DUKE ENERGY.

Mailing Address:
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Cincinnati, Ohio 45202

o: 513-287-4320
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VIA OVERNIGHT DELIVERY

July 24, 2015

RECEIVED
JUL 27 2015
PUBLIC SERVICE
COMMISSION

Mr. Jeff Derouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard, P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: ***Case No. 2015-00187***
In the Matter of the Application of Duke Energy Kentucky, Inc., for an Order Approving the Establishment of a Regulatory Asset for the Liabilities Associated with Ash Pond Asset Retirement Obligations

Dear Mr. Derouen:

Enclosed please find an original and twelve copies of the *Responses of Duke Energy Kentucky, Inc. to Commission Staff's First Set of Requests for Information and Petition for Confidential Treatment,* for filing in the above referenced matter. The confidential information, to be filed under seal, is being provided in a white envelope.

Please date-stamp the two copies of the letter, petition and filing and return to me in the enclosed envelope.

Sincerely,

Rocco D'Ascenzo
Associate General Counsel
rocco.d'ascenzo@duke-energy.com

cc: Hon. Jennifer Hans

586968

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR AN ORDER APPROVING THE ESTABLISHMENT OF A REGULATORY ASSET FOR THE LIABILITIES ASSOCIATED WITH ASH POND ASSET RETIREMENT OBLIGATIONS	)	**CASE NO. 2015-00187**

DUKE ENERGY KENTUCKY, INC.'S

PETITION FOR THE CONFIDENTIAL TREATMENT OF CERTAIN INFORMATION CONTAINED IN ITS RESPONSES TO STAFF'S FIRST SET OF DATA REQUESTS

Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company), pursuant to 807 KAR 5:001, Section 13, respectfully requests the Commission to classify and protect certain information provided by Duke Energy Kentucky filed in response to STAFF-DR-01-001 and STAFF-DR-01-003. The information contained in STAFF-DR-01-001 CONF Attachment and Confidential STAFF-DR-01-003 Attachment (Attachments) which Duke Energy Kentucky now seeks confidential treatment (Confidential Information), includes forecasted projected costs.

In support of this Petition, Duke Energy Kentucky states:

1. The Kentucky Open Records Act exempts from disclosure certain commercial information. KRS 61.878(1)(c). To qualify for this exemption and, therefore, maintain the confidentiality of the information, a party must establish that disclosure of the commercial information would permit an unfair advantage to competitors of that

party. Public disclosure of the information identified herein would, in fact, prompt such a result for the reasons set forth below.

2. The information submitted and for which the Company is seeking confidential protection are the Attachments which contain Duke Energy Kentucky's proprietary forecasted projected costs. More specifically, Confidential Attachment to STAFF-DR-01-001 shows calculations of the expected cash flows and environmental costs to comply with Federal mandates, along with screen shots from the PowerPlan system of the various inputs for the fair value calculation. If made public, this information would provide economically valuable information that would give the Company's vendors and competitors a distinct commercial advantage. This information, if released publicly, would provide detailed cost estimates of what the Company is forecasting it will incur. This information could be used by potential counter parties to undermine the Company's efforts to reduce costs ultimately harming customers. Similarly, Confidential Attachment to STAFF-DR-01-003 provides detailed forecasts of costs and accounting adjustments decades into the future. This information, if released publicly, would provide competitors with detailed information regarding Duke Energy Kentucky's operations that they could then use to disadvantage the Company and its customers.

3. The Confidential Information is distributed within Duke Energy Kentucky, only to those who must have access for business reasons, and is generally recognized as confidential and proprietary in the energy industry.

4. The Confidential Information for which Duke Energy Kentucky is seeking confidential treatment is not known outside of Duke Energy Corporation.

5. Duke Energy Kentucky does not object to limited disclosure of the confidential information described herein, pursuant to an acceptable protective agreement, with the Attorney General or other intervenors with a legitimate interest in reviewing the same for the purpose of participating in this case.

6. This information was, and remains, integral to Duke Energy Kentucky's effective execution of business decisions. And such information is generally regarded as confidential or proprietary. Indeed, as the Kentucky Supreme Court has found, "information concerning the inner workings of a corporation is 'generally accepted as confidential or proprietary.'" Hoy v. Kentucky Industrial Revitalization Authority, 904 S.W.2d 766, 768 (Ky. 1995).

7. In accordance with the provisions of 807 KAR 5:001, Section 13(3), the Company is filing one copy of the Confidential Information separately under seal, and one copy without the confidential information included.

8. Duke Energy Kentucky respectfully requests that the Confidential Information be withheld from public disclosure for a period of ten years. This will assure that the Confidential Information – if disclosed after that time – will no longer be commercially sensitive so as to likely impair the interests of the Company or its customers if publicly disclosed.

9. To the extent the Confidential information becomes generally available to the public, whether through filings required by other agencies or otherwise, Duke Energy Kentucky will notify the Commission and have its confidential status removed, pursuant to 807 KAR 5:001 Section 13(10)(a).

WHEREFORE, Duke Energy Kentucky, Inc., respectfully requests that the Commission classify and protect as confidential the specific information described herein.

Respectfully submitted,

DUKE ENERGY KENTUCKY, INC.

Rocco D'Ascenzo (92796)
Associate General Counsel
Amy B. Spiller (85309)
Deputy General Counsel
139 East Fourth Street
1303 Main
Cincinnati, Ohio 45201-0960
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CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing filing was served on the following via overnight mail, this 24th day of July, 2015:

Kentucky Public Staff
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky, 40601

Rocco D'Ascenzo

VERIFICATION

STATE OF NORTH CAROLINA)
) SS:
COUNTY OF MECKLENBURG)

The undersigned, Cynthia S. Lee, being duly sworn, deposes and says that she is the Director of Asset Accounting, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of her knowledge, information and belief.

Cynthia S. Lee

Cynthia S. Lee, Affiant

Subscribed and sworn to me by Cynthia S. Lee on this 23rd day of July, 2015.

Kim V. Beal

NOTARY PUBLIC

My Commission expires: Oct. 24, 2019

KIM V BEAL
Notary Public
Catawba County
NORTH CAROLINA

VERIFICATION

STATE OF OHIO	**)**	
	)	**SS:**
COUNTY OF HAMILTON	**)**	

The undersigned, Peggy Laub, Director of Rates & Regulatory Planning, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing supplemental data request, and that the answers contained therein are true and correct to the best of her knowledge, information and belief.

Peggy Laub

Peggy Laub, Affiant

Subscribed and sworn to before me by Peggy Laub on this 21st day of July, 2015.

E. Minna Rolfes

NOTARY PUBLIC

My Commission Expires: 7/8/17

NOTARY PUBLIC ★ STATE OF OHIO ★

E. MINNA ROLFES
Notary Public, State of Ohio
My Commission Expires
July 8, 2017

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STAFF-DR-01-001 PUBLIC

REQUEST:

Refer to paragraph 7 of the Application regarding the quantification of the asset retirement obligation liability of approximately $116 million associated with the East Bend ash pond. Explain how Duke Kentucky arrived at this amount. Include any relevant work papers, spreadsheets, etc., showing the calculation of the $116 million.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)

The ARO liability of approximately $116 million for the East Bend ash pond was calculated in accordance with FASB ASC 410-20 *Asset Retirement and Environmental Obligations*. ASC 410-20 indicates that the initial measurement of an ARO liability should be made in the period in which it is incurred at fair value, which GAAP defines as "the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date." The fair value of an ARO is estimated by discounting expected cash flows using a credit-adjusted risk-free rate. The expected cash flows should include assumptions that a third party might use to assume the obligation, including inflation, overhead, profit margin, market-risk premium, probabilities of different timing of cash flows, cost contingencies, etc.

The expected cash flows for closure of the East Bend ash basin were developed with input from Duke Energy's Ash Basin Strategic Action Team (ABSAT) and Coal Combustion Products (CCP) Team. Preliminary scientific studies on the ash basin at East Bend indicate that the ash will most likely be excavated to an on-site landfill by 2021. Engineers in ABSAT and CCP provided information to Asset Accounting regarding the volume of ash to be excavated, the expected costs of closing the basin, building a lined on-site landfill, capping that landfill, and conducting post-closure maintenance.

To those estimated costs, Asset Accounting applied overheads and contingencies to arrive at estimated cash flows which are entered into the PowerPlan sub ledger system. In addition to the estimated cash flows, inflation rates, the credit-adjusted risk-free discount rate, and profit margin are entered into PowerPlan. PowerPlan uses these inputs to calculate and record the fair value of the ARO liability.

The file in STAFF-DR-01-001 CONF Attachment shows the calculation of the expected cash flows on the "East Bend" tab, along with screen shots from the PowerPlan system of the various inputs for the fair value calculation on the "PPLT Input" tab. This attachment has been filed with the Commission under a petition for confidential treatment.

PERSON RESPONSIBLE: Cynthia S. Lee

Duke Energy Kentucky
Case No. 2015-00187
Staff First Set Data Requests
Date Received: July 17, 2015

STAFF-DR-01-002

REQUEST:

Refer to paragraph 9 of the Application, specifically, the first full sentence on page 6. Concerning the mismatch of revenues and expenses discussed in the paragraph, explain how "revenues and expenses will be inflated and thus overstate financial performance." (Emphasis added)

RESPONSE:

Duke Energy Kentucky (DEK) requests deferral of the depreciation of the Asset Retirement Cost (ARC) and the accretion of the Asset Retirement Obligation (ARO) because depreciation and accretion expense must be recognized beginning May 2015. The deferral request allows DEK to defer the income statement impacts of the depreciation and accretion until such time that a recovery mechanism is approved. Without deferral authority, DEK's financial performance would be understated, due to the recording of these expenses without matching revenues. Conversely, DEK's financial performance may be overstated or inflated due to revenues potentially exceeding expenses in the future when a recovery mechanism is approved without matching expenses. DEK's preferred method would be to defer the impacts of the required ARO accounting to a regulatory asset, and then amortize the regulatory asset to expense in conjunction with revenues recovered through an approved recovery mechanism such as base rates. Thus, the deferral mechanism would allow DEK to match its revenue and expenses in each relevant accounting period.

PERSON RESPONSIBLE: Cynthia S. Lee

STAFF-DR-01-003 PUBLIC

REQUEST:

Refer to paragraph 9 of the Application and footnote 8 regarding the $35 million in accretion expense. Explain how this amount was derived. Include any relevant work papers, spreadsheets, etc., showing the calculation of the $35 million.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)

Accretion expense is calculated and recorded monthly by the PowerPlan sub-ledger system using the annual schedule of expected cash flows and annual discount rate. The $35 million of accretion expense was the total forecasted accretion expense for the East Bend ash pond ARO at the time of Duke Kentucky's Application. As additional information regarding estimated closure costs and timing is obtained, this forecasted accretion expense will change accordingly. See Confidential STAFF-DR-01-003 Attachment, which has been filed with the Commission under a petition for confidential treatment.

PERSON RESPONSIBLE: Cynthia S. Lee

Duke Energy Kentucky
Case No. 2015-00187
Staff First Set Data Requests
Date Received: July 17, 2015

STAFF-DR-01-004

REQUEST:

Refer to paragraph 9 of the Application regarding carrying costs associated with the proposed regulatory assets.

a. Identify the authority for the carrying charges associated with the proposed regulatory assets.

b. State when Duke Kentucky expects to incur actual costs, other than the $1.8 million mentioned in paragraph 10 of the application, with respect to the coal ash pond at East Bend. Provide a schedule showing the expected date and amount of the actual costs to be incurred.

c. Identify and describe what constitutes Duke Kentucky's carrying costs associated with the proposed regulatory asset.

d. Explain how Duke Kentucky determined, or intends to determine, the carrying costs associated with the proposed regulatory assets. Include any relevant work papers, spreadsheets, etc., showing the calculation of the carrying costs.

RESPONSE:

a. Pursuant to KRS 278.220, the system of accounts established by the Commission for keeping by the Company must conform as nearly as practicable to the system adopted by the Federal Energy Regulatory Commission (FERC). Relevant precedent from FERC reflects the fact that jurisdictional utilities are regularly authorized to accrue a carrying charge on a regulatory asset until the regulatory asset is included in rate base. *See, e.g.*, *Green Power Express LP*, 127 F.E.R.C. ¶ 61,031 (April 10, 2009); *MidAmerican Transco Central California Transco, LLC*, 147 F.E.R.C. ¶ 61,179 (June 3, 2014). See STAFF-DR-01-004a Attachment 1 and Attachment 2. Such an accrual is appropriate because the subject costs are necessarily incurred by the Company and, like the ARO-related liabilities associated with the East Bend ash pond, are expenses resulting from a statutory or administrative directive. *See In the Matter of the Application of East Kentucky Power Cooperative, Inc. for an Order Approving Accounting Practices to Establish a Regulatory Asset Related to Certain Replacement Power Costs Resulting from Generation Forced Outages*, Final Order, Case No. 2008-00436 (Ky. P.S.C., Dec. 23, 2008); *In the Matter of the Application of Louisville Gas and Electric Company for an Order Approving the Establishment of a Regulatory Asset,* Final Order, Case No. 2008-00456 (Ky. P.S.C., Dec. 22, 2008); *In the Matter of the Application of Kentucky Utilities Company for an Order Approving the Establishment of a Regulatory Asset,* Final Order, Case No. 2008-00457 (Ky. P.S.C., Dec. 22, 2008); *In the matter of the Joint Application of Duke Energy Kentucky, Inc., Kentucky Power Company, Kentucky Utilities Company and Louisville Gas and Electric Company for an Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities Related to Certain Payments Made to the Carbon Management Research Group and the Kentucky Consortium for*

Carbon Storage, Final Order, Case No. 2008-00308 (Ky. P.S.C., Oct. 30, 2008); *In the Matter of the Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for an Order Approving Proposed Deferred Debits and Declaring the Amortization of the Deferred Debits to be Included in Earnings Sharing Mechanism Calculations,* Final Order, Case No. 2001-00169 (Ky. P.S.C., Dec. 3, 2001). While Duke Energy Kentucky is unaware of any Kentucky Public Service Commission precedent which squarely addresses this issue, guidance from FERC and prudent accounting principles support the inclusion of carrying costs as part of the subject regulatory asset until the Commission determines whether the deferred costs are recoverable.

Notably, the carrying costs associated with the regulatory asset are not recovered elsewhere by the Company; moreover, if the regulatory asset is added to rate base as part of the Company's revenue requirement, the Company will earn a return on the unamortized balance of the regulatory asset and, therefore, will stop accruing carrying charges on the regulatory asset. *See, e.g.*, 127 F.E.R.C. ¶ 61,031, *supra*. The availability and method of recovery for these deferred expenses, like all costs that are included in a properly-established regulatory asset, will be determined in a future proceeding and are not issues presently before the Commission.

b. Yes, Duke Energy Kentucky currently expects to incur costs of $107.7 million from 2015-2051 related to closure of the ash pond at East Bend. The current expected annual cash flows (in 2015 dollars) are shown in row 40 of the "East

Bend" tab of the file attached in response to Confidential STAFF-DR-01-001. These amounts will continue to be revised as additional information regarding estimated closure costs and timing is obtained. As noted throughout Duke Energy Kentucky's Application, many factors can change these estimates. Duke Energy Kentucky's proposal is to record actual amounts spent to Account 182.3 Other Regulatory Assets ("CCR Compliance Regulatory Asset") for future recovery in retail rates.

c. Duke Energy Kentucky's (DEK) carrying charge is equivalent to its annual weighted average cost of capital (WACC), calculated similar to its allowance for funds used in construction (AFUDC) rate. This WACC rate is calculated based on DEK's capital structure including short and long-term debt and equity. The calculation is based on the FERC formula to derive AFUDC rates and is updated monthly and converted from an annual to a monthly rate.

d. The carrying costs will be calculated using the WACC described in 4.c. and recorded monthly on the unamortized balance of the CCR Compliance Regulatory asset. The CCR Compliance Regulatory Asset will represent only cash expended to satisfy the ARO liability related to closing the ash basin at East Bend and the carrying costs recorded. The calculation is: Unamortized CCR Compliance Regulatory Asset balance * Monthly WACC rate = carrying charge. This amount will be debited to the CCR Compliance Regulatory Asset (182.3) and credited to interest income for the equity portion (419) and miscellaneous interest expense (432) for the debt portion.

PERSON RESPONSIBLE: a. Legal b. Cynthia S. Lee
c. Cynthia S. Lee d. Cynthia S. Lee

127 FERC ¶ 61,031
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Suedeen G. Kelly, Marc Spitzer,
and Philip D. Moeller.

Green Power Express LP Docket No. ER09-681-000

ORDER ON TRANSMISSION RATE INCENTIVES
AND FORMULA RATE PROPOSAL AND
ESTABLISHING HEARING AND SETTLEMENT JUDGE PROCEDURES

(Issued April 10, 2009)

1. On February 9, 2009, Green Power Express LP (Green Power) filed, under sections 205 and 219 of the Federal Power Act (FPA),[1] a request for approval of various transmission infrastructure investment incentives,[2] certain accounting treatments, and new *pro forma* tariff sheets that include a formula rate for transmission service. Green Power's request concerns its proposal to build a series of 765 kV transmission lines in the Midwest. In this order, we conditionally grant Green Power's request for transmission rate incentives, effective on the dates requested, and accept the *pro forma* tariff sheets for filing subject to hearing and settlement judge procedures, as set forth below.

I. Background

A. Description of Green Power

2. Green Power is a transmission-only limited partnership formed by ITC Holdings Corp. (ITC Holdings) under Delaware law. Green Power is a wholly-owned subsidiary of ITC Green Power Express, LLC, a Michigan limited liability company. ITC Green Power Express, LLC, in turn, is wholly-owned by ITC Holdings.

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[1] 16 U.S.C. §§ 824d; 824s (2006).

[2] *See Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

3. ITC Holdings is a publicly traded, Michigan-based corporation. It is currently the nation's largest independent electric transmission company that, through its subsidiaries, International Transmission Company (International Transmission), Michigan Electric Transmission Company, LLC (METC), and ITC Midwest LLC (ITC Midwest), operates transmission systems in Illinois, Iowa, Michigan, Minnesota, and Missouri. ITC Holdings also has formed ITC Great Plains to serve as a transmission builder, owner and operator in the Southwest Power Pool, Inc. (SPP) region.[3]

B. The Green Power Express Transmission Proposal

4. Green Power proposes to build the Green Power Express Project (Project), which it describes as a 765 kV green power "superhighway" transmission network that will eventually include approximately 3,000 miles of transmission lines and bring up to 12,000 MW of wind energy and stored energy from the Dakotas, Minnesota, and Iowa to Midwest load centers in Chicago, southeastern Wisconsin and Minneapolis. Green Power estimates the proposed Project will cost between $10-$12 billion, depending on its final scope and route. As proposed, the Project will consist of three interconnected loops in North and South Dakota, Minnesota, and Iowa, with extensions from these loops into Wisconsin, Illinois and Indiana. The Project would interconnect with existing substations in North Dakota, South Dakota, Indiana, Minnesota, Wisconsin, Iowa, and Illinois, and with new high-voltage backbone transmission substations to be constructed in Iowa and North Dakota. There would also be interconnections with existing lower voltage transmission facilities, which Green Power states will provide capacity to support additional improvements. The initial phase of the Project is expected to be in service in 2020.

5. Green Power states that the Project will provide various and significant benefits both on a stand-alone basis and as a component of the coordinated development of a nationwide high-voltage backbone transmission system. The Project will also create considerable economic and environmental benefits. The Project will support environmental and policy objectives reflected in proposals to adopt a national renewable portfolio standard while at the same time enhancing competitive regional electric markets by increasing supply alternatives and decreasing congestion on existing facilities.

6. Green Power asserts that the Project will facilitate the interconnection of various renewable energy projects, relieving existing and reasonably foreseeable congestion over a large portion of the upper Midwest. Green Power also believes the Project will improve reliability because the impacts of localized weather on wind generation will be spread more widely. Green Power states that a solid transmission backbone will handle unpredicted energy flows across the system, thus reducing the prospect for outages and

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[3] *See ITC Great Plains, LLC*, 126 FERC ¶ 61,223 (2009).

blackouts. Green Power also contends that, relative to other methods of moving power out of wind-rich areas of the upper Midwest, the Project will unload existing underlying lower-voltage networks, thereby providing additional operating flexibility, increasing reliability, reducing transmission losses, relieving transmission congestion, and allowing lower-cost energy to be delivered to load. According to Green Power, the Project will also use an open architecture design that is suitable to support energy storage devices, allowing them to help mitigate intermittency issues associated with wind energy generation.

7. Green Power requests the following transmission infrastructure incentives for the Project: (1) recovery of costs of abandoned facilities; (2) deferred recovery for start-up, development and pre-construction costs through the creation of regulatory assets; (3) 100 percent construction work in progress (CWIP) in rate base; (4) a hypothetical capital structure of 60 percent equity and 40 percent debt; and (5) a 160 basis point incentive Return on Equity (ROE) adder (50 basis points for participating in a Regional Transmission Organization (RTO), 100 basis points for independence, and 10 basis points for the risks and challenges of the Project).

8. Green Power requests an overall ROE of 12.38 percent, inclusive of the 160 basis point incentive adders. Green Power supports its request with a Discounted Cash Flow (DCF) analysis with a median ROE of 10.78 percent. In addition, Green Power requests that the Commission accept for filing a formula rate structure under which the costs of the Project will ultimately be recoverable through the applicable open access transmission tariffs of Midwest Independent Transmission System Operator, Inc. (Midwest ISO) and PJM Interconnection, L.L.C. (PJM).

9. While a final decision is still subject to further study and final engineering, Green Power states that it intends to utilize several types of advanced technologies on the Project. Green Power intends to utilize a six conductor bundle design, phase and shield wire transposition, fiber optics shield wire, wide-area monitoring and control, remote station equipment diagnostics, switchable shunt reactors, and either a static VAR compensator or a static synchronous compensator. Green Power is not requesting any additional incentives for the use of these advanced technologies.

II. Notice of Filings and Responsive Pleadings

10. Notice of Green Power's filing was published in the *Federal Register*, 74 Fed. Reg. 7882, with interventions and comments due on or before March 9, 2009. On February 24, 2009, Xcel, Otter Tail and Great River filed a motion for extension of time to file comments. On February 25, 2009, Allete, Inc. filed a motion to intervene and request for extension of time. On February 26, 2009, the Commission issued a notice extending the comment period until March 6, 2009.

11. Numerous parties filed timely motions to intervene or motions to intervene with comments and/or protests. In addition, several parties filed untimely motions to intervene or untimely motions to intervene with comments and/or protests. A full listing of those parties is set forth in Attachment A.

12. On March 13, 2009, Midwest ISO filed an answer to various comments and protests. On March 23, 2009, Green Power filed an answer to the comments and protests. CAPX2020 Participants and Great River (on April 3, 2009), Xcel (on April 7, 2009) and Integrys (on April 8, 2009) filed answers to Green Power's answer.

III. Discussion

A. Procedural Matters

13. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[4] the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure,[5] the Commission will grant the late-filed motions to intervene given the parties' interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.[6]

14. Rule 213(a) of the Commission's Rules of Practice and Procedure[7] prohibits an answer to a protest or an answer to an answer, unless otherwise permitted by the decisional authority. We will accept Midwest ISO's and Green Power's answers because they have provided information that assisted us in our decision-making process. We are not persuaded to accept the answers of CAPX2020 Participants, Great River, Xcel and Integrys and, therefore, reject them.

B. Section 219 and Order No. 679 Incentives

1. Section 219 Requirements

15. In the Energy Policy Act of 2005,[8] Congress added section 219 to the FPA and directed the Commission to establish rules providing incentives to promote capital

[4] 18 C.F.R. § 385.214 (2008).

[5] *Id.* § 385.214(d).

[6] The parties that submitted late-filed interventions are listed on Appendix A.

[7] 18 C.F.R. § 385.213(a)(2) (2008).

[8] Pub. L. No. 109-58 § 1241 (2005), 119 Stat. 594.

investment in transmission infrastructure. The Commission subsequently issued Order No. 679, setting forth processes by which a public utility may seek transmission rate incentives pursuant to section 219, such as the incentives requested here by Green Power.

16. Pursuant to section 219, an applicant must show that "the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion."[9] Also, as part of this demonstration, "section 219(d) provides that all rates approved under the Rule are subject to the requirements of sections 205 and 206 of the FPA, which require that all rates, charges, terms and conditions be just and reasonable and not unduly discriminatory or preferential."[10]

17. Order No. 679 provides that a public utility may file a petition for declaratory order or a section 205 filing to obtain incentive rate treatment for transmission infrastructure investment that satisfies the requirements of section 219 (i.e., the applicant must demonstrate that the facilities for which it seeks incentives either ensure reliability and/or reduce the cost of delivered power by reducing transmission congestion).[11] Order No. 679 established a process for an applicant to follow to demonstrate that it meets this standard, including a rebuttable presumption that the standard is met if: (1) the transmission project results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission; or (2) the transmission project has received construction approval from an appropriate state commission or state siting authority.[12] Order No. 679-A clarifies the operation of this rebuttable presumption by noting that the authorities and/or processes on which it is based (i.e., a regional planning process, a state commission, or siting authority) must, in fact, consider whether the project ensures reliability or reduces the cost of delivered power by reducing congestion.[13]

a. <u>Green Power Proposal</u>

18. Green Power acknowledges that it does not meet the rebuttable presumption under Order No. 679 but believes that it provides enough evidence for the Commission to make a finding under section 219. Green Power states that there is a great need for its proposed 765 kV transmission network. It notes that there is currently 62.8 GW of proposed wind

[9] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 76.

[10] *Id.* P 8 (citing 16 U.S.C. §§ 824(d) and 824(e) (2006)).

[11] 18 C.F.R. § 35.35(i) (2008).

[12] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 58.

[13] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 49.

capacity in the Midwest ISO interconnection queue.[14] It states that the current transmission grid in the Midwest simply cannot handle transmission of substantial amounts of wind energy. Green Power argues that the Project is the best option available versus other options it studied.

19. In support of its claim that it meets the requirements of section 219, Green Power submitted a study that examined a number of alternatives such as an "ad hoc" build up, a single 345 kV build up, and a double 345 kV build up against the Project. As part of its study, Green Power performed a transfer analysis that considered several factors including: (1) examination of the ability of the transmission system to transfer incremental wind generation from Minnesota, Iowa, and the Dakotas to load centers; (2) a programmatic build up of the existing transmission system to estimate the upgrades that may be necessary to integrate an additional 12,000 MW of wind energy; and (3) a boundary analysis of the amount of capacity currently in place to move power away from wind rich areas.[15] From this study, Green Power found its proposed Project to be the best choice among the options it considered.

20. Green Power argues that its study shows that that the Project will reduce congestion because: (1) the Project will be able to transfer the largest amount of power with the least impact on the underlying system;[16] (2) when wind is not at maximum generation, the Project will be able to facilitate long distance transfers at low impedances; (3) the Project will provide additional transfer capacity of 12,000 MW to serve some of the approximately 62 GW of proposed wind generation currently in the Midwest ISO interconnection queue; and (4) the Project will alleviate operating constraints on the underlying network. Green Power argues that the Project is the best solution available to reduce congestion and ensure reliability as large amounts of wind generation are installed in the region.[17]

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[14] Green Power February 9, 2009 Transmittal Letter at 18 (Transmittal Letter) (citing Midwest ISO Transmission Expansion Plan for 2008 (MTEP08) at 54).

[15] Vitez Test. at 19-20, Exhibit No. GPE-500.

[16] 5,000 MW was modeled flowing across the 345 kV test build-up, the double 345 kV test build-up, and the Project. In the Project case, only 7.5 percent of power was found to flow on the underlying facilities, whereas in the 345 kV and double 345 kV cases, the amount of power that flowed on the underlying facilities was found to be 67.1 percent and 42.5 percent, respectively (Vitez Test. at 39-39, Exhibit No. GPE-500).

[17] Vitez Test. at 17-20, Exhibit No. GPE-500.

21. Green Power states that the Project ensures reliability because: (1) the AC network design of the Project provides system redundancy and the ability to redirect power flows;[18] (2) the Project will provide a robust transmission backbone capable of handling unexpected energy flows across the system, which greatly reduces the probability for cascading outages and blackouts;[19] and (3) the Project will need the least reactive power support of the options considered.[20]

22. While Green Power acknowledges that the Project has not been approved by a regional planning process or by a state regulatory commission, Green Power asserts that the Project nevertheless meets the requirements of section 219 and Order No. 679 and should be granted incentives. Green Power further emphasizes that it is submitting its application now because the Project is consistent with regional planning goals as well as state and national planning and policy objectives. Green Power believes that the absence of market participant influence was critical in developing the right solution that improves electric reliability, effectively and efficiently integrates high amounts of renewable energy capacity to promote a cleaner environment and enhances national security. Green Power argues that it is, in effect, filling a gap that exists within the industry due to a lack of independent regional planning.[21]

23. Green Power believes that the Project falls outside any current planning process because the Project lies within or connects with facilities in Midwest ISO, PJM and the non-RTO area of the Mid-Continent Area Power Pool (MAPP) and because the Project promotes economic and environmental benefits beyond those currently considered in the RTOs' planning processes. However, Green Power acknowledges that unless a broader one-stop planning process is developed, the Project will need to be considered in the existing regional planning processes of Midwest ISO, PJM, and individual transmission owners within MAPP.[22] Green Power confirms that it will also need approvals and siting authorizations in various combinations from seven states: North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Illinois, and Indiana.[23]

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[18] Transmittal Letter at 22-23.

[19] *Id.* at 19.

[20] *Id.* at 28-31.

[21] Welch Test. at 16:17-22, Exhibit No. GPE-100.

[22] Transmittal Letter at 11 and 49.

[23] *Id.* at 11, 36 and 49.

24. Although it commits that the Project will be evaluated through a Commission-approved regional planning process that is appropriate for the Project,[24] Green Power believes the processes that now exist will not allow for approval of the Project. For example, Green Power states that Midwest ISO has recognized that the criteria in Midwest ISO's current planning processes fail to properly evaluate the true benefits of a large-scale expansion such as the Project.[25] Green Power also notes that no project has qualified under the 3:1 benefit/cost ratio requirement under Midwest ISO's planning process for economic upgrades.[26] Green Power argues that under this unreasonable benefit/cost criteria, this Project or any other significant high voltage facility cannot reasonably be approved. Green Power also points out that Midwest ISO and PJM specifically state in their recent cost allocation proposal for economic cross-border projects that a project that is primarily designed to allow renewable generation facilities to serve load in the RTOs pursuant to any renewable portfolio standards, such as high voltage backbone transmission overlays, will likely not qualify as an economic cross-border project.[27]

25. Green Power believes the Project will require unprecedented cooperation and the development of a new inter-regional planning process. Although Green Power states that the creation of such a process is outside the scope of this proceeding, it believes that the Commission has authority under section 209 of the FPA to implement a coordinated

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[24] *Id.* at 63 and 72.

[25] *Id.* at 67 (citing MTEP08 at 24 (stating that large-scale projects provide widespread benefits beyond the market efficiency metrics currently reflected in the economic Regional Expansion Criteria and Benefits (RECB) criteria)).

[26] To qualify for regional cost allocation within Midwest ISO, a Regionally Beneficial (i.e., economic) Project must meet general and project specific financial and operational requirements. Generally, to qualify for regional cost sharing, a Regionally Beneficial Project must: (1) cost more than $5 million; (2) involve facilities with voltages of 345 kV or more; and (3) not be a Baseline Reliability Project or New Transmission Access Project. In addition to the general requirements, the proposed project must meet tests relating to Adjusted Production Cost Benefits, Locational Marginal Pricing based energy cost benefits and a variable Benefits to Cost Ratio threshold that varies linearly from 1.2 to 1 (for projects with an in-service date within one year of the project's MTEP approval date) to 3.0 to 1 (for projects with an in-service date ten or more years from the projects MTEP approval date). *See, e.g., Midwest Indep. Transmission Sys. Operator, Inc.*, 120 FERC ¶ 61,080, at P 4-6 (2007).

[27] Transmittal Letter at 67 and 73, n.192 (citing Midwest ISO and PJM's January 28, 2009 Joint Compliance Filing, Docket No. ER05-6-108 at 6).

regional effort to evaluate the Project. Specifically, under section 209, the Commission may refer any matter under its jurisdiction to a board, which could be comprised of members of each affected state for a particular project. Such boards have the authority to hold hearings and shall be "vested with the same power and be subject to the same duties and liabilities as in the case of a member of the Commission . . . ."[28] Further, this statutory authority provides the Commission the right to confer with any state commission "regarding the relationship between rate structures, costs, accounts, charges, practices, classifications, and regulations of public utilities subject to the jurisdiction of such State commission."[29] Green Power is not requesting a joint board but states that the Commission should consider all the means within its statutory authority to facilitate federal-state cooperation with respect to the proposed Project.

b. Comments and Protests

26. The vast majority of entities that filed protests argue that Green Power's filing is premature because Green Power developed the Project outside of a Commission-approved transmission planning process. They argue that Green Power did not notify, let alone coordinate with, even those transmission owners through whose territory the Project would cross or to whom the Project would interconnect. They add that there is no evidence that Green Power held any planning meetings as it developed the Project or that it solicited any stakeholder input. As such, the impact of the Project on the region, including, for example, on lower voltage facilities and the comparative benefits of possible competing proposals, is unknown. They assert that the Commission should defer acting on or reject as premature the proposal due to Green Power's lack of effort to seek consensus or regional support through any coordinated planning process.

27. Many protesters acknowledge that the Commission has previously found that incentive proposals for projects that had not yet been approved in a Commission-approved regional planning process still can meet the section 219 requirements, such as in *Tallgrass*[30] and *PG&E*.[31] These commenters argue, however, that the situation here is distinguishable from those cases. They contend that the applicants in *Tallgrass* and *PG&E* demonstrated that their proposed projects were similar to those that had been suggested by regional planning bodies, while Green Power makes no such showing here.

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[28] 16 U.S.C. § 824h(a) (2006).

[29] *Id.* § 824h(b).

[30] *Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248 (2008) (*Tallgrass*).

[31] *Pacific Gas and Elec. Co.*, 123 FERC ¶ 61,067 (2008) (*PG&E*).

28. Some protesters argue that Commission approval of Green Power's "project first, plan later" approach may have unintended consequences. For example, CapX2020 Participants and Great River believe that such a process could lead to a situation where a number of transmission owners engage in autonomous transmission planning and incur considerable development costs, only to have a subsequent regional planning process determine that a project is not reasonable and/or appropriate. If such developers are granted cost recovery without regard to transmission planning, developers may have little incentive to participate in regional planning on the front end, leading to situations where the market incurs costs for transmission projects that may have little merit when balanced against regional objectives and needs.

29. Several protesters also state that because Green Power planned the Project in isolation, they do not have sufficient information to take a position on the merits of the Project or whether incentives are justified. While commenters generally support the addition of transmission improvements to support increased use of renewable energy and to ensure reliability of the overall transmission system, some argue that the proposed Project is little more than a concept that does not warrant incentives at this stage of its development. Since the Project has not been subject to any transmission planning process, some parties argue that whether or not the Project will pass a reliability scrutiny or whether it contains the most advantageous economic facilities is unclear. Therefore, they argue that the Commission should defer acting on Green Power's filing or reject it without prejudice to give Green Power the opportunity to have the Project evaluated as part of the on-going planning processes and regional planning initiatives.

30. Many protesters also disagree with Green Power's assertion that the Commission needs to create a new regional planning process, using the Commission's authority under section 209 of the FPA or otherwise to evaluate the Project. If the Commission does find a new regional planning process is needed to handle expansion proposals such as the Project, the Commission should not create a new planning process to support a single project proposed by one entity. Furthermore, several commenters assert that Green Power has chosen to side-step several important regional planning initiatives, some of which Green Power mentions and others it does not. As such, Green Power's proposal is not informed by, nor coordinated with, any of these on-going planning initiatives.

31. In addition, some protesters argue that Green Power has not produced sufficient evidence to meet the section 219 requirement. They do not believe that the Commission can tell whether the Project will ensure reliability or reduce the cost of delivered power by reducing congestion. Consumers Energy states that while it does not disagree that the current grid is wholly inadequate to carry the proposed wind generation, it is not clear whether Green Power is an adequate solution. As such, Consumers Energy asks the Commission to set the Project for hearing to determine if the Project meets the section 219 requirements.

32. Several parties submitted comments in support of Green Power's proposal. These supporting commenters note that a significant challenge currently facing renewable energy involves the proximity of the resources to transmission facilities. These parties therefore support the idea of a green power "superhighway" to move much-needed wind power from the areas in which it is abundant to load centers in the Midwest. They suggest that, absent proper signals from the Commission, projects such as the one Green Power proposes will not get built, and wind energy will continue to be "stranded." National Wind describes the Project as a critical infrastructure upgrade to address a deficiency in transmission capacity, and other parties note the inherent challenges in building a project that crosses both state and RTO borders.

33. Some supporting commenters note that this Project would help meet renewable portfolio standards on both the state and national level. National Wind states, for example, that conservative estimates suggest that the country would need at least 150,000 MW of new renewable energy generation in the next 10 years to meet a 20 percent national renewable portfolio standard, if such a national standard becomes a priority. With 12,000 MW of clean energy, National Wind argues that the Project must be built and expedited. In addition, Denali Energy Partners state that high-capacity lines minimize environmental impacts and are more cost-efficient to construct than lower-voltage lines.

34. RES Americas states that Green Power offers a compelling solution to the challenges Midwest ISO faces with respect to managing the interconnection queue, long-range transmission planning, and the cost allocation process. It notes that the Commission should compare the scale and benefits of this Project with comparable project initiatives set forth by the Upper Midwest Transmission Development Initiative, Regional Generation Outlet Study and Joint Coordinated System Plan. RES Americas notes that the evaluation criteria should include the likelihood of project success, the breadth of customer benefit across regions, and the efficiency of the voltage level proposed. It believes that the Project meets all of these criteria and will provide benefits to the greatest number of customers.

35. Denali Energy Partners state that, despite having the capability to generate over 10,000 MW of clean, reliable power, their efforts are being stalled due to what they describe as the antiquated approval and permitting process. They contend that the roadblock is the lack of transmission lines necessary to move their power to markets such as Chicago. They ask the Commission to expedite the siting and approval process and to continue with the Commission's recent rate structure approvals for similar transmission projects. Denali Energy Partners also recommend that the Commission consider modeling "superhighway" transmission line approvals after the process used to expand natural gas pipelines.

36. In addition, Wind Capital Group states that it believes that a mix of private capital and public funding provides the best path to a successful expansion of the transmission

system. National Wind states that approving the proposed rate treatment will allow it to raise capital and bring additional parties into the process to most efficiently and effectively bring the Project to fruition.

37. In its answer, Midwest ISO takes no position on the disputes between Green Power and commenters but states that commenters are incorrect to the extent they believe that the Project is being planned outside the Midwest ISO planning process. Midwest ISO states that Green Power has introduced the Project into the Midwest ISO planning process, and the Project is currently being evaluated. In particular, Midwest ISO states that the proposed Project is an appropriate alternative expansion proposal to be considered in its Regional Generation Outlet Study, which is currently in progress in the present planning cycle and that has been underway since early 2008. Midwest ISO also notes that the presence or absence of a rate and/or accounting treatment proceeding at the Commission has not been a factor in determining how Midwest ISO has responded to requests for it to evaluate transmission expansion proposals. In addition, Midwest ISO states that the Project, while not identical, aligns well with elements of the preliminary high voltage overlay proposals that Midwest ISO and other Eastern Interconnection participants studied and reported upon in the recently published Joint Coordinated System Plan.

c. Commission Determination

38. We find that Green Power has adequately demonstrated that the Project will ensure reliability and/or reduce the cost of delivered power by reducing transmission congestion and, thus, meets the requirements of section 219. Based on Green Power's analysis of the existing transmission system in the region, taking into consideration the existing renewable portfolio standards in various states, the amount of generation in Midwest ISO's generation interconnection queue, and future renewable generation expansion scenarios, it established a target of improving transfer capability in the region by approximately 12,000 MW. Green Power then focused on the need for transmission investment to accommodate wind generation in the Dakotas, western Minnesota and western Iowa because these regions have abundant, high quality wind resources.[32]

39. In particular, Green Power notes that Midwest ISO has over 62,000 MW of renewable generation in its active queue.[33] In addition, we note that Midwest ISO estimates that it will need approximately 25,000 MW of renewable generation in its footprint in the next 10 to 15 years to comply with current renewable portfolio standards

[32] Vitez Test. at 8-10, Exhibit No. GPE-500.

[33] Transmittal Letter at 18 (citing MTEP08 at 55).

in the region.[34] Furthermore, many of the wind generation projects in Midwest ISO's generation interconnection queue are located in the areas where Green Power plans to build the Project.[35] Green Power and the many commenters agree that without a substantial increase in transmission infrastructure it will not be possible to move the energy from the proposed renewable generation sources. Additionally, the 2006 Department of Energy (DOE) Congestion Report identified several paths in the proposed Project area as either among the most congested in the Nation or as conditionally constrained.[36]

40. Green Power's analysis demonstrates that its proposed 765 kV Project will provide a robust transmission backbone that could handle unexpected energy flows across the system, reducing the probability for cascading outages and blackouts.[37] Moreover, Green Power states that the Project will unload existing underlying lower-voltage networks, thereby providing additional operating flexibility, increasing reliability, reducing transmission losses, relieving transmission congestion, and allowing lower-cost energy to be delivered to load.[38] Additionally, the Project will improve reliability because the impacts of localized weather on wind generation will be spread more extensively.

41. The Commission finds that Green Power has made an adequate showing to satisfy the requirements of section 219. Green Power has submitted detailed studies and an engineering affidavit that shows that the Project will: (1) reduce congestion in the future

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[34] *See* Midwest ISO, Proposal for Identification of and Subscription to Forward Looking Interconnection Projects (February 6, 2009) at P 10, *available at* http://www.midwestmarket.org/publish/Document/20b78d_11ef44fc9c0_-7bfb0a48324a/Midwest%20ISO%20Draft%20FLIP%20Whitepaper%20v2%20020609%20clean.pdf?action=download&_property=Attachment.

[35] *See* Exhibit No. GPE-505.

[36] *See* DOE, National Electric Congestion Study (August 2006) (DOE 2006 Congestion Study) at page IX *available at* http://www.oe.energy.gov/DocumentsandMedia/Congestion_Study_2006-9MB.pdf. A conditionally constrained area is one in which some transmission congestion currently exists but significant congestion would result if large amounts of new generation resources were developed without simultaneous development of associated transmission.

[37] *See* Transmittal Letter at 16.

[38] *See* Vitez Test. at 38-40, Exhibit No. GPE-500.

by facilitating integration and delivery of low-cost wind energy in the upper Midwest;[39] (2) ensure reliability by providing a robust transmission backbone that is capable of moving large amounts of power and handling unscheduled flows;[40] and (3) improve the voltage profile of underlying lower voltage networks.[41] Further, the 765 kV and looped nature of the project will help to ensure reliability by making the proposed lines and underlying networks less susceptible to outages.[42] Additionally, the Project will also likely reduce congestion on several of the congested paths identified by the DOE as the Project will expand the transfer capacity of paths in those areas.[43]

42. We disagree with commenters that believe Green Power's filing is premature. Although Green Power acknowledges that the Project will have to be evaluated through a Commission-approved transmission planning process, such evaluation is not a prerequisite to the Commission granting incentives. As the Commission has previously found, ruling on a request for incentives pursuant to Order No. 679 does not prejudge the findings of a particular transmission planning process or the siting procedures at state commissions.[44] Midwest ISO confirms that Green Power has submitted the Project into Midwest ISO's Commission-approved planning process and that any Commission action on Green Power's incentive request will not change how Midwest ISO evaluates the Project. Similarly, any finding on Green Power's request for incentives will not change how projects are considered under existing regional transmission planning initiatives nor have an impact on projects, such as those proposed by the CapX2020 Participants, that have already been incorporated into a transmission provider's expansion plans.

43. We also agree with Green Power that the creation of a new planning process is outside the scope of this proceeding. We note, however, that the Commission remains interested in and is examining the adequacy of transmission planning processes. For example, the Commission recently held what is expected to be the first in a series of technical conferences seeking information on the challenges posed by integration of large amounts of variable renewable generation into wholesale markets and grids as well as on

[39] *See Id.* at 39-40.

[40] *See Id.* at 12, 19, 21, 39-40.

[41] *See Id.* at 31-32.

[42] *See Id.* at 12-13; *See also* Transmittal Letter at 16.

[43] *See* DOE 2006 Congestion Study at 23.

[44] *See Pioneer Transmission, LLC*, 126 FERC ¶ 61,281, at 40 (2009) (*Pioneer*); *Tallgrass*, 125 FERC ¶ 61,248 at 43.

innovative solutions to these challenges.[45] In addition, we expect to convene a series of regional public technical conferences later this year to determine the progress and benefits realized by each transmission provider's Order No. 890 Attachment K transmission planning process, obtain customer and other stakeholder input, and discuss any areas that may need improvement.

2. The Nexus Requirement

44. In addition to satisfying the section 219 requirement of ensuring reliability and/or reducing the cost of delivered power by reducing congestion, an applicant must demonstrate that there is a nexus between the incentive sought and the investment being made. In Order No. 679-A, the Commission clarified that the nexus test is met when an applicant demonstrates that the total package of incentives requested is "tailored to address the demonstrable risks or challenges faced by the applicant."[46] The Commission noted that this nexus test is fact-specific and requires the Commission to review each application on a case-by-case basis.

45. As part of this evaluation, the Commission has found the question of whether a project is "routine" to be particularly probative.[47] In *BG&E*, the Commission clarified how it will evaluate projects to determine whether they are routine. Specifically, to determine whether a project is routine, the Commission will consider all relevant factors presented by an applicant. For example, an applicant may present evidence on: (1) the scope of the project (e.g., dollar investment, increase in transfer capability, involvement of multiple entities or jurisdictions, size, effect on region); (2) the effect of the project (e.g., improving reliability or reducing congestion costs); and (3) the challenges or risks

[45] March 2, 2009 Technical Conference on Integrating Renewable Resources Into the Wholesale Electric Grid, Docket No. AD09-4-000 (Integrating Renewables Tech Conference). We note that some participants in that conference raised issues about existing planning processes similar to those expressed here by Green Power. *See, e.g.*, Integrating Renewables Tech Conference Speaker Materials of Michael J. Kormos, Senior Vice President of Operations for PJM at 15 ("[W]e propose that the Commission initiate a rulemaking to evaluate whether current transmission protocols and cost allocation methodologies should be reassessed to include transmission projects such as those associated with the large scale of integration of renewable and other energy resources.").

[46] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 40.

[47] *Baltimore Gas and Elec. Co.*, 120 FERC ¶ 61,084, at P 48 (2007) (*BG&E*), 121 FERC ¶ 61,167, *reh'g denied*, 122 FERC ¶ 61,034 (2007), *reh'g denied*, 123 FERC ¶ 61,262 (2008).

faced by the project (e.g., siting, internal competition for financing with other projects, long lead times, regulatory and political risks, specific financing challenges, other impediments).[48] Additionally, the Commission clarified that "when an applicant has adequately demonstrated that the project for which it requests an incentive is not routine, that applicant has, for purposes of the nexus test, shown that the project faces risks and challenges that merit an incentive."[49]

46. In this context, we find that Green Power has satisfied the nexus requirement for each incentive being requested in this proceeding. As Green Power notes, and we agree, the Project is not routine by any measure. If completed as described in the instant application, the Project would span approximately 3,000 miles over a seven state area and cost between $10-12 billion. This makes the Project one of the largest, if not the largest, single transmission project ever developed in the United States. The Project as proposed would nearly double the miles of 765 kV transmission lines that are currently in operation in the United States. It also would help deliver the approximately 62 GW of proposed wind capacity that is currently in the Midwest ISO's interconnection queue. In addition, as the Commission has discussed previously, construction or enhancement of transmission facilities to provide access to remote, location-constrained renewable resources is not routine.[50] We will discuss below the nexus between each requested incentive and the particular risks and challenges that will be faced by Green Power in its pursuit of the Project.

a. Abandoned Plant

i. Green Power Proposal

47. Green Power requests an abandoned plant incentive so that it will have the opportunity to recover prudently incurred costs if the Project is abandoned due to forces beyond Green Power's control. It requests that the abandoned plant incentive become effective on April 11, 2009. Green Power states that, consistent with Commission precedent, it will make a section 205 filing before recovering abandoned plant costs, including any unrecovered costs associated with the regulatory asset, and it will demonstrate that such costs are just and reasonable.[51]

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[48] *Id.* P 52-55.

[49] *Id.* P 54.

[50] *See PacifiCorp*, 125 FERC ¶ 61,076, at P 45 (2008).

[51] Transmittal Letter at 37.

48. Green Power states that the abandoned plant incentive is appropriate in this case because the Project is significant and faces substantial challenges associated with the large geographical scope of the Project and the corresponding need for approval from multiple jurisdictions and planning organizations, as well as other uncertainties that arise in a project of this scope and duration. Green Power also states that the Project faces challenges with respect to possible changes in federal tax policy, energy markets and capital markets. In addition, Green Power notes that the current financial climate has already begun to curtail plans of wind developers, and the primary purpose of the Project is to interconnect wind generation being developed in the northern Great Plains and upper Midwest.[52] Green Power states that the abandoned plant incentive protects Green Power from losing any prudently-incurred investment costs and will help ensure the availability of financing at reasonable terms. The incentive also will provide additional assurance to lenders and investors that any prudently-incurred costs will be recovered.

ii. <u>Comments and Protests</u>

49. Some protesters argue that it may not be prudent for Green Power to incur significant expenses such as detailed studies and route selection while waiting for regional planning approval. Similarly, some parties state that granting Green Power abandonment costs will encourage future speculative projects not analyzed by Commission-approved regional planning processes to seek similar incentives. This potential scenario would discourage cooperation in regional planning processes and have ratepayers fund the costs of transmission projects that do not go forward. Some parties request that the Commission make clear that, if Green Power subsequently seeks abandoned plant recovery, the Commission retains the authority to reduce the resulting charges to exclude, if sought, above-cost components and expenditures that become wasted because Green Power's spending outpaced regional planning approvals. In addition, there is concern that customers who may eventually have to pay abandoned plant costs have not been given proper notice because Green Power has not identified the customers from whom any abandoned plant costs might be recovered. Alliant Energy states that the Commission should provide assurance that if the Project is cancelled, the cost recovery will not be limited to network customers in the ITC Midwest zone and that the widest possible cost recovery mechanism will be used.

iii. <u>Commission Determination</u>

50. We grant Green Power's request to recover its prudently incurred costs if the Project is abandoned for reasons beyond Green Power's control. As the Commission has previously stated, recovery of abandonment costs is an effective means of encouraging

[52] *Id.*, at 52-53 (citing Renewables Recession: FPL Cutting Wind, Duke Chopping Solar, THE ENERGY DAILY, at p. 1, Oct. 28, 2008).

transmission development by reducing the risk of non-recovery of costs.[53] Such is the case here. We expect that allowing Green Power the opportunity to recover the costs that it prudently incurs will help Green Power finance the Project and will assure potential investors that they will likely be able to recover some part of their investments.

51. We find that Green Power has demonstrated a nexus between the risks of the Project and the need to recover prudently incurred costs associated with abandonment of the Project. We find that this incentive will be an effective means to encourage the Project's completion. A primary purpose of the Project is to interconnect wind generation being developed in the northern Great Plains and upper Midwest, and therefore, the Project faces risks associated with generation developers' decisions to develop or terminate wind projects in that region. Given the geographic scope of the Project, Green Power will need to obtain approvals and siting authorizations in various states: North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Illinois, and Indiana. In addition, the Project requires approval for inclusion in Midwest ISO's and PJM's regional expansion plans and the plans of some individual MAPP members[54]. These factors introduce a significant element of risk, and authorizing the abandoned plant incentive will help lessen this risk by providing Green Power with some degree of certainty as it moves forward.

52. We note, however, that if the Project is cancelled before it is completed, it is unclear whether Green Power will have any customers from which to recover the costs it incurred. Before it can recover any abandoned plant costs, Green Power states that it will, and we require it to, make a filing under section 205 of the FPA to demonstrate that the costs were prudently incurred.[55] Green Power must also propose in its section 205 filing a just and reasonable rate and cost allocation method to recover these costs. Order No. 679 specifically requires every utility seeking abandonment recovery to submit such a section 205 filing.[56] Protesters that are concerned about their potential exposure to abandoned plant costs will have an opportunity to comment on any proposal to recover such costs if and when Green Power makes the required section 205 filing. Similarly, arguments about whether it was prudent for Green Power to incur specific costs can be raised at that time.

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[53] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 163.

[54] *See*, Transmittal Letter at 11, 37 & 49.

[55] *Id.*, at 37.

[56] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 166.

b. Regulatory Asset

i. Green Power Proposal

53. Green Power states that it currently has no way to recover expenses it incurs in connection with the formation of Green Power and/or development of the Project. Therefore, to address the risk of not recovering these costs, Green Power seeks deferred cost recovery through the creation of several regulatory assets. Green Power states that providing more certainty for cost recovery for these development activities will meet the Commission's objective of encouraging the development of more transmission infrastructure.

54. Under Green Power's proposal, the initial regulatory asset will include: (1) all applicable start-up and development costs Green Power has incurred to-date and (2) start-up and development costs going forward. Green Power will begin to include the initial regulatory asset in rate base on January 1 of the year immediately following the year the Project has first recorded CWIP charges and will amortize the costs over 10 years. Green Power also proposes to accrue carrying charges on the initial regulatory asset from the proposed effective date (April 11, 2009) until such time that the regulatory asset is included in rate base.[57] Additionally, until there is an approved cost allocation methodology for the Project, Green Power requests authorization to include in the regulatory asset account carrying charges on items properly includable in its revenue requirement under the formula rate.[58]

55. Green Power states that the start-up and development costs that it proposes to include in the initial regulatory asset are costs that are not capitalized and that are not included in CWIP. These costs include Green Power's costs associated with efforts to establish the formula rate sought in this filing; obtaining the necessary approvals and authorizations from state regulators and from various regional transmission organizations; and additional costs related to education and outreach to stakeholders on the merits of the Project.[59] These costs would also include attorney and consultant fees; entity formation costs; administrative expenditures; taxes (other than income taxes);

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[57] Green Power will calculate the carrying charges based on the actual cost of long-term debt and the ROE that the Commission approves for the Project. It will use a hypothetical capital structure of 60 percent equity 40 percent debt until any portion of the Project is placed into service and will use Green Power's actual capital structure thereafter.

[58] Transmittal Letter at 35 and Neff Test. at 11:20-12:2, Exhibit No. GPE-700.

[59] Stibor Test. at 5:12-7:9, Exhibit No. GPE-600.

travel costs; and other expenditures related to the corporate structure. In addition, Green Power expects to incur costs related to engineering studies and routing studies, such as those to determine the feasibility of the Project and analyses mandated by regulatory bodies and regional planning processes related to pre-construction approvals. Green Power states that deferring recovery of these types of costs through the creation of a regulatory asset is appropriate because the costs: (1) would otherwise be chargeable to expense in the period incurred; (2) are not recoverable in current rates; and (3) are ones for which future recovery is probable.[60]

56. After Green Power begins to recover the initial regulatory asset in its revenue requirement under the formula rate, Green Power requests permission to create a set of new regulatory assets. Green Power explains that it anticipates incurring costs for engineering and routing studies and continued development costs for other portions of the Project even after it begins to recover the initial regulatory asset in rate base. Therefore, Green Power proposes to create a new regulatory asset each year (vintage year regulatory asset) that will include all on-going development costs, and it will create a new vintage year regulatory asset each year until all development activities are complete. Green Power will separately maintain and identify each vintage year regulatory asset such that carrying charges will accrue monthly until the regulatory asset is included in rate base. The costs in each vintage year regulatory asset will first be included in rate base on January 1 of the immediately following year and, like the initial regulatory asset, Green Power will amortize each new vintage year regulatory asset over 10 years.

ii. <u>Comments and Protests</u>

57. In addition to arguments that the filing is premature, which we address above, AMP-Ohio argues that the regulatory asset should not extend to all of the costs Green Power incurred in connection with the formation of the partnership. AMP-Ohio asserts that ITC Holdings was not required to create a new limited partnership to develop the Project and it is not clear that the decision to create one has any benefit whatsoever to consumers, although it undoubtedly does to the owners of ITC Holdings. In addition, if the Commission allows development costs to be included in a regulatory asset, the costs should be limited to those essential to the development of the Project and should not include legal and other costs incurred to shelter the parent company from risk and liability. Alliant Energy also recommends that, if the regulatory asset is granted, the Commission require Green Power to provide semi-annual reports to the Commission about the accrued level of costs charged to the regulatory asset in sufficient detail to allow stakeholders to reasonably understand the nature of the costs.

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[60] Transmittal Letter at 34.

58. RES Americas supports Green Power's request for a regulatory asset designation. It argues that this regulatory asset will enable Green Power to explore the possibility of the proposed business model while reducing risks usually inherent to such an exploration.

iii. Commission Determination

59. We grant Green Power's request for authorization to create the initial regulatory asset, effective April 11, 2009, and subsequent vintage year regulatory assets, effective January 1 of each year following the year in which Green Power begins recovering the initial regulatory asset. This will allow Green Power to defer recovery of pre-construction costs, as well as start-up and development costs, and, to the extent Green Power has customers to assess those costs, recover them later. We find the incentive is tailored to Green Power's risks and challenges because this incentive will provide Green Power with added up-front regulatory certainty and can reduce interest expense, improve coverage ratios, and facilitate the financing of the Project on good terms. Granting this incentive encourages development of more transmission infrastructure, thereby fulfilling the goals of section 219.

60. We also authorize Green Power's request to accrue a carrying charge on the initial regulatory asset from April 11, 2009, the requested effective date, until the regulatory asset is included in rate base. Subsequent vintage year regulatory assets may also accrue carrying charges until the amounts are included in rate base. Additionally, Green Power may accrue carrying charges on items properly includable in its revenue requirement under the formula rate, like CWIP, until there is an approved cost allocation methodology for the Project.[61] We authorize Green Power to amortize each regulatory asset over ten years, starting from the date it begins to recover the regulatory asset as part of the revenue requirement under its formula rate. Once Green Power begins to recover the initial regulatory asset (or any vintage year regulatory asset) as part of the revenue requirement under its formula rate, Green Power will earn a return on the unamortized balance of the regulatory asset and, therefore, Green Power must stop accruing carrying charges on such regulatory asset.

61. Like the abandoned plant incentive, if the Project is cancelled before completion, it is unclear whether Green Power will have any customers from which to recover the costs in a regulatory asset. Thus, while we provide Green Power with the ability to create the initial regulatory asset to record Project-specific start-up, development and pre-construction costs, Green Power must make a section 205 filing before it starts amortizing the initial regulatory asset, as well each vintage year regulatory asset, to

[61] To the extent Green Power accrues carrying charges on CWIP balances because there is not an approved cost allocation methodology for the Project, Green Power cannot also accrue AFUDC on those same CWIP balances.

demonstrate that the costs included in the regulatory asset were prudently incurred and are just and reasonable. In addition, if the initial regulatory asset includes carrying charges on items that would have otherwise been included in Green Power's revenue requirement during a period before the formula rate took effect, Green Power must demonstrate in the section 205 filing that the items on which it accrued such carrying charges were properly includable in the revenue requirement under its formula rate. Parties, such as AMP-Ohio, will be able to challenge these costs at that time. In addition, since Green Power will have to make a future filing before recovering any costs included in the regulatory assets, we find that requiring Green Power to submit semi-annual reports with the accrued level of costs charged to the regulatory asset is unnecessary.

c. Construction Work in Progress

i. Green Power Proposal

62. Green Power seeks inclusion of 100 percent of CWIP in rate base for the Project with a deferred effective date. Green Power will submit a compliance filing requesting authorization to begin charging rates based on a revenue requirement including CWIP at least 60 days prior to its requested effective date.[62] Green Power states that the CWIP incentive will not eliminate negative cash flows during construction of the Project, but it will allow for some level of revenues for Green Power and enable it to service its debt, which ultimately results in lower borrowings and overall cost savings for the Project. Without this cash flow, Green Power states, the cost of borrowing capital to finance construction would increase, if it could be secured at all. Green Power states that at minimum this would result in increases to the cost of the Project or it could necessitate the outright abandonment of the Project.

63. Green Power states that the Project will require unprecedented capital expenditures during the multi-year construction period, thus creating significant pressures on Green Power's cash flow. Including 100 percent of CWIP in rate base during construction will, according to Green Power, significantly improve cash flow stability and will produce a credit rating of investment grade much quicker. Green Power states that the CWIP incentive is designed to ensure that the Project goes forward. Green Power also states that the Commission has recognized the benefits of permitting 100 percent of CWIP in rate base as an incentive to building needed new transmission, and such an incentive is all the more important here where a start-up, independent transmission company with no existing rate base is embarking on a major transmission expansion project that requires significant levels of new investment.

[62] Transmittal Letter at 5.

ii. Comments and Protests

64. In addition to arguments that the filing is premature, which we address above, Consumers Energy believes the CWIP incentive adequately addresses risks and challenges facing the Project.

iii. Commission Determination

65. We grant Green Power's request for the CWIP incentive with a deferred effective date. Green Power must, as it acknowledges,[63] make a compliance filing requesting authorization to begin charging rates based on a revenue requirement that includes CWIP at least 60 days prior to the effective date Green Power ultimately requests. In Order No. 679, the Commission established a policy that allows utilities to include, where appropriate, 100 percent of prudently-incurred transmission-related CWIP in rate base.[64] The Commission noted in Order No. 679 that this rate treatment will further the goals of section 219 by providing up-front regulatory certainty, rate stability, and improved cash flow for applicants, thereby reducing the pressures on their finances caused by investing in transmission projects.[65]

66. We find that Green Power has shown a nexus between the proposed CWIP incentive and its investment in the Project. The Commission stated in Order No. 679 that authorizing inclusion of 100 percent of prudently incurred transmission-related CWIP in rate base improves cash flow and eases pressure on applicants' finances caused by transmission development programs.[66] Due to the significant investment it presents—estimated as between $10 billion and $12 billion—and the estimated in service dates beginning in 2020, it is appropriate to grant this incentive to Green Power. Consistent with Order No. 679, we find that authorizing 100 percent of CWIP in rate base for the Project will facilitate Green Power receiving an investment grade credit rating sooner, improve cash flow and lower borrowing costs. Green Power has also committed to employ appropriate accounting controls to prevent charging customers for both capitalized allowance for funds used during construction and a return on CWIP for the Project, as discussed further below.

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[63] *Id.*

[64] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 29 and 117.

[65] *Id.* P 115.

[66] *Id.*

67. We also find that allowing Green Power to include 100 percent of CWIP in rate base for the Project will result in better rate stability for customers. As we have explained in prior orders,[67] we find that, without CWIP in rate base, a new project has no direct effect on consumer prices until it begins being used to provide service. If the Commission does not permit Green Power to recover a return on CWIP in rate base, the Project's borrowing costs will be accrued over these years and capitalized and recovered once each phase of the Project goes into service, along with a return of the investment cost through depreciation. Such a process will increase customers' bills more significantly at the time the Project begins to be placed into service than if the Commission were to allow CWIP to be included in rate base.[68]

d. Hypothetical Capital Structure

i. Green Power Proposal

68. Green Power seeks authorization to use a hypothetical capital structure of 60 percent equity and 40 percent debt. Once any portion of the proposed Project is placed into service, Green Power will begin using its actual capital structure. Green Power intends to maintain, to the extent possible, a capital structure of 60 percent equity and 40 percent debt even during the period that it uses the requested hypothetical capital structure.

69. Green Power proposes to use a hypothetical capital structure because it expects its actual capital structure to fluctuate during the development and construction phases of the Project due to the timing and frequency of new borrowings and new equity infusions. Given the substantial projected cost of the Project and the resulting need for a significant amount of investment during the construction phase, the use of a hypothetical capital structure until some of the Project assets are placed into service will provide Green Power with regulatory certainty, support its efforts to obtain investment grade credit ratings, and smooth out the wide swings in the debt to equity ratio that can result from the cash demands of the construction.

70. In addition, Green Power believes its request to use a hypothetical capital structure is consistent with Commission's decision in *PATH*.[69] Green Power also notes that the

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[67] *See, e.g., American Elec. Power Co.*, 116 FERC ¶ 61,059, at P 59 (2006), *order on reh'g*, 118 FERC ¶ 61,041, at P 27 (2007).

[68] We address below Consumers Energy's comments related to whether the Commission should grant both the CWIP incentive and the ROE incentive.

[69] Transmittal Letter at 43 (citing *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188, at P 55 (2008) (*PATH*)).

equity ratio reflected in its requested hypothetical capital structure is the same as the capital structure the Commission has authorized for ITC Holdings' other regulated affiliates – International Transmission and ITC Midwest.

ii. Comments and Protests

71. AMP-Ohio believes that Green Power's proposed 60 percent equity ratio in its proposed hypothetical capital structure is too high and will inappropriately increase Green Power's profits and costs to consumers. It believes that the Commission should direct Green Power to use the same 50 percent debt and 50 percent equity capital structure the Commission approved in *Tallgrass*. Basin Electric argues that Green Power's capital structure proposal is premature and should not be granted until basic issues of the Project configuration have been addressed. Consumer Energy notes that Green Power is a wholly owned subsidiary of ITC Holdings, an entity with significant assets. Consumer Energy suggests, therefore, that the Commission should require Green Power to use the capital structure of its parent until such time as the first facilities of the Project are placed into service, and thereafter Green Power should start using its actual capital structure.

iii. Commission Determination

72. We find that it is appropriate for Green Power to use a hypothetical capital structure of 60 percent equity and 40 percent debt until any portion of the proposed Project is placed into service, at which time Green Power states that it will begin using its actual capital structure. This is the same capital structure that the Commission previously authorized for two of ITC Holdings' regulated subsidiaries.[70] As Green Power notes, this structure has been shown to contribute to those subsidiaries achieving and maintaining credit ratings and accessing the capital markets. Moreover, this hypothetical structure is the same as Green Power's target capital structure, which it will employ at the time that any of Green Power's assets are placed in service.

73. In Order No. 679-A, the Commission stated that to encourage the development of new transmission investment, it will evaluate each proposal on a case-by-case basis and will not prescribe specific criteria or set target debt to equity ratios for evaluating hypothetical capital structures.[71] Furthermore, the Commission said that the use of hypothetical capital structures "can be an appropriate ratemaking tool for fostering new

[70] *See ITC Holdings Corp.*, 102 FERC ¶ 61,182 (2003) and *ITC Holdings Corp.*, 121 FERC ¶ 61,229 (2007).

[71] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 91.

transmission in certain relatively narrow circumstances."[72] The Commission found, however, that adoption of such a hypothetical capital structure would require a demonstration of the required nexus between the need for a hypothetical capital structure and the proposed investment project.[73]

74. We find that Green Power has shown a nexus between its proposed hypothetical capital structure and its ability to borrow funds during the pre-commercial period for the Project. Green Power will operate as a start-up independent transmission company and will have no revenues beyond those received from operation of the Project. Moreover, given the estimated cost of its Project, Green Power will need to raise significant levels of new debt and equity capital. Maintenance of an investment grade credit rating during financing will allow Green Power to access a broader base of investors and ultimately obtain financing at a reasonable cost, which should lower the overall cost of capital.

75. We disagree with AMP-Ohio that the 60 percent equity component of Green Power's requested capital structure is too high and that the Commission should grant Green Power the same 50 percent debt and 50 percent equity capital structure it granted in *Tallgrass*. In *Tallgrass*, the Commission granted what it considered to be just and reasonable hypothetical capital structures on the basis of the entire transmission project proposal. As the Commission has stated, it will consider transmission incentive requests on a case-by-case basis. Other than citing to *Tallgrass*, AMP-Ohio does not provide any evidence as to why it believes the 60 percent equity component is too high. Here, we find Green Power's proposed hypothetical capital structure of 60 percent equity and 40 percent debt is just and reasonable.[74]

76. We also find that Green Power should not be required to use the capital structure of its parent, ITC Holdings. We find that adopting its parent's capital structure until such time that it has its own capital structure would be inappropriate and would go against the intent of the hypothetical capital structure incentive discussed in Order No. 679. Green Power's use of a hypothetical capital structure prior to plant going into service will avoid

[72] *Id.* P 93.

[73] *Id.*

[74] We note that the proposed hypothetical capital structure is within the range of actual capital structures for transmission owners. For example, Green Power's proposed hypothetical capital structure is within the range of the capital structures used in the Attachment O rate formula by other investor-owned Midwest ISO Transmission Owners. *See* Attachment O formula calculations for rates taking effect January 2009, posted at http://www.midwestiso.org/publish/Document/20b78d_11ef44fc9c0_-7fb00a48324a?rev=3.

reflecting in rates swings in its actual capital structure and will provide a consistent cash flow during the construction period when Green Power is expected to have a negative cash flow position, therefore assisting in the building of the Project.

e. Transmission Investment ROE Incentive

i. Green Power Proposal

77. Green Power requests a 10 basis point ROE incentive adder in recognition of the risk and challenges associated with the Project.[75]

ii. Comments and Protests

78. Consumers Energy contends that Green Power has not distinguished between the risks and challenges faced in undertaking the Project that would necessitate the CWIP incentive and those that necessitate the requested ROE adder. Consumers Energy believes the CWIP incentive adequately addresses such risks and challenges. Accordingly, Consumers Energy states that Green Power should not get both the CWIP incentive and the ROE incentive because such incentives are duplicative. Consumers Energy also argues the Green Power has not supported approval of the 10 basis point adder because the only justification Green Power provides for that adder is that the 10 basis points is needed to brings its ROE up to the 12.38 percent ROE that the Commission previously approved for Midwest ISO transmission owners.

79. In addition, Consumers Energy argues that Green Power's risk assessment ignores the risk-reducing effect of having formula transmission rates. Consumers Energy believes that having formula rates in effect guarantees cost recovery, significantly reducing the risk associated with a project for which formula rates have been approved. Consumers Energy states that if the Commission grants Green Power's formula rates for the Project, the risk reducing effects of formula rates should be considered as an offsetting element in Green Power's overall risk profile and thus result in a reduction in any ROE incentive.

iii. Commission Determination

80. We grant the 10 basis point incentive adder in recognition of the size, scope, benefits, risks and challenges of the Project. Order No. 679-A makes clear that the most compelling case for incentive ROEs are new projects that present special risks or

[75] Green Power also requests a 50 basis point adder for participation in an RTO and a 100 basis point adder for being a transmission-only company, both of which we discuss in the next section.

challenges, not investments made in the ordinary course. The investments proposed in the Project satisfy this standard. For example, Green Power must secure approval through two RTOs' and certain individual MAPP utilities' transmission planning processes. In addition, the Project is estimated to cost between $10 and $12 billion and will go through parts of seven states. The Project is also proposed to consist of 3,000 miles of 765 kV lines, which is more miles of 765 kV lines than the approximate amount in operation in the United States today.

81. We disagree with Consumers Energy that the ROE incentive adders for the Project must be adjusted if we also grant a CWIP incentive and/or allow cost recovery through a formula rate. Order No. 679 did not contemplate a generic rule requiring a reduction in the ROE incentive when other incentives are granted.[76] The Commission looks at each case on an individual basis. As discussed further below, Green Power's overall ROE, including the incentives granted here, is substantially below the top of the range of reasonableness. Given the size, scope and cost of the Project, Green Power faces risks and challenges that warrant the adder without any reduction due to the granting of CWIP. We are not persuaded by the parties' protests that the 10 basis point incentive is unreasonable in these circumstances.

3. RTO and Transco[77] ROE Incentives

a. Green Power Proposal

82. In addition to the 10 basis point ROE adder, Green Power requests two additional ROE incentives under Order No. 679: (1) a 50 basis point ROE adder for participation in an RTO;[78] and (2) a 100 basis point ROE adder in recognition of its status as an independent transmission-only company.

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[76] *See, e.g.*, *Pioneer,* 126 FERC ¶ 61,281 at 60; *Tallgrass*, 125 FERC ¶ 61,248 at P 61; and *Pepco Holdings, Inc.* 125 FERC ¶ 61,130, at P 75 (2008).

[77] For purposes of transmission investment incentives, a Transco is a stand-alone transmission company that has been approved by the Commission and that sells transmission services at wholesale and/or on an unbundled retail basis, regardless of whether it is affiliated with another public utility. *See* Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 201.

[78] Green Power states that it will apply to become a transmission owning RTO participant as soon as appropriate Project assets exist, the Project has been approved by a planning process, and a cost allocation method for the Project has been authorized. *See* Transmittal Letter at 62.

b. Comments and Protests

83. Consumers Energy believes that if the Commission grants the 100 basis point adder based on Green Power's status as an independent transmission company, the Commission should condition such approval on Green Power not partnering with a generation owning entity.

84. Other protesters also contend that if the Commission grants Green Power an ROE incentive based on RTO membership, the Commission should allow such ROE incentive to become effective only once all of the Project's facilities are placed under the operational control of an RTO and the Project has been formally approved for inclusion in a regional transmission expansion plan.

c. Commission Determination

85. We grant Green Power's request for a 50 basis point incentive adder based on Green Power's commitment to participate in an RTO. This adder will become effective on the date Green Power becomes a transmission owning member of an RTO and places the Project under an RTO's operational control.[79] Our decision to grant Green Power's incentive ROE for participation in an RTO is consistent with the stated purpose of section 219 of the FPA. The incentive applies to all utilities joining a transmission organization and is intended to encourage participation in an RTO.[80]

86. We grant the 100 basis point incentive adder based on Green Power's status as an independent transmission company. This adder will become effective on April 11, 2009, as requested. The Commission has found that the singular focus of transmission-only companies, the elimination of competition for capital between generation and transmission investments, and the access to capital markets all support the value of the transmission-only business model for getting new transmission built.[81] In addition, the purpose of our policy of incentives for transmission-only companies is to build much needed transmission infrastructure, and Green Power's proposal is consistent with this policy. It is for these reasons that the Commission adopted incentive-based rate

[79] *See, e.g., San Diego Gas & Elec. Co.*, 118 FERC ¶ 61,073, at P 25-26 (2007).

[80] *Id.* P 26 (finding that there are considerable benefits associated with a utility's membership in a regional transmission organization).

[81] *See* Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 222-223.

treatments applicable to transmission-only companies that would both encourage formation of these entities and attract investment.[82]

87. Our approval of the 100 basis point adder is based on Green Power's existing status as fully-owned subsidiary of ITC Holdings, a fully independent transmission-only company. We note, however, that Green Power states that it is actively exploring the potential for partnering with other companies in developing the Project, including generation-owning utilities in the region. Therefore, as a condition of the 100 basis point Transco incentive adder, we require Green Power to promptly inform the Commission of any changes in its partnership agreement, or any other agreement, or new facts (including but not limited to any new financial interests acquired in or by market participants) so that we can ensure that Green Power continues to qualify for the Transco incentive.[83]

4. Nexus with Total Package of Incentives

88. We find that Green Power has shown that, consistent with Order No. 679-A, the total package of incentives is tailored to address the demonstrable risks or challenges faced by Green Power.[84] Consistent with Order No. 679, the Commission has, in prior cases, approved multiple rate incentives for particular projects.[85] This is consistent with our interpretation of FPA section 219 as authorizing the Commission to approve more than one incentive rate treatment for an applicant proposing a new transmission project, as long as each incentive is justified by a showing that it satisfies the requirements of FPA section 219 and there is a nexus between the incentives being proposed and the investment being made. Here, as discussed above, Green Power has explained why it is seeking each incentive and how each is relevant to the proposed Project. Thus, we find that Green Power has shown a nexus for the total package of incentives.

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[82] *See* Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 77.

[83] The Commission will consider granting incentives to Transcos with various business models and arrangements and does not exclude affiliated Transcos with active ownership by market participants. However, an applicant must demonstrate the value of its particular affiliated Transco proposal. The Commission considers the eligibility of such arrangements for incentives based on a showing of how the specific characteristics of a proposed Transco affect its ability and propensity to increase transmission investment. *See* Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 201-202.

[84] *See* Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 21, 27.

[85] *See, e.g., PATH*, 122 FERC ¶ 61,188; *Southern California Edison Co.*, 121 FERC ¶ 61,168 (2007).

89. Further, we find that Green Power has appropriately tailored the requested incentives to the unique challenges facing the Project. As we discuss above, the CWIP and regulatory asset incentives are designed to provide Green Power with up-front regulatory certainty, rate stability, and improved cash flow, thereby easing the pressures on its finances caused by transmission development programs. The abandonment incentive will encourage transmission development by reducing the risk of non-recovery of prudently incurred costs associated with abandoned transmission projects if such abandonment is outside of management's control. The incentive ROE adder for new transmission, together with the 50 basis point adder for RTO membership and 100 basis points for transmission-only status, are designed to facilitate Green Power's ability to raise capital, given the challenges of securing the Project's approval from numerous state regulatory bodies and various transmission planning processes.

C. Section 205 Demonstration

1. Range of Reasonableness

a. Green Power Proposal

90. Green Power's overall ROE of 12.38 percent (inclusive of the total 160 basis points in incentive adders discussed above) reflects a base return on equity of 10.78 percent. In support of its base return on equity, Green Power performs a DCF analysis that results in a range of reasonableness with a high-end of 16.14 percent and a low-end of 8.48 percent, which yields a midpoint of 12.31 percent and a median of 10.78 percent. Green Power's proxy group has 11 companies within SPP, Midwest ISO and PJM that had Corporate Credit Ratings (CCRs) between BBB- and BBB+ (Green Power uses its parent company's (ITC Holdings) CCR, which is BBB), have investment grade bond ratings, had no dividend cuts or mergers and acquisitions, have sustainable growth rates and have estimated cost of equity above their cost of debt.

b. Comments and Protests

91. No party protested Green Power's DCF analysis.

c. Commission Determination

92. We grant Green Power an overall ROE of 12.38 percent, inclusive of the 160 basis point incentive adders described above, subject to the conditions regarding the RTO and Transco incentive adders. We find that Green Power's proposed base return on equity of 10.78 percent is reasonable because the Commission's analysis supports a median return on equity of 10.79 percent and a range of reasonableness of 8.91 percent through

14.29 percent.[86] Moreover, no party protests Green Power's DCF analysis. Accordingly, we exclude the base return on equity and zone of reasonableness issues from the hearing we order below.

2. Formula Rate

a. Green Power Proposal

93. Green Power proposes to implement a forward-looking formula rate similar to formula rates that the Commission has accepted for Green Power's affiliates (International Transmission, METC, and ITC Midwest).[87] Green Power requests a deferred effective date for the formula rate until the Project is included in a regional transmission expansion plan as part of an Order No. 890 compliant transmission planning process and an appropriate cost allocation proposal is accepted by the Commission.[88] The formula rate will serve as the basis for calculating the annual transmission revenue requirement for Green Power as an independent, stand-alone transmission company in Midwest ISO and PJM. Accordingly, Green Power requests the Commission accept for filing a formula rate under which the costs of the Project ultimately will be recoverable through the open access tariffs of Midwest ISO and PJM. Green Power states that as filed, the formula rate will establish a revenue requirement and will result in transmission service rates when the actual cost allocation for the Project is known.

94. Green Power states that, like the forward-looking formula rates the Commission approved for International Transmission, METC, and ITC Midwest, Green Power's base formula rate is designed to track increases and decreases in costs and investment. A true-up mechanism implemented following the end of a rate period ensures that any difference in revenue collections from Green Power's actual revenue requirement during the rate

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[86] The Commission's proxy group has six companies within SPP, Midwest ISO and PJM that have CCRs between BBB- and BBB+; have investment grade bond ratings; have had no recent dividend cuts; are not involved in any merger or acquisition activities; have sustainable growth rates; and have estimated costs of equity approximately equal to or above their cost of debt.

[87] *See International Transmission Co.*, 116 FERC ¶ 61,036 (2006); *Michigan Elec. Transmission Co. LLC*, 117 FERC ¶ 61,314 (2006); and *ITC Holdings Corp.*, 121 FERC ¶ 61,229 (2007).

[88] Transmittal Letter at 61.

period is addressed via an adjustment (with interest) to the annual transmission revenue requirement in a subsequent rate period.[89]

95. Pursuant to the formula rate structure proposed, Green Power will estimate, by September 1 of each year, its revenue requirement for the following year with respect to the facilities in service, or to be placed in service, or under construction during that following year. This estimated revenue requirement will then be used by Midwest ISO and PJM to update the required attachments to their tariffs, under which Green Power will recover the costs of its facilities. When Green Power files its Form No. 1 for the year in which the revenue requirement was estimated, Green Power's transmission revenues for that year will be trued up against the actual net revenue requirement, and refunds or additional collections will be reflected in the Midwest ISO and PJM tariff schedules in a subsequent year.

96. With respect to its initial rates and prior to the period before Green Power would be required to file a Form No. 1, Green Power proposes to make a compliance filing at least on an annual basis that would contain the relevant information relating to the company's expenses and rates that would be identified in a Form No. 1.

b. Comments and Protests

97. Some protesters request that the Commission suspend and set the formula rate and related protocols for hearing and settlement judge procedures. In addition to arguments that the formula rate is premature, Midwest TDUs state that the protocols submitted by Green Power are not defined and lack customer protections and the Commission should defer the formula rate protocols and set them for settlement judge and hearing procedures at the appropriate time. Further, Midwest TDUs state that the Commission should clarify that any approvals granted herein are subject to future protocols once cost allocation methodologies have been adopted.

98. Xcel states that Green Power has proposed accelerated depreciation rates for several items, without discussing the justification for this ratemaking incentive under Order No. 679. Specifically, Xcel states that Green Power proposes a depreciation rate of 10 percent (with a 10 year average service life) for items in Account No. 393, store equipment, of the Uniform System of Accounts (USofA). Xcel states that it is concerned about the impacts to customers of the aggressive depreciation requested by Green Power and believes that a clearer justification and understanding of the costs at issue is needed before those costs should be imposed on customers. Xcel also states that Green Power's filing did not expressly seek accelerated depreciation treatment for these investments under Order No. 679, nor did it demonstrate how this aspect of the Proposal meets the

[89] Neff Test. at 5:5-15, Exhibit No. GPE-700.

nexus test to receive accelerated depreciation as a transmission rate incentive. It therefore argues that Green Power's formula rate employing the accelerated depreciation rates cannot be approved as just and reasonable based upon the information provided in the filing.

99. In addition, Consumers Energy states the annual compliance filing Green Power commits to make prior to Green Power having to file a Form No. 1 must contain information in the same format, and with at least the same level of granularity, as the information that is required to be provided in a Form No. 1. Xcel Energy states that the proposed formula rates are procedurally flawed because Green Power does not have the right to make unilateral filings to the Midwest ISO or PJM tariffs under section 205 of the FPA, and Green Power filed its proposed formula rates for inclusion in the tariffs without coordinating with Midwest ISO or PJM. PJM also argues that Green Power is asking the Commission for actual rate approval, and if the Commission accepts the formula rate for inclusion in the PJM tariff, the Commission will be prejudging the outcome of the PJM transmission planning process.

c. Green Power's Answer

100. Green Power states that there is no need for hearings related to the formula rate. Green Power states that the formula rate is just and reasonable and is consistent with those approved previously for the ITC Holdings operating companies.[90] Further, with respect to the depreciation rate of 10 percent for Account No. 393, Green Power states that the depreciation rate is based on an estimate of average service life and net salvage and that Green Power took into account the ITC Holdings operating companies' experience with owning and operating similar facilities. In addition, Green Power states, the Commission has previously accepted a 10 year average service life for Account No. 393.[91]

101. In response to concerns about its filing rights, Green Power states that it is not seeking to modify any RTO tariffs and states that modification of the RTO tariffs should come as a section 205 filing by the RTOs or by means of a section 206 filing.[92]

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[90] Green Power March 23, 2009 Answer (Green Power Answer) at 29.

[91] *Id.* at 28 (citing filing accepted in *Duke Power Energy Co. LLC*, Docket No. ER06-1040-000 (June 29, 2006) (unpublished delegated letter order)).

[92] *Id.* at 29-30.

d. Commission Determination

102. Green Power's formula rates and rate protocols raise issues of material fact that cannot be resolved based on the record before us, and are more appropriately addressed in the hearing ordered below. Our preliminary analysis indicates that Green Power's proposal has not been shown to be just and reasonable and may be unjust and unreasonable, unduly discriminatory or preferential, or otherwise unlawful. Therefore, we will accept Green Power's formula rates subject to refund, and set them for hearing and settlement judge procedures. At the hearing, Green Power will be required to demonstrate the justness and reasonableness of its proposal except to the extent we have made a summary finding herein.

103. While we are setting these matters for a trial-type evidentiary hearing, we encourage the parties to make every effort to settle their disputes before hearing procedures are commenced. To aid the parties in their settlement efforts, we will hold the hearing in abeyance and direct that a settlement judge be appointed, pursuant to Rule 603 of the Commission's Rules of Practice and Procedure.[93] If the parties desire, they may, by mutual agreement, request a specific judge as a settlement judge in the proceeding; otherwise the Chief Judge will select a judge for this purpose.[94] The settlement judge shall report to the Chief Judge and the Commission within 30 days of appointment of the settlement judge concerning the status of settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions or provide for the commencement of a hearing by assigning the case to a presiding judge.

104. Nonetheless, we find that we can narrow the scope of the hearing by making a summary finding involving certain formula components. We accept four rate incentives, as discussed above, and those incentives are not set for hearing; however, the formula calculations that reflect those incentives may be addressed in the hearing. Generally, when the formula rate includes a placeholder for an incentive that requires a future section 205 filing, the Commission requires a placeholder equal to zero in the amount column.[95] Having summarily determined the ROE of 12.38 percent (reflecting a base

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[93] 18 C.F.R. § 385.603 (2008).

[94] If the parties decide to request a specific judge, they must make their request to the Chief Judge by telephone at 202-502-8500 within five days of the date of this order. The Commission's website contains a listing of Commission judges and a summary of their background and experience (www.ferc.gov - click on Office of Administrative Law Judges).

[95] *See, e.g., American Elec. Power Serv. Corp.*, 120 FERC ¶ 61,025, at P 36-37 (2007).

ROE of 10.78, 50 basis points for participation in an RTO, 100 basis points for being a Transco, and 10 basis points for the risks and challenges of the proposed Project) and the range of reasonableness, as discussed, those issues are not included in the hearing and settlement procedures. In addition, we find that concerns about Green Power not having the right to file revisions to the Midwest ISO and PJM tariffs are unwarranted. Green Power filed *pro forma* tariff sheets, which will need to be replaced by actual tariff sheets. Green Power acknowledges that there will need to be a future filing under section 205 or 206 of the FPA before any tariff sheets are incorporated into the Midwest ISO and/or PJM tariffs.

D. Accounting Issues

1. Incentive for Inclusion of 100 Percent of CWIP in Rate Base

105. Under Order No. 679 and the Commission's regulations, an applicant must propose accounting procedures that ensure that customers will not be charged for both capitalized AFUDC and corresponding amounts of CWIP in rate base.[96] To satisfy this requirement, Green Power states that it will use its fixed asset accounting system, PowerPlant, to exclude projects that are permitted to include CWIP in rate base from accruing AFUDC.[97] Additionally, Green Power states that the fixed asset accounting system requires certain basic information to establish a work order, such as whether the work order is eligible for AFUDC. Green Power claims these accounting procedures will assure that AFUDC is not capitalized on CWIP included in rate base. Further, Green Power notes that these controls are subject to internal monitoring and the overall control framework is subject to external auditor procedures and attestation annually.[98] The Commission finds that Green Power's proposed procedures demonstrate that it has accounting procedures and internal controls in place to prevent recovery of AFUDC to the extent it is allowed to include CWIP in rate base.

106. Public utilities that receive a current return on CWIP by including CWIP in rate base recover this cost in a different period than it would ordinarily be charged to expense under the general requirements of the Commission's USofA. To promote comparability of financial information between entities, the Commission has required a specific accounting treatment or the use of footnote disclosures to recognize the economic effects

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[96] 18 C.F.R. § 35.25 (2008) (recovery of construction work in progress in rate base).

[97] Stibor Test. at 12, Exhibit No. GPE-600.

[98] *Id.* at 13.

of having CWIP in rate base.[99] Green Power requests authorization to use footnote disclosures consistent with disclosures previously authorized by the Commission.[100] We will authorize Green Power to provide footnote disclosures in the notes to the financial statements of its annual FERC Form No. 1 and its quarterly FERC Form No. 3-Q that: (1) fully explain the impact of the CWIP in rate base; (2) include details of AFUDC not capitalized because of the incentive allowing CWIP in rate base for the current year, the previous two years, and the sum of all years; and (3) include a partial balance sheet consisting of the Assets and Other Debits section of the balance sheet to include the amount of AFUDC not capitalized because of the inclusion of CWIP in rate base.

2. Regulatory Asset Treatment

107. Green Power proposes to record the regulatory assets in Account No. 182.3, Other Regulatory Assets, and to accrue carrying charges on the regulatory assets.[101] Green Power proposes to charge carrying charges of the regulatory assets to Account No. 182.3, with the interest component credited to Account No. 431, Other Interest Expenses and the equity component charged to Account No. 407.4, Regulatory Credits. Green Power proposes to record the amortization to Account No. 566 "Miscellaneous Transmission Expenses" such that it is recoverable through the formula rate design.[102]

108. For accounting purposes, we accept Green Power's proposal to utilize Account No. 182.3 to record all pre-construction period expenses that are not recovered as CWIP. The regulatory asset may only include amounts that would otherwise be chargeable to expense in the period incurred, are not recoverable in current rates, and are probable for recovery in rates in a different period.[103] Furthermore, the instructions to Account

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[99] *See American Transmission Co. LLC*, 105 FERC ¶ 61,388, at P 37-40 (2003), *order on reh'g*, 107 FERC ¶ 61,117, at P 16-17 (2004); *Trans-Allegheny Interstate Line Co.*, 119 FERC ¶ 61,219, at P 44-45, *order on reh'g*, 121 FERC ¶ 61,009 (2007); *Tallgrass*, 125 FERC ¶ 61,248 at P 80.

[100] Stibor Test. at 11-12, Exhibit No. GPE-600.

[101] *Id.* at 6.

[102] Neff Test. at 15, Exhibit No. GPE-700.

[103] The term "probable" as used in the definition of regulatory assets, refers to that which can reasonably be expected or believed on the basis of available evidence or logic but is neither certain nor proved. *Revisions to Uniform Systems of Accounts to Account for Allowances under the Clear Air Act Amendments of 1990 and Regulatory-Created Assets and Liabilities and to Form Nos. 1, 1-F, 2, and 2-A*, Order No. 552, FERC Stats. & Regs., Regulations Preambles January 1991-June 1996 ¶ 30,967 (1993).

No. 182.3 require that amounts deferred in this account are to be charged to expense concurrently with the recovery of the amounts in rates. If rate recovery of all or part of the costs deferred in Account No. 182.3 is later disallowed, the disallowed amount shall be charged to Account No. 426.5, Other Deductions, in the year of disallowance.

109. Green Power proposes to accrue carrying charges on each vintage year regulatory asset balance until it is included in rate base by charging Account No. 182.3 and crediting Account No. 431 and Account No. 407.4. However, carrying charges on regulatory assets are properly recorded by crediting Account No. 421, Miscellaneous Nonoperating Income.[104] Therefore, Green Power must adjust its accounting for carrying charges accordingly.

3. Income Taxes

110. Green Power is a limited partnership and is not subject to federal taxation. Instead, the tax obligations incurred through its operations are reported on the tax return of its corporate parent, ITC.[105] For ratemaking purposes, the Commission treats pass-through entities such as Green Power as though they are corporations and allows them to receive an income tax allowance for the tax liability ultimately paid by its corporate parent. Therefore, we require Green Power to maintain its books of account based on the Commission's USofA as if it were a corporation, including the deferred income tax accounting requirements of the USofA.[106]

111. Green Power also states that the creation of the regulatory assets will trigger the recognition of a deferred tax liability for the book and tax basis difference of the regulatory assets. Green Power proposes not to recognize the deferred tax liability

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[104] *Revisions to Uniform Systems of Accounts to Account for Allowances under the Clean Air Act Amendments of 1990 and Regulatory-Created Assets and Liabilities and to Form Nos. 1, 1-F, 2, and 2-A*, Order No. 552, 58 Fed. Reg. 17,982 (April 7, 1993).

[105] Stibor Test. at 13-14, Exhibit No. GPE-600.

[106] Commission policy requires Green Power to follow the income tax accounting requirements of the Uniform System of Accounts prescribed in *General Instructions No. 18, Comprehensive Interperiod Income Tax Allocation; and Text to Account 190, Accumulated Deferred Income Taxes, Account 236, Taxes Accrued, Account 281, Accumulated Deferred Income Taxes-Accelerated Amortization Property, Account 282, Accumulated Deferred Income Taxes-Other Property, and Account 283, Accumulated Deferred Income Taxes-Other*, 18 C.F.R. Part 101 (2008). *See PATH*, 122 FERC ¶ 61,188 at P 157.

relating to the regulatory assets until it is included in rate base to achieve consistent rate treatment.

112. Green Power's proposal to defer recognition of the deferred tax liability relating to the regulatory assets is inconsistent with the Commission's income tax accounting requirements. A regulatory asset is a temporary difference for which deferred income taxes must be recognized and recorded in Account No. 281, Accumulated Deferred Income Taxes-Accelerated Amortization Property, Account No. 282, Accumulated Deferred Income Taxes-Other Property, and Account No. 283, Accumulated Deferred Income Taxes-Other, as appropriate.[107] Therefore, for accounting purposes, Green Power must recognize all deferred tax assets and liabilities in the periods in which differences between book accounting income and taxable income arise, including those related to regulatory assets.

E. Request for Waivers

113. Green Power requests waiver of section 35.3 of the Commission's regulations to permit an effective date of more than 120 days after this filing for the formula rate and CWIP aspects of this proposal. Further, Green Power requests temporary waiver of Order No. 614[108] for the proposed *pro forma* tariff sheets. Green Power states that if the formula rate is accepted, Green Power will refile the tariff sheets with the appropriate tariff sheet designations in compliance with Order No. 614. Green Power states that no expenses or costs in connection with this tariff filing have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.[109]

114. Green Power requests waiver of any applicable regulations to allow the filing to take effect in the manner prescribed. Green Power states that the statements it provided and the supporting testimony demonstrate the reasonableness of the proposed formula rate structure. Green Power further states that detailed cost-of-service statements (as required by section 35.13) are not necessary and waiver of these requirements would be consistent with Commission precedent because its proposed formula rate will produce an

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[107] *Accounting for Income Taxes*, Docket No. AI93-5-000 (April 23, 1993).

[108] *Designation of Electric Rate Schedule Sheets*, Order No. 614, FERC Stats. & Regs. ¶ 31,096 (2000).

[109] Transmittal Letter at 74.

annual revenue requirement based on the actual costs reflected in Green Power's FERC Form No. 1.[110] There were no comments on the waiver requests.

115. We grant Green Power's request for temporary waiver of Order No. 614 and accept its commitment to refile the tariff sheets with the appropriate tariff sheet designations in its future section 205 filing to make the formula rate effective. We will also grant Green Power's request for waiver of section 35.3 for the formula rate and CWIP. In addition, we also grant Green Power's request for waiver of section 35.13 requirements pertaining to the filing of cost statements, consistent with our prior approval of formula rates.[111] Nonetheless, to the extent that parties in the hearing procedures ordered herein can show the relevance of additional information needed to evaluate this proposal, the presiding judge can provide for appropriate discovery of such information.

F. Other Issues

116. LS Power requests that the Commission: (1) clarify that transmission incentive rates and accounting treatment, in particular abandoned plant cost recovery and regulatory asset treatment, are available to merchant transmission developers on the same terms and conditions that they are to an existing transmission owner (or its affiliate); and (2) explain what mechanisms are available to merchant developers to recover those costs. In addition, National Wind advocates for an open-season subscription process that would exist outside of the RTOs to ensure that the Project receives the proper attention it needs. Fox Ridge, Horizon Wind, and Crownbutte Wind request information on how to interconnect to the Project.

117. We find that incentives for other potential projects and questions about the process for securing transmission service over or interconnection with the Project are issues that are beyond the scope of this proceeding.

<u>The Commission orders</u>:

(A) Green Power's proposed *pro forma* tariff sheets are hereby conditionally accepted for filing, suspended and set for hearing and settlement judge procedures, as described below. The effective date for the proposed *pro forma* tariff sheets is deferred until the Green Power Project: (1) is approved by a Commission-approved regional

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[110] *See, e.g.*, *Tallgrass*, 125 FERC ¶ 61,248 at P 95; *Commonwealth Edison Co.*, 119 FERC ¶ 61,238, at P 94 (2007); *Oklahoma Gas & Electric Co.*, 122 FERC ¶ 61,071, at P 41 (2008).

[111] *Id.*

transmission planning processes; and (2) the Commission approves a cost allocation mechanism for the Project, as discussed more fully above.

(B) We direct Green Power to make a compliance filing requesting an effective date for its formula rate and proposing actual tariff sheets to replace the *pro forma* tariff sheets at least 60 days prior to its requested effective date.

(C) Green Power's request for the CWIP incentives is hereby granted, effective concurrent with the ultimate effective date for Green Power's formula rate, as discussed more fully above.

(D) Green Power's request for abandoned plant, regulatory asset and hypothetical capital structure incentives, and its request for a 10 basis point ROE adder for new transmission and a 100 basis points for being a Transco, are hereby granted, effective April 11, 2009, as discussed more fully above.

(E) Green Power's request for a 50 basis points ROE adder for RTO participation is hereby granted, effective on the date Green Power becomes a transmission owning member of an RTO and places the Project under an RTO's operational control, as discussed more fully above.

(F) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Commission by section 402(a) of the Department of Energy Organization Act and by the Federal Power Act (FPA),[112] particularly sections 205 and 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the FPA (18 C.F.R. Chapter I), a public hearing shall be held concerning the issues outlined above in Docket No. ER09-681-000. However, the hearing shall be held in abeyance to provide time for settlement judge procedures, as discussed in Ordering Paragraphs (G) – (I) below.

(G) Pursuant to Rule 603 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.603 (2008), the Chief Administrative Law Judge is hereby directed to appoint a Settlement Judge in this proceeding within fifteen (15) days of the date of this order. Such Settlement Judge shall have all the powers and duties enumerated in Rule 603 and shall convene a settlement conference as soon as practicable after the Chief Judge designates the Settlement Judge. If the parties decide to request a specific judge, they must make their request to the Chief Judge in writing or by telephone within five (5) days of the date of this order.

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[112] 16 U.S.C. § 824e (2006).

(H) Within thirty (30) days of the date of this order, the Settlement Judge shall file a report with the Commission and the Chief Judge on the status of the settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions, if appropriate, or assign this case to a presiding judge for a trial-type evidentiary hearing, if appropriate. If settlement discussions continue, the Settlement Judge shall file a report at least every sixty (60) days thereafter, informing the Commission and the Chief Judge of the parties' progress toward settlement.

(I) If settlement judge procedures fail and a trial-type evidentiary hearing is to be held, a presiding judge, to be designated by the Chief Judge, shall, within fifteen (15) days of the date of the presiding judge's designation, convene a prehearing conference in this proceeding in a hearing room of the Commission, 888 First Street, NE, Washington, DC 20426. Such a conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates and to rule on all motions (except motions to dismiss) as provided in the Commission's Rules of Practice and Procedure.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix A – Parties and Abbreviations

Parties that submitted timely interventions or interventions with comments and/or protests:

Acciona Wind Energy USA, LLC
Allegheny Power & Trans-Allegheny Interstate Line Company
Allete, Inc.
Alliant Energy Corporate Services, Inc. (Alliant Energy)
Ameren Services Company
American Electric Power Services Corporation
American Municipal Power-Ohio (AMP-Ohio)
American Transmission Company LLC
American Wind Energy Association and Wind on the Wires
Baltimore Gas and Electric Company
Basin Electric Power Cooperative (Basin Electric)
CapX2020 Participants[113]
Central Iowa Power Cooperative
Certain Midwest ISO Transmission Owners[114]
Coalition of Midwest Transmission Customers
Constellation Energy Commodities Group, Inc., Constellation NewEnergy, Inc. & Constellation Power Source Generation, Inc.
Consumers Energy Company (Consumers Energy)
Crownbutte Wind Power, Inc. (Crownbutte Wind)
Dairyland Power Cooperative (Dairyland)
Dayton Power and Light Company
Delaware Public Service Commission
Denali Energy & Montgomery Power Partners (Craig Fink) (Denali Energy Partners)

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[113] CapX 2020 Participants joining this filing are Central Minnesota Municipal Power Agency, Dairyland, Great River, Minnesota Power, Missouri River Energy Services, Otter Tail, Rochester Public Utilities, Southern Minnesota Municipal Power Agency, the Northern States Power Company of Minnesota, Northern States Power Company of Wisconsin, and WPPI Energy.

[114] The Certain Midwest ISO Transmission Owners for this filing consist of: City of Columbia Water and Light Department (Columbia, MO); City Water, Light & Power (Springfield, IL); Duke Energy Business Services, LLC for Duke Energy Ohio, Inc., Duke Energy Indiana, Inc., and Duke Energy Kentucky, Inc.; Indianapolis Power & Light Company; Michigan Public Power Agency; Northern Indiana Public Service Company; Southern Indiana Gas & Electric Company; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.

Dominion Resources Services, Inc.
Duquesne Light Company
Electric Transmission America
Exelon Corporation
FirstEnergy Service Company
Great River Energy (Great River)
Hoosier Energy Rural Electric Cooperative, Inc.
Horizon Wind Energy LLC (Horizon Wind)
Iberdrola Renewables, Inc.
Illinois Commerce Commission
Indiana Utility Regulatory Commission
Indicated PJM and Midwest ISO Members[115]
Integrys Energy Group (Integrys)
Iowa Office of Consumer Advocate
Iowa Utilities Board
LS Power Associates, L.P. (LS Power)
Michigan Public Service Commission
MidAmerican Energy Company
Midwest Independent Transmission System Operator, Inc.
Midwest TDUs[116]

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[115] American Transmission Systems, Incorporated, The Cleveland Electric Illuminating Company, Jersey Central Power & Light Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Electric Company, and Pennsylvania Power Company, all subsidiaries of FirstEnergy Corp.; Baltimore Gas and Electric Company; Virginia Electric and Power Company; Monongahela Power Company, The Potomac Edison Company and West Penn Power Company, all doing business as Allegheny Power, and Trans-Allegheny Interstate Line Company; Pepco Holdings, Inc., and its subsidiaries Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company; Public Service Electric and Gas Company, PSEG Energy Resources & Trade LLC, PSEG Power LLC; Old Dominion Electric Cooperative; PPL Electric Utilities Corporation; Exelon Corporation on behalf of its operating company affiliates Commonwealth Edison Company (and its wholly-owned subsidiary Commonwealth Edison Company of Indiana, Inc.) and PECO Energy Company; Dayton Power and Light Company.

[116] Midwest TDUs includes Great Lakes Utilities, Lincoln Electric System, Madison Gas & Electric Company, Midwest Municipal Transmission Group, Missouri Joint Municipal Electric Utility Commission, Missouri River Energy Services, Southern Minnesota Municipal Power Agency, and WPPI Energy.

Minnesota Public Utilities Commission & Minnesota Office of Energy Security
Montana Consumer Counsel
Montana Public Service Commission
Montana-Dakota Utilities
NextEra Energy Resources, LLC
North Carolina Agencies[117]
North Dakota Public Service Commission
Northern Indiana Public Service Company
NorthWestern Energy Corporation
Old Dominion Electric Cooperative
Otter Tail Power Company (Otter Tail)
Pepco Holdings Inc.
PHI Companies[118]
PJM Interconnection, L.L.C. (PJM)
PPL Electric Utilities Corporation
Public Service Commission of Wisconsin
Public Service Electric and Gas Company & PSEG Energy Resources & Trade LLC & PSEG Power LLC
Renewable Energy Systems Americas Inc. (RES Americas)
Root River Energy, LLC
South Dakota Public Utilities Commission
Southern Illinois Power Cooperative
The Detroit Edison Company
Western Area Power Administration
Wind Capital Group
Wisconsin Electric Power Company
Wisconsin Industrial Energy Group
Xcel Energy Services Inc. (Xcel)

Parties that filed late interventions or late interventions with comments:
Generation Energy, Inc. (Richard Haddon)
Emmet County Energy, LLC

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[117] The North Carolina Agencies include the North Carolina Utilities Commission, Attorney General of the State of North Carolina, and Public Staff-North Carolina Utilities Commission.

[118] The PHI Companies are members and active participants in the PJM and include Pepco Holdings, Inc., a holding company, and Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company

Fox Ridge Energy and Development Association (Fox Ridge)
Goodhue Wind, LLC
M-Power, LLC
National Wind LLC (National Wind)
Organization of MISO States
Red Rock Wind Energy, LLC
Public Utilities Commission of Ohio
Wind Capital Group

Document Content(s)

147 FERC ¶ 61,179
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Acting Chairman;
Philip D. Moeller, John R. Norris,
and Tony Clark.

MidAmerican Transco Central California Transco, LLC Docket No. ER14-1661-000

ORDER ON TRANSMISSION RATE INCENTIVES AND TRANSMISSION OWNER TARIFF

(Issued June 3, 2014)

1. On April 4, 2014, MidAmerican Central California Transco, LLC (MidAmerican Transco) filed a request to recover certain transmission rate incentives pursuant to sections 205 and 219 of the Federal Power Act[1] (FPA) and Order No. 679[2] for its investment in the 230 kV Central Valley Transmission Upgrade Project in Central California (Project). MidAmerican Transco also filed an initial transmission owner tariff (TO Tariff), which includes a proposed formula rate designed to calculate MidAmerican Transco's annual transmission revenue requirement for inclusion in the California Independent System Operator Corporation's (CAISO) transmission access charge (TAC). As discussed below, this order grants MidAmerican Transco's request for certain transmission rate incentives, accepts MidAmerican Transco's TO Tariff for filing, suspends it for a nominal period to be effective June 5, 2014, and establishes hearing and settlement judge procedures.

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[1] 16 U.S.C. §§ 824d, 824s (2012).

[2] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236, *order on reh'g*, 119 FERC ¶ 61,062 (2007). The Commission provided additional guidance regarding the application of its transmission incentive policies in *Promoting Transmission Investment Through Pricing Reform*, 141 FERC ¶ 61,129 (2012) (2012 Incentives Policy Statement).

I. Background

2. MidAmerican Transco is a wholly owned subsidiary of MidAmerican Transmission, LLC, which is a wholly owned subsidiary of MidAmerican Energy Holdings Company. MidAmerican Transco states that it was formed to construct, finance, own, operate, and maintain new high-voltage electric transmission facilities as a participating transmission owning-member of CAISO.

3. The Project consists of an overhead 68-mile, 230 kV double circuit transmission line connecting Pacific Gas and Electric Company's (PG&E) Gates Substation and Gregg Substation. According to MidAmerican Transco, the Project will use towers designed for a double circuit, but will initially operate as a single circuit, consistent with CAISO's 2012-2013 Transmission Plan.[3]

4. MidAmerican Transco explains that the Project was identified in CAISO's 2012-2013 Transmission Plan as a reliability project.[4] In addition, MidAmerican Transco states that CAISO determined that the Project would generate policy and economic benefits and would, therefore, be eligible for competitive solicitation.

5. MidAmerican Transco states that PG&E and MidAmerican Transmission, LLC submitted a competitive bid to construct, own, and operate the Project under CAISO's transmission planning process and, subsequently, were selected by CAISO to develop the Project. MidAmerican Transco explains that it owns 50 percent of the Project and PG&E owns the remaining 50 percent as tenants in common. Once the Project enters service, MidAmerican Transco states that 25 percent of the Project's transfer capability will be leased to Citizens Energy Corporation (Citizens) under a 30-year lease arrangement, with PG&E and MidAmerican Transco each holding 37.5 percent of the Project's transfer capability.[5] MidAmerican Transco states that the total Project costs are estimated to be $157 million, not including contingencies and inflation.[6]

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[3] MidAmerican Transco April 4, 2014 Filing (MidAmerican Transco Filing) at 2, n.5.

[4] *See* CAISO's 2012-2013 Transmission Plan at 372, *available at:* https://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf.

[5] MidAmerican Transco Filing at 2, n.8.

[6] *Id.* at 2.

6. MidAmerican Transco requests certain transmission rate incentives for the Project: (1) recovery of pre-commercial costs that are not capitalized and included in construction work in progress (CWIP) and authorization to establish a regulatory asset to include all such expenses (Regulatory Asset Incentive), (2) a hypothetical capital structure of 52 percent equity and 48 percent debt (Hypothetical Capital Structure Incentive), (3) recovery of prudently incurred costs in the event that the Project must be abandoned for reasons outside MidAmerican Transco's control (Abandonment Incentive), and (4) a 50 basis point return on equity (ROE) adder for participation in a regional transmission organization (RTO), i.e., CAISO (RTO Participation Adder).

7. In addition to the requested rate incentives, MidAmerican Transco also filed an initial TO Tariff, which includes a template for a cost-of-service formula rate and implementation protocols. MidAmerican Transco requests that the Commission grant its request for transmission rate incentives effective as of the date the Commission issues an order on the instant filing and accept its proposed TO Tariff to be effective June 3, 2014.

II. Notice of Filing and Responsive Pleadings

8. Notice of the MidAmerican Transco Filing was published in the *Federal Register*, 79 Fed. Reg. 21,195 (2014), with interventions or protests due on or before April 25, 2014. Timely motions to intervene were filed by the Modesto Irrigation District; Trans Bay Cable, LLC; the Transmission Agency of Northern California; the City of Santa Clara, California; PG&E; and Citizens. M-S-R Public Power Agency (M-S-R) filed a timely motion to intervene and protest. Transource Energy, LLC (Transource), Southern California Edison Company (SoCal Edison), the California Department of Water Resources State Water Project (SWP), and the Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (Six Cities) filed motions to intervene out-of-time and the California Public Utilities Commission (CPUC) filed a late-filed motion to intervene and protest. MidAmerican Transco filed a motion for leave to answer and answer to the protests filed by M-S-R and the CPUC.

A. Protests

9. M-S-R and CPUC argue that MidAmerican Transco's claims of financial uncertainty—i.e., that it is a start-up company with no financial history or source of regular cash flow—are disingenuous. M-S-R and CPUC contend that MidAmerican Transco's parent company, MidAmerican Energy Holdings Company, has reported $70 billion in assets and that the Commission should consider MidAmerican Transco's corporate structure in evaluating its request for incentive rate treatment. Absent this evaluation, M-S-R warns that any entity could obtain incentive rate treatment by simply

forming a subsidiary corporation.[7] Similarly, CPUC argues that ratepayers should not bear additional financial risk because of MidAmerican Transco's chosen financial structure.[8]

10. M-S-R and CPUC state that CAISO's 2012-2013 Transmission Plan reflects an estimated cost of the Project between $115 million and $145 million, which MidAmerican Transco's $157 million estimate already exceeds. M-S-R and CPUC argue that, in order to ensure that excessive expenditures are not charged to customers, the Commission should limit the application of incentives to the estimate of the Project's costs considered in CAISO's 2012-2013 Transmission Plan.[9] CPUC adds that the financial, regulatory, and competitive challenges MidAmerican Transco faces are typical for new transmission investments and that the size and cost of MidAmerican Transco's project are lower than those of other California transmission lines for which the Commission has authorized incentive rates.[10] Further, CPUC notes there is no evidence to show that there are risks associated with CAISO's competitive solicitation process for selecting transmission project sponsors that warrant rate incentives.[11]

11. M-S-R and CPUC each contend that MidAmerican Transco's proposed ROE is overstated and calculated in a manner that is inconsistent with Commission policy. M-S-R and CPUC respectively argue that MidAmerican Transco's proposed methodology is inconsistent with Commission precedent, which requires that utilities use the median of the discounted cash flow (DCF) analysis.[12] M-S-R requests that the Commission direct MidAmerican Transco to submit a compliance filing revising its base ROE to reflect the median of the DCF analysis, and request that the Commission set the DCF analysis for hearing.[13]

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[7] M-S-R April 25, 2014 Protest at 6-8 (M-S-R Protest).

[8] CPUC May 7, 2014 Protest at 4-5 (CPUC Protest).

[9] M-S-R Protest at 8, CPUC Protest at 6-7.

[10] CPUC Protest at 4.

[11] *Id.* at 5.

[12] M-S-R Protest at 9-14, CPUC Protest at 6.

[13] M-S-R Protest at 14.

12. M-S-R also disputes MidAmerican Transco's proposal to use the depreciation rate established during PG&E's latest rate proceeding. M-S-R argues that the PG&E settlement was not precedential and "would not be the basis for any decision with regard to the burden of proof in any litigation with regard to such matter."[14]

13. M-S-R requests that the Commission direct MidAmerican Transco to revise two aspects of its formula rate protocols that it asserts contradict Commission precedent.[15] Specifically, M-S-R argues that MidAmerican Transco's proposed formula rate protocols involve requirements that could be read to limit a party's ability to raise issues that had not previously been raised informally in formal challenges under Rule 206 of the Commission's Rules of Practice and Procedure. M-S-R also argues that MidAmerican Transco inappropriately incorporates references to Rule 206 in describing the availability of formal challenges under its formula rate protocols.[16]

14. CPUC states that while it does not necessarily oppose MidAmerican Transco's implementation of a formula rate, the formula rate proposal in this instance requires additional scrutiny and discovery and should be set for hearing.[17]

B. MidAmerican Transco's Answer

15. MidAmerican Transco argues that, contrary to M-S-R and CPUC's assertions, it has identified specific financial, developmental, regulatory, and competitive process risks that support its requested package of transmission rate incentives. MidAmerican Transco argues that Commission precedent dictates that the Commission analyze its request for transmission rate incentives as a start-up company, rather than considering the financial resources of its corporate parent.[18] MidAmerican Transco contends that it is appropriate to consider its status as a start-up company because potential creditors will evaluate MidAmerican Transco on the basis of its own creditworthiness without regard to the

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[14] *Id.* at 14-15 (citing PG&E TO-14 Settlement at Article III, Section 3.1, as accepted in *Pacific Gas & Elec. Co.*, 146 FERC ¶ 61,034 (2014)).

[15] *Id.* (citing *Midcontinent Indep. Sys. Operator, Inc.*, 146 FERC ¶ 61,212, at PP 108, 111-112 (2014) (*MISO*)).

[16] M-S-R Protest at 15-17.

[17] CPUC Protest at 7.

[18] MidAmerican Transco May 12, 2014 Answer (MidAmerican Transco Answer) at 4, n.13 (citing *Potomac Appalachian Highline, L.L.C.*, 122 FERC ¶ 61,188, at P 39 (2008) (*PATH*)).

creditworthiness of its corporate parent. In response to CPUC's claim that the Commission typically approves incentive rate requests for projects smaller in cost and size than the Project, MidAmerican Transco states that the Commission recently approved similar incentives for a project with an estimated cost of $64.8 million.[19]

16. MidAmerican Transco also argues that the Commission should not limit incentives to the bid costs submitted in the CAISO competitive process or the cost estimate in CAISO's 2012-2013 Transmission Plan. MidAmerican Transco states that CAISO's competitive solicitation process does not require bidders to submit financially binding cost estimates. Instead, MidAmerican Transco states that the estimate reflected in CAISO's 2012-2013 Transmission Plan for the Project was predicated on the cost estimate included in MidAmerican Transco's bid and was not intended to serve as a cost cap.[20]

17. MidAmerican Transco argues that it has adequately supported its requested ROE and requests that the Commission set any issues regarding its proposed ROE for hearing. MidAmerican Transco also argues that its proposal to adopt PG&E's depreciation rates is appropriate because, since the project is not built, MidAmerican Transco lacks the historical data needed to support an analysis of service life and net salvage characteristics for its Project and because PG&E operates similar facilities in the same area. MidAmerican Transco also notes that the Commission previously approved an arrangement in which a new transmission developer's depreciation rates mirrored those of a corporate parent.[21]

18. Finally, MidAmerican Transco states that its proposed formula rate protocols will permit issues not raised in an informal challenge to nevertheless be raised in a formal challenge, so long as the customer submitted an informal challenge to MidAmerican Transco with respect to one or more issues. MidAmerican Transco states that it does not object to eliminating the reference in its protocols to Rule 206 of the Commission's Rules of Practice and Procedure, consistent with the *MISO* decision,[22] in a subsequent compliance filing if the Commission so directs.

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[19] MidAmerican Transco Answer at 3 (citing *Transource Missouri, LLC*, 141 FERC ¶ 61,075, at P 4 (2012)).

[20] *Id.* at 5.

[21] *Id.* at 7 (citing *RITELine Illinois, LLC*, 137 FERC ¶ 61,039 (2011)).

[22] *See supra* n.18.

III. Discussion

A. Procedural Matters

19. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2013), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2013), the Commission will grant the late-filed motions to intervene of Transource, SoCal Edison, Six Cities, SWP, and CPUC given their respective interests in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.[23]

20. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2013), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept MidAmerican Transco's answer because it provided information that assisted us in our decision-making process.

B. Substantive Matters

21. In the Energy Policy Act of 2005, Congress added section 219 to the FPA, directing the Commission to establish, by rule, incentive-based rate treatments to promote capital investment in transmission infrastructure.[24] The Commission subsequently issued Order No. 679, which sets forth processes by which a public utility may seek transmission rate incentives pursuant to section 219, including the incentives requested here by MidAmerican Transco. Additionally, on November 15, 2012, the Commission issued the 2012 Incentives Policy Statement, which provides additional guidance regarding the evaluation of applications for transmission rate incentives under section 219 and Order No. 679.

1. Section 219 Requirement

22. Pursuant to Order No. 679, an applicant may seek to obtain incentive rate treatment for a transmission infrastructure investment that satisfies the requirements of section 219, i.e., the applicant must show that "the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission

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[23] MidAmerican Transco's answer indicates that it does not object to CPUC's late-filed intervention and protest.

[24] Pub. L. No. 109-58, § 1241, 119 Stat. 594 (2005).

congestion."[25] Order No. 679 established the process for an applicant to demonstrate that it meets this standard, including a rebuttable presumption that the standard is met if: (1) the transmission project results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission; or (2) a project has received construction approval from an appropriate state commission or state siting authority.[26] Order No. 679-A clarifies the operation of this rebuttable presumption by noting that the authorities and/or processes on which it is based (i.e., a regional planning process, a state commission, or siting authority) must, in fact, consider whether the project ensures reliability or reduces the cost of delivered power by reducing congestion.[27]

a. Proposal

23. MidAmerican Transco asserts that the Project meets the rebuttable presumption under Order No. 679-A because the Project was selected under a transmission planning process that has been approved by the Commission[28] and comprehensively identifies upgrades necessary to meet California's policy goals and grid reliability.[29] MidAmerican Transco states that CAISO determined that the Project would provide significant reliability benefits, such as addressing potential overload and voltage collapse conditions in the Greater Fresno area of the PG&E system.

b. Commission Determination

24. The Commission has previously determined that projects found by a regional planning process to ensure reliability are entitled to the rebuttable presumption established in Order No. 679.[30] Here, the Project was selected under an open and non-

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[25] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 76.

[26] *Id.*

[27] *Id.* P 49. *See also* Order No. 679-A, FERC Stats. & Regs. ¶ 31,236.

[28] MidAmerican Transco Filing at 5, n.12 (citing *Cal. Indep. Sys. Operator, Inc.*, 133 FERC ¶ 61,224 (2010); *see also Cal. Indep. Sys. Operator, Inc.*, 143 FERC ¶ 61,057 (2013); *see also Cal. Indep. Sys. Operator, Inc.*, 146 FERC ¶ 61,198 (2014)).

[29] *Id.* at 8, n.26 (citing CAISO's 2012-2013 Transmission Plan at 7).

[30] *See, e.g., Midwest Indep. Transmission Sys. Operator, Inc.*, 141 FERC ¶ 61,121, at P 16 (2012) (finding that two Ameren projects qualified for the rebuttable presumption based on the MISO Board's approval of each project under Criterion 1 as part of

(continued...)

discriminatory regional transmission planning process, and identified in CAISO's 2012-2013 Transmission Plan as necessary to address reliability concerns in the Greater Fresno area.[31] Therefore, we find that, because the Project is necessary to ensure grid reliability and was selected under a Commission-approved regional transmission planning process, the Project meets the rebuttable presumption and satisfies the above-noted requirements of section 219.

2. Nexus Test and Total Package of Incentives

25. An applicant for a transmission rate incentive must demonstrate a nexus between the incentives being sought and the investment being made. In Order No. 679-A, the Commission clarified that its nexus test is met when an applicant demonstrates that the total package of incentives requested is tailored to address the demonstrable risks or challenges faced by the applicant.[32] Applicants must provide sufficient support to allow the Commission to evaluate each element of the package and the interrelationship of all elements of the package. The Commission noted that this nexus test is fact-specific and requires the Commission to review each application on a case-by-case basis. The Commission has, in prior cases, approved multiple rate incentives for particular projects as long as each incentive satisfies the nexus test. This is consistent with Order No. 679 and our interpretation of section 219 authorizing the Commission to approve more than one incentive rate treatment for an applicant proposing a new transmission project, as long as each incentive is justified by a showing that it satisfies the requirements of section 219 and that there is a nexus between the incentives proposed and the investment made.[33]

a. Proposal

26. MidAmerican Transco argues that, consistent with Order Nos. 679 and 679-A, the Project satisfies the Commission's nexus test for incentive-based rate treatment because each of its requested incentives addresses demonstrable risks associated with developing the Project. For example, MidAmerican Transco states that it faces financial risks in developing the Project because it is a start-up transmission company with no business history, no established credit rating, no debt repayment history, no earning history, and

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Appendix A of the 2011 MTEP Report); *Ameren Servs. Co.*, 135 FERC ¶ 61,142, at P 31 (2011) (making the same finding regarding two other Ameren projects).

[31] *See supra* n.28.

[32] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 115.

[33] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 26.

no significant financial guarantees from its corporate parent. By granting its request for the Regulatory Asset Incentive, MidAmerican Transco explains that it will benefit from an enhanced credit rating that will lower its borrowing costs, improve its cash flow during construction, and facilitate its ability to obtain financing. Similarly, MidAmerican Transco argues that its request for the Hypothetical Capital Structure Incentive will improve its ability to obtain capital at a reasonable cost, lowering the Project's debt costs that will ultimately be borne by CAISO's customers.

27. MidAmerican Transco explains that the Abandonment Incentive is appropriate because the Project also faces certain regulatory risks, such as obtaining the regulatory approvals and rights-of-ways necessary to begin construction on the Project. MidAmerican Transco also asserts that the Abandonment Incentive is necessary to eliminate the risk that its lenders will have to bear the Project's costs if it is cancelled for reasons outside of MidAmerican Transco's control.

28. In light of its request for these transmission rate incentives, MidAmerican Transco states that it has not requested any ROE-based incentives other than the 50 basis point adder, which it states is appropriate given its commitment to join and transfer operational control of the Project to CAISO. MidAmerican Transco asserts that its requested package of incentives will reduce the Project's risks and, therefore, render other ROE-based incentives beyond the 50 basis point adder unnecessary, consistent with the guidance provided in the 2012 Incentives Policy Statement.

b. Commission Determination

29. We find that MidAmerican Transco has satisfied the requirements of the nexus test, as required by Order Nos. 679 and 679-A and clarified in the 2012 Incentives Policy Statement.[34] The total package of incentives that MidAmerican Transco requests appropriately addresses the risks and challenges specific to the Project, such as the need for low borrowing costs, easy access to capital, and protection against regulatory risks during the development process. We find that the total package of incentives addresses risks associated with establishing creditworthiness, minimizing the risk associated with possible cancellation of the Project due to circumstances outside MidAmerican Transco's control, and the potential volatility in capital structure as the Project progresses. Also, the RTO Participation Adder incentive acts to encourage MidAmerican Transco to join and remain a member of CAISO. This total package of incentives is tailored to the specific risks associated with MidAmerican Transco's development of the Project, will tend to minimize costs to be passed through to CAISO's customers, and avoids the

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[34] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 26; Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 27.

necessity of potential additional ROE adders to appropriately incent transmission development. Therefore, we find that the total package of incentives is tailored to address those specific risks and challenges, consistent with Order Nos. 679 and 679-A and as clarified in the 2012 Incentives Policy Statement. As discussed below, we grant the request for proposed rate incentives, effective on the date of issuance of this order.

3. Regulatory Asset Incentive

a. Proposal

30. MidAmerican Transco requests that the Commission allow it to recover all pre-commercial costs that are not capitalized and included in CWIP, including costs incurred prior to submitting the instant filing, through a regulatory asset.[35] Once MidAmerican Transco begins recovering its costs through CAISO's TAC pursuant to the formula rate proposed in the instant filing, MidAmerican Transco explains that it will discontinue the practice of booking charges to the regulatory asset and begin to amortize the regulatory asset over five years. MidAmerican Transco states that, at that time, it will begin recovering those expenses through the formula rate, as they are incurred. MidAmerican Transco also requests the Commission's authorization to accrue monthly carrying charges on the regulatory asset balances beginning on the effective date of a Commission order approving its request for the regulatory asset incentive, until the regulatory asset is included in rate base.[36]

31. MidAmerican Transco states that it faces financial risks in developing the Project because it is a start-up transmission company with no business history, no established credit rating, no debt repayment history, no earning history, and no significant financial guarantees from its corporate parent. By granting its request to establish a regulatory asset to recover all prudently incurred pre-commercial costs, MidAmerican Transco explains that it will benefit from an enhanced credit rating that will reduce its interest expenses, improve its cash flow during construction, and facilitate its ability to obtain financing. MidAmerican Transco asserts that the Commission has recognized that the

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[35] These costs could include attorney and consultant fees, administrative expenses, travel expenses, development surveys, and costs to support planning activities that are or have been incurred by MidAmerican related to the project, including appropriate costs incurred prior to MidAmerican Transco's submission of the instant filing. MidAmerican Transco Filing at 13.

[36] MidAmerican Transco Filing at 14.

Regulatory Asset Incentive will help enhance a project developer's credit quality, thereby lowering its borrowing costs.[37]

b. Commission Determination

32. We will grant MidAmerican Transco's request to establish a regulatory asset for the recovery of all prudently incurred pre-commercial costs that are not capitalized and included in CWIP before the effective date of its formula rate as a regulatory asset up to the date that charges are assessed to CAISO customers through the CAISO TAC under the formula rate. We find that this incentive is tailored to the risks and challenges posed by the Project, as discussed above, because this incentive will provide MidAmerican Transco with added up-front regulatory certainty and reduce interest expense, improve coverage ratios, and assist in the construction of the Project.

33. We also approve MidAmerican Transco's request to accrue a carrying charge from the effective date of the regulatory asset until the asset is included in rate base. We accept MidAmerican Transco's proposal to amortize the regulatory asset over five years, consistent with rate recovery. MidAmerican Transco must record all associated carrying charges by debiting Account 182.3 and crediting Account 421, Miscellaneous Nonoperating Income.[38] Further, we authorize MidAmerican Transco to amortize the regulatory asset and related carrying charges associated with the Projects by debiting Account 566 and crediting Account 182.3, consistent with Commission precedent.[39] Once MidAmerican Transco begins to include the initial regulatory asset in rate base as

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[37] *Id.* at 13 (citing *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188, at P 52 (2008) (*PATH*), *order on reh'g*, 133 FERC ¶ 61,152 (2010)).

[38] *See Revisions to Uniform Systems of Accounts to Account for Allowances under the Clean Air Act Amendments of 1990 and Regulatory-Created Assets and Liabilities and to Form Nos. 1, 1-F, 2 and 2*-A, Order No. 552, FERC Stats. and Regs., Regulations Preambles January 1991- June 1996 ¶ 30,967, at 30,825 (requiring that deferred returns and/or carrying charges accrued on regulatory assets be credited to Account 421, Miscellaneous Nonoperating Income).

[39] *See PATH*, 122 FERC ¶ 61,188 at P 154.

part of its revenue requirement, it will earn a return on the unamortized balance of the regulatory asset and, therefore, MidAmerican Transco must stop accruing carrying charges on such regulatory asset.[40]

34. We note that MidAmerican Transco proposes to accrue monthly carrying charges on the regulatory asset balance, including the balance of deferred carrying charges.[41] This proposal has the effect of compounding interest on a monthly basis, which the Commission has previously found to be excessive.[42] Consistent with Commission precedent, the appropriate carrying charge should not result in a higher amount of interest than is allowed for construction expenditures that accrue an allowance for funds used during construction (AFUDC). The Commission's requirements for AFUDC restrict the compounding of interest to no more frequent than semi-annual. Therefore, we will require MidAmerican Transco to restrict the compounding of interest to no more frequently than semi-annually when accruing carrying charges.

35. While this order provides MidAmerican Transco with the ability to record pre-commercial costs as a regulatory asset, MidAmerican Transco must make a section 205 filing to demonstrate that the pre-construction costs are just and reasonable. In that filing, MidAmerican Transco must establish that the costs included in the regulatory asset are costs that would otherwise have been chargeable to expense in the period incurred, and parties will be able to challenge these costs at that time.

4. Hypothetical Capital Structure Incentive

a. Proposal

36. MidAmerican Transco proposes a hypothetical capital structure of 48 percent debt and 52 percent equity, which it states aligns closely with PG&E's capital structure.[43] MidAmerican Transco states it will use its actual capitalization in its proposed formula rate once the Project enters commercial operation. MidAmerican Transco asserts that its

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[40] *See, e.g., Green Power Express LP*, 127 FERC ¶ 61,031 at PP 59-60 (2009); *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 at PP 84, 117 (2009); *RITELine*, 137 FERC ¶ 61,039 at P 96.

[41] MidAmerican Transco Filing, Appendix G at 6.

[42] *See DATC Midwest Holdings, LLC*, 139 FERC ¶ 61,224, at P 71 (2012) (requiring DATC to restrict the compounding of interest to no more frequently than semi-annually).

[43] MidAmerican Transco Filing at 14.

request for the hypothetical capital structure incentive is reasonable and appropriate to reduce the risk associated with raising capital during the construction period, during which its actual capital structure may vary. MidAmerican Transco further states that it will operate with capital infusions from its parent company initially, but that as construction of the Project progresses, MidAmerican Transco will require significant borrowings and additional capital infusions. As a result, according to MidAmerican Transco, the precise debt-to-equity ratio will vary over time.[44]

37. MidAmerican Transco argues that the use of a stable debt-to-equity ratio for ratemaking purposes during construction will provide certainty to lenders and improve its access to capital at a reasonable cost. MidAmerican Transco also asserts that the Commission has found that use of a hypothetical capital structure will result in lower debt costs and permit the borrowing company to vary its financing vehicles according to its construction needs and other financial and regulatory conditions.[45] In addition, MidAmerican Transco states that the Commission has approved hypothetical capital structures with an equity component greater than the 52 percent equity requested,[46] and further notes that the Commission has previously approved a hypothetical capital structure for an entity without an existing capital structure that is designed to align with the capital structure of a project partner.[47]

b. <u>Commission Determination</u>

38. We find that MidAmerican Transco has made a sufficient showing that the requested hypothetical capital structure is tailored to address the risks of its investment in the Project. We find that MidAmerican Transco has demonstrated that a hypothetical capital structure will address the risks and challenges related to raising capital during the construction phase of the Project. We also find that a hypothetical capital structure will assist MidAmerican Transco in maintaining low debt costs while its actual debt-to-equity ratio varies. Accordingly, we will grant MidAmerican Transco's request to use of a hypothetical capital structure of 52 percent equity and 48 percent debt until the Project enters commercial operation.

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[44] *Id.* at 15.

[45] *Id.* (citing *PATH*, 122 FERC ¶ 61,188 at P 55).

[46] *Id.* (citing *Transource Missouri, LLC*, 141 FERC ¶ 61,075, at P 66 (2012) (additional citations omitted)).

[47] *Id.* (citing *Citizens Energy Corp.*, 129 FERC ¶ 61,242, at P 22 (2009)).

5. Abandonment Incentive

a. Proposal

39. MidAmerican Transco requests the ability to recover prudently incurred costs in the event the Project must be abandoned for reasons outside the reasonable control of MidAmerican Transco. MidAmerican Transco asserts that the Abandonment Incentive is appropriate to eliminate the risks that lenders and shareholders may have to bear costs incurred on transmission projects that are cancelled for reasons beyond the developers control and that such risks are potential disincentives to undertaking the Project. MidAmerican Transco adds that the Commission has found the abandonment costs incentive to be effective in encouraging transmission development by reducing the risk of non-recoverable costs.[48]

40. MidAmerican Transco asserts that the Project faces a number of risks that could lead to abandonment, such as environmental, regulatory, siting, and rights-of-way acquisition risks. In addition, MidAmerican Transco argues that, because the Project is one of the first projects approved by CAISO in connection with CAISO's competitive solicitation process, there is the potential for challenges to CAISO's selection of MidAmerican Transco and PG&E as the project sponsors.[49]

b. Commission Determination

41. We will grant MidAmerican Transco's request to recover prudently incurred costs in the event that the Project is abandoned for reasons beyond MidAmerican Transco's control, subject to MidAmerican Transco filing under section 205 of the FPA for recovery of abandonment costs. In Order No. 679, the Commission found that the abandonment incentive is an effective means of encouraging transmission development by reducing the risk of non-recovery of costs.[50] In particular, we find persuasive MidAmerican Transco's argument that this incentive addresses financial risks and challenges that MidAmerican Transco could face with its lenders by assuring cost recovery for prudently incurred costs in the event of an abandonment that is beyond MidAmerican Transco's control.

42. We note, however, that if the Project is cancelled before it is completed, MidAmerican Transco would be required to make a filing under section 205 of the FPA

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[48] *Id.* (citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 163).

[49] *Id.* at 16.

[50] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at PP 163-166.

to demonstrate that the costs were prudently incurred before it can recover any abandoned plant costs. MidAmerican Transco must also propose in its section 205 filing a just and reasonable rate to recover such costs. Order No. 679 specifically requires that any utility granted this incentive that then seeks to recover abandoned plant costs must submit such a section 205 filing.[51]

6. RTO Participation Adder

a. Proposal

43. MidAmerican Transco requests a 50 basis point adder to its base ROE its participation in CAISO, consistent with the Commission's determination in Order No. 679.[52] MidAmerican Transco states that it will become a member of CAISO as soon as permitted under the CAISO Tariff, transfer operational control of the Project to CAISO once the Project is placed into service, and recover its annual transmission revenue requirement through the CAISO TAC pursuant to the CAISO Tariff.

44. MidAmerican Transco argues that the 50 basis point RTO adder provides an incentive for newly established transmission developers to participate in RTOs and recognizes the benefits that flow from membership in RTO organizations. MidAmerican Transco also argues that affording new transmission developers ROE enhancements similar to those granted to existing transmission providers is important to encourage the creation of transmission-focused entities through competitive solicitation processes.

b. Commission Determination

45. We will grant MidAmerican Transco's request for a 50 basis point adder to its base ROE for its participation in CAISO, consistent with the Commission's approval of this incentive for other participating transmission owners in CAISO.[53] We note that our approval of this incentive is based on MidAmerican Transco's commitment to become a member of CAISO, transfer functional control of the Project to CAISO once the Project enters service, and recover the Project's costs through the CAISO TAC.[54]

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[51] *Id.* P 166.

[52] MidAmerican Transco Filing at 16 (citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 326; Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 86).

[53] *Pacific Gas and Electric Co.*, 144 FERC ¶ 61,227 (2013).

[54] MidAmerican Transco Filing at 16.

7. Issues Raised by Intervenors

46. We agree that the Commission may evaluate MidAmerican Transco's request for transmission rate incentives as a request made by a new transmission developer rather than considering the financial resources of MidAmerican Transco's corporate parent. This is consistent with Commission precedent in *PATH*. Thus, we will not alter our decision to grant MidAmerican Transco's requested package of transmission rate incentives based on MidAmerican Transco's corporate parent structure, as requested by M-S-R and CPUC.

47. We also disagree with CPUC that the size and scope of the Project warrants rejection of MidAmerican Transco's request for transmission rate incentives. Our decision to award incentives is based on MidAmerican Transco qualifying for the rebuttable presumption and satisfying the nexus test, as discussed above.

48. Similarly, we reject requests to impose a cap on the dollar amount of costs that are eligible for the transmission rate incentives in this proceeding. All costs included and recovered in rates are subject to prudency considerations and this order only approves transmission rate incentives that apply to prudently incurred costs. Parties will have the opportunity to raise issues concerning the prudency of these costs in subsequent proceedings under MidAmerican Transco's TO Tariff, and we find those subsequent proceedings to be the appropriate place for the determination of costs to be recovered.

8. Citizens Energy Lease Payment

a. Proposal

49. MidAmerican Transco states that it, along with PG&E, will lease a combined total of 25 percent of the Project's transmission capacity through a Transmission Capacity Lease Agreement to Citizens for a period of 30 years. MidAmerican Transco explains that it will retain title to its share of the Project facilities and that the transfer capability of the facilities will revert to MidAmerican Transco upon the expiration of the lease term. MidAmerican Transco expects the lease payment to be prepaid in a lump sum at the closing of the transaction after Citizens exercises the option and will be allocated over the lease term. MidAmerican Transco states that the lease payment will be the proportionate share, i.e. the 25 percent of capacity that Citizens will lease, of actual costs incurred by MidAmerican Transco and PG&E to develop, design, permit, engineer, and construct the Project.[55]

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[55] *Id.* at 26.

50. MidAmerican Transco proposes to record the lease payment in Account 253, Other Deferred Credits, and to amortize the amount to Account 412, Revenues from Electric Plant Leased to Others, over the life of the lease. Also, MidAmerican Transco proposes to record a proportionate share of the Project's original cost that is leased to Citizens in Account 104, Electric Plant Leased to Others, and to depreciate this amount to Account 413, Expenses of Electric Plant Leased to Others, over the 30-year lease term. MidAmerican Transco represents that this accounting will exclude the original cost of the leased property from its transmission plant accounts and rate base under its formula rate. MidAmerican Transco also states that its accounting will transparently ensure that CAISO's transmission customers will not be exposed to any risk that MidAmerican Transco would seek to recover the capital cost attributable to the initial capital investment in the Project already recovered through Citizens' cost-of-service revenue requirement. Finally, MidAmerican Transco explains that it will record operation and maintenance costs and administrative and general costs associated with the leased portion of the Project in Account 413, and any compensation received from Citizens in Account 412, neither of which are included in its formula rate.

b. Commission Determination

51. MidAmerican Transco's accounting for the lease prepayment and the costs of the Project leased to Citizens is consistent with the Commission's Uniform System of Accounts and precedent.[56] Accordingly, MidAmerican Transco must follow this accounting and implement sufficient internal controls and procedures to ensure all costs and revenues associated with the portion of the Project leased to Citizens are recorded in the appropriate accounts and excluded from transmission formula rates.

9. MidAmerican Transco's Proposed TO Tariff

a. Proposal

52. In addition to the requested rate incentives, MidAmerican Transco also filed an initial TO Tariff, which includes a proposed cost-of-service formula rate template and proposed implementation protocols. In the TO Tariff, MidAmerican Transco proposes a base ROE of 10.8 percent, based on the average of the median results of three methods for calculating ROE: (1) the DCF analysis, (2) the utility risk premium approach, and (3) the Empirical Capital Asset Pricing Model.[57] MidAmerican Transco proposes

[56] 18 C.F.R. pt. 101 (2013). *See San Diego Gas & Electric Company*, 129 FERC ¶ 61,233 (2009).

[57] MidAmerican Transco Filing at 23.

depreciation rates based on those approved for use in PG&E's transmission revenue requirement.[58] MidAmerican Transco argues that it is appropriate to use PG&E's depreciation rates because it will be a tenant in common with PG&E and has no historical data of its own to support an analysis of service life and net salvage characteristics.

53. In the formula rate, MidAmerican Transco proposes to forecast its net revenue requirement for each calendar year, which will be assessed to CAISO's customers on January 1 of the succeeding year. MidAmerican Transco states that it will begin recovering pre-commercial costs through the CAISO TAC prior to the Project entering service pursuant to the CAISO Tariff. The proposed formula rate includes a true-up mechanism to ensure customers are not harmed in the event that the actual net revenue requirement is less than the billed net revenue requirement. MidAmerican Transco asserts that the proposed formula rate will provide for collection of a rate that represents its costs in the current period and greater certainty for cost recovery of capital expenditures while ensuring that customers pay only the actual cost-of-service over the life of the Project. MidAmerican Transco argues that the proposed formula rate is reasonable because it is consistent with the tariffs of other participating transmission owners, albeit modified to reflect MidAmerican Transco's unique circumstances.

54. MidAmerican Transco requests that the Commission accept the TO Tariff effective June 3, 2014.

b. <u>Commission Determination</u>

55. Other than the issues summarily resolved above, we find that MidAmerican Transco's proposed TO Tariff raises issues of material fact that cannot be resolved based on the record before us and that are more appropriately addressed in the hearing and settlement judge procedures ordered below.

56. Our preliminary analysis indicates that MidAmerican Transco's proposed TO Tariff, including, but not limited to, MidAmerican Transco's proposed ROE, depreciation rates, and formula rate protocols, has not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. Therefore, we will accept it for filing, suspend it for a nominal period, make it effective June 5, 2014, subject to refund, and set it for hearing and settlement judge procedures. We note that any determinations reached in the hearing concerning MidAmerican Transco's proposed formula rate protocols should remain consistent with guidelines set forth by the Commission in *MISO*.

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[58] *Id.* at 21 (citing *Pacific Gas and Elec. Co.*, 146 FERC ¶ 61,034 (2014)).

57. While we are setting this matter for a trial-type evidentiary hearing, we encourage the parties to make every effort to settle their dispute before the hearing procedures are commenced. To aid the parties in their settlement efforts, we will hold the hearing in abeyance and direct that a settlement judge be appointed, pursuant to Rule 603 of the Commission's Rules of Practice and Procedure.[59] If the parties desire, they may, by mutual agreement, request a specific judge as the settlement judge in the proceeding, otherwise the Chief Judge will select a judge for this purpose.[60] The settlement judge shall report to the Chief Judge and the Commission within thirty days of the date of the appointment of the settlement judge, concerning the status of settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions or provide for commencement of a hearing by assigning the case to a presiding judge.

The Commission orders:

(A) MidAmerican Transco's request for the Regulatory Asset Incentive, Hypothetical Capital Structure Incentive, Abandonment Incentive, and 50 basis point ROE adder for RTO participation for the Project is hereby granted, as discussed in the body of this order.

(B) MidAmerican Transco's proposed TO Tariff is hereby accepted for filing and suspended for a nominal period, to become effective on June 5, 2014, subject to refund, and subject to hearing and settlement judge procedures, as discussed in the body of this order.

(C) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and by the Federal Power Act, particularly sections 205 and 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the Federal Power Act (18 C.F.R. Chapter I), a public hearing shall be held in Docket No. ER14-1661-000 concerning the justness and

[59] 18 C.F.R. § 385.603 (2013).

[60] If the parties decide to request a specific judge, they must make their joint request to the Chief Judge by telephone at (202) 502-8500 within five (5) days of the date of this order. The Commission's website contains a list of Commission judges available for settlement proceedings and a summary of their background and experience (http://www.ferc.gov/legal/adr/avail-judge.asp).

reasonableness of MidAmerican Transco's proposed TO Tariff, as discussed in the body of this order. However, the hearing shall be held in abeyance to provide time for settlement judge procedures, as discussed in Ordering Paragraphs (D), (E), and (F) below.

(D) Pursuant to Rule 603 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.603 (2013), the Chief Administrative Law Judge is hereby directed to appoint a settlement judge in this proceeding within fifteen (15) days of the date of this order. Such settlement judge shall have all powers and duties enumerated in Rule 603 and shall convene a settlement conference as soon as practicable after the Chief Judge designates the settlement judge. If the parties decide to request a specific judge, they must make their request to the Chief Judge within five (5) days of the date of this order.

(E) Within thirty (30) days of the appointment of the settlement judge, the settlement judge shall file a report with the Commission and the Chief Judge on the status of the settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions, if appropriate, or assign this case to a presiding judge for a trial-type evidentiary hearing, if appropriate. If settlement discussions continue, the settlement judge shall file a report at least every sixty (60) days thereafter, informing the Commission and the Chief Judge of the parties' progress toward settlement.

(F) If settlement judge procedures fail and a trial-type evidentiary hearing is to be held, a presiding judge, to be designated by the Chief Judge, shall, within fifteen (15) days of the date of the presiding judge's designation, convene a prehearing conference in these proceedings in a hearing room of the Commission, 888 First Street, NE, Washington, DC 20426. Such a conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates and to rule on all motions (except motions to dismiss) as provided in the Commission's Rules of Practice and Procedure.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Document Content(s)

REQUEST:

Refer to paragraph 10 of the Application concerning the engineering studies and analysis of the impact of the Coal Combustion Residuals rule on the East Bend as pond. Describe in detail the type of studies that are being conducted and provide the timeline for completing those studies.

RESPONSE:

Duke Energy has engaged a third party consultant to develop a Program of Record for the long-term ash basin strategy to eventually close all coal combustion residual (CCR) surface impoundments across Duke's 22-unit coal-fired generating portfolio in compliance with CCR regulations. Their dedicated team with engineering, project estimating, regulatory and construction experience in CCR/ash management has been retained to provide the following:

1) technical and feasibility review and risk assessment of the proposed closure strategies for the 22 sites,
2) assessment of alternative approaches that could reduce cost, schedule and risk and
3) Class 4 estimates for each ash basin site.

To complete this project, the consultant plans to:

- Conduct initial site visits and assessments to verify present conditions and closure concepts

- Review the feasibility of selected ash basin closure strategies for each site, and develop assessment of associated risks and opportunities
- Prepare AACE Class 4 Estimates for each site, incorporating risk and opportunity variables into the individual site estimates

Expected Project Schedule and Deliverables

- July: Kick-off meeting, verification of the project scope and schedule
- August: Progress meeting, including draft deliverable of technical rationale for Closure Strategy for each of the 22 sites and WBS Templates for the three general closure strategy options
- September: Progress meeting to review draft estimates and risk registers and collaborate on key decisions to support the final risk elements and mitigation measures that will be incorporated in the final AACE Class 4 estimates; includes delivery of draft risk registers, estimates, and a template of the basis of estimate reports for the sites
- October: Estimated project completion date, including delivery of final Class 4 estimates with Basis of Estimates and final Risk Registers

PERSON RESPONSIBLE: Cynthia S. Lee

STAFF-DR-01-006

REQUEST:

Refer to paragraph 16 of the Application.

a. Refer to 16.c. Provide a detailed explanation for the calculation of the $0.9 million. Include any relevant work papers, spreadsheets, etc., showing the calculation of the $0.9 million.

b. Refer to 16.e. Provide a detailed explanation for the calculation of the $0.9 million. Include any relevant work papers, spreadsheets, etc., showing the calculation of the $0.9 million.

c. Refer to 16.f. Provide a detailed explanation for the calculation of the $0.9 million. Include any relevant work papers, spreadsheets, etc., showing the calculation of the $0.9 million.

RESPONSE:

a. The $0.9 million represents estimated Cost of Removal (COR) accrued for ash pond closure at East Bend from 1/1/2007 – 6/30/2015. The estimated COR is based upon a 2005 demolition study for East Bend prepared by Sargent & Lundy. This demolition study was the basis for COR accruals in Duke Energy Kentucky's 2005 depreciation study, which was implemented 1/1/2007, and is still in effect today. The assumptions outlined in the 2005 East Bend demolition study indicate that "the ash pond only needs to be pumped dry and two feet of soil cover placed over the debris and/or ash in the ash pond and seeded." This resulted in lower expected costs for the closure of the East Bend ash pond than are currently expected under CCR requirements. Based on a review of the 2005 East Bend demolition study, approximately $3 million was planned for the two feet of soil cover over the ash pond, $672 thousand was planned for seeding and mulching, and $155 thousand was planned for plugging the pipe beneath the ash pond. The $672 thousand for seeding and mulching included areas other than the ash pond, so for this estimate, it was assumed that half of the $672 thousand related to COR accruals related to the ash pond closure. These amounts can be found on page 11 of the 2005 East Bend demolition study also in the calculation of the $0.9 million COR estimate in Attachments STAFF-DR-01-006 (a) and STAFF-DR-01-006 (b), respectively. Consistent with other costs within the 2005 East Bend demolition study, 5% was added to these costs for project indirect costs and 10% was added for contingency.

b. Please see explanation and support of $0.9 million estimated COR accrued for ash pond closure at East Bend in Attachment STAFF-DR-01-006 (a).

c. The $0.9 million in entry 16.f of the Application represents the difference between the $1.8 million of expected 2015 cash flows (from row 40 on the "East Bend" tab of the file attached in response to STAFF-DR-01-001) less the $0.9 million of COR accrued to date in Attachment STAFF-DR-01-006(b).

PERSON RESPONSIBLE: Cynthia S. Lee

DEMOLITION OF "POWER BLOCK" EQUIPMENT AND FACILITIES, AND SITE FACILITIES OUTSIDE THE POWER BLOCK AREA

CONCEPTUAL COST ESTIMATE

PREPARED FOR

CINERGY CORPORATION
EAST BEND - UNIT 1 & 2

SARGENT & LUNDY

ESTIMATE NO. 18008C
PROJECT NO. 09940006
October 28, 2005

REVIEWED BY: ____________

APPROVED BY: ____________

Estimate No: 18008C

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.UN DATE: 10/31/05
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B A S I S of E S T I M A T E

CINERGY CORPORATION
EAST BEND - UNIT 1 & 2
CONCEPTUAL COST ESTIMATE
DEMOLITION OF "POWER BLOCK" EQUIPMENT AND FACILITIES,
AND SITE FACILITIES OUTSIDE THE POWER BLOCK AREA

Page: 1
Estimate No: 18008C
Project No: 09940006
Prepared by: RK / /

Estimate Date: 28OCT05

Scope

DEMOLITION AND REMOVAL OF ALL STRUCTURES AND EQUIPMENT EXCEPT AS NOTED IN THE ASSUMPTIONS

Technical Basis

SEE ASSUMPTIONS BELOW

Assumptions

- ALL COAL, FUEL OIL, AND CHEMICALS WILL BE CONSUMED PRIOR TO DEMOLITION
- NO EXTRAORDINARY ENVIROMENTAL COSTS FOR DEMOLITION HAVE BEEN INCLUDED, EXCEPT ASBESTOS ABATEMENT.
- ITEMS BURIED IN THE GROUND ARE LEFT IN PLACE
- ALL ITEMS ABOVE GRADE FLOOR ELEVATION AT THE SITE ARE DEMOLISHED AND DISPOSED OF ON SITE EXCEPT FOR THE FOLLOWING:
  * PUMPHOUSE & BARGE CELLS IN THE RIVER WILL NOT BE DEMOLISHED
  * THE SWITCHYARD WILL NOT BE DEMOLISHED
- DEMOLISHED MATERIAL HAS NO SCRAP VALUE UNLESS INDICATED OTHERWISE IN THE ESTIMATE
- TRANSPORTATION OF SCRAP MATERIAL TO A PROCESSOR IS INCLUDED
- THERE WILL BE SUFFICIENT VOLUME IN BASEMENTS, HOPPERS BELOW GRADE, OR THE ASH POND TO DISPOSE OF ALL DEBRIS
- THE ASH POND ONLY NEEDS TO BE PUMPED DRY AND TWO FEET OF SOIL COVER PLACED OVER THE DEBRIS AND/OR ASH IN THE ASH POND AND SEEDED
- TWO FEET OF SOIL COVER WILL BE PLACED OVER THE REMAINING FOUNDATIONS AT GRADE AND DISTURBED SITE AREAS, THESE AREAS WILL BE REGRADED TO BLEND INTO THE SURROUNDING GRADE AND BE SEEDED
- ALL SOIL BORROW MATERIAL IS FROM ON SITE
- ALL WORK IS BASED ON 40 HOUR WORKWEEK

Commercial Basis

1. Equipment/Material Cost

   THE QUOTED PRICES FOR METAL SCRAP VALUES ARE:

   - COPPER $1,420.00 PER TON
   - STEEL $120.00 PER TON

2. Labor Wage Rates

   THE FOLLOWING VALUES INCLUDE WAGES, DEMOLITION EQUIPMENT, ON-SITE TRANSPORTATION, DISPOSAL, INSURANCE COSTS, AND OVERHEAD & PROFIT:

- WRECKING CREW	$ 63.27/hr
- EARTHWORK	$125.35/hr
- SEEDING & MULCHING	$ 38.01/hr
- ASBESTOS	$100.00/hr

3. Labor Crews

   S & L STANDARD FOR THIS TYPE OF WORK

4. Productivity

   APPLICABLE TO OHIO AREA

5. Quantity Sources

   BASED ON S & L GENERAL ARRANGEMENT DRAWINGS AND SITE VISIT

B A S I S of E S T I M A T E

Commercial Basis continued

6. Project Schedule

7. Indirect Expenses

   CINERGY INDIRECT EXPENSES - 10% OF TOTAL DIRECT CONSTRUCTION COST

8. Escalation Rates (See Cost Summary for rates)

   NOT INCLUDED

9. Sales/Use Taxes (See Cost Summary for rates)

   NOT INCLUDED

10. Contingency (See Cost Summary for rates)

    SEE COST SUMMARY FOR RATES

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C O S T   S U M M A R Y   R E P O R T

CINERGY CORPORATION
EAST BEND - UNIT 1 & 2
CONCEPTUAL COST ESTIMATE
DEMOLITION OF "POWER BLOCK" EQUIPMENT AND FACILITIES,
AND SITE FACILITIES OUTSIDE THE POWER BLOCK AREA

Estimate No: 18008C
Project No: 09940006
Prepared by: RK / /

Estimate Date: 28OCT05

ACCT.NO.	DESCRIPTION	TOTAL EQUIPMENT COST	TOTAL MATERIAL COST	TOTAL LABOR COST	TOTAL COST
100	UNIT 1			161,000	161,000
200	UNIT 2		412,000	24,516,000	24,928,000
300	ASBESTOS REMOVAL			621,000	621,000
880	SCRAP VALUE (SEE BASIS)		-4,189,000		-4,189,000
	TOTAL CONSTRUCTION COSTS		-3,777,000	25,298,000	21,521,000
	INDIRECT EXPENSES				2,570,000
	ESCALATION				
	SALES/USE TAX				
	CONTINGENCY				6,023,000
	TOTAL PROJECT COST				30,114,000
	AFUDC				
	GRAND TOTAL COST				30,114,000

FINANCIAL ASSUMPTIONS:
ESCALATION RATES: Equipment 0.000%
Material 0.000%
Labor 0.000%
Indirects 0.000%
SALES/USE TAX RATES: Equipment 0.000% Material 0.000%
CONTINGENCY RATES: Equipment 0.0% Material 25.0% Labor 25.0% Indirects 25.0%

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'rice level: 2005

E S T I M A T E   W O R K S H E E T

CINERGY CORPORATION
EAST BEND - UNIT 1 & 2
CONCEPTUAL COST ESTIMATE
DEMOLITION OF "POWER BLOCK" EQUIPMENT AND FACILITIES,
AND SITE FACILITIES OUTSIDE THE POWER BLOCK AREA

Page: 4
Estimate No: 18008C
Project No: 09940006
Prepared by: RK / /

Estimate Date: 28OCT05

lote: Extended costs are rounded up to next thousand dollars

ACCOUNT NO.	WORK PACKAGE	DESCRIPTION	QTY UM	*** MATERIAL RATE	EQUIPMENT COST	MATERIAL COST ***	*** MNHR RATE	MNHRS	WAGE RATE	LABOR COST ***	TOTAL COST
100		UNIT 1									
100B		POWER BLOCK BUILDINGS									
				B							
100BT0		STEAM TURBINE BUILDING									
				BTO							
100BTOBYZ		CONCRETE TURBINE PEDESTAL	1700 CY				1.500	2550	63.27	161,000	161,000
				BTO BYZ							
		SUB TOTAL 100BTO						2,550		161,000	161,000
		SUB TOTAL 100BT						2,550		161,000	161,000
		TOTAL 100						2,550		161,000	161,000

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E S T I M A T E   W O R K S H E E T

Note: Extended costs are rounded up to next thousand dollars

ACCOUNT NO.	WORK PACKAGE	DESCRIPTION	QTY	UM	*** MATERIAL RATE	EQUIPMENT COST	MATERIAL COST ***	*** LABOR MNHR RATE	MNHRS	WAGE RATE	LABOR COST ***	TOTAL COST
200		UNIT 2										
200B	B	POWER BLOCK BUILDINGS										
200BBO	BBO	BOILER BUILDING										
200BBOBBO	BBO	BOILER BUILDING	1031E4	CF				0.010	103182	63.27	6,528,000	6,528,000
200BBOGBE	BBO GBE	PULVERIZED COAL BOILER	4964	TN				4.000	19856	63.27	1,256,000	1,256,000
200BBOGMZ	BBO GMZ	PA, FD AND ID FANS	649	TN				4.000	2596	63.27	164,000	164,000
200BBOGRD	BBO GRD	AIR HEATERS	1706	TN				4.000	6824	63.27	432,000	432,000
200BBOHFZ	BBO HFZ	PULVERIZERS	975	TN				3.000	2925	63.27	185,000	185,000
		SUB TOTAL 200BBO							135,383		8,565,000	8,565,000
		SUB TOTAL 200BB							135,383		8,565,000	8,565,000
200BEO	BEO	CONTROL BUILDING	392832	CF				0.010	3928	63.27	249,000	249,000
200BSO	BSO	SERVICE BUILDING	956250	CF				0.010	9563	63.27	605,000	605,000
200BTO	BTO	STEAM TURBINE BUILDING										
200BTOBTO	BTO	STEAM TURBINE BUILDING	3238E3	CF				0.010	32384	63.27	2,049,000	2,049,000
200BTOBYZ	BTO BYZ	CONCRETE TURBINE PEDESTAL	1700	CY				1.500	2550	63.27	161,000	161,000
200BTOGEZ	BTO GEZ	CONDENSERS	240	TN				4.000	960	63.27	61,000	61,000
200BTOGJZ	BTO GJZ	WATERTREATING EQUIPMENT	250	TN				3.000	750	63.27	47,000	47,000
200BTOGRB	BTO GRB	HEAT EXCHANGERS	460	TN				4.000	1840	63.27	116,000	116,000
200BTOGTA	BTO GTA	FEEDWATER PUMPS	202	TN				3.000	606	63.27	38,000	38,000
200BTOGTF	BTO GTF	CONDENSATE PUMPS	41	TN				3.000	123	63.27	8,000	8,000
200BTOGXZ	BTO GXZ	TURBINE GENERATOR	2134	TN				4.000	8536	63.27	540,000	540,000

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E S T I M A T E   W O R K S H E E T

Note: Extended costs are rounded up to next thousand dollars

ACCOUNT NO.	WORK PACKAGE	DESCRIPTION	QTY UM	MATERIAL RATE	EQUIPMENT COST	MATERIAL COST	MNHR RATE	MNHRS	WAGE RATE	LABOR COST	TOTAL COST
200BTORAZ		MAIN POWER & AUXILIARY TRANSFORMERS	567 TN	BTO RAZ			3.000	1701	63.27	108,000	108,000
200BTORDZ		SWITCHGEAR	215 TN	BTO RDZ			3.000	645	63.27	41,000	41,000
		SUB TOTAL 200BTO						50,095		3,169,000	3,169,000
		SUB TOTAL 200BT						50,095		3,169,000	3,169,000
200X		SCR BUILDINGS AND STRUCTURES		X							
200XA		SCR BLOWER BUILDING	13750 CF	XA			0.010	138	63.27	9,000	9,000
200XB		SCR SWITCHGEAR BUILDING	3630 CF	XB			0.010	36	63.27	2,000	2,000
200XC		ANHYDROUS AMMONIA TANK		XC							
200XC1		CONCRETE	78 CY	XC1			1.500	117	63.27	7,000	7,000
200XC2		STEEL TANK	47 TN	XC2			3.000	141	63.27	9,000	9,000
		SUB TOTAL 200XC						258		16,000	16,000
200XD		NH3 BUILDING	640 CF	XD			0.010	6	63.27		
200XE		SCR		XE							
200XE1		SCR SUPPORT STEEL	1268 TN	XE1			3.000	3804	63.27	241,000	241,000
200XE2		SCR AND DUCTWORK	1170 TN	XE2			4.000	4680	63.27	296,000	296,000
		SUB TOTAL 200XE						8,484		537,000	537,000
200Y		YARD AREAS AND STRUCTURES		Y							
200Y0		SHOPS		Y0							
200Y0D		WELDING SHOP BUILDING	60480 CF	Y0D			0.006	363	63.27	23,000	23,000
200Y0E		TRON SILO		Y0E							
200Y0E1		CONCRETE	6 CY	Y0E			1.500	9	63.27	1,000	1,000
200Y0E2		TRON SILO	45 TN	Y0E			3.000	135	63.27	9,000	9,000

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E S T I M A T E   W O R K S H E E T

Note: Extended costs are rounded up to next thousand dollars

				*** MATERIAL	***		*** LABOR		***		
ACCOUNT NO.	WORK PACKAGE	DESCRIPTION	QTY UM	MATERIAL RATE	EQUIPMENT COST	MATERIAL COST	MNHR RATE	MNHRS	WAGE RATE	LABOR COST	TOTAL COST
		SUB TOTAL 200Y0E						144		10,000	10,000
200Y0F		HYDRATED LIME SILO		Y0F							
200Y0F1		CONCRETE	9 CY	Y0F			1.500	14	63.27	1,000	1,000
200Y0F2		HYDRATED LIME SILO	60 TN	Y0F			3.000	180	63.27	11,000	11,000
		SUB TOTAL 200Y0F						194		12,000	12,000
		SUB TOTAL 200Y0						701		45,000	45,000
200Y1		FGD BUILDINGS AND STRUCTURES		Y1							
200Y1F		THICKENER BASIN		Y1F							
200Y1FBYZ		CONCRETE	530 CY	Y1F BYZ			1.500	795	63.27	50,000	50,000
200Y1FGNZ		THICKNER UNDERFLOW TANK	TN	Y1F GNZ							
		SUB TOTAL 200Y1F						795		50,000	50,000
200Y1Q		SLAKER BUILDING	274000 CF	Y1Q			0.010	2740	63.27	173,000	173,000
200Y1S		FGD WATER PUMPHOUSE BUILDING	162000 CF	Y1S			0.010	1620	63.27	102,000	102,000
200Y1T		FGD PUMPHOUSE BUILDING	7200 CF	Y1T			0.010	72	63.27	5,000	5,000
200Y1U		FGD BUILDING	1600E3 CF	Y1U			0.010	16000	63.27	1,012,000	1,012,000
200Y1W		FGD DISPOSAL AREA GARAGE BUILDING	180000 CF	Y1W			0.006	1080	63.27	68,000	68,000
200Y1X		FGD STACKER CONVEYOR BUILDING		Y1X							
200Y1XHHZ		MATERIAL HANDLING STACKER	135 TN	Y1X HHZ			3.000	405	63.27	26,000	26,000
200Y1XY1X		FGD STACKER CONVEYOR BUILDING	8000 CF	Y1X			0.010	80	63.27	5,000	5,000
		SUB TOTAL 200Y1X						485		31,000	31,000
200Y1Z		LIME SILO		Y1Z							
200Y1ZBYZ02		CONCRETE	1852 CY	Y1Z BYZ			1.500	2778	63.27	176,000	176,000

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E S T I M A T E   W O R K S H E E T

Note: Extended costs are rounded up to next thousand dollars

ACCOUNT NO.	WORK PACKAGE	DESCRIPTION	QTY UM	*** MATERIAL *** MATERIAL RATE	EQUIPMENT COST	MATERIAL COST	*** LABOR *** MNHR RATE	MNHRS	WAGE RATE	LABOR COST	TOTAL COST
200Y1ZCCZ		STEEL LIME SILO	52 TN	Y1Z CCZ			4.000	208	63.27	13,000	13,000
		SUB TOTAL 200Y1Z						2,986		189,000	189,000
		SUB TOTAL 200Y1						25,778		1,630,000	1,630,000
200Y2		PLANT COOLING STRUCTURES		Y2							
200Y2A		COOLING TOWER		Y2A							
200Y2AY2A		COOLING TOWER	1080E3 CF	Y2A			0.010	10800	63.27	683,000	683,000
		SUB TOTAL 200Y2A						10,800		683,000	683,000
200Y2B		CIRCULATING WATER PUMP HOUSE	42000 CF	Y2B			0.010	420	63.27	27,000	27,000
200Y2C		SERVICE WATER PUMP HOUSE	7200 CF	Y2C			0.010	72	63.27	5,000	5,000
		SUB TOTAL 200Y2						11,292		715,000	715,000
200Y3		PARTICULATE REMOVAL - DUCT AND CHIMNEY		Y3							
200Y3A		PRECIPITATOR		Y3A							
200Y3AGSZ		PRECIPITATOR	2214 TN	Y3A GSZ			4.000	8856	63.27	560,000	560,000
		SUB TOTAL 200Y3A						8,856		560,000	560,000
200Y3D		CHIMNEY		Y3D							
200Y3DBYZ		CONCRETE	5000 CY	Y3D BYZ			2.500	12500	63.27	791,000	791,000
		SUB TOTAL 200Y3D						12,500		791,000	791,000
200Y3E		DUCT		Y3E							
200Y3ECAZ		DUCTWORK	2411 TN	Y3E CAZ			4.000	9644	63.27	610,000	610,000
		SUB TOTAL 200Y3E						9,644		610,000	610,000
		SUB TOTAL 200Y3						31,000		1,961,000	1,961,000
200Y4		ASH HANDLING AREA		Y4							
200Y4OHUZ		ASH HANDLING EQUIPMENT	992 TN	Y4O HUZ			3.000	2976	63.27	188,000	188,000

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E S T I M A T E   W O R K S H E E T

Note: Extended costs are rounded up to next thousand dollars

				*** MATERIAL		***	*** LABOR			***	
ACCOUNT NO.	WORK PACKAGE	DESCRIPTION	QTY UM	MATERIAL RATE	EQUIPMENT COST	MATERIAL COST	MNHR RATE	MNHRS	WAGE RATE	LABOR COST	TOTAL COST
200Y4F		FLY ASH SILO		Y4F							
200Y4FBYZ		CONCRETE	506 CY	Y4F BYZ			1.500	759	63.27	48,000	48,000
200Y4FY4F		FLY ASH SILO	585000 CF	Y4F			0.010	5850	63.27	370,000	370,000
		SUB TOTAL 200Y4F						6,609		418,000	418,000
		SUB TOTAL 200Y4						9,585		606,000	606,000
200Y5		MATERIAL HANDLING BUILDINGS		Y5							
200Y5A		CRUSHER HOUSE BUILDING		Y5A							
200Y5AHZZ		MATERIAL HANDLING EQUIPMENT	47 TN	Y5C HZZ			3.000	141	63.27	9,000	9,000
200Y5AY5A		CRUSHER HOUSE BUILDING	486000 CF	Y5A			0.010	4860	63.27	307,000	307,000
		SUB TOTAL 200Y5A						5,001		316,000	316,000
200Y5E		CRUSHER HOUSE LIME		Y5E							
200Y5EBYZ		CONCRETE	1000 CY	Y5E BYZ			1.500	1500	63.27	95,000	95,000
200Y5EY5E		CRUSHER HOUSE LIME	18000 CF	Y5E			0.010	180	63.27	11,000	11,000
		SUB TOTAL 200Y5E						1,680		106,000	106,000
200Y5F		BARGE UNLOADER BUILDING		Y5F							
200Y5FHMZ02		COAL BARGE UNLOADER	138 TN	Y5F HMZ			3.000	414	63.27	26,000	26,000
200Y5FHMZ03		LIME BARGE UNLOADER	144 TN	Y5F HMZ			3.000	432	63.27	27,000	27,000
		SUB TOTAL 200Y5F						846		53,000	53,000
200Y5I		TRANSFER TOWERS JUNCTION HOUSE	67500 CF	Y5I			0.010	675	63.27	43,000	43,000
200Y5J		TRANSFER TOWERS	505920 CF	Y5J			0.010	5059	63.27	320,000	320,000
200Y5M		TRANSFER TOWER DRIVE HOUSE	344400 CF	Y5M			0.010	3444	63.27	218,000	218,000
200Y5N		CONVEYORS		Y5N							

E S T I M A T E   W O R K S H E E T

Note: Extended costs are rounded up to next thousand dollars

ACCOUNT NO.	WORK PACKAGE	DESCRIPTION	QTY	UM	*** MATERIAL RATE	MATERIAL EQUIPMENT COST	*** MATERIAL COST	*** LABOR MNHR RATE	MNHRS	WAGE RATE	*** LABOR COST	TOTAL COST
200Y5NHBZ01		COAL CONVEYOR	1104	TN	Y5N HBZ			3.000	3312	63.27	210,000	210,000
200Y5NHBZ03		LIME CONVEYOR	404	TN	Y5N HBZ			3.000	1212	63.27	77,000	77,000
		SUB TOTAL 200Y5N							4,524		287,000	287,000
200Y5O		TRACTOR GARAGE	18000	CF	Y5O			0.006	108	63.20	7,000	7,000
		SUB TOTAL 200Y5							21,337		1,350,000	1,350,000
200Y6		YARD STRUCTURES			Y6							
200Y6B		ELECTRICAL SWITCHGEAR BUILDING	7200	CF	Y6B			0.010	72	63.27	5,000	5,000
200Y6G		GAS STATION BUILDING	3888	CF	Y6G			0.010	39	63.27	2,000	2,000
200Y6H		GAS STORAGE BUILDING	80000	CF	Y6H			0.010	800	63.27	51,000	51,000
200Y6Q		PUMPHOUSE BUILDING	2880	CF	Y6Q			0.010	29	63.20	2,000	2,000
200Y6W		SECURITY/GATEHOUSE BUILDING	4800	CF	Y6W			0.006	29	63.27	2,000	2,000
200Y6X		VARIABLE FEED DRIVE BLDG			Y6X							
200Y6X1		VFD HEAT EXCHANGERS	6	TN	Y6X			3.000	18	63.27	1,000	1,000
200Y6X2		VFD HT EXCHANGER CONCRETE	18	CY	Y6X			1.500	27	63.27	2,000	2,000
200Y6X3		VARIABLE FEED DRIVE BUILDING	82500	CF	Y6X			0.010	825	63.27	52,000	52,000
		SUB TOTAL 200Y6X							870		55,000	55,000
		SUB TOTAL 200Y6							1,839		117,000	117,000
200Y7		MISCELLANEOUS BUILDINGS			Y7							
200Y7D		MISCELLANEOUS BRICK VALVE BUILDING	1800	CF	Y7D			0.010	18	63.27	1,000	1,000
		SUB TOTAL 200Y7							18		1,000	1,000
200Y8		CHEMICAL BUILDINGS			Y8							
200Y8D		N2 / H2 STATION BUILDING	36000	CF	Y8D			0.010	360	63.27	23,000	23,000

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E S T I M A T E   W O R K S H E E T

ote: Extended costs are rounded up to next thousand dollars

;CCOUNT NO.	WORK PACKAGE	DESCRIPTION	QTY UM	*** MATERIAL RATE	MATERIAL EQUIPMENT COST	*** MATERIAL COST	*** MNHR RATE	LABOR MNHRS	WAGE RATE	*** LABOR COST	TOTAL COST
		SUB TOTAL 200Y8						360		23,000	23,000
?00Y9		WAREHOUSES		Y9							
?00Y9A		WAREHOUSE BUILDING (#1)	324000 CF	Y9A			0.006	1944	63.27	123,000	123,000
?00Y9B		WAREHOUSE BUILDING (#2)	264000 CF	Y9B			0.006	1584	63.27	100,000	100,000
200Y9C		WAREHOUSE BUILDING (#3)	72000 CF	Y9C			0.006	432	63.27	27,000	27,000
		SUB TOTAL 200Y9						3,960		250,000	250,000
200YZ		OVERALL SITE AREA		YZ							
200YZ1		ROADS & PARKING LOTS		YZ1							
200YZ1AHA		PAVEMENT	89150 SY	YZ1 AHA			0.180	16047	63.27	1,015,000	1,015,000
		SUB TOTAL 200YZ1						16,047		1,015,000	1,015,000
200YZ3		SITE AREA EARTH COVER & SEEDING		YZ3							
200YZ3ACZ		2' OF EARTHWORK COVER IN ASH POND AND AT PLANT SITE	972000 CY	YZ3 ACZ			0.025	24300	125.35	3,046,000	3,046,000
200YZ3AFC		SEEDING & MULCHING	300 AC	1100.00 YZ3 AFC		330,000	30.000	9000	38.01	342,000	672,000
200YZ3AZZ		PLUG CIRCULATING WATER PIPE WITH SLURRY & PLACE CONCRETE AT ENDS	1 LT	82300 YZ3 AZZ		82,000				73,000	155,000
		SUB TOTAL 200YZ3				412,000		33,300		3,461,000	3,873,000
200YZ4		SITE AREA TANKS		YZ4							
200YZ4PAZ02		OIL TANKS	833 TN	YZ4 PAZ			3.000	2499	63.27	158,000	158,000
200YZ4PAZ03		CONDENSATE TANK	115 TN	YZ4 PAZ			3.000	345	63.27	22,000	22,000
200YZ4PAZ13		COAL STORAGE BOTTLE TANK	55 TN	YZ4 PAZ			3.000	165	63.27	10,000	10,000
		SUB TOTAL 200YZ4						3,009		190,000	190,000
		SUB TOTAL 200YZ				412,000		52,356		4,666,000	5,078,000
		TOTAL 200				412,000		366,117		24,516,000	24,928,000

Sargent & Lundy
Chicago

E S T I M A T E   W O R K S H E E T

Note: Extended costs are rounded up to next thousand dollars

ACCOUNT NO.	WORK PACKAGE	DESCRIPTION	QTY UM	MATERIAL RATE	EQUIPMENT COST	MATERIAL COST	MNHR RATE	MNHRS	WAGE RATE	LABOR COST	TOTAL COST
				*** MATERIAL ***			*** LABOR ***				
300		ASBESTOS REMOVAL									
300Y2A		COOLING TOWER		Y2A							
300Y2AY2B		ASBESTOS REMOVAL FROM PIPING	13800 LF	Y2A			0.450	6210	100.00	621,000	621,000
		SUB TOTAL 300Y2A						6,210		621,000	621,000
		SUB TOTAL 300Y2						6,210		621,000	621,000
		TOTAL 300						6,210		621,000	621,000

argent & Lundy
Chicago

E S T I M A T E   W O R K S H E E T

ote: Extended costs are rounded up to next thousand dollars

CCOUNT NO.	WORK PACKAGE	DESCRIPTION	QTY UM	*** MATERIAL RATE	MATERIAL EQUIPMENT COST	MATERIAL COST ***	*** LABOR MNHR RATE MNHRS	WAGE RATE	LABOR COST ***	TOTAL COST
80		SCRAP VALUE (SEE BASIS)								
80CZZ		SCRAP VALUE								
80CZZ01		SCRAP VALUE OF STEEL	22460 TN	-120.00 CZZ		-2,695,000				-2,695,000
80CZZ02		SCRAP VALUE OF COPPER	1052 TN	-1420.00 CZZ		-1,494,000				-1,494,000
		SUB TOTAL 880CZZ				-4,189,000				-4,189,000
		SUB TOTAL 880CZ				-4,189,000				-4,189,000
		TOTAL 880				-4,189,000				-4,189,000

E S T I M A T E   W O R K S H E E T

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				*** MATERIAL		***	*** LABOR			***	
ACCOUNT NO.	WORK PACKAGE	DESCRIPTION	QTY UM	MATERIAL RATE	EQUIPMENT COST	MATERIAL COST	MNHR RATE	MNHRS	WAGE RATE	LABOR COST	TOTAL COST
900		INDIRECT EXPENSES									
900ZAB		CINERGY INDIRECT EXPENSES		ZAB						2,570,000	2,570,000
		TOTAL 900								2,570,000	2,570,000
		TOTAL DIRECT & INDIRECT COSTS				-3,777,000		374,877		27,868,000	24,091,000

Duke Energy Kentucky
Estimate of COR for Closure of Ash Ponds
(amounts in millions)

Plant	Decommissioning Amount for Closure of Ash Ponds: Closure of Ash Ponds	Project Indirects Adder (5%)	Contingency (10%)	Total	Estimated Retirement Date per Depr Study	Depr Study Implementation Date	Recovery Period/Remaining Life per Depr Study (in years)	Amount in COR at 12/31/14 (1)	Annual COR Increase Thereafter (1)	**Mos/Year**	**COR accrued 1/1/15 - 6/30/15**	**TTD COR**
	A	B	C	D=A+B+C				I	E	F	G=(E/F)*6	H=I+G
DE Kentucky												
East Bend	3,537,000	$ 176,850	$ 353,700	$ 4,067,550	2041	1/1/2007	34	837,437	119,634	12	$ 59,817	$ 897,254

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Chicago

E S T I M A T E   W O R K S H E E T

Page: 11
Estimate No: 18008C

Note: Extended costs are rounded up to next thousand dollars

ACCOUNT NO.	WORK PACKAGE	DESCRIPTION	QTY UM	MATERIAL RATE	EQUIPMENT COST	MATERIAL COST	MNHR RATE	MNHRS	WAGE RATE	LABOR COST	TOTAL COST		
		SUB TOTAL 200Y8						360		23,000	23,000		
200Y9		WAREHOUSES		Y9									
200Y9A		WAREHOUSE BUILDING (#1)	324000 CF	Y9A			0.006	1944	63.27	123,000	123,000		
200Y9B		WAREHOUSE BUILDING (#2)	264000 CF	Y9B			0.006	1584	63.27	100,000	100,000		
200Y9C		WAREHOUSE BUILDING (#3)	72000 CF	Y9C			0.006	432	63.27	27,000	27,000		
		SUB TOTAL 200Y9						3,960		250,000	250,000		
200YZ		OVERALL SITE AREA		YZ									
200YZ1		ROADS & PARKING LOTS		YZ1									
200YZ1AHA		PAVEMENT	89150 SY	YZ1 AHA			0.180	16047	63.27	1,015,000	1,015,000		
		SUB TOTAL 200YZ1						16,047		1,015,000	1,015,000		
200YZ3		SITE AREA EARTH COVER & SEEDING		YZ3									
200YZ3ACZ		2' OF EARTHWORK COVER IN ASH POND AND AT PLANT SITE	972000 CY	YZ3 ACZ			0.025	24300	125.35	3,046,000	3,046,000	3,046,000	
200YZ3AFC		SEEDING & MULCHING	300 AC	1100.00 YZ3 AFC		330,000	30.000	9000	38.01	342,000	672,000	672,000 336,000	* Assume 1/2 relates to ash pond
200YZ3AZZ		PLUG CIRCULATING WATER PIPE WITH SLURRY & PLACE CONCRETE AT ENDS	1 LT	82300 YZ3 AZZ		82,000				73,000	155,000	155,000	
		SUB TOTAL 200YZ3				412,000		33,300		3,461,000	3,873,000		

Duke Energy Kentucky
Case No. 2015-00187
Staff First Set Data Requests
Date Received: July 17, 2015

STAFF-DR-01-007

REQUEST:

In response to Item 2 of Commission's Staff's Initial Request for Information in Case No. 2015-00120,[1] Duke Kentucky states, regarding the current East Bend depreciation rate, "It is anticipated that this rate would change once the next depreciation study is filed." Explain when Duke Kentucky expects to file the next depreciation study.

RESPONSE:

Duke Energy Kentucky will file its next depreciation study as part of its next base rate case. The timing of the next base electric rate case is not known at this time.

PERSON RESPONSIBLE: Peggy A. Laub

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[1] Case No. 2015-00120, *Application of Duke Energy Kentucky, Inc. for an Order Approving the Establishment of a Regulatory Asset for the Depreciation Expense of Its East Bend Unit 2 Generating Station* (filed Apr. 10, 2015).

Duke Energy Kentucky
Case No. 2015-00187
Staff First Set Data Requests
Date Received: July 17, 2015

STAFF-DR-01-008

REQUEST:

Identify and describe any factors that could impact the regulatory asset treatment proposed by Duke Kentucky.

RESPONSE:

The driving factor for Duke Energy Kentucky (DEK) recording the regulatory asset is the newly enacted federal regulation pertaining to the retirement of coal ash ponds. Some of the additional factors that may impact the regulatory asset accounting treatment include: the initial recording of the ARO liability and ARC asset; depreciation of the ARC asset; accretion recorded to the ARO liability to state it at its fair value; periodic updates to the CCR cost estimates which will prospectively change the depreciation and accretion; timing of cash flows expended to comply with CCR closure plans; WACC rate changes as appropriate; changes in federal law unknown at this time. This is not intended to be an exhaustive list of the factors that could impact the regulatory asset treatment.

PERSON RESPONSIBLE: Cynthia S. Lee