Report on the

DUE DILIGENCE EVALUATION BLUEGRASS GENERATION FACILITY

East Kentucky Power Cooperative

Project No. 70965

January 2013

Due Diligence Evaluation
Bluegrass Generation Facility
Revision 0

prepared for

East Kentucky Power Cooperative
Winchester, Kentucky

January 2013

Project No. 70965

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

January 9, 2013

Mr. Jeff Brandt
Manager – Alternative and Renewable Fuels
East Kentucky Power Coopertive
4775 Lexington Road
Winchester, Kentucky 40391

Re: Due Diligence Evaluation of the Bluegrass Generation Facility

Dear Mr. Brandt:

Burns & McDonnell (BMcD) is pleased to submit our Due Diligence Evaluation Report on the Bluegrass Generation Facility (Plant) prepared on behalf of East Kentucky Power Cooperative (EKPC).

The Plant is a nominal 495 MW summer rated and 576 MW winter rated natural gas-fired simple cycle power plant located just outside the city of La Grange, in Oldham County, Kentucky. The Plant is laid out with the opportunity for future conversion to combined cycle.

The Plant was originally constructed under an Engineer, Procure, Construct contract by H.B. Zachry and Black and Veatch and is currently owned by LS Power (LSP). The Plant is being considered for purchase by EKPC or for EKPC to enter into a long-term power purchase agreement with the Plant. The purpose of the due diligence evaluation was to assist EKPC with an evaluation of the Plant. BMcD's findings are summarized in the attached report.

If you need any additional information, please contact me at (816) 822-4239 or e-mail at jkopp@burnsmcd.com. It is a pleasure to be of service to EKPC in this matter.

Sincerely,

Jeffrey T Kopp

Jeff Kopp, PE
Manager, Project Development

JTK

Enclosure
cc: Clarice Kinsella, BMcD

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LIST OF ABBREVIATIONS AND ACRONYMS

AGC	Automatic Generation Control
Acquisition Company	Bluegrass Generation
BMcD	Burns & McDonnell Engineering Company, Inc.
Bluegrass	Bluegrass Generation Company, LLC
CEMS	Continuous Emissions Monitoring System
CI	Combustor Inspection
COD	Commercial Operation Date
Customer	Bluegrass Generation, LLC
DCS	Distributed Control System
District	Oldham County Water District
DLN	Dry Low-NO_x
EAF	Equivalent Availability Factor
EFDH	Equivalent Forced Derated Hours
EFDHRS	Equivalent Forced Derated Hours during Reserve Shutdown
EFOR	Equivalent Forced Outage Rate
EKPC	East Kentucky Power Cooperative
EMA	Energy Management Agreement
Energy Manager	EDF Trading North America, LLC
EPC	Engineer, Procure, and Construct
Evaluation	Due Diligence Evaluation
Facility	Bluegrass Generation Facility
FERC	Federal Energy Regulatory Commission
FOD	Foreign Object Damage
FOR	Forced Outage Rate
GPD	Gallons Per Day
Gpm	gallons per minute
GSU	Generator Step-Up
HGP	Hot Gas Path
HMI	Human Machine Interface
hp	horsepower
IA	Interconnection and Operating Agreement
KU	Kentucky Utilities Company
LG&E	Louisville Gas and Electric Company

LSP	LS Power
LTP	Long Term Program
MO	Major Outage
NAES	North American Energy Services
NDE	Non-Destructive Examination
NO_x	Nitrogen Oxides
O&M	Operating & Maintenance
Operator	NAES Corporation
Owner	Port River, LLC
PLC	Programmable Logic Controller
Project or Plant	Bluegrass Generation Facility
SCR	Selective Catalytic Reduction
Texas Gas	Texas Gas Transmission Corporation
TXGT	Texas Gas Transmission
UPS	Uninterruptible Power Supply

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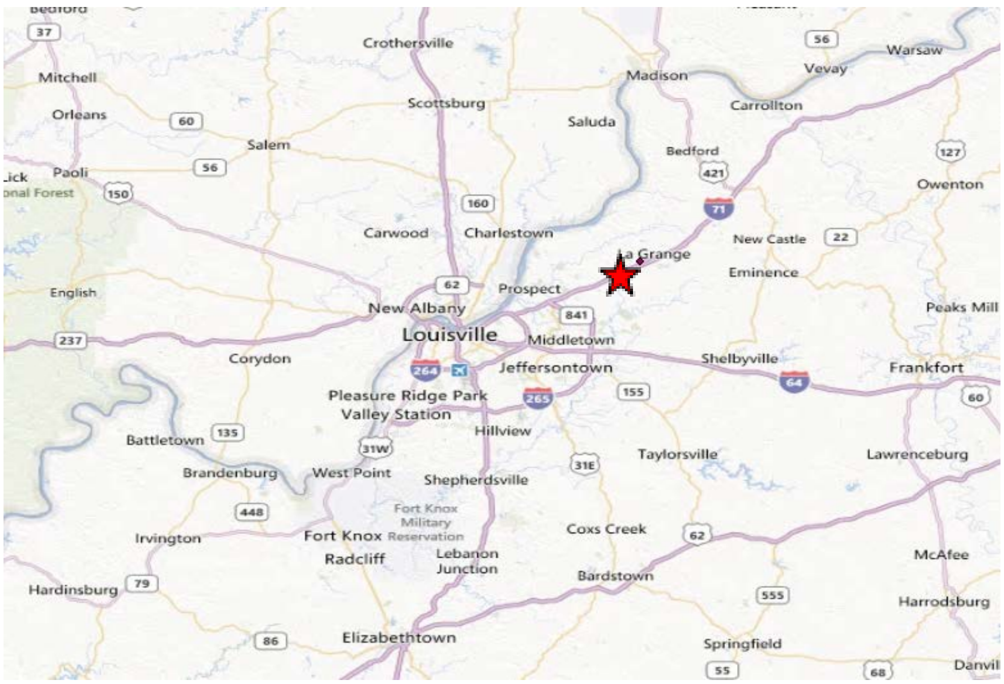
ES.0 EXECUTIVE SUMMARY

ES.1 INTRODUCTION

Burns & McDonnell Engineering Company, Inc. (BMcD) was retained by East Kentucky Power Cooperative (EKPC) to conduct a Due Diligence Evaluation (Evaluation) of the potential acquisition of or entering into a Tolling Agreement with the Bluegrass Generation Facility (Project, Plant, or Facility), which was originally constructed under an Engineer, Procure, Construct (EPC) contract by H.B. Zachry and Black and Veatch and is currently owned by LS Power (LSP).

The Plant is a nominal 495 MW summer rated and 576 MW winter rated natural gas-fired simple cycle power plant located just outside the city of La Grange, in Oldham County, Kentucky. The Plant is laid out with the opportunity for future conversion to combined cycle. The project location is shown below in Figure ES.1.

Figure ES.1: Plant Location



EKPC is evaluating the Project for a potential 20 year tolling agreement or for a potential facility purchase. The purpose of the Evaluation was to determine the Plant has been designed, constructed, and operated in a manner to provide long-term, dependable service as a generation resource, and to determine if any fatal flaws exist with the Project.

The Evaluation was based on a site visit and documents provided to BMcD via an online data room.

ES.2 CONCLUSIONS

Based on the results of the Evaluation conducted for the Project, BMcD did not uncover any fatal flaws associated with the Project in the activities performed to date; however, several areas of concern were noted. The following are the key findings of the Evaluation:

- During the Combustor Inspection (CI) on Unit 1, foreign object damage was indicated on the trailing edge of the #9 inlet guide vane. It is recommended to inspect the vane every 25 equivalent starts or 500 hours, whichever comes first, to verify the integrity of the vane. Other items were noted in the most recent borescope inspection that do not pose major risks, but should be monitored in subsequent borescope inspections.
- Unit 2 has had very few operating hours, and therefore has not yet had a CI performed. In the most recent borescope inspection, early migration of the Row 3 vane knife seals was observed, which will require replacement at the Hot Gas Path (HGP) Inspection.
- Unit 3 has had very few operating hours, and therefore has not yet had a CI performed. In the most recent borescope inspection, cracking and minor coating loss was observed in several areas of the compressor and turbine. It was recommended that a borescope be performed every 25 starts to monitor the status of the crack in the Row 4 diaphragm, which was originally identified in the 2009 borescope inspection. Subsequent inspections have shown no progression or additional cracking in this area.
- The net plant heat rate for each of the Units is slightly higher than expectations for a facility of this size, usage, and type. Moreover, the units did not meet their guaranteed heat rate values in 2002.
- All of the Units have been dispatched very little over the past several years, particularly Unit 2 and Unit 3. The dispatch of the Units overall, has generally trended downward over the recent past.
- Due to the frequent startup and shutdown requirements of simple cycle units, the starting reliability is critical. The Plant has had a high number of starts per operating hour, but this is common for a peaking facility. Generally, the starting reliability of these Units has been relatively high in 2008, 2011, and 2012 and below average in 2009 and 2010.
- The availability of the Units is mostly comparable to typical simple cycle units, with the availability being slightly below average in 2008. No major recurring issues were identified, and the availability has increased to expected levels after 2008.

- Generally, the historical and projected operating and maintenance costs appear reasonable.
- The units did not meet their performance guarantee in 2002 and tested approximately one to two percent higher than the guaranteed heat rate. Prior to purchase of the Facility or entering into a long-term contract, BMcD would recommend a third-party conduct a performance test to determine the current capabilities of the Plant for both capacity and heat rate. The cost for a third-party to conduct a performance test is approximately $150,000 to $200,000.
- The Plant has either implemented each urgent technical advisory and technical advisory, or evaluated them and determined that they were not applicable to the Bluegrass Facility. Product bulletins, service bulletins, and customer service letters were also reviewed to determine if they were required or simply recommended upgrades, and were implemented if determined to be sufficiently beneficial, or targeted for implementation during a future major maintenance activity.
- The Water Supply Agreement is adequate for the Plant and the Plant does not appear to have any technical limitations that would prevent it from meeting the requirements of the Agreement.
- The Electrical Interconnection Agreement is in place for a maximum facility output of 720 MW, which is more than sufficient for the maximum net plant output.
- A Natural Gas Facilities Agreement is in place; however, it does not provide for a minimum gas delivery pressure.
- The Plant is operated by North American Energy Services (NAES) under an Operating and Maintenance (O&M) Agreement; however, the agreement is with Port River, LLC, rather than the Plant. If Port River, LLC is not part of the purchase and sale agreement, the contract would need to be transferred to the new owner of the Plant.
- The fee structure for the Operating and Maintenance Agreement was not provided for review; therefore, no assessment can be made at this point. If EKPC considers purchasing the facility, the fee structure should be reviewed in order to take into consideration whether to keep the O&M contract in place or terminate it.
- Energy is marketed and sold by EDF Trading North America, LLC under an Energy Management Agreement (EMA); however, Port River, LLC is a party to the agreement, and it states that if the Project is ever transferred to a new owner, the Project would no longer be a party to the agreement. If Port River, LLC is not part of the purchase and sale agreement, it should be determined whether the contract will be terminated.
- The fee structure for the EMA was not provided for review; therefore, no assessment can be made at this point. If EKPC considers purchasing the facility, the fee structure should be reviewed in order to take into consideration whether to keep the EMA in place or terminate it.

ES.3 LIMITATIONS

In preparation of this due diligence evaluation, BMcD has relied upon information provided by EKPC, and LSP. While BMcD has no reason to believe that the information provided, and upon which BMcD has relied, is inaccurate or incomplete in any material respect, BMcD has not independently verified such information and cannot guarantee its accuracy or completeness.

* * * * *

1.0 SITE VISIT

Representatives from BMcD and EKPC visited the Facility on December 12, 2012. The purpose of the site visit was to gather information to conduct the due diligence evaluation, interview the Plant management and operations staff, and to conduct an on-site review of the Plant facilities. The following LSP staff provided information during the visit:

- Mr. Ernest Kim, Vice President of Private Equity
- Ms. Carolyne Wass, Senior Vice President and Head of Asset Management
- Mr. Woody Saylor, Asset Manager
- Mr. Mark Yates, Bluegrass Plant Manager

The following BMcD representatives comprised the evaluation team:

- Ms. Clarice Kinsella, Project Manager
- Mr. Tom Stauffer, Engineering Lead

The following EKPC representatives comprised the evaluation team:

- Mr. Jeff Brandt, Manager – Alternative and Renewable Fuels
- Mr. Keith McCoy, J.K. Smith Combustion Turbine Supervisor
- Mr. Phillip Berry, Dale Station Operations Superintendent
- Mr. Earl Ferguson, JK Smith Plant Manager

None of the Units were dispatched during the site visit.

* * * * *

2.0 PLANT DESCRIPTION AND DESIGN

2.1 SITE DESCRIPTION

The Plant sits on approximately 60 acres located in La Grange, KY within Oldham County. La Grange is approximately 25 miles northeast of Louisville, KY. The Plant includes three (3) simple cycle combustion turbines (Units 1, 2 and 3). The Plant includes an administration/control room building, warehouse, a 345 kV switchyard, demineralized water storage tank, service/fire water storage tank, and other ancillary facilities.

The Facility commenced commercial operation in June 2002. Currently, the Plant functions as a merchant electric facility and has an Energy Management Agreement with EDF Trading North America, LLC that commenced on October 15, 2009.

2.2 POWER BLOCK

The Facility consists of three (3) simple cycle trains which operate largely independently. Unit 1 consists of one (1) Siemens Westinghouse 501FD2 technology combustion turbine with Selective Catalytic Reduction (SCR)/ammonia injection system, Unit 2 consists of one (1) Siemens Westinghouse 501FD2 technology combustion turbine with SCR/ammonia injection system and Unit 3 consists of one (1) Siemens Westinghouse 501FD2 technology combustion turbine. The Units were designed for outdoor installation, with the combustion turbines housed inside a standard manufacturer's enclosure. The 501FD2 combustion turbine technology is considered a mature technology and has been in operation for many years in the energy industry. The Units burn pipeline quality natural gas as fuel, and do not have the ability to fire fuel oil. The Units are equipped with dry low-NO_x (DLN) burners and water injection to control CT exhaust NO_x emissions. The Units utilize a fogging system for inlet air conditioning for power augmentation on days with ambient conditions above 59ºF.

The three combustion turbines are largely independent, but do share the following common facilities:.

- Demineralized water system
- 125 V DC and 120 V AC inverter power system
- 345 kV switchyard
- Fuel gas system
- Fire protection system
- Instrument air system

- Potable water system
- Service water system
- Service air system
- Equipment drains system
- Administration building and control room
- Warehouse
- Emergency diesel generator

2.3 COMBUSTION TURINBES AND GENERATORS

2.3.1 Unit 1 Combustion Turbine

The unit appears to be current on product modifications issued by Siemens. Unit 1 underwent a CI in April 2010 at 422 cumulative equivalent starts and 1,176 cumulative equivalent hours. The CI identified a foreign Object Damage (FOD) indication on the trailing edge of the #9 inlet guide vane. Bluegrass contracted for a Non-destructive Examination (NDE) inspection with results showing no rejectable indication on the vane, only coating loss around the area. It is recommended to inspect the vane every 25 equivalent starts or 500 hours, whichever comes first, to verify the integrity of the vane. No other major issues were noted in the CI. The unit underwent borescope inspections multiple times since initial operation and at least once since the CI. The most recent appears to be August 2011. The following are items that were identified in the most recent borescope:

- There appears to be moderate wear in the Row 1compressor blade locking keys due to high turning gear hours that should be monitored for continued wear.
- Additionally, cracks were found on a rib reinforcement plate in the exhaust manifold and upper manway to manifold interface. These types of cracks pose no risk to unit availability, but should be monitored.
- An 8-inch crack along the inner Row 4 access tube weldment on the exhaust static seal that should be monitored for progression and/or weld repaired.
- Minor coating loss on the leading edge of compressor diaphragm rows 1, 2, 3, 4, 5, 6, 8 and 9 . Minor coating loss was also observed on all compressor blade rows.

The unit is not anticipated to receive an HGP inspection until 2023 based on the current operation hours of the unit. The unit has had less than 100 equivalent starts and less than 500 equivalent hours since the combustion inspection.

2.3.2 Unit 1 Generator

A Generator Stator Winding Spark Erosion Inspection has not been performed on the Unit 1 generator due to the limited operating hours of the unit. Most units that are inspected and found to have spark erosion damage have been operating between 15,000 to 55,000 service hours. Siemens has indicated that other users of this model generator have observed fatigue cracking in the rotor winding pole crossovers on generator rotors. Siemens recommends an inspection of the generator pole crossovers for this unit which has not been completed to date. Bluegrass has indicated in their monthly reports that this inspection is currently scheduled for 2017 based on the current anticipated dispatch pattern .

2.3.3 Unit 2 Combustion Turbine

Unit 2 has operated less than 1,200 equivalent operating hours and has less than 320 equivalent starts. Due to the limited operation, a CI has not been performed on the unit and is scheduled for 2018 based on the current operating history. The unit underwent borescope inspections multiple times since initial operation. The most recent appears to be August 2011. The only new finding of significance not previously reported was the early migration of the Row 3 vane knife seals which will require replacement at the next HGP outage. Previously reported minor impact damage to the Row 9 to16 compressor rotating blading/diaphragms had not deteriorated further at the time of the most recent borescope inspection. Some radial rubs previously reported in the turbine section were noted, which indicates the need for blade ring alignment correction at the next HGP outage.

2.3.4 Unit 2 Generator

A Generator Stator Winding Spark Erosion Inspection has not been performed on the Unit 2 generator due to the limited operating hours of the unit. Most units that are inspected and found to have spark erosion damage have been operating between 15,000 – 55,000 service hours. Siemens has indicated that other users of this model generator have observed fatigue cracking in the rotor winding pole crossovers on generator rotors. Siemens recommends an inspection of the generator pole crossovers for the unit which has not been completed to date. Bluegrass has indicated in their monthly reports that this inspection is currently scheduled for 2017 based on the current anticipated dispatch pattern.

2.3.5 Unit 3 Combustion Turbine

Unit 3 has operated less than 1,000 equivalent operating hours and has less than 330 equivalent starts. Due to the limited operation, a CI has not been performed on the unit and is scheduled for 2018 based on the current operating history. The unit underwent borescope inspections multiple times since initial operation. The most recent appears to be August 2011. There were no new findings of significance not previously reported. The previous inspection noted the following:

- A crack exists in the Row 4 diaphragm as identified in the 2009 borescope inspection. Subsequent inspections have shown there is no progression or additional cracking in this area. It is recommended that this unit be inspected approximately every 25 equivalent starts. Siemens recommends pulling the compressor cover and replacing the diaphragm at some point.
- Minor coating loss on the leading edge of all compressor diaphragm rows. Minor coating loss was also observed on all compressor blade rows.
- Leading edge impacts were observed on compressor blade Rows 1, 7, 10 and 14.
- A total of nine crack indications were found in and around the exhaust manifold area.
- A crack indication was found on the inlet splitter plate on the right side with flow in the inlet manifold.
- The upper downstream strut on the left side with flow of the inlet manifold struts was found with a crack indication.
- Some erosion and 3/4-inch cracking was noted on the platform of the Row 1 turbine blades and some 1/8-inch crack indications were noted on the tip of the blades. Coating loss was observed on turbine blade Rows 2 to 4.
- Some coating, erosion and rubs were noted on the turbine stationary ring segment Rows 1 and 2.
- Some coating loss and erosion were noted on the convex and concave side of Row 1 and 2 vane segments. Some minor overheating was noted on the convex and concave side of the Row 3 and 4 vane segment. The Row 3 vane seals were found pushed downstream.

2.3.6 Unit 3 Generator

A Generator Stator Winding Spark Erosion Inspection has not been performed on the Unit 3 generator due to the limited operating hours of the unit. Most units in the FD2 fleet that are inspected and found to have spark erosion damage have been operating between 15,000 to 55,000 service hours. Siemens has indicated that other users of this model generator have observed fatigue cracking in the rotor winding pole crossovers on generator rotors. Siemens recommends an inspection of the generator pole crossovers for the unit which has not been completed to date. Bluegrass has indicated in their monthly reports that this inspection is currently scheduled for 2017 based on the current anticipated dispatch pattern.

2.4 FUEL GAS SYSTEM

The Plant is supplied by a 120-foot long, 12-inch lateral interconnected to the Texas Gas Transmission (TXGT) pipeline. The Plant staff reported that the typical operating pressure of the TXGT mainline is 725 psia, which is sufficient for operating of the combustion turbines. No onsite compression is included at the Plant. TXGT owns, operates, and maintains the connection facilities, including the pipeline section between the Plant and the mainline. Transfer of ownership of the natural gas occurs at the Plant boundary. The Plant maintains pressure regulation facilities downstream of the connection facilities to reduce the pressure of the natural gas prior to entering the combustion turbines.

Each CT has a dedicated fuel supply line. A common natural gas-fired water bath dew point heater is used to heat the natural gas above dew point before entering the CTs. The units also share a single moisture knockout tank.

The Plant does not have the ability to fire using fuel oil. Plant management indicated the Facility does not have any pipeline capacity constraints or pressure issues. The Plant has never been curtailed for natural gas.

2.5 PLANT HIGH VOLTAGE POWER SYSTEM AND INTERCONNECTION

Three generator step-up transformers (GSUs) are located in the outdoor transformer yard, and transform power generated at 18 kV from the Units to the 345 kV high voltage switchyard. Unit 1 and Unit 2 are tied together with a collector bus, which is tied to the Louisville Gas and Electric Company (LG&E) 345-kV Buckner Substation via an overhead transmission line. Unit 3 is individually tied into the Buckner Substation via an overhead transmission line.

2.6 PLANT AUXILIARY POWER SYSTEM

Unit 1 and Unit 2 are equipped with a common auxiliary transformer, while Unit 3 is equipped with its own auxiliary transformer. The Plant includes a 250 kW Caterpillar diesel-fired backup generator for emergency power only. The Plant does not have black start capability. The Plant has an uninterruptible power supply (UPS) system to provide a reliable source of power for critical control and equipment loads during emergency operating conditions.

2.7 WATER SUPPLY AND TREATMENT SYSTEMS

Although the Plant staff reported that the units are equipped with DLN burners, water injection is utilized on the Units to further reduce NO_x emissions levels. In addition, the Units each include an inlet air fogging system to increase plant output on hot days above 59F. Both water injection for NO_x control, and inlet air fogging require the use of demineralized water. The raw water source for the Plant is municipal water, which is provided by the Oldham County Water District. Plant includes a raw water tank that also serves as the supply for fire protection water. Portable demineralizer trailers provide demineralized water for the site, by treating the raw water and filling the onsite 300,000 gallon demineralized water tank. The demineralizer trailers are regenerated off-site.

All equipment and plant drains that may contain oil are routed to the nearest oily water sump and then oil/water separator. Process wastewater from operations, including effluent discharge from the oil/water separator and other miscellaneous drains along with plant sewage are sent to the municipal sanitary sewer system.

2.8 FIRE PROTECTION SYSTEM

The fire protection system for the Plant consists of the following:

- Fire suppression systems in the turbine enclosures, the CEMS building and the Power Control Module
- Heat and smoke detection to a central alarm system in the central control room

The Facility is equipped with an electric motor driven firewater pump with a backup diesel engine firewater pump and an electric jockey pump. The pumps draw water from the Raw Water Tank of which 200,000 gallons of water is reserved for fire protection.

Overall, the fire protection system appears to be of typical design and adequate.

2.9 CONTINUOUS EMISSIONS MONITORING

Each stack of the Facility is equipped with a continuous emissions monitoring system (CEMS). The gas analyzers, the data acquisition system, display panel, and other CEMS hardware are located in a separate enclosed building adjacent to each stack.

2.10 PLANT CONTROL SYSTEMS

The CTGs are controlled by the Siemens provided turbine control system. A separate distributed control system (DCS) is utilized to integrate all Programmable Logic Controllers (PLC) for all other BOP systems for plant monitoring and control. Plant maintenance is managed using the Maximo inventory control and work order processing system. Additionally, the Plant utilizes the PI system for a data historian. The Units are not equipped with Automatic Generation Control (AGC).

The Siemens T3000 control system is included for turbine control, along with a Bentley Nevada vibration monitoring system. The Siemens control package also includes a Human Machines Interface (HMI). The Plant is controlled from a new Control Room located near the Units.

2.11 AIR QUALITY CONTROL SYSTEM

The CTs are equipped with dry low NO_x combustors for NO_x control and also include water injection for additional NO_x control. Additionally, Unit 1 and Unit 2 are equipped with SCR systems for further NO_x reduction; however, the Plant staff reported that these systems have never been operated. One 400 horsepower (hp) tempering air fan is provided for each SCR to reduce the temperature of the exhaust gas to a temperature conducive to the catalytic reaction of the NOx conversion. The SCR systems utilize aqueous ammonia as reagent for the NO_x reduction reaction. The aqueous ammonia is vaporized before entering the ammonia injection grid to be distributed inside the SCR. Unit 1 and Unit 2 are each equipped with their own ammonia storage tank, forwarding, and injection systems. The SCR catalysts are the original from the initial installation. The Plant Management mentioned that they may consider taking out the catalyst since it is not required and has not been operational since the Plant Commercial Operation Date (COD).

2.12 COMMUNICATIONS SYSTEMS

Dispatch communications for the Plant are via telephone and fax dispatch instructions from the Facility's Energy Manager. Plant personnel use two-way radios for communications at the Facility,

2.13 SECURITY AND ACCESS

The Plant site is enclosed with a chain link security fence. The entrance to the site includes a motor operated gate with a keypad and intercom that can be used to open the gate, or to contact the control room where the gate can be remotely operated. The entrance road to the site can be accessed via a publicly dedicated right-of-way.

2.14 STORM WATER DRAINAGE

Storm water runoff at the concrete area near the combustion turbines drains into the network of floor drains in the vicinity. Storm water runoff that is not caught by the floor drains is discharged to natural drainage.

2.15 MAINTENANCE/WAREHOUSE FACILITIES

The Plant includes an onsite building that serves as the administration, control room, and maintenance building. This building includes the control room, staff offices, a conference room, a break room, and the maintenance shop. The building is located on the south end of the site, near the Plant entrance.

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3.0 OPERATIONS AND MAINTENANCE PRACTICES

3.1 OPERATING PHILOSOPHY

The Facility functions as a merchant facility providing power generation to PJM. The Plant does not currently have a long-term power purchase or tolling agreement in place; however, it was reported that the facility did have a power purchase or tolling agreement in place at one point in the past.

As a peaking plant, the majority of the expected dispatch is during the middle of the day on hot summer days when air conditioning requirements increase the demand for power in the region and cause wholesale power prices to increase. It was reported that there is also winter peak in the region, although it is less significant than the summer peak. Reliability is important to an peak resource since annual operating hours will be limited.

The following paragraphs summarize key operational data for the Facility.

3.2 PLANT OPERATIONS

NAES Corporation has staffed and operated the Plant since September of 2009, under an Operating and Maintenance Contract with the Plant. Although the Operating and Maintenance contract with NAES Corporation did not go into effect until 2009, the Plant Manager has been at the Plant since the Plant COD. Currently, the NAES Corporation personnel are responsible for all daily operations of the Facility, including running the Units, routine maintenance, outage maintenance, scheduling any third party contract labor, and reporting operating data for the Project. Dispatch of the Units is scheduled by EDF Trading North America, Inc., acting as a third party Energy Manager through and Energy Management Agreement.

3.2.1 Dispatch and Heat Rate

Plant operating statistics were only provided for 2008 through November of 2012. Since that time, the Plant has been dispatched as peaking resource. Historical capacity factors by unit for 2008 through November of 2012 are listed in Tables 3.1 through 3.3 and Figure 3.1. The tables include totals as reported by the Facility.

Table 3.1 Unit 1: Historical Monthly Plant Capacity Factor

	2008	2009	2010	2011	2012*
January	0.6%	0.0%	0.5%	0.0%	0.0%
February	0.0%	0.0%	0.0%	0.0%	0.0%
March	0.0%	0.0%	0.0%	0.0%	0.0%
April	0.0%	0.0%	0.0%	0.0%	0.0%
May	0.0%	0.0%	0.5%	0.9%	0.0%
June	6.4%	11.4%	5.7%	0.0%	1.7%
July	3.9%	9.4%	3.4%	5.4%	11.0%
August	20.9%	12.3%	10.8%	2.2%	3.9%
September	6.1%	5.8%	5.6%	2.3%	0.0%
October	0.0%	0.0%	0.0%	0.0%	0.0%
November	0.0%	0.0%	0.0%	0.0%	0.0%
December	0.0%	0.0%	0.9%	0.0%	N/A
Annual Average CF	3.2%	3.0%	2.2%	0.8%	1.4%

*Partial Year (thru Nov 2012)

Table 3.2 Unit 2: Historical Monthly Plant Capacity Factor

	2008	2009	2010	2011	2012*
January	0.6%	3.2%	1.7%	0.0%	0.0%
February	0.0%	0.5%	0.0%	0.0%	0.0%
March	0.0%	0.5%	0.0%	0.0%	0.0%
April	0.0%	0.0%	0.0%	0.0%	0.0%
May	0.0%	0.0%	0.0%	0.9%	0.0%
June	0.0%	0.0%	5.6%	0.0%	1.6%
July	0.0%	0.0%	3.2%	5.3%	11.4%
August	0.0%	1.4%	11.8%	2.4%	3.8%
September	0.0%	0.0%	5.3%	2.1%	0.0%
October	0.0%	0.0%	0.0%	0.0%	0.0%
November	0.0%	0.0%	0.0%	0.0%	0.0%
December	2.6%	0.0%	0.0%	0.0%	N/A
Annual Average CF	0.3%	0.5%	2.2%	0.8%	1.4%

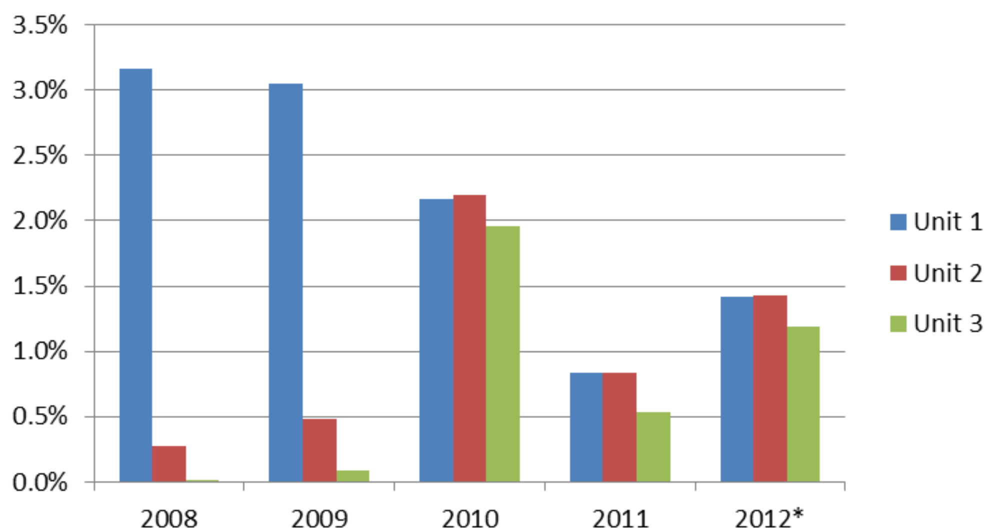
*Partial Year (thru Nov 2012)

Table 3.3 Unit 3: Historical Monthly Plant Capacity Factor

	2008	2009	2010	2011	2012*
January	0.0%	0.0%	1.2%	0.0%	0.0%
February	0.0%	0.0%	0.0%	0.0%	0.0%
March	0.0%	0.0%	0.0%	0.0%	0.0%
April	0.0%	0.0%	0.0%	0.0%	0.0%
May	0.0%	0.0%	0.0%	0.9%	0.0%
June	0.0%	0.0%	5.7%	0.0%	1.4%
July	0.0%	0.0%	2.2%	1.9%	9.2%
August	0.0%	1.2%	10.3%	2.0%	3.4%
September	0.0%	0.0%	5.5%	2.0%	0.0%
October	0.0%	0.0%	0.0%	0.0%	0.0%
November	0.0%	0.0%	0.0%	0.0%	0.0%
December	0.0%	0.0%	0.0%	0.0%	N/A
Annual Average CF	0.0%	0.1%	2.0%	0.5%	1.2%

*Partial Year (thru Nov 2012)

Figure 3.1: Historical Capacity Factors

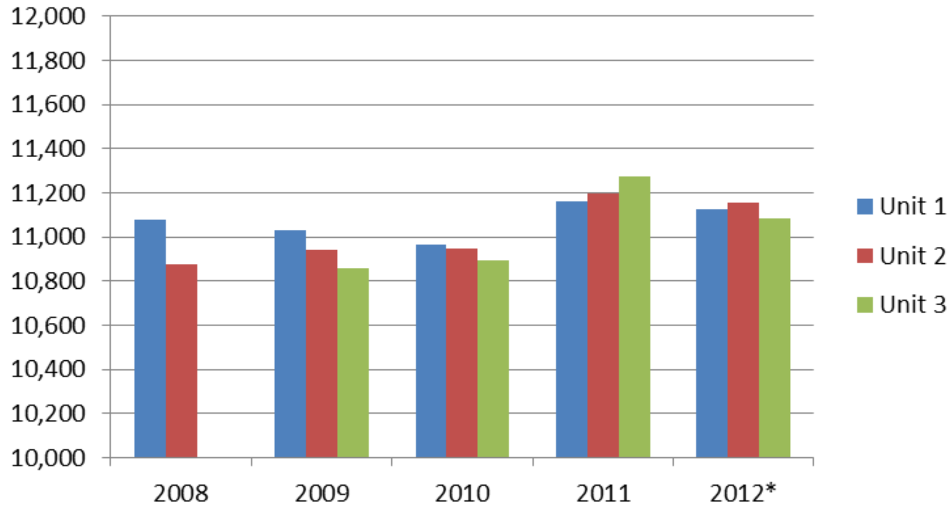


*Partial Year (thru Nov. 2012)

As expected, most of the dispatch hours have been concentrated during the time period of June through September each year. Dispatch was historically heavily weighted toward Unit 1, since Unit 1 had a dedicated tolling agreement in the past, with the highest dispatch on Unit 1 occurring in 2008. Dispatch of Unit 1 has trended downward since that time. Conversely, Unit 2 and Unit 3 dispatch has trended up since 2008, with Unit 2 dispatch at a capacity factor of less than 0.5 percent in 2008, and Unit 3 not dispatched at all in 2008. Unit 2 and Unit 3 had their highest dispatch in 2010, with a capacity factors of approximately 2 percent. Overall, all of these units have been dispatched very infrequently.

The average annual net operational heat rate for each Unit is provided in Figure 3.2.

Figure 3.2: Historical Net Plant Heat Rate



*Partial Year (thru Nov. 2012)

Average operational heat rates are impacted by startups, number of operating hours per start, and part load operations. In general, the average annual heat rates have been between 10,800 Btu/kWh and 11,300 Btu/kWh for each of the units. This is approximately three to eight percent higher than the guaranteed heat rate. This is more than what would be expected from degradation alone for units of this age, usage, and type; however, the heat rates provided could be impacted by startups and part load operation.

The annual historical net energy production for each individual Unit is reported in Figure 3.3.

Figure 3.3: Historical Net Energy Production

*Partial Year (thru Nov. 2012)

3.2.2 Reliability

The outage and availability data for each of the power block from 2001 through 2011 are presented in Tables 3.4 through 3.6 and Figure 3.4.

The tables present the Forced Outage Rate (FOR), Equivalent Forced Outage Rate (EFOR), and Equivalent Availability Factor (EAF). The definitions for each of these terms are presented below.

Forced Outage Rate (FOR):

$$FOR = \frac{FOH}{FOH + SH} x100\%$$

Where:
FOH – Forced Outage Hours
SH – Scheduled Hours

Equivalent Forced Outage Rate (EFOR):

$$EFOR = \frac{FOH + EFDH}{FOH + SH + EFDHRS} x100\%$$

Where:
FOH – Forced Outage Hours
SH – Scheduled Hours
EFDH – Equivalent Unplanned (Forced) Derated Hours

EFDHRS – Equivalent Unplanned (Forced) Derated Hours during Reserve Shutdowns

Equivalent Availability Factor (EAF):

$$EAF = \frac{AH - EPDH - EUDH - ESEDH}{PH} x100\%$$

Where:
AH – Available Hours
EPDH – Equivalent Planned Derated Hours
EUDH – Equivalent Unplanned Derated Hours
ESEDH – Equivalent Seasonal Derated Hours
PH – Period Hours

Table 3.4 Unit 1: Historical Outage and Availability Data

	2008			2009			2010			2011			2012*		
	FOR, %	EFOR, %	EAF, %	FOR, %	EFOR, %	EAF, %	FOR, %	EFOR, %	EAF, %	FOR, %	EFOR, %	EAF, %	FOR, %	EFOR, %	EAF, %
January	0.0	0.0	96.2	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0
February	0.0	0.0	99.5	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0
March	0.0	0.0	91.6	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	86.1	0.0	0.0	100.0
April	0.0	0.0	90.5	0.0	0.0	85.0	0.0	0.0	55.9	0.0	0.0	100.0	0.0	0.0	100.0
May	0.0	0.0	87.6	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0
June	0.0	0.0	85.4	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0
July	0.0	0.0	84.4	2.3	2.3	99.8	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0
August	0.9	0.9	84.7	17.0	17.0	97.1	6.0	6.0	99.3	0.0	0.0	89.8	4.3	4.3	99.8
September	0.0	0.0	86.5	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0
October	0.0	0.0	91.0	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	40.9	0.0	0.0	100.0
November	0.0	0.0	92.2	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0
December	0.0	0.0	99.0	0.0	0.0	100.0	0.0	0.0	99.6	0.0	0.0	100.0	N/A	N/A	N/A
Annual Avg.	0.5	0.5	90.7	6.4	6.4	98.5	2.5	2.5	96.3	0.0	0.0	92.9	1.0	1.0	100.0

*Partial Year (thru Nov 2012)

Table 3.5 Unit 2: Historical Outage and Availability Data

	2008			2009			2010			2011			2012*		
	FOR, %	EFOR, %	EAF, %	FOR, %	EFOR, %	EAF, %	FOR, %	EFOR, %	EAF, %	FOR, %	EFOR, %	EAF, %	FOR, %	EFOR, %	EAF, %
January	0.0	0.0	96.2	0.0	0.7	100.0	2.8	2.8	99.9	0.0	0.0	100.0	0.0	0.0	100.0
February	0.0	0.0	99.5	11.2	11.2	99.7	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0
March	0.0	0.0	91.6	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	86.1	0.0	0.0	100.0
April	0.0	0.0	90.6	0.0	0.0	91.7	0.0	0.0	100.0	0.0	0.0	95.9	0.0	0.0	100.0
May	0.0	0.0	88.6	0.0	0.0	100.0	0.0	0.0	92.8	0.0	0.0	100.0	0.0	0.0	100.0
June	0.0	0.0	85.4	25.0	25.0	99.0	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0
July	0.0	0.0	84.4	0.0	0.0	95.6	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0
August	0.0	0.0	84.9	0.0	0.0	99.6	0.0	0.0	100.0	0.0	0.0	92.5	0.0	0.0	100.0
September	0.0	0.0	86.5	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0
October	0.0	0.0	91.0	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	40.9	0.0	0.0	100.0
November	0.0	0.0	95.3	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0
December	0.0	0.0	99.0	0.0	0.0	100.0	0.0	0.0	99.5	0.0	0.0	100.0	N/A	N/A	N/A
Annual Avg.	0.0	0.0	91.0	5.2	5.6	98.8	0.2	0.2	99.3	0.0	0.0	92.8	0.0	0.0	100.0

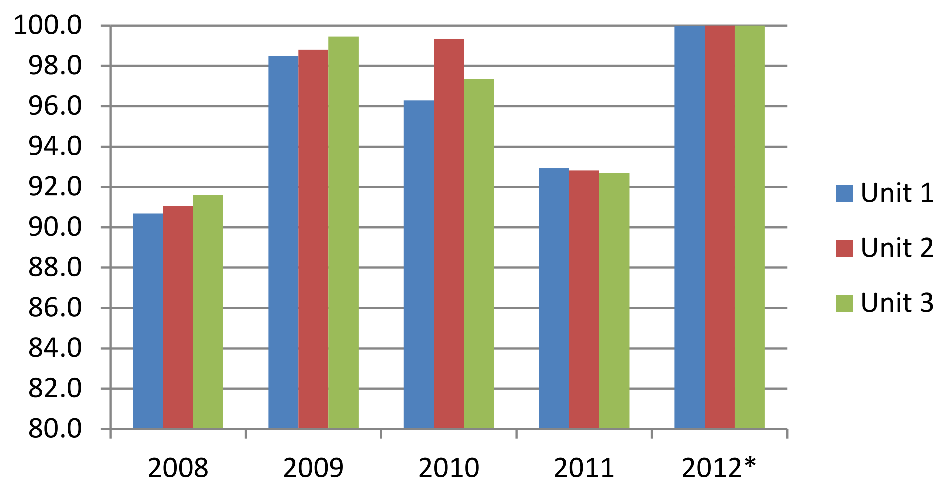
*Partial Year (thru Nov 2012)

Table 3.6 Unit 3: Historical Outage and Availability Data

	2008			2009			2010			2011			2012*		
	FOR, %	EFOR, %	EAF, %	FOR, %	EFOR, %	EAF, %	FOR, %	EFOR, %	EAF, %	FOR, %	EFOR, %	EAF, %	FOR, %	EFOR, %	EAF, %
January	0.0	0.0	100.0	0.0	0.0	100.0	0.6	0.6	100.0	0.0	0.0	100.0	0.0	0.0	100.0
February	0.0	0.0	99.5	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0
March	0.0	0.0	95.3	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	80.2	0.0	0.0	100.0
April	0.0	0.0	89.4	0.0	0.0	95.1	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0
May	0.0	0.0	88.6	0.0	0.0	100.0	0.0	0.0	96.3	0.0	0.0	100.0	0.0	0.0	100.0
June	0.0	0.0	85.4	0.0	0.0	98.8	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0
July	0.0	0.0	84.4	0.0	0.0	100.0	82.0	82.0	89.9	2.5	2.5	100.0	0.2	0.2	100.0
August	0.0	0.0	84.9	0.0	0.0	99.6	0.0	0.0	100.0	0.0	0.0	92.9	0.0	0.0	100.0
September	0.0	0.0	86.5	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	100.0
October	0.0	0.0	91.0	0.0	0.0	100.0	0.0	0.0	100.0	0.0	0.0	40.9	0.0	0.0	100.0
November	0.0	0.0	95.3	0.0	0.0	100.0	100.0	100.0	99.7	0.0	0.0	100.0	0.0	0.0	100.0
December	0.0	0.0	99.0	0.0	0.0	100.0	0.0	0.0	82.9	0.0	0.0	100.0	N/A	N/A	N/A
Annual Avg.	0.0	0.0	91.6	0.0	0.0	99.5	29.1	29.1	97.4	0.7	0.7	92.7	0.1	0.1	100.0

*Partial Year (thru Nov 2012)

Figure 3.4: Equivalent Availability Factor



*Partial Year (thru Nov. 2012)

The forced outage rates, equivalent forced outage rates, and equivalent availability factors presented above were provided by LS Power. All of the Units have had reliability statistics slightly above the average for simple cycle combustion turbine facilities similar to these units.

According to the NERC GADS statistical information, during the time period of 2000 to 2012, the EAF for all simple cycle frame units averaged 89.92 percent and for simple cycle combustion turbines greater than 150 MW, the EAF averaged 91.85 percent. All of the Bluegrass Units exceeded both of these averages on an annual basis from 2009 through 2012. In 2008, the EAF for each unit was slightly below the average of units greater than 150 MW, but greater than the average of all frame simple cycle units.

Over this same time period, the EFOR averaged 47.56 percent for all simple cycle frame units and 22.15 percent for simple cycle combustion turbines greater than 150 MW. It is not uncommon for EFOR to be relatively high, since the outage hours are compared to scheduled hours of operation, not the period hours; therefore, even a short outage when the unit is called upon can result in a high EFOR for a peaking facility, due to its limited dispatch schedule. The EFOR for all of the Bluegrass Units has been well below the industry averages on an annual basis, and in all months except on Unit 2 in June 2009 and on Unit 3 in July 2010 and November 2010. In those months, even though the EFOR was high, the EAF was relatively high, and the increased EFOR was due to very low scheduled operating hours, as evident from the very low capacity factors for those units in those months. The event summary log was reviewed as well and confirmed that these forced outages were short in duration.

The event summary that was provided for all of the Units covered a time period from January of 2008 through May of 2011. This summary was reviewed in relation to the months in which the EAF was higher than the fleet averages to determine the cause of the lowered availability, and to determine if any recurring problems are present. The Units have all had lowered EAF in the spring of each year for annual spring outages, as expected, with the outage on Unit 1 being longer in the spring of 2010 due to a CI being performed on Unit 1. The annual EAF was lowest in 2008 for all of the Units, and was also reduced in comparison to other years in all months that year for all Units, with the exception of January for Unit 3. There were not any major issues during this timeframe, or any recurring issues with the Units that would be cause for concern.

In October 2011 all of the Units had a very low EAF, but this time period was not covered by the event summary document. However, a monthly operations report was available for this time period. The lower

EAF for the plant in October of 2011 was due to a fall planned outage for a scheduled electrical outage to test all switchgear, relays, generator breakers, and transformers.

The number of attempted starts and the starting reliability for the Units from 2008 through November of 2011 are presented in Tables 3.7 through 3.9. and Figure 3.5.

Table 3.7 Unit 1: Historical Start Data

	2008		2009		2010		2011		2012*	
	Attempts	Reliability	Attempts	Reliability	Attempts	Reliability	Attempts	Reliability	Attempts	Reliability
January	1	100%	0	0%	1	100%	0	0%	0	0%
February	0	0%	0	0%	0	0%	0	0%	0	0%
March	0	0%	0	0%	0	0%	0	0%	0	0%
April	0	0%	0	0%	1	100%	0	0%	0	0%
May	0	0%	1	100%	1	100%	2	100%	0	0%
June	7	100%	12	100%	6	100%	0	0%	2	100%
July	5	100%	15	87%	3	100%	5	100%	11	100%
August	21	100%	14	93%	12	92%	2	100%	5	100%
September	7	100%	7	100%	4	100%	2	100%	0	0%
October	0	0%	0	0%	0	0%	0	0%	0	0%
November	0	0%	0	0%	0	0%	0	0%	0	0%
December	0	0%	0	0%	2	100%	0	0%	0	0%
Annual	41	100%	49	94%	30	97%	11	100%	18	100%

*Partial Year (thru Nov 2012)

Table 3.8 Unit 2: Historical Start Data

	2008		2009		2010		2011		2012*	
	Attempts	Reliability	Attempts	Reliability	Attempts	Reliability	Attempts	Reliability	Attempts	Reliability
January	1	100%	2	100%	6	67%	0	0%	0	0%
February	0	0%	2	50%	0	0%	0	0%	0	0%
March	0	0%	1	100%	0	0%	0	0%	0	0%
April	0	0%	0	0%	0	0%	0	0%	0	0%
May	0	0%	0	0%	0	0%	2	100%	0	0%
June	1	100%	0	0%	6	100%	0	0%	2	100%
July	0	0%	0	0%	3	100%	5	100%	11	100%
August	0	0%	1	100%	10	100%	2	100%	4	100%
September	0	0%	0	0%	4	100%	2	100%	0	0%
October	0	0%	0	0%	0	0%	0	0%	0	0%
November	0	0%	0	0%	0	0%	0	0%	0	0%
December	4	100%	0	0%	0	0%	0	0%	0	0%
Annual	6	100%	6	83%	29	93%	11	100%	17	100%

*Partial Year (thru Nov 2012)

Table 3.9 Unit 3: Historical Start Data

	2008		2009		2010		2011		2012*	
	Attempts	Reliability	Attempts	Reliability	Attempts	Reliability	Attempts	Reliability	Attempts	Reliability
January	0	0%	0	0%	3	67%	0	0%	0	0%
February	0	0%	0	0%	0	0%	0	0%	0	0%
March	0	0%	0	0%	0	0%	0	0%	0	0%
April	0	0%	0	0%	0	0%	0	0%	0	0%
May	0	0%	0	0%	0	0%	2	100%	0	0%
June	1	100%	0	0%	6	100%	0	0%	2	100%
July	0	0%	0	0%	2	100%	3	100%	10	100%
August	0	0%	1	100%	9	100%	2	100%	3	100%
September	0	0%	0	0%	4	100%	2	100%	0	0%
October	0	0%	0	0%	0	0%	0	0%	0	0%
November	0	0%	0	0%	0	0%	0	0%	0	0%
December	0	0%	0	0%	2	100%	0	0%	0	0%
Annual	1	100%	1	100%	26	96%	9	100%	15	100%

*Partial Year (thru Nov 2012)

Figure 3.5: Starting Reliability

*Partial Year (thru Nov. 2012)

Starting reliability is important for a peaking facility, due to the limited dispatch and relatively short run time per start. According to the NERC GADS statistical information, during the time period of 2000 to 2012, the starting reliability for all simple cycle frame units averaged 96.62 percent and for simple cycle combustion turbines greater than 150 MW, the starting reliability averaged 97.33 percent. All of the Bluegrass Units exceeded both of these averages on an annual basis in 2008, 2011, and 2012, but fell short of these averages in 2009 and 2010. One recurring cause of failed starts has been high blade path spread, which occurred in 2009 and 2010 on Unit 1; however, that issue appears to have been corrected. Also in 2009, there were some failed starts attributed to debris in the Pilot and A-stage witches hat strainers. A Plant modification was performed to install four common strainers rather than 64 individual strainers, to make it easier to identify the location of strainer debris and resolve the problem quicker if it were to recur.

BMcD's conclusions from the information summarized in the tables above are highlighted as follows:

- The net plant heat rate is slightly higher than expectations for a facility of this size, usage, and type and the units did not meet their guaranteed heat rate values in 2002.
- All of the Units have been dispatched very little over the past several years, particularly Unit 2 and Unit 3. The dispatch of the Units overall, has generally trended downward over the recent past.
- Due to the frequent start-up and shutdown requirements of simple cycle units, the starting reliability is critical. The Plant has had a high number of starts per operating hour, but this is common for a peaking facility. Generally, the starting reliability of these Units has been relatively high in2008, 2011, and 2012 and below average in 2009 and 2010.
- The availability of the Units is mostly comparable to typical simple cycle units, with the availability being slightly below average in 2008. No major recurring issues were identified, and the availability has increased to expected levels after 2008.

3.3 OPERATIONS AND ROUTINE MAINTENANCE

NAES Corporation is responsible for operations and routine maintenance of the Facility. The Facility is currently staffed with a total of 6 non-union employees consisting of a plant manager, an administrative support specialist, and four (4) operators. Additionally, three contractors: an insulator, an E&I technician and a mechanic, are also on the payroll. The operations staff carries out routine and minor maintenance activities. Periodic and required safety training is provided by NAES Corporation. The staffing level is adequate for a peaking facility of this size.

BMcD reviewed the historical and projected O&M cost for the facility. Tables 3.10 and 3.11 present the historical and projected O&M costs, respectively, for the Facility as provided by LS Power. The projected O&M costs were provided by the Plant in its 5-year budget.

Table 3.10 Historical O&M Costs

Variable	**2010**	**2011**	**2012**
Transmission-electric-variable	$ 1,694	$ -	$ -
Maintenance parts and service	$ 130,574	$ 362,896	$ 190,117
Long term service agreement	$ -	$ -	$ -
Chemicals	$ 138	$ 608	$ 6,468
Consumables	$ 52,013	$ 31,206	$ 29,537
Total Variable O&M Costs	**$ 184,418**	**$ 394,710**	**$ 226,122**

Fixed	**2010**	**2011**	**2012**
Transmission-electric-fixed	$ -	$ -	$ -
Utilities	$ 392,507	$ 412,241	$ 422,381
Site labor	$ 776,658	$ 781,345	$ 790,108
Communications	$ 31,904	$ 30,941	$ 85,349
Subcontractor services	$ 33,476	$ 28,253	$ 26,082
Professional services	$ 79,818	$ 123,428	$ 258,804
Permits and emissions fees	$ 400	$ 2,686	$ 9,350
Employee and community relations	$ 13,287	$ 12,678	$ 12,007
Training and Travel	$ 46,511	$ 25,717	$ 24,391
Office expense	$ 64,643	$ 54,521	$ 55,741
Vehicles	$ 17,923	$ 7,428	$ 4,484
Buildings and Grounds	$ 50,218	$ 57,574	$ 76,917
Property taxes and fees	$ 656,161	$ 653,354	$ 610,124
Administrative (1)	$ -	$ -	$ -
Total Fixed O&M Costs	**$ 2,163,506**	**$ 2,190,166**	**$ 2,375,738**

(1) Operating expenses exclude 3rd-party O&M operator and energy manager fees, insurance expenses, legal and accounting expenses.

Generally, the operating and maintenance costs appear reasonable. A few anomalies stand out, including the communications, professional services, and buildings and grounds, which all had significant increases from 2011 to 2012. The values for buildings and grounds and communications are projected to return closer to the 2011 levels in 2013 and going forward. The projected O&M costs from 2013 to 2017 are presented in Table 3.11.

Table 3.11 Projected O&M Costs ($000)

Variable	2013	2014	2015	2016	2017
Transmission-electric-variable	$ -	$ -	$ -	$ -	$ -
Maintenance parts and service	$ 199	$ 203	$ 207	$ 211	$ 216
Long term service agreement	$ -	$ -	$ -	$ -	$ -
Chemicals	$ 16	$ 16	$ 17	$ 17	$ 17
Consumables	$ 35	$ 36	$ 37	$ 37	$ 38
Total Variable O&M Costs	**$ 250**	**$ 255**	**$ 261**	**$ 265**	**$ 271**

Fixed	2013	2014	2015	2016	2017
Transmission-electric-fixed	$ -	$ -	$ -	$ -	$ -
Utilities	$ 436	$ 445	$ 454	$ 463	$ 472
Site labor	$ 842	$ 859	$ 876	$ 894	$ 911
Communications	$ 36	$ 37	$ 38	$ 39	$ 39
Subcontractor services	$ 49	$ 50	$ 51	$ 52	$ 53
Professional services	$ -	$ -	$ -	$ -	$ -
Permits and emissions fees	$ 1	$ 1	$ 1	$ 1	$ 1
Employee and community relations	$ 19	$ 20	$ 20	$ 21	$ 21
Training and Travel	$ 71	$ 72	$ 74	$ 75	$ 76
Office expense	$ 87	$ 89	$ 91	$ 93	$ 95
Vehicles	$ 9	$ 9	$ 9	$ 10	$ 10
Buildings and Grounds	$ 64	$ 65	$ 67	$ 68	$ 69
Property taxes and fees	$ 602	$ 603	$ 604	$ 604	$ 605
Administrative (1)	$ -	$ -	$ -	$ -	$ -
Total Fixed O&M Costs	**$ 2,216**	**$ 2,250**	**$ 2,285**	**$ 2,320**	**$ 2,352**

Generally the operating and maintenance costs projections appear to be reasonable. A projection of electric transmission costs and professional services costs was not provided in the budget and should be considered when evaluating future operating and maintenance costs.

3.3.1 Spare Parts Inventory

LS Power currently shares the capital spares for major maintenance with several other facilities that are owned by LS Power. The current sale agreement does not include a transfer of capital spares as part of the agreement. LS Power indicated that they would be willing to sell a set of capital spares. If the option to purchase the facility is considered, the list of parts included in the set of capital spares should be reviewed, and the price of those capital spares considered in relation to other resources for purchasing capital spares. An inventory of current spare parts held at the Facility was not provided for review. If the option to purchase the facility is considered a spare parts inventory should be reviewed to determine if an appropriate amount of routine spare parts are available for routine maintenance activities.

3.4 MAINTENANCE OVERHAULS

The Units require periodic maintenance overhauls to restore performance to optimal levels and replace worn parts. The maintenance schedule requirements are a function of unit operating parameters such as the number of operating hours and/or equivalent starts. Typical maintenance requirements for 501FD2 combustion turbines include a CI, HGP, and eventually a Major Outage (MO).

Major maintenance activities are based on the Equivalent Hours or Equivalent Starts accumulated on each Unit. The major maintenance intervals for these Units that are recommended by Siemens are as presented in Table 3.12.

Table 3.12 Major Maintenance Schedule

Inspection Type	Total Hours	Equivalent Starts
Combustor Inspection	8,000	400
Hot Gas Path	24,000	800
Major Outage	48,000	1,600

The Plant does not have a Long Term Program (LTP) in place with Siemens for turbine maintenance. Instead, the LSP has opted to self-manage the maintenance of the combustion turbines, since LSP owns several other facilities with the same combustion turbines, and can share capital spares between the facilities to reduce inventory costs. Major maintenance activities and borescope inspections are performed by third party contractors, which also results in reduced costs compared to an LTP with Siemens. If EKPC elects to move forward with acquisition of the Plant, an evaluation should be performed to determine whether turbine maintenance can be self-managed or if an LTP should be considered.

Due to the short runtime per start, the units are on schedule to have major maintenance activities initiated by number of starts. Unit 1 underwent a CI in April 2010 at 422 cumulative equivalent starts and 1176 cumulative equivalent hours. Unit 2 and Unit 3 are not anticipated to require CIs until around 2018, if the dispatch remains similar to historical operations.

3.5 TEST OPERATIONS AND THERMAL PERFORMANCE

The Facility conducted a performance test when the Plant was constructed; however, no performance tests have been performed since then. The units did not meet their performance guarantee in 2002 and tested approximately one to two percent higher than the guaranteed heat rate. Prior to purchase of the Facility or entering into a long-term contract, BMcD would recommend a third-party conduct a performance test to determine the current capabilities of the Plant for both capacity and heat rate. The cost for a third-party to conduct a performance test is approximately $150,000 to $200,000.

3.6 CAPITAL IMPROVEMENTS

The only apparent need for any capital improvements that might increase capacity or decrease heat rate of the Units beyond typical, good utility maintenance practices and major maintenance inspections is for compliance with any Siemens Technical Advisories. A total of $921,000 is allocated for plant improvements for the next 5-year forecast cycle. This includes inlet air filter replacement on each of the Units, replacement of expansion joints, torque converter overhauls, and repairs associated with Siemens Technical Bulletin for the Row 4 compressor diaphragm.

3.7 SIEMENS TECHNICAL ADVISORIES

The Plant provided a spreadsheet they compiled to track all Urgent Technical Advisories, Technical Advisories, Product Bulletins, Service Bulletins, and Customer Service Letters for the Siemens 501FD2 combustion turbines and the status of the Bluegrass Units in relation to each of those Siemens publications. The Plant has either implemented each urgent technical advisory and technical advisory, or evaluated them and determines that they were not applicable to the Bluegrass Facility. Product bulletins, service bulletins, and customer service letters were also reviewed to determine if they were required or simply recommended upgrades, and were implemented if determined to be sufficiently beneficial, or targeted for implementation during a future major maintenance activity.

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4.0 KEY CONTRACTS AND AGREEMENTS

BMcD reviewed the following key Project agreements:

- Water Purchase Agreement
- Electrical Interconnection Agreement
- Natural Gas Interconnection and Supply Agreement
- Operations and Maintenance Agreement
- Energy Management Agreement

4.1 WATER PURCHASE AGREEMENT

A Water Purchase Agreement is in place between The Oldham County Water District (District) and Bluegrass Generation Company, LLC (Bluegrass) for supply of raw water to the site. Details of the water purchase agreement are summarized below.

- The agreement is effective as of February 2001 for a 30 year term for the District to provide a firm, non-interruptible “normal quantity” of water of 80,000 gallons per day (GPD) with a daily maximum quantity of 220,000 GPD to be delivered at a peak delivery rate of 300 gallons per minute (gpm).
- Water delivery pressure shall not be lower than 45 psig.
- The Water Facilities are operated and maintained by the District. The metering station is operated and maintained by the District.
- The cost of water is at the District’s “wholesale” rate and is subject to revisions as approved by the Kentucky Public Service Commission. The rate at the time the agreement was signed was $0.90 per 1000 gallons of water delivered. The most recently published wholesale rate for water from the District is $1.70 per 1000 gallons.
- Bluegrass has the right to audit the quantity and quality of water being delivered to the plant.

Based on a review of the Water Purchase Agreement, BMcD concludes the following with respect to future risks/issues:

- The Water Supply Agreement contains standard industry terms and conditions.
- The Water Supply Agreement is adequate for the Plant and the Plant does not appear to have any technical limitations that would prevent it from meeting the requirements of the Agreement.

4.2 ELECTRICAL INTERCONNECTION AGREEMENT

Bluegrass has an executed Interconnection and Operating Agreement (IA) with Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU), effective February 2001. Details of the IA are provided below:

- The Plant interconnects with LG&E and KU at disconnect switches where the LG&E/KU Buckner Substation interconnects with the Bluegrass interconnection facility. The interconnection voltage is 345-kV.
- The term of the agreement is 30 years.
- The IA is for 720 MW of total capacity.
- Bluegrass owns the LG&E/KU Interconnection Facilities and leases the facilities to LG&E/KU at a rate of one dollar per year in accordance with the Switchyard Sub-Lease agreement effective as of January 2002. Operation and maintenance of the facilities is by LG&E/KU. Bluegrass is responsible for operation and maintenance of facilities owned by Bluegrass on the upstream side of the point of electrical interconnection.
- Transmission services and Ancillary Services are provided to Bluegrass (or any entity acquiring energy generated by the plant) pursuant to the provisions of the LGE&E/KU Open Access Transmission Tariff.
- Bluegrass is subject to Energy Imbalance Service obligations and must purchase balancing services from LG&E/KU or make alternative comparable arrangements when the metered amount of energy is +/- 1.5 percent different than the scheduled amount.
- The agreement appears to contain standard legal clauses such as force majeure, liability limits, assignment, and dispute resolution clauses.

Based on a review of the IA, BMcD concludes the following with respect to future risks/issues:

- The IA includes standard industry terms and conditions
- The IA limits the maximum facility output to 720 MW, which is more than sufficient for the maximum net plant output.

4.3 NATURAL GAS INTERCONNECTION AND SUPPLY

There is a Facilities Agreement in place between Texas Gas Transmission Corporation (Texas Gas) and Bluegrass Generation LLC (Customer). Details of the agreement are summarized below.

- The agreement is effective as of April 2001 and shall remain in full force and effect until the final removal and/or abandonment of the Connection Facilities.
- Texas Gas was responsible for the design, engineering, and construction of the Connection Facilities. Texas Gas owns, operates, and maintains the Connection Facilities and is responsible for the abandonment and removal costs should this occur in the future. Texas Gas shall notify Bluegrass at least 90 days prior to filing for authority from Federal Energy Regulatory Commission (FERC) to abandon or remove the Connection Facilities.
- Bluegrass owns, operates, and maintains the pressure regulation facilities located downstream of the Connection Facilities.
- Texas Gas shall make reasonable efforts to notify Bluegrass at least 72 hours prior to commencing any activity which may result in disruption of gas delivery.
- Texas Gas can deliver gas at any pressure up to the maximum allowable operating pressure of the Texas Gas mainline.

Based on a review of the IA, BMcD highlights the following with respect to future risks/issues:

- Article II, Section 2.2 of the agreement states Texas Gas can abandon the Connection Facilities with only 90 days notice to Bluegrass.
- The agreement does not have a minimum required gas delivery pressure and the Plant does not have gas compressors A sudden drop in gas delivery pressure can potentially disrupt Plant operation.

4.4 OPERATIONS AND MAINTENANCE AGREEMENT

The Plant is operated by NAES Corporation (Operator) under an Operations and Maintenance (O&M) Agreement dated September 15, 2009 with Port River, LLC (Owner). The Operator provides all things necessary for the proper operation and maintenance of the Plant under the O&M Agreement.

Key commercial, technical, and operational components of the O&M Agreement include the following:

- The original term of the agreement was through September 30, 2012. The agreement is automatically extended by successive 3-year periods thereafter unless terminated by Owner or Operator at least 60 days prior to the end of the current term.
- The scope of services provided by the Operator includes providing the following:
    - Facility personnel for plant operations

- Training of facility personnel
- Operating and maintenance procedures for the Plant
- Regulatory compliance, with support from the Owner as necessary
- Environmental compliance, with support from the Owner as necessary
- NERC compliance, including representing the Owner in NERC audits
- Preventive/Predictive maintenance program for the Plant
- Computerized maintenance management system for the Plant
- Administrative procedures manual specific to the Plant
- Facility Operations for startup, operations, and shutdown of the Plant
- Operability and maintainability review, based on Plant drawings
- Maintenance of all Plant equipment, structures, grounds, and utility interfaces
- Corrective maintenance and routine repairs
- Preventive/Predictive maintenance in accordance with preventive maintenance program
- Major maintenance for all equipment
- Plant betterment for Plant enhancement
- Project assessment program for cost justification of all work
- Agreement administration for all Plant agreements
- Goods and services providers scheduling and coordination
- Purchasing with approval from Owner
- Inventory control for spare parts, materials, supplies, and tools
- Programs and procedures as necessary
- Reports for technical, incident reports, outage reports, and financial reports
- Facility books and records maintenance
- Technical library for document control
- Capital improvements/facility changes recommendations
- Assistance to Owner in the performance of Owner duties
- Cooperation with parties signatory to Facility Agreements
- Annual operating plant and budget plus 5-year budget creation
- Fuel management for daily gas fuel supply and balancing
- Energy management support by providing plant operating statistics
- Permits, licenses, and other approvals on behalf of the Owner

- The Owner provides the following support to Operator
  - Facilities, including office, sanitary, and secure storage

    - General management and administrative functions, including audits, tax filing, legal services, etc.
    - Fuel supply procurement
    - Fuel management via Owner or Energy Manager
    - Energy management dispatch directions
    - Permit assistance
    - Access to the Plant
    - Information, such as as-built drawings, manuals, contract, and permits
- The O&M Agreement provides the Owner with several termination provisions with 30 days notice for events by the Operator, including:
    - Violation of the law, resulting in an adverse impact on the Plant
    - Material breach of contract not cured within 30 days
    - Damage to the Plant that cannot be cured within 1 calendar year
    - Equivalent availability factor being less than 97 percent for a consecutive 12 month period, due to the Operator making an error or failing to follow vendor manuals or prudent industry practice
    - A budget variance of greater than a positive 10 percent for two consecutive years
- The Owner may terminate the agreement for convenience at any time with three months written notice to Operator or with 30 days notice upon a sale of the Plant.
- The Operator may terminate the agreement for cause with 30 days written notice.
- The fee structure was redacted in the contract provided for review. The fee structure includes an incentive bonus structure, which was also not provided for review.
- The Owner is required to provide all Special Tools and equipment necessary for compliance with this agreement. These tools must be identified within two months following the commercial operation date of the Plant.
- The Operator is required to staff the Plant at least 20 hours per day, seven days per week.
- The Operator is authorized to make expenditures up to $50,000 or 10 percent of a budget line item on a monthly basis. The Operator is authorized to make expenditures up to $100,000 or 10 percent of a budget line item on a year-to-date basis.

Based on a review of the Operations and Maintenance Agreement, BMcD concludes the following with respect to future risks/issues:

- The O&M Agreement is with Port River, LLC. If Port River, LLC is not part of the purchase and sale agreement, the contract would need to be transferred to the new owner of the Plant.
- The O&M Agreement contains standard industry terms and conditions.
- The Plant does not appear to have any technical limitations that would prevent it from meeting the requirements of the O&M Agreement.
- The Operator is a qualified third-party operator of power generation facilities.
- The fee structure was not provided for review; therefore, no assessment can be made at this point. If EKPC considers purchasing the facility, the fee structure should be reviewed in order to take into consideration whether to keep the O&M contract in place or terminate it.

4.5 ENERGY MANAGEMENT AGREEMENT

Energy output from the Plant is marketed and sold by EDF Trading North America, LLC (Energy Manager) under an Energy Management Agreement (EMA) dated October 15, 2009 with Port River, LLC (Acquisition Company) and Bluegrass Generation Company, LLC (Project).

Key commercial, technical, and operational components of the EMA include the following:

- The Effective Date of the EMA was October 15, 2009 and the EMA will remain in place until terminated by either party. There is no defined end date in the EMA.
- The EMA was amended on December 1, 2009 to provide an Adjusted Generation Margin; however, this information was redacted in the version provided for review.
- The scope of services provided by the Energy Manager includes the following:
    - Transition Services
        - This included supporting the transition of ownership of the Plant from Dynegy to Port River, LLC
    - Power Management Services, including:
        - Negotiating and executing forward hedging transactions
        - Developing day-ahead commitment offers
        - Developing third party customer relationships
        - Developing the Dispatch Model
        - Executing and scheduling real-time Power and Ancillary Services Transactions
        - Assist with Dispatch decisions
        - Assist in scheduling Power, transmission, and settlements with the control area
        - Assist in developing Ancillary Service product bids

        - Assist in buying and selling emissions credits
        - Maintain a 24-hour desk as primary contact between control area and Operator
        - Comply with all FERC Reliability Standards administered by NERC as the Project's purchasing-selling entity
    - Fuel Management Services, including:
        - Procure and supply fuel for the sale of Power
        - Identify opportunities to enter into Commodity Transactions for Fuel
        - Enter into Commodity Transactions for Fuel
        - Arrange Fuel supplier, storage, and Transporter meetings
        - Negotiate related Agreements and reconcile invoices
        - Nominate and schedule delivery of Fuel in accordance with Operating and Dispatch Procedures
        - Nominate, schedule, and balance with suppliers, Transporters, and storage providers of Fuel
        - Assist with development of Fuel procurement and storage optimization strategy
        - Assist with development of commercial strategies
        - Market and sell excess Fuel
        - Evaluate long-term Fuel transportation and storage options
        - Provide Other Services as agreed upon in writing
        - Coordinate with Third Party service providers to accurately nominate Fuel and minimize costs
    - Risk Management Services, including:
        - Arrange and administer heat rate call options, swaps, cross commodity swaps, commodity caps, commodity floors, commodity collars, basis swaps, basis option, or commodity options consistent with the Risk Management Strategy
        - Perform Other Services as agreed upon in writing
    - Generation Margin, which includes maximizing the Generation Margin based on market conditions
    - Reporting Requirements, which includes summary reports of all Transactions and a daily report of mark-to-market exposure and credit available for transactions
- The EMA states that the Project will work with the Energy Manager to develop Energy Management Plans, Risk Management Strategy, and Execution Strategies
- The Project is responsible for selling reactive power
- The Project is responsible for determining the amount of Fuel to be supplied to the Facility

- The Acquisition Company and the Project both have the right to terminate the agreement for convenience at any time with not less than 30 days written notice to the Energy Manager.
- The Energy Manager has the right to terminate the agreement for convenience at any time with not less than 90 days written notice to the Acquisition Company and the Project.
- Both the Project and the Energy Manager have the right to terminate the agreement for cause with not more than 20 days written notice to the defaulting party.
- The EMA includes a provision that a $25,000 fee is payable to the Energy Manager if the Project is transferred to a third party by the Acquisition Company, and the Project will no longer be a party to the EMA.
- The fee structure was redacted in the contract provided for review.

Based on a review of the Operations and Maintenance Agreement, BMcD concludes the following with respect to future risks/issues:

- The EMA is with Port River, LLC and Bluegrass Generation Company, LLC. If Port River, LLC is not part of the purchase and sale agreement, the contract would need to be transferred to the new owner of the Plant or the EMA amended to remove Port River, LLC as a party.
- It appears that the Project would no longer be a party to the EMA if the Project were transferred from the Port River, LLC to another party.
- The EMA contains standard industry terms and conditions.
- The Plant does not appear to have any technical limitations that would prevent it from meeting the requirements of the EMA.
- The fee structure was not provided for review; therefore, no assessment can be made at this point. If EKPC considers purchasing the facility, the fee structure should be reviewed in order to take into consideration whether to keep the EMA contract in place or terminate it.

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5.0 CONCLUSIONS

5.1 CONCLUSIONS

Based on the results of the Evaluation conducted for the Project, BMcD did not uncover any fatal flaws associated with the Project in the activities performed to date; however, several areas of concern were noted. The following are the key findings of the Evaluation:

- During the CI on Unit 1, foreign object damage was indicated on the trailing edge of the #9 inlet guide vane. It is recommended to inspect the vane every 25 equivalent starts or 500 hours, whichever comes first, to verify the integrity of the vane. Other items were noted in the most recent borescope inspection that do not pose major risks, but should be monitored in subsequent borescope inspections.
- Unit 2 has had very few operating hours, and therefore has not yet had a CI performed. In the most recent borescope inspection, early migration of the Row 3 vane knife seals was observed, which will require replacement at the HGP Inspection.
- Unit 3 has had very few operating hours, and therefore has not yet had a CI performed. In the most recent borescope inspection, cracking and minor coating loss was observed in several areas of the compressor and turbine. It was recommended that a borescope be performed every 25 starts to monitor the status of the crack in the Row 4 diaphragm, which was originally identified in the 2009 borescope inspection. Subsequent inspections have shown no progression or additional cracking in this area.
- The net plant heat rate for each of the Units is slightly higher than expectations for a facility of this size, usage, and type. Moreover, the units did not meet their guaranteed heat rate values in 2002.
- All of the Units have been dispatched very little over the past several years, particularly Unit 2 and Unit 3. The dispatch of the Units overall, has generally trended downward over the recent past.
- Due to the frequent startup and shutdown requirements of simple cycle units, the starting reliability is critical. The Plant has had a high number of starts per operating hour, but this is common for a peaking facility. Generally, the starting reliability of these Units has been relatively high in 2008, 2011, and 2012 and below average in 2009 and 2010.
- The availability of the Units is mostly comparable to typical simple cycle units, with the availability being slightly below average in 2008. No major recurring issues were identified, and the availability has increased to expected levels after 2008.

- Generally, the historical and projected operating and maintenance costs appear reasonable.
- The units did not meet their performance guarantee in 2002 and tested approximately one to two percent higher than the guaranteed heat rate. Prior to purchase of the Facility or entering into a long-term contract, BMcD would recommend a third-party conduct a performance test to determine the current capabilities of the Plant for both capacity and heat rate. The cost for a third-party to conduct a performance test is approximately $150,000 to $200,000.
- The Plant has either implemented each urgent technical advisory and technical advisory, or evaluated them and determined that they were not applicable to the Bluegrass Facility. Product bulletins, service bulletins, and customer service letters were also reviewed to determine if they were required or simply recommended upgrades, and were implemented if determined to be sufficiently beneficial, or targeted for implementation during a future major maintenance activity.
- The Water Supply Agreement is adequate for the Plant and the Plant does not appear to have any technical limitations that would prevent it from meeting the requirements of the Agreement.
- The Electrical Interconnection Agreement is in place for a maximum facility output of 720 MW, which is more than sufficient for the maximum net plant output.
- A Natural Gas Facilities Agreement is in place; however, it does not provide for a minimum gas delivery pressure.
- The Plant is operated by NAES under an O&M Agreement; however, the agreement is with Port River, LLC, rather than the Plant. If Port River, LLC is not part of the purchase and sale agreement, the contract would need to be transferred to the new owner of the Plant.
- The fee structure for the Operating and Maintenance Agreement was not provided for review; therefore, no assessment can be made at this point. If EKPC considers purchasing the facility, the fee structure should be reviewed in order to take into consideration whether to keep the O&M contract in place or terminate it.
- Energy is marketed and sold by EDF Trading North America, LLC under an EMA; however, Port River, LLC is a party to the agreement, and it states that if the Project is ever transferred to a new owner, the Project would no longer be a party to the agreement. If Port River, LLC is not part of the purchase and sale agreement, it should be determined whether the contract will be terminated.
- The fee structure for the EMA was not provided for review; therefore, no assessment can be made at this point. If EKPC considers purchasing the facility, the fee structure should be reviewed in order to take into consideration whether to keep the EMA in place or terminate it.

5.2 LIMITATIONS

In preparation of this due diligence evaluation, BMcD has relied upon information provided by ODEC, and LSP. While BMcD has no reason to believe that the information provided, and upon which BMcD has relied, is inaccurate or incomplete in any material respect, BMcD has not independently verified such information and cannot guarantee its accuracy or completeness.

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