Goss
Samford

ATTORNEYS AT LAW | PLLC

David S. Samford
(859) 368-7740
david@gosssamfordlaw.com

August 24, 2018

RECEIVED

AUG 24 2018

PUBLIC SERVICE
COMMISSION

Ms. Gwen Pinson, Executive Director
Kentucky Public Service Commission
P.O. Box 615
211 Sower Boulevard
Frankfort, KY 40602

Re: *In the Matter of the Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity for the Construction of Backup Fuel Facilities at its Bluegrass Generating Station;* PSC Case No. 2018-00292

Dear Ms. Pinson:

Please find enclosed for filing with the Commission an original and ten copies of the Application and supporting exhibits, a Motion for Confidential Treatment and a Motion to Deviate from Filing Requirements, as tendered on behalf of East Kentucky Power Cooperative, Inc. Please assign a docket number to this filing and return a file stamped copy of this filing to my office. As a courtesy, a copy of this filing, less the confidential information which is subject to the motion for confidential treatment, is being provided to counsel for the Attorney General's Rate Intervention Office and the counsel for Nucor Steel Gallatin, LLC.

Should you have any questions, please feel free to contact me.

Sincerely,

David S. Samford

Enclosure

cc: Rebecca Goodman
Kent Chandler
Michael Kurtz

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

AUG 24 2018

PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF BACKUP FUEL FACILITIES AT ITS BLUEGRASS GENERATING STATION	)	**CASE NO. 2018-** 00292

MOTION FOR CONFIDENTIAL TREATMENT

Comes now East Kentucky Power Cooperative, Inc. ("EKPC"), by counsel, pursuant to KRS 61.878, 807 KAR 5:001, Section 13 and other applicable law, and in support of its request that the Commission afford confidential treatment to certain information contained in exhibits to EKPC's Application filed in the above-captioned proceeding, respectfully states as follows:

1. Contemporaneously with this Motion, EKPC has filed an Application seeking a Certificate of Public Convenience and Necessity ("CPCN") for the construction of on-site backup fuel supply resources at its Bluegrass Generating Station ("Bluegrass Station") located in Oldham County, Kentucky (referred to herein as the "Project").

2. EKPC has attached as Exhibit A to its Application a map of the Bluegrass Station with relevant facilities and infrastructure identified. Further, preliminary plans and specifications for the Project have been provided as an appendix to the Project Scoping Report prepared by Burns & McDonnell Engineering Co., Inc. (*see* Attachment SY-3 to Exhibit G, the Direct Testimony of Mr. Sam Yoder, at Appendix A). These documents, which contain detailed information regarding

the location and characteristics of actual and proposed Bluegrass Station facilities, are referred to herein collectively as the "Confidential Information."

3. KRS 61.878(1)(m)(1) protects "[p]ublic records the disclosure of which would have a reasonable likelihood of threatening public safety by exposing a vulnerability in preventing, protecting against, mitigating, or responding to a terrorist act….," and specifically exempts from public disclosure certain records pertaining to public utility critical systems. *See* KRS 61.878(1)(m)(1)(f).

4. The Confidential Information includes identifications and depictions of certain critical energy infrastructure presently located and proposed to be located at EKPC's Bluegrass Station. If disclosed, the Confidential Information could be utilized to commit or further a criminal or terrorist act, disrupt critical public utility systems, and/or intimidate or coerce the civilian population. Disclosure of the Confidential Information could also result in the disruption of innumerable other infrastructure systems which relate to, or rely upon, the safe and reliable provision of electricity. Moreover, disclosure of the Confidential Information could have a reasonable likelihood of threatening the public safety, particularly because it reflects detailed, highly-technical information about the inner-workings of a sizeable generation station fueled by combustible materials. Put plainly, maintaining the confidentiality of the Confidential Information relating to the location, configuration, and security of critical electric systems is necessary to protect the interests of EKPC, its Owner-Members and end-use Members, and the region at large.

5. The Confidential Information is proprietary information that is retained by EKPC on a "need-to-know" basis and that is not publicly available. The Confidential Information is distributed within EKPC only to those employees who must have access for business reasons, and it is generally recognized as confidential and proprietary in the energy industry.

6. EKPC does not object to limited disclosure of the Confidential Information, pursuant to an acceptable confidentiality and nondisclosure agreement, to the Attorney General or any other intervenors with a legitimate interest in reviewing the same for the sole purpose of participating in this case.

7. EKPC seeks confidential treatment for the entirety of Exhibit A to its Application, as well as the entirety of Appendix A to Attachment SY-3 to Exhibit G to its Application. In accordance with the provisions of 807 KAR 5:001, Section 13(2), EKPC is filing one (1) unredacted copy of each of these documents in a separate sealed envelope marked confidential. An original and ten (10) redacted copies of EKPC's Application have also been tendered to the Commission.

8. Further in accordance with the provisions of 807 KAR 5:001, Section 13(2), EKPC respectfully requests that the Confidential Information be withheld from public disclosure indefinitely, as the critical energy infrastructure information reflected in the Confidential Information should remain confidential at least as long as the relevant facilities are in service. If, and to the extent, the Confidential Information becomes publicly available or otherwise no longer warrants confidential treatment., EKPC will notify the Commission and have its confidential status removed, pursuant to 807 KAR 5:001, Section 13(10).

WHEREFORE, on the basis of the foregoing, EKPC respectfully requests an Order from the Commission granting this Motion and protecting the Confidential Information from public disclosure indefinitely.

This 24th day of August, 2018.

Respectfully submitted,

David S. Samford
M. Evan Buckley
GOSS SAMFORD, PLLC
2365 Harrodsburg Road, Suite B-325
Lexington, Kentucky 40504
david@gosssamfordlaw.com
ebuckley@gosssamfordlaw.com
(859) 368-7740

Counsel for East Kentucky Power Cooperative, Inc.

RECEIVED

AUG 24 2018

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF BACKUP FUEL FACILITIES AT ITS BLUEGRASS GENERATING STATION	)	**CASE NO. 2018-** 00292

MOTION TO DEVIATE FROM FILING REQUIREMENTS

Comes now East Kentucky Power Cooperative, Inc. ("EKPC"), by counsel, pursuant to 807 KAR 5:001 Section 22, and in support of its request for an Order permitting a deviation from the filing requirements contained in 807 KAR 5:001 Section 15(2)(d)(2), respectfully states as follows:

1. Contemporaneously with this Motion, EKPC has filed an Application seeking a Certificate of Public Convenience and Necessity ("CPCN") for the construction of on-site backup fuel supply resources at its Bluegrass Generating Station ("Bluegrass Station") located in Oldham County, Kentucky (referred to herein as the "Project"). As part of the CPCN filing, 807 KAR 5:001 Section 15(2)(d)(2) requires the applicant to submit "plans and specifications and drawings of the proposed plant, equipment, and facilities."

2. EKPC has attached as Exhibit A to its Application a map of the Bluegrass Station with relevant facilities and infrastructure identified. Further, preliminary plans and specifications for the Project have been provided as an appendix to the Project Scoping Report prepared by Burns & McDonnell Engineering Co., Inc. (*see* Attachment SY-3 to Exhibit G, the Direct Testimony of

Mr. Sam Yoder). Because these documents include critical energy infrastructure information, they are being filed under seal with a motion for confidential treatments. Although additional design work is being undertaken, the maps, plans and specifications set forth in Exhibit A and the appendix of Attachment SY-3 to Exhibit G are currently the most detailed drawings available to EKPC.

3. EKPC seeks Commission authorization to deviate from applicable filing requirements which may require the submission of final, fully-detailed plans and specifications and drawings related to the Project. To the extent plans and specifications are created during the pendency of this proceeding that are more detailed than (or materially differ from) those submitted with EKPC's Application, EKPC commits to filing such documents once they are available.

WHEREFORE, on the basis of the foregoing and for good cause shown, EKPC respectfully requests an Order from the Commission granting a deviation pursuant to 807 KAR 5:001 Section 22 from the filing requirements contained in 807 KAR 5:001 Section 15(2)(d)(2).

This 24th day of August, 2018.

Respectfully submitted,

David S. Samford
M. Evan Buckley
GOSS SAMFORD, PLLC
2365 Harrodsburg Road, Suite B-325
Lexington, Kentucky 40504
david@gosssamfordlaw.com
ebuckley@gosssamfordlaw.com
(859) 368-7740

Counsel for East Kentucky Power Cooperative, Inc.

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AUG 24 2018

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY	)	
POWER COOPERATIVE, INC. FOR A	)	
CERTIFICATE OF PUBLIC CONVENIENCE	)	**CASE NO. 2018-**00292
AND NECESSITY FOR THE CONSTRUCTION	)	
OF BACKUP FUEL FACILITIES AT ITS	)	
BLUEGRASS GENERATING STATION	)	

APPLICATION

Comes now East Kentucky Power Cooperative, Inc. ("Applicant" or "EKPC"), by counsel, pursuant to KRS 278.020(1), 807 KAR 5:001 Sections 14 and 15, and other applicable law, and hereby requests this Commission enter an Order granting EKPC a Certificate of Public Convenience and Necessity ("CPCN") for the construction of on-site backup fuel supply resources at its Bluegrass Generating Station ("Bluegrass Station") located in Oldham County, Kentucky. In support of the relief it seeks, EKPC respectfully states as follows:

I. INTRODUCTION

1. EKPC has determined that its Bluegrass Station requires backup fuel facilities to ensure the Station's continued reliable and economic operation in light of the Capacity Performance construct now in place within PJM Interconnection, LLC ("PJM"). These backup facilities, which will allow EKPC to power Bluegrass Station's three (3) combustion turbines utilizing No. 2 ultra-low-sulfur-diesel fuel oil in addition to natural gas, represent the lowest cost alternative and the most economic means to mitigate the significant capacity penalty risk faced by

EKPC. The proposed project is estimated to cost $62.8 million and is designed to include dual fuel implementation for the Bluegrass Station's combustion turbines, two (2) on-site fuel oil storage tanks to allow twenty-four (24) hours of plant operation, a demineralized water storage tank, and the erection or refinement of associated balance of plant systems to support dual fuel operation (collectively and as further described herein, the "Project"). EKPC has concluded, following extensive examination of the available options and in cooperation with expert consultants, that the Project is necessary, appropriate, and in the best interest of EKPC and its sixteen (16) Owner-Member Cooperatives ("owner-members").

II. BACKGROUND

A. General Filing Requirements

2. Pursuant to 807 KAR 5:001 Section 14(1), EKPC's mailing address is P.O. Box 707, Winchester, Kentucky 40392-0707. EKPC's electronic mail address to receive service is psc@ekpc.coop. Applicant's counsel should be served at david@gosssamfordlaw.com and ebuckley@gosssamfordlaw.com.

3. Pursuant to 807 KAR 5:001, Section 14(1), the grounds for EKPC's request for a CPCN for the Project are set forth herein and in the testimony filed in support hereof.

4. Pursuant to 807 KAR 5:001, Section 14(2), EKPC is a Kentucky corporation, in good standing, and was incorporated on July 9, 1941.

B. Overview of East Kentucky Power Cooperative, Inc.

5. EKPC is a not-for-profit, rural electric cooperative corporation established under KRS Chapter 279 with its headquarters in Winchester, Kentucky. Pursuant to various agreements, EKPC provides electric generation capacity and electric energy to its sixteen (16) owner-members, which in turn serve approximately 530,000 Kentucky homes, farms and commercial and industrial

establishments in eighty-seven (87) Kentucky counties. EKPC's Board has stated its strategic objective is to maintain a generation fleet that prudently diversifies its fuel sources while maximizing its capital investments and minimizing stranded assets.

6. EKPC is a "utility" as that term is defined in KRS 278.010(3)(a) and a "generation and transmission cooperative" as that term is defined in KRS 278.010(9). Each of EKPC's sixteen (16) owner-members is a "utility" under KRS 278.010(3)(a), as well as a "distribution cooperative" under KRS 278.010(10) and a "retail electric supplier" under KRS 278.010(4).

7. EKPC owns and operates a total of approximately 2,965 MW of net summer generating capability and 3,267 MW of net winter generating capability. EKPC's natural-gas fired generation includes the Bluegrass Station (501 MW (summer)/567 MW (winter)) and J.K. Smith Station in Clark County, Kentucky (753 MW (summer)/989 MW (winter)), and its coal-fired generation includes the John S. Cooper Station in Pulaski County, Kentucky (341 MW) and the Hugh L. Spurlock Station in Mason County, Kentucky (1,346 MW). Additionally, EKPC operates landfill gas-to-energy facilities in Boone County, Laurel County, Greenup County, Hardin County, Pendleton County and Barren County (16 MW total), as well as a Community Solar facility (8 MW) in Winchester, Kentucky. Finally, EKPC purchases hydropower from the Southeastern Power Administration at Laurel Dam in Laurel County, Kentucky (70 MW), and the Cumberland River system of dams in Kentucky and Tennessee (100 MW). EKPC's record peak demand of 3,507 MW occurred on February 20, 2015.

8. EKPC owns 2,940 circuit miles of high voltage transmission lines in various voltages. EKPC also owns the substations necessary to support this transmission line infrastructure. Currently, EKPC has seventy-four (74) free-flowing interconnections with its neighboring utilities.

9. EKPC's transmission system is operated by PJM Interconnection, LLC ("PJM"), of which EKPC has been a fully-integrated member since June 1, 2013.[1] PJM is a regional electric grid and market operator with operational control of over 180,000 MW of regional electric generation, and it operates the largest capacity and energy market in North America. EKPC's generation, including that of its Bluegrass Station,[2] is offered into the capacity and energy markets organized and operated by PJM.

C. The Bluegrass Station

10. The Bluegrass Station is located just outside the city of La Grange in Oldham County, Kentucky, and began commercial operation in 2002.[3] EKPC acquired the Bluegrass Station in late 2015 following the Commission's approval of the acquisition in Case No. 2015-00267.[4] The addition of the Bluegrass Station to EKPC's generation fleet was based on EKPC's demonstrated need to secure adequate capacity to serve its growing load.[5]

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[1] *See In the Matter of the Application of East Kentucky Power Cooperative, Inc. to Transfer Functional Control of Certain Transmission Facilities to PJM Interconnection, LLC*, Order, Case No. 2012-00169 (Ky. P.S.C. Dec. 20, 2012).

[2] The 165 MW output of Bluegrass Station Unit 3 is currently committed to Louisville Gas and Electric Company /Kentucky Utilities Company ("LG&E/KU") under a firm capacity purchase and tolling agreement ("Tolling Agreement"). *See* Case No. 2014-00321, *Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Declaratory Order and Approval Pursuant to KRS 278.300 for a Capacity Purchase and Tolling Agreement* (Ky. P.S.C. Nov. 24, 2014). The Tolling Agreement is scheduled to expire on April 30, 2019, thereby allowing EKPC to offer Unit 3's generation into the PJM markets for delivery thereafter (which EKPC did for the first time as part of the 2019-2020 PJM Base Residual Auction (BRA)).

[3] An aerial map/photograph of the Bluegrass Station with relevant facilities/infrastructure identified is attached hereto and incorporated herein as Exhibit A.

[4] *See In the Matter of the Application of East Kentucky Power Cooperative, Inc. for Approval of the Acquisition of Existing Combustion Turbine Facilities from Bluegrass Generation Company, LLC at the Bluegrass Generating Station in LaGrange, Oldham County, Kentucky and for Approval of the Assumption of Certain Evidences of Indebtedness*, Order, Case No. 2015-00267 (Ky. P.S.C. Dec. 1, 2015).

[5] *Id.*, at p. 27.

11. The Bluegrass Station consists of three (3) simple cycle Siemens 501 FD2 combustion turbine power generation units, each with a net winter output of 189 MW. EKPC undertook extensive efforts to investigate the condition of these units in advance of their purchase, as well as determine their value in light of fuel deliverability and pricing, environmental compliance, and numerous other related issues.[6] The units have a remaining depreciable life of approximately 18 years.

12. The Bluegrass Station is located adjacent to the interstate natural gas pipeline owned and operated by Texas Gas Transmission, LLC ("Texas Gas"). Historically, EKPC has relied on interruptible service from the Texas Gas pipeline to fuel the Bluegrass Station units. In 2017, the Bluegrass Station successfully operated 565.98 hours and generated 80,151 net megawatts.[7]

D. PJM and Capacity Performance

13. According to a PJM factsheet, PJM "serves as the regional transmission organization ('RTO') for a 243,417 square mile area that covers all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia."[8] This geographical region encompasses 65 million Americans, includes 1,373 distinct generation sources comprising 176,569 MWs of electric generation capacity.[9] PJM delivers more than 792 million megawatt

[6] *Id.*, at p. 13.

[7] Bluegrass Station 2017 Annual Operating Report, filed March 30, 2018.

[8] *See* "PJM Statistics – April 2017", http://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/pjm-statistics.ashx?la=en (last accessed July 1, 2018).

[9] *Id.*

hours ("MWh") each year over 82,000 miles of transmission lines, and its peak demand is 165,492 megawatts.[10]

14. PJM administers a Capacity Market for electric generating capacity. The Capacity Market is based around PJM's Reliability Pricing Model ("RPM"), which "uses a market approach to obtaining the capacity needed to ensure reliability, with incentives that stimulate investment both in maintaining existing generation and in encouraging the development of new sources of capacity – resources that include not just generating plants but also demand response and energy-efficiency programs."[11] According to PJM, "[i]nvestors need sufficient long-term price signals to encourage the maintenance and development of generation and other resources. The RPM, based on making capacity commitments three years ahead, creates long-term price signals to attract needed investments in reliability in the PJM region."[12] The Capacity Market operates through a base residual auction held in May of each year and three incremental auctions held in February, August and November.

15. PJM's RPM capacity market was implemented in 2007 and has since undergone significant changes to promote reliability of generation resources, most notably following the extreme cold that accompanied the 2014 Polar Vortex. During that event, on the coldest day of the year, 22 percent of the generation in PJM was unexpectedly unavailable to serve customers.[13]

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[10] *Id.*

[11] See "Reliability Pricing Model – June 2017", http://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/reliability-pricing-model-fact-sheet.ashx?la=en (last accessed July 1, 2018).

[12] *Id.*

[13] *Strengthening Reliability: An Analysis of Capacity Performance*, p. 2, PJM Interconnection (June 20, 2018) (accessible at http://www.pjm.com/~/media/library/reports-notices/capacity-performance/20180620-capacity-performance-analysis.ashx as of July 1, 2018).

"[T]he Polar Vortex of 2014 made it clear to PJM Interconnection that stronger incentives were needed to encourage investment for better generation performance year-round."[14]

16. The prolific forced outage rates experienced during the winter weather event of January 2014, coupled with the coal-to-natural gas fuel transition, encouraged PJM to develop the Capacity Performance product to incent generator reliability and efficiency.[15] Under Capacity Performance, generation resources are required to meet their commitments to deliver electricity whenever PJM determines they are needed to meet power system emergencies, during what are known as Performance Assessment Intervals ("PAI") or Performance Assessment Hours ("PAH"). As a "pay-for-performance" standard, resources that clear in a PJM capacity auction with a Capacity Performance requirement but fail to perform (for essentially any reason) are assessed penalties that are then awarded to resources which over-perform.[16] The Capacity Performance product was approved by the Federal Energy Regulatory Commission ("FERC") and introduced into the August 2015 RPM capacity auction for the 2018/2019 PJM Delivery Year; for the 2020/2021 Delivery Year (the Base Residual Auction for which was held in May of 2017), all resources within the PJM footprint must meet Capacity Performance requirements.

III. DISCUSSION

A. Financial Risk of Nonperformance

17. As aforementioned, EKPC offers all its available generation into the auctions of the PJM capacity market, including that of its three (3) Bluegrass Station units. Beginning with the 2020/2021 PJM Delivery Year, EKPC will be assessed charges if its generating units which have

[14] *Id.*

[15] *Id.*

[16] For the 2020/2021 PJM Delivery Year, the penalty to be assessed against a cleared resource with unavailable generation during a PAI is $3,329/MWh.

cleared the market are unavailable during a PJM-declared PAI; conversely, if the Bluegrass Station units or EKPC's other generators perform as expected or better during a PAI, EKPC will earn bonus payments as a function of the "pay-for-performance" model.

18. EKPC has been cognizant of the risk that accompanies PJM's Capacity Performance product since it was first proposed by PJM, and it began evaluating that risk, particularly as it concerns the Bluegrass Station, before it acquired the units following Case No. 2015-00267.[17] The issue was examined as part of that proceeding and, in its final Order, the Commission stated as follows:

> We also note that PJM is currently implementing a complete redesign of its capacity market. PJM is transitioning from the RPM construct to the Capacity Performance market in response to the extreme forced outage rate experienced by power generators across PJM during the 2014 Polar Vortex. For the next two BRAs, the transition period will allow generating resources to offer in as a CP product or as a non-CP, or base, product. Beginning in the 2020/21 Delivery Year, PJM will require all generating resources to be a CP product. To qualify as a CP product, a generating resource would have to be capable of sustained, predictable operation and be available to provide energy and reserves whenever PJM determines an emergency condition exists. Payments for a CP resource are expected to rise; however, generating resources will also be exposed to significant penalties if the generating resource is not available when called upon by PJM during an emergency condition. In response to information requests and testimony at the hearing, EKPC generally addressed its options for participating in PJM's new CP market. With respect to the CP capacity market, EKPC discussed its consideration of its fuel supply and the possibility of converting the units for dual fuel supply or contracting firm gas transportation in order to maximize the value of the Bluegrass Station capacity. EKPC also indicated that it would consider the option of being

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[17] *See, e.g.*, EKPC's Response to Staff's First Request for Information, Item 31 ("EKPC is considering diesel fuel back-up or firm gas transportation to mitigate unit unavailability due to fuel and the penalties that could arise in the capacity performance market."); Application in that case, at p. 18 ("ACES's analysis of the proposed transaction took into account the fact that PJM is administering a Capacity Performance requirement in subsequent Base Residual Auctions (and certain Transitional Auctions) on electric generators within its footprint with firm fuel, back up fuel capability and/or onsite storage ability, which may possibly necessitate the purchase by EKPC of No Notice Service from Texas Gas for at least some portion of the winter months. Despite that, the availability and forecasted cost of natural gas indicated that the Bluegrass Station was an excellent investment opportunity for EKPC.").

> exposed to the penalty, noting that the amount of penalties could be less than the costs of upgrading the facilities to dual-fuel capability or entering into firm gas transportation contracts. Accordingly, the Commission will direct EKPC to include in the Operating Report its evaluation of how the Bluegrass Station units would qualify as a CP product and how EKPC will address the related risk exposure.[18]

19. Of course, a generation resource may experience a forced outage, and thus be exposed to the financial risk of the Capacity Performance construct, for any number of reasons. With respect to the Bluegrass Station's units, a substantial threat to reliability is the fact that each unit is currently configured to operate using only one type and source of fuel—natural gas provided by the Texas Gas pipeline. EKPC has identified the interruption of fuel supply as the most significant risk faced by the Bluegrass Station that is capable of mitigation but presently not addressed.

20. In order to determine the financial exposure EKPC may face if the Bluegrass Station is unable to perform as expected, EKPC retained Navigant Consulting, Inc. ("Navigant") to perform a Bluegrass Capacity Penalty Risk Analysis.[19] Navigant's examination reveals that, under PJM's rules, each PAH during which Bluegrass Station is unable to operate will cost EKPC approximately \$2.4 million, which is comprised of \$1.4 million in non-performance charges and \$1 million in revenue essentially forfeited by failure to generate (\$0.6 million in bonus payments and \$0.4 million in energy margins). If circumstances present similar to the 2014 Polar Vortex (which had 20 PAHs impact the EKPC zone), and EKPC's Bluegrass Station experiences a forced outage during one-third of those hours, EKPC would face penalties exceeding \$15 million. The maximum penalty EKPC could face climbs to nearly \$79 million if it were to experience a forced

[18] Order at p. at 28-29.

[19] A copy of Navigant's Bluegrass Capacity Penalty Risk Analysis is attached hereto as Attachment RL-2 to Exhibit F, the Direct Testimony of Mr. Ralph Luciani.

outage of the Bluegrass Station during all of the roughly 80 PAHs experienced by the region of PJM most-impacted during the 2014 Polar Vortex.

B. Strategies Examined to Minimize Risk

21. To complement its understanding of the potentially significant financial repercussions of failing to operate under PJM's Capacity Performance construct, EKPC also set out to develop possible strategies to mitigate that risk. In particular, EKPC sought to minimize the impact of interruptions or curtailments of the Bluegrass Station's fuel supply, and in doing so identified the following five (5) alternatives:

a. Purchase firm natural gas service, as opposed to interruptible service, from the Texas Gas pipeline presently serving the Bluegrass Station;

b. Purchase an insurance product to hedge against penalties that may be assessed as a result of fuel supply interruption;

c. Modify the Bluegrass Station to permit the on-site storage and conversion of liquefied natural gas ("LNG") to be used as a backup fuel in the event natural gas from the Texas Gas pipeline is unavailable;

d. Modify the Bluegrass Station to permit the on-site storage and use of fuel oil as a backup fuel in the event natural gas from the Texas Gas pipeline is unavailable (*i.e.*, implement dual fuel capability at the Station (the Project));

e. Accept the risk of nonperformance presented by the Bluegrass Station's single-source, interruptible fuel supply (*i.e.*, do nothing).

22. After obtaining pricing information and examining the available service types and timeframes (full-year firm, short-term firm, and enhanced firm), EKPC determined that changing the Bluegrass Station's natural gas supply from interruptible to firm is not an economically viable

option to mitigate potential Capacity Performance risk. With respect to the Bluegrass Station, which is comprised of peaking units that operate only intermittently, procuring firm natural gas supply is prohibitively expensive considering the limited times it would be utilized. Navigant confirmed this fact as part of its Bluegrass Capacity Penalty Risk Analysis, and thus EKPC rejected this alternative as part of its due diligence process.

23. EKPC also examined in detail the availability of insurance products offered by brokers that allow Capacity Performance resources to hedge against interruption events during PJM-declared PAIs. Though EKPC's investigation determined that certain coverage was available in the market, the limitations, exclusions and pricing of such coverage was not favorable when compared to the cost of (and exposure mitigated by) an on-site backup fuel resource at the Bluegrass Station. Moreover, uncertainty with respect to the availability and future pricing of this type of insurance product (particularly if claims are made and paid) presents risk EKPC seeks to avoid. These facts required EKPC to reject this alternative as an unviable solution.

24. The other actions considered by EKPC sought to limit exposure to Capacity Performance risk by expanding the sources of fuel available for use by the Bluegrass Station in the event that the primary fuel supply is unavailable. The alternatives studied by EKPC involve the installation of on-site storage facilities for backup fuel, as well as modifications to plant systems to permit the preparation and use of the backup fuels by the Bluegrass Units. EKPC retained Burns & McDonnell Engineering Co., Inc. ("Burns & McDonnell"), to perform a screening level cost and feasibility analysis associated with developing fuel oil or LNG on-site backup fuel supply resources, and that analysis included various scenarios based on number, type, and size of the on-site storage tank(s).[20]

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[20] A copy of the Burns & McDonnell Screening Analysis is attached hereto as Attachment SY-2 to Exhibit G, the Direct Testimony of Mr. Sam Yoder.

25. Storing and utilizing LNG as backup fuel supply was examined in detail by EKPC and its expert consultants because it offers mitigation of risk without substantial modification to the existing combustion turbines at the Bluegrass Station. When natural gas is converted to a liquid at very low temperatures, its volume is reduced by a factor of approximately 600, allowing for on-site storage of large amounts of backup fuel for a gas turbine facility. When the LNG is needed to fuel a turbine, it is heated through a vaporizer and converted back to natural gas; because LNG is converted back to natural gas prior to delivery as fuel, combustion turbines (like the Bluegrass Station's 501 FD2) can switch between pipeline natural gas operation and LNG backup operation without interruption.

26. Although the development of LNG as a backup fuel supply resource at Bluegrass Station does present certain benefits, the screening analysis performed by Burns & McDonnell revealed that the installed cost of all the LNG options examined would far exceed the installed cost if fuel oil was implemented as a backup fuel. Moreover, acquiring and storing LNG presents unique logistical and safety challenges, and LNG remains relatively unproven as a fuel for combustion turbines. Based on these reasons and others, EKPC rejected the use of LNG as a backup fuel supply resource for the Bluegrass Station.

27. EKPC, with the assistance of Burns & McDonnell and Navigant, also extensively examined the use of fuel oil as a backup fuel for the Bluegrass Station. The Bluegrass Station units, though historically and currently operated utilizing natural gas as fuel, are designed to accommodate the use of both natural gas and/or fuel oil by employing interchangeable support housings and other modifications. When dual fuel is implemented, the Bluegrass Station's 501 FD2 combustion turbines are capable of switching between natural gas and fuel oil while online at reduced loads.

28. Similar to its screening analysis with respect to LNG, Burns & McDonnell evaluated fuel oil alternatives at the Bluegrass Station with respect to backup fuel duration, practicability/feasibility, indicative capital costs, operational and maintenance impacts, industry experience, and estimated performance and emissions, among other matters. As a result of this investigation, coupled with Navigant's conclusions within its Bluegrass Capacity Penalty Risk Analysis, EKPC determined that implementing fuel oil as a backup fuel supply is the least cost alternative available to EKPC to mitigate the risk of unavailable primary fuel supply at the Bluegrass Station. As an added benefit, the technology is proven and offers little risk to EKPC. For these reasons and others, as further explained herein and in the testimony submitted herewith, EKPC selected the Project as the best course of action to address Capacity Performance risk at the Bluegrass Station.

29. As contemplated within the Commission's final Order in Case No. 2015-00267,[21] EKPC also considered the option of taking essentially no action with respect to the Bluegrass Station, thereby remaining exposed to Capacity Performance penalties should the Station's single-source fuel supply become unavailable during a PAI which impacts the EKPC zone. This analysis, again performed in cooperation with Navigant as part of its Bluegrass Capacity Penalty Risk Analysis, focused both on the amount of possible Capacity Performance penalties that could be levied against the Bluegrass Station, as well as the likelihood that such penalties would be borne over the next twenty (20) years. Because the overall economics of fuel alternatives at the Bluegrass Station depend predominately on whether natural gas will be interrupted at the station during a PAI, a multi-scenario evaluation was conducted to reflect both varying amounts of PAIs and varying amounts of primary fuel supply interruptions. Thereafter, a breakeven analysis was

[21] Order at p. at 28-29.

undertaken to determine how many applicable PAI events would be necessary to offset EKPC's investment in each of the contemplated mitigation strategies (including the implementation of fuel oil as a backup, but also including LNG and firm natural gas arrangements). Ultimately, EKPC concluded that the Capacity Performance risk faced by the Bluegrass Station requires mitigation efforts. The addition of fuel oil as a backup fuel supply resource is a low-technology-risk option that is also the lowest cost alternative at Bluegrass Station and represents the most economic means to mitigate capacity penalty risk, and thus EKPC requests Commission authorization to proceed with the Project.[22]

C. The Project

30. The Project represents the best solution for promoting the continued reliability and economic viability of the Bluegrass Station units for the foreseeable future. It reflects years of planning and evaluation by EKPC and its retained experts, and it is a course of action both reasonable and necessary to adequately and appropriately serve EKPC's owner-members.

31. To follow-up on its screening analysis, EKPC retained Burns & McDonnell to further evaluate and develop the scope, preliminary design, schedule, and cost estimates for dual fuel capability at the Bluegrass Station. The Scoping Report issued by Burns and McDonnell involves three (3) major components of the Project,[23] as follows:

a. Combustion Turbines and Associated Equipment – includes installation of dual fuel nozzles, new fuel oil pump skids, water injection pump skids, drain

[22] A copy of the EKPC Board's Resolution directing management to pursue a CPCN for the Project is attached hereto and incorporated herein as Exhibit B.

[23] A copy of the Burns and McDonnell Scoping Report is attached hereto as Attachment SY-3 to Exhibit G, the Direct Testimony of Mr. Sam Yoder.

and purge system, and control systems for the combustion turbines to operate on fuel oil or natural gas;

b. Fuel Oil System – includes installation of two (2) carbon steel fuel oil storage tanks (each capable of storing 580,000 gallons),[24] unloading equipment and forwarding pumps with inline heaters; and

c. Balance of Plant – includes installation of new piping, controls, instrumentation, electrical, and mechanical equipment, as well as an additional coated carbon steel storage tank capable of storing 400,000 gallons of demineralized water to supplement the existing 300,000 gallons of on-site storage.

32. The schedule for the Project is driven by PJM's implementation of the Capacity Performance construct, which, as aforementioned, is applicable to all generation beginning with the 2020/2021 Delivery Year. Based upon current projections, it is EKPC's intention to immediately begin ordering and securing equipment upon obtaining a CPCN for the Project, with the goal to achieve commercial operation by the end of 2020. In order to keep this schedule, EKPC requests a final Order of this Commission on or before February 28, 2019.

33. In addition to approval from the Commission, the Project will require EKPC to seek approvals, modifications to existing permits or new permits from the following agencies: U.S. Fish and Wildlife Service; U.S. Environmental Protection Agency; United States Department of Agriculture's Rural Utilities Service; and Kentucky Division of Air Quality ("DAQ"). EKPC has begun the process of seeking all necessary permits and approvals. A draft air permit was recently

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[24] The two (2) carbon steel fuel oil storage tanks to be installed as part of the Project will be capable of storing a total of 1,160,000 gallons of usable fuel, which will allow each Bluegrass Station unit to operate continuously at its maximum winter unit rating for a twenty-four (24) hour period. EKPC expects this level of storage to provide adequate protection against the anticipated duration of a PJM-declared PAI.

issued by DAQ and is attached hereto as Attached CJ-2 to Exhibit E, the Direct Testimony of Mr. Craig Johnson.

34. EKPC will finance the Project through its existing credit facility before transitioning it to a long-term debt placement available through its Trust Indenture.

35. EKPC intends to use a multiple contract approach with adjustment unit pricing to develop and construct the Project. This approach allows EKPC to work with Burns and McDonnell to create and procure the necessary construction and major equipment contracts. The approach involves the use of multiple equipment and material contracts and multiple construction contracts and will allow EKPC to minimize procurement costs by providing for competitive bidding to reduce contractor markups.

36. In summary, the Project will provide many benefits to EKPC, including, without limitation, the following:

a. Mitigation of the substantial financial risk posed by the Capacity Performance construct as a result of the single-source fuel supply presently in place at the Bluegrass Station;
b. Promoting the continued reliable and economic operation of the Bluegrass Station in a reasonable, least-cost manner;
c. Positioning EKPC to continue to reap benefits from its ability to bid capacity and energy into the PJM wholesale markets;
d. Furthering EKPC's efforts to provide reliable, safe, adequate and reasonable service to its owner-members at rates that are fair, just and reasonable; and
e. Assuring that EKPC continues to have adequate generation assets to satisfy load requirements.

IV. REQUEST FOR CPCN

37. It is well established that the Commission only possesses such powers as granted by the General Assembly.[25] However, the scope of the powers expressly granted by the General Assembly to the Commission to regulate the "rates" and "service" of utilities is plenary in nature, unless otherwise expressly limited or expressed by statute.[26] In the context of a request for issuance of a CPCN, the Commission's authority under KRS 278.020(1) remains very broad.

A. KRS 278.020(1) Requires Analysis of "Need" and "Wasteful Duplication"

38. Before undertaking a construction project that is not in the ordinary course of business, a utility must obtain a CPCN from the Commission under the authority of KRS 278.020(1), which states in relevant part:

> No person, partnership, public or private corporation, or combination thereof shall…begin the construction of any plant, equipment, property, or facility for furnishing to the public any of the services enumerated in KRS 278.010…until that person has obtained from the Public Service Commission a certificate that public convenience and necessity require the service or construction.… The commission, when considering an application for a certificate to construct a base load electric generating facility, may consider the policy of the General Assembly to foster and encourage use of Kentucky coal by electric utilities serving the Commonwealth.

39. The statute is silent, however, with regard to the criteria which the Commission should apply to any such request from a utility. Accordingly, case law construing KRS 278.020(1) provides the appropriate standard for evaluating EKPC's request for a CPCN in this proceeding.

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[25] *See Boone Co. Water and Sewer Dist. v. Public Service Comm'n,* Ky., 949 S.W.2d 588, 591 (1997); *Simpson Co. Water Dist. v. City of Franklin*, 872 S.W.2d 460, 462 (Ky. 1994); *Com., ex rel. Stumbo v. Kentucky Public Service Comm'n*, 243 S.W.3d 374, 378 (Ky. App. 2007); *Cincinnati Bell Tel. Co. v. Kentucky Public Service Comm'n*, 223 S.W.3d 829, 836 (Ky. App. 2007); *Public Service Comm'n v. Jackson Co. Rural Elec. Co-op., Inc.*, 50 S.W.3d 764, 767 (Ky. App. 2000).

[26] *See* KRS 278.040(2); *Kentucky Public Service Comm'n v. Commonwealth of Kentucky, ex rel. Conway*, 324 S.W.3d 373, 383 (Ky. 2010); *Southern Bell Tel. & Tel. Co. v. City of Louisville*, 265 Ky. 286, 96 S.W.2d 695, 697 (Ky. 1936).

The leading authority on CPCNs is *Kentucky Utilities Co. v. Public Service Comm'n*, which articulates a two-part test for demonstrating entitlement to a CPCN: (1) need; and (2) absence of wasteful duplication. *Kentucky Utilities Co.* provides significant guidance as to what further considerations should be taken into account when evaluating a request for a CPCN under these two criteria.

40. As to "need," Kentucky's highest Court wrote:

> We think it is obvious that the establishment of convenience and necessity for a new service system or a new service facility requires first a showing of a substantial inadequacy of existing service, involving a consumer market sufficiently large to make it economically feasible for the new system or facility to be constructed and operated. Second, the inadequacy must be due either to a substantial deficiency of service facilities, beyond what could be supplied by normal improvements in the ordinary course of business; or to indifference, poor management or disregard of the rights of consumers, persisting over such a period of time as to establish an inability or unwillingness to render adequate service.[27]

41. The need for the Project described herein is demonstrated by the fact that, without it, EKPC will face significant and ongoing exposure to PJM Capacity Performance penalties and the inability to operate its Bluegrass Station in a prudent, reliable, and economic fashion.

42. With regard to what constitutes "wasteful duplication", the Court opined:

> [W]e think that 'duplication' also embraces the meaning of an excessive investment in relation to productivity or efficiency, and an unnecessary multiplicity of physical properties, such as right of ways, poles and wires. An inadequacy of service might be such as to require construction of an additional service facility to supplement an inadequate existing facility, yet the public interest would be better served by substituting one large facility, adequate to serve all the consumers, in place of the inadequate existing facility, rather than constructing a new small facility to

[27] *Kentucky Utilities Co.*, at 890.

> supplement the existing small facility. A supplementary small facility might be constructed that would not create duplication from the standpoint of an excess of capacity, but would result in duplication from the standpoint of an excessive investment in relation to efficiency and a multiplicity of physical properties.[28]

43. In evaluating the "wasteful duplication" aspect of CPCN analysis, the Court further instructed, "[w]e are of the opinion that the Public Service Commission should have considered the question of duplication from the standpoints of excessive investment in relation to efficiency, and an unnecessary multiplicity of physical properties."[29] While the avoidance of "wasteful duplication" is a primary consideration for evaluating a request for a CPCN, *Kentucky Utilities Co.* makes clear that the Commission must not focus exclusively upon the cost of a proposal alone. The Commission must also look at an application for a CPCN in relation to the service to be provided by the utility:

> [W]e do not mean to say that *cost* (as embraced in the question of duplication) is to be given more consideration than the need for *service*. If, from the past record of an existing utility, it should appear that the utility cannot or will not provide adequate service, we think it might be proper to permit some duplication to take place, and some economic loss to be suffered so long as the duplication and resulting loss be not greatly out of proportion to the need for service.[30]

44. In other words, the complete absence of "wasteful duplication" need not be shown to an absolute certainty, "it is sufficient that there is a reasonable basis of anticipation" that the "consumer market in the immediately foreseeable future will be sufficiently large to make it

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[28] *Id.*, at 891.

[29] *Id.*

[30] *Id.*, at 892 (emphasis in original).

economically feasible for a proposed system or facility to be constructed...."[31] As recently as 2012, the Commission affirmed this point:

> To demonstrate that a proposed facility does not result in wasteful duplication, we have held that the applicant must demonstrate that a thorough review of all alternatives has been performed. Selection of a proposal that ultimately costs more than an alternative does not necessarily result in wasteful duplication. All relevant factors must be balanced.[32]

45. EKPC satisfies the "wasteful duplication" component of the CPCN analysis by virtue of the considerable due diligence it has undertaken to determine that targeted investment should be made in the Bluegrass Station to ensure its continued use as a reliable and cost-effective generation resource. The proposed Project presents the reasonable, least cost option for mitigation of Capacity Performance risk at the Bluegrass Station and helps insure the Station's units may continue to be valuable resources within the PJM marketplace.

B. Filing Requirements

46. Pursuant to 807 KAR 5:001, Section 15(2)(a), the facts relied upon to show that the proposed construction or extension is or will be required by public convenience or necessity are set forth in paragraphs seventeen (17) through thirty-six (36) herein.

47. Pursuant to 807 KAR 5:001, Section 15(2)(b), EKPC states that it is in the process of obtaining all environmental permits and approvals necessary for the proposed construction. A matrix reflecting the permits and approvals relevant to the Project is provided as Attachment CJ-1

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[31] *Kentucky Utilities Co. v. Public Service Commission*, 390 S.W.2d 168, 172 (Ky. 1965).

[32] *In re the Application of Big Rivers Electric Corporation for Approval of its 2012 Environmental Compliance Plan*, Case No. 2012-00063, Final Order, pp. 14-15 (Ky. P.S.C. Oct. 1, 2012) (citations omitted).

to Exhibit E, the Direct Testimony of Mr. Craig Johnson. Mr. Johnson's testimony (at Attachment CJ-2) contains the Draft DAQ Permit relevant to the Project.

48. Pursuant to 807 KAR 5:001, Section 15(2)(c), a full description of the proposed location, route, or routes of the proposed construction or extension is contained in the testimonies of Mr. Craig Johnson (Exhibit E) and Mr. Sam Yoder (Exhibit G), as well as reflected in the map attached as Exhibit A hereto and incorporated herein. A description of the manner of construction is set forth fully in the testimonies of Mr. Craig Johnson and Mr. Sam Yoder, and specifically in Attachment SY-3 to Mr. Yoder's testimony (the Burns & McDonnell Scoping Report). There are no public utilities, corporations or persons with whom the proposed construction or extension is likely to compete.

49. Pursuant to 807 KAR 5:001, Section 15(2)(d), EKPC is providing herewith one (1) copy in portable document format on electronic storage medium and two (2) copies in paper medium of the following information: maps to suitable scale showing the location or route of the proposed construction or extension, as well as the location to scale of like facilities owned by others located anywhere within the map area with adequate identification as to the ownership of the other facilities (see Exhibit A); and plans and specifications and drawings of the proposed plant, equipment, and facilities (see Attachment SY-3 to Exhibit G, at Appendix A). The Exhibits are the subject of a motion for confidential treatment and a motion for a filing deviation that are filed contemporaneously herewith.

50. Pursuant to 807 KAR 5:001, Section 15(2)(e), a detailed description of the manner in which EKPC intends to finance the proposed construction or extension is set forth in paragraph thirty-four (34) herein and the testimony of Mr. Thomas Stachnik.

51. Pursuant to 807 KAR 5:001, Section 15(2)(f), EKPC estimates that the annual cost of operation of the Bluegrass Station will increase approximately $587,000 after the proposed facilities are placed into service.

V. OVERVIEW OF TESTIMONY

52. EKPC is providing written testimony to support its Application from the following individuals:

a. Mr. Don Mosier, P.E., Executive Vice President and Chief Operating Officer, who offers testimony supporting EKPC's corporate profile, strategic objectives and the due diligence that has gone into the development of this proposal.

b. Mr. David Crews, Senior Vice President of Power Supply, who offers testimony describing PJM's RPM capacity market and the Capacity Performance construct, as well as EKPC's efforts to identify and develop various strategies to ensure reliable and economic operation of the Bluegrass Station in light of Capacity Performance;

c. Mr. Craig Johnson, P.E., Senior Vice President of Power Production, who offers testimony describing the options considered for mitigation of Capacity Performance risk at the Bluegrass Station, as well as the components, anticipated costs, project schedule, and other details of the Project;

d. Mr. Ralph Luciani, Director with Navigant, who offers testimony describing his firm's work with regard to evaluating the present value of various options considered for mitigating Capacity Performance risk at the Bluegrass Station, and particularly detailing Navigant's Bluegrass Capacity Penalty Risk Analysis;

e. Mr. Sam Yoder, P.E., Energy Division Project Manager with Burns & McDonnell, who offers testimony describing the details of the proposed Project, as well as sponsoring and authenticating the Screening Analysis and Scoping Report prepared by Burns & McDonnell as part of EKPC's due diligence; and

f. Mr. Thomas Stachnik, Vice President of Finance and Treasurer, who offers testimony concerning the cost and financing of the Project.

VI. CONCLUSION

53. EKPC has determined that it is reasonable and necessary to develop dual fuel capability at its Bluegrass Station to ensure the Station's continued reliable and economic operation in the event of a primary fuel supply interruption. The proposed Project will mitigate substantial risk presented by PJM's Capacity Performance construct, and it represents the lowest cost alternative available. As a result of extensive examination of the available options and in cooperation with expert consultants, EKPC seeks Commission authorization to proceed with the Project.

WHEREFORE, on the basis of the foregoing, EKPC respectfully requests the Commission enter an Order, on or before February 28, 2019, issuing a CPCN to EKPC for the Project, as well as granting to EKPC all other relief to which it may appear entitled.

This 24th day of August, 2018.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF CLARK)

Comes now Don Mosier, Executive Vice President and Chief Operating Officer of East Kentucky Power Cooperative, Inc., and, after being duly sworn, does hereby verify, swear and affirm that the averments set forth in the foregoing Application are true and correct based upon my personal knowledge and belief, formed after reasonable inquiry, as of this ____ day of August, 2018.

Don Mosier

Don Mosier, Executive Vice President
and Chief Operating Officer

East Kentucky Power Cooperative, Inc.

The foregoing Verification was verified, sworn to and affirmed before me, the NOTARY PUBLIC by Don Mosier, Executive Vice President and Chief Operating Officer of East Kentucky Power Cooperative, Inc. on this 24th day of August, 2018.

Gwyn M. Willoughby

NOTARY PUBLIC

Commission No. 590567

My Commission Expires: 11/30/21

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021

Respectfully submitted,

____

David S. Samford
M. Evan Buckley
GOSS SAMFORD, PLLC
2365 Harrodsburg Road, Suite B-325
Lexington, Kentucky 40504
david@gosssamfordlaw.com
ebuckley@gosssamfordlaw.com
(859) 368-7740

Counsel for East Kentucky Power Cooperative, Inc.

VII. EXHIBITS

Tab #

1 A. Map of Bluegrass Station with Identified Facilities/Infrastructure (per 807 KAR 5:001, Section 15(2)(d)(1))

2 B. EKPC Board of Directors Resolution, dated March 13, 2018

3 C. Testimony of Mr. Don Mosier

4 D. Testimony of Mr. David Crews

5 E. Testimony of Mr. Craig Johnson
1. Matrix of Project permits and approvals (Attachment CJ-1)
2. Draft Kentucky Division of Air Quality Permit (Attachment CJ-2)

6 F. Testimony of Mr. Ralph Luciani
1. *Curriculum Vitae* (Attachment RL-1)
2. Navigant's Bluegrass Capacity Penalty Risk Analysis, dated July 31, 2018 (Attachment RL-2)

7 G. Testimony of Mr. Sam Yoder
1. *Curriculum Vitae* (Attachment SY-1)
2. Burns & McDonnell Screening Analysis, August 2018 (Attachment SY-2)
3. Burns & McDonnell Scoping Report, August 2018 (Attachment SY-3) (including Plans, Specifications and Drawings per 807 KAR 5:001, Section 15(2)(d)(2))

8 H. Testimony of Mr. Thomas Stachnik

**FROM THE MINUTE BOOK OF PROCEEDINGS
OF THE BOARD OF DIRECTORS OF
EAST KENTUCKY POWER COOPERATIVE, INC.**

At a regular meeting of the Board of Directors of East Kentucky Power Cooperative, Inc. held at the Headquarters Building, 4775 Lexington Road, located in Winchester, Kentucky, on Tuesday, March 13, 2018, at 9:30 a.m., EDT, the following business transacted:

Approval to Implement the Bluegrass Dual Fuel Addition Project, in Order to Mitigate Risks Associated with Potential Wholesale Electric Market Capacity Penalties

After review of the applicable information, a motion to approve to Implement the Bluegrass Dual Fuel Addition Project, in Order to Mitigate Risks Associated with Potential Wholesale Electric Market Capacity Penalties was made by Strategic Issues Committee Chairman Tim Eldridge, seconded by Wayne Stratton, and passed by the Board to approve the following:

Whereas, East Kentucky Power Cooperative, Inc., ("EKPC") presently has three combustion gas turbine units located at the Bluegrass Power Station ("Bluegrass Station"), in La Grange, Kentucky, served by a single natural gas source;

Whereas, Capacity Performance Penalties may be assessed by PJM Interconnection LLC , a Regional Transmission Organization in delivery year 2020/2021, there exists the potential of significant financial impact if the risk of fuel interruption is not mitigated at Bluegrass Station, and such facilities are required for EKPC to obtain Capacity Performance Insurance to protect against non-performance events that are not related to fuel supply;

Whereas, A screening level study was performed indicating that the addition of a backup fuel oil system is the best alternative to mitigate this risk at Bluegrass Station;

Whereas, The EKPC Board of Directors ("Board") directed staff to develop a project plan to implement the addition of a backup fuel oil system at Bluegrass Station for their further consideration;

Whereas, A Project Scoping Report for the Bluegrass Dual Fuel Addition has been developed that identifies the addition of combustion gas turbine modifications, additional fuel oil storage and conveyance systems, demineralized water storage upgrades, and electrical / control systems as necessary to achieve adequate fuel supply backup, and estimates the total cost of those improvements to be $62.8M; now, therefore, be it

Resolved, The Board hereby authorizes the President and Chief Executive Officer, or his designee, to proceed with the implementation of the Bluegrass Dual Fuel

Addition Project in the amount of $62.8M, and to use general funds until such time as Rural Utilities Services ("RUS") loan or other funds become available, and

Resolved, The Board further authorizes the President and Chief Executive Officer, or his designee to execute contracts, file for required or advisable certificates, permits and approvals with regulatory and environmental agencies of the Commonwealth of Kentucky and the United States Federal Government or other entities, to authorize applying for and borrowing funds from RUS and other lenders, and requesting any needed authorization for financing from the Kentucky Public Service Commission, to hire additional plant employees as required to operate and maintain this equipment, to amend the RUS 3-Year Construction Work Plan, accordingly, in order to timely implement the Project, and to take any other actions necessary or desirable to complete this project.

The foregoing is a true and exact copy of a resolution passed at a meeting called pursuant to proper notice at which a quorum was present and which now appears in the Minute Book of Proceedings of the Board of Directors of the Cooperative, and said resolution has not been rescinded or modified.

Witness my hand and seal this 13th day of March 2018.

Jody E. Hughes

Jody E. Hughes, Secretary

Corporate Seal

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF BACKUP FUEL FACILITIES AT ITS BLUEGRASS GENERATING STATION	))))))	**CASE NO. 2018-________**

DIRECT TESTIMONY OF DON MOSIER ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: August 24, 2018

Q. Please state your name, position, and business address.

A. My name is Don Mosier and my business address is East Kentucky Power Cooperative, Inc. ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391. I am Executive Vice President and Chief Operating Officer at EKPC.

Q. Please briefly describe your education and professional experience.

A. I obtained my Bachelor of Science degree in civil engineering from the University of Virginia and my Master of Business Administration degree from the Kenan-Flagler Business School at the University of North Carolina. My professional experience includes work at Carolina Power & Light (now Duke Energy Carolinas) in Raleigh, North Carolina, developing merchant generation projects and marketing activities, regulatory affairs, and nuclear power plant engineering and operations. I also was an engineering manager of U.S. Operations for Canatom Corp., a Toronto-based engineering firm that provides nuclear plant engineering and construction services. Immediately prior to joining EKPC, I served as Vice President of St. Louis-based Ameren Energy Marketing ("AEM"), a subsidiary of Ameren Corp. At AEM, I managed wholesale power trading, plant dispatch, North American Electric Reliability Corporation and SERC compliance, transmission and congestion management activities, and customer account management for Ameren Corporation's unregulated merchant generation fleet located in the Midcontinent ISO and PJM Interconnection, LLC ("PJM"), a Regional Transmission Organization.

Q. Please provide a brief description of your duties at EKPC.

A. I manage the day-to-day operations of power production and construction, power delivery, power supply, and system operations. I report directly to EKPC's President and Chief Executive Officer, Mr. Anthony S. Campbell.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support EKPC's application in this proceeding by first discussing EKPC's corporate profile and strategic goals. I will describe EKPC's generation fleet, its relationship with PJM, and it decision to request the Commission's approval to construct on-site backup fuel supply resources at the Bluegrass Generating Station ("Bluegrass Station" or the "Station") in Oldham County, Kentucky. Finally, I will discuss the overall advantages and benefits that will inure to EKPC, its Owner-Member Cooperatives ("owner-members") and their End-Use Retail Members ("retail members") as a result of the proposed project that is the subject of this case.

Q. Are you sponsoring any exhibits?

A. No.

Q. Please describe EKPC and its owner-members' system.

A. EKPC is a not-for-profit, rural electric cooperative corporation established under KRS Chapter 279 with its headquarters in Winchester, Kentucky. EKPC has $3.8 billion in assets and 688 employees. In 2017, EKPC's energy sales exceeded 12.5 million megawatt hours, contributing to an operating revenue of $862 million and a net margin of $22 million. Pursuant to various agreements, EKPC provides electric generation capacity and electric energy to its sixteen (16) owner-members:

Big Sandy RECC, Blue Grass Energy, Clark Energy, Cumberland Valley Electric, Farmers RECC, Fleming-Mason Energy, Grayson RECC, Inter-County Energy, Jackson Energy, Licking Valley RECC, Nolin RECC, Owen Electric, Salt River Electric, Shelby Energy, South Kentucky RECC and Taylor County RECC. Those owner-members in turn serve approximately 530,000 Kentucky homes, farms and commercial and industrial establishments in eighty-seven (87) Kentucky counties.

EKPC owns and operates a total of approximately 2,965 MW of net summer generating capability and 3,267 MW of net winter generating capability. EKPC's natural-gas fired generation includes the Bluegrass Station (501 MW (summer)/567 MW (winter)) and J.K. Smith Station in Clark County, Kentucky (753 MW (summer)/989 MW (winter)), and its coal-fired generation includes the John S. Cooper Station in Pulaski County, Kentucky (341 MW) and the Hugh L. Spurlock Station in Mason County, Kentucky (1,346 MW). Additionally, EKPC operates landfill gas-to-energy facilities in Boone County, Laurel County, Greenup County, Hardin County, Pendleton County and Barren County (16 MW total), as well as a Community Solar facility (8 MW) in Winchester, Kentucky. Finally, EKPC purchases hydropower from the Southeastern Power Administration at Laurel Dam in Laurel County, Kentucky (70 MW), and the Cumberland River system of dams in Kentucky and Tennessee (100 MW). EKPC's record peak demand of 3,507 MW occurred on February 20, 2015.

EKPC also owns 2,940 circuit miles of high voltage transmission lines in various voltages and the substations necessary to support this transmission line infrastructure. Currently, EKPC has seventy-four (74) free-flowing interconnections with its neighboring utilities.

Q. Please describe EKPC's Strategic Plan.

A. EKPC's Board of Directors has developed a strategic plan that it reviews and updates regularly with a goal of guiding management in the day-to-day operations of the cooperative while also providing a roadmap for what EKPC hopes to accomplish over the long-term. The current Strategic Plan was last updated in 2016 and includes eight (8) strategic objectives in the areas of governance, people, financial integrity, generation and transmission assets, rates and regulatory relations, communications and public relations, economic development and cyber and physical security. The Strategic Plan has been instrumental in guiding management to identify and develop the best possible solutions to challenges presented by environmental regulations, operational constraints, and other influences. EKPC's decision to pursue the Bluegrass Station dual-fuel project (the "Project") is consistent with its Strategic Plan, and particularly the cooperative's objective to "maximize returns on capital investments and mitigate exposure to stranded costs to limit impact on system reliability and exposure to future regulatory changes."

Q. Was EKPC's decision to acquire the Bluegrass Station in late 2015 also consistent with its Strategic Plan?

A. Yes. EKPC has stated that one of its strategic objectives is to "provide leadership and vision to identify, exercise due diligence and recommend…supply resources that diversify the portfolio via increased reliance on natural gas, viable renewable resources, distributed generation and bilateral market purchases." With the implementation of the federal Mercury Air Toxics Standards Rule, EKPC was forced to retire its coal-fired Dale Station and thus lose 200 megawatts (MW) of electric generating capacity beginning in 2016. After a lengthy process, EKPC was able to secure 567 MW of new winter capacity by acquiring the Bluegrass Station following receipt of Commission approval in Case No. 2015-00267.[1] The Bluegrass Station acquisition represented a shift in EKPC's generation portfolio away from coal and towards natural gas, but it also allowed EKPC to maximize its peak diversity within PJM. The acquisition of the Bluegrass Station was and remains a good business transaction that achieved value for EKPC's owner-members while also advancing the Board's efforts to diversify the cooperative's generation portfolio.

Q. Please generally describe the Bluegrass Station.

A. The Bluegrass Station is located just outside the city of La Grange in Oldham County, Kentucky, and began commercial operation in 2002. Its three (3) simple cycle combustion turbine power generation units, each with a net winter output of 189 MW, are presently powered exclusively by natural gas delivered via an interstate pipeline owned and operated by Texas Gas Transmission, LLC. EKPC undertook extensive efforts to investigate the condition of these units in advance of

[1] *See In the Matter of the Application of East Kentucky Power Cooperative, Inc. for Approval of the Acquisition of Existing Combustion Turbine Facilities from Bluegrass Generation Company, LLC at the Bluegrass Generating Station in LaGrange, Oldham County, Kentucky and for Approval of the Assumption of Certain Evidences of Indebtedness*, Order, Case No. 2015-00267 (Ky. P.S.C. Dec. 1, 2015).

their purchase, as well as determine their value in light of fuel deliverability and pricing, environmental compliance, and numerous other related issues.

Q. Does EKPC offer the output of the Bluegrass Station into the PJM marketplace?

A. Yes, but with a temporary caveat. As the Commission is aware, EKPC has been a fully-integrated member of PJM since June 1, 2013, and its generation is offered into the capacity and energy markets organized and operated by PJM. As the Commission is also aware, the output of Bluegrass Station Unit 3 is currently committed to Louisville Gas and Electric Company /Kentucky Utilities Company under a firm capacity purchase and tolling agreement ("Tolling Agreement"). The Tolling Agreement is scheduled to expire on April 30, 2019, which allows EKPC to offer Unit 3's generation into the PJM markets for delivery thereafter (which EKPC did for the first time as part of the Base Residual Auction (BRA) for the 2020/2021 PJM Delivery Year).

Q. Has EKPC been pleased with the performance of its Bluegrass Station units since their acquisition?

A. Yes. Although the plant experienced 37.45 unplanned outage hours during 2017, the Bluegrass Station successfully operated 565.98 hours and generated 80,151 net megawatts, performing to an average net heat rate of 11,377.59 (BTU/KWH). EKPC's brief experience as the owner and operator of the Bluegrass Station has been positive thus far, and EKPC expects to continue to enjoy the benefits of the Bluegrass Station for years to come.

Q. What modifications or upgrades to the Bluegrass Station does EKPC propose to make as part of this proceeding?

A. EKPC has determined that its Bluegrass Station requires backup fuel facilities to ensure the Station's continued reliable and economic operation in light of developments (specifically, the Capacity Performance construct) now in place within PJM. These backup facilities will allow EKPC to power the Bluegrass Station's three (3) combustion turbines utilizing No. 2 ultra-low-sulfur-diesel fuel oil in addition to natural gas. Though full detail with respect to the proposed construction is provided as part of the testimony and exhibits proffered herein by Mr. Sam Yoder of Burns & McDonnell Engineering Co., Inc. ("Burns & McDonnell"), the project will involve dual fuel implementation, two (2) on-site fuel oil storage tanks to allow twenty-four (24) hours of plant operation, a demineralized water storage tank, and the erection or refinement of associated balance of plant systems to support dual fuel operation (collectively, the "Project"). The Project is expected to cost $62.8 million.

Q. What motivates EKPC to seek implementation of dual fuel capability at its Bluegrass Station?

A. EKPC's decision to pursue a backup fuel supply for its Bluegrass Station is the result of PJM's decision to implement a new "pay-for-performance" model within its Capacity Market. As further described in the testimony submitted herewith of Mr. David Crews, EKPC's Senior Vice President of Power Supply, prolific forced outage rates experienced during the Polar Vortex of January 2014, coupled with the coal-to-natural gas fuel transition, encouraged PJM to develop the Capacity

Performance product to incent generator reliability and efficiency. In sum, Capacity Performance requires generation resources to meet their commitments to deliver electricity whenever PJM determines they are needed to meet power system emergencies, during what are known as Performance Assessment Intervals ("PAI") or Performance Assessment Hours. Resources that clear in a PJM capacity auction with a Capacity Performance requirement but fail to perform (for essentially any reason, including unavailability of fuel) are assessed penalties that are then awarded to resources which over-perform. In order to ensure that its Bluegrass Station is best positioned to satisfy the requirements of the PJM Capacity Performance construct, EKPC has determined to implement a second fuel source to power the Station's units in the event the primary fuel source (natural gas) is unavailable.

Q. Did EKPC consider the possible impacts of the Capacity Performance construct on the Bluegrass Station when it acquired the units in late 2015?

A. Yes. EKPC has been cognizant of the risk that accompanies PJM's Capacity Performance product since it was first proposed by PJM, and it began evaluating that risk, particularly as it concerns the Bluegrass Station, before it acquired the units following Case No. 2015-00267. Both then and now, interruption of the Bluegrass Station's natural gas fuel supply has been identified by EKPC as the most significant risk with respect to Capacity Performance faced by the cooperative.

Q. Please describe the deliberative process undertaken by EKPC to evaluate the available options for addressing Bluegrass Station's Capacity Performance risk.

A. EKPC's Board and management have invested considerable time and attention to investigating PJM's Capacity Performance construct and its potential impact upon the cooperative. The due diligence conducted by EKPC includes detailed analyses and research conducted both internally and by third-party experts, namely Navigant Consulting, Inc. ("Navigant") and Burns & McDonnell. As discussed in Mr. Luciani's testimony tendered herewith, the break-even analysis performed by Navigant compared the anticipated costs and rewards associated with various potential alternative fuel arrangements (including firm gas service during all or parts of the winter season and installation of backup fuel oil or LNG capability at the Bluegrass Station) with the status quo option of doing nothing. As discussed in Mr. Yoder's testimony tendered herewith, the screening level cost and feasibility analysis performed by Burns & McDonnell evaluated numerous scenarios to develop fuel oil or LNG on-site backup fuel supply resources at the Bluegrass Station. EKPC also requested and obtained a Scoping Report from Burns & McDonnell that further developed the scope, preliminary design, schedule, and cost estimates associated with implementing dual fuel capabilities at the Bluegrass Station. Finally, EKPC examined in detail the availability of insurance products offered by brokers that allow Capacity Performance resources to hedge against interruption events during PJM-declared PAIs. As a result of these extensive examinations, coupled with EKPC's own deliberate and detailed analyses, it became clear to EKPC's leadership that the Project as proposed in this case is the best solution for promoting the continued reliability and economic viability of the Bluegrass Station.

Q. What benefits to EKPC and its owner-members are expected to result from the Project?

A. EKPC has identified multiple benefits that will accrue to it and its owner-members as a result of pursuing the Project. First, the Project will help mitigate the substantial risk of nonperformance posed by the Capacity Performance construct; by addressing the problem of the single-source fuel supply presently in place at the Bluegrass Station, EKPC will have a much greater likelihood of generating the power it has committed to provide within the PJM Capacity Market (especially during PJM-imposed PAIs), thereby avoiding potentiality-sizeable penalties for nonperformance. Additionally, the Project will allow EKPC to continue to reap benefits from its ability to bid capacity and energy into the PJM wholesale markets; when the Bluegrass Station units perform as expected or better during a PAI, EKPC will enjoy returns on energy sales and possibly bonus payments paid by nonperforming PJM generators. Overall, the proposed Project promotes the continued reliable and economic operation of the Bluegrass Station in a reasonable, least-cost manner, thereby furthering EKPC's efforts to provide reliable, safe, and adequate service to its owner-members at rates that are fair, just and reasonable.

Q. What relief does EKPC seek in this proceeding?

A. Quite simply, based on EKPC's showing of need and the absence of wasteful duplication of facilities, EKPC requests that the Commission issue a Certificate of Public Convenience and Necessity for the Project.

Q. Why is the Project needed?

A. Although EKPC cannot know with certainty the number and frequency of future PJM-imposed PAIs (nor which of those events will coincide with natural gas unavailability at the Bluegrass Station), EKPC has determined that the financial risks and benefits presented by PJM's Capacity Performance construct require the implementation of prudent preparations to avoid generator unavailability due to lack of fuel. Stated another way, the Project will mitigate EKPC's significant and ongoing exposure to PJM Capacity Performance penalties and grant EKPC the ability to operate its Bluegrass Station in a prudent, reliable, and economic fashion.

Q. Will the Project result in wasteful duplication of facilities?

A. No, and in fact, the Project prevents the wasteful duplication of facilities because it allows EKPC to utilize its existing generation resources to their fullest potential. EKPC, with the assistance of multiple experts, has conducted considerable due diligence to determine that targeted investment should be made in the Bluegrass Station to ensure its continued use as a reliable and cost-effective generation resource. The proposed Project presents the reasonable, least-cost option for mitigation of Capacity Performance risk at the Bluegrass Station and helps ensure the Station's units may continue to be valuable resources within the PJM marketplace. Moreover, the Project helps ensure that EKPC's owner-members and their retail members are able to recognize and achieve the full value of the investments they have already made in the Bluegrass Station through rates by minimizing the amount of stranded or unavailable assets.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF BACKUP FUEL FACILITIES AT ITS BLUEGRASS GENERATING STATION	)	**CASE NO. 2018-________**

VERIFICATION OF DON MOSIER

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF CLARK)

Don Mosier, Executive Vice President and Chief Operating Officer at East Kentucky Power Cooperative, Inc., being duly sworn, states that he has read the foregoing prepared direct testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief, formed after reasonably inquiry.

Don Mosier

Don Mosier

The foregoing Verification was signed, acknowledged and sworn to before me this 24th day of August, 2018, by Don Mosier.

Gwyn M. Willoughby

NOTARY PUBLIC

Commission No. 590567

My Commission Expires: 11/30/21

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY	)	
POWER COOPERATIVE, INC. FOR A	)	
CERTIFICATE OF PUBLIC CONVENIENCE	)	**CASE NO. 2018-________**
AND NECESSITY FOR THE CONSTRUCTION	)	
OF BACKUP FUEL FACILITIES AT ITS	)	
BLUEGRASS GENERATING STATION	)	

DIRECT TESTIMONY OF DAVID CREWS
ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: August 24, 2018

Q. Please state your name, business address and occupation.

A. My name is David Crews and my business address is East Kentucky Power Cooperative, Inc. ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391. I am Senior Vice President of Power Supply at EKPC.

Q. Please state your education and professional experience.

A. I hold a Bachelor's degree in Civil Engineering from North Carolina State University and am a registered professional engineer in North Carolina. Prior to joining EKPC, I served as Manager of Federal Regulatory Affairs at Progress Energy Service Co. I also served as the Director of Coal Marketing and Trading for Progress Fuels, and as Director of Power Trading Operations at Progress. I began working at EKPC in January of 2011; in all, I have more than 32 years of experience in the electric utility industry.

Q. Please provide a brief description of your duties at EKPC.

A. Generally, I oversee EKPC's Power Supply, which includes the areas of Power Supply Planning, Load Forecasting, PJM Interconnection, LLC ("PJM") Market Operations, Fuel Supply, Renewable Energy Projects, Demand Side Management and Energy Efficiency.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is first to describe EKPC's Bluegrass Generating Station ("Bluegrass Station") and its role within EKPC's generation fleet. I will also discuss PJM's Reliability Pricing Model ("RPM") and Capacity Market and its Capacity Performance construct, as well as EKPC's efforts to identify and develop various strategies to ensure reliable and economic operation of the Bluegrass Station in light of Capacity Performance.

Q. Are you sponsoring any exhibits?

A. No.

Q. Please describe EKPC's generation portfolio.

A. EKPC owns and operates a total of approximately 2,965 MW of net summer generating capability and 3,267 MW of net winter generating capability. EKPC's natural-gas fired generation includes the Bluegrass Station (501 MW (summer)/567 MW (winter)) and J.K. Smith Station in Clark County, Kentucky (753 MW (summer)/989 MW (winter)), and its coal-fired generation includes the John S. Cooper Station in Pulaski County, Kentucky (341 MW) and the Hugh L. Spurlock Station in Mason County, Kentucky (1,346 MW). Additionally, EKPC operates landfill gas-to-energy facilities in Boone County, Laurel County, Greenup County, Hardin County, Pendleton County and Barren County (16 MW total), as well as a Community Solar facility (8 MW) in Winchester, Kentucky. Finally, EKPC purchases hydropower from the Southeastern Power Administration at Laurel Dam in Laurel County, Kentucky (70 MW), and the Cumberland River system of dams in Kentucky and Tennessee (100 MW). EKPC's record peak demand of 3,507 MW occurred on February 20, 2015.

Q. Please further describe EKPC's Bluegrass Station.

A. EKPC's Bluegrass Station is located just outside the city of La Grange in Oldham County, Kentucky, and began commercial operation in 2002. It consists of three (3) simple cycle Siemens 501 FD2 combustion turbine power generation units, each with a net winter output of 189 MW. The units have a remaining depreciable life of approximately 18 years.

The Bluegrass Station units are peaking units, which means they generally only operate during the hours of the year when there is the highest demand for power across the PJM footprint. In 2017, the Bluegrass Station successfully operated 565.98 hours and generated 80,151 net megawatts.

Q. How are the Bluegrass Station units fueled?

A. Presently, the Bluegrass Station units are configured to operate using only one (1) type and source of fuel—natural gas provided by an adjacent interstate natural gas pipeline owned and operated by Texas Gas Transmission, LLC ("Texas Gas"). Historically, EKPC has relied on interruptible service from Texas Gas; interruptible natural gas service has allowed EKPC to obtain natural gas at a lower cost than firm service and has been adequate in light of the fact that the Bluegrass Station is comprised of peaking units that operate only intermittently. Of course, the major disadvantage of an interruptible fuel supply is that it is not guaranteed to be available when needed. To have a dedicated, on-demand fuel supply, EKPC would have to acquire natural gas on a firm basis, which is more expensive.

Q. When did EKPC acquire the Bluegrass Station?

A. Following a request-for-proposals process and with the assistance of multiple third-party experts, EKPC identified and pursued the Bluegrass Station as the reasonable, least-cost option to economically address system needs for additional generation capacity. EKPC acquired the Bluegrass Station in late 2015 following the Commission's approval of the acquisition in Case No. 2015-00267.[1]

Q. Explain EKPC's decision to purchase the Bluegrass Station.

A. EKPC purchased the Bluegrass Station to address a significant shortfall of generation capacity resulting from its growing load and the loss of the Dale Station (199 MW) as an economic resource (primarily due to coal-focused environmental regulation). Moreover, the extreme weather occasioned by the 2014 Polar Vortex, combined with EKPC's record demand peaks in winter 2015 and increased price volatility, confirmed that significant additional capacity was necessary to mitigate the market risk arising from EKPC's capacity shortfall, which totaled nearly 650 MW on February 20, 2015.

Q. Briefly, what is PJM?

A. PJM is a regional electric grid and market operator with operational control of over 180,000 MW of regional electric generation, and it operates the largest capacity and energy market in North America. According to a PJM factsheet, PJM "serves as the regional transmission organization for a 243,417 square mile area that covers all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia."[2] This geographical region encompasses 65 million

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[1] *See In the Matter of the Application of East Kentucky Power Cooperative, Inc. for Approval of the Acquisition of Existing Combustion Turbine Facilities from Bluegrass Generation Company, LLC at the Bluegrass Generating Station in LaGrange, Oldham County, Kentucky and for Approval of the Assumption of Certain Evidences of Indebtedness*, Order, Case No. 2015-00267 (Ky. P.S.C. Dec. 1, 2015).

[2] *See* "PJM Statistics – April 2017", http://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/pjm-statistics.ashx?la=en (last accessed July 1, 2018).

Americans, includes 1,373 distinct generation sources comprising 176,569 MWs of electric generation capacity.[3] PJM delivers more than 792 million megawatt-hours each year over 82,000 miles of transmission lines, and its peak demand is 165,492 MW.[4]

Q. Is EKPC a member of PJM?

A. Yes, EKPC has been a fully-integrated member of PJM since June 1, 2013.[5]

Q. Please briefly explain the capacity market administered by PJM.

A. PJM administers a Capacity Market for electric generating capacity. The Capacity Market is based around PJM's RPM, which "uses a market approach to obtaining the capacity needed to ensure reliability, with incentives that stimulate investment both in maintaining existing generation and in encouraging the development of new sources of capacity – resources that include not just generating plants but also demand response and energy-efficiency programs."[6] According to PJM, "[i]nvestors need sufficient long-term price signals to encourage the maintenance and development of generation and other resources. The RPM, based on making capacity commitments three years ahead, creates long-term price signals to attract needed investments in reliability in the PJM region."[7] The Capacity Market operates through a base residual auction held in May of each year and three

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[3] *Id.*

[4] *Id.*

[5] *See In the Matter of the Application of East Kentucky Power Cooperative, Inc. to Transfer Functional Control of Certain Transmission Facilities to PJM Interconnection, LLC*, Order, Case No. 2012-00169 (Ky. P.S.C. Dec. 20, 2012).

[6] See "Reliability Pricing Model – June 2017", http://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/reliability-pricing-model-fact-sheet.ashx?la=en (last accessed July 1, 2018).

[7] *Id.*

incremental auctions held in February, August and November.

Q. Does EKPC offer the output of the Bluegrass Station into the energy and capacity markets administered by PJM?

A. Yes; however, as the Commission is aware, the 165 MW output of Bluegrass Station Unit 3 is currently committed to Louisville Gas and Electric Company /Kentucky Utilities Company under a firm capacity purchase and tolling agreement ("Tolling Agreement"). The Tolling Agreement is scheduled to expire on April 30, 2019, which allows EKPC to offer Unit 3's generation into the PJM markets for delivery thereafter (which EKPC did for the first time as part of the Base Residual Auction ("BRA") for the 2019/2020 PJM Delivery Year).

Q. Prior to acquiring the Bluegrass Station, did EKPC investigate the current and anticipated economic value of the Bluegrass Station within PJM?

A. Yes. As part of the due diligence leading up to the acquisition, EKPC engaged the services of Navigant Consulting and relied upon internal analysis to arrive at the conclusion that the Bluegrass Station would be a valuable generation resource within the PJM Capacity Market. EKPC would continue to be able to have owned-generation to serve its load during most hours of the year even after the Dale units were retired and, in instances where EKPC enjoyed excess capacity, it would be able to monetize the availability of Bluegrass Station within PJM's energy market.

Q. Please explain PJM's Capacity Performance construct.

A. PJM's Capacity Performance construct represents a significant change to PJM's Capacity Market, designed to provide greater incentives for generators to pursue and ensure reliability and efficiency. Under Capacity Performance, generation resources are required to meet their commitments to deliver electricity whenever PJM determines they are needed to meet power system emergencies, during what are known as Performance Assessment Intervals ("PAI") or Performance Assessment Hours ("PAH"). As a "pay-for-performance" standard, resources that clear in a PJM capacity auction with a Capacity Performance requirement but fail to perform (for essentially any reason) are assessed penalties that are then awarded to resources which over-perform.

Q. Are Capacity Performance requirements presently in place?

A. The Capacity Performance product was approved by the Federal Energy Regulatory Commission and introduced into the August 2015 RPM capacity auction for the 2018/2019 PJM Delivery Year; for the 2020/2021 Delivery Year (the BRA for which was held in May of 2017), all resources within the PJM footprint must meet Capacity Performance requirements.

Q. When did EKPC begin considering the potential impact of Capacity Performance upon its generation portfolio?

A. EKPC began evaluating the potential impact of the Capacity Performance standards as soon as they were first proposed. As the proposal moved through the PJM stakeholder process, EKPC provided comments to assure that the Capacity Performance requirements would be fair. EKPC also examined what options, if any, should be pursued to assure that its generation fleet could have the best shot at satisfying the Capacity Performance standards once they took effect.

Q. Can Capacity Performance penalties be significant?

A. Yes. For the 2020/2021 PJM Delivery Year, the penalty to be assessed against a cleared resource with unavailable generation during a PAH is $3,329/MWh.

Q. Has EKPC undertaken an examination of the potential impact of Capacity Performance on the Bluegrass Station?

A. Yes. In order to determine the financial exposure EKPC may face if the Bluegrass Station is unable to perform as expected, EKPC retained Navigant Consulting, Inc. ("Navigant") to perform a Bluegrass Capacity Penalty Risk Analysis.[8] Navigant's examination reveals that, under PJM's rules, each PAH during which Bluegrass Station is unable to operate will cost EKPC approximately $2.4 million, which is comprised of $1.4 million in non-performance charges and $1 million in revenue essentially forfeited by failure to generate ($0.6 million in bonus payments and $0.4 million in energy margins). If circumstances similar to the 2014 Polar Vortex (which had 20 PAHs impact the EKPC zone) reoccurred, and EKPC's Bluegrass Station experienced a forced outage during one-third of those hours, EKPC would face penalties exceeding $16 million. The maximum penalty EKPC could face climbs to nearly $79 million if it were to experience a forced outage of the Bluegrass Station during all of the roughly 80 PAHs experienced by the region of PJM most-impacted during the 2014 Polar Vortex.

Q. What could cause the Bluegrass Station to be unavailable during a PAI/PAH, and thus be subject to Capacity Performance penalties?

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[8] A copy of Navigant's Bluegrass Capacity Penalty Risk Analysis is attached hereto as Attachment RL-2 to **Exhibit F**, the Direct Testimony of Mr. Ralph Luciani.

A. A generation resource may experience a forced outage, and thus be exposed to the financial risk of the Capacity Performance construct, for any number of reasons. These reasons include, but are not limited to, mechanical malfunctions, acts of God, terrorism, sabotage, labor disputes, and others. With respect to the Bluegrass Station's units in particular, a substantial threat to reliability is the fact that each unit is currently configured to operate using only one type and source of fuel—natural gas provided by the Texas Gas pipeline. EKPC has identified the interruption of fuel supply as the most significant risk faced by the Bluegrass Station that is capable of mitigation but presently not addressed.

Q. What options did EKPC consider in response to the risk presented by Capacity Performance?

A. EKPC identified the following five (5) alternatives in response to the risk presented by Capacity Performance caused by the Bluegrass Station's fuel supply status quo:

a. Purchase firm natural gas service, as opposed to interruptible service, from the Texas Gas pipeline presently serving the Bluegrass Station;

b. Purchase an insurance product to hedge against penalties that may be assessed as a result of fuel supply interruption;

c. Modify the Bluegrass Station to permit the on-site storage and conversion of liquefied natural gas ("LNG") to be used as a backup fuel in the event natural gas from the Texas Gas pipeline is unavailable;

d. Modify the Bluegrass Station to permit the on-site storage and use of fuel oil as a backup fuel in the event natural gas from the Texas Gas pipeline is unavailable (*i.e.*, implement dual fuel capability at the Station (the "Project"));

e. Accept the risk of nonperformance presented by the Bluegrass Station's single-source, interruptible fuel supply (*i.e.*, do nothing).

Q. Please describe EKPC's due diligence with respect to exploring the alternative of purchasing firm natural gas service for the Bluegrass Station.

A. EKPC first obtained pricing information and examined the available service types and timeframes available from Texas Gas. At the Bluegrass Station, natural gas firm transportation can be procured from the Texas Gas pipeline for a full year ("FT")[9] or on a short-term firm ("STF")[10] monthly basis at a higher monthly reservation price. With FT or STF, the contracted amount of firm gas must be spread evenly over the hours in a day (*i.e.*, the maximum hourly amount is 1/24th of the total), which makes it relatively prohibitive in cost for peaking units like those which comprise the Bluegrass Station. Enhanced firm gas service ("EFT")[11] is available at an extra cost which allows the maximum gas quantity in each hour to be 1/16th of the contracted amount. With natural gas unavailability being

[9] Firm Transportation (FT) Service provides customers with nominated firm transportation service from designated receipt points to designated delivery points. The firm transportation contract demand must be a daily transportation quantity which is the same for each day of the contract term, which term must be for at least twelve (12) consecutive months of service. FT Service provides customers with firm hourly deliveries up to 1/24th of their firm transportation contract demand.

[10] Short Term Firm Transportation Service (STF) is similar to Texas Gas' FT Rate Schedule except that STF shall be for a term of less than twelve (12) consecutive months, or the daily contract demand may vary by month or season over the term of an agreement one (1) year or longer in length. The seasonal nature of this service is reflected in its peak (winter) and off-peak (summer) rates.

[11] Enhanced Firm Transportation Service (EFT) is available to Texas Gas customers who have a transportation service agreement under the FT or STF Rate Schedule. EFT service permits customers to receive deliveries of gas at a variable hourly flow rate up to one-sixteenth (1/16th) of their contract demand, except when are provided notice that EFT service is unavailable.

unlikely in the summer, EKPC examined the alternatives of procuring STF or EFT over the full winter (November to March) and for a more cost-effective 3-month period (December to February).

Q. Why did EKPC not elect to pursue this alternative?

A. EKPC determined that changing the Bluegrass Station's natural gas supply from interruptible to firm is not an economically viable option to mitigate potential Capacity Performance risk. With respect to the Bluegrass Station, which is comprised of peaking units that operate only intermittently, procuring firm natural gas supply is prohibitively expensive considering the limited times it would be utilized. Navigant confirmed this fact as part of its Bluegrass Capacity Penalty Risk Analysis, and thus EKPC rejected this alternative as part of its due diligence process.

Q. Please describe EKPC's due diligence with respect to exploring the alternative of purchasing an insurance product to hedge against penalties that may be assessed as a result of fuel supply interruption at the Bluegrass Station.

A. EKPC examined in detail the availability of insurance products offered by brokers that allow Capacity Performance resources to hedge against interruption events during PJM-declared PAIs. Though EKPC's investigation determined that certain coverage was available in the market, the limitations, exclusions and pricing of such coverage was not favorable when compared to the cost of (and exposure mitigated by) an on-site backup fuel resource at the Bluegrass Station. Moreover, uncertainty with respect to the availability and future pricing of this type of insurance product (particularly if claims are made and paid) presents its own set of risks, which EKPC seeks to avoid. These facts required EKPC to reject this alternative as an unviable solution.

Q. Please describe EKPC's due diligence with respect to on-site backup fuel supply options at the Bluegrass Station.

A. In addition to increasing the reliability of the Bluegrass Station's existing fuel supply and hedging against its unavailability, EKPC also considered actions that sought to limit exposure to Capacity Performance risk by expanding the sources of fuel available for use by the Bluegrass Station. EKPC engaged Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") to prepare a screening level feasibility and cost analysis of each backup fuel supply option. The results of this analysis are further discussed in the testimony of Mr. Sam Yoder and Mr. Ralph Luciani submitted herewith.

EKPC first considered whether it could utilize LNG as an on-site backup fuel supply resource. Storing and utilizing LNG as a backup fuel supply was examined in detail by EKPC and its expert consultants because it offers mitigation of risk without substantial modification to the existing combustion turbines at the Bluegrass Station; because LNG is converted to natural gas prior to delivery as fuel, combustion turbines (like the Bluegrass Station's 501 FD2) can switch between pipeline natural gas operation and LNG backup operation without interruption.

EKPC, with the assistance of Burns & McDonnell, formally evaluated no less than four (4) alternatives for storing LNG at the Bluegrass Station site to serve as a backup fuel. The alternatives varied based on the type of storage tank(s) to be utilized (bullet v. field erected), as well as the amount of fuel to be stored (24-hour capacity v. 48-hour capacity).

Q. Please describe the notable advantages and disadvantages of utilizing LNG as a backup fuel supply option at the Bluegrass Station.

A. LNG provides an on-site back-up fuel that can be readily available and utilized at the plant. Other than fuel storage, few modifications would need to be made to the existing plant to be able to utilize LNG. However, LNG is a relatively new fuel source and there is little industry experience utilizing this fuel in a utility-scale power plant environment. The underlying risk of depending on this fuel source is unknown at this time. While LNG is available, the closest supplier is in Indianapolis, Indiana; the lack of multiple supply chain options was an additional concern for EKPC. Ultimately, the use of LNG as an on-site backup fuel did not economically compare favorably with the use of fuel oil.

Q. Are the Bluegrass Station units designed to operate on fuel oil?

A. The Bluegrass Station units, though historically and currently operated utilizing only natural gas as fuel, are designed to accommodate the use of both natural gas and/or fuel oil by employing interchangeable support housings and other modifications. Once the dual fuel system is implemented, the Bluegrass Station's 501 FD2 combustion turbines will be capable of switching between natural gas and fuel oil while online at reduced loads.

Q. Please further explain the "reduced loads" required to switch from natural gas to fuel oil and vice versa.

A. The original equipment manufacturer has developed a procedure to switch between fuels. This procedure recommends dropping load prior to switching between fuel sources. Dropping load reduces the amount of fuel being consumed and allows for a safe and reliable transfer of fuel source. Once the fuel source is successfully switched, the unit can return to full load quickly.

Q. What fuel oil backup fuel supply options did EKPC consider as part of its due diligence?

A. EKPC, again with the assistance of Burns & McDonnell, also evaluated fuel oil options at the Bluegrass Station with respect to backup fuel duration, practicability/feasibility, indicative capital costs, operational and maintenance impacts, industry experience, and estimated performance and emissions, among other matters. Four (4) distinct alternatives, differentiated by number of storage tanks (one or two) and total storage capacity (24-hour v. 48-hour), were explored in detail.

Q. Please describe the notable advantages and disadvantages of utilizing fuel oil as a backup fuel supply option at the Bluegrass Station.

A. On-site fuel oil will allow the Bluegrass Station units to operate should there be a physical interruption of the gas supply. It will also allow EKPC to rely on the interruptible gas transportation, which will not burden customers with the year-over-year cost of firm gas transportation. Forced outage rates can be higher for dual-fuel units switching fuels, particularly during severe weather, if the dual-fuel capability is not regularly tested. This disadvantage is mitigated by EKPC's experience with dual fuel operations at seven (7) of its Smith units. If fuel oil is relied on heavily, there is the potential for the alternative fuel to run out, particularly if fuel oil transportation to the Bluegrass Station is limited by a weather event. Overall, the one-time capital cost to implement fuel oil capability and storage coupled with the annual fixed O&M and fuel carrying costs provides the most flexibility at the least cost.

Q. What alternative did EKPC select?

A. Ultimately, EKPC selected the lowest cost alternative available—the implementation of fuel oil as an on-site backup fuel, utilizing two (2) storage tanks providing 24-hours' worth of fuel storage capacity (*i.e.*, the Project). The total cost of the Project is estimated by Burns & McDonnell at $62.8 million.

Q. Please describe in detail how the Project compares with the alternative of taking no action to address the risk of fuel-supply interruption at the Bluegrass Station.

A. As contemplated within the Commission's final Order in Case No. 2015-00267,[12] EKPC extensively considered the option of taking essentially no action with respect to the Bluegrass Station, thereby remaining exposed to Capacity Performance penalties should the Station's single-source fuel supply become unavailable during a PAI which impacts the EKPC zone. This analysis, again performed in cooperation with Navigant as part of its Bluegrass Capacity Penalty Risk Analysis, focused both on the amount of possible Capacity Performance penalties that could be levied against the Bluegrass Station, as well as the likelihood that such penalties would be borne over the next twenty (20) years. Because the overall economics of

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[12] *See* Order, pp. 28-29.

fuel alternatives at the Bluegrass Station depend predominately on whether natural gas will be interrupted at the station during a PAI, a multi-scenario evaluation was conducted to reflect both varying amounts of PAIs and varying amounts of primary fuel supply interruptions. Thereafter, a breakeven analysis was undertaken to determine how many applicable PAI events would be necessary to offset EKPC's investment in each of the contemplated mitigation strategies (including the implementation of fuel oil as a backup, but also including LNG and firm natural gas arrangements). Ultimately, EKPC concluded that the Capacity Performance risk faced by the Bluegrass Station requires mitigation efforts. The addition of fuel oil as a backup fuel supply resource is a low-technology-risk option that is also the lowest cost alternative at Bluegrass Station and represents the most economic means to mitigate Capacity Performance penalty risk, and thus EKPC requests Commission authorization to proceed with the Project.

Q. Will the Project have any impact upon the local community?

A. The Bluegrass Station is located in an industrial park. Any impact on the local community should be limited to the construction phase of the Project; increase truck traffic is expected during the mobilization phase and in the final phase of the Project as a result of fuel delivery. Once the project is complete, there should be no incremental impact to the local community. Replenishing backup fuel supplies will occur infrequently and will have minimal effect on the community.

Q. Are any local approvals necessary prior to moving forward with the Project?

A. EKPC personnel have met with local authorities and have ensured that no additional local approvals are required.

Q. What will most likely happen to Bluegrass Station Unit 3 after the Tolling Agreement expires?

A. EKPC has offered the Unit 3 capacity into the PJM RPM capacity auction starting on June 1, 2019. EKPC currently plans to utilize the capacity and energy of Unit 3 in the PJM market.

Q. Other than the Bluegrass Station, how is the balance of EKPC's generation fleet presently positioned with respect to Capacity Performance?

A. The remainder of EKPC's generation fleet has cleared the PJM RPM capacity auction as Capacity Performance units on previous occasions. The coal units have redundant mechanical systems and maintain an on-site fuel inventory, so they are well positioned in the Capacity Performance market. Seven of the nine gas units at J.K. Smith Station are capable of operating on dual fuels and are backed up with a large fuel oil tank. There are multiple natural gas pipelines available for supply at the site, so all nine units have at least two options for natural gas supply.

Q. Does the Capacity Performance construct impact the overall value of EKPC's membership in PJM?

A. EKPC purchases capacity for its projected summer peak load requirements from the PJM RPM capacity auction, plus its proportionate share of reserves. EKPC covers the expense of this purchase by selling its capacity into the PJM RPM capacity auction as Capacity Performance eligible units. EKPC continues to have more capacity available to sell into the auction than is required to cover the expense of its summer load requirements. This sale of excess capacity helps EKPC keep its cost to its owner-members lower. The risk of a potential PAH/PAI has increased the risk exposure to EKPC for the reliable operations of its units. EKPC has addressed this risk through reliable operations, secured fuel sources, and Capacity Performance insurance coverage. Much of EKPC's value of being a PJM member is obtained from the "trade benefits" of being able to purchase energy from the PJM market at a cost below EKPC's own generation costs. This trade benefit continues to be strong and very beneficial to EKPC.

Q. In your opinion, is the Project the most reasonable option for mitigating the Capacity Performance risk affecting the Bluegrass Station in future delivery years?

A. Yes.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF BACKUP FUEL FACILITIES AT ITS BLUEGRASS GENERATING STATION	))))))	**CASE NO. 2018-________**

VERIFICATION OF DAVID CREWS

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF CLARK)

David Crews, Senior Vice President of Power Supply at East Kentucky Power Cooperative, Inc., being duly sworn, states that he has read the foregoing prepared direct testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief, formed after reasonable inquiry.

Dan Crews

David Crews

The foregoing Verification was signed, acknowledged and sworn to before me this 24th day of August, 2018, by David Crews.

Gwyn M. Willoughby

NOTARY PUBLIC

Commission No. 590567

My Commission Expires: 11/30/21

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY	)	
POWER COOPERATIVE, INC. FOR A	)	
CERTIFICATE OF PUBLIC CONVENIENCE	)	CASE NO. 2018-________
AND NECESSITY FOR THE CONSTRUCTION	)	
OF BACKUP FUEL FACILITIES AT ITS	)	
BLUEGRASS GENERATING STATION	)	

DIRECT TESTIMONY OF CRAIG JOHNSON ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: August 24, 2018

I. INTRODUCTION

Q. Please state your name, business address and occupation.

A. My name is Craig A. Johnson and my business address is East Kentucky Power Cooperative, Inc. ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391. I am the Senior Vice President of Power Production of EKPC.

Q. Please state your education and professional experience.

A. I received a Bachelor's degree in Engineering from West Virginia Institute of Technology and a Master's of Science degree in Engineering from the University of Kentucky. I am a licensed professional engineer in the Commonwealth of Kentucky. I have been employed by EKPC since September 1989 and have held my current position within the EKPC organization since January 2010.

Q. Please provide a brief description of your duties at EKPC.

A. I am responsible for all operational and maintenance functions at EKPC's two (2) coal fired power plants, two (2) combustion turbine plants, six (6) landfill gas plants and one (1) community solar facility. I am responsible for Production Engineering and Construction. I report directly to EKPC's Executive Vice President and Chief Operating Officer, Mr. Don Mosier.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe EKPC's Bluegrass Generating Station ("Bluegrass Station" or the "Station"), as it currently exists, as well as the various options that EKPC considered when determining how best to address risk associated with the Capacity Performance construct within PJM Interconnection, LLC ("PJM").

I will also provide a detailed description of the proposed plan to bring dual fuel capability to the Bluegrass Station (as described herein, the "Project") that was selected by EKPC and serves as impetus of this proceeding.

Q. Are you sponsoring any exhibits?

A. Yes. Attached hereto as Attachment CJ-1 is a matrix of the permits and approvals relevant to the Project. This attachment was prepared by me or by individuals working under my supervision. Additionally, attached hereto as Attachment CJ-2 is a copy of the draft air permit issued to EKPC by the Kentucky Division of Air Quality ("DAQ") on July 27, 2018.

Q. Please describe EKPC's Bluegrass Station.

A. EKPC's Bluegrass Station is located just outside the city of La Grange in Oldham County, Kentucky, and began commercial operation in 2002. It consists of three (3) simple cycle Siemens 501 FD2 combustion turbine power generation units, each with a net winter output of 189 MW. The units have a remaining depreciable life of approximately 18 years. In 2017, the Bluegrass Station successfully operated 565.98 hours and generated 80,151 net megawatts.

Q. When did EKPC acquire the Bluegrass Station?

A. EKPC acquired the Bluegrass Station in late 2015 following the Commission's approval of the acquisition in Case No. 2015-00267.[1] EKPC undertook extensive

[1] *See In the Matter of the Application of East Kentucky Power Cooperative, Inc. for Approval of the Acquisition of Existing Combustion Turbine Facilities from Bluegrass Generation Company, LLC at the Bluegrass Generating Station in LaGrange, Oldham County, Kentucky and for Approval of the Assumption of Certain Evidences of Indebtedness*, Order, Case No. 2015-00267 (Ky. P.S.C. Dec. 1, 2015).

efforts to investigate the condition of the Station in advance of its purchase, as well as determine its value in light of fuel deliverability and pricing, environmental compliance, and numerous other related issues. The addition of the Bluegrass Station to EKPC's generation fleet was based on EKPC's demonstrated need to secure adequate capacity to serve its growing load.

Q. Please briefly describe any major the modifications and upgrades that EKPC has undertaken with respect to the Bluegrass Station since acquiring it in late 2015.

A. The Bluegrass Station has required minimal major modifications or upgrades since EKPC acquired it in 2015. In the fall of 2017, EKPC installed a Siemens T3000 distributed control system, an upgrade necessitated by the obsolescence of the Station's existing distributed control system (Siemens TXP).

Q. Has EKPC been pleased with the operational reliability of the Bluegrass Station units since their acquisition?

A. Yes. As documented in EKPC's Bluegrass Station 2017 Annual Operating Report filed with this Commission on March 30, 2018, the Station's units have maintained a high equivalent availability.

Q. How are the Bluegrass Station units fueled?

A. Presently, the Bluegrass Station units are configured to operate using only one (1) type and source of fuel—natural gas provided by an adjacent interstate natural gas pipeline owned and operated by Texas Gas Transmission, LLC ("Texas Gas"). Historically, EKPC has relied on interruptible service from Texas Gas; interruptible natural gas service has allowed EKPC to obtain natural gas at a lower cost than firm service and has been adequate in light of the fact that the Bluegrass Station is comprised of peaking units that operate only intermittently. Of course, the major disadvantage of an interruptible fuel supply is that it is not necessarily available when needed.

Q. Are the Bluegrass Station units designed to operate exclusively on natural gas?

A. The Bluegrass Station units, though historically and currently operated utilizing only natural gas as fuel, are designed to accommodate the use of both natural gas and/or fuel oil by employing interchangeable support housings on the combustion cans and other modifications. When dual fuel is implemented, the Bluegrass Station's 501 FD2 combustion turbines will be capable of switching between natural gas and fuel oil while online at reduced loads.

Q. Please summarize the relief sought by EKPC in this matter.

A. EKPC seeks the Commission's authorization to proceed with the implementation of dual fuel capabilities at the Bluegrass Station. The Project, as further described below and in the testimony and exhibits proffered herein by Mr. Sam Yoder of Burns & McDonnell Engineering Co., Inc. ("Burns & McDonnell"), involves construction of backup facilities which will allow EKPC to power the Bluegrass Station's combustion turbines utilizing No. 2 ultra-low-sulfur-diesel fuel oil in addition to natural gas, as well as installation of two (2) on-site fuel oil storage tanks to allow twenty-four (24) hours of plant operation, a demineralized water storage tank, and the erection or refinement of associated balance of plant systems to support dual fuel operation.

Q. What motivates EKPC to seek implementation of dual fuel capability at its Bluegrass Station?

A. EKPC's decision to pursue a backup fuel supply for its Bluegrass Station is the result of PJM's decision to implement a new "pay-for-performance" model within its Capacity Market. As further described in the testimony submitted herewith of Mr. David Crews, EKPC's Senior Vice President of Power Supply, prolific forced outage rates experienced during the Polar Vortex of January 2014, coupled with the coal-to-natural gas fuel transition, encouraged PJM to develop the Capacity Performance product to incent generator reliability and efficiency. In sum, Capacity Performance requires generation resources to meet their commitments to deliver electricity whenever PJM determines they are needed to meet power system emergencies, during what are known as Performance Assessment Intervals ("PAI") or Performance Assessment Hours. Resources that clear in a PJM capacity auction with a Capacity Performance requirement but fail to perform (for essentially any reason, including unavailability of fuel) are assessed penalties that are then awarded to resources which over-perform. In order to ensure that its Bluegrass Station is best positioned to satisfy the requirements of the PJM Capacity Performance construct, EKPC has determined to implement a second fuel source to power the Station's units in the event the primary fuel source (natural gas) is unavailable.

Q. Will dual fuel capability at the Bluegrass Station eliminate the risk of incurring penalties under PJM's Capacity Performance construct?

A. No, it will not. As further explained by Mr. Crews in his testimony, PJM's Capacity Performance construct is perhaps best described as "unforgiving" – there are essentially no valid excuses for a generator not to perform during a PAI, and every generator within the PJM footprint is subject to these requirements beginning with the 2020/2021 PJM Delivery Year. Thus, whenever a cleared generator experiences a forced outage during a PAI, whether that outage is the result of lack of fuel, some mechanical malfunction, act of God, operator error, or some other cause, that generator is subject to Capacity Performance penalties as a result. That said, EKPC has identified the interruption of fuel supply as the most significant Capacity Performance risk faced by the Bluegrass Station that is capable of mitigation but presently not addressed.

Q. Did EKPC consider other options for addressing Capacity Performance risk at the Bluegrass Station?

A. Yes, EKPC considered and extensively evaluated a number of different alternatives to minimize the risk of noncompliance with PJM's Capacity Performance rules. These options, which are detailed more fully in Mr. Crews' testimony, included securing firm natural gas service (as opposed to interruptible service) from the Texas Gas pipeline presently serving the Bluegrass Station, as well as purchasing an insurance product to hedge against penalties that may be assessed as a result of fuel supply interruption. Unfortunately, these options proved prohibitively expensive or otherwise unappealing, as explained by Mr. Crews. The other actions considered by EKPC sought to limit exposure to Capacity Performance risk by expanding the sources of fuel available for use by the Bluegrass Station in the event that the primary fuel supply becomes unavailable. EKPC engaged Burns & McDonnell to prepare a screening level feasibility and cost analysis ("Screening Analysis") of each backup fuel supply option, the results of which are incorporated in the evaluation and testimony of Mr. Ralph Luciani submitted herewith.

Q. What natural gas backup fuel supply options did EKPC consider as part of its due diligence?

A. As stated previously, EKPC's Bluegrass Station is presently configured to operate utilizing natural gas as its fuel. For this reason, EKPC considered whether an alternative source of natural gas could provide the desired level of security in light of PJM's Capacity Performance requirements. Though the construction of a natural gas transmission pipeline separate and apart from the existing Texas Gas pipeline was briefly explored, it became quickly apparent that such an option was not feasible. For this reason and others, EKPC's attention focused on natural gas backup fuel supply options to be located on the site of the Bluegrass Station.

Storing and utilizing liquefied natural gas ("LNG") as backup fuel supply was examined in detail by EKPC and its consultants because it offers mitigation of risk without substantial modification to the existing combustion turbines at the Bluegrass Station. When natural gas is converted to a liquid at very low temperatures, its volume is reduced by a factor of approximately 600, allowing for on-site storage of large amounts of backup fuel for a gas turbine facility. When the LNG is needed to fuel a turbine, it is heated through a vaporizer and converted back to natural gas; because LNG is converted back to natural gas prior to delivery as fuel, combustion turbines (like the Bluegrass Station's 501 FD2) can switch between pipeline natural gas operation and LNG backup operation without interruption.

EKPC, with the assistance of Burns & McDonnell, formally evaluated no less than four (4) alternatives for storing LNG at the Bluegrass Station site to serve as a backup fuel. The alternatives varied based on the type of storage tank(s) to be utilized (bullet v. field erected), as well as the amount of fuel to be stored (24-hour capacity v. 48-hour capacity).

EKPC, again with the assistance of Burns & McDonnell, also evaluated fuel oil options at the Bluegrass Station with respect to backup fuel duration, practicability/feasibility, indicative capital costs, operational and maintenance impacts, industry experience, and estimated performance and emissions, among other matters. Four (4) distinct alternatives, differentiated by number of storage tanks (one or two) and total storage capacity (24-hour v. 48-hour), were explored in detail.

Q. What alternative did EKPC select?

A. Ultimately, EKPC selected the lowest-cost alternative available—the implementation of fuel oil as an on-site backup fuel, utilizing two (2) storage tanks providing 24-hours' worth of fuel storage capacity (*i.e.*, the Project). The total cost of the Project is estimated by Burns & McDonnell at $62.8 million.

Q. Explain why EKPC selected the option that provides enough storage capacity for 24-hours of plant operation, as opposed to 48-hours or longer.

A. The two (2) carbon steel fuel oil storage tanks to be installed as part of the Project will be capable of storing a total of 1,160,000 gallons of usable fuel, which will allow each Bluegrass Station unit to operate continuously at its maximum winter unit rating for a twenty-four (24) hour period. EKPC expects this level of storage to provide adequate protection against the anticipated duration of a PJM-declared PAI.

Q. What is involved in developing and constructing the Project?

A. In follow-up to its Screening Analysis, EKPC retained Burns & McDonnell to further evaluate and develop the scope, preliminary design, schedule, and cost estimates for dual fuel capability at the Bluegrass Station. The Scoping Report issued by Burns and McDonnell involves three (3) major components of the Project, as follows:

a. Combustion Turbines and Associated Equipment – includes installation of dual fuel nozzles, new fuel oil pump skids, water injection pump skids, drain and purge system, and control systems for the combustion turbines to operate on fuel oil or natural gas;

b. Fuel Oil System – includes installation of two (2) carbon steel fuel oil storage tanks (capable of storing 580,000 gallons each), unloading equipment and forwarding pumps with inline heaters; and

c. Balance of Plant – includes installation of new piping, controls, instrumentation, electrical, and mechanical equipment, as well as an additional coated carbon steel storage tank capable of storing 400,000 gallons of demineralized water to supplement the existing 300,000 gallons of on-site storage.

Q. Please describe the location of the fuel oil storage tanks that are proposed as part of the Project and whether that location presents any public safety concerns.

A. The fuel oil storage tanks will be located adjacent to Unit 3 on property already owned and controlled by EKPC. The entire Bluegrass Station is surrounded by a security fence. Access to the tanks will be through the main secured entrance of the Station. The two (2) tanks will be constructed on a concrete pad with concrete walls for emergency containment. This concrete containment area is designed for 100% of fuel oil volume in one of the storage tanks, plus a 25-year, 24-hour rain event and six (6) inches of freeboard. Three (3) truck unloading pumps will be included next to the tank area. Required spill containment will be installed for all equipment and piping.

Q. Please explain how EKPC intends to purchase and obtain the necessary backup fuel oil that will be stored on-site at the Bluegrass Station.

A. Fuel oil will be procured and inventory will be managed at the Bluegrass Station by EKPC's Fuel & Emissions group like it is at EKPC's J.K. Smith Station. Fuel oil will be purchased by EKPC's Fuel & Emissions group, which purchases fuel and fuel-related commodities in accordance with EKPC policies, strategy, and procedure. The backup fuel oil will be delivered to the site by tanker truck.

Q. What is the function of the supplemental demineralized water storage tank and why is it necessary?

A. Demineralized water is injected into the turbine to control NOx emissions. The existing 300,000 gallons of demineralized water stored on-site is not an adequate supply to support a 24-hour continuous operation of all three (3) units at the Bluegrass Station. The supplemental 400,000 gallon storage tank will ensure there is an adequate demineralized water for 24-hours of continuous operation.

Q. Will the Project interfere with any other utilities' facilities?

A. No.

Q. Has EKPC selected a contracting approach with respect to the Project?

A. Yes. EKPC intends to use a multiple contract approach with adjustment unit pricing to develop and construct the Project. This approach allows EKPC to work with Burns & McDonnell to create and procure the necessary construction and major equipment contracts. The approach involves the use of multiple equipment and material contracts and multiple construction contracts and will allow EKPC to minimize procurement costs by providing for competitive bidding to reduce contractor markups.

Q. Please describe the Project schedule.

A. The schedule for the Project is driven by PJM's implementation of the Capacity Performance construct, which, as aforementioned, is applicable to all EKPC generating units beginning with the 2020/2021 Delivery Year. Based upon current projections, it is EKPC's intention to immediately begin ordering and securing equipment upon obtaining this Commission's approval of the Project, with the goal to achieve commercial operation of the Bluegrass Station in a dual fuel configuration by the end of 2020.

Q. Does EKPC seek an Order from the Commission by a certain date in order to keep its schedule?

A. Yes, EKPC requests a final Order of this Commission on or before February 28, 2019. An Order received by this date should allow EKPC to complete the Project by December 2020, essentially in advance of the winter months that generally present the greatest risk (January and February) with respect to forced outages and PJM-declared PAIs.

Q. Besides the Commission's authorization, has EKPC determined what other permits or approvals are necessary in order to undertake and complete the Project?

A. Yes. As part of Burns & McDonnell's Scoping Report, it identified the permits and approvals that should be considered by EKPC and that may impact the Project scope or schedule. EKPC also undertook an in-depth internal analysis in this regard and has determined that the Project will require approvals, modifications to existing permits or new permits from the following agencies: U.S. Fish and Wildlife Service; U.S. Environmental Protection Agency; United States Department of Agriculture's Rural Utilities Service; and Kentucky DAQ. EKPC has begun the process of seeking all necessary permits and approvals. EKPC received a draft permit for the Project from the Kentucky DAQ on July 27, 2018. Attached hereto as Attachment CJ-1 is a matrix and associated documentation reflecting the permits received, pending, or to be requested that are relevant to the Project, as determined by EKPC. A copy of the DAQ draft permit is attached here as Attachment CJ-2.

Q. Please describe the additional operations and maintenance expense EKPC will incur at the Bluegrass Station once the Project is completed.

A. EKPC estimates that the incremental annual operations and maintenance expense associated with the Project following its completion will be approximately $587,000. This may be further broken down to include $458,000 in fixed O&M expenses (including two (2) additional full-time employees) and $129,000 in variable O&M expenses (primarily related to additional demineralized water costs). EKPC will operate each unit on fuel oil once per quarter to ensure reliability. The cost of the fuel oil use in testing is approximately $100,000 annually.

Q. Based upon your professional background and experience, do you believe that the Project is the reasonable, least-cost option for allowing EKPC to appropriately mitigate the risk at the Bluegrass Station presented by the PJM Capacity Performance construct?

A. Yes.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF BACKUP FUEL FACILITIES AT ITS BLUEGRASS GENERATING STATION	))))))	**CASE NO. 2018-________**

VERIFICATION OF CRAIG JOHNSON

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF CLARK)

Craig Johnson, Senior Vice President of Power Production at East Kentucky Power Cooperative, Inc., being duly sworn, states that he has read the foregoing prepared direct testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief, formed after reasonable inquiry

Craig Johnson
Craig Johnson

The foregoing Verification was signed, acknowledged and sworn to before me this 24th day of August, 2018, by Craig Johnson.

Gwyn M. Willoughby
NOTARY PUBLIC

Commission No. 590567

My Commission Expires: 11/30/21

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021

EXHIBIT E
Attachment CJ-1

Item No.	Permit/Clearance	Regulatory Agency	Details	When Required	Applicability	Required	Submitted	Regulatory Position
Federal								
1	Clean Water Act - Section 404 Permit	U.S. Army Corps of Engineers, Louisville District	Nationwide Permit No. 39 for Commercial and Institutional Developments: Less than 0.5 acre/300 linear feet of wetland/stream impacts, Individual Permit: Greater than 0.5 acre/300 linear feet of wetland/stream impacts	Prior to construction	Not Applicable (NA)	No	No	Not required - no jurisdictional water of US impacted
2	Section 7 Threatened and Endangered Species Consultation and Clearance	U.S. Fish & Wildlife Service (FWS), Ecological Services	If the project will potentially impact protected species or their respective habitat, or if a Section 404 permit is required, then the FWS must be contacted. The FWS will determine the level of effort needed for the project to proceed (e.g., habitat assessment, species surveys, avian impact studies, etc.).	Prior to construction	Yes	Yes	pending	Site-specific field survey completed July 5-6, 2018, no potential endangered species impacts identified. USFWS Section 7 Informal Consultation concurrence pending. Submittal to USFWS 20-Aug-2018
3	Migratory Bird Treaty Act / Bald and Golden Eagle Protection Act Compliance	U.S. Fish & Wildlife Service (FWS), Ecological Services	Required when construction or operation of a proposed facility could impact migratory birds, their nests, and especially threatened or endangered species	Prior to construction	No	No	NA	NA
4	Spill Prevention, Control, and Countermeasure (SPCC) Plan Amendment	U.S. Environmental Protection Agency (EPA)	An amendment to the facility's SPCC Plan will be required to address additional onsite fuel storage and secondary containment.	Prior to fuel delivery	Yes	Yes	Not required to submit the SPCC Plan to the EPA for review	Required to be updated to address new fuel oil storage and secondary containment
5	Facility Response Plan (FRP)	U.S. Environmental Protection Agency (EPA)	A FRP is required for facilities that could reasonably be expected to cause "substantial harm" to the environment by discharging oil into or on navigable waters.	Prior to oil delivery	Applicability Determination on-going	Determination required	in progress	in progress
6	National Environmental Policy Act (NEPA), Environmental Report (ER)	USDA Rural Utility Services (RUS)	Project will require an ER because the project is requesting financing from RUS. NHPA -Section 106 Addressed through this process	Prior to construction	Yes	Yes	pending approval from USFWS	Will submit after USFWS concurs with Section 7 & 106
State - Kentucky								
7	CPCN	Kentucky Public Service Commission	Required for the construction of electric generating facilities	Prior to construction	Yes	Yes	Yes	in progress
8	Title V - Air Permit, Non-PSD	Kentucky Division of Air Quality	Clean Air Act and title V authorization is for natural gas only. Changes to fuels, monitoring and emissions require air permit modifications	Prior to construction	Yes	Yes	Yes	DAQ issued a draft permit on July 27, 2018
9	Section 401 Water Quality Certification	Kentucky Division of Water	WQC confirms that discharge materials included in Section 404 permit will meet the States applicable water quality standards	Prior to construction	Not Applicable	NA	NA	No Waters of the Commonwealth anticipated or impacted

Commonwealth of Kentucky
Energy and Environment Cabinet
Department for Environmental Protection
Division for Air Quality
300 Sower Boulevard, 2nd Floor
Frankfort, Kentucky 40601
(502) 564-3999

Draft

AIR QUALITY PERMIT
Issued under 401 KAR 52:020

Permittee Name:	**East Kentucky Power Cooperative (EKPC), Inc.**
Mailing Address:	**4775 Lexington, Road, PO Box 707 Winchester, KY 40392-0707**
Source Name:	**EKPC Bluegrass Generating Station**
Mailing Address:	**3095 Commerce Parkway LaGrange, KY 40031**
Source Location:	**Near exit 18 on I-71**
Permit:	**V-16-018 R1**
Agency Interest:	**39541**
Activity:	**APE20180001**
Review Type:	**Title V, Construction / Operating**
Source ID:	**21-185-00036**
Regional Office:	**Frankfort Regional Office 300 Sower Boulevard, 1st Floor Frankfort, KY 40601 (502) 564-3358**
County:	**Oldham**
Application Complete Date:	**May 17, 2016**
Issuance Date:	**March 3, 2017**
Revision Date:	
Expiration Date:	**March 3, 2022**

____
Sean Alteri, Director
Division for Air Quality

Version 10/16/13

Table of Contents

Permit Number	Permit type	Activity#	Complete Date	Issuance Date	Summary of Action
V-16-018	Title V	APE20160002	5/17/2016	3/3/2017	Title V Renewal
V-16-018 R1	Title V/Syn Minor	APE20180001	6/27/18		Significant Revision add fuel oil as back up fuel for the turbines.

SECTION A - PERMIT AUTHORIZATION

Pursuant to a duly submitted application the Kentucky Energy and Environment Cabinet (Cabinet) hereby authorizes the operation of the equipment described herein in accordance with the terms and conditions of this permit. This permit has been issued under the provisions of Kentucky Revised Statutes (KRS) Chapter 224 and regulations promulgated pursuant thereto.

The permittee shall not construct, reconstruct, or modify any affected facilities without first submitting a complete application and receiving a permit for the planned activity from the permitting authority, except as provided in this permit or in 401 KAR 52:020, Title V Permits.

Issuance of this permit does not relieve the permittee from the responsibility of obtaining any other permits, licenses, or approvals required by the Cabinet or any other federal, state, or local agency.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS

Emissions Unit 01, 02, and 03 **Natural Gas-Fired, Simple Cycle Combustion Turbine**

Description:

Model:	Siemens-Westinghouse 501FD
Construction Commenced:	October, 2000 – Emissions Units 01 and 02
	June, 2001– Emissions Unit 03
Maximum Continuous Rating:	2,076 MMBtu/hr rated heat input capacity (each), 208 MW rated capacity output (each)
Primary Fuel:	Natural gas
Secondary Fuel:	No. 2 Ultra Low Sulfur Diesel Fuel Oil
Control Equipment:	Dry-Low NO_x Burners & Water Injection on all three units
	High Temperature Selective Catalytic Reduction (SCR) on Units 01 & 02

APPLICABLE REGULATIONS:

401 KAR 51:160, NO_x requirements for large utility and industrial boilers

401 KAR 51:210, Clean Air Interstate Rule (CAIR) NO_x Annual Trading Program

401 KAR 51:220, CAIR NO_x Ozone season Trading Program

401 KAR 51:230, CAIR SO_2 Trading Program

401 KAR 52:060, Acid rain permits

401 KAR 63:020, Potentially hazardous matter or toxic substances

401 KAR 60:005, Section 2(2)(pp) 40 C.F.R. 60.330 to 60.335 (Subpart GG), Standards of Performance for Stationary Gas Turbines

40 CFR 75, Continuous Emissions Monitoring (CEM)

40 CFR Part 97, Subpart AAAAA, CSAPR NO_X Annual Trading Program (See Section L)

40 CFR Part 97, Subpart BBBBB, CSAPR NO_X Ozone Season Group 1 Trading Program (See Section L)

40 CFR Part 97, Subpart CCCCC, CSAPR SO_2 Group 1 Trading Program (See Section L)

40 CFR Part 97, Subpart EEEEE, CSAPR NO_X Ozone Season Group 2 Trading Program (See Section L)

STATE-ORIGIN REQUIREMENTS:

401 KAR 63:020, Potentially hazardous matter or toxic substances

1. Operating Limitations:

a) Combined operating hours for all turbines shall not exceed 4,757 hours during any consecutive twelve (12) month total **[Self-imposed to preclude 401 KAR 51:017]**.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

b) Firing on fuel oil is restricted to emergency circumstances such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine **[40 CFR 40.331]**. Firing on fuel oil is also permissible when required for maintenance and readiness testing.

c) Based upon the emission rates of toxics and hazardous air pollutants provided in the application and supplemental information submitted by the source, the Cabinet determines the affected facility to be in compliance with 401 KAR 63:020.

d) See **Section D** for source-wide operating limitations

2. Emission Limitations:

a) The concentration of nitrogen oxides (NO_x) in the exhaust gas from each unit shall not exceed 111 part per million (ppm) by volume at 15 percent oxygen, on a dry basis, and based on a four-hour rolling average **[40 CFR 60.332(a)(1)]**.

Compliance Demonstration:

The permittee shall demonstrate compliance by averaging the ppm level of NO_x measured using the NO_x CEM and comparing the result to the NO_x emission standard **[40 CFR 60.334(b)]**. The NO_x emission rate and mass calculations will be based on prorated natural gas and fuel oil fuel factors from 40 CFR Part 75, Appendix F.

b) The permittee shall either not discharge any gases into the atmosphere which contain sulfur dioxide (SO_2) in excess of 0.015 percent by volume at 15 percent oxygen, on a dry basis, or not burn any fuel which contains sulfur in excess of 0.8 percent by weight **[40 CFR 60.333(a) and (b)]**.

Compliance Demonstration:

See **Specific Monitoring Requirement 4.d.** and **4.f.**

c) Carbon monoxide (CO) emissions shall not exceed 50 ppm on a three-hour rolling average basis from each unit except during start-up, shutdown, and malfunction events. The start-up and shutdown emission calculation shall be based on emission rates determined from representative data derived from actual emissions testing. The CO emissions from the source during start-up and shutdown shall be included in the total emission cap of 245 tons per year as specified in **Section D** of this permit **[401 KAR 52:020, Section 10** and **Self-imposed to preclude 401 KAR 51:017]**.

Compliance Demonstration:

The permittee shall demonstrate compliance by averaging the ppm level of CO measured using a CEM and comparing the result to the CO emission standard. The CO emission rate and mass calculations will be based on prorated natural gas and fuel oil fuel factors from 40 CFR Part 75, Appendix F.

d) See **Section D** for source-wide emission limitations.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

3. Testing Requirements:

a) In conducting performance tests for nitrogen oxides as required by 40 CFR 60.8, the permittee shall use either EPA Method 20; ASTM D6522-00 incorporated by reference 40 CFR 60.17; EPA Method 7E and either EPA Method 3 or 3A in Appendix A of Part 60 or other acceptable reference methods or procedures as specified in 40 CFR 60.335 so as to determine compliance with the standard **[40 CFR 60.335(a)]**.

b) If the permittee elects to install and certify a NO_X CEMS under 40 CFR 60.334(e), then the initial performance test required under 40 CFR 60.8 may be done in the following alternative manner using the test data both to demonstrate compliance with the applicable NO_X emission limit under 40 CFR 60.332 and to provide the required reference method data for the RATA of the CEMS described under 40 CFR 60.334(b) **[40 CFR 60.335(b)(7)(ii)]**.

c) Performance testing is not required for any emergency fuel as defined in 40 CFR 60.331 (See Operating Limitation 1.b. of permit V-16-018 R1) **[40 CFR 60.335(b)(2)]**.

d) Testing shall be conducted at such times as may be required by the Cabinet **[401 KAR 50:045, Section 4]**.

4. Specific Monitoring Requirements:

a) The permittee shall install, calibrate, maintain, and operate a NO_x CEM. The NO_x CEM shall be used to demonstrate continuous compliance with the NO_x emission standard. Excluding the start-up and shutdown periods, if any four-hour rolling average exceeds the NO_x emission limitation, the permittee shall, as appropriate, initiate an investigation of the cause of the exceedance and complete necessary control device/process/CEM repairs or take corrective action as soon as practicable **[401 KAR 60:005, 40 CFR 60.334(b), and 40 CFR 75]**.

b) The nitrogen oxides CEM shall be used in lieu of the water to fuel monitoring system for reporting excess emissions in accordance with **40 CFR 60.334(b)(3)(iii)**. The calibration of the water to fuel monitoring device required in 40 CFR 60.334(a) will be replaced by the 40 CFR 75 certification tests of the nitrogen oxides CEMS monitor.

c) The permittee shall install, calibrate, maintain, and operate a CEM system for measuring oxygen levels **[401 KAR 52:020, Section 10]**.

d) The permittee shall determine sulfur dioxide emissions by using the heat input calculated using a certified fuel flow monitoring system in conjunction with the default SO_2 emission rate for pipeline natural gas from Section 2.3.1 of Appendix D and equation F-20 in Appendix F **[40 CFR 75.11(d)(2)]**.

e) The permittee shall comply with all the monitoring requirements of **40 CFR 75**.

f) The permittee shall monitor the sulfur content of the fuel being fired in the turbine. The frequency of determination of these values shall be as specified in the following approved custom fuel monitoring schedule **[40 CFR 60.334(h)]**:

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

1) The sulfur content of the gaseous fuel shall be determined twice per year. The monitoring shall be conducted during the first and third quarters of each calendar year **[401 KAR 52:020, Section 10]**.

2) The permittee may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine if the fuel meets the definition of natural gas in 40 CFR 60.331(u) **[40 CFR 60.334(h)(3)]**.

3) If there is a change in fuel supply, the permittee shall notify the Division of such change for re-examination of this custom schedule. A substantial change in fuel quality shall be considered a change in fuel supply. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined **[401 KAR 52:020, Section 10]**.

4) When fuel oil is used, the permittee shall sample the fuel oil sulfur content daily in accordance with 40 CFR 75, Appendix D **[40 CFR 60.334(i)(1)]**.

g) The permittee shall monitor for carbon monoxide, using a CO CEM **[401 KAR 52:020, Section 10]**.

h) The permittee shall install, calibrate, operate, test, and monitor all continuous monitoring systems and monitoring devices **[40 CFR 60.13 or 40 CFR 75]**. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device(s).

i) The permittee shall conduct a performance evaluation of the continuous monitoring system during any performance test required under 40 CFR 60.8 or within 30 days thereafter, in accordance with the applicable performance specification in 40 CFR 60 Appendix B, for NO_x performance evaluations of CEM systems shall be conducted at other times as required **[40 CFR 60.13(c)]**.

j) For affected facilities that are infrequently operated, an alternative monitoring procedure for CO monitors zero and span calibration checks has been approved by the Director. The permittee shall check the zero and span drift of the CO monitors at least once daily when operating, in accordance with and consistent with NO_x and O_2 monitor requirements under 40 CFR 75. The following provisions shall be adhered to while executing this alternative procedure **[401 KAR 59:005 Section 4(9)(b)]**:

1) Conditions for monitoring emissions data out-of-control periods as defined in 40 CFR 75.24 for CEMS shall apply to the CO monitors including but not limited to failed zero/span checks, and RATA tests. This out-of-control data shall not be used to calculate hourly emissions for the time period considered out-of-control until that time when the appropriate corrective measures specified in 40 CFR 75.24 are successfully completed and the data is back in-control.

2) Data substitution rules shall apply to the CO emissions data for out-of-control periods, including monitoring downtime, and those substituted emission data values shall count toward the facility source-wide annual federally enforceable CO emissions limit. For the purpose of complying with this requirement, the data substitution rules for NO_x monitors listed in 40 CFR 75.33 shall be applied to the CO monitors.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

k) Except during system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d), all continuous monitoring systems shall be in continuous operation and shall meet the minimum frequency of operation requirements by completing one cycle of operation (sampling, analyzing, and data recording) for each successive fifteen (15) minute period **[40 CFR 60.13(e)]**.

l) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the emissions units are obtained. Additional procedures for location of continuous monitoring systems, as contained in the applicable Performance Specifications of 40 CFR 60 Appendix B, shall be used **[40 CFR 60.13(f)]**.

m) The permittee shall reduce all data to one-hour averages for the continuous monitoring systems. The one-hour averages shall be computed from four or more data points equally spaced over each one-hour period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non-reduced form (e.g., ppm pollutant and percent oxygen). All excess emissions shall be converted into units of the applicable standard using the applicable conversion procedures specified in 40 CFR 60, Subpart GG. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used to specify the applicable emission standard **[40 CFR 60.13(h)]**.

n) The permittee shall monitor operating parameters for SCR and low NO_x burner **[401 KAR 52:020, Section 10]**.

o) The permittee shall monitor the quantity of fuel oil (in 1000 gallons), and natural gas (in MMscf), fired in each turbine, for any consecutive 12 month rolling total **[401 KAR 52:020, Section 10]**.

p) The permittee on a daily basis shall monitor the hours of operation for each turbine and fuel used**[401 KAR 52:020, Section 10]**.

5. **<u>Specific Recordkeeping Requirements</u>:**

a) The permittee of the gas turbine shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems and devices; and all other information required by 401 KAR 59:005 recorded in a permanent form suitable for inspection **[401 KAR 59:005, Section 3]**.

b) The permittee shall maintain records, including those documenting the results of each compliance test and all other records and reports required by this permit, and shall be maintained for five (5) years **[401 KAR 52:020, Section 3]**.

c) The permittee shall maintain the records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of the emissions units; any malfunction

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

of the air pollution control equipment; or any period during which a continuous monitoring system or monitoring device is inoperative **[401 KAR 59:005, Section 3]**.

d) The permittee shall maintain a log of all sulfur content measurements. Records of sample analysis and fuel supply data pertinent to the custom fuel sulfur monitoring schedule shall be retained for a period of five (5) years, and shall be available for inspection by personnel of federal, state, and local air pollution control agencies **[401 KAR 59:005, Section 3]**.

e) The permittee shall maintain records of operating parameters of the control equipment **[401 KAR 59:005, Section 3]**.

f) The permittee shall maintain a log of the rolling total of the quantity of fuel oil (in 1000 gallons), and natural gas (in MMscf), fired in each turbine, for any consecutive 12 month rolling total **[401 KAR 52:020, Section 10]**.

g) The permittee on a daily basis shall monitor the hours of operation for each turbine and fuel used **[401 KAR 52:020, Section 10]**.

6. <u>Specific Reporting Requirements</u>:

a) The minimum data reporting requirements, which follow, shall be maintained and furnished in the format specified by the Cabinet. The permittee shall submit a written report of excess emissions (as defined in applicable sections) to the cabinet for every calendar quarter. All quarterly reports shall be postmarked by the thirtieth (30th) day following the end of each calendar quarter and shall include the following information **[401 KAR 59:005, Section 3]**:

1) The magnitude of the excess emissions computed in accordance with 401 KAR 59:005, Section 4(8), any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.

2) Specific identification of each period of excess emission that occurs during start-ups, shutdowns, and malfunctions of the emission unit including the nature and cause of any malfunction (if known), the corrective action taken or preventive measures adopted.

3) The date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of the system repairs or adjustments.

4) When no excess emissions have occurred or the continuous monitoring system(s) has not been inoperative, repaired, or adjusted, such information shall be stated in the report.

b) For the reports regarding NO_X excess emissions, in lieu of those based on the water to fuel ratio monitoring, periods of excess emissions are defined for turbines using NO_X and diluent CEMS as follows **[40 CFR 60.334(j)(1)]**:

1) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_X concentration exceeds the applicable emission limit in 40 CFR 60.332(a)(1) or (2). For the purposes of 40 CFR 60, Subpart GG, a "4-hour

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

rolling average NO_x concentration" is the arithmetic average of the average NO_x concentration measured by the CEMS for a given hour (corrected to 15 percent O_2 and, if required under 40 CFR 60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NO_x concentrations immediately preceding that unit operating hour.

2) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_x concentration or diluent (or both).

3) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the permittee has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. The permittee does not have to report ambient conditions if the permittee opts to use the worst case ISO correction factor as specified in 40 CFR 60.334(b)(3)(ii), or if the permittee is not using the ISO correction equation under the provisions of 40 CFR 60.335(b)(1).

c) Excess emissions of SO_2 are defined by each unit operating hour included in the period beginning on the date and hour of any sample (or as otherwise required in the custom fuel sulfur monitoring plan) for which the sulfur content of the fuel being fired in the gas turbine(s) exceeds the limitations set forth in **Subsection 2. Emission Limitations**; and ending on the date and hour that a subsequent sample is taken that demonstrates compliance. These periods of excess emissions shall be reported quarterly **[40 CFR 60.334(j)(2)]**.

d) See **Section F**.

7. **Specific Control Equipment Operating Conditions:**

a) The permittee has the option to apply high temperature selective catalytic reduction (SCR) for NO_x control in its operation after initial demonstration of compliance with emission limitation set forth in Subsection 2. Emission Limitations. The NO_x emissions limitations shall not exceed the permit limit when the SCR system is not in use. The total emission cap for the facility shall not exceed the limit established in **Section D [401 KAR 50:055, Section 2]**.

b) The dry low-NO_x burners shall be operated while burning natural gas to maintain compliance with permitted emission limitations, in accordance with manufacturer's specifications and/or standard operating practices **[401 KAR 50:055, Section 2]**.

c) The water injection systems shall be operated while burning fuel oil to maintain compliance with permitted emission limitations, in accordance with manufacturer's specifications and/or standard operating practices **[401 KAR 50:055 Section2]**.

d) See **Section E, Source Control Equipment Requirements**, for further requirements.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Unit 04 (HTR) **Natural Gas-Fired Heater**

Description:

Gas Tech Heater

Primary Fuel:	Natural Gas
Maximum Continuous Rating:	5 MMBtu/hr
Construction Commenced:	2001

APPLICABLE REGULATIONS:

401 KAR 59:010, New process operations.

1. **Operating Limitations:**
See **Section D** for source-wide operating limitations.

2. **Emission Limitations:**
a) Particulate matter (PM) emissions from each stack shall not exceed the emissions listed below **[401 KAR 59:010, Section 3(2)]**.

P = Process Rate in tons/hr	E = Particulate matter emissions rate in lb/hr
$P < 0.50$	$E = 2.34$ lb/hr
$0.50 < P < 30$	$E = 3.59*P^{0.62}$
$P > 30$	$E = 17.31*P^{0.16}$

b) No person shall cause, suffer, allow or permit a continuous emission into the open air from a control device or stack associated with any affected facility, which is equal to or greater than twenty (20) percent opacity **[401 KAR 59:010, Section 3(1)]**.

Compliance Demonstration for a and b:

The unit is assumed to be in compliance with PM and opacity standards while burning natural gas.

3. **Testing Requirements:**

None

4. **Monitoring Requirements:**

The permittee shall monitor the amount of fuel burned, in MMscf, and hours of operation for the unit on a monthly basis **[401 KAR 52:020, Section 10]**.

5. **Recordkeeping Requirements:**

The permittee shall maintain record of the amount of fuel burned, in MMscf, and hours of operation for the unit on a monthly basis **[401 KAR 52:020, Section 10]**.

6. **Specific Reporting Requirements:**

See **Section F**.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

Emission Units 05-06 **Existing CI Emergency RICE <500 HP**

Emission Unit	Description	Manufacture Date	Maximum Continuous Rating (HP)	Fuel	Control Equipment
05	Caterpillar 3306B Emergency Generator	2001	382	Diesel	None
06	Cummins 6BTA5.9-F1 Emergency Fire Pump	2001	208	Diesel	None

APPLICABLE REGULATIONS:

40 CFR 63 Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Note: D.C. Circuit Court [*Delaware v. EPA*, 785 F. 3d 1 (D.C. Cir. 2015)] has vacated the provisions in 40 CFR 63, Subpart ZZZZ that contain the 100-hour exemption for operation of emergency engines for purposes of emergency demand response under 40 CFR 63.6640(f)(2)(ii)-(iii). The D.C. Circuit Court issued the mandate for the vacatur on May 4, 2016.

1. **Operating Limitations:**

a) For each unit the permittee shall **[40 CFR 63.6603(a), 40 CFR 63.6625(e), and 40 CFR 63.6625(i)]**:

1) Change oil and filter every 500 hours of operation or annually, whichever comes first, or change oil utilizing an oil analysis program according to the methods and requirements in order to extend the specified oil change requirements

2) Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first;

3) Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

4) Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-start emission limitations apply.

Compliance Demonstration:

The permittee shall operate and maintain the engines according to the manufacturer's emission-related operating and maintenance instructions, or develop and follow the permittee own maintenance plan which shall provide, to the extent practicable, for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions **[40 CFR 63.6625(e)]**.

b) For each unit, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for fifty (50) hours per year is

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

prohibited. There is no limit on the use of emergency stationary RICE in emergency situations. Maintenance checks and readiness testing of these units is limited to 100 hours per year. Operation of a unit in non-emergency situations is counted towards the 100 hours per year provided for maintenance and testing **[40 CFR 63.6640(f)(1)(i)]**.

c) The permittee shall be in compliance with the emission limitations and operating limitations in 40 CFR 63, Subpart ZZZZ that apply at all times **[40 CFR 63.6605(a)]**.

d) See **Section D** for source-wide operating limitations.

2. Emission Limitations:

None

3. Testing Requirements:

None

4. Specific Monitoring Requirements:

The permittee shall monitor the hour of operation on a monthly basis **[401 KAR 52:020, Section 10]**.

5. Specific Recordkeeping Requirements:

a) The permittee shall keep records of each notification and report that is submitted, the occurrence and duration of each malfunction of operation or the air pollution control and monitoring equipment, records of performance tests and performance evaluations as required in 40 CFR 63.10(b)(2)(viii), records of all required maintenance performed on the air pollution control and monitoring equipment, and records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation **[40 CFR 60.6655(a)]**.

b) The permittee shall maintain records of the maintenance conducted on the engine in order to demonstrate that the engine were operated and maintained, including any after-treatment control device, according to the maintenance plan for the engine. **[40 CFR 63.6655(e)]**.

c) If the engines are not certified to the standards applicable to non-emergency engines (see Table 2d to 40 CFR 63, Subpart ZZZZ), then the permittee shall keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The permittee shall document how many hours are spent for emergency operation; including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for demand response, records shall be kept of the notification of the emergency situation, and the time the engines were operated as part of demand response **[40 CFR 63.6655(f)(1)]**.

SECTION B - EMISSION POINTS, EMISSION UNITS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS (CONTINUED)

6. Specific Reporting Requirements:

a) The permittee shall report each instance in which the operating limitations in Subsection 1 have not been met. These instances are deviations from the emission and operating limitation in 40 CFR 63, Subpart ZZZZ and shall be reported according to 40 CFR 63.6650 **[40 CFR 63.6640(b)]**.

b) The permittee shall report each instance in which the requirements of Table 8 to 40 CFR 63, Subpart ZZZZ, that apply, have not been met [40 CFR 63.6640(e)]. The notifications listed in 40 CFR 63.7(b) and (c), 40 CFR 63.8(e), (f)(4) and (f)(6), 40 CFR 63.9(b) through (e), and (g) are not required **[40 CFR 63.6645(a)(5)]**.

c) See **Section F**.

SECTION C - INSIGNIFICANT ACTIVITIES

The following listed activities have been determined to be insignificant activities for this source pursuant to 401 KAR 52:020, Section 6. Although these activities are designated as insignificant the permittee shall comply with the applicable regulation. Process and emission control equipment at each insignificant activity subject to an opacity standard shall be inspected monthly and a qualitative visible emissions evaluation made. Results of the inspection, evaluation, and any corrective action shall be recorded in a log.

	Description	Generally Applicable Regulation
1.	Two (2) 3,0000 Gallon Tanks 19% Aqueous Ammonia Solutions	N/A
2.	Two (2) 300 Gallon Diesel Fuel Storage Tanks	N/A
3.	3000 Gallon Oil/Water Separator Tank	N/A
4.	259 Gallon By-Product Condensate Tank	N/A
5.	Fugitive Emissions from Natural Gas Fuel Handling System	401 KAR 63:010
6.	Two Fuel Oil Storage Tanks (580,000 Gallons Each)	N/A
7.	Fugitive Emissions from No. 2 ULSD Fuel Oil Handling System	401 KAR 63:010

SECTION D - SOURCE EMISSION LIMITATIONS AND TESTING REQUIREMENTS

1. As required by Section 1b of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26; compliance with annual emissions and processing limitations contained in this permit, shall be based on emissions and processing rates for any twelve (12) consecutive months.

2. Emissions of NO_x and CO, measured by applicable reference methods, or an equivalent or alternative method specified in 40 C.F.R. Chapter I, or by a test method specified in the state implementation plan shall not exceed the respective limitations specified herein.

3. For the gas combustion turbines, electric generator, fire water pump, and natural gas heater, emergency generator and emergency fire pump (Emission Units 01-06):

   a) Pursuant to 401 KAR 60:005, incorporating by reference 40 CFR 60, Subpart GG, and to preclude the applicability of 401 KAR 51:017, potential emissions of CO from the combustion turbines, electric generator, fire water pump, and natural gas heater (source-wide), Emission Units 01 through 06, shall not exceed 245 tons per year, during any consecutive twelve (12) month period. The potential emissions of NO_x from the combustion turbines, electric generator, fire water pump, and natural gas heater (source-wide), Emission Units 01 through 06, shall not exceed 95 tons per year, during any consecutive twelve (12) month period. The permittee shall assure compliance with these limitations by use of CEM systems for the combustion turbines and by performing calculations for the natural gas heater using emission factors provided in the permit application.

   b) 1. NOx and CO Emissions from the combustion turbines Emission Unit 01 thru 03 shall be determined with CEMs.

      2. NOx and CO Emissions from Emission Unit 04 natural gas heater may be calculated with the following equations: NO_x emissions = (emission factor from manufacturer = 0.12 lb/MMBtu)*(heat input = 5 MMBtu/hr)*(hours operated per month)*(1 ton/2000lbs) CO emissions = (emission factor from manufacturer = 0.05 lb/MMBtu)*(heat input = 5 MMBtu/hr)*(hours operated per month)*(1 ton/2000lbs).

      3. NOx and CO Emissions from the Emission Unit 05 382 HP Diesel Emergency Generator may be calculated with the following equations: NO_x emissions = (emission factor from 2016 application = 617.40 lb/1000 Gallons)*(Hourly Design Capacity = 0.0179 1000 Gallons/hr)*(hours operated per month)*(1 ton/2000lbs) CO emissions = (emission factor from 2016 application = 133 lb/1000 Gallons)*(Hourly Design Capacity = 0.0179 1000 Gallons/hr)*(hours operated per month)*(1 ton/2000lbs)

SECTION D - SOURCE EMISSION LIMITATIONS AND TESTING REQUIREMENTS (CONTINUED)

4. NOx and CO Emissions from the Emission Unit 06 208 HP Diesel Emergency Fire pump may be calculated with the following equations: NO_x emissions = (emission factor from 2016 application = 617.40 lb/1000 Gallons)*(Hourly Design Capacity = 0.01 1000 Gallons/hr)*(hours operated per month)*(1 ton/2000lbs) CO emissions = (emission factor from 2016 application = 133 lb/1000 Gallons)*(Hourly Design Capacity = 0.01 1000 Gallons/hr)*(hours operated per month)*(1 ton/2000lbs)

c) The permittee shall calculate and record the tons of NO_x and CO emissions emitted from the source on a monthly basis. Additionally, the permittee shall also calculate and record the tons of NO_x and CO emissions emitted from the source during any consecutive twelve (12) months.

d) Compliance with the annual NO_x and CO emission limitations shall be determined by summing the emissions from the turbines, electric generator, fire water pump, and the gas heater for any consecutive twelve (12) months total.

e) Records of tons of NO_x and CO emissions emitted from the source in any consecutive twelve (12) month period shall be reported quarterly to the Division's Frankfort Regional Office.

SECTION E - SOURCE CONTROL EQUIPMENT REQUIREMENTS

Pursuant to 401 KAR 50:055, Section 2(5), at all times, including periods of startup, shutdown and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Division which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

SECTION F - MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS

1. Pursuant to Section 1b-IV-1 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26, when continuing compliance is demonstrated by periodic testing or instrumental monitoring, the permittee shall compile records of required monitoring information that include:

   a. Date, place as defined in this permit, and time of sampling or measurements;

   b. Analyses performance dates;

   c. Company or entity that performed analyses;

   d. Analytical techniques or methods used;

   e. Analyses results; and

   f. Operating conditions during time of sampling or measurement.

2. Records of all required monitoring data and support information, including calibrations, maintenance records, and original strip chart recordings, and copies of all reports required by the Division for Air Quality, shall be retained by the permittee for a period of five (5) years and shall be made available for inspection upon request by any duly authorized representative of the Division for Air Quality [Sections 1b-IV-2 and 1a-8 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

3. In accordance with the requirements of 401 KAR 52:020, Section 3(1)h, the permittee shall allow authorized representatives of the Cabinet to perform the following during reasonable times:

   a. Enter upon the premises to inspect any facility, equipment (including air pollution control equipment), practice, or operation;

   b. To access and copy any records required by the permit:

   c. Sample or monitor, at reasonable times, substances or parameters to assure compliance with the permit or any applicable requirements.

   Reasonable times are defined as during all hours of operation, during normal office hours; or during an emergency.

4. No person shall obstruct, hamper, or interfere with any Cabinet employee or authorized representative while in the process of carrying out official duties. Refusal of entry or access may constitute grounds for permit revocation and assessment of civil penalties.

5. Summary reports of any monitoring required by this permit shall be submitted to the Regional Office listed on the front of this permit at least every six (6) months during the life of this permit, unless otherwise stated in this permit. For emission units that were still under construction or which had not commenced operation at the end of the 6-month period covered by the report and are subject to monitoring requirements in this permit, the report shall indicate that no monitoring was performed during the previous six months because the emission unit was not in operation [Sections 1b-V-1 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

SECTION F - MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS (CONTINUED)

6. The semi-annual reports are due by January 30th and July 30th of each year. All reports shall be certified by a responsible official pursuant to 401 KAR 52:020, Section 23. If continuous emission and opacity monitors are required by regulation or this permit, data shall be reported in accordance with the requirements of 401 KAR 59:005, General Provisions, Section 3(3). All deviations from permit requirements shall be clearly identified in the reports.

7. In accordance with the provisions of 401 KAR 50:055, Section 1, the permittee shall notify the Regional Office listed on the front of this permit concerning startups, shutdowns, or malfunctions as follows:

    a. When emissions during any planned shutdowns and ensuing startups will exceed the standards, notification shall be made no later than three (3) days before the planned shutdown, or immediately following the decision to shut down, if the shutdown is due to events which could not have been foreseen three (3) days before the shutdown.

    b. When emissions due to malfunctions, unplanned shutdowns and ensuing startups are or may be in excess of the standards, notification shall be made as promptly as possible by telephone (or other electronic media) and shall be submitted in writing upon request.

8. The permittee shall promptly report deviations from permit requirements, including those attributable to upset conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken shall be submitted to the Regional Office listed on the front of this permit. Where the underlying applicable requirement contains a definition of prompt or otherwise specifies a time frame for reporting deviations, that definition or time frame shall govern. Where the underlying applicable requirement does not identify a specific time frame for reporting deviations, prompt reporting, as required by Sections 1b-V, 3 and 4 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26, shall be defined as follows:
    a. For emissions of a hazardous air pollutant or a toxic air pollutant (as identified in an applicable regulation) that continue for more than an hour in excess of permit requirements, the report must be made within 24 hours of the occurrence.
    b. For emissions of any regulated air pollutant, excluding those listed in F.8.a., that continue for more than two hours in excess of permit requirements, the report must be made within 48 hours.
    c. All deviations from permit requirements, including those previously reported, shall be included in the semiannual report required by F.6.

9. Pursuant to 401 KAR 52:020, Title V permits, Section 21, the permittee shall annually certify compliance with the terms and conditions contained in this permit, by completing and returning a Compliance Certification Form (DEP 7007CC) (or an alternative approved by the regional office) to the Regional Office listed on the front of this permit and the U.S. EPA in accordance with the following requirements:

    a. Identification of the term or condition;

    b. Compliance status of each term or condition of the permit;

    c. Whether compliance was continuous or intermittent;

SECTION F - MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS (CONTINUED)

d. The method used for determining the compliance status for the source, currently and over the reporting period.

e. For an emissions unit that was still under construction or which has not commenced operation at the end of the 12-month period covered by the annual compliance certification, the permittee shall indicate that the unit is under construction and that compliance with any applicable requirements will be demonstrated within the timeframes specified in the permit.

SECTION F - MONITORING, RECORDKEEPING, AND REPORTING REQUIREMENTS (CONTINUED)

f. The certification shall be submitted by January 30th of each year. Annual compliance certifications shall be sent to the following addresses:

Division for Air Quality Frankfort Regional Office 300 Sower Boulevard, 1st Floor Frankfort, KY 40601	U.S. EPA Region 4 Air Enforcement Branch Atlanta Federal Center 61 Forsyth St. Atlanta, GA 30303-8960

10. In accordance with 401 KAR 52:020, Section 22, the permittee shall provide the Division with all information necessary to determine its subject emissions within 30 days of the date the Kentucky Emissions Inventory System (KYEIS) emissions survey is mailed to the permittee.

SECTION G - GENERAL PROVISIONS

1. General Compliance Requirements

   a. The permittee shall comply with all conditions of this permit. Noncompliance shall be a violation of 401 KAR 52:020, Section 3(1)(b), and a violation of Federal Statute 42 USC 7401 through 7671q (the Clean Air Act). Noncompliance with this permit is grounds for enforcement action including but not limited to termination, revocation and reissuance, revision or denial of a permit [Section 1a-3 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

   b. The filing of a request by the permittee for any permit revision, revocation, reissuance, or termination, or of a notification of a planned change or anticipated noncompliance, shall not stay any permit condition [Section 1a-6 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

   c. This permit may be revised, revoked, reopened and reissued, or terminated for cause in accordance with 401 KAR 52:020, Section 19. The permit will be reopened for cause and revised accordingly under the following circumstances:

      (1) If additional applicable requirements become applicable to the source and the remaining permit term is three (3) years or longer. In this case, the reopening shall be completed no later than eighteen (18) months after promulgation of the applicable requirement. A reopening shall not be required if compliance with the applicable requirement is not required until after the date on which the permit is due to expire, unless this permit or any of its terms and conditions have been extended pursuant to 401 KAR 52:020, Section 12;

      (2) The Cabinet or the United States Environmental Protection Agency (U. S. EPA) determines that the permit shall be revised or revoked to assure compliance with the applicable requirements;

      (3) The Cabinet or the U. S. EPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit;

      (4) New requirements become applicable to a source subject to the Acid Rain Program.

      Proceedings to reopen and reissue a permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of the permit for which cause to reopen exists. Reopenings shall be made as expeditiously as practicable. Reopenings shall not be initiated before a notice of intent to reopen is provided to the source by the Division, at least thirty (30) days in advance of the date the permit is to be reopened, except that the Division may provide a shorter time period in the case of an emergency.

   d. The permittee shall furnish information upon request of the Cabinet to determine if cause exists for modifying, revoking and reissuing, or terminating the permit; or to determine compliance with the conditions of this permit [Sections 1a- 7 and 8 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

   e. Emission units described in this permit shall demonstrate compliance with applicable requirements if requested by the Division [401 KAR 52:020, Section 3(1)(c)].

SECTION G - GENERAL PROVISIONS (CONTINUED)

f. The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall promptly submit such supplementary facts or corrected information to the permitting authority [401 KAR 52:020, Section 7(1)].

g. Any condition or portion of this permit which becomes suspended or is ruled invalid as a result of any legal or other action shall not invalidate any other portion or condition of this permit [Section 1a-14 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

h. The permittee shall not use as a defense in an enforcement action the contention that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance [Section 1a-4 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

i. All emission limitations and standards contained in this permit shall be enforceable as a practical matter. All emission limitations and standards contained in this permit are enforceable by the U.S. EPA and citizens except for those specifically identified in this permit as state-origin requirements. [Section 1a-15 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

j. This permit shall be subject to suspension if the permittee fails to pay all emissions fees within 90 days after the date of notice as specified in 401 KAR 50:038, Section 3(6) [Section 1a-10 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

k. Nothing in this permit shall alter or affect the liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance [401 KAR 52:020, Section 11(3) 2.].

l. This permit does not convey property rights or exclusive privileges [Section 1a-9 of the *Cabinet Provisions and Procedures for Issuing Title V Permits* incorporated by reference in 401 KAR 52:020, Section 26].

m. Issuance of this permit does not relieve the permittee from the responsibility of obtaining any other permits, licenses, or approvals required by the Cabinet or any other federal, state, or local agency.

n. Nothing in this permit shall alter or affect the authority of U.S. EPA to obtain information pursuant to Federal Statute 42 USC 7414, Inspections, monitoring, and entry [401 KAR 52:020, Section 11(3) 4.].

o. Nothing in this permit shall alter or affect the authority of U.S. EPA to impose emergency orders pursuant to Federal Statute 42 USC 7603, Emergency orders [401 KAR 52:020, Section 11(3) 1.].

p. This permit consolidates the authority of any previously issued PSD, NSR, or Synthetic Minor source preconstruction permit terms and conditions for various emission units and incorporates all requirements of those existing permits into one single permit for this source.

q. Pursuant to 401 KAR 52:020, Section 11, a permit shield shall not protect the permittee from enforcement actions for violating an applicable requirement prior to or at the time of

SECTION G - GENERAL PROVISIONS (CONTINUED)

permit issuance. Compliance with the conditions of this permit shall be considered compliance with:

(1) Applicable requirements that are included and specifically identified in this permit; and

(2) Non-applicable requirements expressly identified in this permit.

2. Permit Expiration and Reapplication Requirements

   a. This permit shall remain in effect for a fixed term of five (5) years following the original date of issue. Permit expiration shall terminate the source's right to operate unless a timely and complete renewal application has been submitted to the Division at least six (6) months prior to the expiration date of the permit. Upon a timely and complete submittal, the authorization to operate within the terms and conditions of this permit, including any permit shield, shall remain in effect beyond the expiration date, until the renewal permit is issued or denied by the Division [401 KAR 52:020, Section 12].

   b. The authority to operate granted shall cease to apply if the source fails to submit additional information requested by the Division after the completeness determination has been made on any application, by whatever deadline the Division sets [401 KAR 52:020, Section 8(2)].

3. Permit Revisions

   a. A minor permit revision procedure may be used for permit revisions involving the use of economic incentive, marketable permit, emission trading, and other similar approaches, to the extent that these minor permit revision procedures are explicitly provided for in the State Implementation Plan (SIP) or in applicable requirements and meet the relevant requirements of 401 KAR 52:020, Section 14(2).

   b. This permit is not transferable by the permittee. Future owners and operators shall obtain a new permit from the Division for Air Quality. The new permit may be processed as an administrative amendment if no other change in this permit is necessary, and provided that a written agreement containing a specific date for transfer of permit responsibility coverage and liability between the current and new permittee has been submitted to the permitting authority within ten (10) days following the transfer.

4. Construction, Start-Up, and Initial Compliance Demonstration Requirements

   Pursuant to a duly submitted application the Kentucky Division for Air Quality hereby authorizes the construction of the equipment described herein, emission units EU 01, 02 and 03 in accordance with the terms and conditions of this permit V-18-018 R1.

   a. Construction of any process and/or air pollution control equipment authorized by this permit shall be conducted and completed only in compliance with the conditions of this permit.

   b. Within thirty (30) days following commencement of construction and within fifteen (15) days following start-up and attainment of the maximum production rate specified in the permit application, or within fifteen (15) days following the issuance date of this permit, whichever is later, the permittee shall furnish to the Regional Office listed on the front of this permit in writing, notification of the following:

      (1) The date when construction commenced.

SECTION G - GENERAL PROVISIONS (CONTINUED)

(2) The date of start-up of the affected facilities listed in this permit.

(3) The date when the maximum production rate specified in the permit application was achieved.

c. Pursuant to 401 KAR 52:020, Section 3(2), unless construction is commenced within eighteen (18) months after the permit is issued, or begins but is discontinued for a period of eighteen (18) months or is not completed within a reasonable timeframe then the construction and operating authority granted by this permit for those affected facilities for which construction was not completed shall immediately become invalid. Upon written request, the Cabinet may extend these time periods if the source shows good cause.

d. Pursuant to 401 KAR 50:055, Section 2(1)(a), an owner or operator of any affected facility subject to any standard within the administrative regulations of the Division for Air Quality shall–demonstrate compliance with the applicable standard(s) within sixty (60) days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of such facility. Pursuant to 401 KAR 52:020, Section 3(3)(c), sources that have not demonstrated compliance within the timeframes prescribed in 401 KAR 50:055, Section 2(1)(a), shall operate the affected facility only for purposes of demonstrating compliance unless authorized under an approved compliance plan or an order of the cabinet.

e. This permit shall allow time for the initial start-up, operation, and compliance demonstration of the affected facilities listed herein. However, within sixty (60) days after achieving the maximum production rate at which the affected facilities will be operated but not later than 180 days after initial start-up of such facilities, the permittee shall conduct a performance demonstration on the affected facilities in accordance with 401 KAR 50:055, General compliance requirements. Testing must also be conducted in accordance with General Provisions G.5 of this permit.

f. Terms and conditions in this permit established pursuant to the construction authority of 401 KAR 51:017 or 401 KAR 51:052 shall not expire.

5. Testing Requirements

a. Pursuant to 401 KAR 50:045, Section 2, a source required to conduct a performance test shall submit a completed Compliance Test Protocol form, DEP form 6028, or a test protocol a source has developed for submission to other regulatory agencies, in a format approved by the cabinet, to the Division's Frankfort Central Office a minimum of sixty (60) days prior to the scheduled test date. Pursuant to 401 KAR 50:045, Section 7, the Division shall be notified of the actual test date at least thirty (30) days prior to the test.

b. Pursuant to 401 KAR 50:045, Section 5, in order to demonstrate that a source is capable of complying with a standard at all times, any required performance test shall be conducted under normal conditions that are representative of the source's operations and create the highest rate of emissions. If [When] the maximum production rate represents a source's highest emissions rate and a performance test is conducted at less than the maximum production rate, a source shall be limited to a production rate of no greater than 110 percent of the average production rate during the performance tests. If and when the facility is capable of operation at the rate specified in the application, the source may retest to demonstrate compliance at the new production rate. The Division for Air Quality may waive these requirements on a case-by-case basis if the source demonstrates

SECTION G - GENERAL PROVISIONS (CONTINUED)

to the Division's satisfaction that the source is in compliance with all applicable requirements.

c. Results of performance test(s) required by the permit shall be submitted to the Division by the source or its representative within forty-five days or sooner if required by an applicable standard, after the completion of the fieldwork.

6. Acid Rain Program Requirements

a. If an applicable requirement of Federal Statute 42 USC 7401 through 7671q (the Clean Air Act) is more stringent than an applicable requirement promulgated pursuant to Federal Statute 42 USC 7651 through 7651o (Title IV of the Act), both provisions shall apply, and both shall be state and federally enforceable.

b. The permittee shall comply with all applicable requirements and conditions of the Acid Rain Permit and the Phase II permit application (including the Phase II NO_X compliance plan and averaging plan, if applicable) incorporated into the Title V permit issued for this source. The source shall also comply with all requirements of any revised or future acid rain permit(s) issued to this source.

7. Emergency Provisions

a. Pursuant to 401 KAR 52:020, Section 24(1), an emergency shall constitute an affirmative defense to an action brought for the noncompliance with the technology-based emission limitations if the permittee demonstrates through properly signed contemporaneous operating logs or relevant evidence that:

(1) An emergency occurred and the permittee can identify the cause of the emergency;

(2) The permitted facility was at the time being properly operated;

(3) During an emergency, the permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards or other requirements in the permit; and

(4) Pursuant to 401 KAR 52:020, 401 KAR 50:055, and KRS 224.01-400, the permittee notified the Division as promptly as possible and submitted written notice of the emergency to the Division when emission limitations were exceeded due to an emergency. The notice shall include a description of the emergency, steps taken to mitigate emissions, and corrective actions taken.

(5) This requirement does not relieve the source of other local, state or federal notification requirements.

b. Emergency conditions listed in General Condition G.7.a above are in addition to any emergency or upset provision(s) contained in an applicable requirement [401 KAR 52:020, Section 24(3)].

c. In an enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof [401 KAR 52:020, Section 24(2)].

8. Ozone Depleting Substances

a. The permittee shall comply with the standards for recycling and emissions reduction pursuant to 40 CFR 82, Subpart F, except as provided for Motor Vehicle Air Conditioners (MVACs) in Subpart B:

SECTION G - GENERAL PROVISIONS (CONTINUED)

(1) Persons opening appliances for maintenance, service, repair, or disposal shall comply with the required practices contained in 40 CFR 82.156.

(2) Equipment used during the maintenance, service, repair, or disposal of appliances shall comply with the standards for recycling and recovery equipment contained in 40 CFR 82.158.

(3) Persons performing maintenance, service, repair, or disposal of appliances shall be certified by an approved technician certification program pursuant to 40 CFR 82.161.

(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances (as defined at 40 CFR 82.152) shall comply with the recordkeeping requirements pursuant to 40 CFR 82.166

(5) Persons owning commercial or industrial process refrigeration equipment shall comply with the leak repair requirements pursuant to 40 CFR 82.156.

(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant shall keep records of refrigerant purchased and added to such appliances pursuant to 40 CFR 82.166.

b. If the permittee performs service on motor (fleet) vehicle air conditioners containing ozone-depleting substances, the source shall comply with all applicable requirements as specified in 40 CFR 82, Subpart B, *Servicing of Motor Vehicle Air Conditioners*.

9. Risk Management Provisions

a. The permittee shall comply with all applicable requirements of 401 KAR Chapter 68, Chemical Accident Prevention, which incorporates by reference 40 CFR Part 68, Risk Management Plan provisions. If required, the permittee shall comply with the Risk Management Program and submit a Risk Management Plan to:

RMP Reporting Center
P.O. Box 1515
Lanham-Seabrook, MD 20703-1515.

b. If requested, submit additional relevant information to the Division or the U.S. EPA.

SECTION H - ALTERNATE OPERATING SCENARIOS

None

SECTION I - COMPLIANCE SCHEDULE

None

SECTION J - ACID RAIN PERMIT

1. Statement of Basis:

Statutory and Regulatory Authorities: The Energy and Environmental Cabinet, Division for Air Quality issues this permit pursuant to 401 KAR 52:020, title V permits, 401 KAR 52:060, Acid rain permits, and 40 CFR 76 and in accordance to KRS 224.10-100 and Titles IV and V of the Clean Air Act.

2. SO_2 allowances allocated under this permit and NOx requirements for each affected unit.

Plant Name: Bluegrass Generating Station, East Kentucky Power Cooperative, Inc.
Affected Units: (GTG-01) – EU03 (G7G03)

SO_2 Allowances	**Year**				
Tables 2, 3, or 4 of	2016	2017	2018	2019	2020
40 CFR Part 73	0	0	0	0	0

NOx Requirements	
NOx Limits	N/A

3. Comments, Notes, and Justifications:

a. The three combustion turbines, Emission Units 01-03 have no SO_2 allowances allocated by U.S. EPA.

b. The three combustion turbines, Emission Units 01-03 do not have applicable NO_x limits set by 40 CFR Part 76.

4. Permit Application:

The Acid Rain Permit Application and CAIR Permit Application are a part of this permit and the source shall comply with the standard requirements and special provisions set forth in the applications.

SECTION K - CLEAN AIR INTERSTATE RULE

1. **Statutory and Regulatory Authority:**

   In accordance with KRS 224.10-100, the Kentucky Energy and Environmental Cabinet issues this permit pursuant to 401 KAR 52:020, Title V permits, 401 KAR 51:210, CAIR NO_x annual trading program, 401 KAR 51:220, CAIR NO_x Ozone season Trading Program, and 401 KAR 51:230, CAIR SO_2 Trading Program.

2. **Application and Requirements:**

   The CAIR application for three (3) electrical generating units was submitted to the Division and received on July 5, 2007. The standard requirements and special provisions set forth in the application are hereby incorporated into and made part of this CAIR Permit. [401 KAR 51:210, 401 KAR 51:220, and 401 KAR 51:230]. Pursuant to 401 KAR 52:020, Section 3, the source shall operate in compliance with those requirements.

3. **Unit Description**

   The affected units are three (3) natural gas-fired simple combustion turbines each rated at 2076 MMBtu /hour (EU 01, EU 02 and 03). Each unit has a capacity to generate 208MW of electricity, which is offered for sale.

4. **Summary of Actions**

   The CAIR Permit is being issued as part of the Title V permit for this source. Public, affected state and U.S. EPA review followed the procedures specified in 401 KAR 52:100.

   A December 2008 court decision kept the requirements of CAIR in place temporarily but directed EPA to issue a new rule to implement Clean Air Act requirements concerning the transport of air pollution across state boundaries. On July 6, 2011, EPA finalized the Cross-State Air Pollution Rule (CSAPR). On December 30, 2011, CSAPR was stayed prior to implementation. On April 29, 2014, the United States Supreme Court issued an opinion reversing an August 21, 2012 D.C. Circuit decision that had vacated CSAPR. Following the remand of the case to the appellate court, EPA requested that the court lift the CSAPR stay and toll the CSAPR compliance deadlines by three years. On October 23, 2014 EPA's request was granted. CSAPR Phase I implementation is now in place and replaces requirements under CAIR.

SECTION L - CROSS-STATE AIR POLLUTION RULE (CSPAR)

The CSAPR subject unit, and the unit-specific monitoring provisions, at this source are identified in the following table. This unit is subject to the requirements for the CSAPR NO_x Annual Trading Program, CSAPR NO_x Ozone Season Trading Program, and CSAPR SO_2 Group 1 Trading Program.

Unit ID 01 thru 03: Three natural gas fired simple cycle turbines.					
Parameter	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR part 75, Subpart B (for SO_2 monitoring) and 40 CFR part 75, Subpart H (for NO_X monitoring)	Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR part 75, appendix D	Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR part 75, appendix E	Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19	EPA-approved alternative monitoring system requirements pursuant to 40 CFR part 75, Subpart E
SO_2		X			
NO_X	X				
Heat input	X				

1. The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (CSAPR NO_X Annual Trading Program), 97.830 through 97.835 (CSAPR NO_X Ozone Season Trading Program), and 97.630 through 97.635 (CSAPR SO_2 Group 1 Trading Program). The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable CSAPR trading programs.

2. Owners and operators shall submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the EPA's website at

   http://www.epa.gov/airmarkets/emissions/monitoringplans.html.

3. Owners and operators that want to use an alternative monitoring system shall submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR part 75, Subpart E and 40 CFR 75.66 and 97.435 (CSAPR NO_X Annual Trading Program), 97.835 (CSAPR NO_X Ozone Season Trading Program), and/or 97.635 (CSAPR SO_2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the EPA's website at http://www.epa.gov/airmarkets/emissions/petitions.html.

SECTION L - CROSS-STATE AIR POLLUTION RULE (CONTINUED)

4. Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (CSAPR NO_X Annual Trading Program), 97.830 through 97.834 (CSAPR NO_X Ozone Season Trading Program), and/or 97.630 through 97.634 (CSAPR SO_2 Group 1 Trading Program) shall submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (CSAPR NO_X Annual Trading Program), 97.835 (CSAPR NO_X Ozone Season Trading Program), and/or 97.635 (CSAPR SO_2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on the EPA's website at

   http://www.epa.gov/airmarkets/emissions/petitions.html.

5. The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (CSAPR NO_X Annual Trading Program), 97.830 through 97.834 (CSAPR NO_X Ozone Season Trading Program), and 97.630 through 97.634 (CSAPR SO_2 Group 1 Trading Program), and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add or change this unit's monitoring system description.

CSAPR NO_X Annual Trading Program requirements (40 CFR 97.406)

a) Designated representative requirements.
The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.413 through 97.418.

b) Emissions monitoring, reporting, and recordkeeping requirements.

1) The owners and operators, and the designated representative, of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.431 (initial monitoring system certification and recertification procedures), 97.432 (monitoring system out-of-control periods), 97.433 (notifications concerning monitoring), 97.434 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.435 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).
2) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of CSAPR NO_X Annual allowances under 40 CFR 97.411(a)(2) and (b) and 97.412 and to determine compliance with the CSAPR NO_X Annual emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

c) NO_X emissions requirements.

1) CSAPR NO_X Annual emissions limitation.

SECTION L - CROSS-STATE AIR POLLUTION RULE (CONTINUED)

i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall hold, in the source's compliance account, CSAPR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.424(a) in an amount not less than the tons of total NO_X emissions for such control period from all CSAPR NO_X Annual units at the source.

ii) If total NO_X emissions during a control period in a given year from the CSAPR NO_X Annual units at a CSAPR NO_X Annual source are in excess of the CSAPR NO_X Annual emissions limitation set forth in paragraph (c)(1)(i) above, then:

A) The owners and operators of the source and each CSAPR NO_X Annual unit at the source shall hold the CSAPR NO_X Annual allowances required for deduction under 40 CFR 97.424(d); and

B) The owners and operators of the source and each CSAPR NO_X Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, Subpart AAAAA and the Clean Air Act.

2) CSAPR NO_X Annual assurance provisions.

i) If total NO_X emissions during a control period in a given year from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.425(b), of multiplying— (A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and (B) The amount by which total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state for such control period exceed the state assurance level.

ii) The owners and operators shall hold the CSAPR NO_X Annual allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

iii) Total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the State during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the state NO_X Annual trading budget under 40 CFR 97.410(a) and the state's variability limit under 40 CFR 97.410(b).

iv) It shall not be a violation of 40 CFR part 97, Subpart AAAAA or of the Clean Air Act if total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual

SECTION L - CROSS-STATE AIR POLLUTION RULE (CONTINUED)

sources in the State during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state during a control period exceeds the common designated representative's assurance level.

v) To the extent the owners and operators fail to hold CSAPR NO_X Annual allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,
   A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and
   B) Each CSAPR NO_X Annual allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, Subpart AAAAA and the Clean Air Act.

3) Compliance periods.
   i) A CSAPR NO_X Annual unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.
   ii) A CSAPR NO_X Annual unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

4) Vintage of allowances held for compliance.
   i) A CSAPR NO_X Annual allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year shall be a CSAPR NO_X Annual allowance that was allocated for such control period or a control period in a prior year.
   ii) A CSAPR NO_X Annual allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year shall be a CSAPR NO_X Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

5) Allowance Management System requirements. Each CSAPR NO_X Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, Subpart AAAAA.

6) Limited authorization. A CSAPR NO_X Annual allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:
   i) Such authorization shall only be used in accordance with the CSAPR NO_X Annual Trading Program; and
   ii) Notwithstanding any other provision of 40 CFR part 97, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

7) Property right. A CSAPR NO_X Annual allowance does not constitute a property right.

SECTION L - CROSS-STATE AIR POLLUTION RULE (CONTINUED)

d) Title V permit revision requirements.

1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_X Annual allowances in accordance with 40 CFR part 97, Subpart AAAAA.

2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.430 through 97.435, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, Subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, Subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.406(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

e) Additional recordkeeping and reporting requirements.

1) Unless otherwise provided, the owners and operators of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.
   i) The certificate of representation under 40 CFR 97.416 for the designated representative for the source and each CSAPR NO_X Annual unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416 changing the designated representative.
   ii) All emissions monitoring information, in accordance with 40 CFR part 97, Subpart AAAAA.
   iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NO_X Annual Trading Program.
2) The designated representative of a CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall make all submissions required under the CSAPR NO_X Annual Trading Program, except as provided in 40 CFR 97.418. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

f) Liability.

1) Any provision of the CSAPR NO_X Annual Trading Program that applies to a CSAPR NO_X Annual source or the designated representative of a CSAPR NO_X Annual source shall also apply to the owners and operators of such source and of the CSAPR NO_X Annual units at the source.
2) Any provision of the CSAPR NO_X Annual Trading Program that applies to a CSAPR NO_X Annual unit or the designated representative of a CSAPR NO_X Annual unit shall also apply to the owners and operators of such unit.

SECTION L - CROSS-STATE AIR POLLUTION RULE (CONTINUED)

g) Effect on other authorities.
No provision of the CSAPR NO_X Annual Trading Program or exemption under 40 CFR 97.405 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_X Annual source or CSAPR NO_X Annual unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

CSAPR NO_X Ozone Season Trading Program Requirements (40 CFR 97.806)

a) Designated representative requirements.
The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.813 through 97.818.

b) Emissions monitoring, reporting, and recordkeeping requirements.

1) The owners and operators, and the designated representative, of each CSAPR NO_X Ozone Season source and each CSAPR NO_X Ozone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.830 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.831 (initial monitoring system certification and recertification procedures), 97.832 (monitoring system out-of-control periods), 97.833 (notifications concerning monitoring), 97.834 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.835 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).
2) The emissions data determined in accordance with 40 CFR 97.830 through 97.835 shall be used to calculate allocations of CSAPR NO_X Ozone Season allowances under 40 CFR 97.811(a)(2) and (b) and 97.812 and to determine compliance with the CSAPR NO_X Ozone Season emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.830 through 97.835 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

c) NO_X emissions requirements.

1) CSAPR NO_X Ozone Season emissions limitation.
   i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Ozone Season source and each CSAPR NO_X Ozone Season unit at the source shall hold, in the source's compliance account, CSAPR NO_X Ozone Season allowances available for deduction for such control period under 40 CFR 97.824(a) in an amount not less than the tons of total NO_X emissions for such control period from all CSAPR NO_X Ozone Season units at the source.
   ii) If total NO_X emissions during a control period in a given year from the CSAPR NO_X Ozone Season units at a CSAPR NO_X Ozone Season source are in excess of the CSAPR NO_X Ozone Season emissions limitation set forth in paragraph (c)(1)(i) above, then:

SECTION L - CROSS-STATE AIR POLLUTION RULE (CONTINUED)

A) The owners and operators of the source and each CSAPR NO_X Ozone Season unit at the source shall hold the CSAPR NO_X Ozone Season allowances required for deduction under 40 CFR 97.824(d); and

B) The owners and operators of the source and each CSAPR NO_X Ozone Season unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR part 97, Subpart BBBBB and the Clean Air Act.

2) CSAPR NO_X Ozone Season assurance provisions.

i) If total NO_X emissions during a control period in a given year from all CSAPR NO_X Ozone Season units at CSAPR NO_X Ozone Season sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_X Ozone Season allowances available for deduction for such control period under 40 CFR 97.825(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.825(b), of multiplying—

A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and

B) The amount by which total NO_X emissions from all CSAPR NO_X Ozone Season units at CSAPR NO_X Ozone Season sources in the state for such control period exceed the state assurance level.

ii) The owners and operators shall hold the CSAPR NO_X Ozone Season allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

iii) Total NO_X emissions from all CSAPR NO_X Ozone Season units at CSAPR NO_X Ozone Season sources in the state during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season trading budget under 40 CFR 97.810(a) and the state's variability limit under 40 CFR 97.810(b).

iv) It shall not be a violation of 40 CFR part 97, Subpart BBBBB or of the Clean Air Act if total NO_X emissions from all CSAPR NO_X Ozone Season units at CSAPR NO_X Ozone Season sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the CSAPR NO_X Ozone Season units at CSAPR NO_X Ozone Season sources in the state during a control period exceeds the common designated representative's assurance level.

SECTION L - CROSS-STATE AIR POLLUTION RULE (CONTINUED)

v) To the extent the owners and operators fail to hold CSAPR NO_X Ozone Season allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,
   A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and
   B) Each CSAPR NO_X Ozone Season allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, Subpart BBBBB and the Clean Air Act.

3) Compliance periods.
   i) A CSAPR NO_X Ozone Season unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of May 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter.
   ii) A CSAPR NO_X Ozone Season unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter.
4) Vintage of allowances held for compliance.
   i) A CSAPR NO_X Ozone Season allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year shall be a CSAPR NO_X Ozone Season allowance that was allocated for such control period or a control period in a prior year.
   ii) A CSAPR NO_X Ozone Season allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year shall be a CSAPR NO_X Ozone Season allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.
5) Allowance Management System requirements. Each CSAPR NO_X Ozone Season allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, Subpart BBBBB.
6) Limited authorization. A CSAPR NO_X Ozone Season allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:
   i) Such authorization shall only be used in accordance with the CSAPR NO_X Ozone Season Trading Program; and
   ii) Notwithstanding any other provision of 40 CFR part 97, Subpart BBBBB, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.
7) Property right. A CSAPR NO_X Ozone Season allowance does not constitute a property right.

d) Title V permit revision requirements.

1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_X Ozone Season allowances in accordance with 40 CFR part 97, Subpart BBBBB.

SECTION L - CROSS-STATE AIR POLLUTION RULE (CONTINUED)

2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.830 through 97.835, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, Subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, Subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.806(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

e) Additional recordkeeping and reporting requirements.

1) Unless otherwise provided, the owners and operators of each CSAPR NOx Ozone Season source and each CSAPR NOx Ozone Season unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.
   i) The certificate of representation under 40 CFR 97.816 for the designated representative for the source and each CSAPR NOx Ozone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.816 changing the designated representative.
   ii) All emissions monitoring information, in accordance with 40 CFR part 97, Subpart BBBBB.
   iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NOx Ozone Season Trading Program.
2) The designated representative of a CSAPR NOx Ozone Season source and each CSAPR NOx Ozone Season unit at the source shall make all submissions required under the CSAPR NOx Ozone Season Trading Program, except as provided in 40 CFR 97.818. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

f) Liability.

1) Any provision of the CSAPR NOx Ozone Season Trading Program that applies to a CSAPR NOx Ozone Season source or the designated representative of a CSAPR NOx Ozone Season source shall also apply to the owners and operators of such source and of the CSAPR NOx Ozone Season units at the source.
2) Any provision of the CSAPR NOx Ozone Season Trading Program that applies to a CSAPR NOx Ozone Season unit or the designated representative of a CSAPR NOx Ozone Season unit shall also apply to the owners and operators of such unit.

g) Effect on other authorities.

No provision of the CSAPR NOx Ozone Season Trading Program or exemption under 40 CFR 97.805 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NOx Ozone Season source or CSAPR NOx Ozone

SECTION L - CROSS-STATE AIR POLLUTION RULE (CONTINUED)

Season unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

CSAPR SO_2 Group 1 Trading Program requirements (40 CFR 97.606)

a) **Designated representative requirements.**
The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.613 through 97.618.

b) **Emissions monitoring, reporting, and recordkeeping requirements.**
   1) The owners and operators, and the designated representative, of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.630 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.631 (initial monitoring system certification and recertification procedures), 97.632 (monitoring system out-of-control periods), 97.633 (notifications concerning monitoring), 97.634 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.635 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).
   2) The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of CSAPR SO_2 Group 1 allowances under 40 CFR 97.611(a)(2) and (b) and 97.612 and to determine compliance with the CSAPR SO_2 Group 1 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

c) **SO_2 emissions requirements.**
   1) CSAPR SO_2 Group 1 emissions limitation.
      i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO2 Group 1 unit at the source shall hold, in the source's compliance account, CSAPR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all CSAPR SO_2 Group 1 units at the source.
      ii) If total SO_2 emissions during a control period in a given year from the CSAPR SO_2 Group 1 units at a CSAPR SO_2 Group 1 source are in excess of the CSAPR SO_2 Group 1 emissions limitation set forth in paragraph (c)(1)(i) above, then:
         A) The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall hold the CSAPR SO_2 Group 1 allowances required for deduction under 40 CFR 97.624(d); and
         B) The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton

SECTION L - CROSS-STATE AIR POLLUTION RULE (CONTINUED)

of such excess emissions and each day of such control period shall constitute a separate violation 40 CFR part 97, Subpart CCCCC and the Clean Air Act.

2) CSAPR SO_2 Group 1 assurance provisions.
   i) If total SO_2 emissions during a control period in a given year from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO_2 emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.625(b), of multiplying—
      A) The quotient of the amount by which the common designated representative's share of such SO_2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state for such control period, by which each common designated representative's share of such SO_2 emissions exceeds the respective common designated representative's assurance level; and
      B) The amount by which total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state for such control period exceed the state assurance level.
   ii) The owners and operators shall hold the CSAPR SO_2 Group 1 allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.
   iii) Total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state during a control period in a given year exceed the state assurance level if such total SO_2 emissions exceed the sum, for such control period, of the state SO_2 Group 1 trading budget under 40 CFR 97.610(a) and the state's variability limit under 40 CFR 97.610(b).
   iv) It shall not be a violation of 40 CFR part 97, Subpart CCCCC or of the Clean Air Act if total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state during a control period exceed the state assurance level or if a common designated representative's share of total SO_2 emissions from the CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state during a control period exceeds the common designated representative's assurance level.
   v) To the extent the owners and operators fail to hold CSAPR SO_2 Group 1 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,
      A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and
      B) Each CSAPR SO_2 Group 1 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR part 97, Subpart CCCCC and the Clean Air Act.

SECTION L - CROSS-STATE AIR POLLUTION RULE (CONTINUED)

3) Compliance periods.
   i) A CSAPR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.
   ii) A CSAPR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.
4) Vintage of allowances held for compliance.
   i) A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year shall be a CSAPR SO_2 Group 1 allowance that was allocated for such control period or a control period in a prior year.
   ii) A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year shall be a CSAPR SO_2 Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.
5) Allowance Management System requirements. Each CSAPR SO_2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR part 97, Subpart CCCCC.
6) Limited authorization. A CSAPR SO_2 Group 1 allowance is a limited authorization to emit one ton of SO_2 during the control period in one year. Such authorization is limited in its use and duration as follows:
   i) Such authorization shall only be used in accordance with the CSAPR SO_2 Group 1 Trading Program; and
   ii) Notwithstanding any other provision of 40 CFR part 97, Subpart CCCCC, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.
7) Property right. A CSAPR SO_2 Group 1 allowance does not constitute a property right.

d) Title V permit revision requirements.

1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR SO_2 Group 1 allowances in accordance with 40 CFR part 97, Subpart CCCCC.
2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.630 through 97.635, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR part 75, Subparts B and H), an excepted monitoring system (pursuant to 40 CFR part 75, appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR part 75.19), and an alternative monitoring system (pursuant to 40 CFR part 75, Subpart E), Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.606(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

SECTION L - CROSS-STATE AIR POLLUTION RULE (CONTINUED)

e) Additional recordkeeping and reporting requirements.

1) Unless otherwise provided, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.
   i) The certificate of representation under 40 CFR 97.616 for the designated representative for the source and each CSAPR SO_2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.616 changing the designated representative.
   ii) All emissions monitoring information, in accordance with 40 CFR part 97, Subpart CCCCC.
   iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR SO_2 Group 1 Trading Program.
2) The designated representative of a CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall make all submissions required under the CSAPR SO_2 Group 1 Trading Program, except as provided in 40 CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR parts 70 and 71.

f) Liability.

1) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 source or the designated representative of a CSAPR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the CSAPR SO_2 Group 1 units at the source.
2) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 unit or the designated representative of a CSAPR SO_2 Group 1 unit shall also apply to the owners and operators of such unit.

g) Effect on other authorities.

No provision of the CSAPR SO_2 Group 1 Trading Program or exemption under 40 CFR 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR SO_2 Group 1 source or CSAPR SO_2 Group 1 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

Commonwealth of Kentucky
Division for Air Quality

PERMIT APPLICATION SUMMARY FORM

Completed by: Daniel Porter

GENERAL INFORMATION:

Name:	EKPC Bluegrass Generating Station
Address:	3095 Commerce Parkway, LaGrange, KY 40031
Date application received:	06/05/2018
SIC Code/SIC description:	4911, Electric Services (fossil fuel power generation)
Source ID:	21-185-00036
Agency Interest:	39541
Activity:	APE20180001
Permit:	V-16-018 R1

APPLICATION TYPE/PERMIT ACTIVITY:

[ ] Initial issuance	[ ] General permit
[ ] Permit modification	[ ] Conditional major
__Administrative	[x] Title V
__Minor	[ ] Synthetic minor
__Significant	[ ] Operating
[x] Permit renewal	[x] Construction/operating

COMPLIANCE SUMMARY:

[ ] Source is out of compliance
[ ] Compliance schedule included
[x] Compliance certification signed

APPLICABLE REQUIREMENTS LIST:

[ ] NSR	[x] NSPS	[x] SIP
__ Non-Attainment	[ ] NESHAPS	[ ] Other
__ PSD	[x] CAM	
__ Netted out of PSD/NSR		
__ Not major modification per 401 KAR 51:001, 1(116) (b)		

MISCELLANEOUS:

[x] Acid rain source
[ ] Source subject to 112(r)
[ ] Source applied for federally enforceable emissions cap
[ ] Source provided terms for alternative operating scenarios
[ ] Source subject to a MACT standard
[ ] Source requested case-by-case 112(g) or (j) determination
[ ] Application proposes new control technology
[x] Certified by responsible official
[ ] Diagrams or drawings included
[ ] Confidential business information (CBI) submitted in application
[ ] Pollution Prevention Measures
[ ] Area is non-attainment (list pollutants):

EMISSIONS SUMMARY:

Pollutant	Actual* (tpy)	Potential (tpy)
Criteria Pollutants		
$PM/PM_{10}/PM_{2.5}$	6.41/6.41/6.41	25.5/25.5/25.5
SO_2	0.18	14.9
NO_x	19.7	95^
CO	64.4	245^
Lead	--	0.00
VOC	5.90	23.3
Greenhouse Gases		
CO_2	35824	97113
N_2O	0.89	3.5
Methane	2.55	18.1
CO_2 Equivalent (add CO_2 x 1 + NO_x 298 + Methane x 25)	36153	98602
Hazardous Air Pollutants (HAPs)		
Ethyl Benzene	--	0.15
Formaldehyde	1.06	3.43
Toluene	0.00	0.64
Manganese	--	0.12
Source wide HAPs	1.06	4.34

*Actual Emissions listed from 2017 Emissions Inventory
^See Emission and Operation Caps Descriptions below for NO_x and CO

SOURCE DESCRIPTION:

The facility has three Siemens-Westinghouse 501FD2 natural gas-fired simple cycle combustion turbines for peak electricity generation (EU 01-03). Each of the combustion turbines is rated at 2,076 MMBtu/hr heat input capacity at 208 MW output and are equipped with dry-low NOx burners and water injection. Additionally, EU 01 and EU 02 are equipped with hot selective catalytic reduction (SCR). EU 04 is a five (5) MMBtu/hr natural gas heater that raises the temperature of the gas coming out of the ground piping to insure it remains above the dew point to prevent liquids from reaching the combustion nozzles. The natural gas heater utilizes a liquid bath, heated by a fire-tube, to heat a process coil submerged in a glycol bath. EU 05 is a 382 horsepower (hp) emergency diesel generator (EDG) that is a single package unit built by Caterpillar to provide backup power to vital equipment in the event of a loss of all electricity power from the local utility (LG&E). In the event of a loss of all electricity the EDG automatically starts and provides backup power to the battery chargers, control room power, air compressors, and microprocessor based controls. EU 06 is a 208 hp emergency diesel fire pump which is a part of the fire protection_system for the facility. The pump intake is connected to the site fire water supply tank, and provides water flow at a high pressure to the sprinkler system and fire hydrants throughout the plant. The facility is classified as a Title V source, operating with federally enforceable limits on emissions of nitrogen oxides (NO_x) and carbon monoxide (CO).

EMISSIONS AND OPERATING CAPS DESCRIPTIONS:

The facility is classified as a Title V source because potential emissions exceed 100 tons per year for CO. The permittee has accepted a source-wide emissions cap of 95 tons per year for NO_x to preclude the applicability of 401 KAR 51:052, *Review of new sources in or impacting upon nonattainment areas.* In addition, source-wide emissions of CO shall not exceed 245 tons per year to preclude the applicability of 401 KAR 51:017, *Prevention of significant deterioration of air quality (PSD).* The source-wide emission caps apply to all combustion equipment such as turbines, natural gas heater, emergency generator, emergency firepump, and insignificant activities, based on any 12 consecutive months. The permittee will assure compliance for each pollutant with data collected from continuous emission monitors and calculation procedures based on U.S EPA methods to convert combustion turbine monitored concentrations to emission rates in mass per unit time. In addition, Bluegrass will monitor hours of operation of each combustion turbine weekly, hours of operation of the natural gas heater monthly, emissions monthly, and 12 month rolling emission totals monthly. Potential emissions of hazardous air pollutant (HAP) are less than 10 tons/year of a single HAP, and less than 25 tons/year of combined HAPs, therefore Bluegrass is classified as an area source of HAPs. For the acid rain permit, the number of allowances allocated to Phase II affected units by the U.S. EPA may change under 40 CFR 73. In addition, the number of allowances actually held by an affected source in a unit account may differ from the number allocated by the U.S. EPA. Neither of the aforementioned conditions necessitates a revision to the unit SO_2 allowance allocations identified in this permit (see 40 CFR 72.84).

OPERATIONAL FLEXIBILITY:

None.

Commonwealth of Kentucky
Division for Air Quality
STATEMENT OF BASIS

Title V, Construction/Operating
Permit: V-16-018 R1
EKPC Bluegrass Generating Station
June 27, 2018
Daniel Porter, Reviewer

SOURCE ID:	21-185-00036
AGENCY INTEREST:	39541
ACTIVITY:	APE20180001

CURRENT PERMITTING ACTION V-16-018 R1:

On June 05, 2018 East Kentucky Power Cooperative, Inc. (EKPC) applied to the Kentucky Division for Air Quality (Division) for Significant Revision to their permit V-16-018 R1. EKPC is requesting to add #2 fuel oil as secondary fuel in case of natural gas curtailment. EKPC is also requesting the addition of two fuel storage tanks. EKPC requested applicability determination for the following regulations: 40 CFR 60 Subpart KKKK, 40 CFR 60 Subpart TTTT, 40 CFR 60 Subpart Kb, and 40 CFR 63 Subpart YYYY. The Division has reviewed EKPC request and has determined that these regulations are not applicable (See below for the reasons).

PRIOR PERMITTING ACTION V-16-018:

On March 18, 2016, East Kentucky Power Cooperative, Inc. (EKPC) applied to the Kentucky Division for Air Quality (Division) to renew Title V permit V-11-005 R1 for Bluegrass Generating Station (Bluegrass). In response to requests made by EKPC, the following changes have been made to V-11-005 R1 in this renewal:

1. Clarification of the description of Emission Units 01 – 03 to reflect that the maximum continuous rating listed is for each unit.
2. Update of permit conditions related to the NO_x emission limitation on Emission Units 01 – 03 to be consistent with 40 CFR 60, Subpart GG.
3. Listing of malfunction events, in addition to startup and shutdown, as time periods exempt from the 50 ppm CO emission limitation on Emission Units 01 – 03. CO emissions during malfunction events shall be counted toward the emission cap on CO of 245 tons per year.
4. Update of monitoring requirements for SO_2 to accurately cite the regulatory and Part 75 Appendix provisions in the approved monitoring plan. The Division has review the approved monitoring plan and has updated the permit.
5. Remove Compliance Assurance Monitoring (CAM) for Emission Units 01 – 03. These units have CEM which meet the definition of "continuous compliance determination method" in 40 CFR 64.1. The Division has updated the permit to reflect this request.
6. Update the language in the Acid Rain, Clean Air Interstate Rule (CAIR), and Cross State Air Pollution Rule (CSAPR) section of the permit. The Division has updated the permit to reflect these requests.

In addition, the Division added an operation limitation stating that EKPC was in compliance with 401 KAR 63:020, Potentially hazardous matter or toxic substances. Also formatting changes were made during this permit renewal.

Source Wide

<u>PRECLUDED REGULATIONS:</u>

401 KAR 51:017, Prevention of significant deterioration of air quality. The source has voluntarily accepted federally-enforceable limitations on emissions of CO to preclude this regulation.

EU 01, 02, and 03

<u>APPLICABLE REGULATIONS:</u>

401 KAR 51:160, NO_x requirements for large utility and industrial boilers, applies to NO_x budget units and includes provisions for the allocation and sale of NO_x allowances.

401 KAR 51:210, CAIR NO_x annual trading program, applies to CAIR NO_x units that are subject to 40 CFR 96.104. EU 01, 02, and 03 are subject to 40 CFR 96.104 as fossil-fuel combustion turbines with nameplate capacities of more than 25 MWe producing electricity for sale.

401 KAR 51:220, CAIR NO_x ozone season trading program, applies to CAIR NO_x ozone season units that are subject to 40 CFR 96.304, Subpart AAAA. EU 01, 02, and 03 are subject to 40 CFR 96.304 as they are fossil-fuel combustion turbines with nameplate capacities of more than 25 MWe producing electricity for sale.

401 KAR 51:230, CAIR SO_2 trading program, applies to CAIR SO_2 sources and CAIR SO_2 units under the CAIR SO_2 Trading Program that are subject to 40 CFR 96.204. EU 01, 02, and 03 are subject to 40 CFR 96.204 as they are fossil-fuel combustion turbines with nameplate capacities of more than 25 MWe producing electricity for sale.

401 KAR 52:060, Acid rain permits, applies to affected sources and affected units under the Acid Rain Program. The regulation incorporates by reference federal acid rain provisions codified in 40 CFR parts 72 to 78.

401 KAR 63:020, Potentially hazardous matter or toxic substances (State Origin Regulation). Applicable to each affected facility which emits or may emit potentially hazardous matter or toxic substances as defined in Section 2 of 401 KAR 63:020, provided such emissions are not elsewhere subject to the provisions of the administrative regulations of the Division for Air Quality.

401 KAR 60:005, Section 2(2)(pp) 40 C.F.R. 60.330 to 60.335 (Subpart GG), Standards of Performance for Stationary Gas Turbines, applies to stationary gas turbines with heat input at peak load equal to or greater than 10 MMBtu/hr for which construction commenced after October 3, 1977.

40 CFR 75, Continuous Emission Monitoring, establishes general requirements for the installation, certification, operation, and maintenance of continuous emission or opacity monitoring systems.

40 CFR Part 97, Subpart AAAAA, BBBBB, CCCCC, and EEEEE collectively make up the requirements commonly referred to as the Cross-State Air Pollution Rule (CSAPR). As the requirements of CSAPR apply to stationary, fossil-fuel-fired boilers serving at any time, on or after

January 1, 2005, a generator with nameplate capacity of more than 25MWe producing electricity for sale.

<u>NON-APPLICABLE REGULATIONS:</u>

401 KAR 60:005, Section 2(2)(ffff) 40 C.F.R. 60.4300 to 60.4420, Table 1 (Subpart KKKK), Standards of Performance for Stationary Combustion Turbines. The regulation is not applicable based on the definition. Pursuant to 40 CFR 60.14(a) the definition of modification means any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere. However in 40 CFR 60.14(e) has the following shall not by themselves be considered modifications. In 40 CFR 60.14(e)(4), use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by § 60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification. EKPC contacted Siemens to confirm that the turbines listed in this permit V-16-018 R1 were designed at the time of installation to accommodate the use of both natural gas and/or fuel oil. In Appendix D of EKPC application there is a letter from Siemens stating these turbines were designed to support natural gas and fuel oil. The regulation is also not applicable based on the definition of reconstruction. Pursuant to 40 CFR 60.15(b), "Reconstruction" means the replacement of components of an existing facility to such an extent that: (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and (2) It is technologically and economically feasible to meet the applicable standards set forth in this part. EKPC used the original cost and adjusted the cost for April of 2018 to determine the cost of the turbines in 2018. The total cost for these turbines is $139,253,780, while the projected cost for the fuel oil storage tanks and deliver systems is $62,000,000. Based on the costed list in the application reconstruction definition does not apply.

401 KAR 60:005, Section 2(2)(jjjj) 40 C.F.R. 60.5508 to 60.5580, Tables 1 to 3 (Subpart TTTT), Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units. The regulation does not apply see 40 CFR 60 Subpart KKKK for the reason.

401 KAR 60:005, Section 2(2)(r) 40 C.F.R. 60.110b to 60.117b (Subpart Kb), Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984. The volume of the tanks is 2,196 m^3 or 580,00 gallons and the maximum true vapor pressure less than 3.5 kPa. According to 40 CFR 60.110b(b) This subpart does not apply to storage vessels with a capacity greater than or equal to 151 m3 storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m3 but less than 151 m3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa.

401 KAR 63:002, Section 2(4)(jjjjj) 40 C.F.R. 63.11193 to 63.11237, Tables 1 to 8 (Subpart JJJJJJ), National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and

Institutional Boilers Area Sources. This facility is minor source for HAPS and no boilers are located at this facility thus the regulation does not apply.

401 KAR 63:002, Section 2(4)(dddd) 40 C.F.R. 63.6080 to 63.6175, Tables 1 to 7 (Subpart YYYY), National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. This facility is minor source for HAPS thus the regulation does not apply.

EU 04

APPLICABLE REGULATIONS:

401 KAR 59:010, New process operations, applies to each affected facility or source, associated with a process operation, which is not subject to another emission standards with respect to particulates and commenced construction on or after July 2, 1975. A process operation means any method, form, action, operation, or treatment of manufacturing or processing, and shall include any storage of handling of materials or products, before, during, or after manufacturing or processing.

EU 05 and EU 06

APPLICABLE REGULATIONS:

40 CFR 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, applies to stationary reciprocating internal combustion engines which use reciprocating motion to convert heat energy into mechanical work and which are not mobile.

NON APPLICABLE REGULATIONS:

40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition (CI) Internal Combustion Engines, for EU 05 and 06. This subpart does not apply to units constructed prior to July 11, 2005. [40 CFR 60.4200(a)(2)].

EMISSIONS AND OPERATING CAPS DESCRIPTIONS:

The facility is classified as a Title V source because potential emissions exceed 100 tons per year for CO. The permittee has accepted a source-wide emissions cap of 95 tons per year for NO_X to preclude the applicability of 401 KAR 51:052, *Review of new sources in or impacting upon nonattainment areas.* In addition, source-wide emissions of CO shall not exceed 245 tons per year to preclude the applicability of 401 KAR 51:017, *Prevention of significant deterioration of air quality (PSD).* The source-wide emission caps apply to all combustion equipment such as turbines, natural gas heater, emergency generator, emergency firepump, and insignificant activities, based on any 12 consecutive months. The permittee will assure compliance for each pollutant with data collected from continuous emission monitors and calculation procedures based on U.S EPA methods to convert combustion turbine monitored concentrations to emission rates in mass per unit time. In addition, Bluegrass will monitor hours of operation of each combustion turbine weekly, hours of operation of the natural gas heater monthly, emissions monthly, and 12 month rolling emission totals monthly. Potential emissions of hazardous air pollutant (HAP) are less than 10 tons/year of a single HAP, and less than 25 tons/year of combined HAPs, therefore Bluegrass is classified as an area source of HAPs. For the acid rain permit, the number of allowances allocated to Phase II affected units by the U.S. EPA may change under 40 CFR 73. In addition, the number of allowances actually held by an affected source in a unit account may differ from the number allocated by the U.S. EPA. Neither of the aforementioned conditions necessitates a revision to the unit SO_2 allowance allocations identified in this permit (see 40 CFR 72.84).

OPERATIONAL FLEXIBILITY:

None.

AIR QUALITY PERMIT NOTICE

Draft Title V Construction/Operating Permit V-16-018 R1
EKPC Bluegrass Generating Station
Plant ID: 21-185-00036 - Agency Interest: 39541

East Kentucky Power Cooperative (EKPC), Inc. of 4775 Lexington, Road, Winchester, KY 40392-0707 has applied to the Kentucky Division for Air Quality for a permit to construct and operate a Natural Gas Peaking Units facility at 3095 Commerce Parkway, LaGrange, KY 40031. The plant is classified as a Title V major source due to its emissions of non-hazardous regulated air pollutants. This permit contains practically enforceable limitations to restrict this source's potential emissions of NOx and CO to less than PSD major source thresholds.

An electronic copy of the Division's draft permit should shortly become available at http://dep.gateway.ky.gov/eSearch/Search_AI.aspx. Official copies of the Division's draft permit and relevant supporting information are available for inspection by the public during normal business hours at the following locations:

Division for Air Quality, 300 Sower Boulevard, 2nd Floor, Frankfort, KY 40601, Phone (502) 782-6977; Division for Air Quality, Frankfort Regional Office, 300 Sower Boulevard, 1st Floor, Frankfort, KY 40601, Phone (502) 564-3358; and the Oldham County Public Library, 308 Yager Ave, LaGrange, KY 40031-1492, Phone (502) 222-9713

For a period of 30 days the Division will accept comments on the draft permit and afford the opportunity for a public hearing. The first day of the 30 day period is the day after the publication of this notice. Comments and/or public hearing requests should be sent to Mr. Shawn Hokanson at the above Frankfort address or e-mail shawn.hokanson@ky.gov. Any person who requests a public hearing must state the issues to be raised at the hearing. If the Division finds that a hearing will contribute to the decision-making process by clarifying significant issues affecting the draft permit, a hearing will be announced. All relevant comments will be considered in issuing the proposed permit. U.S. EPA has up to 45 days following issuance of the proposed permit to submit comments. The status regarding EPA's 45-day review of this project and the deadline for submitting a citizen petition will be posted at the following website address: http://www2.epa.gov/caa-permitting/kentucky-proposed-title-v-permits shortly after the end of this 30-day comment period. Further information can be obtained by calling Mike Kennedy at (502) 782-6997.

The Commonwealth of Kentucky does not discriminate on the basis of race, color, national origin, sex, religion, age or disability in employment or the provision of services and provides, upon request, reasonable accommodation including auxiliary aides and services necessary to afford individuals an equal opportunity to participate in all programs and activities. Materials will be provided in alternate format upon request.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY	)	
POWER COOPERATIVE, INC. FOR A	)	
CERTIFICATE OF PUBLIC CONVENIENCE	)	**CASE NO. 2018-_________**
AND NECESSITY FOR THE CONSTRUCTION	)	
OF BACKUP FUEL FACILITIES AT ITS	)	
BLUEGRASS GENERATING STATION	)	

DIRECT TESTIMONY OF RALPH LUCIANI ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: August 24, 2018

Q. Please state your name, business address, and occupation.

A. My name is Ralph L. Luciani and my business address is 1200 19th Street, N.W., Suite 700, Washington, DC 20036. I am a Director at Navigant Consulting, Inc. ("Navigant").

Q. Please briefly describe the business conducted by Navigant.

A. Navigant is a global professional services firm that primarily serves clients in the healthcare, energy, and financial services industries. In energy services, our experts work in areas related to regulatory processes, pricing, supply-and-demand dynamics, market design, fuel sourcing, financing, resource planning, technologies and operations.

Q. Please state your education and professional experience.

A. I hold a Bachelor of Science degree in Electrical Engineering and Economics from Carnegie Mellon University, as well as a Master of Science degree from the Graduate School of Industrial Administration at Carnegie Mellon University. I have more than twenty-five (25) years of consulting experience analyzing economic and financial issues affecting the electric industry, including those related to costing, ratemaking, generation and transmission planning, environmental compliance, fuel supply, competitive restructuring, stranded cost, asset valuation, wholesale power solicitations, power marketing, and Regional Transmission Organization costs and benefits. Prior to joining Navigant, I was a Vice President at Charles River Associates, a Senior Vice President at PHB Hagler Bailly, and a Director at Putnam, Hayes and Bartlett, Inc. My education and professional experience is more fully described in my *curriculum vitae*, a copy of which is attached to this testimony as Attachment RL-1.

Q. Have you ever testified before the Kentucky Public Service Commission?

A. Yes. In Case No. 2012-00169,[1] I offered testimony describing the costs and benefits of EKPC's proposed membership in PJM Interconnection, LLC ("PJM"), and in Case No. 2017-00376,[2] I offered testimony analyzing the short- and long-term value of EKPC's Hugh L. Spurlock Station. Most relevantly, I served as an expert witness on behalf of EKPC in Case No. 2015-00267,[3] regarding the cooperative's acquisition of the Bluegrass Generating Station ("Bluegrass Station").

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe and provide Navigant's work with regard to evaluating the present value of various options considered by EKPC for mitigating risk associated with PJM's Capacity Performance construct at the Bluegrass Station. Navigant's methodologies and conclusions are fully detailed in the Bluegrass Capacity Penalty Risk Analysis provided herewith.

Q. Are you sponsoring any exhibits as part of your testimony?

A. Yes. My *curriculum vitae* is attached hereto as Attachment RL-1, and a copy of the Bluegrass Capacity Penalty Risk Analysis is attached hereto as Attachment RL-2. Both of these documents were prepared by me or by individuals working directly under my supervision.

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[1] *See In the Matter of Application of East Kentucky Power Cooperative, Inc. to Transfer Functional Control of Certain Transmission Facilities to PJM Interconnection, LLC*, Order, Case No. 2012-00169, (Ky. P.S.C. Dec. 20, 2012).

[2] *See In the Matter of the Application of East Kentucky Power Cooperative, Inc. for Approval to Amend its Environmental Compliance Plan and Recover Costs pursuant to its Environmental Surcharge, Settlement of Certain Asset Retirement Obligations and Issuance of a Certificate of Public Convenience and Necessity and Other Relief*, Order, Case No. 2017-00376 (Ky. P.S.C., May 18, 2018).

[3] *See In the Matter of Application of East Kentucky Power Cooperative, Inc. for Approval of the Acquisition of Existing Combustion Turbine Facilities from Bluegrass Generation Company, LLC at the Bluegrass Generating Station in LaGrange, Oldham County, Kentucky and for Approval of the Assumption of Certain Evidences of Indebtedness*, Order, Case No. 2015-00267, (Ky. P.S.C. Dec. 1, 2015).

Q. Please briefly describe EKPC's Bluegrass Station.

A. EKPC's Bluegrass Station consists of three simple-cycle natural gas-fired combustion turbines of 198 MW (winter) and 165 MW (summer) each located in Oldham County, Kentucky. Each Bluegrass unit has an unforced capacity ("UCAP") value in the PJM capacity market of approximately 159 MW, yielding a station total of 477 MW. Historically, EKPC has relied on interruptible service from an adjacent interstate natural gas pipeline operated by Texas Gas Transmission, LLC, to fuel the Bluegrass Station units.

Q. Please describe Navigant's work in this matter.

A. Navigant was retained by EKPC to determine the financial exposure EKPC may face if the Bluegrass Station is unable to perform as expected during PAHs, and particularly to perform a 20-year break-even analysis with respect to numerous alternatives under consideration to mitigate the risk of nonperformance due to natural gas unavailability. The options analyzed by Navigant involved EKPC procuring firm gas supply (including short-term firm and enhanced firm transportation), as well as developing alternative on-site backup fuel resources (including fuel oil and liquified natural gas, or LNG). Because the economics of each alternative examined is highly dependent on two (2) uncertain variables (namely the number of future PAHs in the EKPC PJM zone and the likelihood of gas pipeline interruptions at Bluegrass Station during these PAHs), Navigant developed *Low*, *Mid* and *High* cases to assess the impact of these two (2) variables on each alternative.

Q. What did your analysis conclude?

A. I will let the full report speak for itself, of course, but broadly speaking each of the fuel alternatives identified for the Bluegrass Station (firm gas, LNG, fuel oil) provides similar and substantial risk mitigation against a major, single-year Capacity Performance penalty. The fuel oil alternative, which was ultimately selected by EKPC and is the impetus of this proceeding, is the lowest-cost alternative at the Bluegrass Station and represents the most economic means to mitigate capacity penalty risk. The fuel oil alternative will provide valuable "insurance" against high single year capacity penalties of as much as $79 million.

Q. **Do you authenticate and adopt as part of your testimony the conclusions contained within the Bluegrass Capacity Penalty Risk Analysis attached hereto as Attachment RL-2?**

A. Yes.

Q. **Does this conclude your testimony?**

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF BACKUP FUEL FACILITIES AT ITS BLUEGRASS GENERATING STATION	)	**CASE NO. 2018-________**

VERIFICATION OF RALPH L. LUCIANI

STATE OF VIRGINIA)
)
COUNTY OF FAIRFAX)

Ralph L. Luciani, Director with Navigant Consulting, being duly sworn, states that he has read the foregoing prepared direct testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Ralph L. Luciani

Ralph L. Luciani

The foregoing Verification was signed, acknowledged and sworn to before me this 13 day of August, 2018 by Ralph L. Luciani.

Hala Zein

NOTARY PUBLIC

HALA ZEIN NOTARY PUBLIC REG # 365692 COMMISSION EXPIRES 1/31/2021 COMMONWEALTH OF VIRGINIA

Commission No. 365692

My Commission Expires: 1/31/2021

NAVIGANT

Ralph Luciani
Director

ralph.luciani@navigant.com
1200 19th St. NW, Suite 700
Washington, DC 20036
Phone: 202.973.4537

Professional Summary

Ralph Luciani is a Director in the Energy Practice in Navigant's Washington, D.C. office. He has more than 25 years of consulting experience analyzing economic and financial issues affecting regulated industries. Mr. Luciani focuses on the electricity industry, where he has assisted electric utilities and generating companies with business planning, resource planning, power solicitations, ratemaking, transmission cost-benefit studies, fuel and power supply contract negotiations, and environmental compliance strategy.

He led the economic evaluation performed by the Eastern Interconnection Planning Collaborative (EIPC) in a two-year study of the expansion of the transmission system needed to support future generation. Mr. Luciani has also recently performed cost-benefit studies for electric utilities considering joining a Regional Transmission Organization (RTO). In 2016, he oversaw the economic evaluation performed of renewable energy proposals in the New England Clean Energy RFP.

Mr. Luciani has assisted clients and their legal counsel in the management of numerous complex litigation matters, including electric utility prudence and rate cases, and assessments of economic damages in commercial disputes. He has appeared as an expert witness in a number of Federal Energy Regulatory Commission (FERC) and state public utility commission regulatory proceedings.

Prior to joining Navigant, Mr. Luciani was a Vice President at Charles River Associates and a Director at Putnam, Hayes & Bartlett, Inc. He holds an M.S. in Industrial Administration from Carnegie Mellon University, and a B.S. in Electrical Engineering and Economics from Carnegie Mellon University.

Professional Experience

RTOs and Transmission

- **RTO Cost-Benefit Studies.** Performed a number of major cost-benefit studies of RTOs over the last ten years, and provided related testimony in state regulatory proceedings. Coordinated a utility team in implementing a transition into an RTO in 2015.
- **Transmission Planning**. On behalf of EIPC, led the economic evaluation in a two-year study of the potential build-out of the transmission system in the eastern U.S. needed through 2030.
- **Competitive Transmission.** Assisted a transmission owner in developing transmission proposals in a RTO competitive bidding process to pass cost-benefit and reliability screens.

NAVIGANT

Ralph Luciani
Director

- **RTO Administrative Costs and Rates**. Served as the lead consultant in a FERC settlement process in which PJM establishing stated rates for the recovery of its administrative costs.

- **Transmission Ratemaking.** On a number of occasions, filed testimony which developed OATT transmission, ancillary service, and reactive power rates.

- **Transmission Costing**. Provided testimony and negotiated settlement agreements in a FERC settlement process regarding the assignment of costs for through and out transmission charges.

Generation and Power Marketing

- **Power Solicitations.** Assisted electric utilities in conducting numerous solicitations for power, including serving as an independent evaluator, formulating the RFP, conducting bidder's conferences, negotiating term sheets and definitive agreements, and obtaining regulatory approvals.

- **Nuclear Power.** Assisted a utility in negotiating the sale of a nuclear plant, developed the financial model used in a utility's application for DOE-supported financing of a new nuclear facility, and provided testimony on CWIP financing in rates to support new nuclear plants.

- **Wind/Transmission Studies.** Performed a number of wind/transmission cost-benefit studies, including analyzing the economics of installing 765 kV transmission lines to support new wind power in the Southwest Power Pool.

- **Generation Valuation Lecturer.** Served as the lead lecturer and instructor of an advanced training course on generation valuation under cost-of-service rates and under market-based pricing offered annually at a large U.S. investor-owned utility.

- **Power Marketing.** Prepared several affidavits at FERC analyzing wholesale trading activities of power marketers, developed utility cost-based rates for wholesale sales of capacity and energy, and assisted counsel in reaching an arbitration settlement regarding standby power charges.

- **Stranded Cost Derivation.** Presented testimony before four state utility commissions on the quantification of the stranded cost associated with the deregulation of generation.

Financial Evaluation

- **Cost of Capital.** Testified before the U.S. Bankruptcy Court and assisted counsel in arbitration proceedings regarding the proper discount rate to apply in assessing termination payments for wholesale power contracts, and assessed capital structure and rates for use in FERC proceedings.

- **Municipalization.** Assisted an electric utility in deriving the exit charges to be assessed for a proposed municipalization of a portion of the electric utility's service territory.

- **Mergers and Acquisitions.** Analyzed the potential acquisition of electric utilities and formulated transmission and distribution pro forma financials.

NAVIGANT

Ralph Luciani
Director

- **Organizational Restructuring.** Lead facilitator in a 12-month project that functionally unbundled the operation of an integrated electric utility into stand-alone profit centers.

Distribution and Retail

- **Distribution Performance-Based Rates.** Formulated a performance-based ratemaking (PBR) plan, for an electric utility, and presented the plan to the state public utility commission.
- **Efficiency Programs.** Developed a financial and rate incentive model for an electric utility to evaluate the impact on rates and earnings of adopting energy efficiency programs.
- **Retail Market Strategy.** Formulated models to assess the profitability of new retail loads in a competitive market and a product to reduce on-peak demand in residences.

Environmental and Fuel

- **Environmental Regulations.** Assisted utilities in formulating strategies for Clean Air Act provisions regarding SO_2 and NO_x, and in assessing potential climate change regulations.
- **Fuel Supply.** Assisted an electric utility in negotiating the terms of a buyout and replacement of a long-term coal supply contract, and in obtaining approval for the rate treatment.
- **Nuclear.** Assisted counsel in litigation involving the responsibility for costs incurred in nuclear spent fuel storage and the estimation of damages related to steam generator replacement

Professional History

Director, Navigant Consulting, Inc.
Vice President, Charles River Associates
Senior Vice President, PHB Hagler Bailly
Director, Putnam, Hayes & Bartlett, Inc.
Edison Engineer, General Electric Company (GE)

Education

M.S., Industrial Administration, Carnegie Mellon University
B.S., Electrical Engineering and Economics, Carnegie Mellon University

Expert Testimony Experience

- Testified before the Arkansas, Kansas, Kentucky, Louisiana, Maryland, Mississippi, Missouri, Ohio, Pennsylvania, Texas and Wisconsin public utility commissions, the Ontario Energy Board, the U.S. Bankruptcy Court, the U.S. Postal Service Commission, and the Federal Energy Regulatory Commission (FERC).

NAVIGANT

Ralph Luciani
Director

Testimony or Expert Report Experience

Date	Case	Venue
2017	Application of East Kentucky Power Cooperative, Inc. for Approval to Amend its Environmental Compliance Plan and Recover Costs Pursuant to its Environmental Surcharge and Issuance of a Certificate of Public Convenience and Necessity, Case No. 2017-00376	Kentucky Public Service Commission
2015	Application of Wisconsin Power and Light Company for a Certificate of Public Convenience and Necessity to Build an Approximately 650 Megawatt Natural Gas-Fuel Power Plant, Docket No. 6680-CE-176	Public Service Commission of Wisconsin
2015	Application of East Kentucky Power Cooperative, Inc. for Approval of the Acquisition of Existing Combustion Turbine Facilities from Bluegrass Generation Company, LLC, Case No. 2015-00267	Kentucky Public Service Commission
2013	Westar Generating, Inc., Purchase Power Agreement, Analysis of the Affiliate Transaction under the Commission's *Boston Edison Co. Re: Edgar Electric Energy Co.*, 55 FERC ¶ 61,382 (1991) ("*Edgar*") Precedent, Docket No. ER13-1210-002	Federal Energy Regulatory Commission
2013	In the Matter of the Application of Duke Energy Ohio, Inc. For the Establishment of a Charge Pursuant to Revised Code Section 4909.18. Case No. 12-2400-EL-UNC	Public Utilities Commission of Ohio
2012	Application of East Kentucky Power Cooperative, Inc. to Transfer Functional Control of Its Transmission Assets to the PJM Interconnection, L.L.C., PSC Case No. 2012-00169	Kentucky Public Service Commission
2012	Show Cause Order Directed to Entergy Arkansas, Inc. Regarding Its Continued Membership in the Current Entergy System Agreement and Regarding the Future Operation and Control of Its Transmission Assets, Docket No. 10-011-U	Arkansas Public Service Commission
2012	Application of Entergy Texas, Inc. for Approval to Transfer Operational Control of Its Transmission Assets to the MISO RTO, Docket No. 40346	Texas State Office of Administrative Hearings
2012	Joint Application of Entergy Mississippi, Inc., and the Midwest Independent Transmission System Operator, Inc., for Transfer of Functional Control of Entergy Mississippi's Transmission Facilities to MISO, Docket No. 2011-UA-376	Mississippi Public Service Commission
2012	Joint Application of Entergy New Orleans, Inc. and Entergy Louisiana, L.L.C. Regarding Transfer of Functional Control of Certain Transmission Assets to the Midwest Independent Transmission System Operator, Docket No. UD-11-01	New Orleans City Council
2010	Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of its Transmission System to Midwest Independent Operator, Inc., Case No. 2010-00043	Kentucky Public Service Commission

NAVIGANT

Ralph Luciani

Director

2010	Cost-based Revenue Requirement for the Provision of Reactive Supply and Voltage Control from Generation Sources under Schedule 2 of the PJM Interconnection, L.L.C. Open Access Transmission Tariff, Docket No. ER10-865-000	Federal Energy Regulatory Commission
2010	Application by Ontario Power Generation Inc., Payment Amounts for Prescribed Facilities for 2011 and 2012, Docket No. EB-2010-0008	Ontario Energy Board
2008	Application of Ameren Energy Marketing Company under Section 205 of the Federal Power Act, Docket No. ER09-398-000	Federal Energy Regulatory Commission
2008	Application of Aquila, Inc. for Authority to Transfer Operational Control of Certain Transmission Assets to the Midwest ISO, Docket No. EO-2008-0046	Missouri Public Service Commission
2008	Arizona Public Service Company, Docket No. ER08-514-000	Federal Energy Regulatory Commission
2007-8	TransCanada Pipelines Ltd. vs. USGen New England, Inc., Case Number 03-30465	U.S. Bankruptcy Court for the District of Maryland
2007	Application of Big Rivers Electric Corporation for Approval of Wholesale Tariff Additions, Case No. 2007-00455	Kentucky Public Service Commission
2006	Postal Rate and Fee Changes, Docket No. R2006-1	U.S. Postal Rate Commission
2006	Arizona Public Service Company, Docket No. ER07-23-000	Federal Energy Regulatory Commission
2006	Midwest Independent Transmission System Operator, Docket No. ER-05-6-001	Federal Energy Regulatory Commission
2006	Generic Issues, RP-2005-0020/EB-2005-0529, 2006 Distribution Rates	Ontario Energy Board
2005	Investigation of Practices of the California Independent System Operator, Docket No. EL-00-95-000	Federal Energy Regulatory Commission
2005	Investigation of Practices of the California Independent System Operator, Docket No. EL-00-95-000	Federal Energy Regulatory Commission
2005	Application of Southwest Power Pool for a Certificate of Public Convenience and Necessity, Docket No. 04-137-U	Arkansas Public Service Commission
2005	Application of Southwest Power Pool for a Certificate of Convenience, Docket No. 06-SPPE-202	Kansas State Corporation Commission
2005	Policy Issues Related to Southwest Power Pool, Case No. EO-2006-0142	Missouri Public Service Commission
2003	Investigation of Practices of the California Independent System Operator, Docket No. EL-00-95-000	Federal Energy Regulatory Commission
2003	Midwest Independent Transmission System Operator, Docket No. EL02-111-000	Federal Energy Regulatory Commission

NAVIGANT

Bluegrass Capacity Penalty Risk Analysis

Prepared for:

East Kentucky Power Cooperative

EAST KENTUCKY POWER COOPERATIVE

A Touchstone Energy Cooperative

Submitted by:
Navigant Consulting, Inc.
1200 19th Street, N.W
Suite 700
Washington, DC 20036

navigant.com

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1. INTRODUCTION AND SUMMARY

Navigant was retained by East Kentucky Power Cooperative (EKPC) to perform an evaluation of PJM[1] capacity penalties during Performance Assessment Hours (PAHs) at the Bluegrass Generating Station (Bluegrass) under various potential alternative fuel arrangements. Bluegrass consists of three simple-cycle natural gas-fired combustion turbines of 198 MW (winter) and 165 MW (summer) each located in Oldham County, Kentucky. Each Bluegrass unit has an unforced capacity (UCAP) value in the PJM capacity market of approximately 159 MW, yielding a station total of 477 MW.[2]

Based on widespread generating unit unavailability during the January 2014 Polar Vortex event, PJM instituted capacity performance requirements for PJM generating resources, which phase in over the 2016 to 2020 period. PJM calls PAHs in emergency conditions, and capacity performance resources must be available to provide energy during PAHs throughout the delivery year or be assessed non-performance charges. Beginning in the 2020/21 PJM delivery year, Bluegrass is required to be bid as a capacity performance resource in the PJM capacity market and is subject to PJM non-performance charges if the units at the station fail to supply their UCAP during PAHs.

Bluegrass could be unavailable during PAHs for two primary reasons, a forced outage or natural gas unavailability. For Bluegrass, non-performance charges would be about $1.4 million for a single PAH and could reach as high as $79 million in a single year. This compares to the annual value of Bluegrass in the PJM capacity market of $24 million using 2021/2022 capacity performance prices. As a result, EKPC is considering alternatives to limit fuel unavailability at Bluegrass, including firm gas service during all or parts of the winter season and installation of back-up fuel oil or LNG capability.

Table 1. Bluegrass Fuel Alternatives Overview

Fuel Alternative	Levelized Fixed Cost (M$/year)	Max 1-Year Penalty Across Scenarios Examined (M$)	PV Benefits (Cost) across Scenarios Relative to Status Quo (M$)	Additional Available PAHs Needed to Breakeven with Status Quo over 20 years
Status Quo	$0.0	$17 / $65	--	--
24-hr STF Dec-Feb.	$7.0	$1 / $4	($91) to $10	60
16-hr EFT Dec.-Feb.	$5.5	$1 / $4	($71) to $30	47
24-hr STF Winter	$11.7	$1 / $4	($154) to ($52)	100
16-hr EFT Winter	$9.1	$1 / $4	($120) to ($19)	79
LNG	$6.0	$1 / $4	($78) to $23	51
Fuel Oil	$4.8	$1 / $4	($62) to $38	42

Each of the fuel alternatives identified for Bluegrass (firm gas, LNG, fuel oil) provides similar and substantial risk mitigation against a major single year capacity penalty. The fuel oil alternative is the lowest cost alternative at Bluegrass and represents the most economic means to mitigate capacity penalty risk. Over a 20-year period, Bluegrass would need to be available in only about 42 more PAHs to cover the cost of the fuel oil alternative. However, to reach this level of additional PAHs, there would

[1] PJM Interconnection, LLC (PJM) is a regional transmission organization (RTO) that manages grid operations and administers the energy, capacity, and ancillary service markets in all or parts of 13 mid-Atlantic and Midwestern states, and the District of Columbia.

[2] Bluegrass summer rating of 165 MW multiplied by (1 minus the Bluegrass EFOR of 3.60%)

need to be enough future PAHs in PJM in which there was a gas interruption on the pipeline serving Bluegrass during the PAHs. Based on the scenarios analyzed in this study, the fuel oil alternative may not pay for itself over 20 years in present value terms. If so, the fuel oil alternative still will provide valuable "insurance" against high single year capacity penalties of as much as $79 million.

Firm Gas Alternatives. At Bluegrass, firm transportation (FT) for gas can be procured from Texas Gas Pipeline for a full-year, or on a monthly basis under short-term firm (STF) at a higher monthly cost. With FT or STF, the contracted amount of firm gas must be spread evenly or "ratably" over the hours in a day (i.e., the maximum hourly amount is 1/24th of the total), which makes it relatively costly for peaking capacity like Bluegrass. Enhanced firm service (EFT) is available at an extra cost which allows the maximum gas quantity in each hour to be 1/16th of the contracted amount. With natural gas unavailability being unlikely in the summer, Navigant examined the alternatives of procuring STF or EFT over the full winter (November to March) and for a more cost-effective 3-month winter period (December to February).

Fuel Oil/LNG Alternatives. Fuel oil capability at Bluegrass will require an estimated $63 million in capital along with additional annual fixed O&M cost and variable O&M charges. LNG capability is estimated to require $81 million in capital along with additional annual fixed O&M and fuel carrying costs.

Levelized Cost of Fuel Alternatives. Table 1 shows the 20-year levelized fixed cost of the fuel alternatives, which range from $4.8 to $11.7 million per year (2018$). These costs could be categorized as the cost of "insurance" against incurring major penalties. Fuel oil is the lowest cost alternative. Procuring EFT from December to February is the next lowest cost alternative, but, unlike fuel oil, does not cover fuel interruptions in any PAHs that could take place in the November or March winter months.

Scenarios Examined. The economics of the Bluegrass fuel alternatives are highly dependent on two uncertain variables, the number of PAHs in the future in the EKPC PJM zone, and the likelihood of gas pipeline interruptions at Bluegrass during these PAHs. As shown in Table 2, Navigant developed *Low*, *Mid* and *High* cases to assess the impact of these two variables yielding 9 total scenarios *(3 x 3)*.

Table 2. PAH and Gas Interruption Cases Analyzed

	Low Case	Mid Case	High Case
Performance Assessment Hours	Polar Vortex every 20 Years with 20 Winter PAHs	Polar Vortex every 10 Years, each with 20 Winter PAHs	Polar Vortex every 5 years, w/four times severity every 10 (80 PAHs)
Gas Interruption during PAHs	5% (1 in 20 Winter PAHs)	20% (1 in 5 Winter PAHs)	33% (1 in 3 Winter PAHs)

The PAH cases are based on the frequency of a Polar Vortex event. Since 2012, there have been no PAHs relevant to EKPC other than during the 2014 Polar Vortex, which had 20 PAHs impacting the EKPC zone. To reflect more severe weather, a 80-PAH polar vortex event every 10 years was included in the *High PAH Case*, based on the most impacted region of PJM during the 2014 Polar Vortex.

Natural gas in the EKPC region during the 2014 Polar Vortex was not interrupted at the EKPC Smith unit, or at Indiana PJM units served from the same pipeline as Bluegrass. However, there have been a number new gas plants on the Texas Gas Pipeline in the PJM area since 2014. The gas interruption cases above were selected to capture a potential range of gas interruptions.

Risk Mitigation. To assess EKPC capacity penalty risk exposure, Table 3 shows the maximum single delivery year penalty incurred across the 9 scenarios examined. This maximum penalty would take place during a polar vortex event year. As reference points, results for 0% and 100% gas interruption during PAHs are also shown (shaded). Each of the fuel alternatives similarly mitigates the maximum single year penalty across the nine scenarios examined, and thus are not listed separately.

Table 3. Maximum Single-Year Penalty in Scenarios Examined (M$2018)

Annual PAHs -->	Polar Vortex (20 PAHs)					Quadruple Polar Vortex (80 PAHs)				
Gas Interuption in PAHs-->	0%	5%	20%	33%	100%	0%	5%	20%	33%	100%
Status Quo	1.0	2.4	7.8	16.7	28.1	3.9	9.2	30.4	65.2	78.9
All Fuel Alternatives	1.0	1.0	1.0	1.0	1.0	3.9	3.9	3.9	3.9	3.9

As shown, the fuel alternatives substantially reduce the potential maximum single year penalty, but the avoided penalty is dependent on the severity of the polar vortex event (e.g., 20 PAHs or 80 PAHs) and the level of gas interruption (e.g., 5%, 20%, or 33%). For example, if there is a 20-PAH polar vortex event and Bluegrass gas was interrupted during 20% of those PAHs (4 hours), the capacity penalty would be $7.8 million. The penalty is never zero in Table 3 given the non-fuel forced outage rate of Bluegrass (3.6%).

PV Benefit/(Cost). Making Bluegrass available in a single PAH would avoid $1.4 million in non-performance charges, but also yield $0.6 million in bonus payments and $0.4 million in energy margins, yielding an incremental net benefit of $2.4 million. Comparing incremental net benefits to the levelized cost of each fuel alternative across the 9 scenarios examined yields the present value benefit (cost) range shown in Table 1. As shown, the range extends from a negative to positive benefit, with fuel oil having the highest benefits.

The last column in Table 1 shows the increased number of available PAHs for Bluegrass to cover the fixed costs of each fuel alternative (i.e., a $0 present value). The fuel oil alternative requires only an additional 42 available PAHs over the 20-year period. Given that penalty risk mitigation is similar (and substantial) across the fuel alternatives[3], the alternative with the lowest levelized cost (fuel oil) is the most economical alternative to select. However, to decide whether the fuel oil alternative is desirable relative to the *Status Quo*, risk mitigation must be assessed against cost.

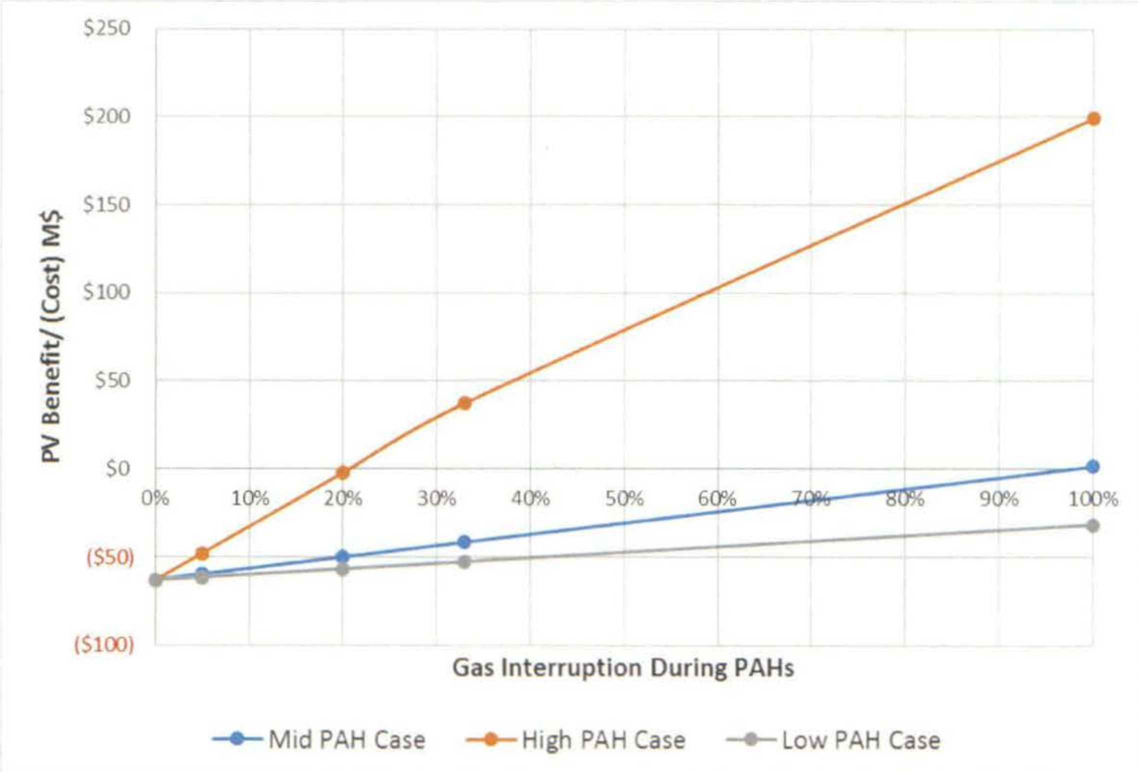
Risk/Cost Trade-off. Based on our assessment, the fuel alternatives may not pay for themselves under a "most likely" future of likely limited gas interruptions and should be viewed as a type of insurance against bad outcomes. This is illustrated for the fuel oil alternative in Figure 1, which shows the present value of benefits/(costs) over a 20-year period under a *Low*, *Mid* and *High PAH Cases*, as a function of gas interruption percentage at Bluegrass during PAHs.

As shown, under the *Mid PAH Case*, gas interruption during PAHs would need to reach nearly 100% for the fuel oil alternative to achieve a positive overall present value benefit. Under the *Low PAH Case*, the fuel oil alternative never achieves a positive overall present value benefits. However, if PAH hours are more severe as in the *High PAH Case*, Bluegrass gas interruption during PAHs would need to be only about 20% or higher for the alternative to yield an overall present value benefit.

[3] However, within the firm gas alternatives, the 3-month (December to February) procurement of firm gas does not cover any PAHs caused by gas interruption that might take place in November or March.

The single year risk reduction results in Table 3 must be compared to net 20-year benefits in Figure 1 to weigh cost in comparison to risk. The fuel oil alternative may not pay for itself on a present value basis absent severe weather events and Bluegrass gas interruption. Just like any type of insurance, this must be weighed against the risk mitigation the fuel alternative provides by limiting single year penalties.

Figure 1: PV Benefit/(Cost) of Fuel Oil Alternative as a Function of PAHs and Gas Interruption



Other Considerations

- Fuel oil also would help hedge against short-term natural gas price spikes, and the new burners required could yield additional Bluegrass operating hours without exceeding annual NOx limits.
- Forced outage rates can be higher for dual-fuel units switching fuels, particularly during severe weather, if the dual-fuel capability is not regularly tested.
- If fuel oil or LNG is heavily used during a short period, there is the potential for the alternative fuel to run out, particularly if transportation to Bluegrass is limited by a weather event.
- Firm gas service can be turned "on" or "off" as future events unfold. However, firm transportation may not be available if not contracted for a longer time-frame.
- Limiting firm gas to selected months does not mitigate the lower, but still finite, risk of fuel unavailability during a PAH in the other months, while fuel oil and LNG largely mitigate this risk.
- Firm gas contract prices are negotiable and could be less than the maximum tariff rates used here. With STF, overage charges could be used to allow for additional delivery in an hour; however, the long-term reliance on the use of overage during a PAH is likely problematic.

- With capacity performance in place, the likelihood of PAHs should be reduced as owners seek to ensure their plants will be available. This may also increase hourly balancing ratios from recent history, making penalties higher and bonuses lower in a given PAH.
- Use of on-site LNG as a back-up fuel for CTs in the Midwestern U.S. is relatively uncommon, making the potential costs for this alternative more uncertain.
- Other uncertainties such as changes in the PJM capacity performance rules, and early retirement of Bluegrass for unrelated reasons, were not considered in this analysis.

2. BACKGROUND AND ASSUMPTIONS

2.1 Historical Performance Assessment Hours

PJM's non-performance charge was formulated by PJM assuming an average of 30 PAHs during any delivery year, although actual PAHs in recent years have been much lower, including in 2014 during the Polar Vortex event. EKPC has not had a PAH called specifically for the EKPC PJM zone since joining PJM, so the best estimate of PAHs for Bluegrass is those called for the full PJM region. As shown in Table 5, there were about 20 PAH for the full PJM RTO in the 2013/14 delivery year during the Polar Vortex, but no PAHs in the last four years. PJM has stated that a Polar Vortex event like that in 2014 could be expected to take place about once every 10 years.[4]

Table 4. PJM Annual Performance Assessment Hours (PAHs) for Full PJM RTO

Delivery Year	Winter Months	Other Months	Total
2012/13	0	0	0
2013/14	20.27	0	20.27
2014/15	0	0	0
2015/16	0	0	0
2016/17	0	0	0
2017/18	0	0	0

2.2 Potential Bluegrass Capacity Penalties

The non-performance charge would be about $1.4 million if the entire Bluegrass station was unavailable during a single PAH.[5] While non-performance penalties for a particular unit have an annual cap, Bluegrass could potentially face an annual penalty of as high as $79 million if the station were unavailable during enough PAHs. This compares to the annual value of Bluegrass in the PJM capacity market of $24 million per year using the most recent 2021/22 delivery year price of $140/MW-day for capacity performance resources in the Rest of RTO region.[6]

Table 5. Potential Annual Penalties for Bluegrass if Unavailable During PAHs ($M 2018)

Annual PAHs	Potential Annual Non-Performance Penalty (M$)	Bluegrass Capacity Value @2019/20 price (M$)	Potential Annual Penalty as % of Annual Capacity Value
10	$14		57%
30	$41	$24	170%
58 or more	$79		325%

[4] PJM Response to FERC Data Request for January 2014 Weather Events (http://www.pjm.com/~/media/library/reports-notices/weather-related/20140113-pjm-response-to-data-request-for-january%202014-weather-events.ashx)

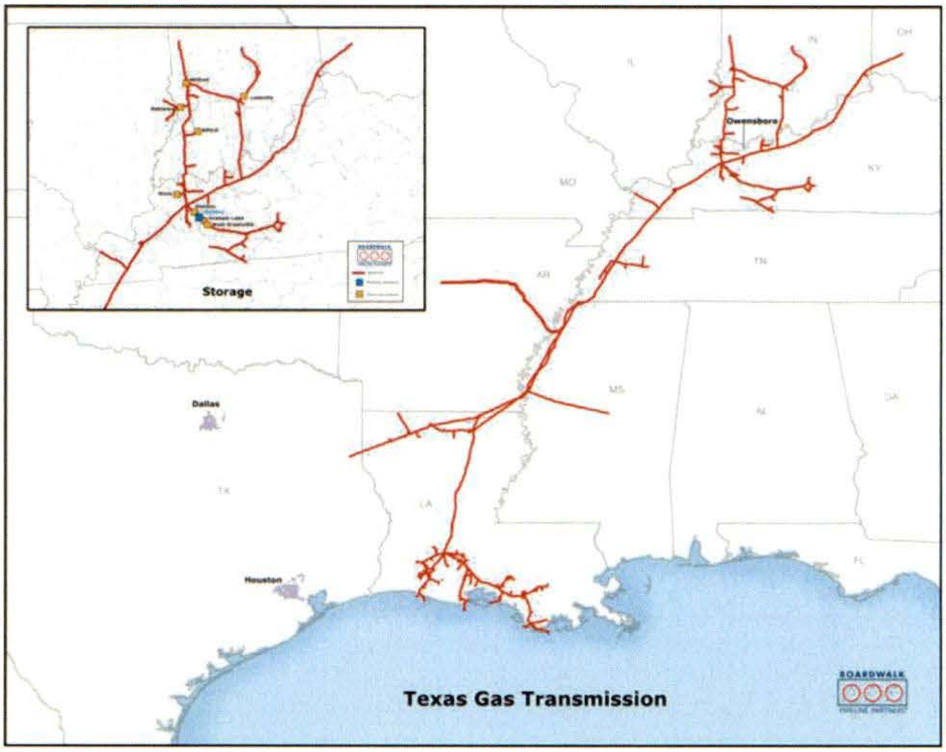
[5] Penalty of $3,687/MWh multiplied by Bluegrass station UCAP of 477 MW and applying a 78.5% Balancing Ratio. The penalties for each unit are subject to an annual cap of 150% of Net CONE. Actual hourly penalties could be higher or lower depending on the balancing ratio during the hour.

[6] $140/MW-day * 477 MW UCAP * 365 days

2.3 Bluegrass Existing Fuel Supply

Natural gas is delivered to Bluegrass by the Texas Gas Transmission pipeline under interruptible service.[7] The Texas Gas system (see Figure 1) is composed of 6,025 miles of pipeline having an average daily throughput of approximately 2.4 billion cubic feet (Bcf) per day in 2016; and has nine natural gas storage fields located in Indiana and Kentucky, which have approximately 84.3 Bcf of working gas capacity.[8]

Figure 2: Texas Gas Transmission Pipeline



2.4 Bluegrass Fuel Alternatives

Given the size of the potential capacity penalties, EKPC is considering alternatives to avoid or limit natural gas unavailability, including firm gas service, and installation of fuel oil or LNG storage.

[7] IT service is subject to interruption both at the receipt and delivery points, with a scheduling priority based on an economic queue. Firm natural gas supplies which require fixed monthly charges are usually not economic to procure for simple cycle combustion turbines given the relatively low number of hours that the units are called upon to operate over the year.

[8] The principal sources of supply for Texas Gas are regional supply hubs and market centers: offshore Louisiana; Perryville, Louisiana; Henry Hub; Agua Dulce; and Carthage, Texas; Wellhead supplies: Fayetteville Shale in Arkansas, East Texas, northern and southern Louisiana and Mississippi; and Canadian natural gas through a pipeline interconnect with Midwestern Gas Transmission Company at Whitesville, Kentucky. http://www.txgt.com/AboutUsTXGT.aspx

At Bluegrass, natural gas firm transportation can be procured from Texas Gas Pipeline for a full-year (FT)[9], or for a short-term firm (STF)[10] monthly basis at a higher monthly reservation price. With FT or STF, the contracted amount of firm gas must be spread over the hours in a day evenly (i.e., the maximum hourly amount is 1/24th of the total), which makes it relatively prohibitive in cost for a peaking unit like Bluegrass. Enhanced firm gas service (EFT)[11] is available at an extra cost which allows the maximum gas quantity in each hour to be 1/16th of the contracted amount. With natural gas unavailability being unlikely in the summer, we examined the alternatives of procuring STF or EFT over the full winter (November to March) and for a more cost-effective 3-month period (December to February).

Fuel oil or LNG capability and storage would require a significant one-time capital cost to implement at Bluegrass, as provided by EKPC, along with annual fixed O&M and fuel carrying costs. The estimated cost of each fuel alternative is summarized in Table 6.

Table 6. Annualized Cost of Bluegrass Fuel Alternatives

Fuel Alternative	One-Time Capital Cost (2020 Nom$)	Annual Costs $M 2018)	Total Levelized Annual Cost Over 20 Years ($M 2018)
STF Gas Dec-Feb.	--	$7.0	**$7.0**
EFT Gas Dec.-Feb.	--	$5.5	**$5.5**
STF Gas Winter	--	$11.7	**$11.7**
EFT Gas Winter	--	$9.1	**$9.1**
LNG	$81.0	$0.5	**$6.0**
Fuel Oil	$62.8	$0.5	**$4.8**

2.5 Penalties and Benefits

Non-performance penalties collected by PJM in any PAH are distributed back as bonus revenues to any generating units that performed above their expected performance value during the PAH. As PAHs are generally driven by extreme weather, high energy prices also usually take place during PAHs resulting in high energy margins for any units available to operate. Based on historical EKPC prices during winter PAHs over the 2013/14 delivery year (which accounts for all of the recent winter RTO-wide PAHs), we assumed Bluegrass energy margins would be approximately $600/MWh (2018$) during winter PAHs.

[9] Firm Transportation Service (FT): Provides customers with nominated firm transportation service from designated receipt points to designated delivery points. The firm transportation contract demand must be a daily transportation quantity which is the same for each day of the contract term, which term must be for at least 12 consecutive months of service. FT Service provides customers with firm hourly deliveries up to 1/24th of their firm transportation contract demand.

[10] Short Term Firm Transportation Service (STF). Similar to Texas Gas' FT Rate Schedule except that STF shall be for a term of less than 12 consecutive months, or the daily contract demand may vary by month or season over the term of an agreement one year or longer in length. The seasonal nature of this service is reflected in its peak (winter) and off-peak (summer) rates.

[11] Enhanced Firm Transportation Service (EFT): Available to Texas Gas customers who have transportation service agreement under the FT or STF Rate Schedule. EFT service permits customers to receive deliveries of gas at a variable hourly flow rate up to one-sixteenth (1/16th) of their contract demand except when given notice to customers that EFT service is unavailable.

As shown in Table 7, if Bluegrass is unavailable during a winter PAH, non-performance charges of $3,687/MWh would apply to the Bluegrass station UCAP of 477 MW multiplied by a 78.5% Balancing Ratio (BR), yielding a charge of $1.4 million (2018$).[12] If Bluegrass is available, 1) bonus payments of $2,949/MWh[13] would apply to the 594 MW winter rating net of the UCAP times BR obligation, and 2) energy margins of $600/MWh would apply to the 594 MW output, yielding a benefit of $1.0 million. Thus, the net incremental benefit of being available during a single winter PAH is about $2.4 million (2018$).

Table 7. Net Benefit of Bluegrass Being Available During a Winter PAH ($2018)

		--------- Benefit / (Cost) --------			
		$/MWh	Applicable MW		Total M$
If Unavailable: Non-Performance		($3,687)	374	*UCAP*BR*	($1.38)
If Available:	**Bonus Payment**	$2,949	220	*ICAP-(UCAP*BR)*	$0.65
	Energy Margin	$600	594	*ICAP*	$0.36
					$1.00
Net Incremental Benefit of Being Available					$2.38
ICAP = 594 MW, UCAP = 477 MW, Balancing Ratio (BR) = 0.785					

2.6 Breakeven PAH for Each Alternative

Using the above net benefit for the Bluegrass station being available during a PAH, the breakeven number of PAHs for each fuel alternative to cover its levelized costs over 20 years can be calculated. As shown in Table 8, Bluegrass would only need to become available in an additional 42 winter PAHs over a 20-year period for the fuel oil to become economic. While this is a relatively low number of hours over 20 years, a key question is: 1) how often PAHs will take place in PJM in the future, and 2) how often would gas be interrupted at Bluegrass during these PAHs thereby making the fuel alternative relevant.

Table 8. Additional Available PAHs Needed to Breakeven for Fuel Alternatives ($M 2018)

Fuel Alternative	Levelized Annual Cost (M$) A	Net M$ Benefit of Being Available per PAH B	Additional Available PAHs over 20 Years to Breakeven A/B * 20
STF Gas Dec-Feb.	$7.0	$2.33	60
EFT Gas Dec.-Feb.	$5.5	$2.33	47
STF Gas Winter	$11.7	$2.33	100
EFT Gas Winter	$9.1	$2.33	79
LNG	$6.0	$2.33	51
Fuel Oil	$4.8	$2.29	42

[12] BR is the ratio of actual PJM generation to total committed PJM generation in the PAH. 78.5% was the average BR in 2014-16.

[13] This $/MWh figure would be identical to the non-performance charge, except a 20% dilution in bonuses is assumed for demand response coming on-line during a PAH and for selected excusals by PJM. Actual PJM data over time will help refine this figure.

[14] These net benefit per PAH figures incorporate the energy margins for each alternative ($650/MWh for firm gas, $662/MWh for LNG (pre-purchased at a non-peak price), and $578/MWh for fuel oil). The net benefit is reduced by the Bluegrass EFOR of 3.6%, because if the plant is on forced outage, the fuel alternative will not provide a benefit. Start-up costs are not included.

3. SCENARIO ANALYSIS

3.1 Number of Future PAHs

PJM has noted that the chance of a 2014 Polar Vortex event is approximately one in 10 years. As shown in Table 9, Navigant developed three PAH Cases, *Low*, *Mid* and *High*, to analyze based on the PAHs in 2014 during the 2014 Polar Event. In the *Low PAH Case*, a Polar Vortex event was assumed to take place in the EKPC zone once during the 20-year evaluation period. In the *Mid PAH Case*, a Polar Vortex event was assumed to take place once every 10 years, or twice during the 20-year evaluation period.

Table 9. PAH Cases Analyzed[15]

	Low PAH Case	Mid PAH Case	High PAH Case
Performance Assessment Hours	Polar Vortex every 20 Years with 20 Winter PAHs	Polar Vortex every 10 Years, each with 20 Winter PAHs	Polar Vortex every 5 years, with quadruple severity every 10 years (80 PAHs)

In the *High PAH Case*, a Polar Vortex event is assumed to take place every 5 years, or 4 times during the 20-year evaluation period. In addition, in the *High PAH Case*, two of the Polar Vortex events are assumed to have 4 times as many PAHs during that winter, based on the PAHs that took place in the most impacted region of PJM during the 2014 Polar Vortex. While these cases are intended to capture the possible range of PAH outcomes, in practice, the actual number of PAHs in the EKPC zone could be outside of the ranges modeled here.

3.2 Likelihood of Bluegrass Gas Interruption

The overall economics of the fuel alternatives at Bluegrass depend predominately on whether gas will be interrupted at the station during a PAH. Absent gas interruption, only a forced outage would result in significant capacity penalties, and this forced outage risk is similar with or without firm gas or back-up fuel.[16] There are a number of considerations in evaluating the likelihood of gas interruption at Bluegrass:

- Natural gas was not interrupted at the EKPC Smith station during the 2014 Polar Vortex PAHs.[17]
- Gas was not interrupted for other PJM units in Indiana located on the Texas Gas pipeline during the 2014 Polar Vortex.[18]
- There were no winter PAHs affecting EKPC in 2015 through 2018, thus there is no data as to whether natural gas would have been interrupted at Bluegrass since the 2014 Polar Vortex.

[15] In all cases, 7 non-winter month PAHs were assumed to take place, with no gas interruption at Bluegrass during those PAHs. For simplicity, no PAHs were modeled in years without a Polar Vortex event. PJM analysis of historical data suggests that no winter PAHs occurred over a ten-year sample period outside of the year with the Polar Vortex event.

[16] A separate analysis of the impact of forced outages rates on capacity penalties is presented later in this report.

[17] Bluegrass was not a generating resource in PJM until EKPC's acquisition of the station in 2015. Smith has access to three pipelines, while Bluegrass is only served by the Texas Gas pipeline

[18] Specifically, the Texas Gas pipeline was not included in the list of interrupted pipelines in PJM's *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (http://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx). Bluegrass was not a part of PJM at the time, but other PJM units were served by the pipeline.

- With much more natural storage in western PJM than in eastern PJM, the likelihood of gas interruption is likely lower in the west (e.g., EKPC).
- There have been recent coal retirements and natural gas-fired additions in the Ohio, Indiana, Kentucky, and Tennessee region of the Texas Gas pipeline since winter 2014, possibly placing additional strain on gas supplies. Several more are planned in the next few years.
- Longer term, there may be additional development of shale gas in Western Kentucky near the Texas Gas pipeline that potentially could increase local gas supplies.

Given this uncertainty in the level of gas interruptions, to help frame the evaluation of risk, three gas interruption scenarios were developed and evaluated as shown in Table 10. In the *Low Gas Interruption Case*, a 5% chance of gas interruption (1 in 20 hours) at Bluegrass during a winter PAH was assumed. In the *Mid Gas Interruption Case*, a 20% chance (1 in 5 PAHs) *was assumed*. In the *High Gas Interruption Case*, a 33% chance of gas interruption (1 in 3 PAHs) was assumed.

Table 10. Gas Interruption Cases Analyzed

	Low Case	Mid Case	High Case
Gas Interruption During PAHs	5% (1 in 20 Winter PAHs)	20% (1 in 5 Winter PAHs)	33% (1 in 3 Winter PAHs)

Again, gas interruption during PAHs could be outside of these ranges. Given the 2014 Polar Vortex experience, there may be no gas interruption at Bluegrass during PAHs in any particular year. If so, the levelized cost of the fuel alternative could be viewed as the cost of "insurance" purchased in which the were no offsetting "claims".

3.3 Scenario Analysis

The PAH and gas interruption cases were combined to create 9 scenarios, and non-performance charges, bonus payments and energy margins were calculated and netted for each scenario. The analysis was performed over a 20-year period from the 2020/21 delivery year to 2039/2040.[19]

3.3.1 Risk Mitigation: Maximum Annual Penalty Under Each Fuel Alternative

To assess EKPC capacity penalty risk exposure, Table 11 shows the maximum single delivery year penalty incurred across the 9 scenarios examined. This maximum penalty takes place during a polar vortex event year. As reference points, results for 0% and 100% gas interruption during PAHs are also shown (shaded). Each of the fuel alternatives similarly mitigates the maximum single year penalty across the nine scenarios, and thus are not listed separately.

[19] A 2.0% inflation rate was assumed, and a 5.93% EKPC discount rate was applied to determine present values. See Appendix A for a detailed list of input assumptions applied.

Table 11. Bluegrass Maximum Annual Capacity Penalty (M$ 2018)

Annual PAHs -->	Polar Vortex (20 PAHs)					Quadruple Polar Vortex (80 PAHs)				
Gas Interuption in PAHs-->	0%	5%	20%	33%	100%	0%	5%	20%	33%	100%
Status Quo	1.0	2.4	7.8	16.7	28.1	3.9	9.2	30.4	65.2	78.9
All Fuel Alternatives	1.0	1.0	1.0	1.0	1.0	3.9	3.9	3.9	3.9	3.9

As shown, the fuel alternatives substantially reduce the potential maximum single year penalty, but the avoided penalty is dependent on the severity of the polar vortex event (e.g., 20 PAHs or 80 PAHs) and the level of gas interruption (e.g., 5%, 20%, or 33%). For example, if there is a 20-PAH polar vortex event and Bluegrass gas was interrupted during 20% of those PAHs (4 hours), the capacity penalty would be $7.8 million. The penalty is never zero in Table 11 given the forced outage rate of Bluegrass (3.6%).

3.3.2 Present Value Benefit (Cost) under each Alternative

While Table 11 above focuses on non-performance charges, the economic impact of the fuel alternatives must take into account the significant impact of bonus payments and energy margins that would be obtained place during a PAH if Bluegrass is available to operate. Captured in Table 12 is the present value of each fuel alternative relative to the *Status Quo*, under a *Low*, *Mid* and *High* number of future PAHs, and a *Low*, *Mid* and *High* probability of gas interruptions during these winter PAHs. For results framing, 0% and 100% gas interruption during winter PAHs are also included *(shaded rows)*.

As shown in Table 12A and 12B, in the *Low and Mid PAH Cases*, none of the alternatives yield a positive present value if gas interruption is 33% or lower. In the *High PAH Case* (Table 12C), the fuel oil alternative has a positive present value if gas interruption is just above 20% or higher, and the two December to January firm gas options yield a positive present value if gas interruption levels are 33% or higher.

As shown in Table 12B, if there is a polar vortex every 10 years *(Mid PAH Case)*, and the Bluegrass gas interruption percentage during the polar vortex is 20% *(Mid Gas Interruption Case)*, then the present value benefit of the fuel oil alternative would be negative $50 million, a net cost. In effect, the fuel oil alternative saves $13 million *(2018 present value)* of the alternative's $63 million full cost *(2018 present value)* by allowing Bluegrass to be available during some of the PAHs when it otherwise would not.

Table 12. Present Value Benefits/(Cost) of Each Fuel Alternative (M$, 2018 Present Value)

A. Low PAH Case *(1 Polar Vortex in 20 years)*

Gas Interrupt %	STF (Dec-Feb)	EFT (Dec-Feb)	STF-Winter	EFT-Winter	LNG	Fuel Oil
0%	($93)	($73)	($155)	($121)	($80)	($63)
5%	($91)	($71)	($154)	($120)	($78)	($62)
20%	($87)	($66)	($149)	($115)	($73)	($57)
33%	($82)	($62)	($145)	($111)	($69)	($53)
100%	($61)	($41)	($123)	($189)	($47)	($32)

B. Mid PAH Case *(1 Polar Vortex every 10 years)*

Gas Interrupt %	STF (Dec-Feb)	EFT (Dec-Feb)	STF-Winter	EFT-Winter	LNG	Fuel Oil
0%	($93)	($73)	($155)	($121)	($80)	($63)
5%	($90)	($70)	($152)	($118)	($76)	($60)
20%	($80)	($60)	($142)	($108)	($67)	($50)
33%	($71)	($51)	($133)	($100)	($58)	($42)
100%	($27)	($7)	($89)	($56)	($14)	$1

C. High PAH Case *(1 Polar Vortex every 5 years, w/Quadruple Severity every 10 years)*

Gas Interrupt %	STF (Dec-Feb)	EFT (Dec-Feb)	STF-Winter	EFT-Winter	LNG	Fuel Oil
0%	($93)	($73)	($155)	($121)	($80)	($63)
5%	($78)	($57)	($140)	($106)	($64)	($48)
20%	($31)	($11)	($193)	($59)	($17)	($2)
33%	$10	$30	($52)	($19)	$23	$38
100%	$176	$196	$114	$147	$190	$200

3.3.3 Forced Outage Impacts

Forced outage rates at Bluegrass will impact the non-performance charges and bonus revenues during PAHs. The higher the Bluegrass forced outage rate, the less value the fuel alternative has (if the plant is forced out during a PAH, having fuel available will not matter). During the 2014 Polar Vortex, forced outages driven by the extreme cold were a significant issue in plant unavailability in PJM. Based on data for natural gas plants during the Polar Vortex throughout PJM, we estimated an 18.3% EFOR could apply. As shown in Table 13, a high EFOR will mostly impact the present value benefit (cost) in the *High PAH Case*, when the value of the fuel alternative is most significant.

Table 13. PV Benefit (Cost) of Fuel Oil Alternative as Bluegrass EFOR Varies

Annual PAHs -->	Low PAH Case			Mid PAH Case			High PAH Case		
Gas Interuption in PAHs-->	5%	20%	33%	5%	20%	33%	5%	20%	33%
0% EFOR	(62)	(57)	(52)	(60)	(50)	(41)	(47)	0	41
3.6% EFOR (Base Case)	(62)	(57)	(53)	(60)	(50)	(42)	(48)	(2)	38
18.3% EFOR	(62)	(58)	(54)	(61)	(52)	(45)	(50)	(11)	22

3.4 Summary of Results

Each of the fuel alternatives identified for Bluegrass (firm gas, LNG, fuel oil) provides similar and substantial risk mitigation against a major single year capacity penalty. The fuel oil alternative is the lowest cost alternative at Bluegrass and represents the most economic means to mitigate capacity penalty risk. EFT firm gas for the three-month period from December to February is the next lowest cost alternative but will not cover any PAHs in which there would be fuel interruption in November or March. Over a 20-year period, Bluegrass would need to be available in only about 42 more PAHs to cover the cost of the fuel oil alternative. However, to reach this level of additional PAHs, there would need to be enough future PAHs in PJM in which there was gas interruption on the pipeline serving Bluegrass during those PAHs. Based on the scenarios analyzed in this study, the fuel oil alternative may not pay for itself over 20 years in present value terms. If so, the fuel oil alternative still will provide valuable "insurance" against high single year capacity penalties of as much as $79 million.

4. APPENDIX A – KEY ASSUMPTIONS

1. PAH Cases (winter only), based on 2014 Polar Vortex RTO-wide PAH
    a. Base: Polar Vortex every 10 winters
        i. 2023/24: 20 PAH, 11 in one day
        ii. 2033/34: 20 PAH, 11 in one day
    b. Low: Polar Vortex every 20 winters
        i. 2028/29: 20 PAH, 11 in one day
    c. High: Polar Vortex every 5 winters, with quadruple severity every 10 winters
        i. Quadruple is roughly similar to the BG&E PAH during the 2014 Polar Vortex for January with an EKPC-level polar vortex in December and February
        ii. 2023/24: 79 PAH, 11 in one day (3 times)
        iii. 2028/29: 20 PAH, 11 in one day
        iv. 2033/34: 79 PAH, 11 in one day (3 times)
        v. 2038/39: 20 PAH, 11 in one day

2. Key Assumptions
    a. Bluegrass parameters
        i. Winter capacity of 198 MW per unit, 3 units
        ii. EFOR: 3.6% (base), units either fully on or out during PAH (no partial outages)
        iii. UCAP: 159 MW per unit (summer 165 MW * (1 - 3.6% EFOR))
        iv. Heat Rate: 10.80 mmBtu/MWh, Variable O&M: $3.15/MWh (2018$)
        v. Non-fuel Start Cost: $9.517 per start (2018$), Start Fuel: 350 mmBTu per start

    b. EKPC discount rate (nominal): 5.91% (EKPC average interest rate on long-term debt year-end 2017 of 3.94% multiplied by a 1.50 TIER); Inflation: 2.0% per year

    c. Bluegrass Capacity Penalties/Bonus
        i. PAH Hourly Penalty/(Bonus) = Expected Performance – Actual Performance
            1. If negative, penalty at penalty payment rate, up to annual maximum
            2. If positive, bonus at bonus payment rate
        ii. Expected Performance: UCAP (159.06 MW) * Balancing Ratio
        iii. Actual Performance: Winter ICAP (198 MW) or full out (0 MW)
        iv. Balancing ratio winter: 78.5%
            1. Based on average balancing ratio during 2014-2016 PAHs per PJM *"CP Market Seller Offer Caps for 2020/2021 and 2021/2022 Delivery Year"*
            2. Balancing Ratio is Actual PJM Generation/Total Committed Generation
        v. Bonus Payment Dilution Factor 80%
            1. Reduces PAH bonus payments based on estimate of entry of non-CP capacity (e.g., DR) and PJM excusals for non-performance during PAH.
        vi. Net CONE in EKPC region of 321.57 $/MW-day for 2021/22 ($303.0 in 2018$)
            1. Per 2021/2022 RPM Base Residual Auction Planning Period Parameters
        vii. Performance penalty of $3,687 per MWh (2018$)
            1. [LDA Net CONE ($/MW-day) * Days in Delivery Year]/30
        viii. Bonus payments of $2,949 per MWh (2018$)
            1. Performance penalty multiplied by Dilution Factor
        ix. Annual penalty cap of $165,905 per UCAP MW-year (2018$)
            1. Annual Stop Loss = 1.5 * LDA Net CONE * Days in Delivery Year

x. Summer season has 7.0 PAH impacting Bluegrass in all scenarios in all years
    1. Bluegrass would incur penalties in summer PAH hours at its 3.6% EFOR
    2. Impacts amount of annual penalty cap that can take place in winter

d. Alternative Costs
    i. Firm Gas
        1. 2138.4 Dth/hour per hour per unit (10.8 heat rate * 198 MW winter)
            a. Amount of gas needed for maximum output chosen to allow for full plant output during PAHs to accrue bonus revenues
        2. STF: $15.17/Dth winter month reservation charge (2018$), 24-hour ratable take, procured for December to February, or all 5 winter months.
        3. EFT: $17.80/Dth per month reservation charge (2018$), 16-hour ratable take, procured for December to February, or all 5 winter months.
            a. Current Texas Gas Pipeline STF and EFT rates set in 2015 inflated to 2018$ to reflect long-term 20-year rate expectation.
    ii. Diesel option
        1. $62.8 million capital (nominal dollars 2020 ISD) + $467 thousand annual fixed O&M (2018$)
        2. No heat rate change, enough fuel oil is stored to cover PAHs
        3. Variable O&M increase of $0.98/MWh under fuel oil operation
        4. Unit start cost increased by 1.3 factor under fuel oil operation
        5. Fuel price hedge value of fuel oil in non-PAH hours not considered
        6. Additional Bluegrass operation from new burners (NOx) not considered
    iii. LNG option
        1. $81 million capital (nominal dollars 2020 ISD) + $467 thousand annual fixed O&M (2018$)

e. Energy Margins during Winter PAH
    i. EKPC LMP during Winter PAH of $718/MWh (2018$), all years
        1. Average LMP at EKPC during 2014 Polar Vortex PAH Hours
    ii. Natural Gas 6.07 $/mmBtu (2018$), all years
        1. 2014 natural gas prices during 2014 Polar Vortex (weighted by PAH hours) plus $0.1692/Dth transmission charge, escalated to 2018$
    iii. LNG: 4.91 $/mmBtu (2018$), all years
        1. LNG Price at Lake Charles, LA + transmission adder
    iv. Fuel Oil: 12.58 $/mmBtu (2018$), based on diesel cost at Spurlock

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:		
THE APPLICATION OF EAST KENTUCKY	)	
POWER COOPERATIVE, INC. FOR A	)	
CERTIFICATE OF PUBLIC CONVENIENCE	)	**CASE NO. 2018-_________**
AND NECESSITY FOR THE CONSTRUCTION	)	
OF BACKUP FUEL FACILITIES AT ITS	)	
BLUEGRASS GENERATING STATION	)	

DIRECT TESTIMONY OF SAM YODER
ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: August 24, 2018

Q. Please state your name, business address, and occupation.

A. My name is Sam Yoder and my business address is 9400 Ward Parkway, Kansas City, MO 64114. I am a Project Manager for Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell").

Q. Please briefly describe the business conducted by Burns & McDonnell.

A. Burns & McDonnell is a full-service engineering, architecture, construction, environmental and consulting solutions firm, based in Kansas City, Missouri. Our staff of 5,700 includes engineers, architects, construction professionals, planners, estimators, economists, technicians and scientists, representing virtually all design disciplines. We plan, design, permit, construct and manage facilities all over the world.

Q. Please state your education and professional experience.

A. I have a B.S. in Chemical Engineering and B.S. in Mathematics from the University of Missouri, Columbia, 2007. I have worked for Burns & McDonnell for 10 years and I am a Professional Engineer in the Commonwealth of Kentucky.

Q. Please provide a brief description of your duties at Burns & McDonnell.

A. I am a Project Manager with Burns & McDonnell's Energy Division. I am responsible for supervising and coordinating engineering staff, design, project schedule and cost, project planning, multi-contract coordination and management, and serve as the primary liaison with the Client.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe the role of Burns & McDonnell in helping EKPC evaluate and develop strategies for mitigating fuel risk at its

Bluegrass Generating Station ("Bluegrass Station") associated with the PJM Interconnection, LLC ("PJM") Capacity Performance construct. I will also describe and authenticate the screening level cost and feasibility analysis ("Screening Analysis"), as well as the Project Scoping Report ("Scoping Report"), that Burns & McDonnell prepared on behalf of EKPC related to this proceeding.

Q. Are you sponsoring any exhibits as part of your testimony?

A. Yes. My *curriculum vitae* is attached hereto as Attachment SY-1; a copy of the Screening Analysis is attached hereto as Attachment SY-2; and a copy of the Scoping Report is attached hereto as Attachment SY-3. These documents were prepared by me or by individuals working directly under my supervision.

Q. Please briefly describe EKPC's Bluegrass Station.

A. EKPC's Bluegrass Station is a 567 MW net winter output facility with three (3) natural gas-fired simple cycle Siemens 501 FD2 combustion gas turbines located just outside the city of La Grange in Oldham County, Kentucky. Historically, EKPC has relied on fuel from an adjacent interstate natural gas pipeline operated by Texas Gas Transmission, LLC, to operate the Bluegrass Station units.

Q. Please describe EKPC's initial engagement of Burns & McDonnell with respect to this matter.

A. EKPC originally retained Burns & McDonnell to perform an assessment of its Bluegrass Station to identify screening level cost and project feasibility associated with developing ultra-low-sulfur-diesel fuel oil ("fuel oil") or liquefied natural gas ("LNG") as on-site backup fuel supply resources. As part of its assessment, Burns & McDonnell examined various fuel oil and LNG alternatives for the Bluegrass

Station with respect to backup fuel duration, practicability/feasibility, indicative capital costs, operational and maintenance impacts, industry experience, and estimated performance and emissions impacts. The assessment was intended to aid EKPC in its planning efforts as they relate to PJM's Capacity Performance program, which aims to address grid reliability concerns highlighted by the Polar Vortex of January 2014. The addition of a backup fuel system at the Bluegrass Station would improve the facility's ability to perform during a similar weather event.

Q. What alternatives did Burns & McDonnell consider as part of its Screening Analysis presented to EKPC?

A. As part of its Screening Analysis, Burns & McDonnell utilized conceptual general arrangement sketches and leveraged similar project experience to develop project schedule and screening level project costs for a total of eight (8) backup supply resource options. These options varied based on type of fuel (fuel oil or LNG), amount of storage capacity (24-hour or 48-hour), and type/number of storage tanks. Burns & McDonnell contacted equipment suppliers to support project cost development and to estimate performance and emissions impacts for backup fuel implementation and operation. Additionally, backup fuel supply logistics were investigated to provide possible supply limitations for the backup fuel options. The methodologies and results of this evaluation are detailed in the Screening Analysis provided as Attachment SY-2.

Q. Please briefly summarize the conclusions set forth in the Screening Analysis.

A. Burns & McDonnell's Screening Analysis revealed that each option considered was feasible based on the layout, designs and other information evaluated. Although, as described in greater detail in the Screening Analysis, each alternative presented advantages and disadvantages in terms of costs, space requirements, capacity, and other factors, Burns & McDonnell concluded that the least-cost option available to EKPC involved the use of fuel oil as a backup fuel utilizing two (2) storage tanks providing in total a 24-hour storage capacity.

Q. Did EKPC elect to proceed with further evaluation of the least-cost option presented in Burns & McDonnell's Screening Analysis?

A. Yes. After extensive review and discussion of the Screening Analysis, EKPC asked Burns & McDonnell to further examine dual fuel implementation for the Bluegrass Station's combustion turbines, including the use of two (2) on-site fuel oil storage tanks to allow twenty-four (24) hours of plant operation, a demineralized water storage tank, and the erection or refinement of associated balance of plant systems to support dual fuel operation (the "Project"). Burns and McDonnell developed the Scoping Report, attached hereto as Attachment SY-3, to define the Project's preliminary design, schedule and cost estimates.

Q. Please describe the Scoping Report prepared for EKPC.

A. The Scoping Report is intended to provide EKPC and other interested parties, such as this Commission, an understanding of the Project scope, assumptions, conceptual design, schedule and associated cost estimate. The Executive Summary and Introduction provide the highest-level summary and put some necessary caveats on what Burns & McDonnell was asked to accomplish as part of its review. Section 3.0, the Project Definition section of the Scoping Report, includes extensive detail about the Project.

The Project Definition section describes the existing layout and configuration of the Bluegrass Station and provides a reasonably high-level overview of the mechanical, electrical and control systems that will be required on the Project. The Project Definition also includes a discussion on permitting requirements that are likely to be applicable to the Project's development.

The next major component of the Scoping Report is the Contracting Approach Section. In that portion of the Scoping Report, the multiple contract approach selected for the Project is described. An important feature of this portion of the Scoping Report is the inclusion of a list of major contracts as well as a matrix showing how each contract interfaces with other contracts. This matrix helps EKPC plan and track the sequencing of the contracts accordingly. The last part of the Contracting Approach section of the Scoping Report provides a general description of the scope of each contract and further breaks the Project down into construction contracts and equipment contracts.

The next section of the Scoping Report covers the Schedule for the Project. It describes the major milestones that must be met to timely complete the work involved and describes how the project will fit into the planned outages for the Bluegrass Station.

The last major section of the Scoping Report is the Cost Estimate discussion. In this part of the Scoping Report, Burns & McDonnell provides estimates for both the capital investment and the operations and maintenance investment associated with the Project. Additionally, a discussion is included of the assumptions used in preparing the cost estimates and how contingency amounts were calculated. Finally, a cash flow estimate is provided based on the Project schedule, contracting approach, and cost estimate.

Q. **Do you believe that the $62.8 million cost estimate associated with the Project is reasonable?**

A. Yes. While assumptions were made in the process of preparing the Scoping Report and certain limitations exist when any engineer develops a project before beginning detailed design for the project, the estimate developed in preparing the Scoping Report is of budgetary planning quality for similar projects of this complexity and size.

Q. **Has Burns & McDonnell continued to assist EKPC in the further development of the Project since completing the Scoping Report?**

A. Yes. Burns & McDonnell continues to provide planning and detailed design work to assist with the development and implementation of the Project. Recent activities toward that end involve working on further development of the project execution plan, gathering plant data and information, and developing long-lead time equipment specifications.

Q. **Do you authenticate and adopt as part of your testimony the conclusions contained within the Screening Analysis and Scoping Report attached hereto as Attachment SY-2 and Attachment SY-3, respectively?**

A. Yes.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF BACKUP FUEL FACILITIES AT ITS BLUEGRASS GENERATING STATION	)	**CASE NO. 2018-________**

VERIFICATION OF SAM YODER

STATE OF Missouri)
)
COUNTY OF Jackson)

Sam Yoder, Energy Division Project Manager with Burns and McDonnell, being duly sworn, states that he has read the foregoing prepared direct testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

Sam Yoder

Sam Yoder

The foregoing Verification was signed, acknowledged and sworn to before me this 17 day of August, 2018 by Sam Yoder.

Sara Beth Acton

NOTARY PUBLIC

Commission No. 15634903

My Commission Expires: 20 April 2019

SARA BETH ACTON
Notary Public - Notary Seal
STATE OF MISSOURI
Jackson County
My Commission Expires April 20, 2019
Commission # 15634903

SAMUEL YODER, P.E.

Project Manager

Mr. Yoder is a Project Manager with Burns & McDonnell's Energy Division. Mr. Yoder has been involved in more than $1.5 Billion in coal-fired power plant pollution control retrofit projects. Mr. Yoder's experience includes all major phases of large capital projects, including project planning studies and evaluations, detailed engineering design, multi-contract coordination and management, construction and commissioning at coal-fired power plants.

EDUCATION

- BS, Chemical Engineering
- BS, Mathematics

REGISTRATIONS

- Professional Engineer (MO, KY)

10 YEARS WITH BURNS & MCDONNELL

10 YEARS OF EXPERIENCE

Spurlock Station Coal Combustion Residuals and Effluent Limitations Guidelines Scoping Study | East Kentucky Power Cooperative

2016-2017

Project manager for the Spurlock Station coal combustion residuals (CCR) and effluent limitations guidelines (ELG) project scoping study. The study involves preliminary engineering design to determine the project costs and schedule to comply with CCR and ELG regulations on Spurlock Units 1 and 2.

Coal Combustion Residuals and Effluent Limitations Guidelines Scoping Study | Confidential Client

2016-2017

Project manager for a coal combustion residuals (CCR) and effluent limitations guidelines (ELG) project scoping study. The study involves preliminary engineering design to determine the project costs and schedule to comply with CCR and ELG regulations at a coal-fired power plant.

Coal Combustion Residual Documents Implementation Program | East Kentucky Power Cooperative

2015-2016

Project manager for the EKPC CCR Implementation Program that included the documents required to meet the new EPA CCR Rule. Documents included inspection lists, groundwater monitoring studies, quality assurance program, fugitive dust program, and website/data management development. Roles included reviewing and developing documentation for EKPC CCR implementation, client coordination and internal engineering coordination.

Spurlock Station Site Drainage Improvement Project | East Kentucky Power Cooperative

2015-2016

Project manager for a diverse and fast paced project at Spurlock Station. The project consists of design and specification development, as well as construction management for rerouting the wet FGD blowdown from the coal pile runoff pond to the ash pond almost 8,000 feet away in less than 6 months. Once the reroute was completed, design and specifications were developed for deepening and lining the existing coal pile runoff pond. Lastly, site pavement design drawings and specifications were developed to pave nearly 15 acres at Spurlock Station.

Wilson Station Dry Sorbent Injection Project | Big Rivers Electric Corporation

2014-2016

Project manager for the Wilson Station Dry Sorbent Injection project. The project consists of dry sorbent injection silo, pipe rack and injection grid on Wilson Unit 1. The project consisted of developing design and specifications for the equipment supply contract as well as the installation contract.

Dale Station Ash Pond Closure and Site Restoration | East Kentucky Power Cooperative

2013-Present

Project manager for closure by removal of ash ponds at East Kentucky Power Cooperative's Dale Station near Ford, Kentucky. The project consists of removal of approximately 500,000 cubic yards of coal combustion residuals (CCR) from multiple ponds along the Kentucky River and hauling the CCR material to a landfill being developed at East Kentucky Power Cooperative's J.K. Smith Station.

Cooper Station Unit 1 – Duct Reroute Project | East Kentucky Power Cooperative

2013-2016

Project manager for the Cooper Unit 1 duct reroute project. The project consists of re-routing the Cooper Unit 1 flue gas into the previously constructed Cooper Unit 2 circulating dry scrubber system for MATS compliance. This unique project consisted of several equipment and material supply contracts as well as two installation contracts.

Green Station Units 1 & 2 MATS Compliance Project | Big Rivers Electric Corporation

2013-2015

Project manager for the Green Station Unit 1 & 2 MATS compliance project. The project consists of dry sorbent injection and powdered activated carbon injection on Green Units 1 & 2 for MATS compliance. The project consisted of detailed design and specification development for equipment supply, pilings, foundations, and mechanical construction. In addition, the project had multiple installation contracts that required coordination.

Spurlock Station Mercury Control Project | East Kentucky Power Cooperative

2013-2015

Project manager for the Spurlock Station mercury control project. The project involves the addition of a wet flue gas desulfurization (FGD) mercury reemission additive and a fuel additive to Spurlock Units 1 and 2.

MATS Compliance Study | Indianapolis Power and Light

2014

Project manager for the Indianapolis Power and Light MATS compliance study that evaluated the potential application of calcium bromide fuel additive for Harding Street Unit 7. The purpose of the study was to determine whether the application of fuel additive alone could bring Harding Street Unit 7 into MATS compliance. In addition to the feasibility evaluation, Mr. Yoder helped develop a testing plan that could be utilized by IP&L for testing the fuel additive application.

Cooper Station Unit 2, East Kentucky Power Cooperative

2009-2013

Mr. Yoder was the process engineer for the Cooper Unit 2 environmental project. The project involved the addition of a circulating dry flue gas desulfurization (FGD) system, baghouse, and selective catalytic reduction (SCR) systems to Cooper Station Unit 2, which is 225 MW.

Mr. Yoder was the field mechanical engineer for the Cooper Unit 2 environmental project. In this role, Mr. Yoder answered both technical and contractual questions from the installing contractors, assisted in coordinating the onsite work activities between multiple installation contractors, and coordinated and managed the equipment manufacturer's field representative services.

Mr. Yoder was the process commissioning engineer for the Cooper Unit 2 environmental project. In this role, Mr. Yoder assisted in commissioning the SCR, the circulating dry scrubbing FGD, primary air fan, forced draft fan, induced draft fan, and air heater. In addition, Mr. Yoder assisted in commissioning the balance of plant equipment for the Cooper Unit 2 environmental project.

Cholla Power Station Unit 3, Arizona Public Service

2007-2010

Mr. Yoder was the process engineer for the Cholla Unit 3 and Unit 4 scrubber and baghouse retrofit project for Arizona Public Service. The project involved the addition of wet FGD systems on each Unit, a new baghouse on Unit 4, and the replacement of the existing hot side electrostatic precipitators (ESP) with a baghouse on Unit 3. The Unit 4 ESP, which was abandoned on the Unit 4 retrofit, was converted into the Unit 3 baghouse.

Seminole Generating Stations Units 1 & 2, Seminole Electric

2007-2009

Detailed engineering and design for modifications to existing air pollution control equipment and installation of new air pollution control equipment for the existing Units 1 and 2. Work included new SCRs, urea injection, sorbent injection testing, sorbent injection equipment for SO_3 control, and FGD modifications including new mist eliminator wash, installation of perforated trays, and new gypsum dewatering equipment.

Merom Station, Hoosier Energy Rural Electric Cooperative, Inc.

2007

Development of specifications and drawings for procurement of sulfuric acid mist (SAM) control system. System was designed for reagent injection upstream of the existing particulate collection device.

BURNS McDONNELL

Bluegrass Generating Station – Backup Fuel Screening Level Evaluation

EAST KENTUCKY POWER COOPERATIVE

East Kentucky Power Cooperative

Project No. 97273
REV. 0
August 2018

Bluegrass Generating Station – Backup Fuel Screening Level Evaluation

Prepared for

East Kentucky Power Cooperative
Winchester, Kentucky

August 2018
REV. 0

Project No. 97273

Prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

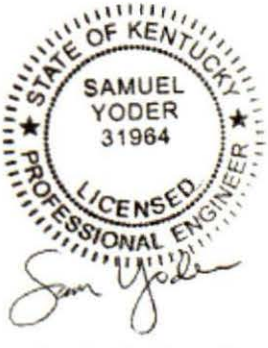
INDEX AND CERTIFICATION

East Kentucky Power Cooperative
Bluegrass Generating Station – Backup Fuel Screening Level Evaluation
Project No. 97273

Report Index

Certification

I hereby certify, as a Professional Engineer in the Commonwealth of Kentucky, that the information in this document was assembled under my direct supervisory control. This report is not intended or represented to be suitable for reuse by East Kentucky Power Cooperative or others without specific verification or adaptation by the Engineer.



Aug 16 2018

Sam Yoder (Kentucky License No. 31964)

Date: August 16, 2018

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
A	Amps
Bluegrass	Bluegrass Generating Station
BMcD	Burns & McDonnell
BMP	Best Management Practices
BOP	Balance of Plant
CCW	Closed-Cooling Water
COD	Commercial Operation Date
CPCN	Certificate of Public Convenience and Necessity
CTG/GTG	Combustion/Gas Turbine Generator
DC	Direct Current
DLN	Dry-Low NOx
EKPC	East Kentucky Power Cooperative
EPA	Environmental Protection Agency
F&E	Furnish and Erect
FNTP	Full Notice to Proceed
GA	General Arrangement
GAL	Gallons
GPM	Gallons Per Minute
HMI	Human Machine Interface
HP	Horsepower
HVAC	Heating, Ventilation and Cooling
kW	Kilowatt
LED	Light-Emitting Diode

LNG	Liquefied Natural Gas
LNTP	Limited Notice to Proceed
LOC	Letter of Credit
MCC	Motor Control Center
MPH	Miles Per Hour
MW	Megawatts
NFPA	National Fire Protection Agency
NOx	Nitrogen Oxides
O&M	Operation & Maintenance
ORSANCO	Ohio River Valley Water Sanitation Commission
OWS	Oil Water Separator
PDC	Power Distribution Center
PHMSA	Pipeline and Hazardous Materials Safety Administration
ppm	Parts per million
PSC	Public Service Commission
PSD	Prevention of Significant Deterioration
PSM	Power Systems Manufacturing
TBD	To Be Determined
TCS	Turbine Control System
ULN	Ultra-Low NOx
ULSD	Ultra-Low Sulfur Diesel
UPS	Uninterruptible Power Supply
V	Volt
XFMR	Transformer

1.0 EXECUTIVE SUMMARY

East Kentucky Power Cooperative (EKPC) retained Burns & McDonnell (BMcD) to perform an assessment of its Bluegrass Generating Station (Bluegrass) to identify screening level cost and feasibility concerns associated with developing fuel oil (ultra-low-sulfur-diesel [ULSD]) or liquefied natural gas (LNG) on-site backup fuel supply resources. In this assessment, various ULSD and LNG alternatives were evaluated at Bluegrass with respect to backup fuel duration, practicability/feasibility, indicative capital costs, operational and maintenance impacts, industry experience, and estimated performance and emissions impacts. The assessment is intended to aid EKPC in their planning efforts as they relate to PJM's Capacity Performance program, which aims to address grid reliability concerns highlighted by the Polar Vortex of January 2014. The addition of a backup fuel system at Bluegrass would help the facility maintain its ability to perform during a similar weather event.

Bluegrass is a 567-megawatt (MW) net winter output facility with three natural gas-fired simple cycle Siemens 501 FD2 combustion gas turbines (CTG) located just outside the city of La Grange in Oldham County, Kentucky. Information provided in this assessment is preliminary in nature and is intended to provide indicative screening-level costs only. These costs should not be used for budgetary purposes, but instead for comparing relevant backup fuel supply options. It is BMcD's understanding that information provided in this assessment will be used by EKPC to evaluate the backup fuel options for Bluegrass. If an option is selected, subsequent stages of project definition and cost estimating would be necessary to develop a project budget.

1.1 ASSESSMENT METHODOLOGY

This assessment utilized conceptual general arrangement (GA) sketches and leveraged similar project experience to develop project schedule and screening level project costs for eight backup supply resource options, as shown in Table 1-1. BMcD contacted equipment suppliers to support project cost development and to estimate performance and emissions impacts for backup fuel conversion and operation. Finally, backup fuel supply logistics were investigated to provide possible supply limitations for the backup fuel options. These results were summarized in this report to assist EKPC in selecting a backup fuel option for subsequent project definition.

Table 1-1: Cost Comparisons of Backup Fuel Supply Options

Option	Backup Fuel Technology Description	Installed Capital Cost
1	Fuel Oil – One Tank, 48 hr Storage	$ 66.5 MM
2	Fuel Oil – One Tank, 24 hr Storage	$ 62.5 MM
3	Fuel Oil – Two Tanks, 48 hr Storage	$ 66 MM
4	Fuel Oil – Two Tanks, 24 hr Storage	$ 62 MM
5	LNG – Bullet Tanks, 48 hr Storage	$ 120 MM
6	LNG – Bullet Tanks, 24 hr Storage	$ 81 MM
7	LNG – Field Erected Tank, 48 hr Storage	$ 91.5 MM
8	LNG – Field Erected Tank, 24 hr Storage	$ 82 MM

1.2 ASSESSMENT SUMMARY

Based on BMcD's assessment of the various backup fuel supply options, each option is feasible. However, as summarized in Table 1-2, there are pros and cons associated with each option.

Table 1-2: Summary Comparisons of Backup Fuel Options

Option	Pro(s)	Con(s)
1 – Fuel Oil / One Tank / 48 hr	• Additional capacity/longer operation (48 hr) • Lower capital cost • Lower space requirement	• Demin water operation and maintenance (O&M) costs • Expensive fuel • No spare tank/storage • Increased emissions
2 – Fuel Oil / One Tank / 24 hr	• Lower capital cost • Lower space requirement	• Demin water O&M costs • Expensive fuel • Reduced capacity/shorter operation (24 hr) • No spare tank/storage • Increased emissions
3 – Fuel Oil / Two Tanks / 48 hr	• Additional capacity/longer operation (48 hr) • Lower capital cost • Lower space requirement • Spare tank/redundant storage	• Demin water O&M costs • Expensive fuel • Increased emissions
4 – Fuel Oil / Two Tanks / 24 hr	• Lower capital cost • Lower space requirement • Spare tank/redundant storage	• Demin water O&M costs • Expensive fuel • Reduced capacity/shorter operation (24 hr)
5 – LNG / Bullet Tanks / 48 hr	• Minor emissions increase • Higher performance • No demin water O&M costs • Additional capacity/longer operation (48 hr)	• Higher capital cost • Boil-off 0.08%/day – over $1 million per yr for refill • Higher space requirement

6 – LNG / Bullet Tanks / 24 hr	• Minor emissions increase • Higher performance • No demin water O&M costs	• Higher capital cost • Boil-off 0.08%/day – over $500 thousand per yr for refill • Higher space requirement
7 – LNG / Field Erected Tank / 48 hr	• Minor emissions increase • Higher performance • No demin water O&M costs • Additional capacity/longer operation (48 hr)	• Higher capital cost • Boil-off 0.2%/day – over $2.8 million per yr for refill
8 – LNG / Field Erected Tank / 24 hr	• Minor emissions increase • Higher performance • No demin water O&M costs	• Higher capital cost • Boil-off 0.2%/day – over $1.4 million per yr for refill

Not noted in Table 1-2 above are potential air permit impacts. BMcD understands that EKPC's permitting approach would limit plant operating hours on the backup fuel and the primary fuel (natural gas) as required to avoid triggering the Environmental Protection Agency (EPA) Prevention of Significant Deterioration (PSD) limits for new major sources. Therefore, it is anticipated that each fuel oil and LNG option would be considered minor changes and minor source additions to the permit, which are not expected to require a permitting process beyond six months. Even though the permitting changes for dual fuel operation are not expected to trigger PSD permitting actions, the switch to fuel oil or LNG could be considered a monitoring change by the state and therefore a significant revision. A significant revision could take approximately 18 months to complete the permitting process, since it is open for public review. The schedule and screening cost estimates in this report were based on an allowance of 18 months to complete the permitting process. LNG is expected to add two minor emissions sources (flare and fired vaporizer). Fuel oil is not expected to add new emissions sources but will require modification to the existing permit for new emissions due to alternate fuel source.

It is recommended that EKPC use the conceptual GAs, screening level costs, information provided herein and the pros and cons to compare and weigh the backup fuel options for Bluegrass Generating Station and select an option for further project definition, schedule, and cost refinement.

2.0 INTRODUCTION

EKPC retained BMcD to perform an assessment of Bluegrass to identify screening level cost and feasibility concerns associated with developing fuel oil or LNG on-site backup fuel supply resources. Bluegrass is a 567 MW net winter output facility with three natural gas-fired simple cycle Siemens 501 FD2 gas turbines located just outside the city of La Grange in Oldham County, Kentucky. The assessment is intended to aid EKPC in their planning efforts as they relate to PJM's Capacity Performance program, which aims to address grid reliability concerns highlighted by the Polar Vortex of January 2014. The addition of a backup fuel system at Bluegrass would help the facility maintain its ability to perform during a similar weather event.

Information provided in this assessment is preliminary in nature and is intended to provide screening-level costs (+/-30 %) for backup fuel oil #2 (ULSD) and backup LNG options at Bluegrass only. These costs should not be used for budgetary purposes but instead for comparing relevant backup fuel technologies. If EKPC elects to pursue one or several of these options for further evaluation, BMcD recommends that EKPC perform a project scope/definition report to further refine the project scope and cost. The next stage of project scope development would include a bottoms up cost estimate based on refinement of a general arrangement, scope assumptions matrix, development of key engineering documents and further refinement of pricing from in-house resources and equipment manufacturers. These documents would be combined in a project scope report with pricing that could then be used for budgetary purposes.

The screening-level costs developed as part of this backup fuel screening assessment included direct costs for equipment and labor, indirect costs, owner's costs, owner's contingency, taxes, and escalation based on project schedule.

3.0 BACKUP FUEL MODIFICATIONS AND SCOPE

BMcD reviewed information received from equipment manufacturers, BMcD's walk-down of the potential project site, and information provided by EKPC to determine the scope of physical modifications required for each backup fuel supply option. The substation shown on the GA sketches is not within the scope of this project but is shown to prevent interference between this project and the substation effort to be conducted by EKPC. The eight backup fuel options evaluated in this assessment are listed in Table 3-1 and the descriptions of the modifications and required scope are described in the following sections.

Table 3-1: Backup Fuel Evaluation Options

Option Number	Backup Fuel	Storage Capacity (Duration)	Number of Fuel Storage Tanks
1	Fuel Oil	48 Hour	1
2	Fuel Oil	24 Hour	1
3	Fuel Oil	48 Hour	2
4	Fuel Oil	24 Hour	2
5	LNG	48 Hour	30 (bullet)
6	LNG	24 Hour	15 (bullet)
7	LNG	48 Hour	1
8	LNG	24 Hour	1

3.1 FUEL OIL IMPLEMENTATION SCOPE AND MODIFICATIONS

The backup fuel oil options will require gas turbine modifications for dual fuel capability and will include new fuel oil tank(s), a new demineralized water tank for water injection, and associated ancillary equipment to support fuel oil operation at Bluegrass. The following sections describe the specific scope, gas turbine experience, and operation for backup fuel oil.

3.1.1 501 FD2 Fuel Oil Experience and Operation

The original equipment manufacturer for the gas turbines (Siemens) confirmed that the 501 FD2 can be retrofitted for dual fuel (fuel oil and natural gas operation). According to Siemens, there are 19, 501 FD2 units capable of dual fuel operation. They estimate the total 501 FD2 fleet hours operated on fuel oil is over 3,700 hours. Furthermore, there are at least 67 units in the entire 5000F fleet (regardless of version) that can operate on fuel oil. They estimate the total 5000F fleet hours operated on fuel oil exceeds 22,000 hours. There are no known feasibility issues with dual fuel implementation and fuel oil operation on the

501 FD2. When dual fuel is implemented, the 501 FD2 is capable of switching between natural gas and fuel oil while online at reduced loads.

Based on Siemens provided scope description, the Siemens Dry-Low NO_x (DLN) dual fuel configuration utilizes dual fuel pilot and main stages to support housing nozzles, atomizing the fuel oil into the swirled air combustion zone of the turbine. Water is injected into the fuel-air mixture, as a combustion diluent for nitrogen oxides (NO_x) control by preventing premature ignition. Additionally, water is injected into the fuel oil lines upstream of the nozzle connections to pre-purge and post-purge the fuel oil nozzles to control coking. Air in the combustor shell maintains pressure in the fuel gas manifold while the combustion turbine operates on fuel oil to keep combustion products from flowing backwards (from high to low pressure zones) through the nozzles. Once fuel oil operation ends, water is circulated through the Siemens equipment to effectively purge the system. Balance of plant (BOP) equipment will not need to be purged.

3.1.2 501 FD2 Combustion Turbine Implementation for Dual Fuel

Multiple contractors are capable of implementing dual fuel on the 501 FD2. Siemens provided an estimate of $7 million (2017 dollars) per turbine, which was the basis for the estimates developed for this report. The Siemens supply and installation scope would include the following:

<u>Auxiliary Components - Fuel Oil System:</u>

- Fuel Oil pump skid assembly, consisting of:
    - Fuel Oil over-speed trip valve
    - Fuel Oil pump suction filter
    - Fuel Oil pump/motor
    - Fuel Oil relief valve
    - Fuel Oil discharge pressure regulator valve
    - Fuel Oil thermocouple
    - Fuel Oil flow meter
- Water Injection pump/motor, consisting of:
    - Water Injection pump suction filter
    - Water Injection arc/back pressure regulator valve
    - Water Injection pump/motor
- Fuel Oil Water Injection skid, consisting of:
    - Water Injection stage A throttle valve
    - Water Injection stage B throttle valve

  - Water Injection pilot throttle valve
  - Fuel Oil stage A control valve
  - Fuel Oil stage B control valve
  - Fuel Oil pilot control valve
  - Fuel Oil Multifunction valve manifold - pilot
  - Fuel Oil Multifunction valve manifold - stage A
  - Fuel Oil Multifunction valve manifold - stage B
  - Fuel Oil pilot stage flow distribution device
  - Fuel Oil stage A flow distribution device
  - Fuel Oil stage B flow distribution device
- Interconnecting piping material consisting of:
  - Water Injection flow meter
  - Water Injection interconnect piping assembly
  - Water Injection piping assembly, turbine pipe rack
  - Water Injection tube track manifold assembly
  - Fuel Oil/Water Injection stage B check valve
  - Fuel Oil/Water Injection pilot check valve
  - Fuel Oil/Water Injection stage A check valve
  - Fuel Oil tube track manifold assembly
  - Fuel Oil interconnect piping assembly, pipe rack
  - Fuel Oil interconnect tubing, fuel oil/water injection skids to turbine
  - Fuel Oil piping assembly, turbine pipe rack

<u>Auxiliary Components - Drain and Purge System:</u>

- Combustor shell drain valve
- Fuel Gas manifold cont. purge isolation valve #1
- Fuel Gas manifold cont. purge isolation valve #2
- Fuel Gas purge vent valve
- Miscellaneous drain system piping

<u>Gas Turbine Hardware</u>

- Support housings
- Dual fuel pilot nozzles

The Siemens provided fuel oil and water injection pump skids would optimally be placed on a pad adjacent to the gas turbine enclosure to reduce routing of turbine piping, which is the approach for the fuel oil options. Pipe routed under the combustion turbines will connect the pump skids to the water injection and fuel oil control valves, on an assembly. Common shafted, positive displacement pumps supplied for each fuel oil combustion stage (A, B, Pilot) provide equal oil flow to each stage on each nozzle set. Multifunction valves (hydraulically driven) downstream of each pump allow for flushing and purging needed to maintain system reliability.

Fuel oil and water injection tubes routed to the nozzles are organized in prefabricated assemblies. A combustor shell drain is added for connection to the plant oily waste drain for purge wastewater and the pilot nozzles and support housings would be exchanged for dual fuel styles.

3.1.2.1 Ultra-Low NOx Combustor

BMcD requested budgetary scope and cost to convert the 501 FD2 units to combustors that reduce NO_x emissions and increase available operation hours before reaching the PSD limit. There are two known potential providers for lower NO_x burners on the 501 FD2, Siemens and Power Systems Manufacturing (PSM).

The Siemens Ultra-Low NO_x (ULN) combustor upgrade is expected to reduce steady-state NO_x emissions while operating on natural gas; however, at this time, Siemens has indicated 15 parts per million (ppm) steady-state NO_x emissions with ULN upgrade. The PSM combustor upgrade would reduce steady-state NO_x emissions to 9 ppm or lower while operating on natural gas. A combustor upgrade may extend maintenance intervals to potentially result in lower CTG major maintenance costs. Other potential benefits of the combustor upgrade include improved performance (decreased heat rate and slightly increased output) and reduced minimum turndown for improved operational flexibility.

Siemens provided an estimate of $6.5 million (2017 dollars) per CTG for ULN upgrades, separate from the dual fuel implementation scope. If both the ULN upgrade and dual fuel implementation were executed, then the estimated price would be $13 million per CTG. The scope and costs for ULN combustor upgrades were not included in the cost estimates in this report.

3.1.3 Fuel Oil Balance of Plant Scope

In addition to the scope provided by Siemens, BOP modifications are required for an effective dual fuel implementation at Bluegrass. The BOP systems would include fuel oil unloading and storage in one or two tanks, with transfer to the Siemens fuel oil skids next to the combustion turbines. The implementation would also require additional demineralized water storage and transfer pumps to supply the Siemens water injection pumps at the combustion turbines. In this assessment demineralized water is considered to be supplied to the new tank by mobile demineralized water trailers (provided by EKPC) via existing trailer connections. No permanent demineralized water system is included. Interconnecting pipe and cable tray would be placed in precast cable trenches to stay above existing underground utilities. The pipe between the heaters and combustion turbine skids would be heat traced since it is considered above ground and because it will not be purged after fuel oil operation. The heat trace will keep the fuel oil in the pipe warm enough to flow for startup and operation during cold weather. Containment is included for both the fuel oil tank(s) and truck unloading areas to properly contain spills/leaks and minimize safety risks and environmental impacts. The BOP scope modifications would include:

- Fuel oil unloading skids (2 x 100% pumps each) – for two truck unloading bays
- Fuel oil storage tanks (s) – 24-hour or 48-hour storage
- Fuel oil forwarding skid (1 x 100% for each unit with 1 x 100% common spare)
- Fuel oil inline heaters (3 – 1 x 100% for each unit)
- Demineralized water storage tank
- Demineralized water transfer pump skid (1 x 100% for each unit with 1 x 100% common spare)
- CO_2 fire protection for each fuel oil supply skids
- Extend fire water loop to fuel oil storage area
- Associated electrical equipment and instrumentation
- Interconnecting pipe

3.2 LNG DESCRIPTION, SCOPE AND MODIFICATIONS

LNG is typically used as a temporary method of storing and transporting natural gas. When natural gas is converted to a liquid at very low temperatures, its volume is reduced by a factor of approximately 600, allowing for on-site storage of large amounts of backup fuel for a gas turbine facility. LNG is heated through a vaporizer and converted back to natural gas when the gas turbines require the use of a backup fuel source, due to insufficient natural gas pipe-line supply. Since LNG is converted back to natural gas prior to delivery to the gas turbine, the 501 FD2 can switch between pipeline natural gas operation and LNG backup operation while online.

3.2.1 LNG Equipment Supplier Scope

BMcD contacted LNG equipment suppliers to receive budgetary quotes and scope of equipment supply for LNG unloading, storage, and regasification. The LNG equipment supplier would supply the following equipment:

- LNG unloading skids (2 x 100% pumps each) – for two truck unloading bays (with scales)
- LNG storage
    - Bullet tanks – 24-hour or 48-hour storage (132,000-gallon tanks) or
    - Furnish and erect (F&E) double wall tank – 24-hour or 48-hour storage
- LNG booster pumps (3 x 50%)
- LNG fired vaporizers (2 x 100%)
- Pressure control manifold
- Flare (for boil-off)
- Associated instrumentation and controls
- Interconnecting pipe

The exact plant location was not provided to suppliers, so a full route study could not be performed by Chart (LNG equipment supplier) for delivery of the large bullet tanks. The large 132,000-gallon tanks have been transported via extended trucks on previous projects; however, there may be unknown limitations for delivery to Bluegrass that would require smaller tanks. In this case, the cost of LNG equipment and required space for LNG storage would increase from what is provided in this assessment.

LNG storage equipment siting will be subject to thermal radiant flux modeling and vapor dispersion modeling results. These results have been used in other LNG projects by the governing fire authority to require the LNG storage to be setback several hundred feet from property lines, major equipment, and buildings. Bullet tank storage setback distances are typically less than that for F&E tanks and have simpler methods to mitigate the distance requirement. However, single wall F&E tanks often require several hundred feet of setback, at a minimum. Double wall (full containment) F&E tanks can be utilized to drastically reduce the required setback. Bluegrass has limited available space and detailed modeling was not completed for this assessment. Therefore, Options 7 and 8 estimates include double wall (full containment) F&E tanks to cover mitigation costs for potential setback requirements.

Following thermal radiant flux and vapor dispersion modeling, there may be opportunities for updating to a single wall tank, but this would still be subject to approval from the authority having jurisdiction (typically the fire marshal). This would reduce the field erected tank costs by approximately 40%.

3.2.2 LNG Balance of Plant Scope

In addition to the scope provided by LNG equipment supplier, BOP modifications are required for a functional LNG backup fuel system at Bluegrass. The BOP systems would include fire water to LNG storage area with booster pumps, and the transfer of natural gas from the vaporizer to the combustion turbines. To stay above existing underground utilities, interconnecting pipe and cable tray would be placed in precast cable trenches towards the north end of the plant and then transition to underground pipe and duct bank, as indicated in the GA sketches. The BOP scope modifications would include:

- Fire water booster pump and hydrants
- Interconnecting pipe (natural gas delivery, fire water)
- Associated instrumentation and electrical

4.0 SCREENING LEVEL COSTS, SCHEDULE, AND PERFORMANCE

4.1 CAPITAL COSTS

Screening level (+/- 30%) capital cost estimates developed for the six backup fuel options are summarized in Table 4-1.

Table 4-1: Screening Level Installed Cost Estimate Summary

Option	1	2	3	4	5	6	7	8
Option Description	Fuel Oil / 48 hr / 1 tank	Fuel Oil / 24 hr / 1 tank	Fuel Oil / 48 hr / 2 tanks	Fuel Oil / 24 hr / 2 tanks	LNG / 48 hr	LNG / 24 hr	LNG / 48 hr / field erected	LNG / 24 hr / field erected
Total Project Cost ($MM)[3]	$66.5	$62.5	$66	$62	$120[1]	$81[2]	$91.5[3]	$82[4]

[1]Estimated LNG tank equipment cost: $40.5 million
[2]Estimated LNG tank equipment cost: $20 million
[3]Estimated LNG tank equipment cost: $38 million
[4]Estimated LNG tank equipment cost: $33 million
[5]Includes Total Project Cost, Owner's contingency, Owner's costs, and taxes

The cost differences between the fuel oil and LNG options are mainly due to LNG equipment costs, specifically the cost for several cryogenic bullet tanks or one double wall (full containment) field erected tank.

4.1.1 Cost Basis

The cost estimates are based on a multi-prime contract approach and were developed based on the general arrangement sketches in Appendix A and conceptual design considerations. These sketches were used to estimate quantities (civil, piping, concrete, mechanical, electrical, etc.) and associated costs for each option. The pricing for most quantities was based on previous projects that have had estimate buildups or have been installed. Major equipment costs were based on budgetary quotes from suppliers.
Total project costs, as shown in Table 4-1, include 10% of total direct project costs for engineering and startup and 10% of total direct project costs for construction management and construction indirects. Escalation is included and based on the expected project schedule shown in Appendix D.

The estimates also include 20% contingency on both direct and indirect project costs included in the Total Project Cost. An additional 5% of Total Project Costs for Owner's contingency, 5% for Owner's project related costs, and 6% sales tax are included to provide an estimated evaluation of costs to the Owner. The estimates do not include initial fill for storage. In today's dollars, the typical cost for fuel oil is $2.25 to $2.50 per gallon, while the typical delivered cost for LNG is between $1.00 and $1.50 per gallon.

4.1.2 Conceptual Cash Flow

Table 4-2 shows the expected conceptual cash flow for any of the backup fuel options, assuming a completion date of December 2020.

Table 4-2: Estimated Annual Cash Flow

Year	2018	2019	2020
Cost Percentage	10%	30%	60%

4.2 OPERATING AND MAINTENANCE COSTS

Estimated O&M costs were developed for each option. The O&M costs are not inclusive of the entire plant O&M but are representative of the additional O&M costs for the operation of added equipment for each option. The O&M costs are comprised of two main categories, fixed O&M costs and variable O&M costs, which are summarized in Table 4-3.

Table 4-3: O&M Costs

	Option 1 - Fuel Oil / One Tank / 48 Hr	Option 2 - Fuel Oil / One Tank / 24 Hr	Option 3 - Fuel Oil / Two Tanks / 48 Hr	Option 4 - Fuel Oil / Two Tanks / 24 Hr	Option 5 - LNG / Bullet Tanks / 48 Hr	Option 6 - LNG / Bullet Tanks / 24 Hr	Option 7 - LNG / F&E Tank / 48 Hr	Option 8 - LNG / F&E Tank / 24 Hr
Fixed O&M Costs								
Additional Fixed O&M Annual Cost, $/yr[2]	$ 458,000	$ 458,000	$ 458,000	$ 458,000	$ 328,000	$ 328,000	$ 313,000	$ 313,000
LNG Boil-Off Makeup, $/yr[9]					$ 1,120,000	$ 560,000	$ 2,800,000	$ 1,400,000
Total Additional Fixed O&M Annual Cost, $/yr[2,4,9]	**$ 458,000**	**$ 458,000**	**$ 458,000**	**$ 458,000**	**$ 1,448,000**	**$ 888,000**	**$ 3,113,000**	**$ 1,713,000**
Variable O&M Costs								
Additional Demineralized Water Cost, $/MWhr[5]	$ 0.96	$ 0.96	$ 0.96	$ 0.96	$ -	$ -	$ -	$ -
Additional Demineralized Water Cost, $/yr[3]	$ 28,000	$ 28,000	$ 28,000	$ 28,000	$ -	$ -	$ -	$ -
Additional Levelized CTG Major Maintenance, $/CT-start[7,8]	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ -	$ -	$ -	$ -
Additional Levelized CTG Major Maintenance, $/yr[7]	$ 101,000	$ 101,000	$ 101,000	$ 101,000	$ -	$ -	$ -	$ -
Total Additional Variable O&M Annual Cost, $/yr[3]	**$ 129,000**	**$ 129,000**	**$ 129,000**	**$ 129,000**	**$ -**	**$ -**	**$ -**	**$ -**

Notes:

1. O&M costs shown are additional O&M to be added to plant existing O&M due to backup fuel implementation option.
2. Based on 2 Full-Time Equivalents (FTE) for fuel oil and 1 FTE for LNG. Assumes cost of $150,000 per FTE.
3. O&M costs shown are based on 50 annual hours of operation on backup fuel per CTG (150 hours for plant).
4. Includes additional fixed annual O&M and LNG boil-off makeup (if applicable).
5. Includes raw water supply costs and demineralized trailer costs. Based on $3.70/kgal for raw water and $6,920/demin trailer for 200 kgal demin water.
6. Total Variable O&M does not include fuel cost for operation.
7. Additional major maintenance costs due to fuel oil operation compared to natural gas operation. Assumes $9,330/GT-start for natural gas operation and 1.3 factor for fuel oil start. Assumes 12 starts/unit each year on fuel oil.
8. Costs shown per start on backup fuel per CTG.
9. Based on $1.00/gallon LNG and $2.60/gallon ULSD.
10. Estimated fuel usage costs for 150 total hours of operation on backup fuel (50 per CTG) is $5.8 million for fuel oil and $3.8 million for LNG (2017 dollars).

4.3 PROJECT SCHEDULES

A level 1 project schedule was developed to represent expected engineering/permitting, procurement, and construction project durations for all options evaluated in this assessment. At this screening level of study, it is likely a safe assumption that schedule durations would be similar between fuel oil and LNG options, which are based on duration discussions with long lead equipment suppliers. Lead times for combustion turbine dual fuel implementation and LNG equipment represent the most significant risk to the project schedule.

4.4 PERFORMANCE SUMMARY

BMcD inquired about maintenance and performance-related impacts directly related to fuel oil operations for the 501 FD2. Siemens provided generic, new and clean fuel oil performances for the 501 FD2, which are included in the performance summary below. Therefore, the performance impacts captured in this assessment are preliminary, yet representative, and will remain preliminary until Siemens is able to provide unit specific performances. Combustion turbine performance will decrease on fuel oil operation and will require additional auxiliary loads (pumps and possibly heaters). Existing auxiliary loads were not determined at this level of the study and, therefore, were not considered in the performance summary below (all existing normal auxiliary loads were assumed to be operating during fuel oil and LNG operation). Fuel oil operation decreases available hours and starts before major maintenance is required but is not expected to significantly impact reliability. LNG performance is expected to be similar to existing natural gas operation since the resultant fuels are similar. However, LNG will require additional auxiliary loads (pumps) beyond normal natural gas operation. Table 4-4 summarizes the performance impacts for the two fuel options.

Table 4-4: Performance Summary

	Fuel Oil Delta Performance		**LNG Delta Performance**	
	Minimum (3 F)	*Annual Average (58 F)*	*Minimum (3 F)*	*Annual Average (58 F)*
Estimated Performance Deltas				
Additional Auxiliary Loads, MW	2.9	1.6	0.7	0.7
Estimated Net Plant Output Delta, MW	-22.8	-20.0	-0.7	-0.7
Estimated Net Plant Heat Rate Delta, Btu/kWh (HHV)	-110	-130	10	10

5.0 SITING AND FUEL SUPPLY RESOURCES

In order to meet PJM's Capacity Performance requirements for operation durations, both fuel oil and LNG backup fuel options will require on-site storage, which demand sufficient site space for both modification of existing BOP equipment and storage, depending on required continuous run-time capacity (24 hour or 48 hour).

5.1 FUEL OIL SITING

The fuel oil implementation space requirements depend on the storage capacity (24 hour or 48 hour) for fuel oil and demineralized water, and the number of storage tanks. Based on current information about the Bluegrass site, the plant is expected to have sufficient space for each fuel oil option evaluated in this assessment, as depicted in the GA sketches in Appendix A.

5.2 LNG SITING

LNG backup fuel space requirements depend on the storage capacity (24 hour or 48 hour) and type of tank storage (i.e. bullet tanks or field erected tanks). The LNG options considered in this assessment are based on bullet tank storage and consume most of the available space on-site, as shown in the GA sketches in Appendix A.

5.3 FUEL SUPPLY AVAILABILITY AND LOGISTICS

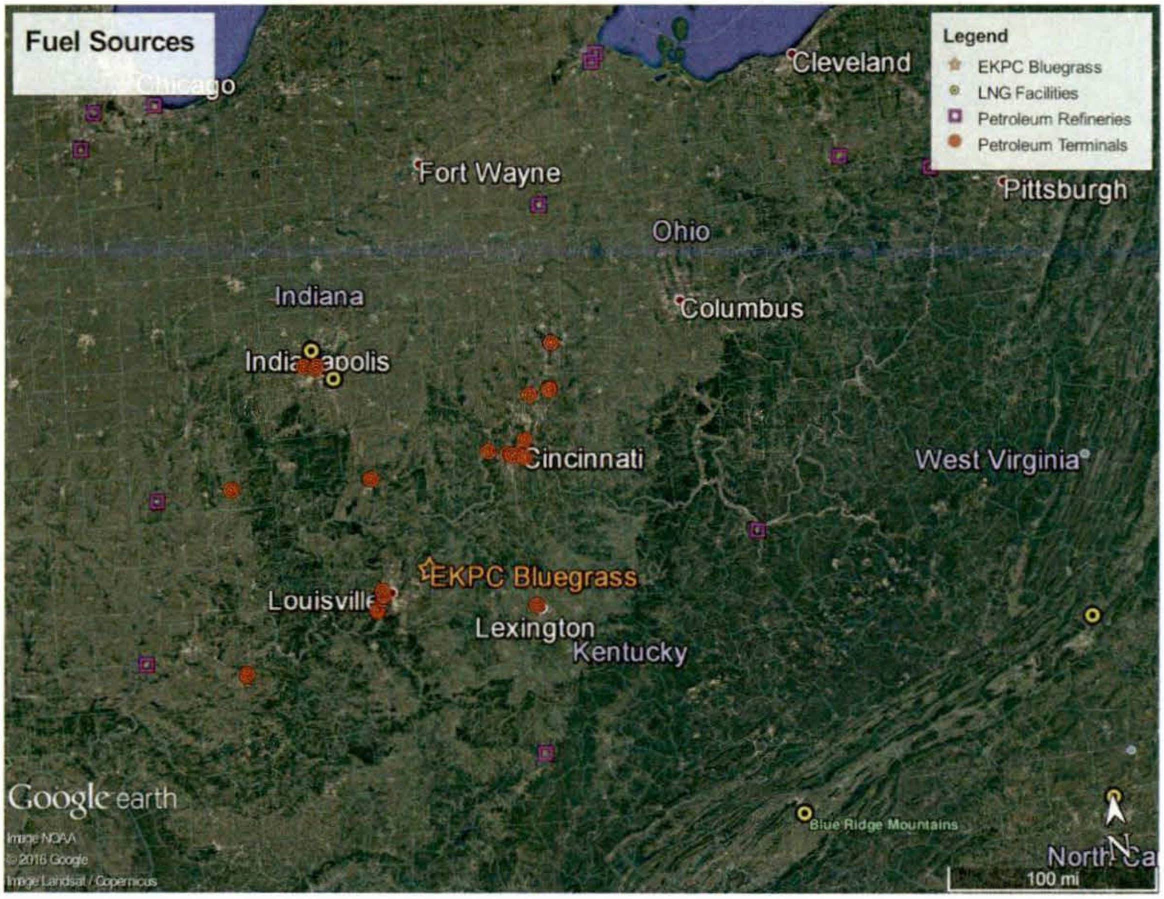
BMcD conducted an assessment of ULSD and LNG supply infrastructure in the region of Bluegrass to ascertain the level of supply resources potentially available.

Information regarding pipeline natural gas supply resources is widely available via commercial subscriptions, and each pipeline company publishes data about its system such as unsubscribed capacity, historical operating pressure, and pipeline diameter. However, petroleum and LNG product pipeline and terminal details are much less transparent due to federal regulations regarding dissemination and use of such data. As such, details regarding flow rates, usage factors, and specific products carried in the pipelines are available to operators and federal, state, and local government officials only. The following sections outline potential sources of these fuels.

5.3.1 On-Road Truck Delivery

An average terminal will often be capable of loading up to a dozen trucks simultaneously (fuel oil and LNG). However, physical space requirements and economic feasibility limit Bluegrass to two truck unloading bays. Each truck takes approximately 45 minutes to unload. State regulations vary, but common tanker trucks are limited to between 7,500 and 9,600 gallons of liquid fuel capacity due to weight limit ratings, with 7,500 gallons being the most common limit. This results in a tank refill rate of approx. 20,000 gallons per hour assuming 7,500-gallon trucks continuous unload at 45 minutes each, with two unloading stations. A truck route around the plant to the unloading areas has been included in each option with a truck turnaround to minimize plant impact to truck delivery logistics. Figure 5-1 shows fuel oil terminals, refineries and LNG facilities near Bluegrass discovered based on a cursory review.

Figure 5-1: Fuel Supply Source Map



During full-load operation, Bluegrass has the capacity to consume approximately 15,000 gallons of fuel oil per hour per unit (45,000 gallons per hour total) and 25,600 gallons of LNG per hour per unit (76,800 gallons per hour total). Therefore, although truck deliveries during fuel oil and LNG usage can extend the usage periods, the Bluegrass units would not be able to run indefinitely on either backup fuel. Table 5-1 provides an overview of the logistical considerations associated with refueling activities at Bluegrass, assuming an emergency backup fuel operation scenario with 16 hours per day dispatch at the plant.

Table 5-1: On-Road Truck ULSD and LNG Delivery Logistics

		Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8
Demand	Tank Storage, gal	2,310,000	1,160,000	2,310,000	1,160,000	3,837,000	1,919,000	3,837,000	1,919,000
	Hourly Consumption	45,000	45,000	45,000	45,000	76,800	76,800	76,800	76,800
	Daily Consumption (16 hrs)	720,000	720,000	720,000	720,000	1,228,800	1,228,800	1,228,800	1,228,800
	Daily Trucks to Replenish (24 hrs)	96	96	96	96	164	164	164	164
	Trucks/Hr Required	4	4	4	4	7	7	7	7
Supply	Terminals w/in 50-Mile Radius	11	11	11	11	1*	1*	1*	1*
	Average Distance to Terminals (Mi.)	31.0	31.0	31.0	31.0	98.0	98.0	98.0	98.0
	Distance to Nearest Terminal (Mi.)	24.0	24.0	24.0	24.0	98.0	98.0	98.0	98.0
	Best Case Round Trip Miles / Truck	48.0	48.0	48.0	48.0	196.0	196.0	196.0	196.0
	Average Speed (MPH)	35	35	35	35	35	35	35	35
	Load/Unload Time (hrs)	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
	Total Delivery Route Time (hrs)	2.9	2.9	2.9	2.9	7.1	7.1	7.1	7.1
	Drivers Required / Hour	**12.0**	**12.0**	**12.0**	**12.0**	**49.0**	**49.0**	**49.0**	**49.0**
	Hours Required to Fill Storage	**116**	**58**	**116**	**58**	**192**	**96**	**192**	**96**
	Maximum Continuous Operation (hrs)**	**69**	**35**	**69**	**35**	**61**	**30**	**61**	**30**

*Closest discovered LNG terminal is 98 miles from Bluegrass

**Based on three-unit operation at baseload. Assumes truck unloading (from two trucks) occurs continuously throughout operation with no truck logistic limitations due to weather/number of drivers/distance traveled. This indicates the max number of continuous operation hours before units must be shutdown to refill fuel storage.

As depicted in Table 5-1, because of the storage requirements and distance from terminals, Bluegrass could experience supply-related issues for fuel oil and LNG because of the number of trucks required to replenish fuel from a 16-hour dispatch. A complete refill of total storage will require multiple days of continuous truck delivery and several truck drivers. There are more supply sources for ULSD near Bluegrass than for LNG which could result in greater supply risk for LNG. The 48-hour storage options would satisfy multiple consecutive day 16-hour dispatch while the 24-hour storage options would have to rely on adequate truck delivery during multiple day 16-hour dispatch to meet fuel requirements.

Weather and road conditions are key risk factors associated with utilizing on-road truck delivery of ULSD and LNG. During a backup fuel usage event, severe cold combined with potentially dangerous road conditions may significantly reduce the resupply rate.

5.3.2 Pipeline and Barge Fuel Supply

Pipeline supply of fuel oil or LNG is a possible option for fuel supply but would require extensive and expensive infrastructure upgrades. Due to substantial costs and permitting implications, pipeline supply was not evaluated in this assessment.

Additionally, barge supply is not a viable solution for fuel delivery to Bluegrass since the plant is not located directly along a major navigable River.

6.0 PERMITTING CONSIDERATIONS

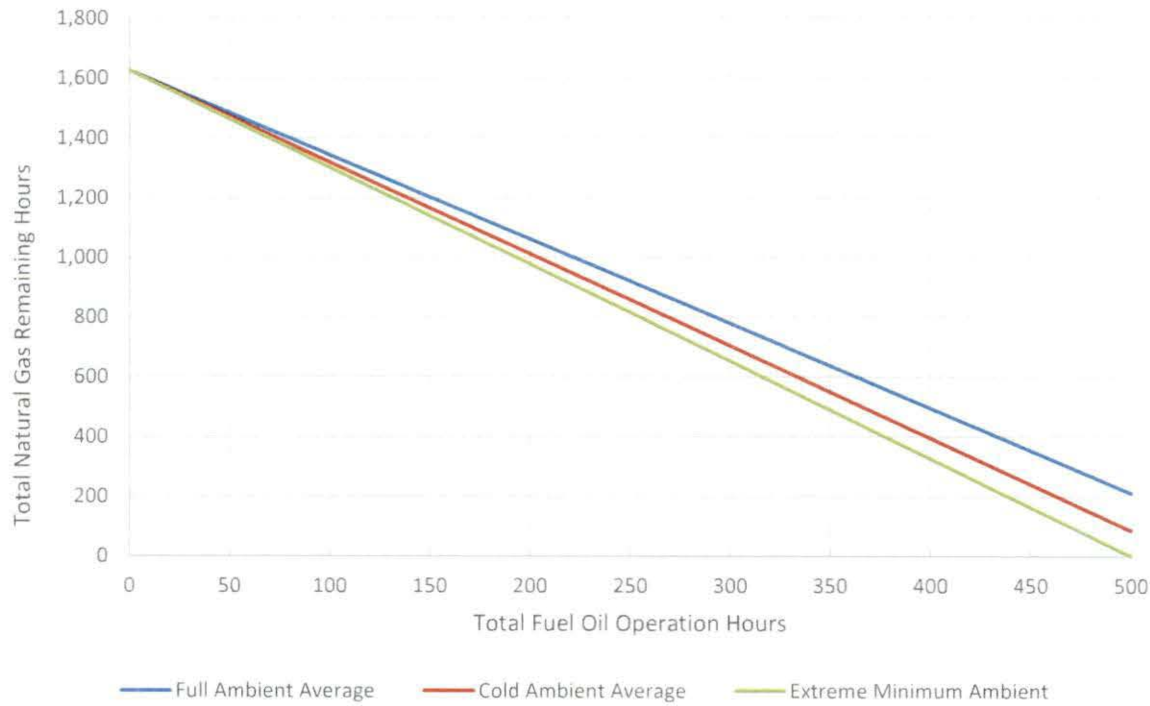
A permit matrix for the project has been developed and included in Appendix E that covers all the permits expected to be required for each backup fuel option. Both backup fuels will require modifications to the existing air permit. LNG is expected to add two minor emissions sources (flare and fired vaporizer). Fuel oil is not expected to add new emissions sources but will require modifications to the existing permit for the fuel change.

BMcD understands that EKPC's permitting approach would limit plant operating hours on the backup fuel and the primary fuel (natural gas) as required to avoid triggering the PSD process. Even though the permitting changes for dual fuel operation are not expected to trigger PSD permitting actions, the switch to fuel oil or LNG could be considered a monitoring change by the state and therefore a significant revision. A significant revision could take approximately 18 months to complete the permitting process, since it is open for public review. The schedule and cost estimate in this report were based on an allowance of 18 months to complete the permitting process.

Expected steady-state emissions were developed for Bluegrass operating on fuel oil. These figures were based on preliminary information provided by Siemens and are summarized in Appendix F. Similar to performances, the Siemens provided emissions information is not site-specific. Therefore, the values in this assessment are preliminary and will remain preliminary until Siemens is able to provide unit specific emissions information. Combustion turbine emissions while operating on LNG are expected to be similar to emissions while operating on natural gas, assuming similar fuel constituencies. Therefore, expected steady-state emissions were not developed for LNG operation.

Since NO_x emissions are the limiting pollutant for Bluegrass and fuel oil NO_x emissions are greater than natural gas NO_x emissions, BMcD developed a chart (Figure 6-1) to indicate the estimated total plant hours available for natural gas operation based on the total plant hours operated on fuel oil. The data in Figure 6-1 was based on existing natural gas emissions information provided by EKPC and preliminary fuel oil emissions information provided by Siemens. The data includes emissions for 40 annual natural gas starts/shutdowns and 12 annual fuel oil starts/shutdowns per combustion turbine (120 and 36 total, respectively).

Figure 6-1: Total Plant Natural Gas vs. Fuel Oil Operation Hours – NOx Limit

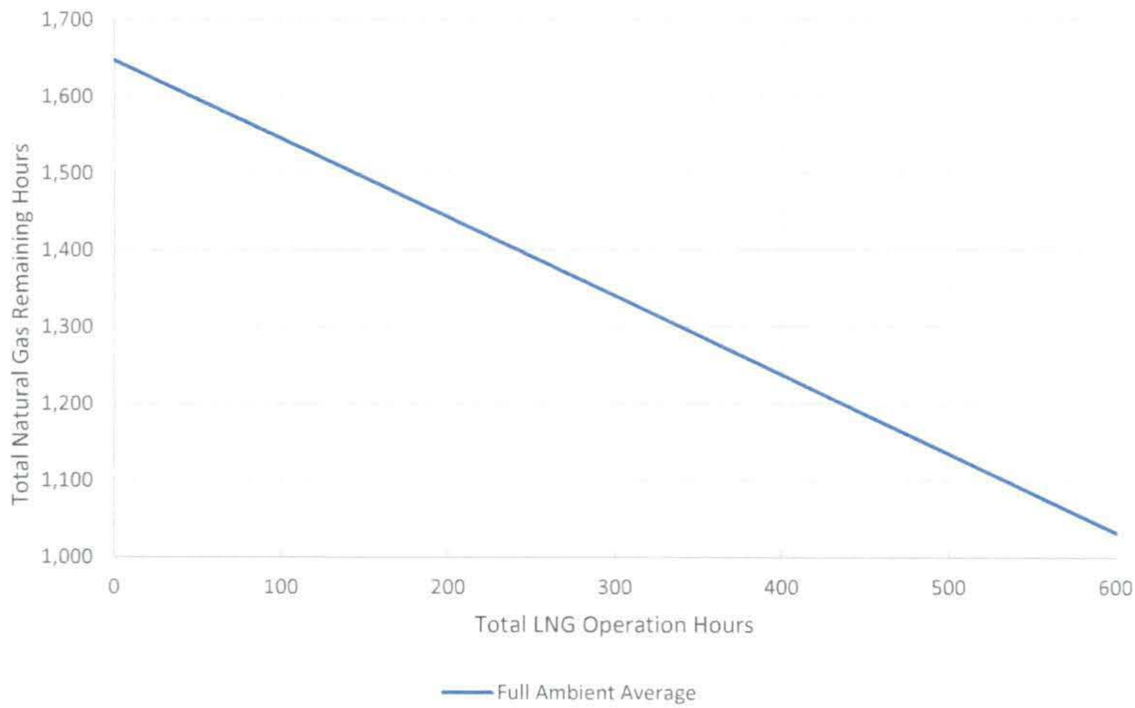


Y = annual hours available for natural gas operation (plant total), X = annual fuel oil operation hours (plant total)
Full Ambient Average: Y = -2.8274*X + 1625
Cold Ambient Average: Y = -3.0800*X + 1625
Extreme Minimum Ambient: Y = -3.2491*X + 1625

Based on natural gas information provided by EKPC, the maximum annual available hours for natural gas operation (no fuel oil operation) after startup and shutdown emissions is 1,625 hours (ambient dependent). As fuel oil operation hours increase, the available natural gas operation hours decrease at an approximate ratio of 3:1 because fuel oil NO_x emissions are higher than natural gas NO_x emissions, as shown in Figure 6-1. For example, after 50 hours of fuel oil operation per unit (150 total fuel oil hours), there would only be about 1,160 total hours available for natural gas operation (387 hours per unit).

A chart was also developed for NO_x emissions limitations based on LNG operation and using the same natural gas emissions data from EKPC. Combustion turbine NO_x emissions are expected to be the same for LNG and natural gas operation. However, the addition of LNG equipment does require two new emissions sources. The fired vaporizer used to regenerate the gas will emit NO_x whenever the facility operates on LNG, and the flare will periodically burn boil-off gas and emit NO_x independent of LNG operation. Both NO_x emission rates have been included in Figure 6-2.

Figure 6-2: Total Plant Natural Gas vs. LNG Operation Hours – NOx Limit



Y = annual hours available for natural gas operation (plant total), X = annual LNG operation hours (plant total)
Full Ambient Average: Y = -1.0258*X + 1648
*Flare will burn LNG storage boil-off, which will contribute NO_x emissions independent of plant operation on LNG. This will reduce estimated available natural gas operation hours from 1,810 to 1,767.

The maximum annual available hours for natural gas operation (no LNG operation), assuming 40 annual starts/shutdowns per CTG, is 1,648 hours (ambient dependent) due to boil-off gas flare operation. As LNG operation hours increase the available natural gas operation hours decrease because of the vaporizer emissions, as shown in Figure 6-2. For example, after 50 hours of LNG operation per unit (150 total LNG hours), there would be about 1,494 hours available for natural gas operation (498 hours per unit). LNG operation does not reduce available natural gas hours as much as fuel oil operation does.

6.1 LNG PERMITTING AND REGULATIONS

The expected permitting process for a new LNG facility could take approximately 18 months (depending on public response to the air permit), during which multiple agencies and organizations must be contacted and some may require permits. Non-state agencies involved in the permitting process include the EPA and federal Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). The EPA also requires a robust Risk Management Plan due to the transfer of LNG to the facility because it is considered Category 1 hazardous liquid. PHMSA does not require a permit, but a detailed Design Spill Package may be required to aid in the state review process.

The state of Kentucky may require various permits and licenses to build an LNG facility. Additional local requirements include:

- Local fire marshal (or other Authority Having Jurisdiction) involvement and evaluation from the beginning stages
- Forest conservation plan (if applicable)
- Grading permit
- Erosion and Sedimentation control plan
- Best Management Practices (BMP)

7.0 SUMMARY & CONCLUSIONS

Based on BMcD's assessment of the various backup fuel supply options at Bluegrass, all eight options are considered feasible. Fuel oil offers a lower capital cost option than LNG but requires modifications to the combustion turbines. All options should fit on-site, but LNG options 5 and 6 with bullet tanks require more space than fuel oil. LNG double wall field erected tank options 7 and 8 require plant space requirements similar to fuel oil. LNG results in better combustion turbine performance and lower additional auxiliary loads than fuel oil. Fuel oil and LNG will require significant logistics planning for truck delivery to fill the storage tanks. Both fuel oil and LNG will require modifications to the existing air permit with similar expected durations.

It is BMcD's understanding that information provided in this assessment will be used by EKPC to evaluate backup fuel options for Bluegrass. If an option is selected, subsequent stages of project definition and cost estimating would be necessary to develop a project budget.

APPENDIX A -CONCEPTUAL GENERAL ARRANGMENTS

EQUIPMENT IDENTIFICATION AND LOCATION LIST	
DWG REF	DESCRIPTION NEW SITE EQUIPMENT
001	NEW SUBSTATION (BY EKPC)
002	FUEL OIL STORAGE TANK (105'-0" DIA)
003	FUEL OIL TANK CONCRETE CONTAINMENT (INSIDE 150'-0" X 150'-0")
004	FUEL OIL FORWARDING PUMP & UNLOADING PUMP CURBED AREA
005	FUEL OIL TRUCK UNLOADING PAD
006	FUEL OIL TRUCK UNLOADING STANCHION
007	FUEL OIL CONTAINMENT AND UNLOADING PAD SUMP
008	DEMINERALIZED WATER TANK (60'-0" DIA)
009	DEMINERALIZED WATER PUMP MAT
010	FUEL OIL INJECTION PUMP SKID
011	WATER INJECTION PUMP SKID
012	FUEL OIL PIPE AND DEMIN PIPE TRENCH
013	FUEL OIL TRUCK UNLOADING TURNAROUND
014	FUEL OIL TRUCK ACCESS ROAD
015	FUEL OIL CONTAIMENT STAIR ACCESS
016	NEW FENCES
017	ELECTRICAL CONDUIT TRENCH
018	POC
019	FUEL OIL INLINE HEATER SKID

PRELIMINARY - NOT FOR CONSTRUCTION

no	date	by	ckd	description
A	03/20/17	MAA		ISSUED FOR OWNER REVIEW

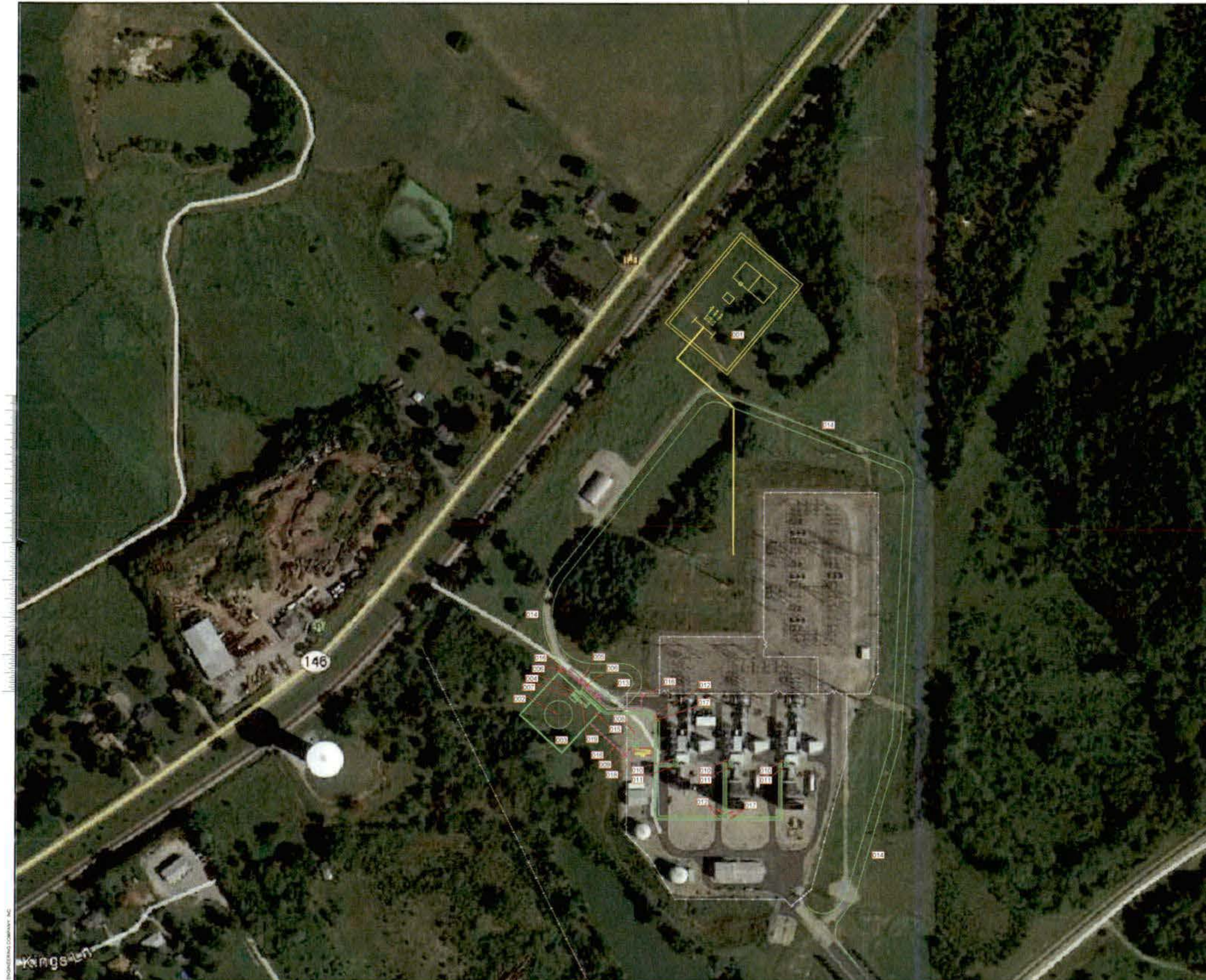
TRUE NORTH
6.5315° PLAN NORTH
NORTH

0 100 200
SCALE IN FEET

BURNS & McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400
FIRM LICENSE NO. 43
designed T. ROBERTSON
detailed M. ATHERTON

EAST KENTUCKY POWER COOPERATIVE
EKPC GENERATION CO. LLC
OLDHAM COUNTY, KENTUCKY

BLUEGRASS STATION
DUEL FUEL PROJECT - OPTION ... FUEL OIL STORAGE LAYOUT (ONE TNK)
project 97273
contract
drawing GA1001
rev — A
sheet 1 of 1 sheets
file 97273GA1000.dwg



DWG REF	EQUIPMENT IDENTIFICATION AND LOCATION LIST DESCRIPTION NEW SITE EQUIPMENT
001	NEW SUBSTATION (BY EKPC)
002	FUEL OIL STORAGE TANK (75'-0" DIA)
003	FUEL OIL TANK CONCRETE CONTAINMENT (150'-0" x 150'-0" INSIDE)
004	FUEL OIL FORWARDING PUMP & UNLOADING PUMP CURBED AREA
005	FUEL OIL TRUCK UNLOADING PAD
006	FUEL OIL TRUCK UNLOADING STANCHION
007	FUEL OIL CONTAINMENT AND UNLOADING PAD SUMP
008	DEMINERALIZED WATER TANK (45'-0" DIA)
009	DEMINERALIZED WATER PUMP MAT
010	FUEL OIL INJECTION PUMP SKID
011	WATER INJECTION PUMP SKID
012	FUEL OIL PIPE AND DEMIN PIPE TRENCH
013	FUEL OIL TRUCK UNLOADING TURNAROUND
014	FUEL OIL TRUCK ACCESS ROAD
015	FUEL OIL CONTAIMENT STAIR ACCESS
016	NEW FENCES
017	ELECTRICAL CONDUIT TRENCH
018	PDC
019	FUEL OIL INLINE HEATER SKID

PRELIMINARY - NOT FOR CONSTRUCTION

EXHIBIT G - Attachment SY-2
Page 35 of 62

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TRUE NORTH
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NORTH

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9400 WARD PARKWAY
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816-333-9400
FIRM LICENSE NO. 43

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detailed: M. ATHERTON

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EKPC GENERATION CO. LLC
OLDHAM COUNTY, KENTUCKY

BLUEGRASS STATI[illegible]
DUEL FUEL PROJECT - OPTION [illegible] FUEL
OIL STORAGE LAYOUT (ONE TNK)

project: 97273
contract:
drawing: GA1002
rev: — A
sheet 1 of 1 sheets
file: 97273GA1000.dwg

EQUIPMENT IDENTIFICATION AND LOCATION LIST	
DWG REF	DESCRIPTION NEW SITE EQUIPMENT
001	NEW SUBSTATION (BY EKPC)
002	FUEL OIL STORAGE TANKS (2 X 75'-0" DIA EACH)
003	FUEL OIL TANK CONCRETE CONTAINMENT (200'-0" X 100'-0" INSIDE)
004	FUEL OIL FORWARDING PUMP & UNLOADING PUMP CURBED AREA
005	FUEL OIL TRUCK UNLOADING PAD
006	FUEL OIL TRUCK UNLOADING TIE-IN
007	FUEL OIL CONTAINMENT AND UNLOADING PAD SUMP
008	DEMINERALIZED WATER TANK (60'-0" DIA)
009	DEMINERALIZED WATER PUMP MAT
010	FUEL OIL INJECTION PUMP SKID
011	WATER INJECTION PUMP SKID
012	FUEL OIL PIPE AND DEMIN PIPE TRENCH
013	FUEL OIL TRUCK UNLOADING TURNAROUND
014	FUEL OIL TRUCK ACCESS ROAD
015	FUEL OIL CONTAIMENT STAIR ACCESS
016	NEW FENCES
017	ELECTRICAL CONDUIT TRENCH
018	PDC
019	FUEL OIL INLINE HEATER SKID

EXHIBIT G - Attachment SY-2
Page 36 of 62

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TRUE NORTH
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SCALE IN FEET

BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400
FIRM LICENSE NO. 43

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EAST KENTUCKY POWER COOPERATIVE
EKPC GENERATION CO. LLC
OLDHAM COUNTY, KENTUCKY

BLUEGRASS STATI[illegible]
DUEL FUEL PROJECT - OPTION [illegible] UEL
OIL STORAGE LAYOUT (TWO TANKS)

project: 97273 | contract:
drawing: GA1003 | rev: – A
sheet 1 of 1 sheets
file 97273GA1000.dwg

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EQUIPMENT IDENTIFICATION AND LOCATION LIST	
DWG REF	DESCRIPTION NEW SITE EQUIPMENT
001	NEW SUBSTATION (BY EKPC)
002	FUEL OIL STORAGE TANKS (2 X 52'-0" DIA EACH)
003	FUEL OIL TANK CONCRETE CONTAINMENT (150'-0" X 100'-0" INSIDE)
004	FUEL OIL FORWARDING PUMP & UNLOADING PUMP CURBED AREA
005	FUEL OIL TRUCK UNLOADING PAD
006	FUEL OIL TRUCK UNLOADING TIE-IN
007	FUEL OIL CONTAINMENT AND UNLOADING PAD SUMP
008	DEMINERALIZED WATER TANK (45'-0" DIA)
009	DEMINERALIZED WATER PUMP MAT
010	FUEL OIL INJECTION PUMP SKID
011	WATER INJECTION PUMP SKID
012	FUEL OIL PIPE AND DEMIN PIPE TRENCH
013	FUEL OIL TRUCK UNLOADING TURNAROUND
014	FUEL OIL TRUCK ACCESS ROAD
015	FUEL OIL CONTAIMENT STAIR ACCESS
016	NEW FENCES
017	ELECTRICAL CONDUIT TRENCH
018	PDC
019	FUEL OIL INLINE HEATER SKID

EXHIBIT G - Attachment SY-2
Page 37 of 62

PRELIMINARY - NOT FOR CONSTRUCTION

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A	03/20/17	MAA		ISSUED FOR OWNER REVIEW

TRUE NORTH
6.5315° PLAN NORTH
NORTH

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SCALE IN FEET

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9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400
FIRM LICENSE NO. 43

designed: T. ROBERTSON
detailed: M. ATHERTON

EAST KENTUCKY POWER COOPERATIVE
EKPC GENERATION CO. LLC
OLDHAM COUNTY, KENTUCKY

BLUEGRASS STATION
DUEL FUEL PROJECT - OPTION [illegible] FUEL OIL STORAGE LAYOUT (TWO TANKS)

project: 97273
contract:
drawing: GA1004
rev: – A
sheet 1 of 1 sheets
file: 97273GA1000.dwg

EQUIPMENT IDENTIFICATION AND LOCATION LIST

DWG REF	DESCRIPTION NEW SITE EQUIPMENT
001	NEW SUBSTATION (BY EKPC)
002	LNG BULLET STORAGE TANKS (28 - 190'-0" LONG X 12'-6" DIA EACH)
003	BERM CONTAINMENT
004	LNG BULLET STORAGE TANKS (2 - 190'-0" LONG X 12'-6" DIA EACH)
005	BOOSTER PUMP SKIDS (3 X 50%)
006	FLARE
007	VAPORIZERS
008	PRESSURE & FLOW CONTROL SKID
009	LNG TRUCK UNLOADING
010	LNG TRUCK UNLOADING TURNAROUND
011	LNG TRUCK ACCESS ROAD
012	EXISTING WAREHOUSE LOCATION
013	RELOCATED WAREHOUSE LOCATION
014	PDC
015	ELECTRICAL CONDUIT TRENCH
016	LNG PIPE TRENCH

PRELIMINARY - NOT FOR CONSTRUCTION

EXHIBIT G - Attachment SY-2
Page 38 of 62

no	date	by	ckd	description
A	03/20/17	MAA		ISSUED FOR OWNER REVIEW

TRUE NORTH
6°53'15"
PLAN NORTH
NORTH
0 100 200
SCALE IN FEET

BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400
FIRM LICENSE NO. 43

designed: C. SWOPE
detailed: M. ATHERTON

EAST KENTUCKY POWER COOPERATIVE
EKPC GENERATION CO. LLC
OLDHAM COUNTY, KENTUCKY

BLUEGRASS STATION
DUEL FUEL PROJECT - OPTION FOUR
LNG STORAGE LAYOUT

project: 97273
contract:
drawing: GA1005
rev: - A
sheet 1 of 1 sheets
file: 97273GA1000.dwg

DWG REF	EQUIPMENT IDENTIFICATION AND LOCATION LIST DESCRIPTION NEW SITE EQUIPMENT
001	NEW SUBSTATION (BY EKPC)
002	LNG BULLET STORAGE TANKS (42 - 190'-0" LONG X 12'-6" DIA EACH)
003	BERM CONTAINMENT
004	LNG BULLET STORAGE TANKS (3 - 190'-0" LONG X 12'-6" DIA EACH)
005	BOOSTER PUMP SKIDS (3 X 50%)
006	FLARE
007	VAPORIZERS
008	PRESSURE & FLOW CONTROL SKID
009	LNG TRUCK UNLOADING
010	LNG TRUCK UNLOADING TURNAROUND
011	LNG TRUCK ACCESS ROAD
012	EXISTING WAREHOUSE LOCATION
013	RELOCATED WAREHOUSE LOCATION
014	PDC
015	ELECTRICAL CONDUIT TRENCH
016	LNG PIPE TRENCH

PRELIMINARY - NOT FOR CONSTRUCTION

no	date	by	ckd	description
A	03/20/17	MAA		ISSUED FOR OWNER REVIEW

TRUE NORTH 6.5315° PLAN NORTH

NORTH

0 100 200 SCALE IN FEET

BURNS & McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400
FIRM LICENSE NO. 43

designed: C. SWOPE | detailed: M. ATHERTON

EAST KENTUCKY POWER COOPERATIVE
EKPC GENERATION CO. LLC
OLDHAM COUNTY, KENTUCKY

BLUEGRASS STAT...
DUEL FUEL PROJECT - OPTIO... ...UR
LNG STORAGE LAYOUT

project: 97273 | contract:
drawing: GA1006 | rev: A
sheet 1 of 1 sheets
file: 97273GA1000.dwg

EQUIPMENT IDENTIFICATION AND LOCATION LIST

DWG REF	DESCRIPTION NEW SITE EQUIPMENT
001	NEW SUBSTATION (BY EKPC)
002	LNG STORAGE TANK (105' 6" DIA)
003	BERM CONTAINMENT
004	PDC
005	BOOSTER PUMP SKIDS (3 X 50%)
006	FLARE
007	VAPORIZERS
008	PRESSURE & FLOW CONTROL SKID
009	LNG TRUCK UNLOADING
010	LNG TRUCK UNLOADING TURNAROUND
011	LNG TRUCK ACCESS ROAD
012	ELECTRICAL CONDUIT TRENCH
013	LNG PIPE TRENCH
014	NEW FENCES

EXHIBIT G - Attachment SY-2
Page 40 of 62

PRELIMINARY - NOT FOR CONSTRUCTION

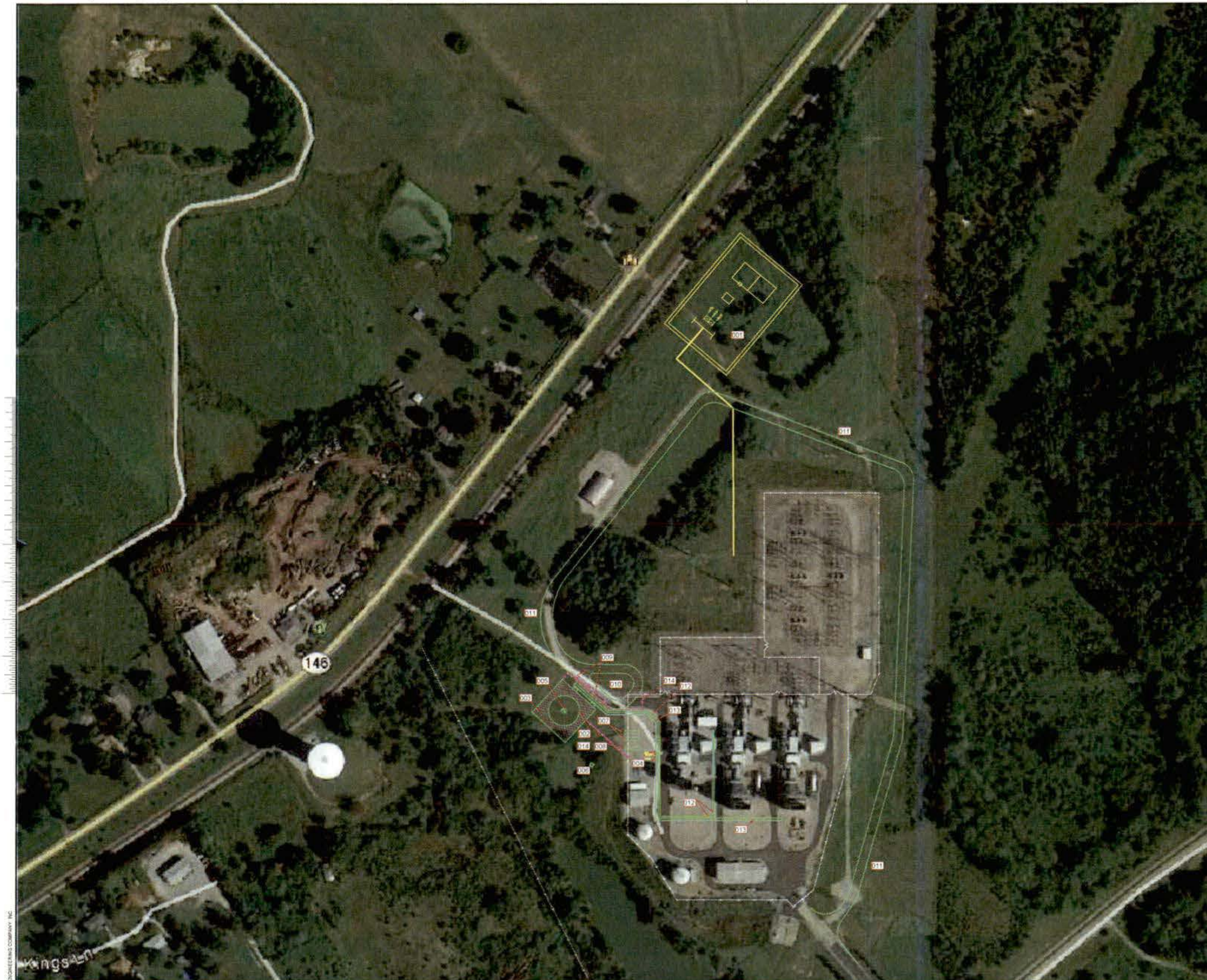
no.	date	by	ckd	description
A	03/28/17	MAA		WORKING COPY

TRUE NORTH
6°53'15"
PLAN NORTH
NORTH
SCALE IN FEET

BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400
FIRM LICENSE NO. 43
designed C. SWOPE
detailed M. ATHERTON

EAST KENTUCKY POWER COOPERATIVE
EKPC GENERATION CO. LLC
OLDHAM COUNTY, KENTUCKY

BLUEGRASS STATION
DUEL FUEL PROJECT - OPTION ...
LNG F/E STORAGE LAYOUT
project 97273
contract
drawing GA1007
rev — A
sheet 1 of 1 sheets
file 97273GA1000.dwg



EQUIPMENT IDENTIFICATION AND LOCATION LIST

DWG REF	DESCRIPTION NEW SITE EQUIPMENT
001	NEW SUBSTATION (BY EKPC)
002	LNG STORAGE TANK (82'-0" DIA)
003	BERM CONTAINMENT
004	PDC
005	BOOSTER PUMP SKIDS (3 X 50%)
006	FLARE
007	VAPORIZERS
008	PRESSURE & FLOW CONTROL SKID
009	LNG TRUCK UNLOADING
010	LNG TRUCK UNLOADING TURNAROUND
011	LNG TRUCK ACCESS ROAD
012	ELECTRICAL CONDUIT TRENCH
013	LNG PIPE TRENCH
014	NEW FENCES

PRELIMINARY - NOT FOR CONSTRUCTION

EXHIBIT G - Attachment SY-2
Page 41 of 62

no	date	by	ckd	description
A	03/28/17	MAA		WORKING COPY

TRUE NORTH
6°53'15"
PLAN NORTH
NORTH

0 100' 200'
SCALE IN FEET

BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400
FIRM LICENSE NO. 43

designed: C. SWOPE | detailed: M. ATHERTON

EAST KENTUCKY POWER COOPERATIVE
EKPC GENERATION CO, LLC
OLDHAM COUNTY, KENTUCKY

BLUEGRASS STATION
DUEL FUEL PROJECT - OPTION 24 HOUR
LNG F/E STORAGE LAYOUT

project: 97273 | contract:
drawing: GA1008 | rev: A
sheet 1 of 1 sheets
file: 97273GA1000.dwg

APPENDIX B -EQUIPMENT LISTS

BURNS McDONNELL

Equipment List

East Kentucky Power Cooperative
Bluegrass Station - Backup Fuel Assessment (Fuel Oil Options)
Project No. 97273

Equipment Name/Description	Skid Name	Motor Rating / Rated Load / Capacity	Options	Notes
Fuel Oil Pump (Unit 1)	Fuel Oil Pump Skid	400 hp	1,2,3,4	Gas Turbine Supplier
Fuel Oil Pump (Unit 2)	Fuel Oil Pump Skid	400 hp	1,2,3,4	Gas Turbine Supplier
Fuel Oil Pump (Unit 3)	Fuel Oil Pump Skid	400 hp	1,2,3,4	Gas Turbine Supplier
Water Injection Pump (Unit 1)	Fuel Oil Water Injection Skid	250 hp	1,2,3,4	Gas Turbine Supplier
Water Injection Pump (Unit 2)	Fuel Oil Water Injection Skid	250 hp	1,2,3,4	Gas Turbine Supplier
Water Injection Pump (Unit 3)	Fuel Oil Water Injection Skid	250 hp	1,2,3,4	Gas Turbine Supplier
Stage A Fuel Oil Flow Divider (Unit 1)	Fuel Oil Water Injection Skid	0.33 hp	1,2,3,4	Gas Turbine Supplier
Stage B Fuel Oil Flow Divider (Unit 1)	Fuel Oil Water Injection Skid	0.33 hp	1,2,3,4	Gas Turbine Supplier
Pilot Fuel Oil Flow Divider (Unit 1)	Fuel Oil Water Injection Skid	0.33 hp	1,2,3,4	Gas Turbine Supplier
Stage A Fuel Oil Flow Divider (Unit 2)	Fuel Oil Water Injection Skid	0.33 hp	1,2,3,4	Gas Turbine Supplier
Stage B Fuel Oil Flow Divider (Unit 2)	Fuel Oil Water Injection Skid	0.33 hp	1,2,3,4	Gas Turbine Supplier
Pilot Fuel Oil Flow Divider (Unit 2)	Fuel Oil Water Injection Skid	0.33 hp	1,2,3,4	Gas Turbine Supplier
Stage A Fuel Oil Flow Divider (Unit 3)	Fuel Oil Water Injection Skid	0.33 hp	1,2,3,4	Gas Turbine Supplier
Stage B Fuel Oil Flow Divider (Unit 3)	Fuel Oil Water Injection Skid	0.33 hp	1,2,3,4	Gas Turbine Supplier
Pilot Fuel Oil Flow Divider (Unit 3)	Fuel Oil Water Injection Skid	0.33 hp	1,2,3,4	Gas Turbine Supplier
Gas Turbine Hardware (Support Housing and Duel Fuel Pilot Nozzles)	Fuel Oil Water Injection Skid		1,2,3,4	Gas Turbine Supplier
Demineralized Water Transfer Pump 1 (4x33%)	Demineralized Water Pump	20 hp	1,2,3,4	
Demineralized Water Transfer Pump 2 (4x33%)	Demineralized Water Pump	20 hp	1,2,3,4	
Demineralized Water Transfer Pump 3 (4x33%)	Demineralized Water Pump	20 hp	1,2,3,4	
Demineralized Water Transfer Pump 4 (4x33%)	Demineralized Water Pump	20 hp	1,2,3,4	
Fuel Oil Unloading 1 Pump A (2x100%)	Fuel Oil Unloading Skid 1	15 hp	1,2,3,4	
Fuel Oil Unloading 1 Pump B (2x100%)	Fuel Oil Unloading Skid 1	15 hp	1,2,3,4	
Fuel Oil Unloading 2 Pump A (2x100%)	Fuel Oil Unloading Skid 2	15 hp	1,2,3,4	
Fuel Oil Unloading 2 Pump B (2x100%)	Fuel Oil Unloading Skid 2	15 hp	1,2,3,4	
Fuel Oil Forwarding Pump 1 (4x33%)	Fuel Oil Forwarding Skid	30 hp	1,2,3,4	
Fuel Oil Forwarding Pump 2 (4x33%)	Fuel Oil Forwarding Skid	30 hp	1,2,3,4	
Fuel Oil Forwarding Pump 3 (4x33%)	Fuel Oil Forwarding Skid	30 hp	1,2,3,4	
Fuel Oil Forwarding Pump 4 (4x33%)	Fuel Oil Forwarding Skid	30 hp	1,2,3,4	
Fuel Oil Storage Sump Pump (2x100%)		5 hp	1,2,3,4	
Fuel Oil Storage Sump Pump (2x100%)		5 hp	1,2,3,4	
Unit 1 Fuel Oil / Water Injection Pumps Enclosure			1,2,3,4	
Unit 2 Fuel Oil / Water Injection Pumps Enclosure			1,2,3,4	
Unit 3 Fuel Oil / Water Injection Pumps Enclosure			1,2,3,4	
Demineralized Water Storage Tank Option 1 / 3		780,000 gal	1,3	
Demineralized Water Storage Tank Option 2 / 4		390,000 gal	2,4	
Fuel Oil Storage Tank Option 1		2,310,000 gal	1	
Fuel Oil Storage Tank Option 2		1,160,000 gal	2	
Fuel Oil Storage Tanks Option 3 (2 Tanks)		1,160,000 gal (each tank)	3	
Fuel Oil Storage Tanks Option 4 (2 Tanks)		580,000 gal (each tank)	4	
Fuel Oil Inline Heater 1		420 kW	1,2,3,4	
Fuel Oil Inline Heater 2		420 kW	1,2,3,4	
Fuel Oil Inline Heater 3		420 kW	1,2,3,4	
Fuel Oil PDC (15' x 45')			1,2,3,4	
Fuel Oil PDC 4.16kV-480V 2500/3333KVA XFMR #1			1,2,3,4	
Fuel Oil PDC 4.16kV-480V 2500/3333KVA XFMR #2			1,2,3,4	
Fuel Oil PDC 480V 4000A Non-Seg Bus Run #1			1,2,3,4	
Fuel Oil PDC 480V 4000A Non-Seg Bus Run #2			1,2,3,4	
Fuel Oil PDC 480V 4000A SWGR #1			1,2,3,4	
Fuel Oil PDC 480V 4000A SWGR #2			1,2,3,4	
Fuel Oil PDC 480V 2000A MCC #1			1,2,3,4	
Fuel Oil PDC 480V 2000A MCC #2			1,2,3,4	
Fuel Oil PDC 125VDC Battery Charger #1			1,2,3,4	
Fuel Oil PDC 125VDC Battery Charger #2			1,2,3,4	
Fuel Oil PDC 125VDC Battery Rack, Disconnect &			1,2,3,4	
Fuel Oil PDC HVAC #1			1,2,3,4	
Fuel Oil PDC HVAC #2			1,2,3,4	
Unit 1 CO2 Fire Protection System for FO Pump Skid			1,2,3,4	Includes CO2 tank, detection, etc. for new GTG fuel oil pump skid enclosure.
Unit 2 CO2 Fire Protection System for FO Pump Skid			1,2,3,4	Includes CO2 tank, detection, etc. for new GTG fuel oil pump skid enclosure.
Unit 3 CO2 Fire Protection System for FO Pump Skid			1,2,3,4	Includes CO2 tank, detection, etc. for new GTG fuel oil pump skid enclosure.

BURNS & McDONNELL

Equipment List

East Kentucky Power Cooperative
Bluegrass Station - Backup Fuel Assessment (LNG Options)
Project No. 97273

Equipment Name/Description	Skid Name	Motor Rating / Rated Load / Capacity	Options	Notes
LNG Unloading Pump (2x100%)	LNG Unloading Skid	30 hp	5, 6, 7, 8	LNG Supplier
LNG Unloading Pump (2x100%)	LNG Unloading Skid	30 hp	5, 6, 7, 8	LNG Supplier
LNG Booster Pump 1 (3x50%)	LNG Booster Pump Skid 1	430 hp	5, 6, 7, 8	LNG Supplier
LNG Booster Pump 2 (3x50%)	LNG Booster Pump Skid 2	430 hp	5, 6, 7, 8	LNG Supplier
LNG Booster Pump 3 (3x50%)	LNG Booster Pump Skid 3	430 hp	5, 6, 7, 8	LNG Supplier
Fired Water Bath Vaporizer 1 (2x100%)	LNG Vaporizer Skid	55.3 MMBtu/hr	5, 6, 7, 8	LNG Supplier
Fired Water Bath Vaporizer 2 (2x100%)	LNG Vaporizer Skid	55.3 MMBtu/hr	5, 6, 7, 8	LNG Supplier
LNG Pressure Control Manifold	LNG Pressure Manifold Skid		5, 6, 7, 8	LNG Supplier
Odorizer			5, 6, 7, 8	LNG Supplier
LNG Bullet Tanks (30) Option 5		130,000 gal each	5	LNG Supplier
LNG Bullet Tanks (15) Option 6		130,000 gal each	6	LNG Supplier
LNG Fully Contained / Double Wall F&E Tank		3,840,000 gal	7	
LNG Fully Contained / Double Wall F&E Tank		1,920,000 gal	8	
LNG PDC 15' x 25'			5, 6, 7, 8	
LNG PDC 4.16kV-480V 750KVA XFMR #1			5, 6, 7, 8	
LNG PDC 4.16kV-480V 750KVA XFMR #2			5, 6, 7, 8	
LNG PDC 480V 800A MCC #1			5, 6, 7, 8	
LNG PDC 480V 800A MCC #2			5, 6, 7, 8	
LNG PDC HVAC #1			5, 6, 7, 8	
LNG PDC HVAC #2			5, 6, 7, 8	
Booster Fire Water Pump	Booster Fire Water Pump		5, 6, 7, 8	
Gas and Flame Detection System			5, 6, 7, 8	At unloading, storage and booster areas.

APPENDIX C -SCOPE ASSUMPTIONS MATRIX

BURNS & McDONNELL

		Y/N	Number	% Capacity (per Unit)	Notes
GENERAL PROJECT INFORMATION					
Project Description					
	Project Location				Near La Grange, KY.
	Site Description				Existing brownfield site at Bluegrass Station.
	Contracting Approach				Multi-prime.
	Labor				Union.
	Project Liquidated Damages				TBD.
	Project Bonding /LOC				100% Bonding.
	Project COD Dates				December 2020.
	Project Expansion				No future expansion considered; Combined Cycle location not considered and SCR remains decommissioned.
MECHANICAL EQUIPMENT					
AQUEOUES AMMONIA SYSTEM					
	Ammonia Flow Control Skid	N			
	Ammonia Forwarding Pump Skid	N			
	Ammonia Storage Tank	N			
	Ammonia Unloading Skid	N			
	SCR Ammonia Distribution Grid	N			
	SCR Catalyst	N			
	Detection				
DEMINERALIZED WATER SYSTEM					
	Demineralized Water Transfer Pumps	Y	4	33	1 x 100% for each unit with 1 x 100% common spare.
	Demineralized Water Storage Tank	Y	1	100	Add new 780,000 gal tank for 48-hours (390,000 gal tank for 24-hours) of fuel oil operation in addition to existing 300,000 gallon tank.
	Demineralized Water Trailers	N			Existing connections for Demin Trailer which handles 200 gpm.
CLOSED COOLING WATER					
	CCW Heat Exchanger	N			
	CCW pumps	N			
	Glycol type	N			
FUEL OIL					
	Storage	Y	1		Fuel Oil Tank sizing for each option: - 2,310,000 gal single tank for 48 hr storage - 1,160,000 gal single tank for 24 hr storage - Two (2) 1,160,000 gal tanks for 48 hr storage - Two (2) 580,000 gal tanks for 24 hr storage All tank options will be in concrete containment sized to contain largest tank volume.
	Transfer Pumps	Y	4	33	1 x 100% for each unit with 1 x 100% common spare located near fuel oil tank.
	Unloading	Y	2	100	Two (2) truck unloading stations, each with 2 x 100% unloading pumps.
	Heating	Y	3	33	3 x 33% inline electric heaters with recirculation system.
MAKE-UP WATER SUPPLY					
	Supply Source				Municipal Water.
	Service/Fire Water Storage	N			Existing 450,000 gallon tank.
	Service Water Transfer Pumps	N			Existing.
WASTEWATER					
	Contaminated Wastewater	Y			Drains for areas around equipment that could be contaminated with oil will be directed through the existing oil/water separator (OWS). Discharge OWS effluent to outfall #001. Existing OWS has capacity of 300 gallons. Take discharge to same outfall on south side of plant.
	Water Treatment Reject	N			No rejects; rental system used.
FIRE PROTECTION					
	Design Basis	Y			FM Global and NFPA 850 recommended practice.
	Insurer/special requirements	N			
	GTG FP	Y			Additional CO2 added for Fuel Oil Injection skid enclosure.
	Pump supply source(s)	N			Existing Electric motor and Diesel driven fire pump taking suction from the Service/Fire Water Storage Tank.
	Storage	N			Existing Service/Fire Water Tank.
	Fire loop	Y			Branch of existing loop extended out to fuel oil storage area to supply hydrant only.
COMPRESSED AIR					
	Air Compressors	N			Tie into existing system. Each unit has its own compressor. Tie to receivers next to Unit 1.
CATHODIC PROTECTION					
	Underground Steel Piping	Y			Cathodic protection system will be galvanic anode type, if required.
	Underground Steel Tanks	Y			Coated with sacrificial anodes, if required.
CONTROLS					
Equipment Control					
	GTG	Y			EKPC is already planning to upgrade Siemens turbine control system to the T-3000 system. No additional controls upgrades required.
	Medium Voltage Switchgear	Y			Interface with upgraded TCS.
	Motor Control Centers	Y			Interface with upgraded TCS.
	Low Voltage Switchgear	Y			Interface with upgraded TCS.
	Plant Control System	Y			Integration with new T-3000 system.
	Plant Historian	Y			Interface with upgraded TCS.
	Offsite Interfaces	Y			Interface with upgraded TCS.
Automatic Generation Control					
	GTG	Y			Interface with upgraded TCS.
Vibration monitoring					
	GTG	N			Existing.
	Fin-Fan Cooler Fans	N			Existing.
Plant Simulator		N			

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		Y/N	Number	% Capacity (per Unit)	Notes
Digital Bus					
	Foundation Fieldbus	N			
	Remote I/O	Y			For fuel oil tank, unloading, and forwarding pumps.
Instrumentation					
	Redundancy	N			1x100% existing typical. Fuel flow to unit is 1x100% existing.
	Transmitters	Y			4-20 mA as available.
	HART	Y			Install tri-loops on valves for feedback.
	Performance Testing	N			
	Meteorological Station	N			
Continuous Emissions Monitoring System		N			Existing; fuel flow meter needs to be downstream side of recirc.; fuel sample will be required to be taken each time the units are run on fuel oil.
Relaying Data Link		N			Existing.
Communication					
	Dispatching	N			Existing.
	Off site monitoring/administrations	N			Existing.
	Switchyard	N			Existing.
	Internal plant	N			Existing; add communications to the new fuel oil tank location.
	External	N			Existing.
NERC CIP Requirements		N			No Changes.
HMI		Y			Local HMI at truck unloading.
ELECTRICAL					
Generator Step-Up Transformers:					
	Gas Turbine	N			Existing.
Auxiliary/Reserve Transformers:					
	Auxiliary Transformer	N			Existing.
Generator Buses:					
	Gas Turbine	N			Existing.
Electrical Equipment Enclosures:					Existing.
Bus Duct:					
	Iso-Phase	N			Existing.
Switchgear:					
	4160V Switchgear	N			Existing, 4.16kV, 33kA interrupting, low resistance grounded system, main-tie-main configuration, GE SR750/469 relays, sufficient capacity to source main-tie-main from one main breaker; 2 spare motor contactors, one on each bus and space to add another section on the bus.
	480V Switchgear	N			Existing, 480V, 65kA interrupting, high resistance grounded system with dedicated ground detection system, main-tie-main configuration, sufficient capacity to source main-tie-main from one main breaker; spare breakers available; space available to add vertical sections in existing building.
Motor Control Centers:					
	480 V MCCs	N			Existing, 480V, 3-Phase, 3-Wire, 65kA; spare buckets available.
Emergency Power:					
	Uninterruptible Power (UPS)	N			Existing, in main admin building (120V).
	DC System	N			Existing.
On-Line Battery Monitoring:		N			
Lighting		Y			LED for roadway lighting; lighting required for new road and unloading area.
CIVIL/STRUCTURAL					
Existing Facilities					Brownfield site. Tie into existing Bluegrass system.
Disposal of Spoils					Excess spoils will be disposed of on-site, used for fill if possible. No hazardous materials accounted for in project estimate.
Soils Conditions / Stability					No piles required based on review of existing foundations at site. Geotechnical investigation to confirm piles are not required for the new tanks and equipment.
Subsurface Rock					Subsurface rock is expected to be encountered for installation of the foundations. It will be removed as required to install these foundations.
Subsurface water					No dewatering included.
Cut/Fill					Use existing site materials to grade the site and avoid off-site borrow.
Disposal of debris					Disposed of on-site.
Permanent Stormwater					Existing.
Construction Stormwater					Erosion control will be in accordance with state and local guidelines and regulations.
Roads					Add new plant road to allow for fuel oil deliveries via truck. Roads will be surfaced with asphalt topping and two-lane. Loop/turn-around at fuel truck unloading station to keep trucks from going through the plant.
Surfacing					Maintenance areas will be covered with crushed rock. Other areas top soil and seeded.
Soil Bearing Capacity					Suitable fill based on review of existing foundations at site. Geotechnical investigation to confirm soil bearing capacity.
Foundation type					Shallow or mat foundations based on review of existing foundations at site. Geotechnical investigation to confirm shallow or mat foundations are acceptable for the new tanks and equipment..
Enclosures					
	Pumps Electrical (see electrical section)	N			Fuel oil pump injection skid and water injection skin in new enclosure. Forwarding pumps and unloading station will be located outdoors.
Access					
	Spacing between units				Unchanged.
Maintenance cranes		N			
Guardshack		N			New slide gate for fuel oil truck road opening.
Fence		Y			Relocated around fuel oil tanks and unloading area and around relocated guardshack.
CONSTRUCTION					
Utilities					
	Power				Tie-in to EKPC.

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		Y/N	Number	% Capacity (per Unit)	Notes
	Communication				Tie-in to EKPC.
	Construction Water				Tie-in to EKPC.
	Potable Water				Tie-in to EKPC.
	Sanitary				Tie-in to EKPC.
Parking					
Gate Entry					
	Main				Existing Bluegrass guard shack.
	Personnel/Craft				Existing Bluegrass main gate and guard shack.
	Delivery				New slide gate for fuel oil truck road opening.
Construction Field Office / Trailers					
	Owner				Office in Existing Admin Building.
	Engineer				Trailers in Owners Costs.
	Vendors				Trailers in Owners Costs.
	Contractors				Trailers in Owners Costs.
	Site Services				Trailers in Owners Costs.
Laydown area					Near existing warehouse, northwest of plant, in open flat area.
Warehouses					Existing warehouse is full; Contractor will provide necessary storage space during construction.
OWNER COSTS / MISC.					
Permits					
	See Permit Matrix	Y			EKPC w/ BMcD Support.
Owner's Costs		Y			

BURNS & McDONNELL

		Y/N	Number	% Capacity (per Unit)	Notes
GENERAL PROJECT INFORMATION					
Project Description					
	Project Location				Near La Grange, KY.
	Site Description				Existing brownfield site at Bluegrass Station.
	Contracting Approach				Multi-prime.
	Labor				Union.
	Project Liquidated Damages				TBD.
	Project Bonding /LOC				100% Bonding.
	Project COD Dates				December 2020.
	Project Expansion				No future expansion considered; Combined Cycle location not considered and SCR remains decommissioned.
MECHANICAL EQUIPMENT					
AQUEOUES AMMONIA SYSTEM					
	Ammonia Flow Control Skid	N			
	Ammonia Forwarding Pump Skid	N			
	Ammonia Storage Tank	N			
	Ammonia Unloading Skid	N			
	SCR Ammonia Distribution Grid	N			
	SCR Catalyst	N			
	Detection				
DEMINERALIZED WATER SYSTEM					
	Demineralized Water Transfer Pumps	N			
	Demineralized Water Storage Tank	N			
	Demineralized Water Trailers	N			Existing connections for Demin Trailer which handles 200 gpm.
CLOSED COOLING WATER					
	CCW Heat Exchanger	N			
	CCW pumps	N			
	Glycol type	N			
LNG					
	Storage	Y			LNG Storage tanks for each option: - 3,840,000 gal total storage for 48-hours (30 bullet tanks) - 1,920,000 gal total storage for 24-hours (15 bullet tanks) Tanks will be set on concrete mat with curb for containment.
	Transfer/Booster Pumps	Y	3	50	3 x 50% located near LNG tanks.
	Unloading	Y	2	100	Two (2) truck unloading stations with scales.
	Heating	Y	2	100	Fired vaporizer to regenerate natural gas for delivery to plant - 2 x 100%.
MAKE-UP WATER SUPPLY					
	Supply Source				Municipal Water.
	Service/Fire Water Storage	N			Existing 450,000 gallon tank.
	Service Water Transfer Pumps	N			Existing.
WASTEWATER					
	Contaminated Wastewater	N			
	Water Treatment Reject	N			No rejects; rental system used.
FIRE PROTECTION					
	Design Basis	Y			FM Global and NFPA 850 recommended practice.
	Insurer/special requirements	N			
	GTG FP	N			No changes required.
	Pump supply source(s)	Y			Existing Electric motor and Diesel driven fire pump taking suction from the Service/Fire Water Storage Tank. Electric booster pump added to ensure sufficient pressure at loop around new LNG storage area.
	Storage	N			Existing Service/Fire Water Tank.
	Fire loop	Y			Branch of existing loop extended out to LNG storage area with fire water booster pump to supply hydrants only.
COMPRESSED AIR					
	Air Compressors	N			Tie-in to existing system. Each unit has its own compressor. Tie to receivers next to Unit 1. Air is not limited.
CATHODIC PROTECTION					
	Underground Steel Piping	Y			Cathodic protection system will be galvanic anode type, if required.
	Underground Steel Tanks	Y			Coated with sacrificial anodes, if required.
CONTROLS					
Equipment Control					
	GTG	N			EKPC is planning to upgrade Siemens turbine control system to the T-3000 system under a separate project.
	Medium Voltage Switchgear	Y			Interface with upgraded TCS.
	Motor Control Centers	Y			Interface with upgraded TCS.
	Low Voltage Switchgear	Y			Interface with upgraded TCS.
	Plant Control System	Y			Integration with new T-3000 system.
	Plant Historian	Y			Interface with upgraded TCS.
	Offsite Interfaces	Y			Interface with upgraded TCS.
Automatic Generation Control					
	GTG	Y			Interface with upgraded TCS.
Vibration monitoring					
	GTG	N			Existing.
	Fin-Fan Cooler Fans	N			Existing.
Plant Simulator		N			
Digital Bus					
	Foundation Fieldbus	N			
	Remote I/O	Y			For LNG tanks, unloading, and forwarding pumps.
Instrumentation					

BURNS McDONNELL

	Y/N	Number	% Capacity (per Unit)	Notes
Redundancy	N			1x100% existing typical. Fuel flow to unit is 1x100% existing.
Transmitters	Y			4-20 mA as available.
HART	Y			Install tri-loops on valves for feedback.
Performance Testing	N			
Meteorological Station	N			
Continuous Emissions Monitoring System	N			Existing.
Relaying Data Link	N			Existing.
Communication				
Dispatching	N			Existing.
Off site monitoring/administrations	N			Existing.
Switchyard	N			Existing.
Internal plant	N			Existing; add communications to the new LNG tanks location.
External	N			Existing.
NERC CIP Requirements	N			No Changes.
HMI	Y			Local HMI at truck unloading.
ELECTRICAL				
Generator Step-Up Transformers:				
Gas Turbine	N			Existing.
Auxiliary/Reserve Transformers:				
Auxiliary Transformer	N			Existing.
Generator Buses:				
Gas Turbine	N			Existing.
Electrical Equipment Enclosures:	N			Existing.
Bus Duct:				
Iso-Phase	N			Existing.
Switchgear:				
4160V Switchgear	N			Existing, 4.16kV, 33kA interrupting, low resistance grounded system, main-tie-main configuration, GE SR750/469 relays, sufficient capacity to source main-tie-main from one main breaker; 2 spare motor contactors, one on each bus and space to add another section on the bus.
480V Switchgear	N			Existing, 480V, 65kA interrupting, high resistance grounded system with dedicated ground detection system, main-tie-main configuration, sufficient capacity to source main-tie-main from one main breaker; spare breakers available; space available to add vertical sections in existing building.
Motor Control Centers:				
480 V MCCs	N			Existing, 480V, 3-Phase, 3-Wire, 65kA; spare buckets available.
Emergency Power:				
Uninterruptible Power (UPS)	N			Existing, in main admin building (120V).
DC System	N			Existing.
On-Line Battery Monitoring:	N			
Lighting	Y			LED for roadway lighting; lighting required for new road and unloading area.
CIVIL/STRUCTURAL				
Existing Facilities				Brownfield site. Tie into existing Bluegrass system.
Disposal of Spoils				Excess spoils will be disposed of on-site, used for fill if possible. No hazardous materials accounted for in project estimate.
Soils Conditions / Stability				No piles required based on review of existing foundations at site. Geotechnical investigation to confirm piles are not required for the new tanks and equipment.
Subsurface Rock				Subsurface rock is expected to be encountered for installation of the foundations. It will be removed as required to install these foundations.
Subsurface water				No dewatering included.
Cut/Fill				Use existing site materials to grade the site and avoid off-site borrow.
Disposal of debris				Disposed of on-site.
Permanent Stormwater				Existing.
Construction Stormwater				Erosion control will be in accordance with state and local guidelines and regulations.
Roads				Add new plant road to allow for LNG deliveries via truck. Roads will be surfaced with asphalt topping and two-lane. Loop/turn-around at LNG truck unloading station to keep trucks from going through the plant.
Surfacing				Maintenance areas will be covered with crushed rock. Other areas top soil and seeded.
Soil Bearing Capacity				Suitable fill based on review of existing foundations at site. Geotechnical investigation to confirm soil bearing capacity.
Foundation type				Shallow or mat foundations based on review of existing foundations at site. Geotechnical investigation to confirm shallow or mat foundations are acceptable for the new tanks and equipment..
Enclosures				
Pumps	N			Forwarding pumps and unloading station will be located outdoors.
Electrical (see electrical section)				
Access				
Spacing between units				Unchanged.
Maintenance cranes	N			
Guardshack	N			New slide gate for LNG truck road opening.
Fence	Y			Relocated around LNG tanks and unloading area and around relocated guardshack.
CONSTRUCTION				
Utilities				
Power				Tie-in to EKPC.
Communication				Tie-in to EKPC.
Construction Water				Tie-in to EKPC.
Potable Water				Tie-in to EKPC.
Sanitary				Tie-in to EKPC.
Parking				
Gate Entry				

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		Y/N	Number	% Capacity (per Unit)	Notes
	Main				Existing Bluegrass guard shack.
	Personnel/Craft				Existing Bluegrass main gate and guard shack.
	Delivery				New slide gate for LNG truck road opening.
Construction Field Office / Trailers					
	Owner				Office in Existing Admin Building.
	Engineer				Trailers in Owners Costs.
	Vendors				Trailers in Owners Costs.
	Contractors				Trailers in Owners Costs.
	Site Services				Trailers in Owners Costs.
Laydown area					Near existing warehouse, northwest of plant, in open flat area.
Warehouses					Existing warehouse is full; Contractor will provide necessary storage space during construction. Warehouse will be relocated closer to plant based on storage capacity and required space.
OWNER COSTS / MISC.					
Permits					
	See Permit Matrix	Y			EKPC w/ BMcD Support.
Owner's Costs		Y			

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		Y/N	Number	% Capacity (per Unit)	Notes
GENERAL PROJECT INFORMATION					
Project Description					
	Project Location				Near La Grange, KY.
	Site Description				Existing brownfield site at Bluegrass Station.
	Contracting Approach				Multi-prime.
	Labor				Union.
	Project Liquidated Damages				TBD.
	Project Bonding /LOC				100% Bonding.
	Project COD Dates				December 2020.
	Project Expansion				No future expansion considered; Combined Cycle location not considered and SCR remains decommissioned.
MECHANICAL EQUIPMENT					
AQUEOUES AMMONIA SYSTEM					
	Ammonia Flow Control Skid	N			
	Ammonia Forwarding Pump Skid	N			
	Ammonia Storage Tank	N			
	Ammonia Unloading Skid	N			
	SCR Ammonia Distribution Grid	N			
	SCR Catalyst	N			
	Detection				
DEMINERALIZED WATER SYSTEM					
	Demineralized Water Transfer Pumps	N			
	Demineralized Water Storage Tank	N			
	Demineralized Water Trailers	N			Existing connections for Demin Trailer which handles 200 gpm.
CLOSED COOLING WATER					
	CCW Heat Exchanger	N			
	CCW pumps	N			
	Glycol type	N			
LNG					
	Storage	Y			LNG Storage tank for each option (7 & 8): - 3,840,000 gal fully contained F&E tank for 48 hr storage - 1,920,000 gal fully contained F&E tank for 24 hr storage Tank will be set on concrete mat with curb for containment.
	Transfer/Booster Pumps	Y	3	50	3 x 50% located near LNG tank.
	Unloading	Y	2	100	Two (2) truck unloading stations with scales.
	Heating	Y	2	100	Fired vaporizer to regenerate natural gas for delivery to plant - 2 x 100%.
MAKE-UP WATER SUPPLY					
	Supply Source				Municipal Water.
	Service/Fire Water Storage	N			Existing 450,000 gallon tank.
	Service Water Transfer Pumps	N			Existing.
WASTEWATER					
	Contaminated Wastewater	N			
	Water Treatment Reject	N			No rejects; rental system used.
FIRE PROTECTION					
	Design Basis	Y			FM Global and NFPA 850 recommended practice.
	Insurer/special requirements	N			
	GTG FP	N			No changes required.
	Pump supply source(s)	Y			Existing Electric motor and Diesel driven fire pump taking suction from the Service/Fire Water Storage Tank. Electric booster pump added to ensure sufficient pressure at loop around new LNG storage area.
	Storage	N			Existing Service/Fire Water Tank.
	Fire loop	Y			Branch of existing loop extended out to LNG storage area with fire water booster pump to supply hydrants only.
COMPRESSED AIR					
	Air Compressors	N			Tie-in to existing system. Each unit has its own compressor. Tie to receivers next to Unit 1. Air is not limited.
CATHODIC PROTECTION					
	Underground Steel Piping	Y			Cathodic protection system will be galvanic anode type, if required.
	Underground Steel Tanks	Y			Coated with sacrificial anodes, if required.
CONTROLS					
Equipment Control					
	GTG	N			EKPC is planning to upgrade Siemens turbine control system to the T-3000 system under a separate project.
	Medium Voltage Switchgear	Y			Interface with upgraded TCS.
	Motor Control Centers	Y			Interface with upgraded TCS.
	Low Voltage Switchgear	Y			Interface with upgraded TCS.
	Plant Control System	Y			Integration with new T-3000 system.
	Plant Historian	Y			Interface with upgraded TCS.
	Offsite Interfaces	Y			Interface with upgraded TCS.
Automatic Generation Control					
	GTG	Y			Interface with upgraded TCS.
Vibration monitoring					
	GTG	N			Existing.
	Fin-Fan Cooler Fans	N			Existing.
Plant Simulator		N			
Digital Bus					
	Foundation Fieldbus	N			
	Remote I/O	Y			For LNG tank, unloading, and forwarding pumps.

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		Y/N	Number	% Capacity (per Unit)	Notes
Instrumentation					
	Redundancy	N			1x100% existing typical. Fuel flow to unit is 1x100% existing.
	Transmitters	Y			4-20 mA as available.
	HART	Y			Install tri-loops on valves for feedback.
	Performance Testing	N			
	Meteorological Station	N			
Continuous Emissions Monitoring System		N			Existing.
Relaying Data Link		N			Existing.
Communication					
	Dispatching	N			Existing.
	Off site monitoring/administrations	N			Existing.
	Switchyard	N			Existing.
	Internal plant	N			Existing; add communications to the new LNG tank location.
	External	N			Existing.
NERC CIP Requirements		N			No Changes.
HMI		Y			Local HMI at truck unloading.
ELECTRICAL					
Generator Step-Up Transformers:					
	Gas Turbine	N			Existing.
Auxiliary/Reserve Transformers:					
	Auxiliary Transformer	N			Existing.
Generator Buses:					
	Gas Turbine	N			Existing.
Electrical Equipment Enclosures:		N			Existing.
Bus Duct:					
	Iso-Phase	N			Existing.
Switchgear:					
	4160V Switchgear	N			Existing, 4.16kV, 33kA interrupting, low resistance grounded system, main-tie-main configuration, GE SR750/469 relays, sufficient capacity to source main-tie-main from one main breaker; 2 spare motor contactors, one on each bus and space to add another section on the bus.
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Lighting		Y			LED for roadway lighting; lighting required for new road and unloading area.
CIVIL/STRUCTURAL					
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Cut/Fill					Use existing site materials to grade the site and avoid off-site borrow.
Disposal of debris					Disposed of on-site.
Permanent Stormwater					Existing.
Construction Stormwater					Erosion control will be in accordance with state and local guidelines and regulations.
Roads					Add new plant road to allow for LNG deliveries via truck. Roads will be surfaced with asphalt topping and two-lane. Loop/turn-around at LNG truck unloading station to keep trucks from going through the plant.
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Enclosures					
	Pumps	N			Forwarding pumps and unloading station will be located outdoors.
	Electrical (see electrical section)				
Access					
	Spacing between units				Unchanged.
Maintenance cranes		N			
Guardshack		N			New slide gate for LNG truck road opening.
Fence		Y			Relocated around LNG tank and unloading area and around relocated guardshack.
CONSTRUCTION					
Utilities					
	Power				Tie-in to EKPC.
	Communication				Tie-in to EKPC.
	Construction Water				Tie-in to EKPC.
	Potable Water				Tie-in to EKPC.
	Sanitary				Tie-in to EKPC.
Parking					

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		Y/N	Number	% Capacity (per Unit)	Notes
Gate Entry					
	Main				Existing Bluegrass guard shack.
	Personnel/Craft				Existing Bluegrass main gate and guard shack.
	Delivery				New slide gate for LNG truck road opening.
Construction Field Office / Trailers					
	Owner				Office in Existing Admin Building.
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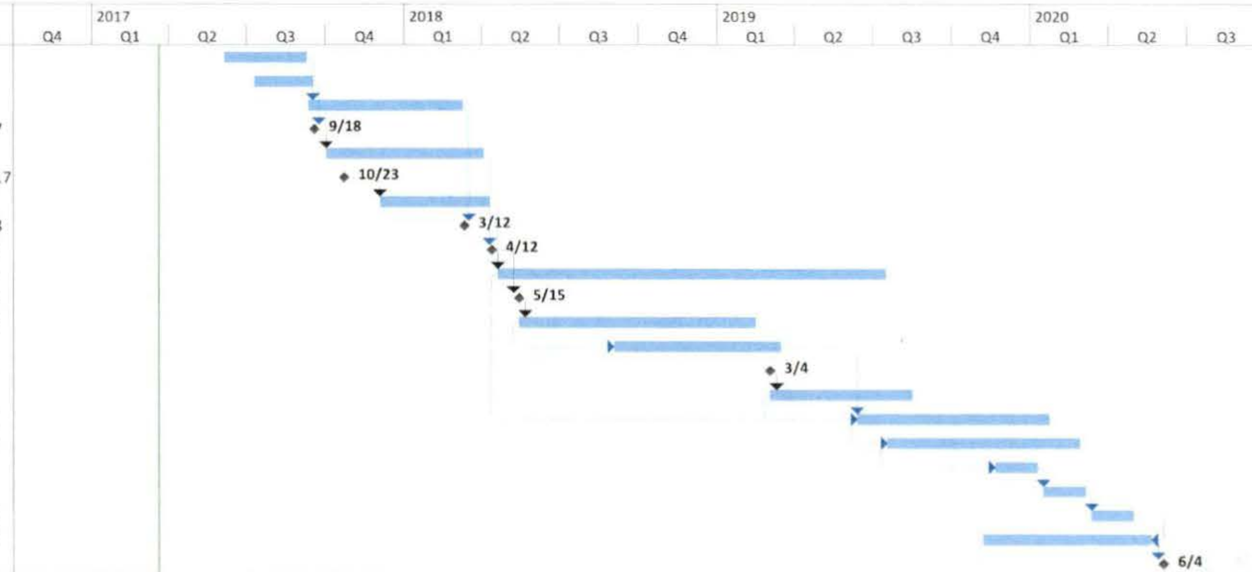
Laydown area					Near existing warehouse, northwest of plant, in open flat area.
Warehouses					Existing warehouse is full; Contractor will provide necessary storage space during construction. Warehouse will be relocated closer to plant based on storage capacity and required space.
OWNER COSTS / MISC.					
Permits					
	See Permit Matrix	Y			EKPC w/ BMcD Support.
Owner's Costs		Y			

APPENDIX D -PRELIMINARY LEVEL 1 SCHEDULE

ID	Task Name	Start	Finish
1	Air Permitting Development	Mon 6/5/17	Fri 9/8/17
2	EKPC Commence Board Approval	Mon 7/10/17	Fri 9/15/17
3	Air Permit Application	Mon 9/11/17	Fri 3/9/18
4	EKPC Board Approval	Mon 9/18/17	Mon 9/18/17
5	CPCN / PSC Approval Process	Mon 10/2/17	Mon 4/2/18
6	LNTP Engineering	Mon 10/23/17	Mon 10/23/17
7	Bid / Award of Long Lead Equipment	Mon 12/4/17	Mon 4/9/18
8	Air Permit Received	Mon 3/12/18	Mon 3/12/18
9	CPCN / PSC Approved	Thu 4/12/18	Thu 4/12/18
10	Procure Long Lead Equipment	Fri 4/20/18	Tue 7/16/19
11	FNTP Engineering	Tue 5/15/18	Tue 5/15/18
12	Engineering / Permitting	Tue 5/15/18	Thu 2/14/19
13	Procurement	Mon 9/3/18	Fri 3/15/19
14	Commence Construction	Mon 3/4/19	Mon 3/4/19
15	Civil Construction	Mon 3/4/19	Fri 8/16/19
16	Mechanical Construction	Fri 6/14/19	Thu 1/23/20
17	Electrical Construction	Fri 7/19/19	Thu 2/27/20
18	Unit 1 Outage	Fri 11/22/19	Thu 1/9/20
19	Unit 2 Outage	Fri 1/17/20	Thu 3/5/20
20	Unit 3 Outage	Fri 3/13/20	Thu 4/30/20
21	Startup	Fri 11/8/19	Thu 5/21/20
22	Commercial Operation Date	Thu 6/4/20	Thu 6/4/20



Project: Bluegrass Dual Fuel Project Date: Mon 3/20/17

Task		External Tasks		Manual Task		Finish-only	
Split		External Milestone		Duration-only		Deadline	
Milestone		Inactive Task		Manual Summary Rollup		Progress	
Summary		Inactive Milestone		Manual Summary		Manual Progress	
Project Summary		Inactive Summary		Start-only			

Note: Long lead equipment refers to either gas turbine or liquefied natural gas (LNG). Dual Fuel Implementation of the gas turbine requires approximately 12 months for procurement and LNG requires 15 months.

APPENDIX E -PERMIT MATRIX

Item No.	Permit/Clearance	Regulatory Agency	Details	When Required	Anticipated Agency Review Time	Associated Fees	Comments
Federal							
1	Clean Water Act - Section 404 Permit	U.S. Army Corps of Engineers, Louisville District	Required to dredge or place fill in a jurisdictional water, including wetlands Nationwide Permit: Less an or equal to 0.5 acre of wetland or stream impacts Individual Permit: Greater than 0.5 acre of wetland or stream impacts	Prior to construction	45 to 90 days for a Nationwide Permit 12 to 18 months for an Individual Permit	No application or mitigation fees	A wetland and stream delineation will likely not be required. Impacts to jurisdictional waters or wetlands are not anticipated based on the Project's proposed equipment and work locations. If the project impacts wetlands and/or surface waters and qualifies for a Nationwide Permit 39 (Commercial and Institutional Developments), a pre-construction notification would be required.
2	Section 7 Threatened and Endangered Species Consultation and Clearance	U.S. Fish & Wildlife Service (FWS), Ecological Services	If the project will potentially impact protected species or their respective habitat, or if a Section 404 permit is required, then the FWS must be contacted. The FWS will determine the level of effort needed for the project to proceed (e.g., habitat assessment, species surveys, avian impact studies, etc.).	Prior to construction	30 days for initial response, additional 30 days for determination of field survey results (if required)	No fees	Formal consultation likely not required if construction will take place in an already developed area and no Section 404 Permit is required. Due to the nature of this site, impacts to protected species are not likely.
3	Migratory Bird Treaty Act / Bald and Golden Eagle Protection Act Compliance	U.S. Fish & Wildlife Service (FWS), Ecological Services	Required when construction or operation of a proposed facility could impact migratory birds, their nests, and especially threatened or endangered species	Prior to construction	30 days for data request, 30 days for report review	No fees	Formal consultation likely not required if construction will take place in an already developed area and no Section 404 Permit is required. Due to the nature of this site, impacts to migratory birds are not likely.
4	Notice of Proposed Construction	Federal Aviation Administration (FAA)	Required for the construction of structures 200 feet tall or within the distance to height ratio from the nearest point of a FAA airport runway. Also required for construction equipment reaching heights over 200 feet	Prior to construction	45+ days	No fees	Notifying the FAA includes completing Form 7460-1 for all required structures and providing a site layout map depicting structure locations. No temporary construction equipment or permanent structures will be over 200 feet tall
5	Spill Prevention, Control, and Countermeasure (SPCC) Plan Amendment	U.S. Environmental Protection Agency (EPA)	An amendment to the facility's SPCC Plan will be required to address additional onsite fuel storage and secondary containment.	Prior to fuel delivery	Not required to submit the SPCC Plan to the EPA for review, unless requested.	No fees	Required to be updated to address new fuel oil storage and secondary containment, including the Site Plan, Wastewater and Stormwater Flow Diagram, Table 1, and portions of the SPCC Plan narrative.
6	Facility Response Plan (FRP)	U.S. Environmental Protection Agency (EPA)	A FRP is required for facilities that could reasonably be expected to cause "substantial harm" to the environment by discharging oil into or on navigable waters. A facility may pose "substantial harm" if it: 1) has a total oil storage capacity greater than or equal to 42,000 gallons and it transfers oil over water to/from vessels; or 2) has a total oil storage capacity greater than or equal to 1 million gallons meets one of the following conditions: a. does not have sufficient secondary containment for each aboveground storage tank b. is located at a distance such that a discharge from the facility could cause "injury" to fish, wildlife, and sensitive environments c. is located at a distance such that a discharge from a facility would shut down a public drinking water intake d. has had, within the past 5 years, a reportable discharge greater than or equal to 10,000 gallons	Prior to oil delivery	Must submit a certification form and the FRP to the EPA regional office. The Regional Administrator (RA) will review and determine if the facility should be classified as a "substantial harm" facility or a "significant and substantial harm" facility. If the RA determines that the facility could cause "significant and substantial harm", the FRP requires approval by the RA. Approval can take anywhere from a couple of months up to 2 years depending on the regional office and its workload. The facility is still required to implement the FRP even during the EPA's review.	No fees	The RA determines if a facility could, because of its location, cause "significant and substantial harm" to the environment by discharging oil into or on the navigable waters and adjoining shorelines. This is determined by factors similar to the "substantial harm" criteria, as well as: age of tanks, type of transfer operations, oil storage capacity; lack of secondary containment, spill history, etc.
State - Kentucky							
7	Certificate of Public Convenience and Necessity (CPCN)	Kentucky Public Service Commission	Required for the construction of electric generating facilities	Prior to construction	120 to 180 days after the submission of a complete application	Project specific	

Item No.	Permit/Clearance	Regulatory Agency	Details	When Required	Anticipated Agency Review Time	Associated Fees	Comments
8	Environmental Assessment (EA) or Environmental Impact Statement (EIS)	Kentucky Public Service Commission	Facility modifications may trigger an EA or EIS because the project is requesting financing from the USDA Rural Utilities Service (RUS).	Prior to construction	6 to 9 months	No fees	This project will request funding from USDA RUS. An EIS is likely not required since significant environmental impacts are not anticipated; however, an EA may be required.
9	Air Construction Permit (non-PSD)	Kentucky Department of Environmental Protection Division for Air Quality	Required to modify the equipment to burn fuel oil and to incorporate limits on fuel oil operation to maintain PSD minor status. Also required to add vaporizer and flare emission sources for LNG operation.	Prior to construction	6 to 18 months	No fees	
10	Noise Compliance	Kentucky State Board on Electric Generation and Transmission Siting	No permit is required; however, a special use permit requires that the facility comply KRS 224.30-50, which prohibits emissions beyond the property that interfere with enjoyment of life or with any lawful business or activity.	Prior to construction	No agency review	No fees	A noise study is recommended to determine if the project will result in an increase in ambient noise, which might impact the surrounding community.
11	Permit to Construct Across or Along a Stream	Kentucky Department of Environmental Protection Division of Water	In addition to authorizing stream crossings, this permit also provides floodplain construction approval.	Prior to construction	20 business days for stream crossing and floodplain impact approval	No fees	The permit application must be reviewed and signed by the local county floodplain coordinator(s) prior to submitting the application to the State.
12	Section 401 Water Quality Certification (WQC)	Kentucky Department of Environmental Protection Division of Water	The purpose of the WQC is to confirm that the discharge of fill materials (Section 404 Permit) will be in compliance with the State's applicable water quality standards.	Prior to construction	If wetland/stream impacts are authorized under a Section 404 Nationwide Permit, then WQC approval is issued concurrently in 45 to 90 days. If a Section 404 Individual Permit is required, then separate WQC approval from the State could take 12 months.	Stream impact greater than 500 linear feet and less than 1,000 feet -- $1,000 Stream impact 1,000 to 5,000 linear feet -- $2,500 Stream impact greater than 5,000 linear feet -- $5,000 Wetland impacts -- $500 per acre, not to exceed $5,000	Assumes automatic Water Quality Certification authorization through the Corps' Nationwide Program. If the project will require a Section 404 Individual Permit from the Corps, then the Kentucky Department of Environmental Protection must issue an Individual Section 401 WQC.
13	General Permit for Stormwater Discharges Associated with Construction Activities	Kentucky Department of Environmental Protection Division of Water	Required for all stormwater discharges from construction activities which will disturb 1 or more total acres of land. The General Permit requires the development of a Stormwater Pollution Prevention Plan (SWPPP) prior to submitting a Notice of Intent for permit coverage.	Prior to construction	7 days	No fees	The permit also authorizes the discharge of construction dewatering waters if managed through the use of appropriate best management practices.
14	Operational SWPPP Modification	Kentucky Department of Environmental Protection Division of Water	If the facility's KPDES Operational Discharge Permit (KY0109363) requires an operational SWPPP, the SWPPP must be updated to address new fuel storage, secondary containment, and modified stormwater flows.	Prior to operation	Not required to submit operational SWPPP for review, unless requested	No fees	
15	National Historic Preservation Act – Section 106 Clearance	Kentucky Heritage Council State Historic Preservation Office (SHPO)	Under Section 106 of the National Historic Preservation Act, Federal agencies must work with the State Historic Preservation Office to address historic preservation issues when planning projects or issuing funds or permits that may affect historic properties and archaeological resources listed in or determined eligible for the National Register of Historic Places.	Prior to construction	45 Days	$40 for Preliminary Site Check through SHPO database	Formal consultation likely not required if construction will take place in an already developed area and no Section 404 Permit is required.
16	Threatened & Endangered Species Clearance (State)	Kentucky Department of Fish and Wildlife Resources, Kentucky State Nature Preserves Commission, and Kentucky Division of Forestry	Required when a proposed project may impact State-listed species or when a project lies within an area of known occurrence of listed species or the habitat of a listed species.	Prior to construction	30 days for initial response, additional 30 days for determination of field survey results (if required)	No fees	Formal consultation likely not required if construction will take place in an already developed area and no Section 404 Permit is required.
County							
17	Storm Water Quality Management and Erosion Control Permit	Oldham County Engineering	Required for construction activities that will require 1 or more acres of ground disturbance.	Prior to construction	14 calendar days	$100 per acre of disturbance	Required SWPPP should be developed to address both State and County requirements.

APPENDIX F -EMISSIONS SUMMARY

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Client	EKPC
Project	Bluegrass Fuel Oil
	3 x 501FD2 (Fuel Oil)
Date:	8/13/2018
Revision:	3

NOTE: Not for Guarantee

Case #		Case 1	Case 2
Case Description		100% 0°F	100% 51°F
Ambient Temperature		0 F	51 F
Gas Turbine Load		100%	100%
Evaporative Cooling		OFF	OFF
Water Injection		ON	ON
No. of Gas Turbines In Operation		1 to 3	1 to 3
Gas Turbine Fuel		Fuel Oil	Fuel Oil
Ambient Conditions			
Temperature	degree F	0	51
Relative Humidity	%	66%	60%
Wet Bulb Temperature	degree F	-1.1	44.5
Pressure	psia	14.60	14.60
Gas Turbine Generator Performance (Per GTG)			
GTG Heat Input- LHV	MMBtu/hr	1,971	1,772
GTG Heat Input- HHV	MMBtu/hr	2,103	1,890
Water Injection Rate (per GTG)	lb/hr	42,740	38,410
Exhaust Flow (per GTG)	lb/hr	4,416,322	4,067,237
Stack Volumetric Analysis, Wet			
Ar	%	0.90%	0.89%
CO_2	%	5.04%	4.91%
H_2O	%	6.30%	6.79%
N_2	%	75.00%	74.57%
O_2	%	12.76%	12.84%
Stack Emissions at Exit			
NOx Emissions			
NOx,@15% O_2	ppmvd	42.0	42.0
NOx, as NO_2 (per GTG)	lb/hr	353.0	317.0
CO Emissions			
CO, @ 15% O_2	ppmvd	30.0	30.0
CO (per GTG)	lb/hr	154.0	138.0
SO_2 Emissions			
SO_2 in Exhaust Gas (assuming no conversion) (per GTG)	lb/hr	107.0	96.0
SO_2 in Exhaust Gas (assuming no conversion) (per GTG)	lb/MMBtu	0.0509	0.0508
Volatile Organic Compounds			
VOC @ 15% O_2	ppmvd	10.0	10.0
VOC as CH_4 (per GTG)	lb/hr	29.0	26.0
Particulates			
PM, Filterable & Condensable (per GTG)	lb/hr	63.0	58.0
PM, Filterable & Condensable (per GTG)	lb/MMBtu	0.0300	0.0307

Notes:
1. Particulate values are per US EPA Method 5/202 (front and back half).
2. Emission values do not include heavy metals (lead, mercury, etc.)
3. Differing fuel composition may change the calculated emissions.
4. CTG performance and emissions based on preliminary information from Siemens.
5. Fuel based on Distillate Fuel Oil No. 2: weight composition - 86.434% C, 13.5% H, 0.05% S, 0.015% FBN, and 0.001% ash.
6. Stack SO_2 content reported with no conversion to SO_3.
7. Emissions exclude ambient air contributions.
8. VOC consists of total hydrocarbons excluding methane and ethane and are expressed in terms of methane.
9. Emissions reported on the basis of pounds per hour are for one combustion turbine.
10. Emissions estimates are for preliminary information only and are NOT guaranteed.

BURNS & McDONNELL

CREATE AMAZING.

Burns & McDonnell World Headquarters
9400 Ward Parkway
Kansas City, MO 64114
O 816-333-9400
F 816-333-3690
www.burnsmcd.com

BURNS McDONNELL

Bluegrass Generating Station – Dual Fuel Implementation Project Scoping Report

EAST KENTUCKY POWER COOPERATIVE

East Kentucky Power Cooperative

Project No. 97273
Rev. 0
August 2018

Bluegrass Generating Station – Dual Fuel Implementation Project Scoping Report

Prepared for

East Kentucky Power Cooperative
Winchester, Kentucky

Project No. 97273

Rev. 0
August 2018

Prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

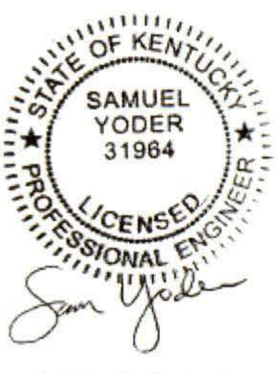
INDEX AND CERTIFICATION

East Kentucky Power Cooperative
Bluegrass Generating Station –
Dual Fuel Implementation Project Scoping Report
Project No. 97273

Report Index

Certification

I hereby certify, as a Professional Engineer in the Commonwealth of Kentucky, that the information in this document was assembled under my direct supervisory control. This report is not intended or represented to be suitable for reuse by East Kentucky Power Cooperative or others without specific verification or adaptation by the Engineer.



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Samuel Yoder (Kentucky License No. 31964

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LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
AACE	Association for the Advancement of Cost Engineering
AC	Alternating Current
ACI	American Concrete Institute
AISC	American Institute of Steel Construction
APE	Auxiliary Power Enclosure
Bluegrass	Bluegrass Generating Station
BMcD	Burns & McDonnell
BMP	Best Management Practices
BOP	Balance of Plant
BTU	British Thermal Unit
CO_2	Carbon Dioxide
COD	Commercial Operation Date
CPCN	Certificate of Public Convenience and Necessity
CTG	Combustion Turbine Generator
DC	Direct Current
DCS	Distributed Control System
DLN	Dry-Low NOx
EKPC	East Kentucky Power Cooperative
EPC	Engineering, Procurement, and Construction
F&E	Furnish and Erect
FNTP	Full Notice to Proceed

Abbreviation	Term/Phrase/Name
GA	General Arrangement
gpm	Gallons per Minute
HHV	Higher Heating Value
HMI	Human Machine Interface
HVAC	Heating, Ventilation, and Air Conditioning
IO	Input Output
KBC	Kentucky Building Code
LED	Light Emitting Diode
LNTP	Limited Notice to Proceed
MCC	Motor Control Center
MM	Million
MVA	Megavolt Amp
MW	Megawatt
NO_x	Nitrogen Oxides
O&M	Operations and Maintenance
OEM	Original Equipment Manufacturer
OSHA	Occupational Safety and Health Administration
P&ID	Process and Instrumentation Diagram
PCM	Power Control Module
PSC	Public Service Commission
PSD	Prevention of Significant Deterioration
PSR	Project Scope Report

Abbreviation	Term/Phrase/Name
SST	Station Service Transformers
SWGR	Switchgear
ULSD	Ultra-Low-Sulfur-Diesel
V	Volt
VDC	Volts of Direct Current

1.0 EXECUTIVE SUMMARY

East Kentucky Power Cooperative (EKPC; Owner) operates Bluegrass Generating Station (Bluegrass) near La Grange, KY. Bluegrass is a 567-megawatt (MW) net winter output facility which consists of three operating Siemens 501FD2 combustion gas turbine (CTG) units.

EKPC has retained Burns & McDonnell (BMcD) to assist in developing the scope, preliminary design, schedule and cost estimates for dual fuel capability at Bluegrass. Siemens has indicated to EKPC that the 501FD2 model was designed to accommodate the use of both natural gas and/or fuel oil through use of interchangeable support housings. The Bluegrass combustion turbines would operate on fuel oil as a back-up to natural gas. PJM's Capacity Performance program was completed in 2015 and aims to address grid reliability concerns highlighted by the Polar Vortex of January 2014. A backup fuel system at Bluegrass would help the facility maintain its ability to perform during a similar weather event, an emergency, or as EKPC deems necessary.

This report summarizes the Project scope and presents the study results for use in EKPC's evaluation of Project feasibility and budgeting. The Project scope includes the items summarized in Table 1-1 and discussed in detail in Section 3.0. The Project scope does not include the substation addition planned by EKPC, which is currently planned to be performed as a separate project. However, the development of both projects will require adequate coordination. The Project scope also does not include plant distributed control system (DCS) changes other than those required for dual fuel implementation.

Table 1-1: Project Scope

Major Scope Items	Description
Combustion Turbine and Associated Equipment	The scope includes dual fuel nozzles, new fuel oil pump skids, water injection pump skids, drain and purge system, and control systems for the combustion turbines to operate on fuel oil or natural gas.
Fuel Oil System	The scope includes two new fuel oil storage tanks (24-hour total storage), unloading equipment and forwarding pumps with inline heaters.
Balance of Plant	The scope includes new piping, controls, instrumentation, electrical, and mechanical equipment in the Project to operate these new systems. This includes an additional demineralized water storage tank and forwarding pumps.

1.1 Purpose

The purpose of this report is to present the study results for use in EKPC's evaluation of Project feasibility and budgeting as part of the Project development phase. The report provides the overall scope, Level 1 schedule, and cost estimate of the Project based on the preliminary design documents contained herein.

Prior to the development of this Project Scoping Report (PSR), a screening level report was developed to assess backup fuel options at Bluegrass. The selected scope following EKPC's review of the screening level report included dual fuel implementation for the combustion turbines, two fuel oil storage tanks for 24 hours of plant operation, and associated balance of plant system modifications to support the fuel oil operation, which are described herein.

Additionally, an Electrical Load Flow Study report was prepared by BMcD to assess the electrical powering options available for the Dual Fuel Implementation Project equipment.

1.2 Project Execution Approach

The selected contracting strategy for the Project is a multiple contract approach with adjustment unit pricing. The multiple contract approach provides EKPC with more control over the design of the Project, the quality and type of the equipment and materials, and more ability to make changes as the Project design progresses.

In the multiple contract approach, EKPC and an Owner's Engineer will work together to create and procure the construction and major equipment contracts for the Project. The procurement of the long lead time equipment is necessary early in the Project to support detailed design and equipment delivery schedules that meet the expected commercial operation date. The contracting approach includes multiple equipment / material contracts and several construction contracts, as referenced in Section 4.2, via competitive bidding to reduce costs and markups. The multiple contract approach allows EKPC to reduce the cost of contractor markup that would occur in an engineering, procurement, and construction (EPC) contracting arrangement.

1.3 Schedule

The Level 1 Project schedule is driven by the goal to achieve commercial operation by end of 2020 to provide EKPC the ability to meet the final expected PJM timeframe associated with the Capacity Performance Program. PJM expects to transition 100% of capacity to Capacity Performance resources by the 2020/2021 delivery years. The critical path of the Project is impacted by long procurement lead time items. Additionally, a Certificate of Public Convenience and Necessity (CPCN) is required for this Project. The duration of the CPCN permitting process is significant as equipment cannot be procured, and construction cannot commence until the CPCN is approved, which may take up to 12 months to complete. Table 1-2 reflects the major milestones for the Project. The complete schedule is provided in Appendix E.

Table 1-2: Project Milestones

Activity	Date
Commence EKPC Board Approval of Project	February 2018
Commence CPCN Application Preparation	April 2018
Limited Notice to Proceed (LNTP) Engineering/Permitting Activities Commence	April 2018
Submit Air Permit Application to KDAQ	May 2018
CPCN Application Filed with PSC	August 2018
EKPC Board Approval of Project	December 2018
LNTP Award of Long Lead Equipment (Engineering Only)	December 2018
CPCN / PSC Approved	February 2019
Full Notice to Proceed (FNTP) Engineering	April 2019
FNTP Award of Long Lead Equipment	April 2019
Final Air Permit Received from KDAQ	October 2019
Commence Construction	October 2019
Unit 1 Outage Commence	May 2020
Unit 1 Outage Complete	July 2020
Unit 2 Outage Commence	July 2020
Unit 2 Outage Complete	September 2020
Unit 3 Outage Commence	September 2020
Unit 3 Outage Complete	November 2020
Commercial Operation Date (COD)	December 2020

1.4 Cost Estimate

Safety will be a primary focus for the Project. The Project estimate includes one full time safety professional on-site during construction to oversee the entire Project's safety. Each contractor will also be required to provide full time safety professionals to properly manage safety during Project execution.

The estimated capital cost for the Project is $62.8 MM including escalation for commercial operation in December 2020. The Project estimate is a Class 3 budgetary cost estimate as defined by the Association for the Advancement of Cost Engineering (AACE). This estimate is based on the capital cost basis and assumptions in Section 6.0 and Appendix C. A Project estimate and definition contingency is included in this estimate to cover the accuracy of pricing and commodity estimates for the scope defined in this report. In addition, an Owner's cost of $6.0 MM is included in the Project estimate based on input from EKPC. Per EKPC's request, a contingency for Owner's discretionary costs is not included.

1.5 Project Risks

Long lead equipment poses risk to schedule and cost if there is an increase in market demand for the equipment. An increase in market demand could cause longer lead times and higher pricing.

The unknown equipment condition of combustion turbine internals upon inspection is another potential Project risk. This poses schedule and cost risks as there may be unknown issues that arise.

There are some legacy easements which may need to be encroached upon for the Project. EKPC verified that these particular easements have been released.

Environmental permitting poses potential risk to the project schedule due to unanticipated delays associated with Project permitting approval. However, approximately 18 months has been allotted for development, submittal and permitting agency process approval to attempt to mitigate risk.

Another possible Project risk is associated with the potential new EKPC substation. The new substation being developed by EKPC could pose layout and scheduling conflicts with the Dual Fuel Implementation Project since the substation project schedule is unknown, and the layout is under development.

Lastly, due to projects conceivably being constructed by others in the same time frame, there is a Project risk for labor availability and the associated labor rates assumed with this estimate.

* * * * *

2.0 INTRODUCTION

2.1 Background

EKPC is developing a Dual Fuel Implementation Project for Bluegrass Generating Station near La Grange, Kentucky. As part of the Project development, EKPC retained BMcD to evaluate and develop the scope, preliminary design, schedule, and cost estimates for dual fuel capability at Bluegrass to operate the combustion turbines on fuel oil as a back-up to natural gas. Bluegrass is a part of PJM, which completed its Capacity Performance program in 2015 to address grid reliability concerns highlighted by the Polar Vortex of January 2014. A backup fuel system at Bluegrass would help the facility maintain its ability to perform during a similar, short term weather event. This report summarizes the Project scope and presents the study results to support EKPC's evaluation of Project feasibility and budgeting.

2.2 Scope of Study

The PSR includes preparation of the following major items:

1. Project Design Basis / Scope Matrix
2. Key Preliminary Design Documents
3. Class 3 AACE Capital Cost Estimate
4. Owner's Cost Estimate
5. Operations and Maintenance (O&M) Cost Estimate
6. Project Execution Level 1 Schedule
7. Project Annual Cash Flow
8. Permitting Matrix

The PSR defines preliminary design parameters for major components of the Project and provides adequate information to support the following activities:

1. Evaluation of the economics of the Project
2. Preparation of a Project schedule
3. CPCN Application and Public Service Commission (PSC) Approval process
4. Required federal and state permitting process

2.3 Limitations and Qualifications

Estimates and projections prepared by Burns & McDonnell relating to schedules, performance, construction costs, and operating and maintenance costs are based on our experience, qualifications and judgment as a professional consultant. Since Burns & McDonnell has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding and market conditions or other factors affecting such estimates or projections, Burns & McDonnell does not guarantee that actual rates, costs, performance, schedules, etc., will not vary from the estimates and projections prepared herein.

* * * * *

3.0 PROJECT DEFINITION

3.1 Project Overview

The Dual Fuel Implementation Project for Bluegrass includes the addition of new fuel oil storage and delivery systems to support fuel oil operation of the combustion turbines, adjustments to balance of plant systems and implementation of the dual fuel capability of the combustion turbines which is an inherent design characteristic of the 501FD2 combustion turbine according to Siemens.

3.2 Plant Location and Layout

Bluegrass is an existing power plant located just outside the city of La Grange in Oldham County, Kentucky. The Dual Fuel Implementation Project implements the dual fuel capability of the existing combustion turbines on the site to be capable of operating on fuel oil. The Project layout is influenced by existing structures, site access, constructability, capital costs, and O&M costs. A preliminary set of general arrangement and site layout drawings for the Project are included in Appendix A. Plant north is approximately a 7-degree rotation to the east of true north. The general arrangements and site layout drawings reflect a plant northing on the drawings, not a true northing.

The layout began with the preliminary sizing of the new fuel oil unloading, storage, and forwarding equipment and locating that equipment in available areas. As the Project developed, the arrangements were modified with vendor input on equipment sizing for the major systems based on budgetary specifications developed by Burns & McDonnell.

The assumed location for the new fuel oil unloading, storage, and forwarding area for the Project is west of the combustion turbines and plant area, next to the warehouse access road. Asphalt road surfacing will be added to some of the existing plant roadways and a truck turnaround will be included to provide fuel truck access routed through the plant to the new fuel oil unloading stations next to the fuel oil storage tanks. The new demineralized water storage tank and forwarding pumps are located west of Unit 1 and north of the existing demineralized water tank. Additionally, the new demineralized water trailer stanchion is located next to the existing stanchions to accommodate the existing service water connections and trailer pull-up area. A new pre-manufactured electrical building (APE 2) supplied with pre-installed electrical equipment will provide power to much of the new equipment and will be located near the new demineralized water tank.

Combustion turbine dual fuel equipment (fuel oil and water injection enclosures) was arranged within the power block area as close to each unit as existing equipment arrangements allow. The fuel oil and water injection skids will be placed on an existing foundation just west of each combustion turbine and inside a combined enclosure.

3.3 Plant Performances

Performance of the 501FD2 combustion turbines on fuel oil will be different than while operating on natural gas. Table 3-1 below indicates the expected plant performance differential between natural gas operation and fuel oil operation based on information provided by Siemens (original equipment manufacturer [OEM]). The values in this assessment are preliminary and will remain preliminary until Siemens is able to provide unit specific performance guarantee information. The summary shows that fuel oil operation will result in reduced plant output, as compared to natural gas operation, due to output reduction from the combustion turbines as well as an increase in auxiliary load. However, fuel oil operation is expected to result in improved heat rate (on a higher heating [HHV] basis) for the plant compared to natural gas operation.

Table 3-1: Performance Impacts of Fuel Oil Operation

	Fuel Oil vs. Natural Gas Performance	
	Minimum (3 °F)	*Annual Average (58 °F)*
Estimated Performance Deltas		
Additional Auxiliary Loads, MW	2.9	1.6
Estimated Net Plant Output Delta, MW	-22.8	-20.0
Estimated Net Plant Heat Rate Delta, Btu/kWh (HHV)	-110	-130

3.4 Mechanical Systems

Balance of plant (BOP) equipment will be sized to provide continuous combustion turbine operation without interruption. Table 3-2 summarizes the basis for fuel oil and demineralized water storage estimates. Increased demineralized water storage is needed for water injection at the combustion turbines to control NO_x during fuel oil operation. Tank sizes include freeboard, allowance for expansion and pump minimum suction levels.

Table 3-2: Bluegrass Fuel Oil Operation Storage Basis

	Fuel Oil	Demineralized Water
Combustion Turbine Consumption Rate, gpm (per Combustion Turbine)	268	90
Total Consumption Rate, gpm	805	270

	Fuel Oil	Demineralized Water
Storage Duration, hr	24	24
Usable Storage Capacity, gallons (per tank)	580,000	400,000
Total Tank Volume, gallons (per tank)	635,000	476,000

The scope for the mechanical systems is split between items provided and constructed by the OEM and the balance of plant systems. Section 3.4.1 presents the scope associated with the OEM while the remaining 3.4 sub-sections provide the balance of plant scope for the mechanical systems.

3.4.1 Combustion Turbine Dual Fuel Implementation

There are multiple suppliers capable of converting the combustion turbines to dual fuel operation. The estimate in this report is based on the combustion turbine OEM designing, supplying, and installing the combustion turbine equipment and materials for dual fuel operation.

Based on combustion turbine OEM provided dual fuel implementation scope description, the Siemens Dry-Low NO_x (DLN) dual fuel configuration utilizes dual fuel pilot and main stages to support housing nozzles, atomizing the fuel oil into the swirled air combustion zone of the turbine. Water is injected into the fuel-air mixture, as a combustion diluent for nitrogen oxides (NO_x) control by preventing premature ignition. Additionally, water is injected into the fuel oil lines upstream of the nozzle connections to pre-purge and post-purge the fuel oil nozzles to control coking. Air in the combustor shell maintains pressure in the fuel gas manifold while the combustion turbine operates on fuel oil to keep combustion products from flowing backwards (from high to low pressure zones) through the nozzles. Once fuel oil operation ends, water is circulated through the combustion turbine OEM equipment to effectively purge the system. The combustion turbine OEM scope includes the following elements (scope may vary based on final selected supplier):

Auxiliary Components - Fuel Oil System:

- Fuel Oil pump skid assembly
- Water Injection pump/motor
- Fuel Oil Water Injection skid
- Interconnecting piping

Auxiliary Components - Drain and Purge System:

- Combustor shell drain valve
- Fuel Gas manifold cont. purge isolation valve #1
- Fuel Gas manifold cont. purge isolation valve #2

- Fuel Gas purge vent valve
- Miscellaneous drain system piping

Gas Turbine Hardware

- Support housings with dual fuel nozzles

3.4.2 Fuel Oil System

The fuel oil system will provide the combustion turbines with No.2 ultra-low-sulfur-diesel (ULSD) fuel oil for combustion. Two carbon steel storage tanks will be located within concrete containment designed for 100% of fuel oil volume in one of the storage tanks, plus a 25-year, 24-hour rain event and 6 inches of freeboard. The two tanks will be separated by a trench within the containment, which will drain to the sump within the containment.

Two truck unloading stations will be included next to the storage area. Three (3) x 100% fuel oil unloading pumps will be provided to send fuel oil from either truck unloading station to either fuel oil storage tank. Four (4) x 100% fuel oil forwarding pumps will be provided to send fuel oil to the turbine fuel oil pump skids. Each pump is sized to supply full flow to one combustion turbine at baseload. Three pumps will operate if all units are operating, with one common spare offline. Three (3) x 50% electric fuel oil inline heaters will be used to heat the fuel oil from 15°F to a minimum of 40°F to meet combustion turbine minimum temperature requirements at the fuel oil pump skids. Each heater is sized for half the total fuel oil flow to all three units operating at baseload.

Fuel oil piping between the unloading stations and the inline heaters will be single wall carbon steel because these areas will be inside curbed containment and above ground. Fuel oil piping from the outlets of the heaters to the turbine fuel oil pump skids will be laid in a precast trench and will be double wall carbon steel containment piping. Return piping from the turbine fuel oil pump skids will be double wall and laid in the same trench. A recirculation line back to the fuel oil storage tanks will be located downstream of the inline heaters for heating of the stored fuel oil.

The piping, equipment, and instrumentation associated with the fuel oil system as well as the tie-ins are shown on piping and instrumentation diagrams (P&IDs) FOL-001 and FOL-002 and general arrangement drawings included in Appendix A.

3.4.3 Demineralized Water System

The demineralized water system will provide demineralized water to the combustion turbines for NOx emissions control during fuel oil operation. The existing 300,000-gallon demineralized storage tank has inadequate capacity to supply demineralized water to the combustion turbines for NOx control injection during the 24-hour fuel oil design duration, particularly if fogging is utilized during fuel oil operation. Therefore, a new 400,000-gallon coated carbon steel demineralized water storage tank will be provided to supplement the existing 300,000 gallons of storage. Four (4) x 100% demineralized water transfer pumps are included to provide demineralized water from the new storage tank to the turbine water injection skids. Each pump is sized to supply the required flow to one unit for fuel oil operation, with one common spare. Make-up water to the new demineralized water storage tank can be supplied from either of two sources: service water from the existing process/fire water storage tank and processed through mobile demineralized water trailer(s) supplied by EKPC via the new trailer stanchion included in this Project; demineralized water from the existing demineralized water storage tank via the existing demineralized water pumps. The new and existing demineralized water storage tanks will be cross-tied to provide potential additional storage capacity in the case that fuel oil trucks supply the plant continuously to extend continuous fuel oil operation.

The piping, equipment, and instrumentation associated with the demineralized water system as well as the tie-ins to the existing plant piping are shown on P&IDs M2668 and GTG-001 and general arrangement drawings included in Appendix A.

3.4.4 Fire Protection Water

The new structures for the Project will require new fire hydrants located in the vicinity of the fuel oil storage area. Tie-ins will be made to the existing fire protection water system and routed below grade to the location of the new hydrants. The approximate tie-in location has been identified on drawings GA1000 and P&ID M2547 located in Appendix A.

3.4.5 Fire Protection Carbon Dioxide (CO_2)

Three new pressurized CO_2 storage containers will be located near each combustion turbine to supply fire suppressant to each enclosure containing combustion turbine fuel oil and water injection pumps. Each fire protection system will include fire alarms, which will be integrated into the existing plant fire alarm system. The piping, equipment, and instrumentation associated with the CO_2 fire protection systems are shown on P&ID GCG-001 located in Appendix A.

3.4.6 Compressed Air

The turbine fuel oil and water injection pump enclosures will receive compressed air from the existing plant system. The fuel oil storage area will also be supplied with compressed air from the existing plant system as assumed at the approximate tie-in location identified on drawing GA1000. The main compressed air users in these areas will be service air hose drops, valves, and instruments. Based on discussions with EKPC, the existing compressed air system is expected to have sufficient capacity to supply the new users from the Project, particularly since many existing compressed air users will not operate when the combustion turbines operate on fuel oil. The new compressed air lines will be laid in the precast trench, as appropriate, and supported on existing structures elsewhere.

The piping and instrumentation associated with the new compressed air users as well as the tie-in to the existing plant air system are shown in P&ID M2181 and general arrangement drawings included in Appendix A.

3.4.7 Oily Waste Drains

A sump will be included at the fuel oil storage containment to collect drainage from the storage tank containment and curbed containments in the area. Two (2) x 100% sump pumps will be provided to supply oily waste from the sump to the existing oil water separator (OWS) via pipe in the precast trench.

Three additional sumps will be included along the route of the precast trench, as shown on drawings GA1000 and GA1000A, to collect drainage within the trench. Each sump will contain one (1) x 100% sump pump to supply oily waste from the sump to the existing OWS.

Existing oily waste drains in the combustion turbine areas will handle new oil waste from the combustor drains and any potential fuel oil leaks near the combustion turbines.

Based on discussions with EKPC, the existing OWS is not sized to handle these additional sump drains during a rain event. However, the existing OWS is expected to be capable of processing stormwater from the new sumps after processing existing plant stormwater and drains.

The piping, equipment, and instrumentation associated with the oily waste drain additions, as well as the tie-in to the existing plant piping, are shown on P&IDs M2644 and DOC-001 and drawing GA1000 included in Appendix A.

3.4.8 Utility Racks

Inside the power block area utilities will be located on elevated racks due to spatial constraints. The rack will be located along the roads between the units. Cable tray will also be routed on this rack for the power feed cables and for fiber connection. Plan and section views of the utility racks are shown on drawings in Appendix A.

3.5 Permitting Considerations

A permit matrix for the Project has been developed and included in Appendix H that covers the permits expected to be required for the Project. The addition of fuel oil may require revisions to the existing Title V permit.

BMcD understands that EKPC will continue to comply with the synthetic minor Title V permit requirements, including but not limited to existing emissions tonnage and operating hours limitations in place, post-project to avoid triggering the Prevention of Significant Deterioration (PSD) process. The switch to fuel oil may require monitoring and other changes to the existing synthetic minor Title V permit. This Report therefore conservatively allows approximately 18 months to complete the permitting process for revision of the Title V permit, in the event that public notice and comment is necessary. The Project schedule and cost estimate in this report were based on an allowance of 18 months to complete the permitting process.

Estimated steady-state emissions were developed for operating on fuel oil. These figures were based on generic emissions information provided by the combustion turbine OEM and are summarized in Appendix D. The values in this assessment are preliminary and will remain preliminary until the combustion turbine OEM is able to provide unit specific emissions guarantee information.

Appendix D also includes curves comparing estimated available natural gas operating hours based on fuel oil operating hours, due to existing NO_x emissions limits in the Title V permit.

3.6 Easements

There are several existing easements on-site including an underground gas line, overhead transmission lines, and legacy easements. Some legacy easements may be encroached upon by pieces of equipment and a new road turnaround, as a result of this Project. EKPC verified that these particular easements have been released. Appendix A includes an easement plan drawing with the new Project equipment and road turnaround.

3.7 Electrical Systems

3.7.1 Auxiliary Electrical Power Supply

The existing 4160V switchgear (SWGR)/motor control centers (MCC) will supply power to three fuel oil pump motors, three water injection pump motors, and two dry-type station service transformers (SST). The two SST's will serve a 480V switchgear lineup located in the fuel oil electrical building, also referred to as APE 2. The 480V switchgear is arranged in a main-tie-main configuration to provide redundancy on the 480V system which matches the existing electrical philosophy at Bluegrass. The 480V switchgear buses will supply the fuel oil inline heaters and two 480V MCCs, which will supply the fuel oil/demineralized water process, heat trace, and lighting loads. The existing 480V CTG MCCs will supply power to the fuel oil/water injection pump enclosures. Based on the equipment list included in Appendix B, the total anticipated load of the equipment for the Project is approximately 4 MVA.

The existing contactors in 4160V MCC #1 for CTG1 & CTG2 dilution air blowers will be repurposed to supply CTG1 & CTG2 fuel oil pumps, respectively. New contactors will be installed in 4160V MCC #1 spare cubicle 1A and MCC #2 spare cubicle 12A to supply CTG1 water injection pump and CTG3 fuel oil pump, respectively. A new two-high contactor section will be installed for 4160V MCC #2 section 13 to supply CTG2 & CTG3 water injection pumps. A new breaker will be installed in 4160V SWGR #1 spare cubicle 5A to supply fuel oil SST #1. The existing breaker in 4160V SWGR #2 spare cubicle 9A will be repurposed to supply fuel oil SST #2.

The Project is based upon the large electrical power distribution equipment being housed in the new APE 2 building that will be shop fabricated and shipped to site with electrical equipment installed and pre-wired. The APE 2 will be elevated on concrete piers with the cable tray system installed under the enclosure and both cable and non-segregated phase bus passing through cutouts in the floor into the electrical power equipment, which will be specified for bottom entry. Platforms and stairs will be provided to access the APE 2.

Transformer differential protection will be installed for the SSTs for equipment protection and to reduce arc flash hazard rating at the 480V switchgear. Electrical relays in the switchgear will be wired to the DCS for monitoring (see Section 3.8). Maintenance switches will be installed at 480V switchgear and 480V MCCs to reduce arc flash hazard rating while maintaining equipment.

Overall electrical one-line diagrams (E1001 & EE0001) of the electrical distribution system for the fuel oil equipment have been included in Appendix A. These drawings show the electrical changes required based on a preliminary evaluation of the power requirements of the new equipment. A list of major electrical equipment is included in Appendix B.

3.7.2 Direct Current (DC) Power Supply

The 125 VDC power for the fuel oil equipment will be supplied from a new valve-regulated lead acid battery system located in the fuel oil APE 2. The battery sizing is based upon 120-minute capacity after the loss of alternating current (AC) power. The battery charger is based upon a 12-hour re-charge time for the batteries while serving the continuous load.

3.7.3 Communications

The system will include speakers, handsets, and wiring to match the existing plant GAI-Tronics communication systems. The page/party system will be connected into the existing plant system but will be powered from the new power distribution system.

3.7.4 Grounding and Lightning Protection

An extension of the existing plant grounding system will be provided. The Project includes a system of buried bare copper ground conductor and copper-alloy sectional type ground rods. Grounding is included around the perimeter of the APE 2, fuel oil/water injection enclosures, and along the utility racks. Grounding has also been included for tanks and skids as identified in the equipment list in Appendix B.

The Project includes lightning protection for the fuel oil storage tanks, demineralized water storage tank, and APE 2.

3.7.5 Area Lighting

Roadway light emitting diode (LED) lighting is included to adequately light the new fuel oil unloading road turnaround. Stanchion mounted LED lighting is also included for new skids and stairs/platforms on new tanks. The APE 2 building will include its own LED lighting.

3.7.6 Heat Trace

Fuel oil piping from the fuel oil heaters to the combustion turbine fuel oil pumps in the enclosures will include heat trace and insulation to keep the fuel oil in these pipes at or above 40°F to decrease required time to start fuel oil operation. The new, above grade portions of the demineralized water piping and oily waste drain piping will also be heat traced and insulated for freeze protection. The two 480V MCCs will supply heat trace loads. Heat traced piping is shown in the P&IDs in Appendix A.

3.8 Control Systems

3.8.1 General

The existing plant DCS, by the combustion turbine OEM, will be adapted to incorporate the new controls to be installed. A new set of redundant processors will be installed in the new APE 2.

Control logic implemented within the DCS will be based on information and logic submittals from the equipment manufacturers. The graphics developed for the DCS will be P&ID style graphics based on the graphic examples and P&IDs from the equipment vendors and other Project P&IDs. Existing DCS templates and standards for both logic and graphics will be incorporated into the new equipment design.

EKPC has indicated that there will be a project addressing the existing plant's DCS system in the near future. If possible and if requested, this will be coordinated and implemented with this Project, however that has not been included in the Project estimate, execution, or schedule currently.

3.8.2 DCS System Architecture

New DCS equipment will be provided to control and monitor the new Project equipment to be installed. The DCS will be complete with redundant controllers, input / output (IO), Remote IO, power supplies, and ancillary hardware, fully wired and tested. The combustion turbine OEM controllers are using a SIMATIC NET fiber optic plant bus communication in a loop topology. The new fuel oil/demineralized water APE 2 DCS controllers will be tied to this loop between the existing APE controller and the Unit 3 controllers. Connection to the existing plant DCS will allow for the interface of existing plant DCS IO with the new equipment. The existing control room's Human Machine Interface (HMI) will have new P&ID style graphics, faceplate controls, status screens and alarm screens for monitoring and control of the new fuel oil/demineralized water devices.

A new set of redundant DCS processors and local IO will be installed in the new APE 2. DCS communication cabling will be fiber for communication external to the APE 2. The control system architecture drawings are located in Appendix A.

3.8.3 Instrumentation

The Project instrumentation will either be supplied by an equipment supplier or under the associated mechanical construction contract. On-skid instrumentation will be provided by the associated equipment supplier. The remaining contingent of instruments for BOP will be provided under the mechanical construction contract.

3.8.4 Startup and Commissioning

Startup management is included by Owner's Engineer with craft support by mechanical and electrical contractors. The equipment suppliers will support and advise equipment and controls startup and commissioning with technical advisors. Startup will include communications tests and IO checkout. Each piece of equipment will be operated from the HMI to confirm control and status. Sequence operations will be tested and verified. It is expected that equipment vendors for the DCS and switchgear will be present to assist with communications testing.

3.9 Civil / Structural / Architectural

3.9.1 Geotechnical

Geotechnical information includes a report provided by S&ME in April 2017 with recommendations for foundations and roadway sections based on the assumed delivery traffic. Based on this geotechnical report and review of the existing foundations at site, major equipment foundations were preliminarily sized. It is expected that deep foundations will not be required as bedrock was approximately 5 feet below grade for major foundations. This condition is similar to the existing plant equipment, which are not supported on deep foundations. A separate geotechnical investigation is not currently anticipated for the Project, unless the layout of major equipment or the new road turnaround substantially changes from the preliminary design outlined in this report.

3.9.2 Civil

3.9.2.1 Coordinate System

The civil design coordinate system will provide horizontal and vertical control for precise location of proposed construction activities with respect to predetermined datum points. The drawings will provide sufficient information to show Bluegrass plant grid system and orientation needed to properly locate existing and new work within the plant site, including the location of enclosures and structures (existing and new) with respect to a known location and elevation.

3.9.2.2 Clearing, Grading, and Landscaping

The areas to be cleared will be determined on the basis of the approximate construction limits so that as much as possible of the existing vegetation remains undisturbed. Removal and disposal will be subject to the guidelines of federal, state and local regulations in effect at the time of construction. Disposal of contaminated and hazardous materials will be off-site. Other construction trash and debris will be placed in trash containers and disposed of off-site.

Preliminary grades have been established as shown on drawing CG001 in Appendix A to accommodate the new equipment, new road turnaround, and minimize impact to EKPC's planned substation addition.

Crushed rock surfacing will be provided in the area just east of the new fuel oil tanks and will tie-in with the existing plant crushed rock surfacing. This will be provided inside the extents of the new fenced area as shown on drawing CG002 in Appendix A.

Prior to construction, topsoil will be stripped from areas to be disturbed and stored separately on-site for use in site finishing construction. The areas adjacent to structures and exposed footings will be finish graded. The topsoil will be spread over areas which are disturbed during construction and do not receive other types of surface treatment such as riprap, crushed rock, or paving. Prior to completion of the work, these areas will be fine graded, seeded, and mulched.

Native grass seeding will be provided for areas disturbed by construction which are not covered with other surfacing. Sloped areas which are particularly subject to erosion will be protected by erosion mat or other methods of erosion control.

3.9.2.3 Storm Drainage

Structures, piping, and grading will be provided to allow for positive storm drainage from the new equipment work areas. New reinforced concrete pipe culverts will drain portions of the new site and road turnaround appropriately. Modifications to the existing site drainage, particularly on the east side of the existing switchyard, are included in the Project to continue providing positive site drainage.

New catch basins and other structures, if deemed necessary during detailed design, will be constructed of reinforced concrete, and / or reinforced precast concrete. New structures will be designed to safely support external earth loads plus HS20 wheel loads, or greater, as necessary.

New storm drainage systems will be sized to handle the peak flow rate of the 10-year, 24-hour storm occurrence with minimal ponding and will be checked for flooding using the 25-year, 24-hour storm occurrence. New open ditches will have a minimum flow line slope of 0.3% with a maximum side slope of 3 horizontal to 1 vertical.

3.9.2.4 Roads, Drives, and Surfaced Areas

A new road turnaround near the new fuel oil tanks is provided as part of the Project to provide access for fuel oil trucks to unload and exit the plant. The road consists of a concrete road section with 9-inch-thick reinforced concrete section over a 12-inch-thick aggregate base course and compacted subgrade. This concrete paving section matches the existing concrete paved section at site that currently crosses the gas line. This section was used since there are significant grade changes prior to turns in the road to minimize road maintenance. Much of the existing plant roadway will be reinforced with 2-inch-thick asphalt overlay to facilitate fuel oil truck access to the fuel oil unloading area via existing plant roads. The road turnaround and additional asphalt overlay are designed for 1,000 fuel oil trucks per year over a 20-year life and for HS20 or greater loading. Drawings CG001 and CG002 in Appendix A provide the road turnaround layout.

Construction roads will be maintained throughout the construction period by various construction contracts. This maintenance will include removal of mud and snow, necessary grading and placing of additional crushed stone on temporary roads, and watering of roads during dry periods to mitigate dust problems. Existing and typical road maintenance will be maintained by EKPC during the construction period unless damaged by the construction contractor. It is anticipated that during site prep that the base course for the new road turnaround and the extended temporary heavy haul access road will be established and utilized by each construction contractor to access the site and perform most of the Project work near the new fuel oil tank area. Best Management Practices will be deployed to ensure compliance with the KPDES permit.

3.9.2.5 Dewatering

Dewatering is not anticipated for the Project as groundwater was not encountered during the borings with the geotechnical investigation. Additionally, dewatering of ponds is not anticipated as part of the Project.

3.9.2.6 Utility Trenches

New precast concrete trenches to house utilities have been included in the Project. These trenches, as shown on the general arrangement drawings in Appendix A, will be routed from the fuel oil tanks over to the existing units to maintain a bottom depth above the existing buried utilities that are routed within the plant. The precast concrete trenches will be supplied with concrete lids meeting HS20 loadings at road crossings.

During detailed design, the trenches will be reviewed and determined if it is feasible and economical to modify certain areas to be direct buried pipe and / or duct bank. However, fuel oil pipe will remain above grade in trenches or on utility racks to allow EKPC the ability to check that the piping is intact.

3.9.2.7 Foundations

The foundation system used will be spread footing, mat-type, or ring wall. Concrete will be designed in accordance with the American Concrete Institute Building Code (ACI 318) and the Kentucky Building Code (KBC). Shallow foundations will bear at or below the frost depth of 24 inches as defined in ACI 318 and the KBC. Uplift forces will be taken by the weight of the footing and soil overburden or by piling embedment into rock or stiff soil. Foundations supporting rotating machinery will be checked for resonant frequency and will be isolated using expansion joints or isolation pads. Allowable settlements for total and differential settlement will be 1 inch and ½ inch, respectively.

3.9.3 Structural

3.9.3.1 Access

The Project will be arranged to facilitate access to equipment and systems for operations and maintenance. Stairs are provided to access the fuel oil tank containment area with a secondary egress via ladders. The utility racks do not have an access platform along their lengths and it is not expected that there will be valves or instrumentation requiring routine operational inspection. Sumps will be accessed via ladders built into the concrete structures. The new APE 2 building will be elevated approximately 6 feet above grade and have access via stairs to new platforms to required places on the building. Tanks will be provided with spiral stairs to access the roof.

3.9.3.2 Basic Design Criteria

Basic design criteria for the Project will be in accordance with the KBC. The soil properties have been defined by the geotechnical investigation and report provided in April 2017 by S&ME. Materials for the Project will comply with the Occupational Safety and Health Administration (OSHA) Regulations and Standards 29CFR1910. Work performed on-site will comply with OSHA Regulations and Standards 29CFR1926. Additionally, work and materials will be in compliance with local, county, state, federal regulations, codes, standards, laws, and ordinances.

3.9.3.3 Steel Structures

Structural steel will be designed in accordance with American Institute of Steel Construction (AISC) 341 and 360. Steel structures associated with the Project include utility racks, sump grating support, and the fuel oil containment stair support structure.

3.9.4 Lead and Asbestos Abatement

It is not anticipated that asbestos or lead will be encountered due to the relatively new nature of this facility. Removal of asbestos materials and lead based paints are not specifically included in the current Project cost estimate. The contracts will allow for a mutually agreed upon amount of time within the construction schedule to accommodate asbestos and lead abatement activities without impacting the overall completion date. Asbestos materials and lead based paints in newly supplied equipment will be strictly prohibited.

3.9.5 Pre-Engineered Buildings

Per EKPC request, the fuel oil injection and water injection skids will have a pre-engineered structure provided and installed by the mechanical construction contractor to house these pieces of equipment on each unit. The structures will be designed in accordance with the KBC and other relevant codes. It will include heating, ventilation, and lighting.

* * * * *

4.0 CONTRACTING APPROACH

4.1 General Approach

The selected contracting strategy for the Project is a multiple contract approach with adjustment unit pricing. The multiple contract approach provides EKPC with more control over the design of the Project, the quality of the equipment and materials, and more ability to make changes as the Project progresses.

In the multiple contract approach, EKPC and an Owner's Engineer will work together to create and procure the construction and major equipment contracts to be procured by EKPC. The procurement of the long lead time equipment is necessary early in the Project to support detailed design and equipment delivery schedules that meet the required outage dates. The contracting approach includes multiple equipment / material contracts and construction contracts. The multiple contracts approach allows EKPC to reduce the cost of contractor markup that would occur in an EPC contracting arrangement.

The equipment contracts were setup in recognition of long lead time items that will need to be ordered early in the Project to support the schedule and are not impacted by the selection of other contractors. This section contains detailed descriptions of each contract along with an itemized list of the scope being provided for each. To assist in understanding the coordination of work between the multiple contracts, this section also provides detailed information on the coordination of responsibilities for design, fabrication, delivery, receipt & protection, foundations, piping, wiring, erection, commissioning and startup interfaces. The contract terms and required milestones will be coordinated to establish and manage the critical path for the Project.

4.2 Contract List

The following is the list of contracts that were used as a basis for this Project:

Table 4-1: List of Contracts

Contract Number	Contract Name
Construction Contracts	
C1120	Combustion Turbine Dual Fuel Implementation
C2970	Field Erected Tanks (F&E)
C8110	Site Preparation / Civil / Foundations
C8140	Site Finishing
C8320	Mechanical Construction
C8360	Fire Protection Construction
C8410	Electrical Construction

Table 4-1: List of Contracts

Contract Number	Contract Name
C9020	Surveying
C9030	Pilot Trenching
C9250	Performance Testing
C9260	Emissions Testing
Equipment Contracts	
C2190	Miscellaneous Pumps
C2763	Fuel Oil Heating
C5300	Switchgear Modifications
C5310	Electrical Building (APE 2)
C6110	Distributed Control System (DCS)

4.3 Interface Schedule

The following table identifies the interfaces between contracts to identify the responsibilities for each equipment foundation, receipt, installation, piping and wiring.

Table 4-2: Contracts Interfaces

Contract		Contract Interfaces				
No.	Description	RCVD BY	INST BY	FDNS BY	PIPE BY	WIRE BY
Construction Contracts						
C1120	Combustion Turbine Dual Fuel Implementation	C1120	C1120	C8110	C1120	C8410
C2970	Field Erected Tanks (F&E)	C2970	C2970	C8110	NA	NA
C8110	Site Preparation / Civil / Foundations	C8110	C8110	C8110	C8110	C8410
C8140	Site Finishing	C8140	C8140	NA	NA	NA
C8320	Mechanical Construction	C8320	C8320	C8110	C8320	C8410
C8360	Fire Protection Construction	C8360	C8360	C8110	C8360	C8360
C8410	Electrical Construction	C8410	C8410	C8110	NA	C8410
C9020	Surveying	NA	C9020	NA	NA	NA
C9030	Pilot Trenching	NA	C9030	NA	NA	NA
C9250	Performance Testing	NA	C9250	NA	NA	NA
C9260	Emissions Testing	NA	C9260	NA	NA	NA
Equipment Contracts						
C2190	Miscellaneous Pumps	C8320	C8320	C8110	C8320	C8410

Contract		Contract Interfaces				
C2763	Fuel Oil Heating	C8320	C8320	C8110	C8320	C8410
C5300	Switchgear Modifications	C8410	C8410	N/A	NA	C8410
C5310	Electrical Building (APE 2)	C8410	C8410	C8110	NA	C8410
C6110	Distributed Control System (DCS)	C5310	C5310	NA	NA	C8410/ C5310

4.4 Contract Scopes

4.4.1 General

The following scope descriptions itemize the general content of the contracts that are currently contemplated. Table 4-2 identifies responsibilities for foundations, receipt of equipment and materials, construction / erection, and special interfaces to assist the reader in understanding the coordination of work. The following sections provide descriptions and assumptions made when dividing major scope among the construction contractors.

4.4.1.1 Site Preparation / Foundations

The scope of the contracts is based on an engineering sequence to permit design and construction of underground utilities and foundations as early as possible in the construction sequence. This approach allows completion of trenching and excavation activities earlier for improved access and coordination of contractors or construction crafts. Laydown and construction facility area preparation, storm water drains, underground electrical utilities, foundations, precast trenches, initial road preparation and construction, and grounding will be included in Contract C8110 – Site Preparation and Foundations. Possible laydown and construction facility areas are shown in drawing CS001 in Appendix A.

4.4.1.2 Mechanical Construction

Equipment, piping, and instrumentation furnished by equipment contracts will be erected and installed by Contract C8320 – Mechanical Construction. Additionally, structural steel for utility racks, enclosures, and miscellaneous equipment supports will be included in C8320. Piping and instrumentation not included on equipment skids are generally included in C8320.

4.4.1.3 Electrical Construction

Electrical equipment and materials furnished by equipment contracts will be erected and installed by Contract C8410 – Electrical Construction. Major electrical equipment installation, wiring, and all interconnecting wiring for systems and equipment are generally included in C8410. Wiring for lighting /

convenience outlets, heating, ventilation and cooling (HVAC) and communication system is also included in the C8410. Additionally, electrical testing will be included in C8410.

4.4.1.4 Start-Up

Start-up and commissioning will be provided as part of this Project and coordinated with EKPC. Contractors provide the construction labor and superintendents required to place equipment and systems into operation. Manufacturer's field services are furnished through equipment contracts to provide technical direction for equipment start-up. The Owner's Engineer will manage the start-up and commissioning portion of the Project.

4.4.2 Construction Contracts

CONTRACT C1120 – COMBUSTION TURBINE DUAL FUEL IMPLEMENTATION

A. General Description: Design, furnish, deliver, and install of the following:
   1. Combustion turbine dual fuel implementation, including but not limited to the following:
      - Dual fuel support housing with nozzles.
      - Drain and purge system.
      - Throttling and controls system.
   2. Fuel oil injection skids.
   3. Water injection skids.
   4. Electrical, piping and control interconnects with the CTGs

CONTRACT C2970 – FIELD ERECTED TANKS

A. General Description: Design, furnish, deliver, and erect of the following:
   1. Two fuel oil storage tanks.
   2. One demineralized water storage tank.
   3. Field applied coatings for tanks as required.
   4. Stairs to access tanks.
   5. Lighting on tanks.
   6. Piping and piping supports at tanks.
   7. Painting of tanks.

CONTRACT C8110 – SITE PREPARATION / CIVIL / FOUNDATIONS

B. General Description: This is a construction contract for site preparation, civil and foundations. Services include the following:

1. Comply with requirements of the Project's Best Management Practices (BMP), including providing sediment and erosion control materials and maintaining them.
2. Perform clearing, grubbing, and grading of required area on plant site.
3. Perform sampling, testing and analysis of the site soil compaction.
4. Performing rough and finish grading for the following:
    a. New equipment areas.
    b. Construction parking including surfacing.
    c. Construction lay-down including surfacing.
    d. New roadway(s) and construction surfacing.
5. Construction service roads.
6. Precast utility trenches.
7. Underground utilities relocation, if required.
8. Underground utilities installation, if required.
9. Temporary yard lighting.
10. Fencing and gates.
11. Storm drainage system.
12. Perform final trash and construction debris removal and disposal of required areas on plant site.
13. Maintain temporary construction facilities (runoff ponds, lay-down area, parking areas, access roads, temporary fencing, temporary utilities, etc.).
14. Install and construct mats, foundations, grade beams and anchor bolts as required for Contracts C2190, C2763, C2970, C5300, C5310, and C6110.
15. Furnish and install below grade electrical grounding grid.
16. Excavation, subgrade preparation, dewatering and backfill for foundations.
17. Furnish and install electrical manholes, duct banks, and below grade conduit embedded in or under concrete.
18. Furnish and install permanent drains to existing system as required.
19. Manufacture and / or test and deliver to site the following Equipment and Materials including:
    a. Concrete and rebar.
    b. Crushed rock base and surface course.
20. Construction labor, supervision, materials, tools, equipment, machinery, scaffolding and blocking necessary for performing final construction work not included in other contracts, including the following:

  a. Storm drainage system including curbs and gutters, if applicable.
  b. Rock surfaces.

21. Miscellaneous foundations.

CONTRACT C8140 – SITE FINISHING

A. General Description: This is a construction contract for finish grading and concrete pavement installation and required site work not covered by other contracts. Contractor's responsibilities include the following:

1. Construct the subgrade for the final surfacing.
2. Concrete paving.
3. Asphalt overlay of existing plant roads.
4. Complete finish grading and final drainage.
5. Furnish and place crushed rock, concrete paving, and concrete surfacing not completed under Contract C8110.
6. Complete final pavement markings, if required.
7. Comply with requirements of the Project's BMP.
8. Topsoil and seed disturbed areas not receiving alternate surfacing.
9. Upon completion of the Project, remove erosion control structures once proper grass has been established.

CONTRACT C8320 – MECHANICAL CONSTRUCTION

A. General Description: This is a construction contract including the following:

1. Unload, receive, store (if required), and install equipment furnished by the following contracts:
   a. Miscellaneous Pumps by Contract C2190 – Miscellaneous Pumps.
   b. Fuel oil heaters by Contract C2763 – Fuel Oil Heating.
2. Procure, fabricate, deliver, receive, protect, store, haul, assemble, erect, install, and place into service equipment and material including, but is not limited to, the following:
   a. Balance of plant piping, valves, pipe supports (including supplemental structural steel and miscellaneous concrete pads), piping specials (expansion joints, strainers, filters, etc.) insulation and lagging.
   b. Line mounted instruments for monitoring and analog control of the supporting systems and associated equipment.
   c. Miscellaneous instruments and transmitters not included in another equipment package, including installation materials, such as brackets, adapters, tubing, etc.

d. Enclosures for CTG fuel oil and water injection skids, including heating and ventilation equipment.
e. Structural steel for utility racks, stair towers, and miscellaneous supports.
f. Fire water equipment and materials including:
    1) Piping and valves to extend the existing underground fire protection system to new equipment areas for new hydrants.
g. Plant heat tracing system for areas (if required). Work will be completed to specified terminal points and include monitoring system. Wiring from terminal points will be by Contract C8410 – Electrical Construction.
h. Pipe insulation, if required.

3. Complete checkout, testing and assisting EKPC in placing into service of mechanical systems and equipment installed under this package.
4. Performing touch-up painting for equipment and materials provided by other contracts (if required).
5. Applying final paint systems to equipment and materials installed by Contract C8320 including the following:
    a. Equipment.
    b. Utility rack.
6. Providing final cleanup of areas worked around or painted by this Contract.

CONTRACT C8360 – FIRE PROTECTION CONSTRUCTION

A. General Description: This is a construction contract for fire protection construction including the following:

1. CO_2 Fire water equipment and materials including:
    a. CO_2 storage containers
    b. Piping, valves, and instrumentation to supply CO_2 to fuel oil and water injection pump enclosures.
2. Fire alarm systems including:
    a. Integration with existing fire alarm system
    b. Additional fire alarms for CO_2 protection equipment and
3. Complete checkout, testing and assisting EKPC in placing into service of mechanical systems and equipment installed under this package.
4. Providing final cleanup of areas worked around or painted by this Contract.

CONTRACT C8410 – ELECTRICAL CONSTRUCTION

A. General Description: This is a construction contract for electrical construction including the following:

1. Furnish and install wiring for equipment, instruments and controls on the Project.
2. Receive, unload, store, install and wire the following equipment:
   a. Contract C5300 – Switchgear Modifications.
   b. Contract C5310 – Electrical Building (APE 2).
3. Provide the following electrical equipment:
   a. Lighting transformers.
   b. 480V power panels.
   c. 120 / 208V lighting panels.
   d. Lighting contactors.
4. Furnish and install above grade conduit raceway systems.
5. Furnish and install cable tray.
6. Furnish and install power cabling to heat trace equipment provided by others.
7. Perform electrical testing.
8. Make final grounding connections.
9. Furnish and install welding outlets.
10. Label cable tray and cable.
11. Perform structure-related wiring including:
    a. Furnish, install and wire lighting / convenience outlets.
    b. Wire HVAC systems.
    c. Furnish and install extension to existing GAI-Tronics communication / paging system.
12. Provide electrical testing services including:
    a. Test equipment.
    b. Personnel to perform wire checking and testing of wiring systems, equipment and controls.
13. Perform electrical system testing of the following systems:
    a. Small power transformers.
    b. Switchgear.
    c. Bus duct.
    d. Protective relays.
    e. Motor control centers.

f. Power panels and associated dry type transformers.

g. Heat trace monitoring panels.

h. Power wiring.

i. Control wiring.

CONTRACT C9020 – SURVEYING

A. General Description: Perform the scope of work as outlined below:

1. Survey of existing site for new equipment locations.
2. Topographic surveys of existing areas associated with the Project
3. Provide survey report and drawings.

CONTRACT C9030 – PILOT TRENCHING

A. General Description: This is a construction contract including the following:

1. Excavation, waste material management, and bracing for trenching to uncover existing below-grade utilities, foundations, and other obstructions by means of a water / air jet and vacuum-extraction system or open cut excavation.
2. Removal and replacement of pavement where required.
3. Dewatering of pilot trenches.
4. Backfilling and compaction of pilot trenches.
5. Soil/compaction testing services as required.
6. Surveying/documenting utilities that have been found.

CONTRACT C9250 – PERFORMANCE TESTING

A. General Description: Perform the scope of work as outlined below:

1. Develop and provide performance test protocol for Owner review.
2. Provide labor and materials required for performance testing of the three CTGs on fuel oil and natural gas operation after dual fuel implementation.
3. Coordinate with EKPC and other parties to obtain fuel oil and fuel gas samples during performance testing.
4. Perform on-site and off-site laboratory analyses on fuel oil and fuel gas samples collected.
5. Provide performance testing report following completion of testing.

CONTRACT C9260 – EMISSIONS TESTING

A. General Description: Perform the scope of work as outlined below:

1. Develop and provide emissions test protocol for Owner review.

2. Provide labor and materials required for emissions testing of the three CTGs on fuel oil and natural gas operation after dual fuel implementation.
3. Coordinate with EKPC and other parties to obtain fuel oil and fuel gas samples during emissions testing, if additional fuel samples required beyond those taken for performance testing.
4. Perform on-site and off-site laboratory analyses on fuel oil and fuel gas samples collected, if required.
5. Provide emissions testing report following completion of testing.

4.4.3 Equipment Contracts

CONTRACT C2190 – MISCELLANEOUS PUMPS

A. General Description: Design, manufacture and deliver equipment and materials including the following:
   1. Miscellaneous pumps as indicated on the equipment list for C2190.
   2. Piping, valves, and instruments on the skids, as required.
   3. Submittals and operating and maintenance manuals.
   4. Field technical services to support startup.

CONTRACT C2763 – FUEL OIL HEATING

A. General Description: Design, manufacture and deliver equipment and materials including the following:
   1. Fuel oil electric heaters as indicated on the equipment list for C2763.
   2. Valves and instruments on skids, as required.
   3. Submittals and operating and maintenance manuals.
   4. Field technical services to support startup.

CONTRACT C5300 – SWITCHGEAR MODIFICATIONS

A. General Description: Design, manufacture, and deliver Equipment and Materials including the following:
   1. New breakers for existing 4160V Switchgear #1 & #2.
   2. New contactors for existing 4160V MCC #1 & #2.
   3. New contactor section for existing 4160V MCC #2.

CONTRACT C5310 – ELECTRICAL BUILDING (APE 2)

A. General Description: Design, manufacture, and deliver Equipment and Materials including the following:
   1. Power control module (PCM) for the low-voltage fuel oil equipment.
   2. 480V switchgear and MCC's.
   3. 4160V – 480V transformers.
   4. Non-segregated phase bus.
   5. 125VDC battery and chargers.

CONTRACT C6110 – DISTRIBUTED CONTROL SYSTEM (DCS)

A. General Description: Design, manufacture and deliver Equipment and Materials including the following:
   1. DCS controllers and IO.
   2. DCS communications hardware and software to communicate with new equipment to be installed.
   3. DCS network equipment and requisite media converters.
B. Provide services to integrate logic diagrams and graphic sketches to control and monitor the new fuel oil and demineralized water equipment.
C. Furnish field services to integrate the new DCS equipment with the existing DCS equipment and to support the startup and commissioning of the logic, operator graphics, and communication interfaces.

* * * * *

5.0 SCHEDULE

5.1 Critical Milestones

The current schedule is based on a limited notice to proceed on engineering for the Project in April 2018, with the new equipment in service and operational in December 2020. Several key Project milestones will need to be accomplished to meet the overall schedule for the Project. A list of suggested important milestones as indicated on the Level 1 Project schedule included with this report are listed in Table 1-2.

The schedule is dependent on Project approvals and a variety of other influences, in particular the CPCN permit approval. Equipment may not be procured, and construction cannot commence until the CPCN permit approval is received. The LNTP for detailed design is meant to prepare the major equipment specification for the combustion turbine dual fuel implementation, initiate preliminary engineering to achieve the indicated schedule milestone dates, and initiate engineering design for the combustion turbine contractor.

5.2 Project Schedule

A level 1 Project schedule was prepared by BMcD for this Project which is included in Appendix E. PJM plans to phase in Capacity Performance changes and requirements beginning in the 2018/2019 delivery years. The proposed schedule will not provide backup fuel oil at Bluegrass in time for the beginning phases of the Capacity Performance changes, but it is expected to provide EKPC the ability to meet the final expected PJM timeframe associated with the Capacity Performance Program. PJM expects to transition 100% of capacity to Capacity Performance resources by the 2020/2021 delivery years. As part of the Project, three outages, one for each combustion turbine, will be needed to perform construction that can only be accomplished while each unit is off-line. Currently, those outages are arranged in consecutive fashion in lieu of in parallel, however performing the outages in parallel can be further refined during the LNTP phase. Mechanical and electrical construction will take place prior to and in parallel with the three outages for the balance of plant including the fuel oil tanks, electrical building (APE 2), interconnecting piping and cables.

The scope split for the equipment and construction contracts is described in Section 4.0 – Contracting Approach. The performance of each construction contract is anticipated to be continuous without intermediate demobilization and remobilization.

The schedules are based on early procurement of the long lead equipment. Vendor submittals are required from each equipment contractor which will support the detailed design of infrastructure (foundations, piping, wiring, instrumentation, etc.) required for installation of this equipment. Sufficient time has been built into the schedule for an Owner's Engineer to perform the detailed design to obtain competitive, lump sum bids for the respective equipment and construction contracts.

* * * * *

6.0 COST ESTIMATE

6.1 General

A Class 3 capital cost estimate for the proposed Project is included in Appendix F. The estimated cost for these upgrades, inclusive of contingency and escalation is $62.8 MM. No financing fees or interest during construction was included in the Project costs.

6.2 Basis and Assumptions

The following describes the methodology used in the development of the Project cost estimate.

- The estimate is based on the assumptions and scope of supply indicated in this document and the Project assumptions in Section 3.0 and Appendix C. Design parameters and scope typically defined by these scoping studies are estimated based on information provided by EKPC, preliminary calculations and BMcD experience.
- BMcD solicited and received budget level vendor quotations for the following:
  - Combustion Turbine Dual Fuel Implementation
  - Fuel Oil Heating
  - Field Erected Tanks (F&E)
  - Fuel Oil Unloading Pumps
  - Fuel Oil Forwarding Pumps
  - Demineralized Water Transfer Pumps
- The new EKPC proposed substation is not considered in this cost estimate.
- The EKPC planned work on the existing plant's DCS system is not considered in this cost estimate.
- Balance of Plant equipment: BMcD utilized in-house information from similar projects when developing the estimate, if budgetary quotes were not solicited.
- Construction Estimates: BMcD used recent pricing information from an internal database and industry standard pricing for construction commodities and indirect costs in the area of La Grange, Kentucky.
- Labor rates: Labor rates and productivity factors were developed based on BMcD in-house information which included a labor study in nearby regions.

6.2.1 Capital Cost Estimate Scope

A Project scope description for the cost estimate is included in Section 3.0. These descriptions along with the drawings and lists included in Appendices A, B and C define the scope included in the cost estimate.

6.2.2 Major Capital Cost Estimate Assumptions

Several major assumptions were used in developing the capital cost estimate. These assumptions include the following:

- Commercial operation of the equipment is assumed to be December 2020.
- Labor is assumed union labor and available without excessive hourly incentives or incentive packages.
- Escalation is assumed to average 2% per year for equipment and materials and 3% per year for labor.
- Contingency is included at 12% for Project estimate and definition contingency. Owner's contingency for discretionary expenditures has not been included and will be evaluated on a case-by-case basis during Project execution.
- Cost for Builder's Risk Insurance was based on 0.45% of the direct costs.
- Costs for Performance Bonds were included in the major contract pricing buildups.
- Sales tax at 6% is included on the equipment and material costs associated with the Project, since this Project does not meet a sales tax exemption in Kentucky.
- No financing fees or interest during construction was included.

6.2.3 Major Commercial Terms

The following lists the major commercial terms assumed in developing the cost estimates. Minor assumptions are either self-evident in the data or have an insignificant effect on the estimated Project capital costs.

- Project is assumed to be performed with multiple prime contracts for the construction work as defined in Section 4.0 – Contracting Approach. Major equipment identified in Section 3.0 and minor equipment items (piping specialties, small-bore piping, wiring and other construction commodities) are expected to be included in the construction contracts.
- Project will include multiple equipment procurement contracts including contracts for combustion turbine dual fuel implementation, miscellaneous pumps, fuel oil heating, field erected tanks, and APE 2 as defined in Section 4.0 – Contracting Approach.
- Project will be executed with durations similar to those shown on the Project schedule with the objective of achieving the Project milestone dates. It is assumed the Project will be executed with a schedule sufficient to minimize overtime. A 50-hour workweek was assumed as a means of providing an incentive to attract labor. This includes 40 hours of straight time and 10 hours of

overtime for normal construction periods. A 50-hour workweek was assumed during commissioning and start-up. It is anticipated that a 60-hour workweek will be utilized by the combustion turbine contractor to make the necessary changes for dual fuel implementation; however, this detail was not provided by the OEM. No additional overtime is included to accommodate a compressed work schedule.

6.3 Operations & Maintenance Estimates

The differential (new vs. existing) O&M costs for Bluegrass in 2017 dollars for this Project have been calculated and determined to be an additional $600k per year, based on operating assumptions. Refer to Appendix F for a summary of the O&M costs and basis assumptions.

6.4 Economic Conditions Considerations

An estimate for escalation of Project costs has been included in the capital cost estimate. Escalation of construction labor, materials, and indirects (including warranty, bond, and insurance) was based upon the average increase in craft labor costs for the United States at the time of this evaluation.

6.5 Contingency

A Project estimate and scope contingency is included to cover accuracy of pricing and commodity estimates for the defined Project scope. This contingency is not intended to cover changes in the general Project scope (i.e. addition of buildings, addition of redundant equipment, addition of systems, etc.) nor major shifts in market conditions that could result in significant increases in contractor margins, major shortages of qualified labor, significant increases in escalation, or major changes in the cost of money (interest rate on loans).

Owner's contingency has been excluded per EKPC direction and discretionary costs will be evaluated during Project execution on a case-by-case basis.

6.6 Summary Cost Estimate

The capital cost estimate developed for the Bluegrass Dual Fuel Implementation Project is contained in Appendix F.

6.7 Summary Cost Item Description

The cost estimate is based on the multiple contracting approach defined in Section 4.0 – Contracting Approach. Additional mark up costs have been included for equipment, labor and material assumed subcontracted. The contracting approach was developed concurrently with the cost estimate and the summary cost estimate is not broken down by Contract.

6.8 Cash Flow

A cash flow based on the Project schedule, contracting approach, and the cost estimate was developed and is included in Appendix G.

* * * * *

APPENDIX A - DRAWINGS

EXHIBIT G

Attachment SY-3

Appendix A - Drawings

APPENDIX B - EQUIPMENT LIST

BURNS & McDONNELL

Equipment List

East Kentucky Power Cooperative
Bluegrass Station - Dual Fuel
Project No. 97273

Equipment Name / Description	Skid Name	Motor Rating / Rated Load / Capacity	Supply By	Construct By	Notes
Fuel Oil Pump (Unit 1)	Fuel Oil Pump Skid	400 hp	5.1120	5.1120	Gas Turbine Supplier
Fuel Oil Pump (Unit 2)	Fuel Oil Pump Skid	400 hp	5.1120	5.1120	Gas Turbine Supplier
Fuel Oil Pump (Unit 3)	Fuel Oil Pump Skid	400 hp	5.1120	5.1120	Gas Turbine Supplier
Water Injection Pump (Unit 1)	Water Injection Pump Skid	250 hp	5.1120	5.1120	Gas Turbine Supplier
Water Injection Pump (Unit 2)	Water Injection Pump Skid	250 hp	5.1120	5.1120	Gas Turbine Supplier
Water Injection Pump (Unit 3)	Water Injection Pump Skid	250 hp	5.1120	5.1120	Gas Turbine Supplier
Stage A Fuel Oil Flow Divider (Unit 1)	Fuel Oil Water Injection Skid	0.33 hp	5.1120	5.1120	Gas Turbine Supplier
Stage B Fuel Oil Flow Divider (Unit 1)	Fuel Oil Water Injection Skid	0.33 hp	5.1120	5.1120	Gas Turbine Supplier
Pilot Fuel Oil Flow Divider (Unit 1)	Fuel Oil Water Injection Skid	0.33 hp	5.1120	5.1120	Gas Turbine Supplier
Stage A Fuel Oil Flow Divider (Unit 2)	Fuel Oil Water Injection Skid	0.33 hp	5.1120	5.1120	Gas Turbine Supplier
Stage B Fuel Oil Flow Divider (Unit 2)	Fuel Oil Water Injection Skid	0.33 hp	5.1120	5.1120	Gas Turbine Supplier
Pilot Fuel Oil Flow Divider (Unit 2)	Fuel Oil Water Injection Skid	0.33 hp	5.1120	5.1120	Gas Turbine Supplier
Stage A Fuel Oil Flow Divider (Unit 3)	Fuel Oil Water Injection Skid	0.33 hp	5.1120	5.1120	Gas Turbine Supplier
Stage B Fuel Oil Flow Divider (Unit 3)	Fuel Oil Water Injection Skid	0.33 hp	5.1120	5.1120	Gas Turbine Supplier
Pilot Fuel Oil Flow Divider (Unit 3)	Fuel Oil Water Injection Skid	0.33 hp	5.1120	5.1120	Gas Turbine Supplier
Combustion Turbine Hardware (Support Housing and Duel Fuel Pilot Nozzles)	Fuel Oil Water Injection Skid		5.1120	5.1120	Gas Turbine Supplier
CTG Fuel Oil/Water Injection Pump Enclosure Fan (Unit 1)		10 hp	5.8320	5.8320	
CTG Fuel Oil/Water Injection Pump Enclosure Fan (Unit 2)		10 hp	5.8320	5.8320	
CTG Fuel Oil/Water Injection Pump Enclosure Fan (Unit 3)		10 hp	5.8320	5.8320	
CTG Fuel Oil/Water Injection Pump Enclosure heater (Unit 1)		10 kW	5.8320	5.8320	
CTG Fuel Oil/Water Injection Pump Enclosure heater (Unit 2)		10 kW	5.8320	5.8320	
CTG Fuel Oil/Water Injection Pump Enclosure heater (Unit 3)		10 kW	5.8320	5.8320	
Demineralized Water Transfer Pump 1 (4x100%)	Demineralized Water Pump Skid 1	20 hp	5.2190	5.8320	
Demineralized Water Transfer Pump 2 (4x100%)	Demineralized Water Pump Skid 2	20 hp	5.2190	5.8320	
Demineralized Water Transfer Pump 3 (4x100%)	Demineralized Water Pump Skid 3	20 hp	5.2190	5.8320	
Demineralized Water Transfer Pump 4 (4x100%)	Demineralized Water Pump Skid 4	20 hp	5.2190	5.8320	
Fuel Oil Unloading Pump 1 (2x100%)	Fuel Oil Unloading Skid 1	10 hp	5.2190	5.8320	
Fuel Oil Unloading Pump 2 (2x100%)	Fuel Oil Unloading Skid 2	10 hp	5.2190	5.8320	
Fuel Oil Unloading Pump 3 (2x100%)	Fuel Oil Unloading Skid 3	10 hp	5.2190	5.6320	
Fuel Oil Forwarding Pump 1 (4x100%)	Fuel Oil Forwarding Skid 1	40 hp	5.2190	5.8320	
Fuel Oil Forwarding Pump 2 (4x100%)	Fuel Oil Forwarding Skid 2	40 hp	5.2190	5.8320	
Fuel Oil Forwarding Pump 3 (4x100%)	Fuel Oil Forwarding Skid 3	40 hp	5.2190	5.8320	
Fuel Oil Forwarding Pump 4 (4x100%)	Fuel Oil Forwarding Skid 4	40 hp	5.2190	5.8320	
Fuel Oil Storage Sump Pump (2x100%)		5 hp	5.2190	5.8320	
Fuel Oil Storage Sump Pump (2x100%)		5 hp	5.2190	5.8320	
Trench Sump Area 1 Pump (1x100%)		3 hp	5.2190	5.8320	
Trench Sump Area 2 Pump (1x100%)		3 hp	5.2190	5.8320	
Trench Sump Area 3 Pump (1x100%)		3 hp	5.2190	5.8320	
Demineralized Water Storage Tank		400,000 gal	5.2970	5.2970	
Fuel Oil Storage Tanks (2 Tanks)		580,000 gal (each tank)	5.2970	5.2970	
Fuel Oil Inline Heater (3x50%)		670 kW	5.2763	5.8320	50% of total fuel oil flow (all three units)
Fuel Oil Inline Heater (3x50%)		670 kW	5.2763	5.8320	50% of total fuel oil flow (all three units)
Fuel Oil Inline Heater (3x50%)		670 kW	5.2763	5.8320	50% of total fuel oil flow (all three units)
Fuel Oil Electrical Building (APE 2) (15' x 45')			5.5310	5.8410	
Fuel Oil Electrical Building (APE 2) 4.16KV-480V 2000/2667KVA XFMR #1			5.5310	5.8410	
Fuel Oil Electrical Building (APE 2) 4.16KV-480V 2000/2667KVA XFMR #2			5.5310	5.8410	
Fuel Oil Electrical Building (APE 2) 480V 3200A Non-Seg Bus Run #1			5.5310	5.8410	
Fuel Oil Electrical Building (APE 2) 480V 3200A Non-Seg Bus Run #2			5.5310	5.8410	
Fuel Oil Electrical Building (APE 2) 480V 3200A SWGR #1			5.5310	5.8410	
Fuel Oil Electrical Building (APE 2) 480V 3200A SWGR #2			5.5310	5.8410	
Fuel Oil Electrical Building (APE 2) 480V 1200A MCC #1			5.5310	5.8410	
Fuel Oil Electrical Building (APE 2) 480V 1200A MCC #2			5.5310	5.8410	
Fuel Oil Electrical Building (APE 2) 125VDC Battery Charger #1			5.5310	5.8410	
Fuel Oil Electrical Building (APE 2) 125VDC Battery Charger #2			5.5310	5.8410	
Fuel Oil Electrical Building (APE 2) 125VDC Battery Rack, Disconnect & Panelboard			5.5310	5.8410	
Fuel Oil Electrical Building (APE 2) HVAC #1			5.5310	5.8410	
Fuel Oil Electrical Building (APE 2) HVAC #2			5.5310	5.8410	
Demineralized Water Trailer Stanchion			5.8320	5.8320	New trailer connection next to existing stanchion (200 gpm).
Unit 1 CO2 Fire Protection System for FO Pump Skid			5.8360	5.8360	Include CO2 tank, detection, etc. for new CTG fuel oil pump skid enclosure.
Unit 2 CO2 Fire Protection System for FO Pump Skid			5.8360	5.8360	Include CO2 tank, detection, etc. for new CTG fuel oil pump skid enclosure.
Unit 3 CO2 Fire Protection System for FO Pump Skid			5.8360	5.8360	Include CO2 tank, detection, etc. for new CTG fuel oil pump skid enclosure.
CTG Fuel Oil/Water Injection Pump Enclosure (3)			5.8320	5.8320	Pre-manufactured building for equipment on each unit.

APPENDIX C - SCOPE ASSUMPTIONS MATRIX

BURNS McDONNELL

		Scope Included (Y/N)	Number	% Capacity (per Unit)	Notes
GENERAL PROJECT INFORMATION					
Project Description					Dual fuel for three 501FD2 simple cycle combustion turbines to operate on fuel oil as well as existing natural gas. Requires addition of two new fuel oil tanks and a new demin water tank to provide 24-hours of backup fuel oil operation for the plant.
	Project Location				Near La Grange, KY.
	Site Description				Existing brownfield site at Bluegrass Station.
	Contracting Approach				Multi-prime.
	Labor				Union.
	Project Liquidated Damages				TBD.
	Project Bonding /LOC				100% Bonding.
	Project COD Dates				December 2020.
	Project Expansion				No future expansion considered; Combined Cycle location not considered and SCR remains decommissioned.
MECHANICAL EQUIPMENT					
AQUEOUES AMMONIA SYSTEM					
	Ammonia Flow Control Skid	N			
	Ammonia Forwarding Pump Skid	N			
	Ammonia Storage Tank	N			
	Ammonia Unloading Skid	N			
	SCR Ammonia Distribution Grid	N			
	SCR Catalyst	N			
	Detection	N			
DEMINERALIZED WATER SYSTEM					
	Demineralized Water Transfer Pumps	Y	4	100	1 x 100% for each combustion turbine unit with 1 x 100% common spare.
	Demineralized Water Storage Tank	Y	1	100	Add new 400,000 gal tank for 24-hours of fuel oil operation in addition to existing 300,000 gallon tank. New and existing tanks will be cross-tied.
	Demineralized Water Trailers	Y	1		Add one Demin Trailer stanchion next to existing connections for Demin Trailer which handles 200 gpm.
CLOSED COOLING WATER					
	CCW Heat Exchanger	N			
	CCW pumps	N			
	Glycol type	N			
FUEL OIL					
	Storage	Y	1		Two (2) 580,000 gal tanks for 24 hr storage. Tanks will be in concrete containment sized to contain largest tank volume.
	Transfer Pumps	Y	4	100	1 x 100% for each combustion turbine unit with 1 x 100% common spare located near fuel oil tank.
	Unloading	Y	3	100	Two (2) truck unloading stations. 1 x 100% unloading pump for each unloading station with 1 x 100% common spare.
	Heating	Y	3	50	3 x 50% inline electric heaters with recirculation system. Each heater sized for 50% of total plant fuel oil flow (all three units).
MAKE-UP WATER SUPPLY					
	Supply Source				Municipal Water.
	Service/Fire Water Storage	N			Existing 450,000 gallon tank.
	Service Water Transfer Pumps	N			Existing.
WASTEWATER					
	Contaminated Wastewater	Y			Drains for areas around equipment that could be contaminated with oil will be directed through the existing oil/water separator (OWS). Discharge OWS effluent to outfall #001. Existing OWS has capacity of 300 gallons.
	Water Treatment Reject	N			No rejects; rental system used.
FIRE PROTECTION					
	Design Basis	Y			FM Global and NFPA 850 recommended practice.
	Insurer/special requirements	N			
	CTG FP	Y			Additional CO2 and fire alarm added for Fuel Oil/Water Injection skid enclosures.
	Pump supply source(s)	N			Existing Electric motor and Diesel driven fire pump taking suction from the Service/Fire Water Storage Tank.
	Storage	N			Existing Service/Fire Water Tank.
	Fire loop	Y			Branch of existing loop extended out to fuel oil storage area to supply hydrants only.
COMPRESSED AIR					
	Air Compressors	N			Tie-in to existing system. Each unit has its own compressor. Tie-in to receivers next to each unit to provide compressed air to new enclosures. Fuel oil storage area will have compressed air provided from Unit 1's tie-in to the existing compressor.
CATHODIC PROTECTION					
	Underground Steel Piping	N			
	Underground Steel Tanks	N			
CONTROLS					
Equipment Control					
	CTG	Y			EKPC is already planning to upgrade Siemens turbine control system to the T-3000 system. No additional controls upgrades required. Interface with upgraded TCS.
	Medium Voltage Switchgear	Y			Interface with upgraded TCS.
	Motor Control Centers	Y			Interface with upgraded TCS.
	Low Voltage Switchgear	Y			Interface with upgraded TCS.
	Plant Control System	Y			Interface with upgraded TCS.
	Plant Historian	Y			Interface with upgraded TCS.
	Offsite Interfaces	Y			Interface with upgraded TCS.
Automatic Generation Control					
	CTG	Y			Interface with upgraded TCS.

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	Scope Included (Y/N)	Number	% Capacity (per Unit)	Notes
Vibration monitoring				
CTG	N			Existing.
Fin-Fan Cooler Fans	N			Existing.
Plant Simulator	N			
Digital Bus				
Foundation Fieldbus	N			
Remote I/O	Y			For fuel oil tank, unloading, and forwarding pumps.
Instrumentation				
Redundancy	N			1x100% existing typical. Fuel flow to unit is 1x100% existing.
Transmitters	Y			4-20 mA as available.
HART	Y			Install tri-loops on valves for feedback.
Performance Testing	N			
Meteorological Station	N			
Continuous Emissions Monitoring System	N			Existing; fuel flow meter needs to be downstream side of recirc.; fuel sample will be required to be taken each time the units are run on fuel oil.
Relaying Data Link	N			Existing.
Communication				
Dispatching	N			Existing.
Off site monitoring/administrations	N			Existing.
Switchyard	N			Existing.
Internal plant	N			Existing; add communications to the new fuel oil tank location.
External	N			Existing.
NERC CIP Requirements	N			No Changes.
HMI	Y			Local HMI at truck unloading.
ELECTRICAL				
Generator Step-Up Transformers:				
Gas Turbine	N			Existing.
Auxiliary/Reserve Transformers:				
Auxiliary Transformer	N			Existing.
Generator Buses:				
Gas Turbine	N			Existing.
Electrical Equipment Enclosures:	Y			Shop fabricated Auxiliary Power Enclosure (APE 2) to house large electrical power distribution equipment.
Bus Duct:				
Iso-Phase	N			Existing.
Switchgear:				
4160V Switchgear	Y			Existing, 4.16KV, 33KA interrupting, low resistance grounded system, main-tie-main configuration, GE SR750/469 relays, sufficient capacity to source main-tie-main from one main breaker, scope includes modifications for new fuel oil equipment; 2 spare motor contactors, 1 spare breaker, 3 spare cubicles, 1 new section.
480V Switchgear	Y			480V, 65KA interrupting, high resistance grounded system with dedicated ground detection system, main-tie-main configuration, sufficient capacity to source main-tie-main from one main breaker.
Motor Control Centers:				
480 V MCCs	Y			480V, 3-Phase, 3-Wire, 65KA.
Emergency Power:				
Uninterruptible Power (UPS)	N			Existing, in main admin building (120V).
DC System	Y			Existing, in main admin building (120V).
On-Line Battery Monitoring:	Y			
Lighting	Y			LED for roadway lighting; lighting required for new road turnaround and unloading area.
CIVIL/STRUCTURAL				
Existing Facilities	Y			Brownfield site. Tie into existing Bluegrass system.
Disposal of Spoils	Y			Excess spoils will be disposed of on-site, used for fill if possible. No hazardous materials accounted for in project estimate.
Soils Conditions / Stability	Y			No piles required based on review of existing foundations at site and geotechnical investigation from April 2017.
Subsurface Rock	Y			Subsurface rock is expected to be encountered for installation of the foundations. It will be removed as required to install these foundations.
Subsurface water	N			No dewatering included as groundwater not encountered in geotechnical investigation performed in April 2017.
Cut/Fill	Y			Use existing site materials to grade the site and minimize off-site borrow.
Disposal of debris	Y			Disposed of on-site.
Permanent Stormwater	Y			Modifications required for new road turnaround to existing stormwater system.
Construction Stormwater	Y			Erosion control will be in accordance with state and local guidelines and regulations and EKPC's BMPs.
Roads	Y			Existing plant roads to access the fuel oil storage area will have additional asphalt surfacing for truck delivery. Add new road loop/turnaround at fuel truck unloading station.
Surfacing	Y			Maintenance areas will be covered with crushed rock. Other areas top soil and seeded.
Soil Bearing Capacity	Y			Soil bearing capacity at 3,000 psf net allowable, per geotechnical report.
Foundation type	Y			Shallow or mat foundations based on review of existing foundations at site.
Enclosures				
Pumps	Y			Fuel oil pump injection skid and water injection skin in new enclosure. Forwarding pumps and unloading station will be located outdoors.
Electrical (see electrical section)				
Access				
Spacing between units				Unchanged.

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		Scope Included (Y/N)	Number	% Capacity (per Unit)	Notes
Maintenance cranes		N			
Guard shack		N			
Fence		Y			Modified around fuel oil tanks and unloading area.
CONSTRUCTION					
Utilities					
	Power	Y			Tie-in to EKPC or existing overhead line near existing warehouse.
	Communication	Y			Tie-in to EKPC.
	Construction Water	Y			Tie-in to EKPC.
	Potable Water	Y			Tie-in to EKPC.
	Sanitary	Y			Tie-in to EKPC.
Parking					
Gate Entry					
	Main	Y			Existing Bluegrass guard shack.
	Personnel/Craft	Y			Existing Bluegrass main gate and guard shack.
	Delivery	Y			Construction deliveries via truck. Unloading and handling by each Contractor.
Construction Field Office / Trailers					
	Owner	Y			Office in Existing Admin Building.
	Engineer	Y			Trailers in Owners Costs.
	Vendors	Y			Trailers in Owners Costs.
	Contractors	Y			Trailers in Owners Costs.
	Site Services	Y			Trailers in Owners Costs.
Laydown area		Y			Near existing warehouse, northwest of plant, in open flat area.
Performance Testing		Y			Allowance included.
Permits		Y			Construction permits are included.
Warehouses		N			Existing warehouse is full; Contractor will provide necessary storage space during construction.
TRANSMISSION / INTERCONNECTION					
Transmission		N			Not included.
Substation		N			Not included.
COMMERCIAL					
General Liability Insurance		Y			Allowance included.
Builder's Risk Insurance		Y			Allowance included.
Performance Bonds		Y			Included in individual contract buildups within the Project costs.
Project L/D's		Y			Schedule and performance for each contract.
Retention		Y			A 10% retention will be required for each contract.
Warranty		Y			Warranty on major equipment will be required for 18 months + 18 months from commercial operation. Warranty on auxiliary equipment will be required for 18 months + 18 months from substantial completion to the extent possible.
PROJECT INDIRECTS					
Project Development		Y			Allowance included in Owners Costs.
Owner's Operation Personnel		Y			Allowance included in Owners Costs.
Owner's Project Management		Y			Allowance included in Owners Costs.
Owner's Engineering		Y			Allowance included in Owners Costs.
Owner's Legal Counsel		Y			Allowance included in Owners Costs.
Operator Training		Y			Allowance included.
Permitting & License Fees		Y			Allowance included in Owners Costs.
Landfill		N			Not applicable.
Site Security		Y			Allowance included in Owners Costs.
Warehouse Shelves		N			Not included.
Mobile Equipment, Vehicles		Y			Allowance included.
Laboratory Equipment		Y			No special laboratory equipment is included or required.
Commissioning Fuel & Consumables		Y			Allowance included in Owners Costs.
Commissioning Test Power Sales		N			Not included.
Operating Spare Parts		Y			Allowance included in Owners Costs.
Commissioning Spares and First Fills		Y			Included in Project Costs and Owners Costs.
Plant Maintenance Tools		N			Not included.
Sales Tax		Y			Included in estimate for materials and equipment.
Escalation		Y			Escalation is included at 2% per year on materials and equipment, and 3% per year on labor.
Contingency		Y			Estimate and definition contingency of 12%. Owner's contingency not included and will be treated on a case-by-case basis.
OWNER COSTS / MISC.					
Permits					
	See Permit Matrix	Y			EKPC w/ Owner's Engineer Support.

APPENDIX D - SUMMARY EMISSIONS INFORMATION

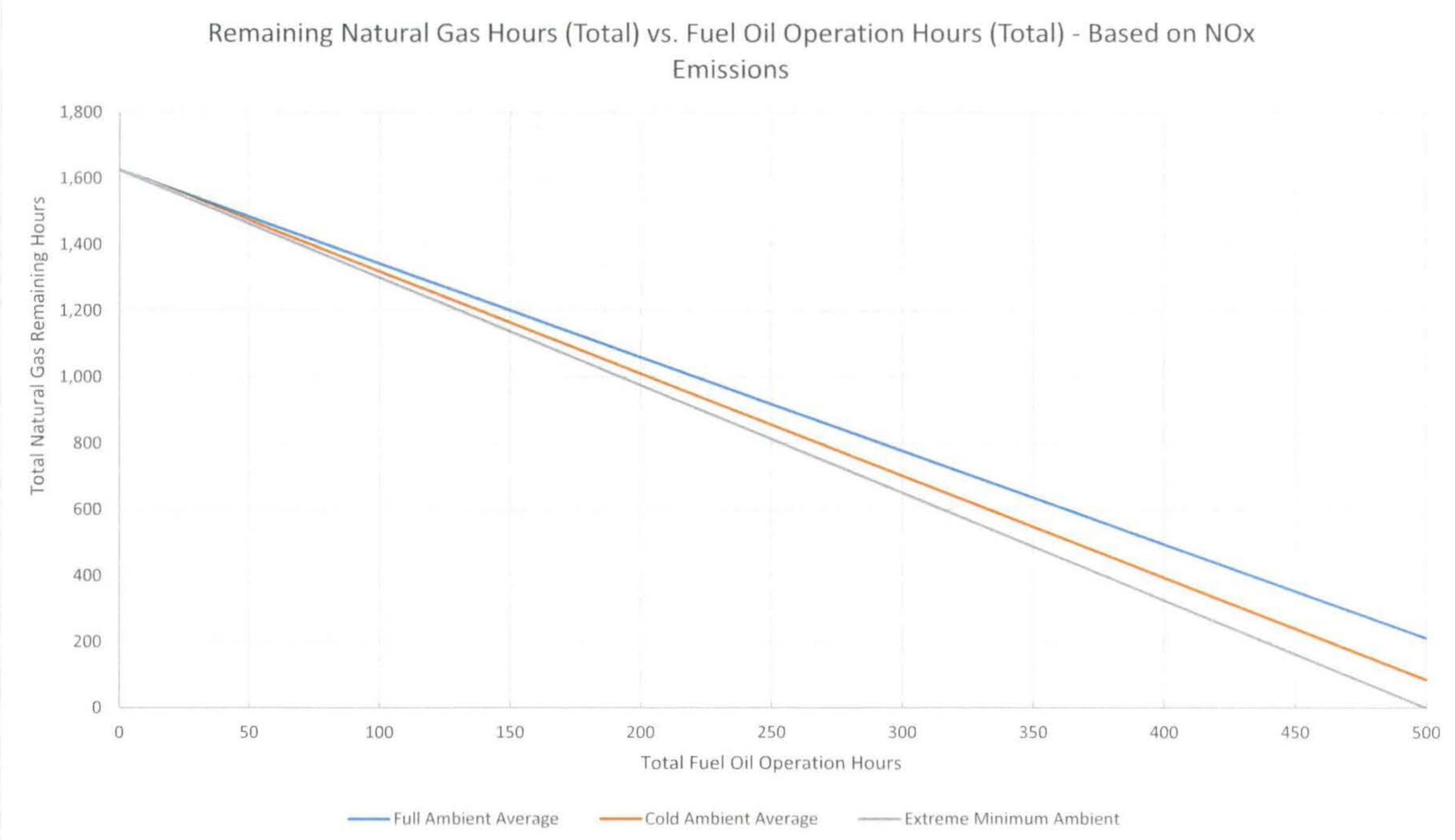
BURNS & McDONNELL

Client	EKPC		
Project	Bluegrass Fuel Oil	Date:	8/13/2018
	3 x 501FD2 (Fuel Oil)	Revision:	3

NOTE: Not for Guarantee

Case #		Case 1	Case 2
Case Description		100% 0°F	100% 51°F
Ambient Temperature		0 F	51 F
Gas Turbine Load		100%	100%
Evaporative Cooling		OFF	OFF
Water Injection		ON	ON
No. of Gas Turbines In Operation		1 to 3	1 to 3
Gas Turbine Fuel		Fuel Oil	Fuel Oil
Ambient Conditions			
Temperature	degree F	0	51
Relative Humidity	%	66%	60%
Wet Bulb Temperature	degree F	-1.1	44.5
Pressure	psia	14.60	14.60
Gas Turbine Generator Performance (Per GTG)			
GTG Heat Input- LHV	MMBtu/hr	1,971	1,772
GTG Heat Input- HHV	MMBtu/hr	2,103	1,890
Water Injection Rate (per GTG)	lb/hr	42,740	38,410
Exhaust Flow (per GTG)	lb/hr	4,416,322	4,067,237
Stack Volumetric Analysis, Wet			
Ar	%	0.90%	0.89%
CO2	%	5.04%	4.91%
H2O	%	6.30%	6.79%
N2	%	75.00%	74.57%
O2	%	12.76%	12.84%
Stack Emissions at Exit			
NOx Emissions			
NOx,@15% O2	ppmvd	42.0	42.0
NOx, as NO2 (per GTG)	lb/hr	353.0	317.0
CO Emissions			
CO, @ 15% O2	ppmvd	30.0	30.0
CO (per GTG)	lb/hr	154.0	138.0
SO2 Emissions			
SO2 in Exhaust Gas (assuming no conversion) (per GTG)	lb/hr	107.0	96.0
SO2 in Exhaust Gas (assuming no conversion) (per GTG)	lb/MMBtu	0.0509	0.0508
Volatile Organic Compounds			
VOC @ 15% O2	ppmvd	10.0	10.0
VOC as CH4 (per GTG)	lb/hr	29.0	26.0
Particulates			
PM, Filterable & Condensable (per GTG)	lb/hr	63.0	58.0
PM, Filterable & Condensable (per GTG)	lb/MMBtu	0.0300	0.0307

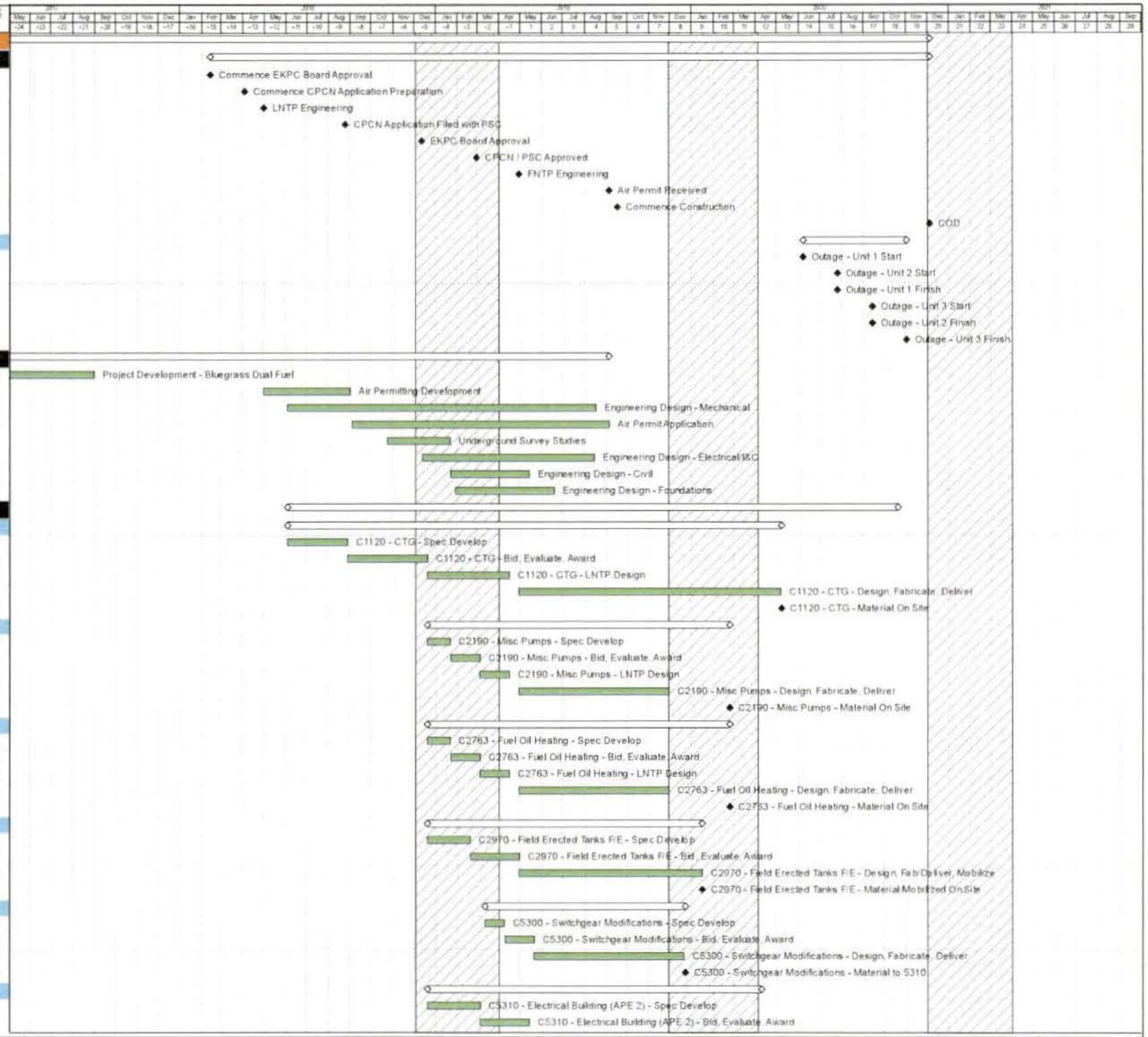
Notes:
1. Particulate values are per US EPA Method 5/202 (front and back half).
2. Emission values do not include heavy metals (lead, mercury, etc.)
3. Differing fuel composition may change the calculated emissions.
4. CTG performance and emissions based on preliminary information from Siemens.
5. Fuel based on Distillate Fuel Oil No. 2: weight composition - 86.434% C, 13.5% H, 0.05% S, 0.015% FBN, and 0.001% ash.
6. Stack SO2 content reported with no conversion to SO3.
7. Emissions exclude ambient air contributions.
8. VOC consists of total hydrocarbons excluding methane and ethane and are expressed in terms of methane.
9. Emissions reported on the basis of pounds per hour are for one combustion turbine.
10. Emissions estimates are for preliminary information only and are NOT guaranteed.



Y = annual hours available for natural gas operation (plant total), X = annual fuel oil operation hours (plant total)
Full Ambient Average: Y = -2.8274*X + 1625
Cold Ambient Average: Y = -3.0800*X + 1625
Extreme Minimum Ambient: Y = -3.2491*X + 1625
*Maximum annual natural gas operation hours (1625) based on Emissions with Current HW.xlsx provided by EKPC.
*Assumes natural gas NOx emissions is 105 lb/hr.
*Includes NOx emissions for 40 natural gas starts/shutdowns per year and 12 fuel oil starts/shutdowns, per combustion turbine (120 and 36 total, respectively)

APPENDIX E - SCHEDULE

Activity ID	Activity Name	OD	Start	Finish	TOTAL FLOAT
EKPC - Bluegrass Dual Fuel Conversion					
Milestones					
MS-1020	Commence EKPC Board Approval	0	13-Feb-18*		0
MS-1031	Commence CPCN Application Preparation	0	03-Apr-18*		0
MS-1010	LNTP Engineering	0	30-Apr-18*		0
MS-1033	CPCN Application Filed with PSC	0		24-Aug-18	64
MS-1021	EKPC Board Approval	0		11-Dec-18*	0
MS-1032	CPCN / PSC Approved	0		28-Feb-19	64
MS-1011	FNTP Engineering	0	30-Apr-19		22
MS-1040	Air Permit Received	0		04-Sep-19	53
MS-1062	Commence Construction	0	16-Sep-19		46
MS-9000	COD	0		04-Dec-20*	0
Plant Outages for Project					
MS-OUT-U1S	Outage - Unit 1 Start	0	07-Jun-20*		1
MS-OUT-U2S	Outage - Unit 2 Start	0	26-Jul-20*		1
MS-OUT-U1F	Outage - Unit 1 Finish	0		26-Jul-20*	0
MS-OUT-U3S	Outage - Unit 3 Start	0	13-Sep-20*		1
MS-OUT-U2F	Outage - Unit 2 Finish	0		13-Sep-20*	0
MS-OUT-U3F	Outage - Unit 3 Finish	0		01-Nov-20*	0
Engineering Services					
EN-CPD	Project Development - Bluegrass Dual Fuel	171	03-Jan-17*	31-Aug-17	166
PP-1010	Air Permitting Development	88	30-Apr-18	31-Aug-18	53
EN-1030	Engineering Design - Mechanical	307	04-Jun-18	16-Aug-19	32
PP-1020	Air Permit Application	255	04-Sep-18	04-Sep-19	53
EN-1010	Underground Survey Studies	60	24-Oct-18	21-Jan-19	51
EN-1080	Engineering Design - Electrical/I&C	170	13-Dec-18	14-Aug-19	46
EN-1040	Engineering Design - Civil	80	22-Jan-19	13-May-19	68
EN-1120	Engineering Design - Foundations	100	29-Jan-19	18-Jun-19	46
Procurement Services					
1120 - Combustion Turbine Generator					
PR1120-10	C1120 - CTG - Spec Develop	60	04-Jun-18	27-Aug-18	32
PR1120-20	C1120 - CTG - Bid, Evaluate, Award	80	28-Aug-18	19-Dec-18	32
PR1120-41	C1120 - CTG - LNTP Design	80	20-Dec-18	15-Apr-19	32
PR1120-30	C1120 - CTG - Design, Fabricate, Deliver	260	30-Apr-19	06-May-20	22
PR1120-40	C1120 - CTG - Material On Site	0	07-May-20		22
2190 - Misc Pumps					
PR2190-10	C2190 - Misc Pumps - Spec Develop	20	20-Dec-18	21-Jan-19	46
PR2190-20	C2190 - Misc Pumps - Bid, Evaluate, Award	30	22-Jan-19	04-Mar-19	46
PR2190-41	C2190 - Misc Pumps - LNTP Design	30	05-Mar-19	15-Apr-19	188
PR2190-30	C2190 - Misc Pumps - Design, Fabricate, Deliver	150	30-Apr-19	29-Nov-19	178
PR2190-40	C2190 - Misc Pumps - Material On Site	0	24-Feb-20		121
2763 - Fuel Oil Heating					
PR2763-10	C2763 - Fuel Oil Heating - Spec Develop	20	20-Dec-18	21-Jan-19	46
PR2763-20	C2763 - Fuel Oil Heating - Bid, Evaluate, Award	30	22-Jan-19	04-Mar-19	46
PR2763-41	C2763 - Fuel Oil Heating - LNTP Design	30	05-Mar-19	15-Apr-19	188
PR2763-30	C2763 - Fuel Oil Heating - Design, Fabricate, Deliver	150	30-Apr-19	29-Nov-19	178
PR2763-40	C2763 - Fuel Oil Heating - Material On Site	0	24-Feb-20		121
2970 - Field Erected Tanks F/E					
PR2970-10	C2970 - Field Erected Tanks F/E - Spec Develop	40	20-Dec-18	18-Feb-19	48
PR2970-20	C2970 - Field Erected Tanks F/E - Bid, Evaluate, Award	50	19-Feb-19	30-Apr-19	48
PR2970-30	C2970 - Field Erected Tanks F/E - Design, Fab/Deliver, Mobilize	180	30-Apr-19	15-Jan-20	48
PR2970-40	C2970 - Field Erected Tanks F/E - Material Mobilized On Site	0	16-Jan-20		48
5300 - Switchgear Modifications					
PR5300-10	C5300 - Switchgear Modifications - Spec Develop	20	12-Mar-19	08-Apr-19	117
PR5300-20	C5300 - Switchgear Modifications - Bid, Evaluate, Award	30	09-Apr-19	20-May-19	117
PR5300-30	C5300 - Switchgear Modifications - Design, Fabricate, Deliver	150	21-May-19	20-Dec-19	117
PR5300-40	C5300 - Switchgear Modifications - Material to 5310	0	23-Dec-19		117
5310 - Electrical Building (APE 2)					
PR5310-10	C5310 - Electrical Building (APE 2) - Spec Develop	50	20-Dec-18	04-Mar-19	46
PR5310-20	C5310 - Electrical Building (APE 2) - Bid, Evaluate, Award	50	05-Mar-19	13-May-19	46



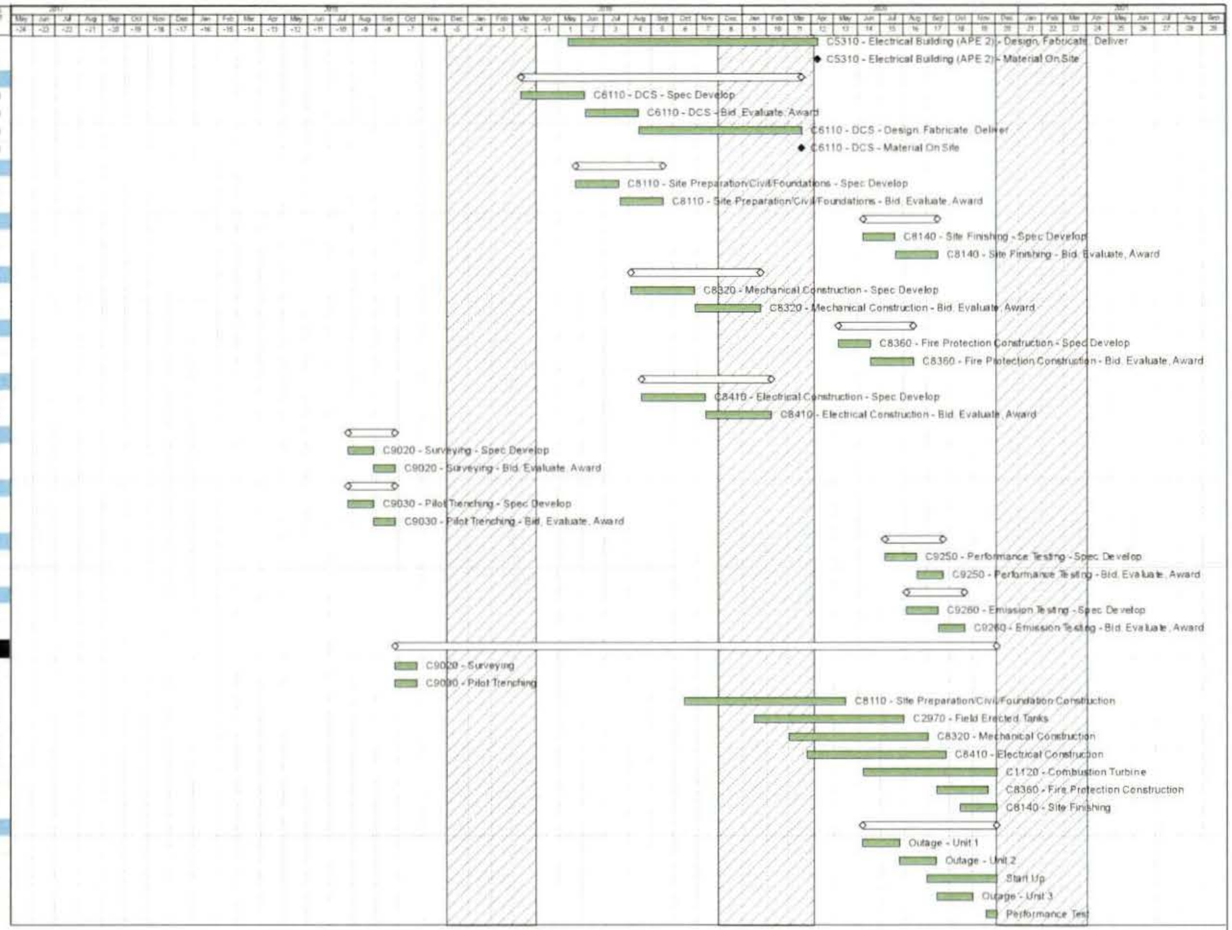
Start Date 03-Jan-17
Finish Date 04-Dec-20
Run Date 13-Aug-18

EKPC BLUEGRASS STATION
Dual Fuel Project

1 of 2

Date	Revision	Checked	Approved
06-Jun-17	B - IFOR	TR	SY
20-Mar-18	C - IFOR	TR	SY
13-Aug-18	D - IFOR		SY

Activity ID	Activity Name	OD	Start	Finish	Total Float
PR5310-30	C5310 - Electrical Building (APE 2) - Design, Fabricate, Deliver	230	14-May-19	08-Apr-20	46
PR5310-40	C5310 - Electrical Building (APE 2) - Material On Site	0	09-Apr-20		46
6110 - Distributed Control System (DCS)					
PR6110-10	C6110 - DCS - Spec Develop	60	12-Mar-19	04-Jun-19	130
PR6110-20	C6110 - DCS - Bid, Evaluate, Award	50	05-Jun-19	14-Aug-19	130
PR6110-30	C6110 - DCS - Design, Fabricate, Deliver	150	15-Aug-19	18-Mar-20	130
PR6110-40	C6110 - DCS - Material On Site	0	19-Mar-20		130
8110 - Site Preparation/Civil/Foundations					
PR8110-10	C8110 - Site Preparation/Civil/Foundations - Spec Develop	40	23-May-19	19-Jul-19	46
PR8110-20	C8110 - Site Preparation/Civil/Foundations - Bid, Evaluate, Award	40	22-Jul-19	16-Sep-19	46
8140 - Site Finishing					
PR8140-10	C8140 - Site Finishing - Spec Develop	30	08-Jun-20	20-Jul-20	2
PR8140-20	C8140 - Site Finishing - Bid, Evaluate, Award	40	21-Jul-20	15-Sep-20	2
8320 - Mechanical Construction					
PR8320-10	C8320 - Mechanical Construction - Spec Develop	60	05-Aug-19	28-Oct-19	51
PR8320-20	C8320 - Mechanical Construction - Bid, Evaluate, Award	60	29-Oct-19	24-Jan-20	51
8360 - Fire Protection Construction					
PR8360-10	C8360 - Fire Protection Construction - Spec Develop	30	06-May-20	17-Jun-20	2
PR8360-20	C8360 - Fire Protection Construction - Bid, Evaluate, Award	40	18-Jun-20	13-Aug-20	2
8410 - Electrical Construction					
PR8410-10	C8410 - Electrical Construction - Spec Develop	60	19-Aug-19	11-Nov-19	58
PR8410-20	C8410 - Electrical Construction - Bid, Evaluate, Award	60	12-Nov-19	07-Feb-20	58
9020 - Surveying					
PR9020-10	C9020 - Surveying - Spec Develop	25	24-Jul-18	27-Aug-18	51
PR9020-20	C9020 - Surveying - Bid, Evaluate, Award	20	28-Aug-18	25-Sep-18	51
9030 - Pilot Trenching					
PR9030-10	C9030 - Pilot Trenching - Spec Develop	25	24-Jul-18	27-Aug-18	51
PR9030-20	C9030 - Pilot Trenching - Bid, Evaluate, Award	20	28-Aug-18	25-Sep-18	51
9250 - Performance Testing					
PR9250-10	C9250 - Performance Testing - Spec Develop	30	07-Jul-20	17-Aug-20	2
PR9250-20	C9250 - Performance Testing - Bid, Evaluate, Award	25	18-Aug-20	22-Sep-20	2
9260 - Emission Testing					
PR9260-10	C9260 - Emission Testing - Spec Develop	30	04-Aug-20	15-Sep-20	2
PR9260-20	C9260 - Emission Testing - Bid, Evaluate, Award	25	16-Sep-20	20-Oct-20	2
Construction					
CN9020	C9020 - Surveying	20	26-Sep-18	23-Oct-18	51
CN9030	C9030 - Pilot Trenching	20	26-Sep-18	23-Oct-18	51
CN8110	C8110 - Site Preparation/Civil/Foundation Construction	150	15-Oct-19	15-May-20	46
CN2970	C2970 - Field Erected Tanks	140	16-Jan-20	31-Jul-20	48
CN8320	C8320 - Mechanical Construction	130	02-Mar-20	01-Sep-20	46
CN8410	C8410 - Electrical Construction	130	25-Mar-20	25-Sep-20	46
CN1120	C1120 - Combustion Turbine	125	08-Jun-20	02-Dec-20	2
CN8360	C8360 - Fire Protection Construction	50	14-Sep-20	20-Nov-20	2
CN8140	C8140 - Site Finishing	35	14-Oct-20	02-Dec-20	2
Start Up					
MS-OUT1	Outage - Unit 1	48	07-Jun-20	25-Jul-20	1
MS-OUT2	Outage - Unit 2	48	26-Jul-20	12-Sep-20	1
SU1000	Start Up	65	01-Sep-20	02-Dec-20	2
MS-OUT3	Outage - Unit 3	48	13-Sep-20	31-Oct-20	1
SU2000	Performance Test	10	18-Nov-20	02-Dec-20	2



Start Date	03-Jan-17
Finish Date	04-Dec-20
Run Date	13-Aug-18

EKPC BLUEGRASS STATION
Dual Fuel Project

Date	Revision	Checked	Approved
06-Jun-17	B - IFOR	TR	SY
20-Mar-18	C - IFOR	TR	SY
13-Aug-18	D - IFOR		SY

APPENDIX F - COST ESTIMATE

CAPITAL COST ESTIMATE
EKPC - BLUEGRASS
DUAL FUEL
IMPLEMENTATION- FUEL OIL

97273
LAGRANGE, KY

Acct	Area / Discipline		Labor Cost	Material Cost	Engr Equip/ Subcontract Cost	Const. Equipment Cost	Total Cost
01	Engineered Equipment		$9,000,000		$17,200,000		$26,200,000
02	Civil		$600,000	$1,100,000	$300,000	$300,000	$2,300,000
03	Deep Foundations						
04	Concrete		$1,000,000	$400,000	$100,000	$100,000	$1,600,000
05	Structural Steel		$100,000	$100,000			$200,000
06	Architectural		$100,000	$100,000			$200,000
07	Piping		$2,900,000	$600,000		$200,000	$3,700,000
08	Electrical		$1,800,000	$1,200,000		$100,000	$3,100,000
09	Instrument & Control		$100,000	$100,000	$200,000		$400,000
10	Insulation				$200,000		$200,000
11	Coatings						
12	Specialty						
13	Demolition						
14	Misc Directs		$300,000		$300,000		$600,000
	Total Direct Cost		**$15,900,000**	**$3,600,000**	**$18,300,000**	**$700,000**	**$38,500,000**

Rev.	Revision Date
B	05/04/17

Construction Mgmt, Field Staff & Start Up	12%	$4,800,000
Engineering	9%	$3,600,000
Commercial - Builders Risk Insurance	0.5%	$200,000
Escalation	6%	$2,400,000
Total Indirect Cost		**$11,000,000**
Total Direct and Indirect Costs		**$49,500,000**
Project Definition & Estimate Contingency	12.0%	$6,000,000
Total Project Cost		**$55,500,000**
Owner Cost - General	11%	$6,000,000
Owner Cost - Owner Contingency		
Sales Tax	6%	$1,300,000
Total Project Cost Incl. Owner Cost		**$62,800,000**

BURNS McDONNELL
V 3.1m

East Kentucky Power Cooperative
Bluegrass Dual Fuel
Operations Maintenance Costs Estimate

BURNS & McDONNELL

	Additional O&M Costs (2017 Dollars)	
Fixed O&M Costs		
Total Additional Fixed O&M Annual Cost, $/yr[2]	**$**	**458,000**
Variable O&M Costs		
Additional Demineralized Water Cost, $/MWhr[4]	$	0.96
Additional Demineralized Water Cost, $/yr[3]	$	28,000
Additional Levelized GTG Major Maintenance, $/GT-start[6,7]	$	3,000
Additional Levelized GTG Major Maintenance, $/yr[6]	$	101,000
Total Additional Variable O&M Annual Cost, $/yr[3]	**$**	**129,000**
Sum of Annual Fixed and Variable O&M Costs	**$**	**587,000**

Notes:

1. O&M costs shown are additional O&M to be added to plant existing O&M due to dual fuel and fuel oil operation.
2. Based on 2 Full-Time Equivalents (FTE). Assumes cost of $150,000 per FTE.
3. O&M costs shown are based on 50 annual hours of operation on fuel oil per GTG (150 hours for plant).
4. Includes raw water supply costs and demineralized trailer costs. Based on $3.70/kgal for raw water and $6,920/demin trailer for 200 kgal demin water.
5. Total Variable O&M does not include fuel cost for operation.
6. Additional major maintenance costs due to fuel oil operation compared to natural gas operation. Assumes $9,330/GT-start for natural gas operation and 1.3 factor for fuel oil start. Assumes 12 starts/unit each year on fuel oil.
7. Costs shown per start on fuel oil per GTG.
8. Based on $2.60/gallon ULSD.
9. Estimated fuel usage costs for 150 total hours of operation on fuel oil (50 per GTG) is $5.8 million.

APPENDIX G - CASH FLOW

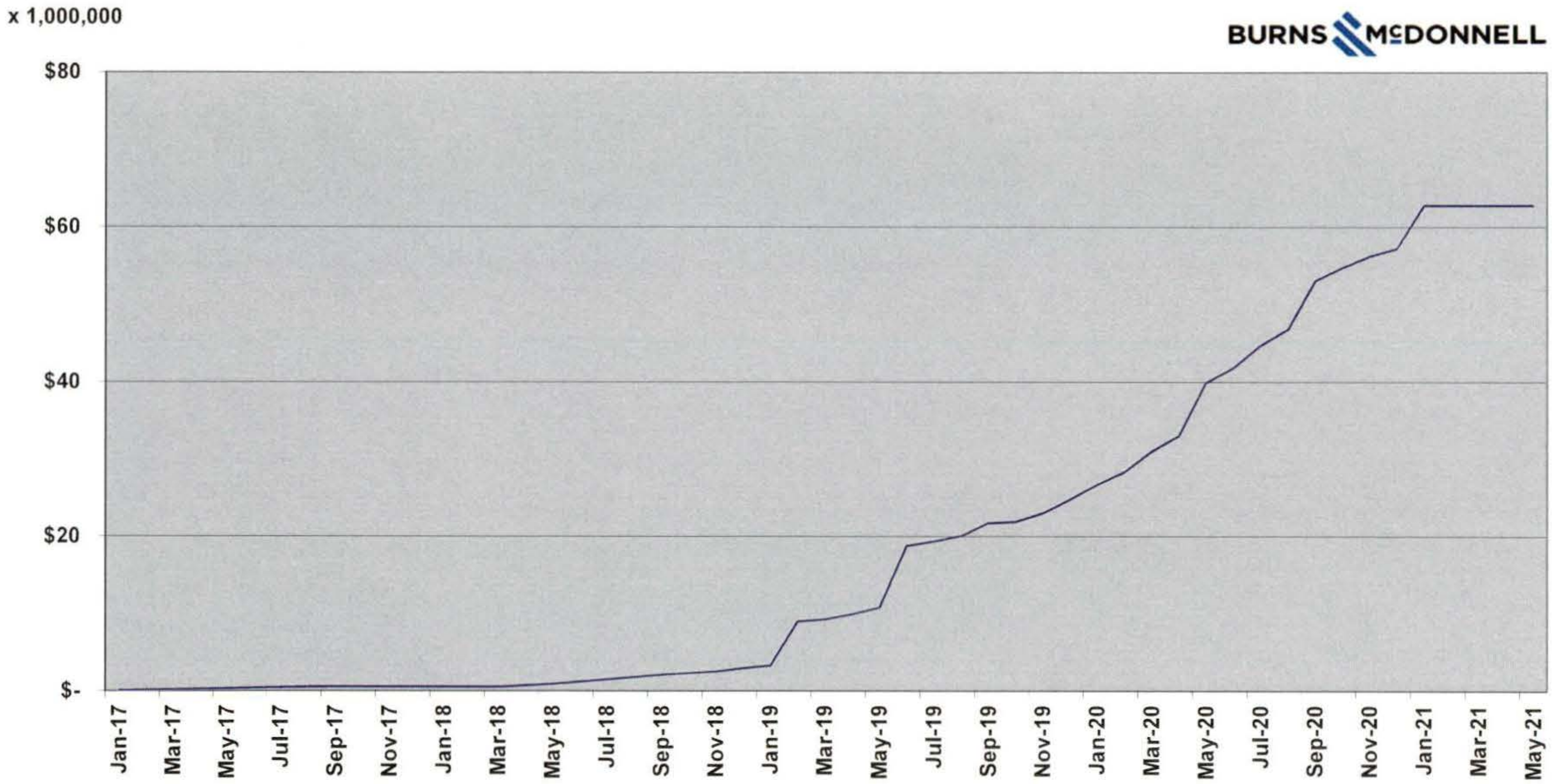
BURNS & McDONNELL

EKPC Bluegrass Dual Fuel Project

Cash Flow

Date	Incremental	Cumulative	Incremental %	Cumulative %	Millions
Jan-17	62,500	62,500	0.1%	0.1%	0.06
Feb-17	62,500	125,000	0.1%	0.2%	0.13
Mar-17	62,500	187,500	0.1%	0.3%	0.19
Apr-17	62,500	250,000	0.1%	0.4%	0.25
May-17	62,500	312,500	0.1%	0.5%	0.31
Jun-17	62,500	375,000	0.1%	0.6%	0.38
Jul-17	62,500	437,500	0.1%	0.7%	0.44
Aug-17	62,500	500,000	0.1%	0.8%	0.50
Sep-17	-	500,000	0.0%	0.8%	0.50
Oct-17	-	500,000	0.0%	0.8%	0.50
Nov-17	-	500,000	0.0%	0.8%	0.50
Dec-17	-	500,000	0.0%	0.8%	0.50
Jan-18	-	500,000	0.0%	0.8%	0.50
Feb-18	-	500,000	0.0%	0.8%	0.50
Mar-18	-	500,000	0.0%	0.8%	0.50
Apr-18	184,187	684,187	0.3%	1.1%	0.68
May-18	247,491	931,679	0.4%	1.5%	0.93
Jun-18	279,089	1,210,768	0.4%	1.9%	1.21
Jul-18	296,382	1,507,149	0.5%	2.4%	1.51
Aug-18	302,819	1,809,969	0.5%	2.9%	1.81
Sep-18	259,929	2,069,897	0.4%	3.3%	2.07
Oct-18	248,724	2,318,621	0.4%	3.7%	2.32
Nov-18	220,105	2,538,726	0.4%	4.0%	2.54
Dec-18	388,998	2,927,724	0.6%	4.7%	2.93
Jan-19	358,410	3,286,134	0.6%	5.2%	3.29
Feb-19	5,713,440	8,999,574	9.1%	14.3%	9.00
Mar-19	285,271	9,284,845	0.5%	14.8%	9.28
Apr-19	652,031	9,936,877	1.0%	15.8%	9.94
May-19	873,790	10,810,667	1.4%	17.2%	10.81
Jun-19	8,012,426	18,823,093	12.8%	30.0%	18.82
Jul-19	568,328	19,391,421	0.9%	30.9%	19.39
Aug-19	721,638	20,113,058	1.1%	32.0%	20.11
Sep-19	1,630,442	21,743,500	2.6%	34.6%	21.74
Oct-19	194,000	21,937,500	0.3%	34.9%	21.94
Nov-19	1,129,570	23,067,070	1.8%	36.7%	23.07
Dec-19	1,751,803	24,818,873	2.8%	39.5%	24.82
Jan-20	1,959,240	26,778,113	3.1%	42.6%	26.78
Feb-20	1,619,969	28,398,082	2.6%	45.2%	28.40
Mar-20	2,611,463	31,009,545	4.2%	49.4%	31.01
Apr-20	2,078,815	33,088,360	3.3%	52.7%	33.09
May-20	6,856,744	39,945,104	10.9%	63.6%	39.95
Jun-20	1,910,744	41,855,848	3.0%	66.6%	41.86
Jul-20	2,871,365	44,727,213	4.6%	71.2%	44.73
Aug-20	2,051,661	46,778,874	3.3%	74.5%	46.78
Sep-20	6,284,753	53,063,628	10.0%	84.5%	53.06
Oct-20	1,718,652	54,782,280	2.7%	87.2%	54.78
Nov-20	1,437,895	56,220,175	2.3%	89.5%	56.22
Dec-20	981,000	57,201,175	1.6%	91.1%	57.20
Jan-21	5,598,825	62,800,000	8.9%	100.0%	62.80

Cumulative Cashflow



APPENDIX H - PERMITTING MATRIX

Item No.	Permit/Clearance	Regulatory Agency	Details	When Required	Anticipated Agency Review Time	Associated Fees	Comments
Federal							
1	Clean Water Act - Section 404 Permit	U.S. Army Corps of Engineers, Louisville District	Required to dredge or place fill in a jurisdictional water, including wetlands Nationwide Permit: Less an or equal to 0.5 acre of wetland or stream impacts Individual Permit: Greater than 0.5 acre of wetland or stream impacts	Prior to construction	45 to 90 days for a Nationwide Permit 12 to 18 months for an Individual Permit	No application or mitigation fees	A wetland and stream delineation will likely not be required. Impacts to jurisdictional waters or wetlands are not anticipated based on the Project's proposed equipment and work locations. If the project impacts wetlands and/or surface waters and qualifies for a Nationwide Permit 39 (Commercial and Institutional Developments), a pre-construction notification would be required.
2	Section 7 Threatened and Endangered Species Consultation and Clearance	U.S. Fish & Wildlife Service (FWS), Ecological Services	If the project will potentially impact protected species or their respective habitat, or if a Section 404 permit is required, then the FWS must be contacted. The FWS will determine the level of effort needed for the project to proceed (e.g., habitat assessment, species surveys, avian impact studies, etc.).	Prior to construction	30 days for initial response, additional 30 days for determination of field survey results (if required)	No fees	Formal consultation likely not required if construction will take place in an already developed area and no Section 404 Permit is required. Due to the nature of this site, impacts to protected species are not likely.
3	Migratory Bird Treaty Act / Bald and Golden Eagle Protection Act Compliance	U.S. Fish & Wildlife Service (FWS), Ecological Services	Required when construction or operation of a proposed facility could impact migratory birds, their nests, and especially threatened or endangered species	Prior to construction	30 days for data request, 30 days for report review	No fees	Formal consultation likely not required if construction will take place in an already developed area and no Section 404 Permit is required. Due to the nature of this site, impacts to migratory birds are not likely.
4	Notice of Proposed Construction	Federal Aviation Administration (FAA)	Required for the construction of structures 200 feet tall or within the distance to height ratio from the nearest point of a FAA airport runway. Also required for construction equipment reaching heights over 200 feet.	Prior to construction	45+ days	No fees	Notifying the FAA includes completing Form 7460-1 for all required structures and providing a site layout map depicting structure locations. No temporary construction equipment or permanent structures will be over 200 feet tall.
5	Spill Prevention, Control, and Countermeasure (SPCC) Plan Amendment	U.S. Environmental Protection Agency (EPA)	An amendment to the facility's SPCC Plan will be required to address additional onsite fuel storage and secondary containment.	Prior to fuel delivery	Not required to submit the SPCC Plan to the EPA for review, unless requested.	No fees	Required to be updated to address new fuel oil storage and secondary containment, including the Site Plan, Wastewater and Stormwater Flow Diagram, Table 1, and portions of the SPCC Plan narrative.
6	Facility Response Plan (FRP)	U.S. Environmental Protection Agency (EPA)	A FRP is required for facilities that could reasonably be expected to cause "substantial harm" to the environment by discharging oil into or on navigable waters. A facility may pose "substantial harm" if it: 1) has a total oil storage capacity greater than or equal to 42,000 gallons and it transfers oil over water to/from vessels; or 2) has a total oil storage capacity greater than or equal to 1 million gallons meets one of the following conditions: a. does not have sufficient secondary containment for each aboveground storage tank b. is located at a distance such that a discharge from the facility could cause "injury" to fish, wildlife, and sensitive environments c. is located at a distance such that a discharge from a facility would shut down a public drinking water intake d. has had, within the past 5 years, a reportable discharge greater than or equal to 10,000 gallons	Prior to oil delivery	Must submit a certification form and the FRP to the EPA regional office. The Regional Administrator (RA) will review and determine if the facility should be classified as a "substantial harm" facility or a "significant and substantial harm" facility. If the RA determines that the facility could cause "significant and substantial harm", the FRP requires approval by the RA. Approval can take anywhere from a couple of months up to 2 years depending on the regional office and its workload. The facility is still required to implement the FRP even during the EPA's review.	No fees	The RA determines if a facility could, because of its location, cause "significant and substantial harm" to the environment by discharging oil into or on the navigable waters and adjoining shorelines. This is determined by factors similar to the "substantial harm" criteria, as well as: age of tanks, type of transfer operations, oil storage capacity; lack of secondary containment, spill history, etc.
State - Kentucky							
7	Certificate of Public Convenience and Necessity (CPCN)	Kentucky Public Service Commission	Required for the construction of electric generating facilities	Prior to construction	120 to 180 days after the submission of a complete application	Project specific	
8	Environmental Assessment (EA) or Environmental Impact Statement (EIS)	Kentucky Public Service Commission	Project may trigger an EA or EIS because the project is requesting financing from the USDA Rural Utilities Service (RUS).	Prior to construction	6 to 9 months	No fees	This project will request funding from USDA RUS. An EIS is likely not required since significant environmental impacts are not anticipated; however, an EA may be required.

Item No.	Permit/Clearance	Regulatory Agency	Details	When Required	Anticipated Agency Review Time	Associated Fees	Comments
9	Air Permit Revision (non-PSD)	Kentucky Department of Environmental Protection Division for Air Quality	Required revision to reflect new operational mode and added equipment. Will continue to meet existing hours limits and emissions caps.	Prior to construction	6 to 18 months	No fees	
10	Noise Compliance	Kentucky State Board on Electric Generation and Transmission Siting	No permit is required; however, a special use permit requires that the facility comply KRS 224.30-50, which prohibits emissions beyond the property that interfere with enjoyment of life or with any lawful business or activity.	Prior to construction	No agency review	No fees	A noise study is recommended to determine if the project will result in an increase in ambient noise, which might impact the surrounding community.
11	Permit to Construct Across or Along a Stream	Kentucky Department of Environmental Protection Division of Water	In addition to authorizing stream crossings, this permit also provides floodplain construction approval.	Prior to construction	20 business days for stream crossing and floodplain impact approval	No fees	The permit application must be reviewed and signed by the local county floodplain coordinator(s) prior to submitting the application to the State
12	Section 401 Water Quality Certification (WQC)	Kentucky Department of Environmental Protection Division of Water	The purpose of the WQC is to confirm that the discharge of fill materials (Section 404 Permit) will be in compliance with the State's applicable water quality standards.	Prior to construction	If wetland/stream impacts are authorized under a Section 404 Nationwide Permit, then WQC approval is issued concurrently in 45 to 90 days. If a Section 404 Individual Permit is required, then separate WQC approval from the State could take 12 months.	Stream impact greater than 500 linear feet and less than 1,000 feet -- $1,000 Stream impact 1,000 to 5,000 linear feet -- $2,500 Stream impact greater than 5,000 linear feet -- $5,000 Wetland impacts -- $500 per acre, not to exceed $5,000	Assumes automatic Water Quality Certification authorization through the Corps' Nationwide Program. If the project will require a Section 404 Individual Permit from the Corps, then the Kentucky Department of Environmental Protection must issue an Individual Section 401 WQC.
13	General Permit for Stormwater Discharges Associated with Construction Activities	Kentucky Department of Environmental Protection Division of Water	Required for all stormwater discharges from construction activities which will disturb 1 or more total acres of land. The General Permit requires the development of a Stormwater Pollution Prevention Plan (SWPPP) prior to submitting a Notice of Intent for permit coverage.	Prior to construction	7 days	No fees	The permit also authorizes the discharge of construction dewatering waters if managed through the use of appropriate best management practices.
14	Operational SWPPP Modification	Kentucky Department of Environmental Protection Division of Water	If the facility's KPDES Operational Discharge Permit (KY0109363) requires an operational SWPPP, the SWPPP must be updated to address new fuel storage, secondary containment, and modified stormwater flows.	Prior to operation	Not required to submit operational SWPPP for review, unless requested	No fees	
15	National Historic Preservation Act – Section 106 Clearance	Kentucky Heritage Council - State Historic Preservation Office (SHPO)	Under Section 106 of the National Historic Preservation Act, Federal agencies must work with the State Historic Preservation Office to address historic preservation issues when planning projects or issuing funds or permits that may affect historic properties and archaeological resources listed in or determined eligible for the National Register of Historic Places.	Prior to construction	45 Days	$40 for Preliminary Site Check through SHPO database	Formal consultation likely not required if construction will take place in an already developed area and no Section 404 Permit is required.
16	Threatened & Endangered Species Clearance (State)	Kentucky Department of Fish and Wildlife Resources, Kentucky State Nature Preserves Commission, and Kentucky Division of Forestry	Required when a proposed project may impact State-listed species or when a project lies within an area of known occurrence of listed species or the habitat of a listed species	Prior to construction	30 days for initial response, additional 30 days for determination of field survey results (if required)	No fees	Formal consultation likely not required if construction will take place in an already developed area and no Section 404 Permit is required.
County							
17	Storm Water Quality Management and Erosion Control Permit	Oldham County Engineering	Required for construction activities that will require 1 or more acres of ground disturbance.	Prior to construction	14 calendar days	$100 per acre of disturbance	Required SWPPP should be developed to address both State and County requirements.

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY	)	
POWER COOPERATIVE, INC. FOR A	)	
CERTIFICATE OF PUBLIC CONVENIENCE	)	**CASE NO. 2018-________**
AND NECESSITY FOR THE CONSTRUCTION	)	
OF BACKUP FUEL FACILITIES AT ITS	)	
BLUEGRASS GENERATING STATION	)	

DIRECT TESTIMONY OF THOMAS STACHNIK
ON BEHALF OF EAST KENTUCKY POWER COOPERATIVE, INC.

Filed: August 24, 2018

Q. Please state your name, position, and business address.

A. My name is Thomas Stachnik and my business address is East Kentucky Power Cooperative, Inc. ("EKPC"), 4775 Lexington Road, Winchester, Kentucky 40391. I am Vice President of Finance and Treasurer at EKPC.

Q. Please briefly describe your education and professional experience.

A. I have a Bachelor's degree in Chemical Engineering from the University of Illinois and an MBA from the University of Chicago; additionally, I hold the Chartered Financial Analyst and Certified Treasury Professional designations. Prior to establishing a career in finance, I enjoyed work as a chemical engineer for approximately ten (10) years. I worked in the Treasury Department of Brown-Forman Corporation for thirteen (13) years before joining EKPC in August 2015. In 2017, I was promoted from Treasurer and Director of Finance to Vice President of Finance and Treasurer at EKPC.

Q. Please provide a brief description of your duties at EKPC.

A. I am responsible for the management and direction of the treasury area including borrowing, investing, and cash management. I also oversee the financial forecasting, budgeting, and risk management functions. I report directly to EKPC's Executive Vice President and Chief Financial Officer, Mr. Mike McNalley.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony is intended first to generally describe the financial condition of EKPC and its strategic objectives with respect thereto. I will discuss EKPC's plan to finance the construction of backup fuel facilities at its Bluegrass Generating

Station ("Bluegrass Station" or the "Station") (as further described in this proceeding, the "Project"), as well as describe how the costs associated with the Project will impact EKPC and its Owner-Member Cooperatives ("owner-members").

Q. Are you sponsoring any exhibits?

A. No.

Q. Please generally describe EKPC's financial performance during the most recent year.

A. EKPC has enjoyed several years of solid performance which benefitted from weather patterns, cost control, and advantages from its membership in PJM Interconnection, LLC ("PJM"). For the year ended December 31, 2017, EKPC had sales to Owner-Member Cooperatives ("owner-members") of 12,536,264 MWh resulting in total operating revenue of $862 million. EKPC earned a net margin of $22 million and ended the year with $612 million in Members' Equities. EKPC's equity-to-assets ratio was 16.0%. EKPC's Debt Service Coverage ("DSC") ratio was 1.26 and its Times Interest Earned Ratio ("TIER") was 1.19.

Q. What are some of EKPC's long-term strategic objectives with regard to its financial position?

A. EKPC always seeks to balance three goals: financial strength, financial flexibility and affordability. To ensure financial strength, EKPC seeks to maintain appropriate ratios for DSC and TIER metrics. Likewise, EKPC's equity is managed to ensure adequacy for anticipated major investments while also allowing for the eventual return of excess equity to owner-members through the payment of capital credits.

EKPC maintains its financial flexibility by tracking liquidity measures that are in line with "A" credit-rated generation and transmission cooperatives around the country. Finally, EKPC seeks to be affordable to its owner-members by striving to keep its costs as low as possible while continuing to safely provide reliable service.

Q. What resources does EKPC have available to it to fund large capital projects?

A. EKPC has a number of options available to it in order to pay the costs of construction of capital projects. While working capital funds are generally available to fund all or some of such costs, in most cases that involve a significant capital investment EKPC will use the proceeds of its existing Credit Facility to finance the construction of a project. EKPC's Credit Facility is essentially a line of credit in the amount of $600 million that was approved by the Commission in Case No. 2013-00306 and reauthorized in Case No. 2016-00116.[1] Most recently, the Commission approved EKPC's application to issue up to $300 million of secured private placement debt in anticipation of necessary future capital investments.[2]

While utilizing EKPC's Credit Facility is generally a financially-sound financing approach in the short term, EKPC and its owner-members are best served if large portions of the Credit Facility do not remain tied up in construction debt.

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[1] *See In the Matter of East Kentucky Power Cooperative, Inc. Application for Approval of the Issuance of Up to $200,000,000 of Secured Private Placement Debt, for the Amendment and Extension of an Unsecured Revolving Credit Agreement in an Amount Up to $500,000,000, and for the Use of Interest-Rate Management Instruments*, Order, Case No. 2013-00306, (Ky. P.S.C. Sep. 27, 2013); *In the Matter of Application of East Kentucky Power Cooperative, Inc. for Approval of the Amendment and Extension or Refinancing of an Unsecured Revolving Credit Agreement in an Amount Up to $800,000,000 of Which Up to $100,000,000 May Be in the Form of an Unsecured Renewable Term Loan and $200,000,000 of Which Will Be in the Form of a Future Increase Option*, Order, Case No. 2016-00116, (Ky. P.S.C. Apr. 11, 2016).

[2] *See In the Matter of the Application of East Kentucky Power Cooperative, Inc. for Approval of the Authority to Issue up to $300,000,000 of Secured Private Placement Debt and/or Secured Tax Exempt Bonds and For the Use of Interest Rate Management Instruments*, Order, Case No. 2018-00115 (Ky. P.S.C. July 24, 2018).

Accordingly, EKPC routinely rolls short-term indebtedness into long-term indebtedness in accordance with the terms of its Trust Indenture. EKPC's Trust Indenture was approved by the Commission in Case No. 2012-00249.[3]

Q. How much of the $600 million authorized under the Credit Facility is currently available to EKPC?

A. As of August 6, 2018, $345 million is available under EKPC's credit facility.

Q. Please explain how the Credit Facility works.

A. The Credit Facility allows EKPC to borrow, with as little as one day notice, up to the available amount. Our existing rate under the credit facility is LIBOR + 95 bps, currently about 3.0%. Amounts extended to EKPC under the credit facility are fully pre-payable and may be replaced by other debt or paid with operational cash at EKPC's option.

Q. Please describe the process for converting short-term debt to long-term debt through the Trust Indenture.

A. EKPC's two (2) main avenues for borrowing under the Trust Indenture are the Private Placement market and the Rural Utilities Service ("RUS")/Federal Financing Bank. As I stated, proceeds from the issuance of long-term debt can be used to pay down the Credit Facility when advantageous to EKPC.

[3] *See In the Matter of Application of East Kentucky Power Cooperative, Inc. for Approval to Obtain a Trust Indenture*, Order, Case No. 2012-00249 (Ky. P.S.C. Aug. 9, 2012).

Q. Does the Trust Indenture have a limit as to the amount that EKPC can borrow?

A. Yes. EKPC must show sufficient bondable additions or principal repayments for the Trustee to authorize new debt under the Indenture. The current amount that EKPC may borrow after certifying available bondable additions is at least $700 million, so these requirements will not constrain EKPC from borrowing what is necessary to fund this project.

Q. What are the advantages of having the Credit Facility and Trust Indenture available to EKPC?

A. The credit facility allows EKPC to borrow to fund short-term needs or to temporarily finance long-term projects until long-term financing can be put into place. Notably, for RUS borrowing in particular, the Credit Facility is utilized because EKPC cannot generally receive RUS funds until the subject asset is on EKPC's books. The advantage of the Trust Indenture is that it allows EKPC to borrow on a secured basis from different lenders without having to seek permission from other lenders; prior to the Indenture, any non-RUS debt would require a Lien Accommodation, and thus the Indenture effectively opened up the Private Placement market to EKPC. The Private Placement market, while incrementally more expensive than RUS, can be accessed in a matter of weeks rather than years (which can help to opportunistically lock-in fixed rates) and will sometimes finance items (such as regulatory assets) for which RUS funding is not available.

Q. Are you familiar with the Project and its estimated costs?

A. Yes, as I have been involved in several meetings and discussions relating to the financing of the Project. According to estimates prepared by EKPC's expert consultant, Burns & McDonnell Engineering Co., Inc. ("Burns & McDonnell"), the total cost of the Project is $62.8 million and will be incurred almost entirely during the 2019-2020 timeframe. Additionally, Burns & McDonnell estimates that the annual cost of operation of the Bluegrass Station will increase approximately $587,000 after the proposed facilities are placed into service. EKPC has recognized these figures in its budgeting and financial planning processes.

Q. How does EKPC intend to finance the construction of the proposed Project?

A. EKPC will be able to use its working capital and Credit Facility to finance the initial construction of the Project. Over the long-term, EKPC intends to convert that short-term debt to a long-term debt – either with RUS or a private placement through EKPC's existing Trust Indenture.

Q. Will the Credit Facility and Trust Indenture be sufficient to accommodate the borrowing needs of EKPC during the development, planning and construction of the Project?

A. Yes.

Q. Will the Project have any adverse impact upon EKPC's credit ratings?

A. I would not expect the Project to have any impact on EKPC's ratings.

Q. Do you believe that EKPC's plan to finance the development and construction of the Project is reasonable and will result in the lowest possible cost to EKPC's owner-members?

A. Yes.

Q. Does this conclude your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION OF BACKUP FUEL FACILITIES AT ITS BLUEGRASS GENERATING STATION	)	**CASE NO. 2018-________**

VERIFICATION OF THOMAS STACHNIK

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF CLARK)

Thomas Stachnik, Vice President of Finance and Treasurer at East Kentucky Power Cooperative, Inc., being duly sworn, states that he has read the foregoing prepared direct testimony and that he would respond in the same manner to the questions if so asked upon taking the stand, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief, formed after reasonable inquiry.

Thomas J. Stachnik

Thomas Stachnik

The foregoing Verification was signed, acknowledged and sworn to before me this 24th day of August, 2018, by Thomas Stachnik.

Gwyn M. Willoughby

NOTARY PUBLIC

Commission No. 590567

My Commission Expires: 11/30/21

GWYN M. WILLOUGHBY
Notary Public
Kentucky – State at Large
My Commission Expires Nov 30, 2021