Empire District Electric Company

Riverton Unit 12 Conversion to Combined Cycle Project

Construction Permit Application

January 25, 2013

602 Joplin St., PO Box 127, Joplin, MO 64802
1.0 Riverton Power Station Introduction

The Empire District Electric Company (Empire District) owns and operates the Riverton Power Station (0210002) located in Riverton, Kansas which currently consists of two boilers and four simple cycle combustion turbines. The boilers are identified as unit 7 (38 MW, 426 MMBtu/hr) and unit 8 (54 MW, 600 MMBtu/hr) and were designed to combust natural gas as well as coal. In September 2012 units 7 and 8 transitioned from combusting coal while co-firing with natural gas to combusting 100% natural gas. A construction permit for the transition to 100% natural gas was issued by KDHE September 25, 2012.

The simple cycle combustion turbines are identified as unit 9 (12 MW, 199 MMBtu/hr), unit 10 (16 MW, 236 MMBtu/hr), unit 11 (16 MW, 228 MMBtu/hr), and unit 12 (150 MW, 1627 MMBtu/hr). Please note that all unit descriptions listed above are based on net capabilities as per Southwest Power Pool Criteria 12 summer ratings.

Units 7 and 8 were constructed in 1954 and 1955, respectively, and unit 9 was constructed in the 1970’s. Units 10 and 11 were constructed in 1967 and 1968, respectively, and then commenced commercial operation at the Riverton Power Station in the 1989 time-frame. Finally, unit 12 was manufactured April 5, 2002 and commenced commercial operation at Riverton in 2007.

Riverton is located in the southeast corner of Kansas in Cherokee County. Figure 1-1 provides a U.S. Geological Survey (USGS) map showing the facility location and the surrounding area.

Figure 1-1
2.0 Project Description

The existing Riverton unit 12 is a Siemens V84.3A(2) natural gas-fired combustion turbine that commenced commercial operation in 2007. Its nominal rating is 150 MW. At the time of original construction, provisions were made to allow its eventual conversion to combined cycle operation. Empire plans to complete this conversion by June 2016 to replace capacity and energy provided by the boiler units 7 and 8 which will be retired in conjunction with the completion of this project. Dry low-NOx burners were included to control NOx when unit 12 was first installed at Riverton.

The proposed Riverton combined cycle unit will have a nominal capacity of 250 MW. This will require the addition of a heat recovery steam generator (HRSG) with supplemental natural gas duct firing (duct burners) and a condensing steam turbine generator. Other emissions sources that will be constructed as part of the project include a cooling tower and an emergency diesel generator. The capacity of the emergency diesel generator has not yet been determined, but for permitting purposes, Empire District will assume the capacity to be 1102 horsepower (HP) or 750 Kw electrical output. This is a conservative estimate and the actual unit that will be installed could be smaller. Except in the case of an actual emergency, Empire District does not anticipate operating the emergency diesel generator more than 100 hours per year in a non-emergency capacity to accommodate maintenance and readiness testing. The project is designed to include the installation of selective catalytic reduction (SCR) system to control NOx and CO catalyst to control carbon monoxide (CO) and volatile organic compound (VOC) emissions from the turbine and HRSG.

In addition to the above mentioned sources, the project may include a natural gas-fired auxiliary boiler with the capacity to produce 15,000 pounds of steam per hour. The auxiliary boiler would be designed to operate when the combined cycle unit is in a brief period of shutdown and for startup. For permitting purposes, Empire District has included the emissions from the auxiliary boiler which would be designed with its own stack.

3.0 Project Emissions

A facility is considered to be a major source with respect to the Prevention of Significant Deterioration (PSD) regulation if the potential emissions of any PSD pollutant from the facility exceed the major source threshold. The major source threshold for Riverton is 100 tons per year (tpy). Because Riverton currently has the potential to emit more than 100 tpy of at least one PSD pollutant, it is considered to be an existing major source. For an existing major source, PSD review is triggered any time the facility makes a major modification. Any project resulting in an increase in emissions at a facility in excess of the PSD significant emission rates (SER) is considered to be a major modification. As summarized in Table 3-0, the emission increases for PM, PM10, PM2.5, and CO2e associated with the project exceed the PSD SER. Accordingly,
these pollutants are subject to full PSD review including Best Available Control Technology (BACT) analyses and air quality analyses. Appendix A, Table A-9 provides a copy of the worksheet used to determine the estimated emissions increases using the baseline actual emissions, potential to emit, and netting out emissions associated with the retirement of unit 7 and unit 8. Please note that the BACT and air quality analyses are being submitted in addendum.

Table 3-0 Annual Project Emission Increases and PSD SER

<table>
<thead>
<tr>
<th>NOx (tpy)</th>
<th>SO2 (tpy)</th>
<th>CO (tpy)</th>
<th>VOC (tpy)</th>
<th>Lead (tpy)</th>
<th>SAM (tpy)</th>
<th>HF (tpy)</th>
<th>PM (tpy)</th>
<th>PM10 (tpy)</th>
<th>PM2.5 (tpy)</th>
<th>CO2e (tpy)</th>
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<tbody>
<tr>
<td>Unit 12 Combined Cycle Project</td>
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<td>12</td>
<td>60</td>
<td>37</td>
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<td>40</td>
<td>100</td>
<td>40</td>
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<td>7</td>
<td>3</td>
<td>25</td>
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<td>10</td>
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<tr>
<td>PSD Triggered?</td>
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<td>No</td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>Yes</td>
<td>Yes</td>
<td>Yes</td>
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</tr>
</tbody>
</table>

3.1 Baseline Actual Emissions (BAE)

Baseline actual emissions (BAE), as they relate to an electric utility generating unit are defined in 40 CFR 52.21 and adopted by reference in K.A.R. 28-19-350. For this analysis the BAE was determined using monthly CEMS data and KDHE-reported annual emissions reporting for the look-back period.

The BAE for each pollutant associated with units 7, 8, and 12 and how they are derived are presented in copies of the worksheets in Appendix A, Table A-1 through Table A-4

3.2 Potential to Emit (PTE)

In order to determine the maximum emissions from the project, PTE was determined using fleet average performance data from Siemens for the conversion of unit 12 simple cycle turbine to combined cycle.

The converted unit 12 projected emissions include the controlled emissions from both the turbine and the HRSG. Siemens case number five, as represented in Appendix A, Table A-10, was selected from the operational data to determine the emissions combined cycle emissions. Case number five represents steady-state operation at an ambient dry-bulb temperature of 50.0 degrees Fahrenheit; ambient relative humidity of 60.0 percent; combustion turbine operating at base load; and maximum firing of the duct burners. The emissions, in tons per year are calculated assuming 8,760 hours of operation per year for both the unit 12 combustion turbine and the HRSG. The emissions from the combustion turbine and HRSG are calculated at 8,760
hours per year to allow for unlimited operating hours. A dry ambient air composition of 0.98 percent Ar; 78.03 percent N2; and 20.99 percent O2 is assumed. The fuel gas used to determine the emissions is based on natural gas with a sulfur content of 0.5 gr/100scf and lower heating value of 20,426 Btu/lb. The fuel is unheated and supplied at 60.0 degrees Fahrenheit. The PTE for unit 12 are represented in Appendix A, Table A-5

Although the exact equipment has not been determined, in order to estimate the PTE for the auxiliary boiler and cooling tower, emission rates for pollutants typically emitted from these type sources were provided by vendors of the equipment and an assumed operation of 8,760 hours per year was applied. The auxiliary boiler emissions are calculated at 8,760 hours per year to allow for unlimited operating hours. The PTE estimates for the auxiliary boiler and cooling tower are represented in Appendix A, Table A-6.1, Table A-6.2, and Table A-8.

For the emergency generator, the PTE were determined using emission rates provided by a vendor of this type equipment for pollutants expected to be emitted assuming 100 hours of operation per year for non-emergency use including maintenance and readiness testing. The emissions are calculated based on the emergency generator size mentioned in the project description at full standby operation and the PTE estimates are represented in Appendix A, Table A-7.

Also, Appendix A, Tables A-11, A-12.1, and A-12.2 contain the conceptual equipment vendor data used in estimating emissions for the auxiliary boiler and emergency generator. Table A-13 contains a pipeline natural gas sample analysis used to estimate emissions from the auxiliary boiler.

4.0 Regulatory Applicability Analysis

The proposed project will be subject to certain federal and state air quality regulations. This section of the application summarizes the air permitting requirements and the key air quality regulations that will apply to the proposed project. Applicability of the PSD regulations, NSPS, NESHAP, ARP, and KAR are addressed.

4.1 PSD Applicability

Riverton is located in Cherokee County, which has been designated by the U.S.EPA as “attainment” or “unclassifiable” for all criteria pollutants. As such, new construction or modifications that result in emission increases are potentially subject to PSD permitting.

PSD applicability for a proposed project depends on the existing facility’s source classification (whether the facility is an existing PSD major source or an existing PSD minor source) and the emission increases for a proposed project. The PSD regulations define 28 source categories (List of 28) for which the PSD major source threshold is 100 tons per year of potential emissions of any PSD pollutant. Sources not on the List of 28 have a PSD major source
threshold of 250 tons per year of potential emissions of any PSD pollutant. A major source that has a proposed project with emission increases that exceed the PSD significant rates is subject to PSD review for the project.

The Riverton plant falls into the category of the List of 28, the PSD major source threshold is 100 tons per year. Further, since Riverton has the potential to emit more than 100 tons per year, the facility is a major PSD source. Therefore, any PSD pollutants with emission increases resulting from the proposed project that exceed the PSD SER are subject to PSD review.

Table 3-0 shows that the emission increases for PM, PM10, PM2.5, and CO2e from the proposed project will exceed the PSD SER. Therefore, these pollutants are subject to PSD review. Accordingly, air quality and BACT analyses will be included as addendums in this permit application.

4.2 Federal Regulatory Applicability

NSPS Part 60 Subpart KKKK - Stationary Gas Turbines

40 CFR part 60 subpart KKKK applies to stationary combustion turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005. Only the heat input to the combustion turbine should be included when determining applicability of this subpart. Any additional heat input to associated HRSG or duct burners should not be included when determining the peak heat input. However, subpart KKKK does apply to emissions from any associated HRSG and duct burners.

Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of part 60. Heat recovery generators and duct burners regulated under this subpart are exempt from the requirements of subparts Da, Db, and Dc of part 60.

Following the modification of the existing unit 12 from simple cycle to combined cycle, the heat input of the combustion turbine is expected to be approximately 1,677 MMBtu/hr. Based on 40 CFR part 60 subpart KKKK Table 1-A modified turbine firing natural gas greater than 850 MMBtu/hr has a NOx emission limit of 15 ppm at 15 % O2 or 54 ng/J of useful output (0.43 lb/MWhr). The SO2 emissions limit would be not discharge into the atmosphere any gases which contain SO2 in excess of 78 ng/J (6.2 lb/MWhr gross output, or not burn any fuel which contains total sulfur with potential sulfur emissions in excess of 180 ng SO2/J (0.42 lb SO2/MMBtu) heat input.


On March 27, 2012 the USEPA proposed to amend the NSPS for electric generating units and establish the first NSPS for greenhouse gas emissions. The rule would establish CO2...
emission standards for certain new and reconstructed fossil fuel-fired electric generating units and is expected to be published in the Federal Register March 2013. As previously stated, this rule is only proposed at the time of this permit application submittal. In addition, this rule applies to new fossil fuel-fired electric generating units and will not apply to the modification of Riverton unit 12 as it is converted from simple cycle to combined cycle operation.

**NSPS Part 60 Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units**

40 CFR Part 60 Subpart Dc applies to steam generating units that fire between 10 – 100 MMBtu/hr. If constructed, the auxiliary boiler would fire at approximately 18.5 MMBtu/hr therefore; the SO2 and PM standards of Subpart Dc would apply.

**NSPS Part 60 Subpart IIII—Stationary compression ignition internal combustion engines**

40 CFR Part 60 Subpart IIII applies to compression ignition internal combustion engines and will apply to the emergency diesel generator associated with the proposed project.

**NESHAP Part 63 Subpart DDDDD—Industrial, Commercial, and Institutional Boilers and Process Heaters (Boiler MACT)**

40 CFR Part 63 Subpart DDDDD would apply only to the auxiliary boiler, if installed. Since the auxiliary boiler would fire solely natural gas it will not be subject to any emissions limits, but rather would be subject to a work practice standard that requires an annual tune-up in lieu of emission limits.

**NESHAP Part 63 Subpart YYYYY—Stationary Combustion Turbines**

40 CFR Part 63 Subpart YYYYY, 63.6145 requires initial notification. In accordance with 63.6095(d) there are no other applicable requirements of the subpart until EPA takes final action to require compliance and publishes a document in the Federal Register. As of the date on this application, the EPA has not published such a document in the Federal Register.

**NESHAP Part 63 Subpart ZZZZZ—Stationary Reciprocating Internal Combustion Engines (RICE)**

40 CFR Part 63 Subpart ZZZZZ applies to stationary RICE at major or area source of hazardous air pollutant emissions. Subpart ZZZZZ will apply to the emergency diesel generator associated with the proposed project.

**Acid Rain Program (ARP)**

The ARP regulations are located in 40 CFR Part 72 through Part 78, and apply to utility units. A utility unit is defined as a unit owned or operated by a utility that serves a generator in any state that produces electricity for sale. Unit 12, when converted to a combined cycle

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January 25, 2013
operation, will continue to be subject to the ARP. The ARP requires various pollutant monitors in addition to possession of SO2 allowances for each ton of SO2 emitted. The current ARP permit, under which unit 12 currently operates will be modified as the project is completed.

4.3 Kansas Administrative Regulations

K.A.R. 28-19-350 Prevention of Significant Deterioration of Air Quality

Section 28-19-350 of the Kansas Administrative Regulations adopts by reference the following federal requirements for PSD review that are located in 40 CFR 52.21, as in effect on July 1, 2000:

- 52.21(b) - Definitions (Incorporated into this PSD application as appropriate)
- 52.21(c) - PSD Increments (Refer to the air dispersion modeling analysis section of this permit application)
- 52.21(d) - NAAQS (Refer to the air dispersion modeling analysis section of this permit application)
- 52.21(e) - Designation of Class I Areas (No applicable requirements)
- 52.21(g) - Designation of Class II Areas (No applicable requirements)
- 52.21(i) - Exemptions for PSD review (No applicable requirements)
- 52.21(j) - Requirement to conduct BACT analysis (Refer to the BACT analysis section of this permit application)
- 52.21(k) - Requirement to demonstrate compliance with NAAQS and PSD increments (Refer to the air dispersion modeling analysis section of this permit application)
- 52.21(n) - Requirement to submit source information (Refer to the air dispersion modeling analysis section of this permit application)
- 52.21(o) - Requirement to conduct additional impact analysis (Refer to the additional impacts analysis section of this permit application)
- 52.21(p) - Requirement for sources impacting Class I areas (No applicable requirements)
- 52.21(r) – Requirement to operate source in accordance with PSD application

The requirements of KAR Section 28-19-350 are addressed in this PSD application as indicated above for each requirement.

K.A.R. 28-19-650 Emission Opacity Limits

KAR 28-19-650 includes opacity limits for all emission units. Specifically, KAR 28-19-650 states:
Opacity of visible air emissions from any emission unit shall not exceed the following limits: (1) 40% opacity for any portable source existing on or before January 1, 1971; (2) 40% opacity for any emission unit, other than a portable source, that existed on or before January 1, 1971 and that has not been relocated after January 1, 1971; and (3) 20% opacity for any other emission unit.

Exceptions, air emissions opacity levels that exceed the specified limits in subsections (a) and (b) of this regulation shall not be considered a violation of this regulation if the owner or operator of the emission unit demonstrates to the satisfaction of the department that the opacity exceedance is due solely to the presence of uncombined water in the plume.

Since unit 12 is being modified and converted to combined cycle after 1971, it will be subject to a 20 percent opacity limit.