.

iii. Indicate whether Liberty will reimburse Kentucky Transco for such fees and make whole costs.

iv. Confirm that Liberty will not seek recovery of such fees and make whole costs from Kentucky Power customers if they are incurred.

c. Provide an estimate of the fees to obtain the consent of the lenders pursuant to existing debt agreements and senior notes in live Excel format with all formulas intact for each of the acquired companies. Indicate how each of the acquired companies will record such fees, whether Liberty will reimburse them for the fees, and confirm that Liberty will not seek recovery of such fees from customers if they are incurred.

RESPONSE

a. The Kentucky Power debt issuances are not subject to so-called "make-whole" payments as a result of the consummation of the proposed acquisition of Kentucky

Power. It is not expected that Kentucky Power will incur any fees to obtain the consent, if any, of the lenders pursuant to existing debt agreements and senior notes.

b. The Joint Applicants object to this request on the basis that it seeks information that is outside the scope of this proceeding and that is neither relevant to this proceeding or calculated to lead to the discovery of admissible evidence. In support of this objection the Joint Applicants state that information concerning Kentucky Transco is not relevant to this proceeding as the transfer of Kentucky Transco is not at issue in this proceeding.

c. See the Joint Applicant's response to subpart (a) of this request.

Witness: Stephan T. Haynes