7.0 HIGH ENERGY PIPING SYSTEMS

7.1 Main Steam Piping

The main steam piping is composed of a 10-inch O.D. ASTM A335-51T, P-22, 1.125-inch minimum wall thickness seamless steam line and transfers steam from the boiler superheater outlet header to the HP steam turbine. The system operates at approximately 1,510 psig and 1005°F.

Since this operating temperature is greater than 800°F, it is susceptible to creep, which is a high temperature, time dependent phenomenon that can progressively occur at the highest stress locations within the piping system. As such, this piping system is of particular concern.

During the most recent site visit it was mentioned that the pilot valve is outdated and causing a steam admission on the main steam line. A new pilot valve is needed for Unit 7.

In 2011 BPI performed metallographic replications, magnetic particle testing, ultrasonic testing, and diametric measurements on several welds of the main steam line. Specifically, metallographic replication was performed on seven weld locations along the main steam line. There was no evidence of creep voids or cracking in the base metal, heat-affected zone, or weld metal at any of the locations. The base metal hardness and estimated tensile strength was found to meet the original ASME requirements. Magnetic particle testing was performed at nine locations along the main steam line without any relevant indications found. Ultrasonic shear phased array testing was performed on the same nine locations without any relevant indications found. Diametric measurements were taken at five weld locations on the main steam line, all of which were within the allowable creep swell tolerance. Based on their findings, BPI considered the main steam line to be in good condition at the time.

Burns & McDonnell recommends that the pipe support system be visually inspected annually. The hangers should be inspected to verify they are operating within their indicated travel range and are not bottomed out, that their position has not significantly changed since previous inspections, that the pipe is growing (contracting) in the right directions between cold and hot positions, that the actual load being carried is close to its design point and has not changed, and that the pipe support hardware is intact and operating as designed. In addition, Burns & McDonnell recommends that the spring hangers be load tested to determine their actual current loading and that a stress analysis be completed to verify that all loads and stresses are within the allowable limits.

7.2 Hot Reheat Piping

The hot reheat piping consists of a 14-inch steam line from the boiler reheater outlet to a wye fitting and then two 10-inch lines to the turbine. All piping is A335-P22 schedule 60 seamless piping. The system operates at approximately 550 psig and 1,005°F. Since this operating temperature is also within the creep range (greater than 800° F), this piping system is likewise of particular concern.

In 2011 BPI performed metallographic replications, magnetic particle testing, ultrasonic testing, and diametric measurements on several welds of the hot reheat line. Metallographic replication was performed on seven weld locations along the hot reheat line. There was no evidence of creep voids or cracking in the base metal, heat-affected zone, or weld metal at any of the locations. The base metal hardness and estimated tensile strength meets the original ASME requirements. Magnetic particle testing was performed at eight locations along the hot reheat line without any relevant indications found. Ultrasonic shear phased array testing was performed on the same eight locations without any relevant indications found. Diametric measurements were taken at five weld locations on the hot reheat line, all of which were found to be within the allowable creep swell tolerance. Based on their findings, BPI considered the hot reheat line to be in good condition.

Burns & McDonnell recommends that the pipe support system be visually inspected annually. The hangers should be inspected to verify that they are operating within their indicated travel range and are not bottomed out, that their position has not significantly changed since previous inspections, that the pipe is growing (contracting) in the right directions between cold and hot positions, and that the actual load being carried is close to its design point and has not changed.

7.3 Cold Reheat Piping

The cold reheat piping consists of two 10-inch seamless A106, Grade B schedule 40 steam lines and transfers steam from the discharge of the HP steam turbine to the desuperheater and then into the boiler reheater inlet header connections. EPE has not conducted any NDE program to monitor this piping system.

The system operates at approximately 550 psig and 720°F. Since this temperature is below the creep regime (less than 800°F), creep is not a concern for this system. Thus, the cold reheat piping system should not require the level of examination recommended on the main steam and hot reheat system. Burns & McDonnell recommends inspecting only the highest stress weld locations using replication examination to determine the extent of any carbide graphitization that may have occurred from occasional high temperature operations.

Burns & McDonnell recommends that the pipe support system be visually inspected annually. The hangers should be inspected to verify that they are operating within their indicated travel range and are not bottomed out, that their position has not significantly changed since previous inspections, that the pipe is growing (contracting) in the right directions between cold and hot positions, and that the actual load being carried is close to its design point and has not changed.

7.4 Extraction Piping

The extraction piping transfers steam from the various steam turbine extraction locations to the feedwater heaters. These piping systems are not typically a major concern for most utilities and are not examined to the same extent as the main and reheat steam systems.

Burns & McDonnell recommends that the pipe support system be visually inspected annually. The hangers should be inspected to verify that they are operating within their indicated travel range and are not bottomed out, that their position has not significantly changed since previous inspections, that the pipe is growing (contracting) in the right directions between cold and hot positions, and that the actual load being carried is close to its design point and has not changed.

In the previous 2012 study Burns & McDonnell observed that this system does not follow the ASME guidelines to prevent water induction into the steam turbine, and the records provided by EPE do not show that any modifications have been made. The current standard is ASME TDP-1-2013, "Prevention of Water Damage to Steam Turbines Used for Electric Power Generation: Fossil-Fuel Plants." (These practices are requirements for newly built plants, but guidelines only for existing plants.) Since the EPE system operates with little reserve margin during the peak seasons, a water induction incident that could potentially result in a lengthy forced outage presents a significant risk of loss to EPE. Industry-wide, a significant factor in turbine internal damage is turbine water induction from the extraction system, feedwater heater, and associated drains. As such, it is still recommended that EPE implement the ASME recommendations at Rio Grande Unit 7 to ensure operation through 2027 or 2037.

The plant personnel should ensure that the extraction steam non-return valves are tested on a regular basis to confirm proper operation and reduce the risk of turbine over-speed.

7.5 Feedwater Piping

The feedwater piping system transfers water from the deaerator storage tank to the boiler feedwater pumps, through the high pressure feedwater heaters, and eventually to the boiler economizer inlet header. Although at a relatively low temperature, the discharge of the boiler feedwater pumps is the highest pressure location in the plant and thus, should be monitored and regularly inspected.

Flow-accelerated corrosion ("FAC") is an industry wide problem and special attention should be given to the first elbows and fittings downstream of the boiler feedwater pumps. Testing should focus on thinning on the extrados of the sweeping elbows, where turbulence can occur, causing excessive erosion/corrosion.

During the February 2011 inspection BPI took ultrasonic thickness readings on the first two elbows downstream of the two boiler feed water pumps. All four test points were found to have uniform thickness readings throughout the elbows. No indications of FAC were found.

8.0 BALANCE OF PLANT

8.1 Condensate System

The condensate system transfers condensed steam and boiler water in the condenser hotwell through the low pressure heaters to the deaerator.

8.1.1 Condenser

Unit 7 is provided with a two pass tube and shell condenser with divided water boxes. The condenser was retubed in the 1970s. The flooring on the top half of the condenser had to be replaced due to leaks. Some of the condenser tubes have also been plugged. In 2012 Plant personnel were working to remedy cracks in the condenser shell. Burns & McDonnell considers it prudent to expect that the condenser will have to be re-tubed within the next five years.

8.1.2 Condenser Vacuum System

The Unit 7 condenser vacuum system is intended to maintain a negative pressure, or vacuum, in the condenser by removing all non-condensable gases that collect in the condenser. This is accomplished by means of an Allis Chalmers hogging vacuum pump and a Westinghouse Steam Jet Air Ejector ("SJAE"), and backed up by one 100 percent liquid ring Nash vacuum pump. The pumps are in good condition.

8.1.3 Low Pressure Feedwater Heaters

There are two LP vertical closed feedwater heaters and one vertical evaporative condenser installed downstream of the condensate pumps. The heaters were manufactured by Yuba Heat Transfer Corporation. The LP heaters warm the condensate water by transferring heat from the turbine extraction steam to the condensate water in the closed shell and tube, two-pass vertical U-tube design heat exchangers.

The evaporative condenser is permanently out of service, but the condensate is still routed through the tubes. No NDE data or tube mapping data was available for the LP heaters. The LP heater is out of service and has a lot of tube plugging. As such, the Plant simply by-passes the LP heater and has done so for several years. Burns & McDonnell recommends the feedwater heater tubes be inspected by eddy current testing to establish a baseline.

8.2 Feedwater System

The feedwater system is a closed-loop system that transfers water from the deaerator storage tank to the boiler feedwater pumps, through the HP feedwater heaters, through the boiler economizer, and eventually to the boiler drum.

8.2.1 High Pressure Feedwater Heaters

There are two HP closed feedwater heaters installed downstream of the feedwater pumps. The HP heaters increase the efficiency of the plant by transferring heat from the turbine extraction steam to the feedwater in the closed shell and tube, horizontal, two-pass U-tube design heat exchangers.

The 1st point feedwater heater (highest pressure) was replaced with a Perfex unit in 1983 and the 2nd point heater is the original 1957 vintage Griscom-Russel heater. No NDE data or tube mapping data was available for the HP heaters. Burns & McDonnell recommends the feedwater heater tubes be inspected by eddy current testing to establish a baseline.

8.2.2 Deaerator Heater & Storage Tank

The open, tray type deaerator consists of a single vertical vessel containing both the deaerator heater section and storage tank. The deaerator system was manufactured by Cochrane. In the deaerator, extraction steam is used to de-oxygenate and release non-combustible gasses from the water cycle to the atmosphere.

During the 2011 inspection, BPI performed magnetic particle testing on the long seam welds, circumferential welds, and accessible penetrating welds. No service-related indications were found. BPI did find minor pitting throughout the storage vessel, and recommended that this pitting be monitored at each unit planned outage to ensure it does not worsen.

EPE should continue visually inspecting the deaerator vessel at each unit planned outage. All girth and penetration welds should be inspected using magnetic particle and dye penetrant examination. Ultrasonic thickness examinations should also be performed every 3 to 5 years, with special attention being paid to the water level in the storage tank where cracks have been a problem industry wide.

8.3 Condensate and Boiler Feed Pumps

The two electric driven vertical condensate pumps manufactured by Flowserve are each rated at 650 gallons per minute ("gpm") and supply 100 percent of the full load condensate system demand. The Unit No. 7A condensate pump and motor were removed and sent out for refurbishment in the fall 2005 outage. The condensate pumps are reported to be in good condition.

The two main 100 percent capacity boiler feed pumps are motor-driven barrel type Pacific pumps rated at 385,000 lb/hr plus 18,000 lb/hr reheater attemperator flow. The pumps and motors are reported to be in good condition. The Unit No. 7A boiler feedwater pump and motor were removed and sent out for refurbishment in the fall 2005 outage. Spare motors exist for both pumps.

8.4 Circulating Water System

The circulating water system is used to reject heat from the condenser to the atmosphere. The system utilizes two 50 percent capacity Westinghouse circulating water pumps to pump cooling water from the cooling tower basin through the circulating water pipe on to the condenser water box and then back to the cooling tower. During the site visit, EPE representatives discussed that both circulating water pumps must be run due to a blockage in the condenser. The Plant switches between A and B each month to rotate hours, and adjusts pump packaging as needed.

The two electric motor driven horizontal centrifugal circulating water pumps were manufactured by Westinghouse. Each 50 percent capacity pump is direct driven by a Westinghouse electric motor. Both the pumps and motors were removed and sent out for refurbishment in the fall 2005 overhaul outage.

The circulating water piping is carbon steel. The lines under the powerhouse are encased in concrete. During the 2012 study, EPE reported that portions of the circulating water piping had been inspected and were found to be in average condition; however, the section of piping from the pumps to the condenser could not be inspected. The 36-inch and 42-inch 45 degree fittings of the circulating water system piping were replaced in the late 1990s. During the site visit EPE representatives mentioned that the circulating lines will need to be replaced.

The Unit 7 cooling tower was replaced in 1997 with a Hamon 8-cell, counter-flow induced draft tower handling 33,610 gpm. On the site visit the cooling tower was reported to be in decent shape, the fans were "operable," and a gear box had been repaired the week prior. The cooling tower consists of two 4-cell blocks with back to back arrangement. The cooling tower is designed for a range of 20°F with a 12°F approach at a 67.5°F wet bulb. The original cooling tower was demolished and the new tower was built over the same basin. The original cooling tower was erected over a concrete basin having a clearwell at one end from which a 48-inch effluent cooling water line gravity feeds over the Montoya canal to the horizontal circulating water pumps. The cooling tower is operated at 4.5 cycles of concentration and is inspected annually by plant personnel. Burns & McDonnell considers it prudent to expect that the cooling tower will need to be replaced or refurbished within the next five years.

8.5 Water Treatment, Chemical Feed, & Sample Systems

The water supply for cooling tower makeup, cycle makeup, service water, and potable water demands of the Plant are supplied from off-site deep-wells. The cycle makeup water is filtered and sent through two stages of reverse osmosis ("RO") and further demineralized as it passes through a single mixed bed polisher before being directed to the demineralized water storage tank. Demineralizer regenerations wastewater is directed to a PVC neutralization tank where its pH is adjusted and discharged to the lower canal. Service water is supplied from the off-site wells and can also be provided from the upper canal. Service water is directed to the plant services after filtration. Potable water is supplied by the off-site wells, chlorinated, and supplied to the plant potable water facilities.

The plant has a 6-inch connection to the city water system as a backup source of water.

Plant process wastewater is discharged to two canals located between the cooling towers and the generating units. The upper canal overflows to the lower canal from which the plant wastewater is treated and discharged to the Rio Grande River. The Plant was connected to the City of El Paso sewer system in 2004, which receives the plant sanitary wastewater.

Cooling tower blowdown water is directed to the lower canal and boiler blowdown water is directed to the upper canal. Floor drains and roof drains go to the lower canal; however, many of the boiler plant drains are plugged.

EPE indicated that the plant makeup water supply line from the off-site wells has been inspected. This line is a coated and wrapped carbon steel line and was reported to be in good condition. Service water piping was originally installed as carbon steel material which has experienced major scaling throughout the plant life. About 90 percent of this carbon steel piping has, over an extended period of sequential replacements, been replaced with PVC piping.

Two 2-stage RO units supplied by Fluid Process Systems rated at 80 gpm were installed in 1996. The deep bed demineralizer was replaced with a new 100 gpm unit in 2002. The addition of the RO units has significantly extended the demineralizer run time to 1 million to 2 million gallons between regenerations. Cleaning of the RO membranes is conducted annually which is a manual process utilizing temporary hoses.

Rio Grande Unit 7 uses a combination of phosphate, oxygen scavenger, and dispersant for cycle water treatment. Condensate water is treated with Eliminox and amines (morpholine & cyclohexane). Phosphate and Nalco 7221 (dispersant) is injected into the boiler steam drums for boiler water treatment. The cycle water treatment equipment is in adequate condition.

Circulating water treatment consists of injection of sodium bisulfite and ammonia which is occasionally supplemented with bromine powder. As of the 2012 study, the Plant personnel had planned to replace and combine the ammonia chlorinators for Unit 7.

The Plant contracts with Nalco for advising on plant water chemistry. A Nalco consultant is available to the Plant on a weekly basis. The plant chemist reported that the plant water treatment meets or exceeds the industry accepted standards and have only experienced infrequent excursions of copper and ammonia. The general condition of the plant makeup water supply and treatment systems appear to be in adequate condition and, with continued attention and proper maintenance, are expected to continue to operate satisfactorily.

8.6 Fire Protection Systems

The Plant is equipped with two electric fire pumps and one diesel fire pump. Fire sensors are located below the control room.

The Plant reported several improvements to the fire protection system. The diesel fire pump suction has been moved to cleaner water. The switchgear for the electric fire pump has been replaced.

The Plant has also added fire stops to the cable penetrations in the control room.

8.7 Plant Structures

The Plant structures generally appear to be in good condition even though the boiler steel is outdoors. The Plant has continued the plant structure painting program which includes annual reviews of locations requiring protective coating attention.

9.0 ELECTRICAL AND CONTROLS

9.1 Unit 7 Electrical Systems

In January of 2017, Electrical Reliability Services performed a visual and mechanical inspection as well as electrical tests on the following circuit breakers:

1. 11 Westinghouse, 50 DH 150 D, 1,200 A Medium Voltage Circuit Breakers
2. 1 Westinghouse, DB50, 600 A Low Voltage Circuit Breakers
3. 4 Westinghouse, DB15 200 A to 225 A Low Voltage Circuit Breakers

The medium voltage circuit breaker at the Unit 6 boiler feed pump A was found to not always latch closed, so the trip latch was lubricated to ensure the breaker stayed closed. During testing, it was found that the long-time delay functions were out of tolerance on the low voltage circuit breakers of the 480 V feeders numbers 1, 2, and 3. It is recommended that Plant personnel repair or retro-fit the trip unit to solve these issues. The rest of the low and medium voltage circuit breakers were found to be satisfactory during testing. During the testing, Electrical Reliability Services also cleaned dust and dirt from each cell and circuit breaker, vacuumed and wiped down the components with CRC electronic cleaner.

In 2016, 33 Westinghouse CO Relays and 3 Westinghouse CV Relays were tested and the above-mentioned circuit breakers were cleaned and visual inspected. Electrical Reliability Services performed the 2016 testing and reported the equipment to be satisfactory at that time.

During the site visit the breakers were observed to be in good condition. The breakers are 2.4 kV and are refurbished every 3 to 5 years. Equipment including the circulating water pumps, boiler feed pumps and FD fan are on the 2.4 kV system. Spare parts are difficult to find for the 2.4 kV gear, so for a life extension scenario the breakers would need to be upgraded. Likewise, since much of the equipment is tied together on the 480 V system, there would need to be separation for life extension.

The system has a new automatic voltage regulator and new voltage regulators. The burner management system ("BMS") is in the Allen Bradley distributed control system ("DCS"), other controls still on the bench board, the burners, and the STG are manual. Combustion controls are on the DCS. Unit 8 is going to Mark VI controls, which will require separation of Unit 7 and Unit 8. Unit 7 is rolled manually from the control room.

9.1.1 Generator

The generator is a 1956 vintage GE unit rated at 58.824 MVA at 13.8 kV. The stator output is 2,461 Amperes ("A") at 0.85 power factor. The rotor and stator windings are hydrogen cooled. The exciter is a 1956 vintage DC generator exciter rated 596 A at 250 volts DC ("VDC"). The voltage regulator is a GE 1956 vintage electromechanical type located on the ground level under the generator.

Generator protection consists of an ABB GPU2000R microprocessor relay with the following functions:

1. Distance backup (21)
2. Volts/hertz (24)
3. Voltage Supervised Overcurrent backup (51V)
4. Generator Differential (87G)
5. Synchronizing (25/25A)
6. Undervoltage Alarm (27)
7. Reverse Power (32)
8. Loss of Excitation (40)
9. Unbalance (46)
10. Overvoltage (59)
11. Stator Ground (59GN)
12. 100 percent Stator Ground (27TN)
13. Frequency (81)
14. Inadvertent Energizing (50/27)

During the site visit EPE reported no issues with the generator, but mentioned that it is getting older and will likely need a rewind for life extension. The coupling on the STG unit between the generator and exciter has been replaced.

The generator was last inspected at the beginning of 2016. During the outage the generator was disassembled, inspected, and reassembled. The electrical portion of the inspection was performed by ADA Generator Services LLC, including DC electrical test series and Power Factor testing on the generator.

The testing showed the generator T1-T4 phase was weaker than it was in the 2005 inspection. It was recommended that the T1 phase leakage be investigated, which would require at least a partial rewind of the unit. The report recommended the following actions:

1. Request the recommended length and thickness of the designed field removal plan from the OEM and compare this information with the pan in the number 7 turbine room.
2. Change the insulation on the T4 bearing at the next outage, as the current insulation repairs are not considered permanent fixes.
3. At the next outage install an axial set screw in the T3 outer oil deflector to allow for vertical and horizontal adjustment.

During the 2005 inspection, the following tests were performed:

1. Insulation resistance (megger)
2. Power factor
3. Electromagnetic Core Imperfection Detection ("El CID") test (stator iron)
4. Retaining ring ultrasonic inspection

Testing performed by Hampton Tedder Technical Services found moderate partial discharge activity on the C phase winding. The report indicated that this is not unusual for a generator of this age. A recommendation was made to add a permanent partial discharge monitoring system, or at the least perform on-line partial discharge testing. The report also recommended that EL CID test be performed. Since the generator has never been rewound, it is prudent to expect that a re-wind will be appropriate as soon as possible if the life of the Unit is to be extended throughout 2027, or a re-wind will be appropriate sometime within the next five years if the life of the Unit is to be extended through 2037.

9.1.2 Transformers

During the site visit Facility representatives reported that all the transformers have been updated and are maintained by the substation group. Additionally, there is a reserve station for each unit (offline) and a station service for each unit.

9.1.2.1 Main Transformer (Generator Step-up Transformer)

The main GSU transformer is a 2002, Waukesha, three-phase unit located outdoors near the turbine building and steps up the voltage from 13.8 kV to 115 kV. The main unit transformer is rated 45/60 MVA at 66/13.8 kV with a temperature rise of 55/65°C and an impedance of 9.9 percent at 45 MVA. The oil preservation system is a nitrogen blanket type. A spare main transformer is located on site. A deluge system and oil containment are provided for the GSU.

The GSU protection consists of an ABB TPU2000R microprocessor relay with the following functions:

1. Transformer differential (87)
2. Transformer neutral overcurrent (51N)

The transformer was in good condition and with the present testing and maintenance practices, should have 25 to 35 years of remaining life. It is recommended that the Plant continue its current maintenance and testing plan, including a dissolved gas analysis performed on a quarterly basis.

9.1.2.2 Auxiliary Transformer

The unit auxiliary transformer is a three-phase unit located outdoors near the turbine building. The unit auxiliary transformer is rated 3,750/5,000 kilovolt amperes ("KVA") at 14.4 kV to 2.4 kV with a temperature rise of 55/65°C and an impedance of 5.50 percent at 3,750 kVA. The oil preservation system is a nitrogen blanket type. A deluge system is installed for the auxiliary transformer and oil containment is provided. A cable bus connects the auxiliary transformer secondary to the medium voltage switchgear terminals. The cable bus is rated at 3 kV and 1,340 A and is naturally cooled.

The auxiliary transformer protection consists of an ABB TPU2000R microprocessor relay and an electromagnetic CO relay with the following functions:

1. Transformer differential (87)
2. Transformer overcurrent (51)

It is recommended that the Plant continue its current maintenance and testing plan, including a dissolved gas analysis performed on a quarterly basis.

9.1.2.3 Startup Transformer

The startup source consists of one transformer, T3, located in the substation which is rated 7.5 MVA and 66-2.4 kV. A naturally cooled cable bus, rated 3.3 kV and 382 A, connects the secondary of the startup transformer to a lineup of 5 kV load break switches. These load break switches allow sharing of the startup transformer between Units 4, 6, and 7. A set of cables then runs from a load break switch to its associated unit medium voltage switchgear terminals.

During the 2005 inspection, it was noted that the transformer oil level was acceptable and no active oil leaks were observed.

The startup transformer is rarely heavily loaded and should have a long life. It is recommended that the Plant continue its current maintenance and testing plan, including a dissolved gas analysis performed on a quarterly basis.

9.1.3 Cable Bus

Cable bus connects the GSU transformer to the generator terminals. The cable bus is rated 15 kV and 5,000 A. The bus is naturally cooled and is considered in adequate condition.

9.1.4 Medium Voltage Switchgear

The original 1956 vintage Westinghouse 2.4 kV switchgear is installed on the ground floor of the turbine building in an open area. The main breaker is an air magnetic Westinghouse model 50-DH-150 rated 1,200 A, 24 kiloamperes ("kA") interrupting and 39 kA close and latch. The feeder breakers are air magnetic Westinghouse model 50-DH-150 rated 1,200 A, 24 kA interrupting and 39 kA close and latch. The control power for the breakers is 125 VDC.

Based on industry wide experience, the Westinghouse 50-DH-150 breakers have good reliability if kept free from moisture and normal preventative maintenance is performed. The breakers have been regularly inspected, refurbished, and tested (hipot, megger, contact resistance, etc.) and spare breakers are available. The 2.4 kV system is an ungrounded delta system. During our previous site visit in 2012, the indicating voltmeters showed a balanced voltage to ground which indicated that there were no ground faults present at that time.

Assuming normal maintenance is performed, the switchgear should be serviceable until its replacement, which should be undertaken within the next five years.

9.1.5 480 V Load Centers, Switchgear, and Motor Control Centers

The 1955 vintage 480 V switchgear is equipped with Westinghouse 25 kA air-magnetic circuit breakers. The main breakers are Westinghouse DB-25 breakers rated 800 A and 25 kA interrupting with 125 VDC control power. The switchgear is located indoors. In 2018 Unit 7 is scheduled to get 4 new breaker switchgears to the 480 V section at a cost of $110,000.

The unit has two three-phase, 2.4 kV to 0.48 kV, VPI dry-type, load center transformers in free-standing enclosures. The main load center transformer is rated 750 KVA, while the cooling tower load center is rated 500 KVA.

The load center transformers that feed the 480 V switchgear lineups typically have a useful life of 30 to 40 years. A redundant transformer is not available which means that the failure of a load center transformer immediately impacts plant operation. However, there is a tie to the Unit 6 480 V main switchgear which allows operation of the plant until the failed load center transformer is replaced. The two cooling tower switchgear lineups do not have this tie feature.

There are no 480 V motor control centers installed at the Plant. The motor starters are located near the loads in individual enclosures.

9.1.6 2400 Volt Motors

The 2.4 kV motors consist of the following:

1. Circulating Water Pump Motors – two 300 horse power ("hp")
2. Forced draft fan – one 700 hp
3. Boiler feed water pumps – two 1000 hp
4. Condensate pumps – two 100 hp

The Plant has a very competent PdM group that performs comprehensive testing on 2.4 kV motors. The motors should be reconditioned or replaced as determined by the PdM testing.

9.2 Station Emergency Power Systems

The Unit 7 station battery, located in a dedicated room, is provided to supply critical plant systems. The battery is an Exide model FTA-21P flooded-cell lead-acid type with a rating of 1,520 amp-hours. A crosstie is provided between the Units 6 and 7 station battery and the Unit 8 station battery to allow one battery to feed two DC systems.

A new battery serving Units 6 and 7 was installed in 2005. Station batteries are designed for a 20-year life, and should continue to be replaced on a regular basis.

The protective devices in the DC panels are operated infrequently and, along with the DC panel itself, typically have a lifespan in excess of 50 years.

A new battery charger was installed in 2005. The typical life for battery charger power electronics is 20 to 25 years, although the life of this equipment may be extended by relatively inexpensive component replacement, so it should continue to be operable until retirement.

The emergency diesel generator ("EDG") is a 480 V Cummins unit rated for 175 kW. The diesel generator starting power is supplied by a dedicated set of batteries rated 48 VDC. The EDG is located on the ground floor of the Unit 4 turbine building. With regular exercising and fluid changes, the EDG should continue to be operable, however controls may become an issue with age and obsolescence. The starting batteries will probably have to be changed out occasionally as well.

9.3 Electrical Protection

As detailed in Section 9.1.2.1 the Unit 7 generator and transformer protection was upgraded in 2004 to microprocessor based relaying. The 2.4 kV switchgear is protected with electromechanical relays that are nearing the end of their useful life. In the next 10 years replacement relays may become difficult to find. However, microprocessor based replacements are readily available if this becomes an issue in the future.

9.4 2.4 kV Cable

Unit 7 plant medium voltage cables are primarily Kerite unshielded type. The Plant has a very competent PdM group that performs comprehensive testing on 2.4 kV cables. The cables should be replaced as determined by the PdM testing.

9.5 Grounding & Cathodic Protection

The plant ground grid consists of copper conductors buried in the soil under and around the Plant. Equipment and structures appeared to be adequately grounded. Steel columns are grounded in numerous places. Cable trays are grounded by connection to the plant structure at regular intervals.

The Plant is located in an average isokeraunic area with an average of 40 thunderstorm days per year. The Plant is protected from lightning by air terminals on the plant stack. Shield wires are installed on the transmission lines and lines to the GSU and startup transformers.

Cathodic protection is an impressed current rectifier type system and is installed to protect the underground gas lines. It is recommended that continuity testing of the rectifier system and integrity of the anodes be checked as a minimum and necessary repairs made.

9.6 Substation & Transmission Systems

The plant substation is owned and maintained by El Paso Electric. The Unit connects to the substation via the GSU transformers. Four 66 kV transmission lines connect the substation to the transmission system and, therefore, plant generation is not limited by a double transmission line outage. The plant operators stated that the transmission system has no chronic voltage concerns and is not limited by system congestion. Protection for the substation is located in the substation control building and is supplied from an independent sealed lead acid battery also located in the substation control building. Rio Grande does not have onsite blackstart capability. After a total grid failure, the units can only be restarted from the transmission system. The substation experienced one sustained outage in 2005 due to a maintenance-induced loss of breaker pressure while filling an SF6 breaker.

The 66-kV plant substation has several dead-tank, oil, and SF6 circuit breakers. Although the breakers are obsolete, spare parts are available from the original supplier or third parties. There are no upgrades planned for the substation.

9.7 Control Systems

Unit 7 is controlled via an Allen Bradley programmable logic controller ("PLC"). Unit 7 was constructed prior to the formation of NFPA 85 burner management requirements. Unit 7 had a Forney electronic burner management system upgrade installed in 2003. The Plant has a Panalarm annunciator system but no sequence of events recorder function is provided. Bently Nevada vibration monitoring systems are installed for both turbine generators.

The Unit 7 Panalarm system is obsolete and parts may be difficult to obtain. Upgrading the plant controls to a DCS will make the system obsolete, as alarming and sequence of events recording capabilities will be included in the DCS.

9.8 Miscellaneous Electrical Systems

Plant lighting typically consists of the following fixture types:

1. General plant lighting-incandescent
2. Turbine bay lighting-incandescent
3. Maintenance shop lighting-fluorescent
4. Office lighting-incandescent
5. Emergency lighting-station battery

No issues have been identified with the plant lighting.

Lighting is not a part of the power production process but should be maintained regularly for safety concerns and plant maintenance. With regular lamp and fixture replacement the lighting systems should function until retirement.

10.0 OPERATION AND MAINTENANCE

Based on the information reviewed, Plant staff interviews, and visual observations of the Unit, Burns & McDonnell estimated capital expenditures and operation and maintenance ("O&M") costs associated with operating the Unit safely and reliably to extend the retirement date to 2027 or 2037.

10.1 Reliability and Performance

Burns & McDonnell evaluated the Unit's overall reliability and performance against a fleet average of similar types of generating stations. Figure 10-1 presents the equivalent availability factor ("EAF") for the Unit against fleet benchmark data as provided from the North American Electric Reliability Corporation ("NERC") Generator Availability Database System ("GADS") for similar natural gas-fired STG units. Similarly, Figure 10-2 presents the equivalent forced outage rate ("EFOR") for the Unit against the fleet benchmark. As presented in the figures, EPE has been able to maintain the Unit's reliability performance well given the increased age of the unit compared to the average. The 5-year average for EAF for the Unit is slightly lower (or worse) than the fleet benchmark. However, the 5-year average for EFOR is considerably lower (or better) compared to the fleet benchmark.

Figure 10-1: Equivalent Availability Factor (%)

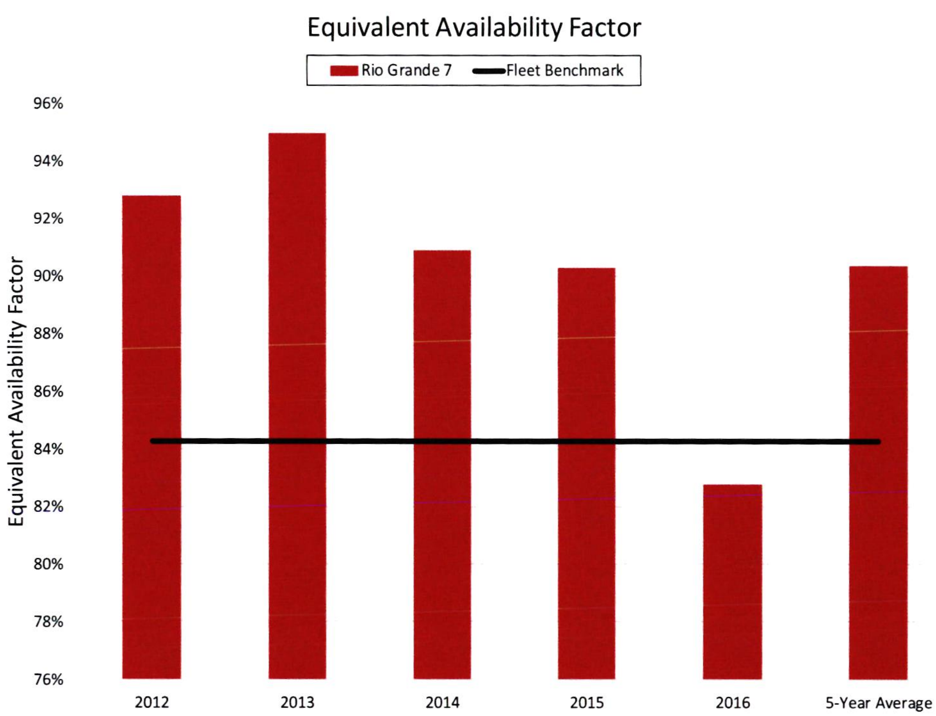
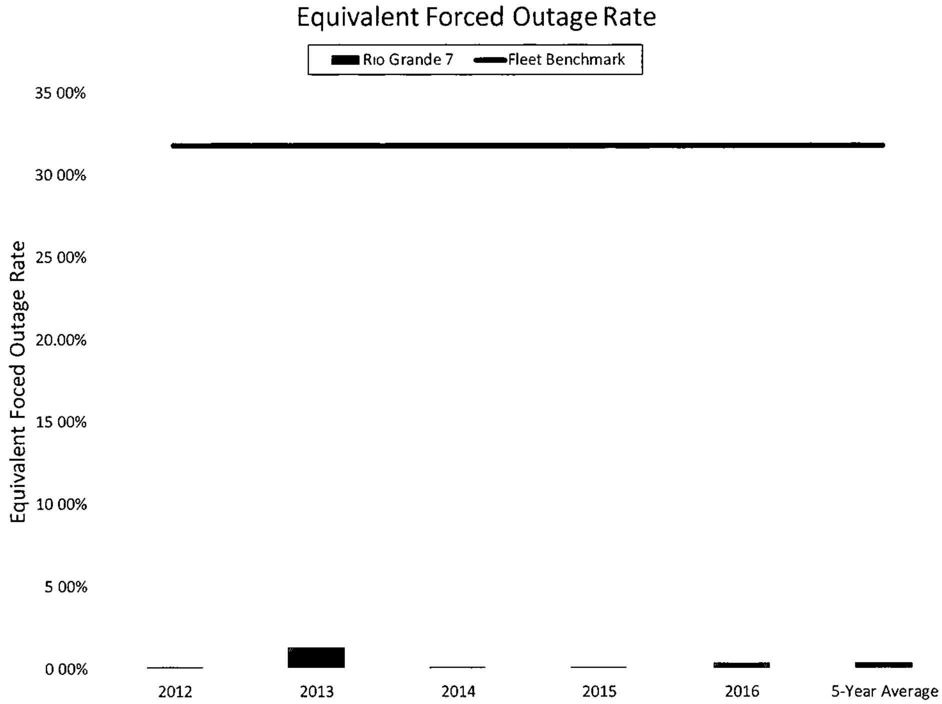


Figure 10-2: Equivalent Forced Outage Rate (%)



10.2 Capital Expenditures Estimate

Unit 7 is currently scheduled for retirement in December 2022, which would reflect a retirement age of 64 years of service. Typical power plant design assumes a 30 to 40-year service life. The service life of a unit can be extended if equipment is refurbished or replaced. Based on the current age of the Unit, it has already served past the typical power plant design life. Burns & McDonnell developed a forecast of capital expenditures that would likely be required to extend the service life beyond the scheduled retirement date.

10.2.1 Life Extension through 2027

To extend the useful service life for the Unit until 2027, many major non-recurring repairs and replacements are highly likely to be required due to age and/or obsolescence as soon as possible, as listed below.

1. Perform NDE of selected areas of the boiler and high energy piping
2. Rewind the generator
3. Perform STG major inspection
4. Comply with TDP-1

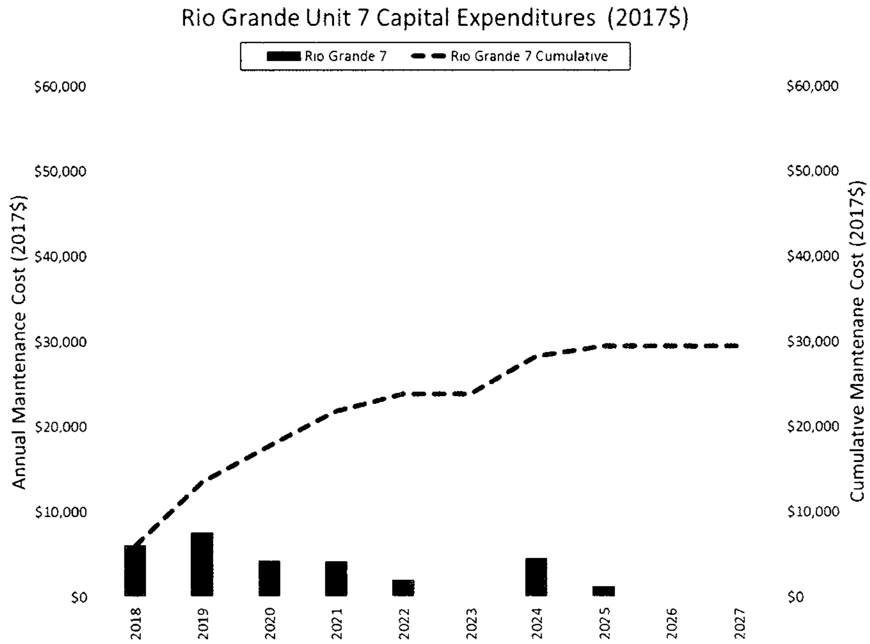
Likewise, the following non-recurring repairs and replacements are highly likely to be required within the next five years.

5. Replace the main steam piping
6. Replace air heater cold end baskets
7. Refurbish cooling tower
8. Add liner to the underground circulating water pipe
9. Replace the feedwater heater tube bundles
10. Re-tube the condenser
11. Carry out major repair work on primary pumps and fans
12. Upgrade the electrical switchgear
13. Replace the unit auxiliary transformer
14. Replace the underground cabling

Additionally, recurring maintenance events will need to continue, such as boiler cleanings and NDE inspections, STG major inspections and turbine valve inspections, and replacement of station batteries, for example. Appendix A provides a detailed schedule of the forecasted capital expenditures and maintenance costs required to extend the life of the Unit to 2027.

Figure 10-3 presents a summary of the capital expenditure estimates derived by Burns & McDonnell for Unit 7 in real/constant dollars (2018$) with no inflation included. Assuming the Unit is in service through 2027, infrastructure replacements and equipment upgrades would be required. For Unit 7, at a nominal capacity of 48 MW, a cost of nearly $30 million will be required to cover capital and maintenance expenditures through 2027, or $0.62/kilowatt ("kW").

Figure 10-3: Capital Expenditures Forecast through 2027



10.2.2 Life Extension through 2037

To extend the useful service life for the Unit until 2037, many major non-recurring repairs and replacements are highly likely to be required due to age and/or obsolescence within the next five years, as listed below.

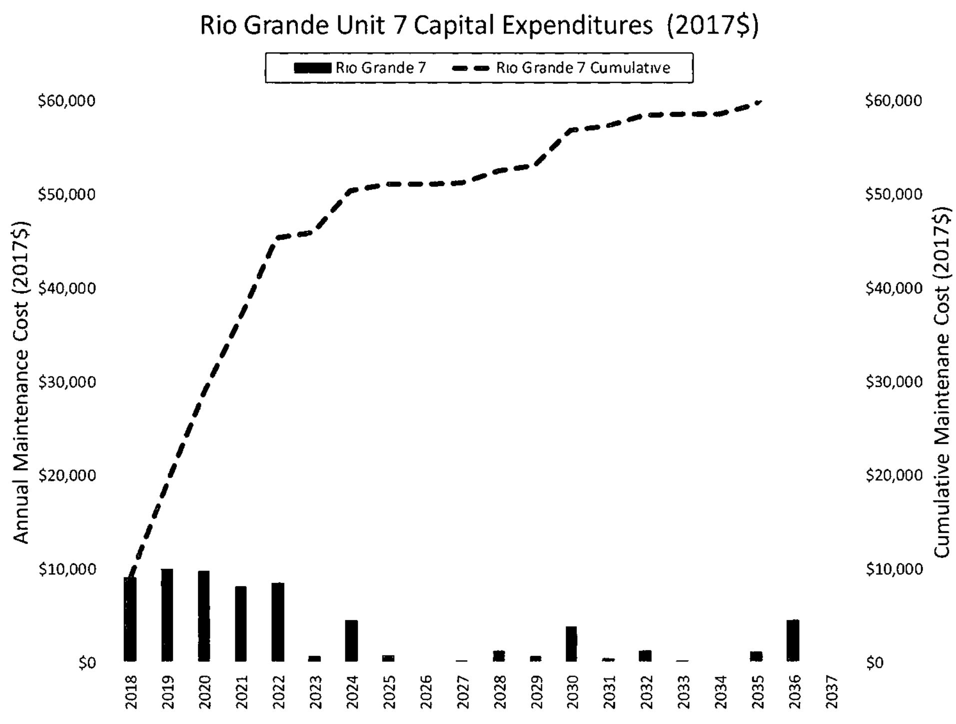
1. Replace primary super heater tubes
2. Replace reheat inlet tubes
3. Replace the main steam piping
4. Replace air heater intermediate and hot end baskets
5. Repair steam turbine blades, rotor, shell, and main valves
6. Rewind the generator
7. Replace the cooling tower
8. Replace the underground circulating water piping
9. Replace the feedwater heater tube bundles
10. Re-tube the condenser
11. Carry out major repair work on primary pumps and fans
12. Complete the conversion to a distributed control system ("DCS")
13. Upgrade the electrical switchgear
14. Replace the unit auxiliary transformer

15. Replace the underground cabling

Additionally, recurring maintenance events will need to continue, such as boiler cleanings and NDE inspections, air heater cold basket replacements, STG major inspections and turbine valve inspections, and replacement of station batteries, for example. Appendix B provides a detailed schedule of the forecasted capital expenditures and maintenance costs required to extend the life of the Unit to 2037.

Figure 10-4 presents a summary of the capital expenditure estimates derived by Burns & McDonnell for Unit 7 in real/constant dollars (2018$) with no inflation included. Assuming the Unit is in service through 2037, infrastructure replacements and equipment upgrades would be required. For Unit 7, at a nominal capacity of 48 MW, a cost of approximately $64.2 million will be required to cover capital and maintenance expenditures through 2037, or $1,337/kilowatt ("kW").

Figure 10-4: Capital Expenditures Forecast through 2037



10.3 Operations & Maintenance Forecast

In addition to replacing key equipment and components through capital upgrades, much of the remaining equipment would require increased maintenance as the Plant continues to age beyond 60 years of service.

A comprehensive benchmark analysis of similar natural gas-fired steam turbine generators nationwide, demonstrates an increasing trend of maintenance costs associated with the ages of the units. Burns & McDonnell evaluated the trend in fixed operation and maintenance costs associated with similar units (in the 25 MW to 150 MW range). The analysis indicates an upward trend of maintenance costs of approximately 1.25 percent per year is observed as power plants age. Figure 10-5 and Figure 10-6 present the fixed O&M costs for similar natural gas-fired steam generating power plants with Unit 7 highlighted (as well as other EPE units).

Figure 10-5: Maintenance Cost Trend Evaluation

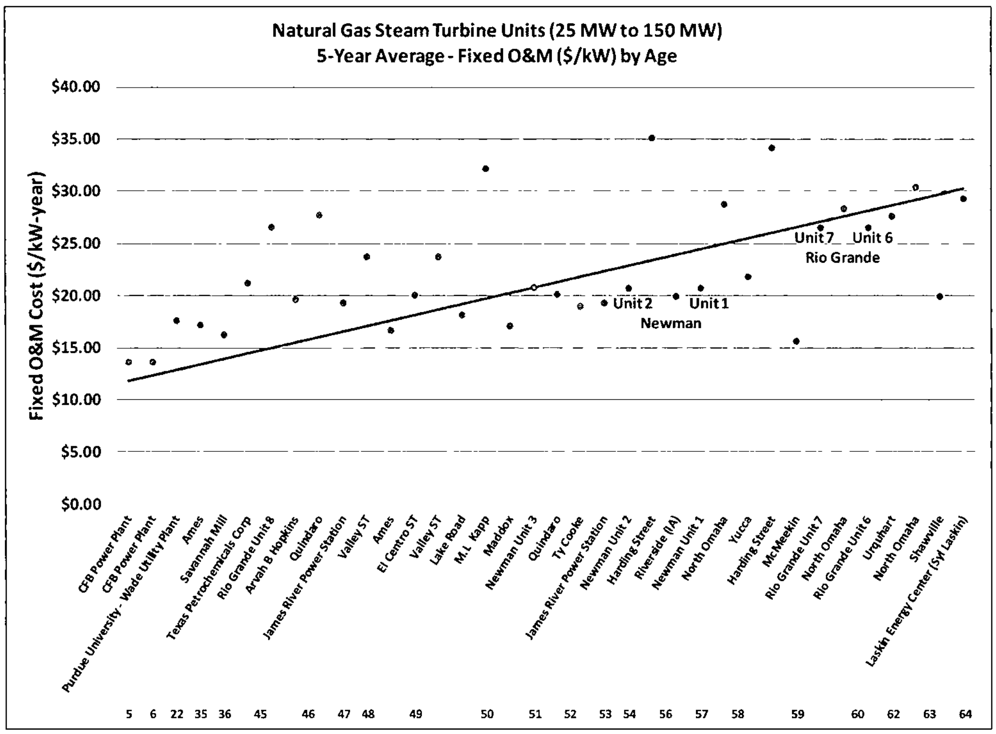
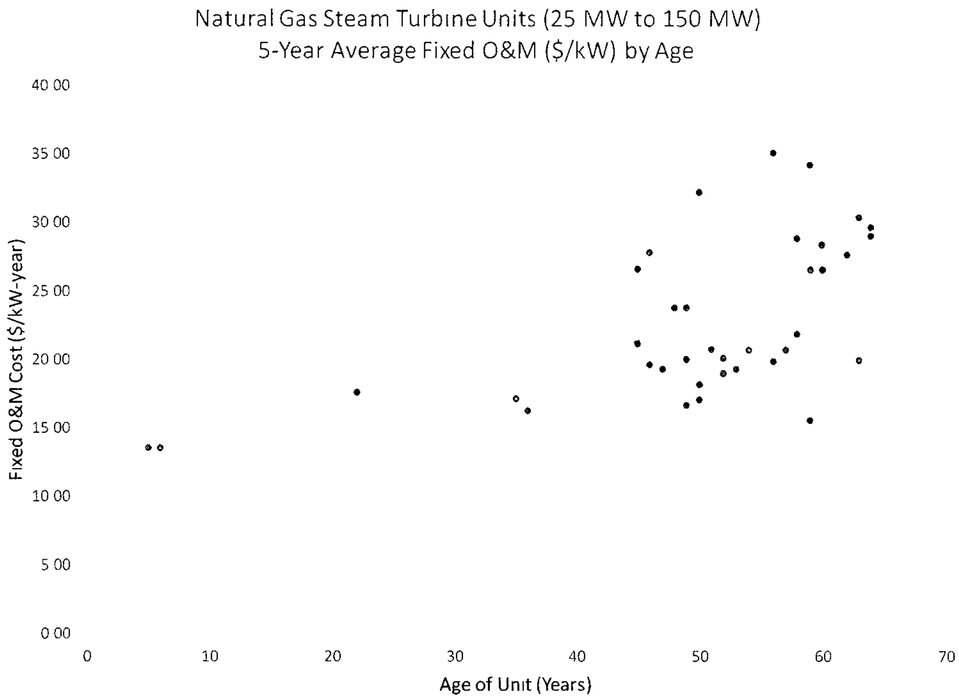
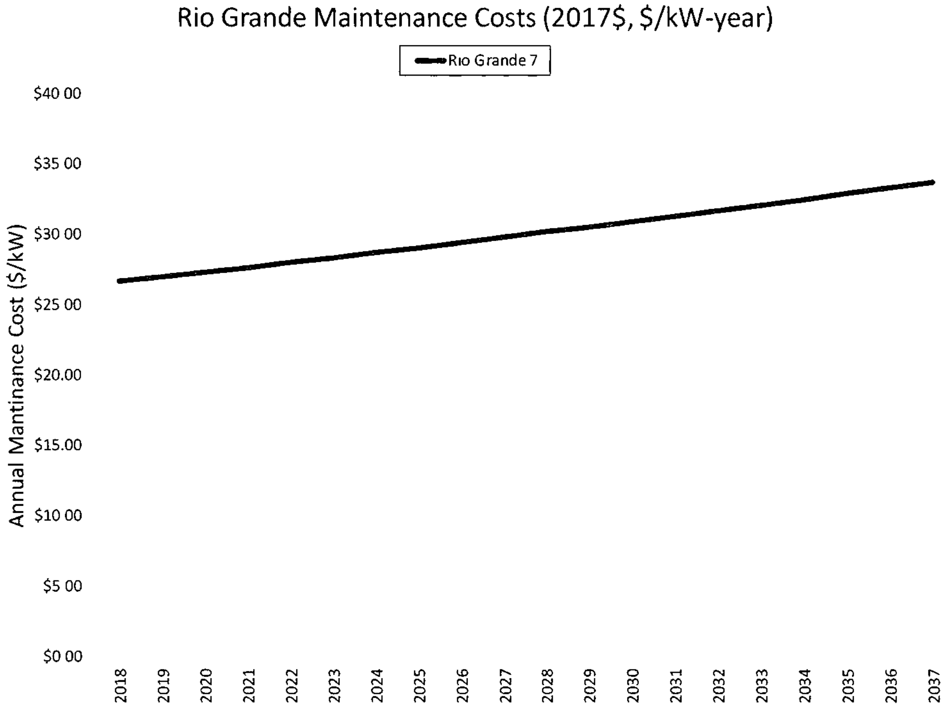


Figure 10-6: Maintenance Cost Trend Evaluation (X-Y Scatter)



As discussed above, as power plants age the overall cost of maintenance increases at a rate of approximately 1.25 percent. At this rate, the maintenance costs would continue to increase for Unit 7 over time from approximately $27/kW-year in 2017 (2018$) to nearly $34/kW-year in 2037 (2018$), excluding inflation increases. Figure 10-7 presents the maintenance cost projections for Unit 7. The costs presented in Figure 10-7 are presented in real, constant dollars (2018$) without including inflation.

Figure 10-7: Maintenance Cost Forecast for Unit 7



Additionally, the Unit will incur a variable O&M cost of approximately $4.68 per megawatt hour for all generation produced.

To further narrow the benchmark, an analysis was performed on the units having similar natural gas-fired steam turbine generators (in the 25 MW to 150 MW range), which had reached a service life of 60 years or older as of 2018. A total of 8 power plants, consisting of 14 units, formed the basis of this focused benchmark. Characteristics of these units are provided in Table 10-1.

Table 10-1: Benchmark Units

Natural Gas-Fired STG Power Plants between 25 MW to 150 MW and at least 60 Years Old

Power Plant	Age of Unit in 2018 (Years)	Operating Capacity (MW)	Fixed O&M ($/kW)	5-Yr Capacity Factor
East River	67	141.7	$114	39%
Harding Street	60	108	$34	56%
Harding Street	60	108	$34	56%
Laskin Energy Center (Syl Laskin)	65	44 5	$30	39%
Laskin Energy Center (Syl Laskin)	65	44.4	$29	41%
McMeekin	60	125	$16	38%
McMeekin	60	125	$16	46%
North Omaha	61	87	$28	53%
North Omaha	64	61	$30	48%
Rio Grande Unit 6	61	48	$27	20%
Rio Grande Unit 7	60	48	$27	24%
Shawville	64	124	$20	21%
Shawville	64	126	$20	24%
Urquhart	63	96	$28	22%
Average	62	92	$26	38%

Note: The Average Fixed O&M is representative of all units except East River, which is an outlier.

The 5-year average capacity factor for the units ranges from 20 percent to 55 percent. The average fixed O&M per kW is $26/kW for all of these units except East River, which is the oldest of the units and has a fixed O&M more than three times that of the other units. Many of these units appear to be dispatched as intermediate units.

As illustrated above, of the nearly 40 originally benchmarked units, only 14 units are still in service today that have an age of 60 years or older. The Rio Grande Unit 7 has an average fixed O&M of approximately $27/kW-year in 2017 (2018$), which is higher than the average fixed O&M for the units of the narrowed benchmark.

The location of each of these units listed in Table 10-1 is illustrated in Figure 10-8. The figure illustrates the majority of the benchmark units are located in the eastern half of the United States.

Figure 10-8: Benchmark Units Locations

10.4 Summary

Overall, the total capital and maintenance costs will be significant to extend the useful service life of the Unit beyond the scheduled retirement date of 2022. Table 10-2 presents the cumulative capital expenditures and maintenance costs over the periods from 2018 to 2027 and 2018 to 2037, presented in 2018$. The costs do not include inflation. As presented in Table 10-2, Unit 7 will incur costs of approximately $881/kW (2018$) for the 2018 to 2027 time period and $1,937/kW (2018$) for the 2018 to 2037 time period.

Table 10-2: Cumulative Capital and Maintenance Costs (2018$)

Time Period	Unit	Total ($000)	Capital ($/kW)	Maintenance ($/kW)	Total ($/kW)
2018 to 2027	Rio Grande Unit 7	$43,041	$615	$281	$897
2018 to 2037	Rio Grande Unit 7	$92,978	$1,337	$600	$1,937

11.0 EXTERNAL & ENVIRONMENTAL FACTORS

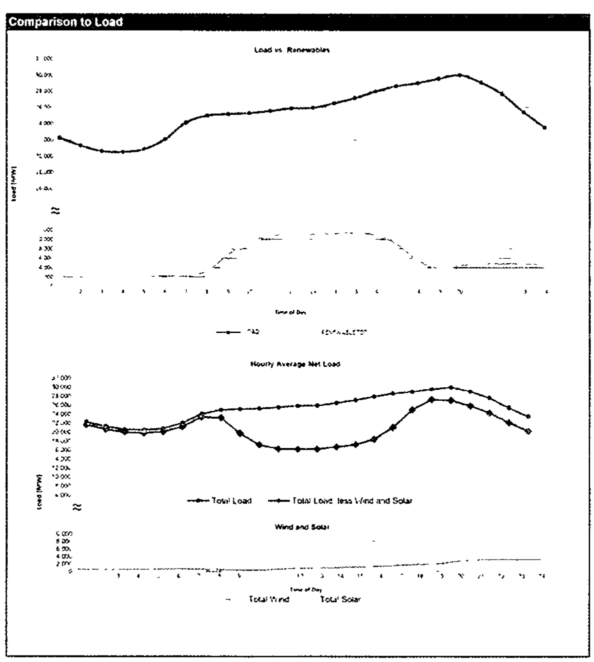
In addition to the costs associated with operating and maintaining the Unit, there are other external factors, such as flexibility or environmental considerations, that may impact the useful service life and long-term viability of the Unit.

11.1 Flexibility

The value of the Unit is less than that of newer generating resources, since through 2027 and further through 2037 the Unit will require more repair and replacement of aging systems in addition to the increased, recurring maintenance. This lower value will be further exacerbated by the poor flexibility of this Unit compared to new resources.

With the higher penetration of renewable, intermittent resources, traditional fossil-fueled generating resources need to have increased flexibility to adjust output based on the needs of the system. The generation from wind and solar resources can fluctuate widely from hour to hour. For illustrative purposes, Figure 11-1 presents a typical day for load and renewable generation in California, which is one of the leading areas for solar resource penetration. As illustrated within the figure, load increases throughout the day and solar generation quickly ramps up from 0 MW to 8,000 MW within a 2-hour time period.

Figure 11-1: Typical Day for Load and Renewables



Source· California ISO

System operators can better optimize the generation supply and cost of generation with highly flexible resources that can quickly adjust generation to meet load demands or fluctuations in renewable resources. Generation assets with quick start times, quick ramp rates, and high turned ratios (or low minimum loads) are extremely valuable within the system since they can often cycle on and off quickly. Less flexible resources, such as Unit 7, do not have the performance characteristics to cycle quickly, therefore these units often operate at their minimum load, providing stability to the system yet operating at their most inefficient load point. Flexible resources can quickly cycle off, thus avoiding costly fuel expenses when the power may not be required. Table 11-1 presents the flexibility characteristics for Unit 7 compared to those of the new generating resources. As presented in the table, the new resources are much more flexible compared to the Unit regarding ramp rates, start times, and heat rate efficiency. These attributes better allow the system operators to optimize power generation costs.

Table 11-1: Flexibility Characteristics

	Unit 7	Reciprocating Engine	Aeroderivative SCGT	F-Class SCGT	F-Class CCGT
Ramp Rate (MW/min)					
Up	3	50	12	40	60
Down	3	50	12	40	60
Start Time					
Cold	8 hrs	45 min	45 min	45 min	180 min
Warm	4 hrs	7 min	8 min	10 to 30 min	120 min
Hot	2 hrs	7 min	8 min	10 to 30 min	80 min
Load (MW)					
Minimum	20	8	42	95	181
Maximum	49	199	169	191	329 (407 Fired)
Heat Rate (BtU/kWh)					
Minimum Load	11,870	8,990	11,490	12,880	7,370
Base Load	11,020	8,190	9,270	10,120	6,580

11.2 Environmental Issues

This section of the report describes the environmental regulations that could impact the Rio Grande Unit 7 in the future. As a general summary, the only regulation that may have near term pollution control requirements is possibly the National Ambient Air Quality Standards ("NAAQS"). NAAQS requirements are area specific and depend on individual plant impacts. Therefore, no control requirements can be determined until the state and Environmental Protection Agency ("EPA") finalize any new pollution control requirements. At this time, no new controls have been identified. General background information on each rule and its current status are discussed below.

11.2.1 Cross State Air Pollution Rule

New Mexico is not currently in the Cross State Air Pollution Rule.

11.2.2 Regional Haze Rule

Regional Haze rules apply to facilities that begin operations after August 7, 1962. Rio Grande Unit 7 is exempt from Regional Haze rules since original operation began before this date.

11.2.3 National Ambient Air Quality Standards

The EPA is required to set limits on ambient air concentrations for each of the following criteria pollutants to protect the public's health and welfare.

1. Sulfur dioxide ("SO_2")
2. Nitrogen dioxide ("NO_2")
3. Carbon monoxide ("CO")
4. Ozone ("O_3")
5. Lead
6. Particulate Matter ("PM")

The EPA is required to review these NAAQS and the latest health data periodically, and modify the standards if needed.

On January 22, 2010, the EPA finalized a new 1-hour primary NAAQS for NO_2 (100 parts per billion ("ppb")). On June 2, 2010, the EPA finalized a new 1-hour primary NAAQS for SO_2 (75 ppb). At this time, the EPA also rescinded the 24-hour and annual SO_2 standard. The new NO_2 and SO_2 standards are much more stringent than the previous standards. For example, the new 1-hour SO_2 standard is lower than the previous 24-hour standard (140 ppb). Demonstrating compliance with the new NO_2 and SO_2 standards will be challenging. Compliance with a NAAQS is traditionally proven by either air dispersion modeling or ambient air monitoring. Air dispersion modeling results are typically very conservative compared with ambient air monitoring results. For this Study, no indicative NO_2 and SO_2 air dispersion modeling was performed to estimate the level of control that may be required to meet NO_2 and SO_2 NAAQS. Since the Rio Grande unit is natural gas-fired, there is no concern about the SO_2 NAAQS, however, there could be NO_2 impacts. Without modeling, no determination can be made on what, if any NO_2 emission reductions will be required.

In addition to the new NO_2 and SO_2 NAAQS discussed above, the EPA is also tightening the NAAQS for O_3 and $PM_{2.5}$. The EPA tightened the 2008 ozone standard from 75 ppb to 70 ppb. Ozone formation is impacted by emissions of volatile organic compounds and NO_x. Therefore, some form of NO_x control could be required for Rio Grande, such as Reasonably Available Control Technology ("RACT"). However, absent any detailed regional air dispersion modeling results, it is impossible to determine what, if any, additional controls will be required.

The EPA tightened the $PM_{2.5}$ standard in 2012. $PM_{2.5}$ primarily consists of sulfate and nitrate particles which are created from SO_2 and NO_x emissions. Therefore, some form of NO_x control could be required for Rio Grande. However, it is impossible to determine what, if any, additional controls will be required without any detailed air dispersion modeling results.

Dona County is currently in attainment with all NAAQS levels. At this time, no further controls would be expected however, a tightening of any of the NAAQS levels would require a re-evaluation of potential impacts.

11.2.4 Greenhouse Gas Regulations and Legislation

On October 23, 2015, two final regulations were published for limiting carbon dioxide emissions from power plants. The first regulation is the Carbon Pollution Emission Guidelines for Existing Electric Generating Units, also known as the Clean Power Plan ("CPP"). In 2016, the Supreme Court granted a stay of the CPP rule. The Trump Administration is reconsidering the CPP rule and is expected to develop new "inside the fence" limitations and work practices. However, at this time, no new proposed rule has been established.

11.2.5 CWA 316(a) and (b) and Water Discharge Limitations

There are three major water regulations that have been developed by the EPA that could potentially impact natural gas-fired power plants: Section 316(a) of the Clean Water Act ("CWA"), CWA Section 316(b), and changes to the National Pollutant Discharge Elimination System ("NPDES") Program. Provisions of Section 316(a) of the CWA apply to thermal discharges. This regulation may require the use of a cooling tower at facilities that do not currently use one. The Rio Grande Station has existing cooling towers so it is not expected to be impacted by any changes to Section 316(a). Provisions of Section 316(b) of the CWA apply to water intakes. Power plants subject to this rule may be required to re-design their cooling water intake structures to protect aquatic life, unless a cooling tower designed for compliance with Section 316(a) is used. Since intake water is not directly from a water source of the United States, this rule does not apply to this facility.

The Clean Water Act was enacted in 1948 (with several revisions thereafter) and establishes procedures and requirements for discharges of pollutants into the waters of the United States and regulates water quality standards for surface water discharges. The CWA is applicable to all wastewater discharges regardless of industry sector. The most recent revision to the CWA affecting the electric utility industry occurred in 1982.

The EPA is required by the CWA to establish national technology-based Effluent Limitations Guidelines ("ELG") and standards and to periodically review all ELGs to determine whether revisions are warranted. In 2016, the EPA finalized ELG rules for the Steam Electric Power Generating industry. The rule addresses primarily coal ash pond discharges and flue gas desulphurization discharges. The new ELG rules do not impact this Facility since it burns only natural gas.

11.2.6 Other Permitting Issues

Units that undergo physical or operational changes without proper permitting could be subject to New Source Review ("NSR") enforcement action. To date, EPA's focus has been on coal units but any unit has the potential risk. For this study, no review of NSR issues was performed.

11.3 Odor, Visibility, & Noise

The Plant did not report any significant issues with odor, visibility, or noise. The Plant is located in an industrial area of El Paso, so the closest residential U.S. neighbor is less than a mile away. This distance provides a buffer zone and minimizes the potential for complaints from neighbors. There have been no complaints from the plant neighbors regarding odor, visibility, or noise from the Plant.

11.1 Water Quality Standards

The Water Quality Standards ("WQS") Regulation (40 CFR 131) establishes the requirements for states and tribes to review, revise and adopt water quality standards. It also establishes the procedures for the EPA to review, approve, disapprove and promulgate water quality standards pursuant to section 303(c) of the Clean Water Act. A WQS can be more stringent than the ELG regulations. The WQS can include:

1. Designated uses for water bodies
2. Triennial reviews of state and tribal WQS
3. Antidegradation requirements
4. WQS variances, and
5. Provisions authorizing the use of schedules of compliance for water quality-based effluent limits ("WQBEL") in NPDES permits

For this Facility, it does not appear that any WQS are driving new limits or technology requirements at this time.

11.2 Mercury and Air Toxics Standard

In February 2008, the U.S. Court of Appeals for the District of Columbia vacated the Clean Air Mercury Rule, a nation-wide mercury cap-and-trade program. As a result of this decision, the EPA was required to develop a Maximum Achievable Control Technology ("MACT") standard for Electric Generating Units under Section 112 of the Clean Air Act. This regulation is also known as the National Emission Standards for Hazardous Air Pollutants from Coal-Fired and Oil-Fired Electric Utility Steam Generating Units, or the Utility MACT. Since this is a natural gas-fired unit, it is not subject to this MACT.

11.3 Disposal of Coal Combustion Residuals

In January 2015, the EPA finalized rules to regulate coal combustion residuals ("CCR") in response to the December 2008 CCR surface impoundment failure at the TVA Kingston Plant. For the purposes of the regulations, CCRs means fly ash, bottom ash, boiler slag, and flue gas desulfurization materials destined for disposal. This unit burns natural gas and/or fuel oil and does not produce coal ash. This rule does not apply to this Facility.

12.0 CONCLUSIONS & RECOMMENDATIONS

12.1 Conclusions

The following provides conclusions and recommendations based on the observations and analysis from this Study.

1. Rio Grande Unit 7 was placed into commercial service June of 1958. The Unit is approaching nearly 60 years of service. The typical power plant design assumes a service life of approximately 30 to 40 years. The Unit has served beyond the typical service life of a power generation facility.
2. The overall condition of Rio Grande Unit 7 appears to be reasonably fair to good considering its age, and the Unit could achieve the planned unit life to 2022 if the interventions recommended in this Study are implemented, and if operational and maintenance problems which could affect operation continue to be actively addressed.
3. Despite its age, the Unit has generally not exhibited a significant loss of reliability, which would be indicative of significant general degradation of the major components. This is likely due to several factors including:
    a. Avoidance of cycling operation during much of its life
    b. Proper attention to water chemistry
    c. An aggressive predictive maintenance ("PdM") program
4. While the Unit has experienced relatively good reliability, much of the major components and equipment for the Unit needs repair or replacement to extend the service life of the Unit to nearly 70 or 80 years. Rio Grande Unit 7 could be capable of technical operations until 2027 or further until 2037 if a significant amount of capital expenditures and increased maintenance costs are incurred to replace and refurbish much of the major equipment and components.
5. Unit operations and maintenance are generally well planned and carried out in a manner consistent with utility industry standards. Plant personnel should continue to actively address any operational and maintenance issues which could affect operation of the unit.
6. The predictive maintenance program used throughout the EPE system has been highly successful in minimizing forced outages in the rotating equipment area. According to EPE, this program has received industry recognition, and should be extended as feasible.
7. With the increased penetration of renewable resources, traditional fossil-fueled generation needs to provide greater flexibility to system operators to better optimize the power supply resources and costs to account for fluctuations within renewable resource generation. The Unit does not

provide as much flexibility regarding ramp rates, start times, or part load operation compared to newer generating resources.

The overall condition of Rio Grande Unit 7 appears to be reasonably fair to good considering its age, and the unit could achieve the planned useful service life to 2022 if the interventions recommended in this Study are implemented, and if operational and maintenance problems which could affect operation continue to be actively addressed. After review of the design, condition, operations and maintenance procedures, long-range planning, availability of consumables, and programs for dealing with environmental considerations, it is Burns & McDonnell's opinion that Rio Grande Unit 7 should be capable of technical operations until 2027 or further until 2037 if a significant amount of capital expenditures and increased maintenance costs are incurred to replace and refurbish the major equipment and components. In evaluating the economics of extending the life of the Unit, EPE should utilize the capital and O&M costs presented within this report.

12.2 Recommendations

The following is a summary of the recommended actions suggested to maintain the safe and reliable operation of Rio Grande Unit 7 should the Unit's life be extended to 2027. To extend the useful service life for the Unit until 2027, the actions recommended to be performed as soon as possible, as listed below.

1. Perform NDE of selected areas of the boiler and high energy piping
2. Rewind the generator
3. Perform STG major inspection
4. Comply with TDP-1

Likewise, the following non-recurring repairs and replacements are highly likely to be required within the next five years.

1. Replace the main steam piping
2. Replace air heater cold end baskets
3. Refurbish cooling tower
4. Add liner to the underground circulating water pipe
5. Replace the feedwater heater tube bundles
6. Re-tube the condenser
7. Carry out major repair work on primary pumps and fans
8. Upgrade the electrical switchgear
9. Replace the unit auxiliary transformer

10. Replace the underground cabling

The following is a summary of the recommended actions suggested to maintain the safe and reliable operation of Rio Grande Unit 7 should the Unit's life be extended to 2037. These recommendations would help maintain the safety, reliability, and reduce the potential for extended unit forced outages. Burns & McDonnell's major recommendations for the unit are:

1. Replace primary super heater tubes
2. Replace reheat inlet tubes
3. Replace the main steam piping
4. Replace air heater intermediate and hot end baskets
5. Repair steam turbine blades, rotor, shell, and main valves
6. Rewind the generator
7. Replace the cooling tower
8. Replace the underground circulating water piping
9. Replace the feedwater heater tube bundles
10. Re-tube the condenser
11. Carry out major repair work on primary pumps and fans
12. Complete the conversion to a distributed control system ("DCS")
13. Upgrade the electrical switchgear
14. Replace the unit auxiliary transformer
15. Replace the underground cabling

Other recommended practices are described in the subsequent sections.

12.3 External & Environmental Factors

1. Continue to monitor changing air emissions regulations ("NAAQS").
2. Continue to monitor well water capacity and quality.

12.3.2 Boiler

1. Conduct regular nondestructive examination ("NDE") of selective areas of water wall tubing, steam drum and connections to the steam drum, superheater outlet header and branch connections to the superheater outlet header, reheater outlet header and branch connections to the reheater outlet header, superheater and reheater inlet headers and branch connections to the headers, and superheater and reheater attemperator(s) and downstream piping.
2. Perform annual testing of the safety relief valves.

3. Conduct boiler chemical cleanings on a 6-year schedule.

12.3.3 Steam Turbine-Generator

1. Conduct steam turbine-generator inspections on a 6-year schedule.
2. Continue steam turbine-generator valve inspections on a 4-year schedule.
3. Perform regular boroscope examinations of the turbine rotor.

12.3.4 High Energy Piping Systems

1. Conduct regular non-destructive examination of selective areas of main steam, hot reheat, boiler feedwater piping, and cold reheat piping.
2. Regularly inspect the feedwater piping downstream of the boiler feed pumps for signs of FAC.
3. Visually inspect the main steam, hot reheat, cold reheat, extraction, and feedwater piping supports on an annual basis.

12.3.5 Balance of Plant

1. Conduct regular eddy current testing of low pressure and high pressure feedwater heater tubing.
2. Conduct regular non-destructive examination of the deaerator and storage tank, including ultrasonic thickness testing of the storage tank shell at the normal water level.
3. Conduct visual inspections of the circulating water piping on a regular basis.
4. Inspect the structural integrity of the stack.
5. The extraction system, feedwater heater piping, and associated drains should be modified for compliance with the turbine water induction prevention recommendations of TDP-1-2006.

12.3.6 Electrical

1. Perform quarterly dissolved gas analysis on the main, auxiliary, and start-up transformers.
2. Continue regular inspection, adjusting, and testing of the medium voltage switchgear.

APPENDIX A - COST FORECASTS THROUGH 2027

El Paso Electric, Inc.
Rio Grande Unit 7
Burns & McDonnell Project No. 101955
Condition Assessment & Life Extension Assessment - 2027

Capital Expenditures and Maintenance Forecasts
All costs are presented in 2018$, no inflation is included

CAPITAL EXPENDITURES (Presented in $000)

DESCRIPTION	CATEGORY	LAST	FREQUENCY	NEXT	TOTAL	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
BOILER & HIGH ENERGY PIPING															
Regular boiler piping replacements	Required	N/A	3 yrs	When due	$3,000		$1,000			$1,000			$1,000		
Main steam piping replacement	Safety	N/A	Once	Within 5 yrs*	$2,000		$2,000								
NDE of selected areas	Industry practice	N/A	3yrs	ASAP	$330	$110			$110			$110			
Replace air heater cold end baskets	Industry practice	2011 (insp)	10 yrs	Within 5 yrs*	$400	$400									
TURBINE GENERATOR															
STG Major Inspection	Industry practice	2005	6 yrs	ASAP	$6,400	$3,200						$3,200			
ST blades/valve repl /repairs	Required	N/A	Once	Next major	$2,000	$2,000									
Valve Inspection	Industry practice	2016	4 yrs	When due	$2,400			$1,200				$1,200			
Generator rewind	Required	N/A	Once	ASAP	$3,500				$3,500						
Comply with TDP-1	Industry practice	N/A	Once	ASAP	$300	$300									
BALANCE OF PLANT															
Reburbish cooling tower	Required	N/A	Once	Within 5 yrs*	$1,500		$1,500								
Add liner to UG circulating water pipe	Required	N/A	Once	Within 5 yrs*	$1,000		$1,000								
Replace FW heater tube bundles	Industry practice	N/A	Once	Within 5 yrs*	$1,500			$1,500							
Condenser retubing	Industry practice	Unknown	Once	Within 5 yrs*	$1,500			$1,500							
Allowance for major pump/fan work	Required	N/A	Once	Within 5 yrs*	$1,000					$1,000					
ELECTRICAL & CONTROLS															
Switchgear upgrade	Industry practice	N/A	Once	Within 5 yrs*	$2,000		$2,000								
Replace station batteries	Required	2005	20 yrs	When due	$200								$200		
Replace unit aux transformers	Required	N/A	Once	Within 5 yrs*	$500				$500						
TOTAL															
TOTAL					$29,530	$6,010	$7,500	$4,200	$4,110	$2,000	$0	$4,510	$1,200	$0	$0

*Distributed over years to spread out expense

APPENDIX B - COST FORECASTS THROUGH 2037

El Paso Electric, Inc
Rio Grande Unit 7
Burns & McDonnell Project No 101955
Condition Assessment & Life Extension Assessment

Capital Expenditures and Maintenance Forecasts
All costs are presented in 2018$, no inflation is included

CAPITAL EXPENDITURES (Presented in $000)

DESCRIPTION	LAST	FREQUENCY	NEXT	TOTAL	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
BOILER & HIGH ENERGY PIPING																								
Boiler clean	2017	6 yrs	When due	$1,800						$600						$600						$600		
Regular boiler piping replacements	N/A	5 yrs	When due	$2,000			$500					$500					$500					$500		
Horizontal primary super heater replacement	N/A	Once	Within 5 yrs*	$5,000			$5,000																	
Reheat inlet tube replacement	N/A	Once	Within 5 yrs*	$4,000					$4,000															
Main steam piping replacement	N/A	Once	Within 5 yrs*	$2,000		$2,000																		
NDE of selected areas	N/A	3yrs	ASAP	$770	$110			$110			$110			$110			$110			$110			$110	
Replace air heater cold end baskets	2011 (insp)	10 yrs	Within 5 yrs*	$800	$400													$400						
Replace air heater intermediate and hot end baskets	N/A	Once	Within 5 yrs*	$1,000				$1,000																
TURBINE GENERATOR																								
STG Major Inspection	2005	6 yrs	ASAP	$12,800	$3,200						$3,200						$3 200						$3,200	
ST blades/rotor/shell/valve repl /repairs	N/A	Once	Next major	$5,000	$5,000																			
Valve Inspection	2016	4 yrs	When due	$6,000			$1,200				$1,200				$1 200				$1,200				$1,200	
Generator rewind	N/A	Once	ASAP	$3,500				$3,500																
Comply with TDP-1	N/A	Once	ASAP	$300	$300																			
BALANCE OF PLANT																								
Replace cooling tower	N/A	Once	Within 5 yrs*	$3,000		$3,000																		
Replace UG circulating water pipe	N/A	Once	Within 5 yrs*	$3,000		$3,000																		
Replace FW heater tube bundles	N/A	Once	Within 5 yrs*	$1,500			$1,500																	
Condenser retubing	Unknown	Once	Within 5 yrs*	$1,500			$1,500																	
Allowance for major pump/fan work	N/A	Once	Within 5 yrs*	$1,000					$1,000															
ELECTRICAL & CONTROLS																								
Conversion to DCS	N/A	Once	Within 5 yrs*	$3,500					$3,500															
Switchgear upgrade	N/A	Once	Within 5 yrs*	$2,000		$2,000																		
Replace station batteries	2005	20 yrs	When due	$200								$200												
Replace unit aux transformers	N/A	Once	Within 5 yrs*	$500				$500																
Replace UG cabling	N/A	Once	Within 5 yrs*	$3,000				$3,000																
TOTAL																								
TOTAL				$64,170	$9,010	$10,000	$9,700	$8,110	$8,500	$600	$4,510	$700	$0	$110	$1,200	$600	$3,810	$400	$1,200	$110	$0	$1,100	$4,510	$0

*Distrubuted over years to spread out expense

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BURNS McDONNELL

Life Extension & Condition Assessment for Newman Unit 1 and Unit 2

The Electric Company
El Paso Electric

El Paso Electric, Inc.

Life Extension & Condition Assessment
Project No. 101995

Revision 1
7/16/2018

Life Extension & Condition Assessment for Newman Unit 1 and Unit 2

prepared for

El Paso Electric, Inc.
Life Extension & Condition Assessment
El Paso, Texas

Project No. 101995

Revision 1
7/16/2018

prepared by

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

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
A	Amperes
ASME	American Society of Mechanical Engineers
BART	Best available retrofit technology
BPI	Babcock Power, Inc.
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
CAMD	Clean Air Markets Data
CCR	Coal combustion residuals
CO	Carbon monoxide
CO_2	Carbon dioxide
CPP	Clean Power Plan
CSAPR	Cross State Air Pollution Rule
CWA	Clean Water Act
DA	Deaerator
DCS	Distributed control system
EAF	Equivalent availability factor
EDG	Emergency diesel generator
EFOR	Equivalent forced outage rate
EGU	Electric Generating Unit
El CID	Electromagnetic core imperfection detection
ELG	Effluent Limitations Guidelines
EPA	Environmental Protection Agency

Abbreviation	Term/Phrase/Name
EPE	El Paso Electric, Inc.
EPRI	Electric Power Research Institute
FAC	Flow-accelerated corrosion
Facility	Newman Power Station
FD	Forced draft
GADS	Generator availability database system
GE	General Electric
gpm	Gallons per minute
GPI	Graphics processing unit
GSU	Generator step-up
hp	Horsepower
HP	High pressure
IP	Intermediate pressure
lb/hr	Pounds per hour
LP	Low pressure
MACT	Maximum Achievable Control Technology
MCR	Maximum continuous rating
MVA	Megavolt amperes
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NDE	Nondestructive examination
NERC	North American Electric Reliability Corporation

Abbreviation	Term/Phrase/Name
Newman	Newman Power Station
NO_2	Nitrogen dioxide
NPDES	National Pollution Discharge Elimination System
NSR	New Source Review
O&M	Operation and maintenance
O_3	Ozone
OEM	Original equipment manufacturer
PdM	Predictive maintenance
Plant	Newman Power Station
PM	Particulate matter
PMT	Preferred Machine & Tool
ppb	Parts per billion
psig	Pounds per square inch gauge
RACT	Reasonably available control technology
RO	Reverse osmosis
SIP	State Implementation Plan
SJAE	Steam jet air ejector
SO_2	Sulfur dioxide
STG	Steam turbine generator
TPU	Tensor processing unit
tpy	Tons per year
TWIP	Turbine Water Induction Protection

Abbreviation	**Term/Phrase/Name**
Units	Unit 1 and Unit 2
UTT	Ultrasonic thickness testing
VDC	Volts DC
WQS	Water Quality Standard

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1.0 EXECUTIVE SUMMARY

1.1 Objective & Background

El Paso Electric, Inc. ("EPE") retained the services of Burns & McDonnell to perform a study to assess the condition of Unit 1 and Unit 2 ("Units") of the Newman Power Station ("Plant", "Newman", or "Facility") and determine the overall costs associated with extending the useful service life of the Units. The Units are currently scheduled for retirement in 2022. The objective of the condition assessment was to estimate the cost of repairing, replacing, maintaining, and operating these Units to extend the useful service life for the periods through 2027 and 2037. This Study includes an analysis of the current condition of the Plant given the expected service life of the Units, as well as any matters of concern with current and expected operations, maintenance, external, and environmental factors. Burns & McDonnell has included estimated capital and incremental operation and maintenance ("O&M") costs associated with operating the Units safely and reliably for the periods from 2018 to 2027 and from 2018 to 2037.

The analysis conducted herein is based on historical operations data, maintenance and operating practices of units similar to Newman, and Burns & McDonnell's professional opinion. For this Study, Burns & McDonnell reviewed data gathered previously combined with updated information provided by EPE, interviewed plant personnel, and conducted a walkdown of the Plant to obtain information on Newman Unit 1 and Unit 2. Burns & McDonnell also analyzed any necessary updates for the Units and need for capital replacements to extend the life through 2027 or 2037.

1.2 Results

1.2.1 Capital Expenditures and O&M Costs

Due to the condition of the Units, much of the major equipment and components will need to be replaced and refurbished to continue to operate the units safely and to extend the life beyond the current retirement date of 2022. Burns & McDonnell developed a capital expenditure and maintenance forecast assuming the retirement date of the Units was extended to 2027 or 2037.

Overall, the total capital and maintenance costs will be significant to extend the useful service life of the Units beyond the scheduled retirement date of 2022. Table 1-1 and Table 1-2 present the cumulative capital expenditures and maintenance costs over the periods from 2018 to 2027 and 2018 to 2037, presented in 2018$. The costs do not include inflation. As provided in Table 1-1 and Table 1-2, Unit 1 and Unit 2 will incur costs of $531/kW and $632/kW (2018$), respectively, for the 2018 to 2027 time period, and approximately $1,275/kW and $1,343/kW (2018$), respectively, for the 2018 to 2037 time period.

Table 1-1: Cumulative Capital and Maintenance Costs through 2027 (2018$)

Unit	Total ($000)	Capital ($/kW)	Maintenance ($/kW)	Total ($/kW)
Newman Unit 1	$40,220	$324	$219	$544
Newman Unit 2	$48,009	$412	$219	$632
Total (Weighted)	$88,229	$368	$219	$588

Table 1-2: Cumulative Capital and Maintenance Costs through 2037 (2018$)

Unit	Total ($000)	Capital ($/kW)	Maintenance ($/kW)	Total ($/kW)
Newman Unit 1	$94,349	$807	$468	$1,275
Newman Unit 2	$102,035	$875	$468	$1,343
Total (Weighted)	$196,384	$841	$468	$1,309

1.3 Conclusions & Recommendations

The following provides conclusions and recommendations based on the observations and analysis from this Study.

1. Newman Unit 1 and Unit 2 were placed into commercial service May 1960 and June 1963, respectively. The Units are approaching nearly 60 years of service. The typical power plant design assumes a service life of approximately 30 to 40 years. The Units have served beyond the typical service life of a power generation facility.
2. The overall condition of the Newman units appears to be reasonably fair to good considering their age. The Units could achieve the planned unit life to 2022 if the interventions recommended in this Study are implemented, and if the Plant personnel continue to actively address any operational and maintenance problems which could affect the operation of the Units.
3. Despite their age, the Units have generally not exhibited a significant loss of reliability, which would be indicative of significant general degradation of the major components. This is likely due to several factors including:
   a. Avoidance of cycling operation during much of their life
   b. Proper attention to water chemistry
   c. An aggressive predictive maintenance ("PdM") program
4. While the Units have experienced relatively good reliability, much of the major components and equipment for the Units need repair or replacement to extend the service life of the Units to nearly 70 or 80 years. Newman Unit 1 and Unit 2 could be capable of technical operations until 2027 or further until 2037 if a significant amount of capital expenditures and increased

maintenance costs are incurred to replace and refurbish much of the major equipment and components.

5. Unit operations and maintenance are generally well planned and carried out in a manner consistent with utility industry standards. Plant personnel should continue to actively address any operational and maintenance issues which could affect operation of the units.
6. The predictive maintenance program used throughout the EPE system has been successful in minimizing forced outages in the rotating equipment area. According to EPE, the program has received industry recognition and should be extended as feasible.
7. While turbine water induction incidents do not occur frequently, when they do, they can be quite damaging to the turbine and result in lengthy outages. Unit 2 has had water induction modifications carried out in accordance with the guidelines of the American Society of Mechanical Engineers ("ASME") turbine water induction protection ("TWIP") standard TDP-1, and modifications to Unit 1 are scheduled to be completed in 2018.
8. With the increased penetration of renewable resources, traditional fossil-fueled generation needs to provide greater flexibility to system operators to better optimize the power supply resources and costs to account for fluctuations within renewable resource generation. The Units do not provide as much flexibility regarding ramp rates, start times, or part load operation compared to newer generating resources.
9. Recommendations
   a. EPE should perform a boiler and high energy piping condition assessment on a regular basis. The implementation of a regular nondestructive examination ("NDE") program would be prudent to provide early warning of major component deterioration.
   b. In evaluating the economics of extending the lives of the Units, EPE should utilize the capital and O&M costs presented within this report.

2.0 INTRODUCTION

2.1 General Plant Description

EPE is an investor-owned electrical utility responsible for supplying power through an interconnected system to a service territory encompassing over 400,000 customers in the Rio Grande Valley in western Texas and southern New Mexico. EPE has interests in Palo Verde Nuclear Plant, in addition to the Copper, Montana, Rio Grande, and Newman Power Stations. Unit 1 of the Newman Power Station began commercial operation in May of 1960 and Unit 2 of Newman began commercial operation in June of 1963. Unit 1 and Unit 2 are scheduled for retirement in 2022.

EPE typically develops budgets for the upcoming year, and occasionally plans a "long-term" budget that extends a few years.

Since 2011 the typical dispatch of Newman has been to baseload the Units from May through September, during which the Plant is not cycled, but rather is ramped up and down. Prior to 2011 the Plant was cycled considerably more, according to plant personnel.

The Plant undergoes a two-week maintenance outage each year, typically in the spring. The focus of the outage is balance of plant equipment, unless any principal equipment is scheduled for major maintenance. Typical spring outage activities involve conditioning oil coolers, cleaning the condenser, conducting all planned inspection and maintenance activities, inspecting the deaerator ("DA"), inspecting the boiler and determining if the boiler needs a chemical cleaning, inspecting valves, and stroking valves.

In 2011 during a freeze event, Newman went offline due to freezing issues with the sensing lines, after which multiple systems froze. A major transmission line outage was planned for October of 2017 for Palo Verde, for which local natural gas-fired units were to be dispatched to provide sufficient energy to meet load.

EPE also employs an aggressive PdM program, which entails continuous monitoring of the steam turbine generator ("STG") by means of a Bently Nevada System 1, visual walk-around observations of other equipment, and monthly testing. Every 30 days the Plant staff perform a vibration analysis, oil analysis, and motor analysis on the major pumps. The Facility would utilize shaft riders for vibration monitoring, but now monitoring is done with the use of XY probes and thermocouples to do so. Lubricating oil is tested by EPE personnel each month and samples are sent for outside testing each quarter. The motor analysis considers the condensate, boiler feed pumps, air compressors, preheaters, circulating water system, cooling tower, and forced draft ("FD") fan. The Plant has dedicated staff for PdM that performs a trending analysis using RBM Ware software.

Newman Unit 1 includes a natural circulation boiler designed by Babcock and Wilcox for 560,000 pounds per hour ("lb/hr") steam flow at 1,510 pounds per square inch gauge ("psig") outlet pressure and 1,005°F superheater and reheater outlet temperatures. The boiler has a pressurized furnace and a single regenerative Ljungstrom air preheater. The Unit has an Allis Chalmers steam turbine that is a tandem compound, impulse reaction double-flow, 21 stage condensing unit. The generator is currently rated at 75 megawatts ("MW"). Cooling water is circulated through a cross-flow cooling tower with treated makeup water provided from the outfall of the local municipal sewage treatment plant. The boiler makeup water and plant service water are provided from a local well system.

Newman Unit 2 also includes a natural circulation boiler designed by Babcock and Wilcox for 560,000 lb/hr steam flow at 1,510 psig outlet pressure and 1,005°F superheater and reheater outlet temperatures. The boiler has a pressurized furnace and a single regenerative Ljungstrom air preheater. The Unit has a General Electric ("GE") steam turbine that is a tandem compound, double-flow condensing unit. The steam turbine generator is nominally rated at 75 MW. Cooling water is circulated through a cross-flow cooling tower with treated makeup water provided from the local municipal sewage treatment plant outfall. Boiler makeup water and plant service water are provided from a local well system.

2.2 Study Objectives & Overview

EPE retained the services of Burns & McDonnell to perform a study to assess the condition of Newman Unit 1 and Unit 2, and to assess the costs of restoring, operating and maintaining these Units to extend their useful service life through 2027 and2037. This Study includes an analysis of the current condition of the Plant and of the issues with current and expected operations, maintenance, and environmental factors, to assess how such issues would impact the Plant's capital expenditure budget and its operations and maintenance budgets if EPE wanted to extend their life until 2027 or 2037. This Study is based on historical operations data and other condition assessment reports provided by EPE, maintenance and operating practices of units similar to Newman, and Burns & McDonnell's professional opinion. Burns & McDonnell has also projected capital expenditures and incremental operation and maintenance costs associated with operating the units through 2027 or 2037.

To complete this assessment, Burns & McDonnell engineers reviewed plant documentation, interviewed EPE management and plant personnel, and conducted a walkdown of the Plant to obtain information on the condition of the Newman Units.

2.3 Study Contents

The following report details the current condition of the Units, and presents the capital expenditures and the ongoing operations and maintenance that would be associated with continued operation of these units past their current retirement date until 2027 or 2037. Since virtually any single component within a power plant can be replaced, the remaining useful life of a plant is typically driven by the economics of replacing the various components as necessary to keep the plant operating economically at industry standards versus shutting it down and either purchasing power or building a replacement facility. Specifically, the critical physical components that will likely determine the Facility's remaining useful life include the following:

1. Steam generator drum, headers, and downcomers
2. High energy piping systems
3. Steam turbine rotor shaft, valves, and steam chest
4. Gas turbine rotor shaft
5. Generator rotor shaft(s), stator and rotor windings, stator and rotor insulator, and retaining rings

The following items, although not as critical as the above, are also influential components that will play a role in determining the remaining useful life of the Plant:

1. Steam generator tubing, ductwork, air preheater, and FD fan
2. Steam turbine blades, diaphragms, nozzle blocks, and casing and shells
3. Gas turbine blades, diaphragms, combustors, casing, and shells
4. Generator stator-winding bracing, DC exciter, and voltage regulator
5. Balance of plant condenser, feedwater heaters, feedwater pumps and motors, controls, and auxiliary switchgear
6. Cooling tower structure, structural steel, stack, concrete structures, and station main generator step-up ("GSU") and auxiliary transformers

External influences that will likely be the major determinant of the future life of the units include environmental influences such as future environmental compliance requirements, economics including fuel costs, comparative plant efficiency, and system needs associated with flexibility, and obsolescence such as the inability to obtain replacement parts and supplies.

3.0 SITE VISIT

Representatives from Burns & McDonnell, along with EPE staff, visited the Plant on September 13, 2017. The purpose of the site visit was to gather information to conduct the condition assessment, interview the plant management and operations staff, and to conduct an on-site review of the Plant.

The following representatives from EPE provided information during the site visit:

1. Jamie Viramontes, Plant Manager
2. J. Kyle Olson, Assistant Plant Manager
3. Wilson (JR) Tademy, Maintenance Manager
4. Robert Tarango, Shift Supervisor

The following Burns & McDonnell representatives comprised the condition assessment team:

1. Mike Borgstadt, Project Manager and Mechanical Engineer
2. Victor Aguirre, Lead Project Analyst and Electrical Engineer
3. Sandro Tombesi, Mechanical Engineer

During the site visit both units were offline. Unit 1 was offline due to a valve latch issue on the main steam valves and Unit 2 was offline due to a significant crack in the main steam line. Unit 1 experienced a boiler outage due to tube leaks a couple weeks prior to the site visit. More recently Unit 1 went down for an extended time because of the valves not latching. This valve issue was fixed at that time. On September 12, 2017, the night before the site visit Unit 1 tripped again after an 8-hour run due to breaker issues when switching from system to Plant [note: it is possible that this trip was a result of operator error as it is not a recurring problem]. The Plant then again experienced an issuing with the valve not latching when restarting the unit. The solution previously used to fix the valve latch could not be repeated to restart the Unit. Additionally, Plant staff indicated it has also been difficult for the Newman plant to find knowledgeable staff to work on the STG.

Through visual observation of the Plant during the site visit, the Facility is maintained adequately and appeared to be in working condition. All buildings seemed to be kept in a clean and proactive manner with no significant corrosion or structural damage to the sidings or roof. The Plant grounds were clean, organized, and free of clutter and debris.

The moving equipment that was visually assessed appeared to be in proper order, free from leakage, and free from any abnormal noise production. Piping appeared to be insulated, sealed, and free from apparent significant leaks. The visual assessment did not reveal any obvious signs of significant deterioration.

During the site visit, some items identified to likely require replacement due to age and/or obsolescence were the high-pressure piping, boiler, circulating water lines, cooling towers, and condenser tubing, fans, and pumps. It was also noted that the backup air compressor is past its useful life and that the primary air compressor is experiencing issues.

4.0 BOILER

4.1 Unit 1 Boiler

The boiler in Newman Unit 1 is a natural circulation, pressurized furnace unit designed by Babcock and Wilcox to burn natural gas or light fuel oil. The unit was originally designed for a maximum continuous rating ("MCR") of 560,000 lb/hr main steam at a superheater outlet condition of 1,510 psig and 1,005° F. The outlet reheat conditions are 416 psig and 1,005° F. The superheater and reheater outlet temperatures are controlled by de-superheater sprays. The boiler design also includes an economizer and Ljungstrom type air heater for flue gas heat recovery.

A couple weeks prior to the site visit the boiler of Unit 1 underwent an outage for tube leaks, then Unit 1 was down for an extended time due to an issue with a valve being unable to latch. In the past few years, the boiler has experienced fewer boiler tube leaks, better chemistry, and less cycling.

Boiler chemical cleaning frequency is on a 4 to 6-year cycle; however, each spring the boilers are inspected to determine if a chemical cleaning is needed sooner. The last chemical cleaning of the boiler in Unit 1 occurred in March 2012. Based on the scheduled retirement date, another boiler chemical cleaning is recommended; however, there is not yet another cleaning planned in the budget.

During the spring of 2017 a major inspection was performed on the boiler. In October of 2010, EPE hired Babcock Power, Inc. ("BPI") to perform a condition assessment of the boiler and high energy piping.

4.1.1 Waterwalls

In 2010 BPI performed a visual inspection of the furnace and waterwalls, and reported that the furnace walls were in good condition. The inspection of the rear slope revealed several poorly repaired tubes that exhibited poor tube fit up or lack of full penetration welds. BPI recommended repair, however EPE elected to not repair the tubes at the time. Ultrasonic thickness testing found the thinnest furnace wall tubes are at 82 percent of their ordered wall thickness and the thinnest rear slope tube was at 77 percent of its ordered wall thickness. BPI noted that Riley Power, Inc. generally recommends replacing tubes thinner than 75 percent of its ordered wall thickness.

Burns & McDonnell recommends repeating the NDE inspections performed by BPI on a regular basis. A regular tube wall thickness inspection program can provide valuable information on boiler waterwall condition and prevent tube rupture-related outages.

4.1.2 Superheater

The superheater sections of the boiler are used to raise the temperature of the steam above the saturation temperature (i.e. superheat the steam). Saturated steam exiting the top of the steam drum passes through the various sections of the superheater and the temperature is continually increased until the steam finally exits the superheater outlet header and continues through the main steam line towards the high pressure steam turbine. The superheater is divided into two stages, primary and secondary, with attemperators positioned in between. At Newman Unit 1, the design of both stages allows for draining the superheaters during outages and startup. Doing so facilitates faster startup, since the startup is not delayed by the amount of time required to drain the superheater.

BPI's late-2010 inspection found the primary superheater in good condition. No major bowing (sagging) was found in the primary superheater bundle. The thinnest tube of the primary superheater was reported to be 0.224-inch from Ultrasonic thickness testing ("UTT") of the tubes. Original tube thickness varied depending upon the location in the bundle, so a percentage of original wall thickness could not be calculated with the information provided.

The secondary superheater at Newman Unit 1 was replaced in 2000. BPI's late-2010 inspection found the secondary superheater to be in fair condition at that time. The primary issue was bowing (sagging) in the center of each superheater row. UTT found the thinnest secondary superheater tube at 90 percent of its ordered wall thickness. BPI indicated that Riley Power, Inc. generally recommends replacing tubes thinner than 75 percent of its ordered wall thickness.

Burns & McDonnell recommends repeating the NDE inspections performed by BPI on a regular basis. Future inspections should also include testing to identify signs of creep, fatigue, and gas side corrosion, as these are the most common damage mechanisms in superheater tubes.

Inspection of the attemperators and piping systems downstream of the attemperators is recommended, since the attemperator operation creates thermal shocking at the loads where it first initiates flow, which could potentially cause a shortened life expectancy for those components.

4.1.3 Reheater

In the reheater section of the boiler the superheat of the steam discharged from the high pressure turbine is increased. Steam exiting the high pressure turbine is transported by the cold reheat steam lines to the reheater inlet header. As the steam passes through the reheater its temperature continually increases until the steam finally exits the reheater outlet header to continue through the hot reheat steam line towards the intermediate pressure steam turbine. At Newman Unit 1, the design of the reheater allows for draining the reheater during outages or startup.

The reheater, like the secondary superheater, was replaced in 2000. The reheater bundle was in good condition at the time of the 2010 visual inspection by BPI. UTT found the thinnest tube was 0.135-inch. Original tube thickness varied depending upon the location in the bundle, so a percentage of original wall thickness could not be calculated with the information provided.

Burns & McDonnell recommends repeating the NDE inspections performed by BPI on a regular basis. Future inspections should also include testing to identify signs of creep, fatigue, and gas side corrosion, as they are the most common damage mechanisms in reheat tubes.

Inspection of the attemperators and the piping systems downstream of the attemperators is recommended, since the attemperator operation creates thermal shocking at the loads where it first initiates flow, which potentially could mean a shortened life expectancy for those components.

4.1.4 Economizer

The economizer section of the boiler is used to improve the efficiency of the thermal cycle by using the exhaust gases to raise the temperature of the feedwater entering the boiler. The boiler feedwater system receives feedwater from the condensate system through the deaerator storage tank and utilizes the boiler feed pumps to convey feedwater through the high pressure feedwater heaters before arriving at the economizer inlet header. From the economizer inlet header, the feedwater temperature is then increased throughout the economizer tube sections in the boiler before exiting through the economizer outlet header and traveling to the steam drum.

BPI's visual inspection in 2010 found the economizer bundle to be in good condition. BPI recommended removal of several rows of tubing that were plugged at the header, but EPE elected to leave them in place at that time. These rows of tubing were bowing and there was a possibility they could affect adjacent tube rows in the future. In June of 2017 the Plant completed an economizer tube replacement on Unit 1.

4.1.5 Drums and Headers

There is one steam drum and two lower waterwall headers on the unit. The boiler drum is visually inspected by plant personnel during the annual outages. Since the drum is most susceptible to fatigue and corrosion damage, Burns & McDonnell recommends regular steam drum inspections including a detailed visual inspection with internals removed, magnetic particle examination of all girth, socket, and nozzle welds, as well as ultrasonic inspection of the welds and thickness readings at the normal water level. The steam drums should be tested, but will likely need to be replaced.

The lower temperature headers include the economizer inlet and outlet headers. Despite being at a relatively low temperature, these headers, in particular the economizer inlet header, tend to be susceptible to ligament cracking caused by thermal stresses incurred during startups and shutdowns. Based on the findings of the initial examination, Burns & McDonnell recommends these headers be inspected periodically to monitor for signs of such damage. Flow-accelerated corrosion ("FAC") has also been an industry wide problem in many economizers.

The low temperature headers should be inspected using the following non-destructive methods:

1. Full borescope examination of the headers.
2. Dimensional analysis of the headers.
3. Magnetic particle examination at all girth and select socket/butt weld locations to detect surface discontinuities in the metal.

The high temperature headers are the primary and secondary superheater outlet and reheat outlet headers. These headers operate under severe conditions and are particularly susceptible to localized overheating, which leads to creep damage and other stress related cracks caused by temperature imbalances applied side-to-side across the headers.

In 2010 BPI performed a visual inspection (using fiber optics), metallographic replication and hardness testing, and diametric measurement on the secondary superheater outlet header and the reheater outlet header.

The 2010 visual inspection of the secondary superheater outlet header found no evidence of erosion, cracking, or corrosion. However, it did reveal moderate to heavy scale buildup. Two locations on the secondary superheater outlet header were examined using metallographic replication. There was no evidence of micro-cracking or creep damage in one of the locations. An indication was found in the other location that was attributed to an overload condition. Limited magnetic particle testing was performed on the middle header girth weld and on two outlet nozzle welds. A crack indication was found on one of the outlet nozzle welds, which was ground out and repaired. Diametric measurement of one girth weld on the header showed the header was within allowable creep swell.

The visual inspection of the reheater outlet header found no evidence of erosion, cracking, or corrosion. However, it did reveal moderate to heavy scale buildup. Two locations on the reheater outlet header were examined using metallographic replication. There was no evidence of micro-cracking or creep damage at either location. Limited magnetic particle testing was performed on the middle header girth weld and on two outlet nozzle welds. Crack indications were found on the outlet nozzle welds, which were ground out and repaired. Diametric measurement of one girth weld on the header showed the header was within allowable creep swell.

Burns & McDonnell recommends repeating the NDE inspections performed by BPI on a regular basis. In addition, the scope of the testing should include the primary superheater header.

4.1.6 Safety Valves

An EVT test was performed July 11, 2017 by Bay Valve Service on the safety valves of Unit 1. The safety valves are tested and recertified every five years by a third party as required by the facility's insurance company. Preventative maintenance is performed on the safety valve drainage system to check for obstruction or leakage.

Burns & McDonnell recommends the valves be tested in accordance with the American Society of Mechanical Engineers ("ASME") code requirements. Annual inspections by the safety valves' Original Equipment Manufacturer ("OEM") are recommended to determine if refurbishment or replacement is required.

4.2 Unit 2 Boiler

The boiler in Newman Unit 2 is a natural circulation, pressurized furnace unit designed by Babcock and Wilcox to burn natural gas or light fuel oil. The unit was originally designed for a MCR of 560,000 lb/hr main steam at a superheater outlet condition of 1,510 psig and 1,005° F. The outlet reheat conditions are 416 psig, 1,005° F. The superheater and reheater outlet temperatures are controlled by desuperheater sprays. The boiler design also included an economizer and Ljungstrom type air heater for flue gas heat recovery.

Boiler chemical cleaning frequency is on a 4 to 6-year cycle; however, each spring the boilers are inspected to determine if a chemical cleaning is needed sooner than planned. The last chemical cleaning of the boiler in Unit 1 occurred in November 2011. Based on the scheduled retirement date, regular boiler chemical cleaning is expected to continue.

The boiler of Unit 2 recently had a tube replacement, though the wall tubes were not replaced. There has also been a lot of testing performed on the boiler tubes and piping. In 2018 a 70-day boiler outage is scheduled for Unit 2, and a valve outage is planned for Unit 2 in 2019.

4.2.1 Waterwalls

In 2010 BPI performed a visual inspection of the furnace and waterwalls. At the time, the furnace walls and rear slope were in good condition. Ultrasonic thickness testing found the thinnest furnace wall tube to be 83 percent of its ordered wall thickness and the thinnest rear slope tube to be 85 percent of its ordered wall thickness. BPI noted that Riley Power, Inc. generally recommends replacing tubes thinner than 75 percent of its ordered wall thickness.

Burns & McDonnell recommends repeating the NDE inspections performed by BPI on a regular basis. A regular tube wall thickness inspection program can provide valuable information on boiler waterwall condition and prevent tube rupture-related outages.

4.2.2 Superheater

The superheater sections of the boiler are used to raise the temperature of the steam above the saturation temperature (i.e. superheat the steam). Saturated steam exiting the top of the steam drum passes through the various sections of the superheater and the temperature is continually increased until the steam finally exits the superheater outlet header and continues through the main steam line towards the high pressure steam turbine. The superheater is divided into two stages, primary and secondary, with attemperators positioned in between.

At the time of BPI's 2010 inspection the primary superheater was in good condition. No major bowing or sagging was found in the primary superheater bundle. Through UTT the thinnest tube of the primary superheater tube was measured to be 0.227-inch. Original tube thickness varied depending upon the location in the bundle, so a percentage of original wall thickness could not be calculated with the information provided.

The secondary superheater is currently undergoing a replacement. At the time of BPI's 2010 inspection the secondary superheater was in fair condition. The primary issue was bowing (sagging) in the center of each superheater row. UTT found the thinnest secondary superheater tube at 0.249-inch. Original tube thickness varied depending upon the location in the bundle, so a percentage of original wall thickness could not be calculated with the information provided. BPI indicated that Riley Power, Inc. generally recommended replacing tubes thinner than 75 percent of its ordered wall thickness.

Burns & McDonnell recommends repeating the NDE inspections performed by BPI on a regular basis. Future inspections should also include testing to identify signs of creep, fatigue, and gas side corrosion, as they are the most common damage mechanisms in superheater tubes.

Inspection of the attemperators and piping systems downstream of the attemperators is recommended, since the attemperator operation, at the loads where it first initiates flow, creates thermal shocking, and potentially a shortened life expectancy for those components.

4.2.3 Reheater

The reheater section of the boiler increases the superheat of the steam discharged from the high pressure turbine. Steam exiting the high pressure turbine is transported by the cold reheat steam lines to the reheater inlet header, where it then passes through the reheater and the temperature is continually increased until the steam finally exits the reheater outlet header and continues through the hot reheat steam line towards the intermediate pressure steam turbine. At Newman Unit 2, the design of the reheater allows for draining the reheater during outages and startup.

The 2010 visual inspection by BPI found the reheater bundle in good condition with well aligned tubes and minor bowing (sagging). Similar to the superheater tubing, UTT found the thinnest tube was thicker than the assumed ordered tube thickness.

Burns & McDonnell recommends repeating the NDE inspections performed by BPI on a regular basis. Future inspections should also include testing to identify signs of creep, fatigue, and gas side corrosion, as they are the most common damage mechanisms in reheat tubes.

Inspection of the attemperators and piping systems downstream of the attemperators is recommended, since the attemperator operation, at the loads where it first initiates flow, creates thermal shocking, and potentially a shortened life expectancy for those components.

4.2.4 Economizer

The economizer section of the boiler is used to improve the efficiency of the thermal cycle by using the exhaust gases to raise the temperature of the feedwater entering the boiler. The boiler feedwater system receives feedwater from the condensate system through the deaerator storage tank and utilizes the boiler feed pumps to convey feedwater through the high pressure feedwater heaters before arriving at the economizer inlet header. From the economizer inlet header, the feedwater temperature is then increased throughout the economizer tube sections in the boiler before exiting through the economizer outlet header and traveling to the steam drum.

At the time of BPI's 2010 visual inspection the economizer bundle was found to be in good condition. The Plant is currently in the process of an economizer tube replacement.

4.2.5 Drums and Headers

There is one steam drum and two lower waterwall headers on the unit. The boiler drum is visually inspected by plant personnel during the annual outages. Since the drum is most susceptible to fatigue and corrosion damage, Burns & McDonnell recommends regular steam drum inspection including a detailed visual inspection with internals removed, magnetic particle examination of all girth, socket, and nozzle welds, as well as ultrasonic inspection of the welds and thickness readings at the normal water level. The steam drums will need to be tested, but will likely require replacement for a life extension through 2037.

The lower temperature headers include the economizer inlet and outlet headers. Despite being at a relatively low temperature, these headers, in particular the economizer inlet header, tends to be susceptible to ligament cracking caused by thermal stresses incurred during startups and shutdowns. Burns & McDonnell recommends these headers be inspected periodically (based on the findings of the initial examination) to monitor for signs of this type of damage. FAC has also been an industry wide problem in many economizers.

The low temperature headers should be inspected using the following non-destructive methods:

1. Full borescope examination of the headers.
2. Dimensional analysis of the headers.
3. Magnetic particle examination at all girth and select socket/butt weld locations to detect surface discontinuities in the metal.

The high temperature headers are the primary and secondary superheater outlet and reheat outlet headers. These headers operate under severe conditions and are particularly susceptible to localized overheating, which leads to creep damage and other stress related cracks caused by temperature imbalances applied side-to-side across the headers.

In 2010, BPI performed visual inspection (using fiber optics), metallographic replication & hardness testing, and diametric measurement on the secondary superheater outlet header and the reheater outlet header.

The 2010 visual inspection of the secondary superheater outlet header found no evidence of erosion, cracking, or corrosion. However, it did reveal moderate to heavy scale buildup. Three locations on the secondary superheater outlet header were examined using metallographic replication. There was no evidence of micro-cracking or creep damage in any of the locations. Limited magnetic particle testing (approximately 50 percent to 70 percent of each weld) was performed on the middle header girth weld and on two outlet nozzle welds. No indications were detected. Ultrasonic phased array testing was done on the middle header girth weld and on two outlet nozzle welds. No indications were detected. Diametric measurements on both sides of the middle girth weld on the header showed the header was within allowable creep swell.

The 2010 visual inspection of the reheater outlet header found no evidence of erosion, cracking, or corrosion. However, it did also reveal moderate to heavy scale buildup. Three locations on the reheater outlet header were examined using metallographic replication. There was no evidence of micro-cracking or creep damage at the locations tested. Limited magnetic particle testing was performed on the middle header girth weld and on two outlet nozzle welds. No indications were detected. Ultrasonic phased array testing was done on the middle header girth weld and on two outlet nozzle welds. No indications were detected. Diametric measurement of one girth weld on the header showed the header was within allowable creep swell.

Burns & McDonnell recommends repeating the NDE inspections performed by BPI on a regular basis. In addition, the scope of the testing should include the primary superheater header.

4.2.6 Safety Valves

The safety valves are tested and recertified every five years by a third party as required by the facility's insurance company. Preventative maintenance is performed on the safety valve drainage system to check for obstruction or leakage. An EVT test of the main valves on Unit 2 will be performed once the unit is back in operation. These valves were checked by Bay Valve Service during the outage earlier in 2018 and the setting of the valves is to follow.

Burns & McDonnell recommends the valves be tested in accordance with the ASME code requirements. Annual inspections by the safety valves' OEM are recommended to determine if refurbishment or replacement is required.

5.0 BOILER AUXILIARY SYSTEMS

5.1 Unit 1 Boiler Auxiliary Systems

5.1.1 Fans

There is one Westinghouse double inlet centrifugal FD fan that provides secondary, or combustion, air to the furnace. The air is heated in the air heater and is then delivered to the furnace through the boiler wind boxes.

This fan has typically been visually inspected every year during the summer preparation outages, and no significant problems have been noted. The inlet vanes are cleaned and inspected yearly. In addition, vibration readings are performed monthly and trended as part of the PdM program for rotating equipment. Oil samples are also taken monthly.

The fan appears to be in good condition based on inspections and on-going maintenance.

5.1.2 Air Heater

Air heating is accomplished by one Ljungstrom type regenerative air heater. This heater is inspected during every outage with minor repairs done immediately. The Ljungstrom air heaters are in good condition.

The air heater baskets (cold side) were previously replaced with like design baskets. The shaft and hot side baskets were replaced during the January 2006 outage.

BPI performed a visual inspection of the air heater from the hot gas inlet side and the hot air outlet side. The baskets were free from debris and the seals were in good condition and appeared tight. No issues were noted.

5.1.3 Flues & Ducts

The ductwork transports combustion air to the boiler and transports hot flue gas away from the boiler, through the air heater, and on to the stack. Since the boiler has operated on natural gas for most of its life, the ducts and flues are considered to be in good shape. As part of the predictive maintenance program, station personnel routinely perform thermography to detect hot spots and leaks in the ductwork and flues.

5.1.4 Blowdown System

At Newman Unit 1, there is an intermediate pressure blowdown tank and another continuous blowdown flash tank. The blowdown system is used to control the water silica levels and remove sludge formations from the steam drum. The continuous blowdown from the steam drum is flashed into the intermediate pressure blowdown tank where the flash steam is exhausted to the deaerating heater and the remaining water continues to the continuous blowdown tank.

The blowdown system appears to be in good condition based on inspections and on-going maintenance.

5.2 Unit 2 Boiler Auxiliary Systems

5.2.1 Fans

There is one Westinghouse double inlet centrifugal FD fan that provides secondary, or combustion, air to the furnace. The air is heated in the air heater and is then delivered to the furnace through the boiler wind boxes.

This fan has typically been visually inspected every year during the summer preparation outages, and no significant problems have been noted. The inlet vanes are cleaned and inspected yearly. In addition, vibration readings are performed monthly and trended as part of the PdM program for rotating equipment. Oil samples are also taken monthly.

The fan appears to be in good condition based on inspections and on-going maintenance.

5.2.2 Air Heater

Air heating is accomplished by one Ljungstrom type regenerative air heater. This heater is inspected during every outage with minor repairs done immediately. The Ljungstrom air heaters are in good condition.

In 2010, BPI performed a visual inspection of the air heater from the hot air outlet side. The baskets were free from debris and the seals were in good condition and appeared tight. No issues were noted.

5.2.3 Flues & Ducts

The ductwork transports combustion air to the boiler and transports hot flue gas away from the boiler, through the air heater, and on to the stack. Since the boiler has operated on natural gas for most of its life, the ducts and flues are considered to be in good shape. As part of the predictive maintenance program, station personnel routinely perform thermography to detect hot spots and leaks in the ductwork and flues.

5.2.4 Blowdown System

At Newman Unit 2, there is an intermediate pressure blowdown tank and another continuous blowdown flash tank. The blowdown system is used to control the water silica levels and remove sludge formations from the steam drum. The continuous blowdown from the steam drum is flashed into the intermediate pressure blowdown tank where the flash steam is exhausted to the deaerating heater and the remaining water continues to the continuous blowdown tank.

The blowdown system appears to be in good condition based on inspections and on-going maintenance.

6.0 STEAM TURBINE

6.1 Unit 1 Steam Turbine

The Newman Unit 1 steam turbine generator was manufactured by Allis Chalmers. Allis Chalmers describes the steam turbine as a tandem compound impulse reaction double flow 21 stage condensing unit.

Even though Allis Chalmers has been out of business for some time, the Unit 1 turbine is still supported by Siemens, and previously was supported by TurbinePro.

6.1.1 Turbine

During the 2017 spring outage the steam turbine of Unit 1 underwent inspection and the feedwater pumps were refurbished. The inspection was originally scheduled to be completed in April, however the outage took longer than expected, from January until May, as parts were not ordered prior to the outage and the Plant did not possess an OEM parts manual. As a result, most parts and hardware had to be sent out for reverse engineering. The unit encountered a few small issues during air testing and with vibrations on the number 3 bearing during start up, however STG of Unit 1 was found to be in good condition and was released for operation. The STG had undergone recent maintenance, during which a few blades were replaced, but no major changes were otherwise made.

Prior to that the low pressure ("LP") and high pressure ("HP") turbines were overhauled by GE Energy Services ("GE") during the spring 2006 outage, which extended from January 16, 2006 to May 9, 2006. The HP/intermediate pressure ("IP") and LP turbine sections were disassembled, blast cleaned and an NDE was performed by Turbine Masters, Inc. All repairs to the rotors and stationary steam path components were made by GE Preferred Machine & Tool ("PMT") in their St. Louis, Missouri shop.

During the 2006 inspection, both the turbine valves steam side and hydraulic sides were disassembled and inspected. New stem bushings were also installed for the main stop, control, and intercept valves during the inspection. Both main stop valve seats were removed and replaced due to cracking in the seat weld areas as well as crack indications in the seating surfaces. All the turbine control components were found to be in acceptable condition based on the information from the last unit inspection. The front standard components were inspected, including the thrust bearing, main oil pump, and the main oil pump volute. All turbine and generator bearings along with the generator hydrogen seals were reconditioned and dual element thermocouples and Bently vibration proximity probes were installed.

Borescopic examinations of the turbine and generator rotors have also been performed within the last 25 years. It is recommended that these examinations be repeated, and the results be compared with the previous examinations. All large forgings such as these rotors have internal flaws, but those flaws are only significant if the extent or size of the flaws has grown over the years.

The turbine is a major focus of the EPE predictive maintenance program. Advanced vibration analysis and a monthly oil analysis are performed to establish trends. These trends then influence the preventive maintenance routines and frequencies. This program was established in 1995 and has been well recognized within the PdM community.

6.1.2 Turbine Valves

The turbine valves are maintained on a 4-year cycle. Unit 1 is having valve issues, and the control valves are having some hydraulic and latching issues. During the spring of 2017 outage detailed in the previous section the following valve inspections were also performed:

1. Main stop valve inspection of two valves and actuators
2. Control valve inspection of six valves and control mechanisms
3. Reheat stop valve inspection of two valves and actuators
4. Intercept valve inspection of two valves and actuators
5. Inspection of the HP stop valve control assembly

Stroking of the valves was completed at the start of May. During the 2017 inspections, minor issues were found with the valve position indicators. The valves were re-checked as the front standard control settings were complete. From the outage, the following recommendations relating to the valves were accepted:

1. Reheat stop valve contact
2. Reheat stop valve: seats, discs, casings, rocker arm

In spring of 2013 a forced valve outage occurred to resolve the issue of the stop valves not opening and to assemble the front standard. TurbinePROs contracted Toshiba PSD to provide technical direction for this outage. After the valve opening issues were resolved, testing was conducted at full arch emission and half arch. The testing was successful and revealed no issues with the stop valves limits.

A turbine valve outage was performed by Power Plant Field Services, LLC in the spring of 2012, during which it was recommended that all the turbine valve studs and nuts be replaced due to reduced tensile strength. In addition, regular inspection of the main steam stop valve bodies was recommended due to numerous crack indications. The next valve inspection was originally planned in the budget for 2022, but has been moved to 2019, during which it is suggested that the studs and nuts be replaced as had been recommended.

6.2 Unit 2 Steam Turbine

The Newman Unit 2 steam turbine generator was manufactured by GE. GE describes the steam turbine as a tandem compound double flow 21 stage condensing unit. ~~TurbinePro is currently supporting Unit 2.~~

6.2.1 Turbine

The steam turbine and the generator underwent a major inspection in September of 2013. During the inspection the HP, IP, and LP turbines were disassembled, cleaned, and inspected by TurboCare. NDE inspections were performed for of all internal turbine components, bearings, bolting and generator fan blades, and valves. No blade replacement was required at that time; however, in January of 2015 the HP and IP turbine blades were replaced. The Unit 2 STG is in good condition, and has a control valve inspection scheduled for 2019, yet depending on timing this planned inspection could likely turn into a major inspection.

Prior to that the LP and HP turbines were inspected by The Wood Group during the fall 2004 outage extending from October 6, 2004 to January 14, 2005. The HP/IP and LP turbine sections were disassembled, blast cleaned and an NDE was performed.

During the 2004 outage the first eleven stage rotor buckets were replaced due to severe erosion, foreign object damage, and pitting. The second through fifth and eighth through eleventh stage diaphragms required major repairs. In addition, the nozzle plate was repaired, as was a crack in the IP turbine shell.

Boresonic inspection of the turbine and generator rotors were performed in October of 2013. The company 3angles, Inc. performed NDEs on the generator field of Newman Unit 2, which revealed no significant flaw indications regarding visual, magnetic particle, eddy current, or ultrasonic testing. It is recommended that these examinations be repeated during the next scheduled maintenance cycle and that the results be compared with the previous examinations. All large forgings such as these rotors have internal flaws, but those flaws are only significant if the extent or size of the flaws has grown over the years.

The turbine is a major focus of the EPE predictive maintenance program. Advanced vibration analysis, as well as monthly oil analysis is performed to establish trends. These trends then influence the preventive maintenance routines and frequencies. This program was established in 1995 and has been well recognized within the PdM community.

6.2.2 Turbine Valves

The turbine valves are maintained on a 4-year cycle, which has proven adequate. In general, the valves usually exhibit minor solid particle erosion when inspected. The valves were disassembled, cleaned, and inspected in September of 2013. The next valve inspection is scheduled for 2019.

7.0 HIGH ENERGY PIPING SYSTEMS

7.1 Unit 1 High Energy Piping Systems

7.1.1 Main Steam Piping

The main steam piping is composed of two ASTM A335 P-11 steam lines and transfers steam from the boiler superheater outlet header to the HP steam turbine. The system operates at approximately 1,500 psig and 1,005°F.

Since this operating temperature is greater than 800°F, the system is susceptible to creep, which is a high temperature, time dependent phenomenon that can progressively occur at the highest stress locations within the piping system. As such, this piping system is of particular concern. During the site visit, Plant representatives discussed that an extensive mapping on the steam lines is needed.

Due to the catastrophic damage potentially caused by a seam-weld failure on high energy steam lines, the Electric Power Research Institute ("EPRI") has issued guidelines and recommendations for utilities to examine longitudinal seams in steam piping systems. In prior years, EPE performed an investigation throughout their system to confirm that their critical piping systems had no seam welds thus eliminating the creep concern at seam welds. However, creep is still a general concern in high stress areas of the piping system.

In the spring of 2011, BPI performed metallographic replication and hardness testing, magnetic particle testing, phased array/ultrasonic shear wave testing, and diametric measurement of several locations on the main steam piping. Metallographic replication and hardness testing was performed on seven girth welds. No evidence of micro-cracking or creep damage was found. Hardness testing found some softening, which was to be expected with the time in service. Magnetic particle testing found indications on six girth welds, which were ground out and re-welded. Ultrasonic testing identified one weld with apparent lack of fusion. The indication was within Code (B31.1) accepted range. Diametric measurement of five welds on the main steam piping indicated allowable creep swell. BPI reported the main steam piping to be in good condition at the time of the 2011 inspection; however, seeing as a significant crack was found by EPE just before the site visit suggests that given the age of the units it would be prudent to project that a replacement will be necessary within the next five years.

Burns & McDonnell recommends repeating the NDE inspections performed by BPI on a regular basis.

As a result of the numerous magnetic particle testing indications on the main steam line, BPI recommended a pipe support inspection on all high energy piping. Burns & McDonnell agrees that the piping support system be visually inspected annually. The hangers should be inspected to verify they are operating within their indicated travel range and are not bottomed out, that their position has not significantly changed since previous inspections, that the pipe is growing, or contracting, in the right directions between cold and hot positions, that the actual load being carried is close to its design point and has not changed, and that the pipe support hardware is intact and operating as designed. It is recommended that the spring hangers be load tested to determine their actual current loading and that a stress analysis be completed to verify that all loads and stresses are within the allowable limits.

7.1.2 Hot Reheat Piping

The hot reheat piping consists of two ASTM A335 Gr P-11 steam lines and transfers steam from the boiler's reheater outlet header to the IP steam turbine. The system operates at approximately 410 psig and 1,005° F. Since this operating temperature is greater than 800°F, the piping system is susceptible to creep, and is of particular concern. As mentioned in the Main Steam section above, EPE has confirmed this system does not have seamed piping or fittings. However, creep is still a concern in the high stress areas of the system. Such areas need to be identified by stress analysis and monitored.

In the spring of 2011, BPI performed metallographic replication and hardness testing, magnetic particle testing, phased array/ultrasonic shear wave testing, and diametric measurement of several locations on the hot reheat steam piping. Metallographic replication and hardness testing were performed on seven girth welds. No evidence of micro-cracking or creep damage was found. Hardness testing found some softening, which is to be expected with the time in service. Magnetic particle testing revealed no indications. Ultrasonic testing identified an indication on one weld and an apparent lack of fusion with another weld. The indication was repaired. The indication showing apparent lack of fusion was within Code (B31.1) accepted range. Diametric measurement of five welds on the hot reheat steam piping indicated allowable creep swell. BPI reported the hot reheat steam piping to be in good condition at the time of the 2011 inspection.

Burns & McDonnell recommends repeating the NDE inspections performed by BPI on a regular basis.

Burns & McDonnell recommends that the piping support system be visually inspected annually. The hangers should be inspected to verify that they are operating within their indicated travel range and are not bottomed out, that their position has not significantly changed since previous inspections, that the pipe is growing, or contracting, in the right directions between cold and hot positions, and that the actual load being carried is close to its design point and has not changed. It is recommended that the spring hangers be load tested soon to determine actual current loading and that a stress analysis should be completed to verify that all loads and stresses are within the allowable limits.

7.1.3 Cold Reheat Piping

The cold reheat piping transfers steam from the discharge of the HP steam turbine to the boiler reheater inlet header. The original material specification for the system reportedly called for the use of ASTM A106 Grade B seamless piping which was confirmed by EPE. The system operates at approximately 550 psig and 720°F. This temperature is less than 800°F and thus below the creep regime. As such, creep is not a concern for this piping system and the system should not require the level of examination recommended on the main steam and hot reheat systems.

Cold reheat piping was not inspected by BPI during the spring of 2011.

Burns & McDonnell recommends inspecting the highest stress weld locations using replication examinations to determine the extent of any carbide graphitization from high temperature operation that may have occurred.

Furthermore, Burns & McDonnell recommends that the piping support system be visually inspected annually. The hangers and snubbers should be inspected to verify that they are operating within their indicated travel range and are not bottomed out, that their position has not significantly changed since previous inspections, that the pipe is growing and contracting in the right directions between cold and hot positions, and that the actual load being carried is close to its design point and has not changed. An inspection program should be developed to inspect this piping soon.

7.1.4 Extraction Piping

The extraction piping transfers steam from the various steam turbine extraction locations to the feedwater heaters. This piping system is not typically a major concern for most utilities and is not examined to the extent that the main and reheat steam systems are.

Extraction piping was not inspected by BPI during the spring of 2011.

Burns & McDonnell recommends that the piping support system be visually inspected on a regular basis. The hangers should be inspected to verify that they are operating within the indicated travel range and are not bottomed out, that their position has not significantly changed since previous inspections, that the pipe is growing, or contracting, in the right directions between cold and hot positions, and that the actual load being carried is close to its design point and has not changed.

Water induction modifications are being made to Unit 1 and are scheduled to be completed in 2018. Such modifications have been made to Unit 2, and EPE's insurance carrier would like Unit 1 to be likewise modified to follow the guidelines of ASME TDP-1 "Prevention of Water Damage to Steam Turbines Used for Electric Power Generation: Fossil-Fuel Plants." The EPE system operates with little reserve margin during the peak seasons. Water induction incidents can result in lengthy forced outages. A significant factor in turbine damage incidents in the industry is turbine water induction from the extraction system, feedwater heater, and associated drains, it will be of benefit for EPE to implement these ASME recommendations.

The plant personnel should ensure that the extraction steam non-return valves are tested on a regular basis to confirm proper operation and reduce the risk of turbine over-speed.

7.1.5 Feedwater Piping

The feedwater piping system transfers water from the deaerator storage tank to the boiler feedwater pumps and then on through the high pressure feedwater heaters and eventually to the boiler economizer inlet header. Although at a relatively low temperature, the discharge of the boiler feedwater pumps is the highest pressure location in the Plant and thus, should be monitored and regularly inspected.

FAC is an industry wide problem and special attention should be given to the first elbows and fittings downstream of the boiler feedwater pumps. Testing would look for thinning on the extrados of the sweeping elbows, where turbulence can occur, causing excessive erosion/corrosion.

BPI took ultrasonic thickness readings on the first two elbows on the discharge of the two boiler feed water pumps. All four elbows were found to have uniform thickness readings throughout the elbow.

Burns & McDonnell recommends repeating the NDE inspections performed by BPI on a regular basis.

7.2 Unit 2 High Energy Piping Systems

7.2.1 Main Steam Piping

The main steam piping, composed of two ASTM A335 P-11 steam lines, transfers steam from the boiler superheater outlet header to the HP steam turbine. The system operates at approximately 1,500 psig and 1,005°F.

Since this operating temperature is greater than 800°F, the system is susceptible to creep, which is a high temperature, time dependent phenomenon that can progressively occur at the highest stress locations within the piping system. As such, this piping system is of particular concern.

The main steam piping of Unit 2 had experienced a leak just before the site visit, which became progressively more of an issue. Upon taking Unit 2 offline it was discovered that the main steam line had a significant crack, which was being repaired at the time of the site visit. During the site visit, Plant representatives also discussed that an extensive mapping on the steam lines is needed.

In prior years EPE performed an investigation throughout the system to confirm that the critical piping systems had no seam welds, thus eliminating the creep concern at seam welds. However, creep is still a general concern in high stress areas of the piping system. These areas should be identified and monitored.

In the fall of 2010, BPI performed metallographic replication and hardness testing, magnetic particle testing, phased array/ultrasonic shear wave testing, ultrasonic thickness measurements, and diametric measurement of several locations on the main steam piping. Metallographic replication and hardness testing were performed on seven girth welds. No evidence of micro-cracking or creep damage was found. Hardness testing revealed some softening, which was to be expected with the time in service. Magnetic particle testing found indications on three girth welds, which were ground out and re-welded. Ultrasonic testing did not identify any indications. Ultrasonic thickness testing on 10 welds revealed minimum thickness of 0.925 inch. Diametric measurement of twelve welds on the main steam piping indicated allowable creep swell. At the time of the 2010 testing, BPI reported the main steam piping to be in good condition.

Burns & McDonnell recommends repeating the NDE inspections performed by BPI on a regular basis.

Burns & McDonnell recommends that the piping support system be visually inspected annually. The hangers and snubbers should be inspected to verify they are operating within the indicated travel range and are not bottomed out, that their position has not significantly changed since previous inspections, that the pipe is growing, or contracting, in the right directions between cold and hot positions, that the actual load being carried is close to its design point and has not changed, and that the pipe support hardware is intact and operating as designed. It is recommended that the spring hangers be load tested soon to determine the actual current loading and that a stress analysis be completed to verify that all loads and stresses are within the allowable limits.

7.2.2 Hot Reheat Piping

The hot reheat piping consists of two ASTM A335 Gr P-11 steam lines and transfers steam from the boiler's reheater outlet header to the IP steam turbine. The system operates at approximately 410 psig and 1,005° F. Since this operating temperature is greater than 800°F, the piping system is susceptible to creep, and is of particular concern. As mentioned in the Main Steam section above, EPE has confirmed that this system does not have seamed piping or fittings. However, creep is still a concern in the high stress areas of the system. Such areas need to be identified by stress analysis and monitored.

In the fall of 2010, BPI performed metallographic replication and hardness testing, magnetic particle testing, phased array/ultrasonic shear wave testing, and diametric measurement of several locations on the hot reheat steam piping. Metallographic replication and hardness testing were performed on seven girth welds. No evidence of micro-cracking or creep damage was found. Replication testing at the inlet to the north stop valve found cracks parallel to the weld fusion line, which have since been repaired. Hardness testing found some softening, which is to be expected with the time in service. Ultrasonic thickness testing on eleven welds revealed minimum thickness of 0.425 inch. Magnetic particle testing revealed three indications, which were repaired. Ultrasonic testing identified two indications at the north and south stop valves. The indications were repaired. Diametric measurement of five welds on the hot reheat steam piping indicated allowable creep swell. BPI reported the hot reheat steam piping to be in good condition at the time of the 2010 inspection.

Burns & McDonnell recommends repeating the NDE inspections performed by BPI on a regular basis.

Burns & McDonnell recommends that the piping and support system be visually inspected annually. The hangers should be inspected to verify that they are operating within their indicated travel range and are not bottomed out, that their position has not significantly changed since previous inspections, that the pipe is growing, or contracting, in the right directions between cold and hot positions, and that the actual load being carried is close to its design point and has not changed. It is recommended that the spring hangers be load tested soon to determine the actual current loading and that a stress analysis should be completed to verify that all loads and stresses are within the allowable limits.

7.2.3 Cold Reheat Piping

The cold reheat piping transfers steam from the discharge of the HP steam turbine to the boiler reheater inlet header. The original material specification for the system reportedly called for the use of ASTM A106 Grade B seamless piping which was confirmed by EPE. The system operates at approximately 550 psig and 720°F. This temperature is less than 800°F and thus below the creep regime. As such, creep is not a concern for this piping system and the system should not require the level of examination recommended on the main steam and hot reheat systems.

Cold reheat piping was not inspected by BPI during the fall of 2010.

Burns & McDonnell recommends inspecting the highest stress weld locations using replication examinations to determine the extent of any carbide graphitization from high temperature operation that may have occurred.

Furthermore, Burns & McDonnell recommends that the piping support system be visually inspected annually. The hangers and snubbers should be inspected to verify that they are operating within the indicated travel range and are not bottomed out, that their position has not significantly changed since previous inspections, that the pipe is growing and contracting in the right directions between cold and hot positions, and that the actual load being carried is close to its design point and has not changed. An inspection program should be developed to inspect this piping soon.

7.2.4 Extraction Piping

The extraction piping transfers steam from the various steam turbine extraction locations to the feedwater heaters. This piping system is not typically a major concern for most utilities and is not examined to the extent that the main and reheat steam systems are.

In the fall of 2010 BPI also performed ultrasonic phased array testing on one weld in the HP extraction line. No indications were found.

Burns & McDonnell recommends that the piping support system be visually inspected on a regular basis. The hangers should be inspected to verify that they are operating within their indicated travel range and are not bottomed out, that their position has not significantly changed since previous inspections, that the pipe is growing, or contracting, in the right directions between cold and hot positions, and that the actual load being carried is close to its design point and has not changed.

In 2013 water induction modifications were completed to the extraction piping of Unit 2 to follow the guidelines of ASME TDP-1, "Prevention of Water Damage to Steam Turbines Used for Electric Power Generation: Fossil-Fuel Plants." The EPE system operates with little reserve margin during the peak seasons and water induction incidents can result in lengthy forced outages. A significant factor in turbine damage incidents in the industry is turbine water induction from the extraction system, feedwater heater, and associated drains.

The plant personnel should ensure that the extraction steam non-return valves are tested on a regular basis to confirm proper operation and reduce the risk of turbine over-speed.

7.2.5 Feedwater Piping

The feedwater piping system transfers water from the deaerator storage tank to the boiler feedwater pumps and then on through the high pressure feedwater heaters and eventually to the boiler economizer inlet header. Although at a relatively low temperature, the discharge of the boiler feedwater pumps is the highest pressure location in the Plant and thus, should be monitored ~~and regularly inspected.~~

In the fall of 2010, BPI took ultrasonic thickness readings on the first two elbows on the discharge of the two boiler feed water pumps. All four elbows were found to have uniform thickness readings throughout the elbow at the time.

8.0 BALANCE OF PLANT

8.1 Unit 1 Balance of Plant

8.1.1 Condensate System

The condensate system transfers condensed steam in the condenser hotwell through the low pressure heaters to the deaerator.

8.1.1.1 Condenser

The condenser tubes were replaced in January 2006 with like-kind admiralty tubes. The condenser neck expansion joint was also replaced. In general, the condenser has performed well and any condenser tube leaks have been promptly repaired.

8.1.1.2 Condenser Vacuum System

The condenser vacuum system is intended to maintain a negative pressure, or vacuum, in the condenser by removing all air that collects in the condenser. This is accomplished by means of an Allis Chalmers hogging vacuum pump and a Westinghouse Steam Jet Air Ejector ("SJAE"), and is backed up by one 100 percent Nash vacuum pump. The pumps are in good condition.

8.1.1.3 Low Pressure Feedwater Heaters

There are two LP closed feedwater heaters and one evaporative condenser installed downstream of the condensate pumps. The heaters were manufactured by Yuba Heat Transfer Corporation. The LP heaters warm the condensate water by transferring heat from the turbine extraction steam to the condensate water in the closed shell and tube, two-pass vertical U-tube design heat exchangers.

The evaporative condenser is permanently out of service, but the condensate is still routed through the tubes. Burns & McDonnell recommends the feedwater heaters be inspected by eddy current testing to establish a baseline for future testing.

8.1.2 Feedwater System

The feedwater system transfers water from the deaerator storage tank to the boiler feedwater pumps and then on through the HP feedwater heaters and eventually to the boiler economizer inlet header.

8.1.2.1 High Pressure Feedwater Heaters

There are two HP closed feedwater heaters installed downstream of the feedwater pumps. These heaters were manufactured by Yuba Heat Transfer Corporation and Senior Engineering. The HP heaters increase the efficiency of the Plant by transferring heat from the turbine extraction steam to the feedwater in the closed shell and tube, two-pass vertical U-tube design heat exchangers.

The first point feedwater heater (highest pressure) was replaced in 1989 and the second point heater was replaced in 1994. Burns & McDonnell recommends the feedwater heaters be inspected by eddy current testing to establish a baseline for future testing.

8.1.3 Deaerator Heater & Storage Tank

The open, tray type deaerator consists of a single vessel containing both the deaerating heater section and storage tank. The deaerator system was manufactured by Cochrane. In the deaerator, extraction steam is used to de-oxygenate and release non-combustible gasses from the water cycle to the atmosphere.

BPI performed magnetic particle testing on many of the welds on the deaerator. Four of the five circumferential welds and three of the four long seam welds were tested. The testing did not reveal any relevant indications.

The deaerator vessel should be visually inspected at each unit planned outage. Ultrasonic thickness examinations should also be performed every 3 to 5 years, with special attention being paid to the vessel wall thickness at the normal water level in the storage tank where cracks have been a problem industry wide.

8.1.4 Condensate and Boiler Feed Pumps

The two condensate pumps are 570 gallons per minute ("gpm") Byron Jackson electric driven vertical pumps each supply 50 percent of the full load demand. The 125 horsepower ("hp") Westinghouse motors are mounted directly on top of the vertical turbine pumps.

The two main boiler feed pumps are motor-driven barrel type Allis Chalmers pumps rated for 688 gpm. The two 50 percent capacity pumps are each driven by a 1250 hp Siemens motor, both of which were installed in 1997. The pumps are inspected on a 5-year cycle. A major crack in the casing can end a pump's life. Since there is no installed spare pump, the station has a spare rotating element in stock. The pumps and motors are reportedly in good condition.

8.1.5 Circulating Water System

The circulating water system is used to reject heat from the condenser to condense the steam leaving the LP turbine. The system utilizes two 50 percent circulating water pumps, to pump cooling water from the cooling tower basin through the circulating water pipe to the condenser water box and then return the water to the cooling tower.

The two electric driven horizontal centrifugal circulating water pumps were manufactured by Westinghouse. Each 50 percent capacity pump is rated for 19,000 gpm and driven by a 450 hp, Westinghouse electric motor. The pumps are located down in a pit.

The circulating water piping near the suction and discharge of the circulating water pumps as well as all buried circulating water piping under the powerhouse structure are carbon steel. The carbon steel circulating lines under the powerhouse are encased in concrete. The above grade and buried piping near the cooling tower are also carbon steel. Some sections of the steel piping are exhibiting significant internal corrosion. These sections were coated during the spring 2006 outage. Recently, the return circulating water line had to be repaired, because a crack was causing it to lose vacuum. The circulating water lines directed to the cooling towers will also need to be replaced or repaired, which would cost approximately $1 million per unit.

The current cooling tower was entirely replaced in 1992. It is a Marley, 5-cell, cross-flow induced draft tower handling 38,000 gpm. It is designed for a range of 21.1°F with a 14°F approach at a 67.5°F wet bulb. All drains go to the cooling tower. It is inspected annually. The cooling towers have taken some abuse in the past 10 years, especially during a significant freeze event that happened in 2011. Both units were running at the time of the freeze event. The cooling towers had several pipes burst, and other equipment was negatively affected. The service water lines were damaged during freeze events, which caused some leaks. The cooling towers need major structural work and possibly replacing. To perform maintenance, the unit must come down, so the Plant must wait for an outage. The Plant prefabricates as much as possible and then replaces the water lines section by section when able. The Plant has installed a significant amount of heat trace.

8.1.6 Water Treatment, Chemical Feed, & Sample Systems

The service water system is shared by Units 1, 2, and 3. The Plant has two water wells and treated wastewater effluent for supply. The water treatment system is supplied from local deep-wells. The water is filtered and sent through two stages of reverse osmosis ("RO") and further demineralized as it passes through a single mixed bed polisher before being directed to the storage tanks. The Plant has 4 total trains for water treatment, including two older RO trains and two newer RO trains that were added with the addition of Unit 5.

Newman Unit 1 uses a combination of phosphate and oxygen scavenger for feedwater treatment. Oxygenated water treatment is the trend in the utility industry. Burns & McDonnell does not feel there is a need to change the feedwater treatment processes considering the relatively low boiler pressure and short remaining unit life expected for Newman Unit 1.

8.1.7 Stack

The prefabricated steel stack is 36.5 feet tall from its base, which rests on boiler room structural steel. It has a brick liner which has never been repaired. The Plant should schedule an inspection to determine the actual condition of the stack and liner.

8.1.8 Plant Structures

The Plant structures generally appear to be in good condition even though the boiler room steel is outdoors.

8.2 Unit 2 Balance of Plant

8.2.1 Condensate System

The condensate system transfers condensed steam in the condenser hotwell through the LP heaters to the deaerator.

8.2.1.1 Condenser

In general, the condenser has performed well and any condenser tube leaks have been promptly repaired. Nevertheless, it is still prudent to expect that given its age, the condenser of Unit 2 will also require re-tubing as has already been performed on Unit 1.

8.2.1.2 Condenser Vacuum System

The condenser vacuum system is intended to maintain a negative pressure, or vacuum, in the condenser by removing all air that collects in the condenser. This is accomplished by means of an Allis Chalmers hogging vacuum pump and a Westinghouse SJAE, and backed up by one 100 percent Nash vacuum pump. The pumps are in good condition.

8.2.1.3 Low Pressure Feedwater Heaters

There are two LP closed feedwater heaters and one evaporative condenser installed downstream of the condensate pumps. The heaters were manufactured by Yuba Heat Transfer Corporation. The LP heaters warm the condensate water by transferring heat from the turbine extraction steam to the condensate water in the closed shell and tube, two-pass vertical U-tube design heat exchangers.

Burns & McDonnell recommends the feedwater heaters be inspected by eddy current testing to establish a baseline for future testing.

8.2.2 Feedwater System

The feedwater system transfers water from the deaerator storage tank to the boiler feedwater pumps and then on through the high pressure feedwater heaters and eventually to the boiler economizer inlet header.

8.2.2.1 High Pressure Feedwater Heaters

There are two HP closed feedwater heaters installed downstream of the feedwater pumps. These heaters were manufactured by Yuba Heat Transfer Corporation and Senior Engineering. The HP heaters increase the efficiency of the Plant by transferring heat from the turbine extraction steam to the feedwater in the closed shell and tube, two-pass vertical U-tube design heat exchangers.

The second point feedwater heater was replaced in August of 2014. Burns & McDonnell recommends the feedwater heaters be inspected by eddy current testing to establish a baseline for future testing.

8.2.3 Deaerator Heater & Storage Tank

The open, tray type deaerator consists of a single vessel containing both the deaerating heater section and storage tank. The deaerator system was manufactured by Cochrane. In the deaerator, extraction steam is used to de-oxygenate and release non-combustible gasses from the water cycle to the atmosphere.

BPI performed magnetic particle testing on a majority of the welds on the deaerator in the fall of 2010. Three of the four circumferential welds and two of the three long seam welds were tested. The testing did not reveal any relevant indications.

The deaerator vessel should be visually inspected at each unit planned outage. Ultrasonic thickness examinations should also be performed every 3 to 5 years, with special attention being paid to the vessel wall thickness at the water level in the storage tank where cracks have been a problem industry wide.

8.2.4 Condensate and Boiler Feed Pumps

The two condensate pumps are 570 gpm Byron Jackson electric driven vertical pumps each supply 50 percent of the full load demand. The 125 hp Westinghouse motors are mounted directly on top of the vertical turbine pumps.

The two main boiler feed pumps are motor-driven barrel type Allis Chalmers pumps rated for 688 gpm. The two 50 percent capacity pumps are each driven by a 1250 hp Siemens motor. The pumps are inspected on a 5-year cycle. A major crack in the casing can end a pump's life. Since there is no installed spare pump, the station has a spare rotating element in stock.

A new motor was installed in one of the boiler feed pumps of Unit 2 in 2013. The other boiler feed pump of Unit 2 is currently out for maintenance, as it suffered bearing damage and was sent to Flow Serve for repair.

8.2.5 Circulating Water System

The circulating water system is used to reject heat from the condenser to condense the steam leaving the low pressure turbine. The system utilizes two 50 percent circulating water pumps, to pump cooling water from the cooling tower basin through the circulating water pipe to the condenser water box and then the water is returned to the cooling tower.

The two 50 percent capacity electric driven horizontal centrifugal circulating water pumps are built by Sulzer, rated for 19,000 gpm, and are driven by 450 hp electric motors.

The circulating water piping near the suction and discharge of the circulating water pumps and all buried circulating water piping under the powerhouse structure are carbon steel. The carbon steel circulating lines under the powerhouse are encased in concrete. In addition, the above grade and buried piping near the cooling tower is carbon steel. Some sections of the steel piping are exhibiting significant corrosion. The circulating water lines directed to the cooling towers will need to be replaced or repaired, which would cost approximately $1 million per unit.

The cooling tower is a 6-cell, cross-flow induced draft tower handling 38,000 gpm. All drains go to the cooling tower. It is inspected by plant personnel at each annual outage. The cooling towers have taken some abuse in the past 10 years, especially during a significant freeze event that happened in 2011. Both units were running at the time of the freeze event. The weight of the ice hurt the structure, and there was some blade damage, which has since been fixed. The cooling towers also had a number of pipes burst, and other equipment was negatively affected. The service water lines were damaged during freeze events, which caused some leaks. In order to perform maintenance, the unit must come down, so the Plant has to wait for an outage. The Plant prefabricates as much as possible and then replaces the water lines section by section when able. The Plant has installed a significant amount of heat trace. The cooling tower of Unit 2 needs work done and the structure needs to be refortified.

8.2.6 Water Treatment, Chemical Feed, & Sample Systems

The service water system is shared by Units 1, 2, and 3. The Plant has two water wells and treated wastewater effluent for supply. The water treatment system is supplied from local deep-wells. The water is filtered and sent through two stages of RO and is further demineralized as it passes through a single mixed bed polisher before being directed to the storage tanks. The Plant has 4 total trains for water treatment, including two older RO trains and two newer RO trains that were added with the addition of Unit 5.

Newman Unit 2 uses a combination of phosphate and oxygen scavenger for feedwater treatment. Oxygenated water treatment is the trend in the utility industry. Burns & McDonnell does not feel there is an incentive to change this proven feedwater treatment processes considering the relatively low boiler pressure.

8.2.7 Stack

The prefabricated steel stack is 36.5 feet tall from its base, which rests on boiler room structural steel. It has a brick liner which has never been repaired. The Plant should schedule an inspection to determine the actual condition of the stack and liner.

8.2.8 Plant Structures

The Plant structures generally appear to be in good condition even though the boiler room steel is outdoors.

9.0 ELECTRICAL AND CONTROLS

9.1 Unit 1 Electrical and Controls

9.1.1 Generator

The generator is a 1960 vintage Allis Chalmers rated 96 megavolt amperes ("MVA") at 13.8 kV. The stator output is 4,017 amperes ("A") at 0.78 power factor. The rotor is hydrogen cooled and the stator windings are water cooled. The exciter is believed to be a 1990 vintage static exciter rated 1,350 A at 250 volts DC ("VDC"), which needs replacement. The voltage regulator is a Westinghouse 1990 analog type located on the ground floor under main generator. Installation of an automatic voltage regulator is scheduled in the budget for 2018.

The protection relays have been upgraded from electromechanical to two ABB GPU2000R microprocessor relays. Assuming the relays are properly set and maintained, they should provide adequate protection for the generator. A generator outage with repairs occurred in the spring of 2017 at the same time as the turbine and valve outage. During the 2017 outage the following recommendations were accepted:

1. Generator journal and journal bearing
2. Generator hydrogen seal and field
3. Generator coil retaining ring inspection and repair

Regarding the generator coil ring, Siemens accepted the blocking as it was without completing the inspection.

The generator of Unit 1 also underwent a motorization event from March 11, 2014 through May 22, 2014. In 2014 an initial electromagnetic core imperfection detection ("El CID") test was performed, during which a major core fault was discovered on the stator iron core. To remove the fault, the affected packets were replaced. At this time, a partial restack was also completed, the core was retorqued, and then a second El CID test was performed. After the installation of complete winding, there were no significant indications seen on the El CID test of the stator iron. During the testing break out torque indicated that the stator core was loose, so the stator core was torqued accordingly. Some of the electrical tests that were performed included the following:

1. DC high voltage testing
2. Contact resistance

3. High potential testing
4. RTD resistance test
5. DC resistance of winding for each phase
6. Insulation resistance
7. Polarization index

Mechanical checks were also performed on the side clearances of the bottom bars and the top bars, in addition to a top ripple spring deflection. All final test results indicated that the rewound stator met required expectations and was fit to go into service.

In 2006 the generator was overhauled, during which the tests performed on the stator included a 10-minute megger and polarization index test, DC hipot test, DC leakage test, armature winding resistance test, and El CID test. The tests that were performed on the rotor were a 10-minute megger and polarization index and an AC impedance test. Additional offline tests included partial discharge analysis of armature and recurrent surge oscillograph of the field winding. At the time, GE found evidence of relaxed stator bar wedging and recommended re-wedging the generator to prevent degradation of the insulation system through abrasion. This was resolved by the re-winding discussed above. GE also found evidence of a fault in the stator core iron. Evidence of stator bar to frame arcing was found on the turbine end of the stator during EL CID testing. GE considered the fault serious, however, EPE chose to return the unit to service with no issues. As a precaution, a thermocouple was installed as near to the damaged area as possible for monitoring and baseline data comparison for the continued operation of the unit.

The following is a list of major tests and repairs performed over the generator life:

1. Stator rewind-1972
2. Retaining ring ultrasonic inspection-1983
3. Rotor reblocking-1983
4. Stator rewedge-1998

The exciter was last inspected in 1998 with the condition considered good. Given its current age and obsolescence though, it is prudent to expect that it will need to be replaced in the near future.

9.1.2 Transformers

Each Unit has a generator step-up transformer, which steps up the voltage from 13.8 kV to 115 kV. Each unit also has a station service transformer. The Plant syncs in the switchyard. As such, there is a common offline service transformer for Units 1, 2, and 3, which was replaced in the 2017 spring outage. Since synching takes place in the switchyard and there are no generator breakers. The service voltages are 480 V and 2,400 V.

9.1.2.1 Startup Transformer

The startup transformer is a 1960 vintage Westinghouse unit located outdoors near the turbine building. The startup transformer is rated 6/7.5 MVA at 115-2.4 kV with a temperature rise of 55/65° C and an impedance of 7.9 percent at 6 MVA. The oil preservation system is a nitrogen blanket type. The startup transformer is shared between Units 1 and 2. A naturally cooled cable bus connects the startup transformer secondary to the unit medium voltage switchgear terminals.

The startup transformer is protected using two ABB TPU2000R microprocessor relays.

The startup transformer is rarely heavily loaded and should have a long thermal life.

It is recommended that the Plant continue its current maintenance and testing plan, including performing dissolved gas analysis on a quarterly basis.

9.1.2.2 Main Transformer (Generator Step-up Transformer)

The GSU transformer is a 2008 vintage, Siemens three phase unit located outdoors near the turbine building. The transformer is rated 70/90/112/125.5 MVA at 115-2.4 kV with a temperature rise of 55/65°C and an impedance of 9.7 percent at 70 MVA. The oil preservation system is a nitrogen blanket type. A common spare main transformer for Units 1 and 2 is located on site. A firewall is installed between the GSU and auxiliary transformer. A fire protection deluge system and oil spill containment are furnished for the GSU.

The main transformer protection is provided by two ABB GPU2000R microprocessor relays. The unit also has a Hydran M2 oil monitor that is monitored by the substation department.

A naturally cooled cable bus connects the main transformer to the generator terminals and is rated 13.8 kV and 5,000 A.

Since the transformer is relatively new and has a much higher MVA rating than the generator, it is expected to last until final plant retirement; however, it is recommended that the Plant continue its current maintenance and testing plan, including performing dissolved gas analysis on an annual basis.

9.1.2.3 Auxiliary Transformer

The unit auxiliary transformer is a 1960 vintage Westinghouse three-phase unit located outdoors near the turbine building. The unit auxiliary transformer is rated 5/5.6 MVA at 13.8-2.4 kV with a temperature rise of 55/65°C and an impedance of 5.5 percent at 5 MVA. The oil preservation system is a nitrogen blanket type. A deluge type fire protection system and oil spill containment are also provided. A cable bus connects the auxiliary transformer secondary to the medium voltage switchgear terminals.

The transformer is protected using an ABB TPU2000R microprocessor relay.

It is recommended that the Plant continue its current maintenance and testing plan, including performing dissolved gas analysis on a quarterly basis.

9.1.3 Medium Voltage Switchgear

The original 1960 vintage Westinghouse 2.4 kV switchgear is installed on the ground floor of the turbine building in an open area. The main breaker is an air magnetic Westinghouse model 50-DH-150E rated 1,200 A, 24 kA interrupting and 39 kA close and latch. The feeder breakers are air magnetic Westinghouse model 50-DH-150E rated 1,200 A, 24 kA interrupting and 39 kA close and latch. The control power for the breakers is 125 VDC.

Based on wide industry experience, the Westinghouse 50-DH-150E breakers have good reliability if kept free from moisture and normal preventative maintenance is performed. The breakers have been regularly inspected, adjusted, and tested (hipot, megger, contact resistance, etc.) on a 5-year schedule.

Spare parts are generally available and most components are relatively inexpensive to replace. The 2.4 kV switchgear bus is a relatively low temperature component. The cleanliness of the insulators and tightness of connections primarily determine the expected life. With good maintenance practice, the life of the bus is virtually unlimited.

Assuming normal maintenance is performed according to the current plant maintenance and testing plan, the switchgear should be serviceable until its replacement, which should be undertaken within the next five years.

9.1.4 480 V Loadcenters, Switchgear, & Motor Control Centers

The 1960 vintage 480 V switchgear is equipped with Westinghouse 25 kA air-magnetic circuit breakers. The main breakers are Westinghouse DB-25 model rated at 600 A and 25 kA interrupting with 125 VDC control power. The switchgear is located indoors.

There are no 480 V motor control centers installed at the Plant. The motor starters are located near the loads in individual enclosures. During the site visit it was discussed that the electromechanical relays for the motor control centers will need to be replaced. The Plant has refurbished the breakers and has the ability to get spare parts; however, it is not known whether new 2.4 kV equipment will be obtainable.

The main unit loadcenter consists of one three-phase, 300 KVA, 2.4-0.48 kV, indoor, VPI dry-type loadcenter transformer in a free-standing enclosure. The cooling tower loadcenter is a three-phase, 500 KVA, 2.4-0.48 kV, outdoor, VPI dry-type transformer in a free-standing enclosure.

Loadcenter transformers typically have a useful life of 30 to 40 years. These transformers are relatively inexpensive to replace and are readily available. A tie to the Unit 2 480 V switchgear is available, therefore, a loadcenter transformer failure has little impact on plant availability.

9.1.5 Station Emergency Power Systems

The Unit 1 and 2 station battery is located in an open ventilated area and is provided to supply critical plant systems. The battery is a GNB model 2-PDQ-17 flooded-cell lead-acid type with a rating of 1,000 amp-hours.

The DC system batteries are tested for specific gravity, cell voltage, and fluid level on a regular basis. The battery is 17 years old. Station batteries are designed for a life of 20 years, and should continue to be replaced on a regular basis.

The DC switchboard breakers are operated infrequently and typically have life in excess of 50 years.

The battery charger is relatively new and should continue to be operable until retirement.

The emergency diesel generator ("EDG") is a Caterpillar unit. The EDG starting power is provided by a dedicated set of batteries rated 48 VDC. The EDG is located outside of the turbine building. With regular exercising and fluid changes, the EDG should continue to be operable, however, controls may become an issue with age and obsolescence. The starting batteries will probably have to be changed out regularly as well.

9.1.6 Electrical Protection

Unit 1 generator and transformer protection was tested in May of 2011. All graphics processing unit ("GPU") and tensor processing unit ("TPU") microprocessor relays passed and were returned to service.

9.1.7 2.4KV Motors and Cables

Plant medium voltage cables are primarily Kerite unshielded type.

The Plant has a very competent PdM group that performs comprehensive testing on 2.4 kV motors and cables. The motors or cables should be reconditioned or replaced as determined by the PdM testing.

9.1.8 Grounding and Cathodic Protection

The plant ground grid consists of copper conductors buried in the soil under and around the Plant. Equipment and structures appeared to be adequately grounded. Steel columns are grounded in numerous places. All equipment and panels were grounded.

The Plant is located in an isokeraunic area with an average of 40 thunderstorm days per year. The Plant is protected from lightning by the steel plant stack. Shield wires are installed on the transmission lines and lines to the GSU and startup transformers.

Cathodic protection consists of an impressed current rectifier type system installed to protect natural gas piping. It is recommended that continuity testing of the rectifier system and integrity of the anodes be checked as a minimum and that necessary repairs be made.

9.1.9 Substation

The 115-kV substation has a number of obsolete dead-tank oil circuit breakers. Although, the breakers are obsolete, spare parts are available from the supplier or third parties.

The breakers are tested and maintained on intervals determined by the number of operations. The night before the site visit Unit 1 tripped after an 8-hour run due to breaker issues when switching from system to plant. It is possible that this trip was a result of operator error as it is not a recurring problem.

The Plant experienced a total blackout condition in 2002 and does not have onsite blackstart capability. If a system blackout occurs, the plant relies on transmission system for startup power.

9.1.10 Control Systems

The bulk of the plant control system is the original pneumatic system augmented with analog loop electronic controllers. The plant burner management system has been upgraded to a Forney electronic system and the combustion control system has been upgraded to utilize a Foxboro distributed control system ("DCS"). A burner management system was put into DCS, and everything else is controlled with the bench board. An upgrade of the bench board to a distributed electronic control system is scheduled