for 2018. The control room supports the entire Plant. During the site visit, plant representatives discussed wanting to upgrade the DCS and control system.

The Plant has a Panalarm annunciator system though a sequence of events recorder is not installed. The Panalarm system is obsolete and parts may be difficult to obtain.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 will be incorporated in the DCS.

9.1.11 Miscellaneous

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 were 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 system should function until retirement.

9.2 Unit 2 Electrical and Controls

9.2.1 Generator

The generator is a 1963 vintage General Electric rated 96 MVA at 13.8 kV. The stator output is 4017 A at 0.85 power factor. The rotor is hydrogen cooled and the stator windings are water cooled. The exciter and voltage regulator were replaced in 2014.

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.

In September of 2013, TurboCare was contracted to perform a major inspection on the steam turbine and generator of Unit 2, during which the generator stator and rotor were disassembled, cleaned, and inspected. Electrical testing was also done on the generator stator and rotor, and the generator H-2 coolers were removed, cleaned, and inspected.

Prior to that the generator was inspected in 2004, during which the tests performed on the stator included a 10-minute megger and polarization index test, DC winding resistance test, and DC controlled overvoltage test. In the 2004 inspection, the generator passed all tests and has since performed well and its condition is considered good.

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

1. Stator rewind-1972
2. Rotor reblocking-1983
3. Retaining ring ultrasonic inspection-1983
4. New wedges and ripple springs-1995

The ReGENco inspection report of November 17, 2004 recommends that the stator be re-wedged with new wedges and ripple spring top filler. This has yet to be done. Burns & McDonnell recommends that the generator stator be rewound within the next five years.

9.2.2 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, so 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 there are no generator breakers. The service voltages are 480 V and 2,400 V.

9.2.2.1 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.

9.2.2.2 Main Transformer (Generator Step-up Transformer)

The GSU transformer is a 1960 vintage Westinghouse three-phase unit located outdoors near the turbine building. The transformer is rated 98.5 MVA at 115-13.8 kV with a temperature rise of 65°C and an impedance of 11.8 percent at 98.5 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 by two ABB GPU2000R microprocessor relays.

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

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

9.2.2.3 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 5.7 percent at 5 MVA. The oil preservation system is a nitrogen blanket type. A deluge fire protection system is installed on each transformer. 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.

9.2.3 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 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.

9.2.4 480 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 600A 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.

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 1 480 V switchgear is available, therefore, a loadcenter transformer failure has little impact on plant availability.

9.2.5 Station Emergency Power Systems

The Unit 1 and 2 station battery, located in an open ventilated area, 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 be operable until final retirement.

The 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 last until Plant retirement. However, controls may become an issue with age and obsolescence. The starting batteries will probably have to be changed out regularly as well.

9.2.6 Electrical Protection

Unit 2 generator and transformer protection was tested on June of 2009. The 87G, 87GB, 87ST, 87T, and 87TB microprocessor relays all passed and were returned to service.

9.2.7 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.

9.2.8 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.

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

9.2.10 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 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 for 2018. The control room supports the entire Plant. During the site visit, Plant representatives discussed wanting to upgrade the DCS and control system.

The Plant has a Panalarm annunciator system, but a sequence of events recorder is not installed. The 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 will be incorporated in the DCS.

9.2.11 Miscellaneous

Plant lighting typically consists of the following fixture types:

1. General plant lighting-incandescent
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No issues were 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 system should function until retirement.

10.0 OPERATION & MAINTENANCE

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

10.1 Reliability and Performance

Burns & McDonnell evaluated the Units' overall reliability and performance against a fleet average of similar type of generating stations. Figure 10-1 presents the equivalent availability factor ("EAF") for the Units against the 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 Units against the fleet benchmark. As presented in the figures, EPE has been able to maintain the Units' reliability performance well given the increased age of the units compared to the average. The 5-year average for EAF for the Units 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 (%)

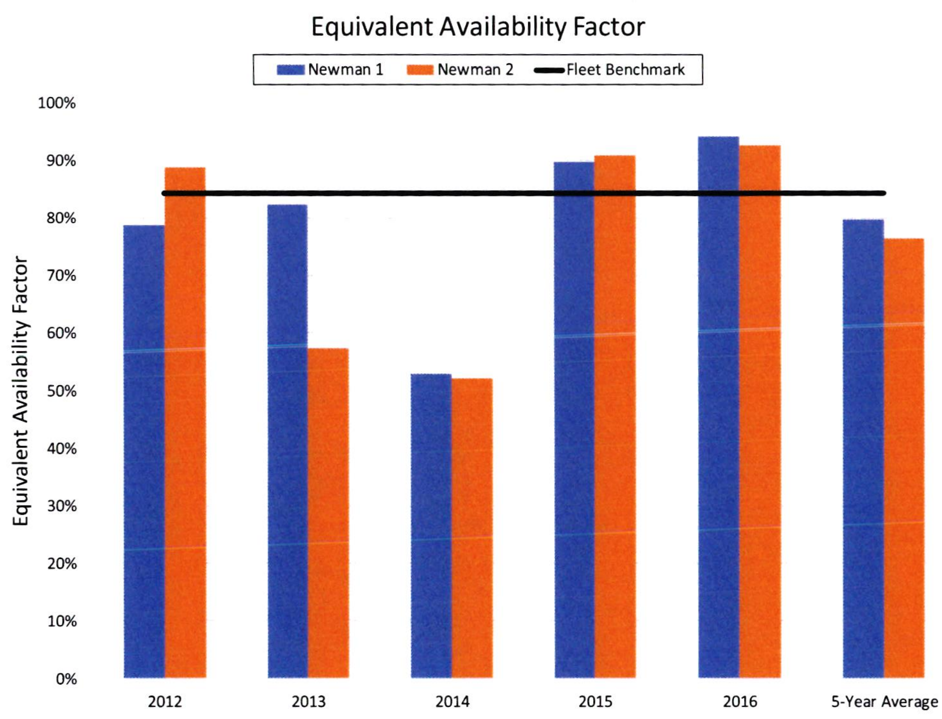
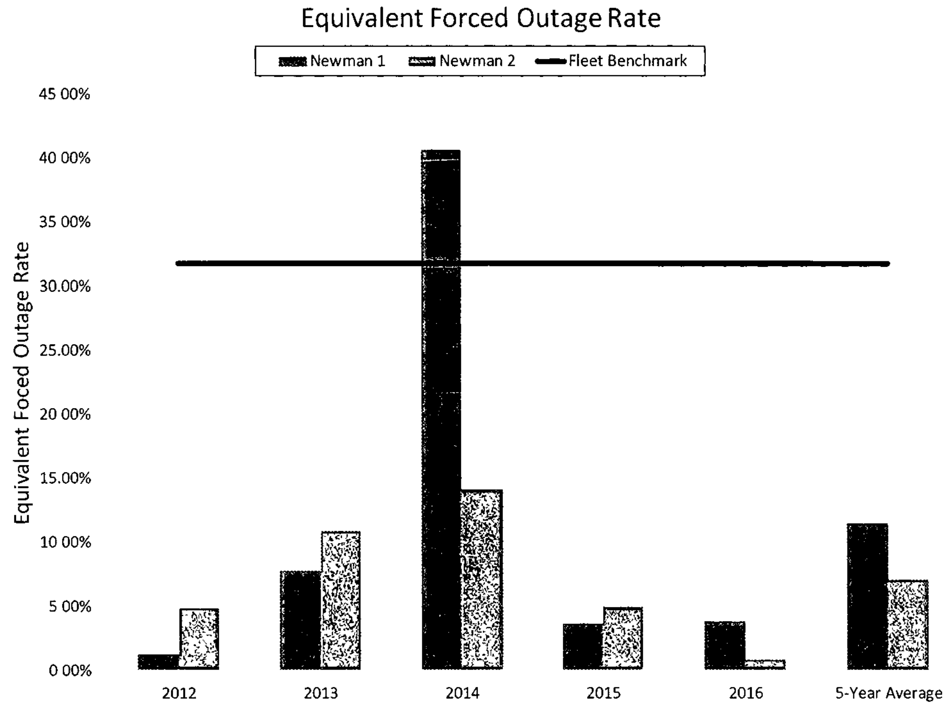


Figure 10-2: Equivalent Forced Outage Rate (%)



10.2 Capital Expenditures Estimate

Unit 1 and 2 are currently scheduled for retirement in December 2022 and December 2023 respectively, which would reflect a retirement age of 62 years of service for Unit 1 and 60 years of service for Unit 2. 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 Units, they have 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 dates.

10.2.1 Life Extension through 2027

To extend the useful service life for the Units until 2027, 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 air heater cold end baskets
2. Refurbish cooling tower
3. Add liner to UG circulating water pipe
4. Replace FW heater tube bundles

5. Condenser retubing
6. Allowance for major pump/fan work
7. Switchgear upgrade
8. Replace unit auxiliary transformers

In addition, for Unit 1 only:

1. Main steam piping replacement
2. Replace the generator exciter

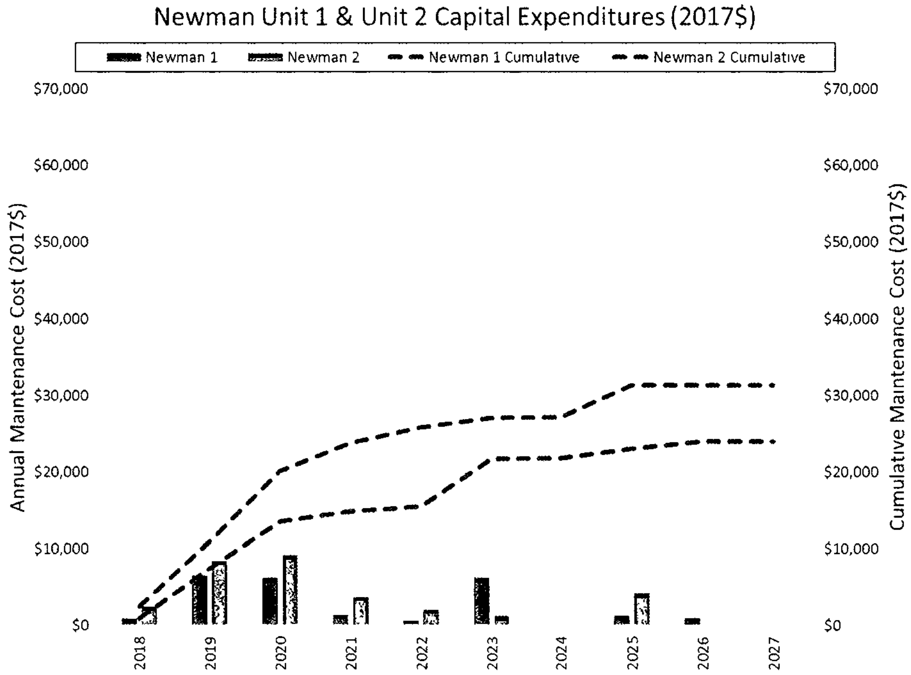
In addition, for Unit 2 only:

1. Rewind the generator
2. Replace the GSU transformer

To achieve operation until 2027, it is recommended that NDE of selected areas be performed on the boiler and high energy piping of both units as soon as possible as well as main steam piping replacement be performed on Unit 2 as soon as possible. Additionally, recurring regular maintenance events will need to continue, such as boiler cleanings and regular boiler piping replacements, NDE inspections, STG major inspections and turbine valve inspections. Appendix A provides a detailed schedule of the forecasted capital expenditures and maintenance costs required to extend the life of the Units to 2027.

Figure 10-3 presents a summary of the capital expenditure estimates derived by Burns & McDonnell for the Newman Units in real/constant dollars (2018$) with no inflation included. Assuming the units are in service through 2027, infrastructure replacements and equipment upgrades would be required. For Unit 1, at a nominal capacity of 74 MW, a cost of approximately $24 million would be required to cover capital and major maintenance expenditures through 2027, or $324/kW. For Unit 2, which has a nominal capacity of 76 MW, a cost of slightly more than $31 million will be required, or $412/kW.

Figure 10-3: Capital Expenditures Forecast through 2027



10.2.2 Life Extension through 2037

To extend the useful service life for the Units 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.

For both Units:

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. Replace the cooling tower
7. Replace the underground circulating water piping
8. Replace the feedwater heater tube bundles
9. Re-tube the condenser
10. Carry out major repair work on primary pumps and fans
11. Complete the conversion to a distributed control system ("DCS")

12. Upgrade the electrical switchgear
13. Replace the unit auxiliary transformer
14. Replace the underground cabling

In addition, for Unit 1 only:

1. Replace the generator exciter

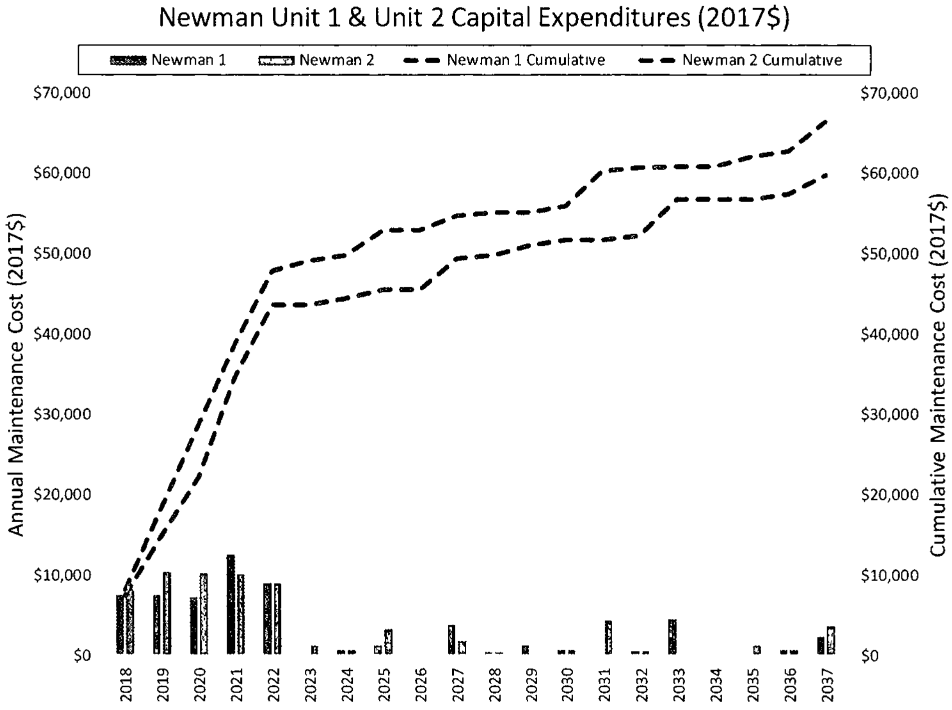
In addition, for Unit 2 only:

1. Rewind the generator
2. Replace the GSU transformer

To achieve operation until 2037, the exciter of Unit 1 should be replaced and a generator rewind be performed on Unit 2. Additionally, recurring regular 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. Appendix B provides a detailed schedule of the forecasted capital expenditures and maintenance costs required to extend the life of the Units to 2037.

Figure 10-4 presents a summary of the capital expenditure estimates derived by Burns & McDonnell for the Newman Units in real/constant dollars (2018$) with no inflation included. Assuming the units are in service through 2037, infrastructure replacements and equipment upgrades would be required. For Unit 1, at a nominal capacity of 74 MW, a cost of approximately $59.7 million would be required to cover capital and major maintenance expenditures through 2037, or $807/kW. For Unit 2, which has a nominal capacity of 76 MW, a cost of approximately $66.5 million will be required, or $875/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 age 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 both Newman Units highlighted (as well as other EPE units).

Figure 10-5: Maintenance Cost Trend Evaluation

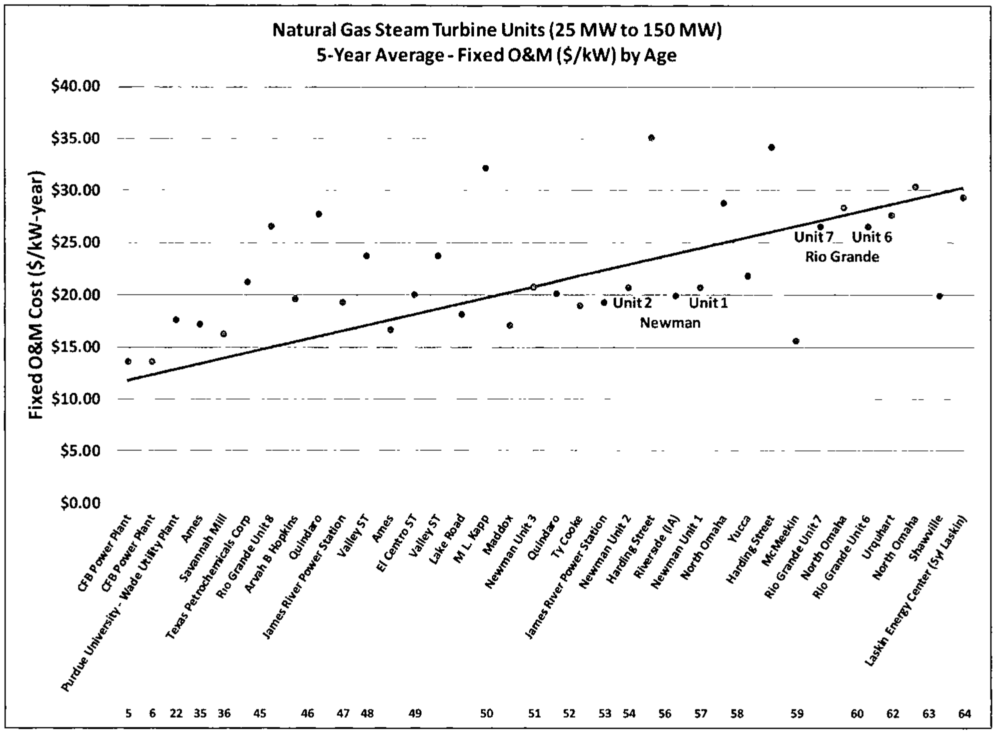
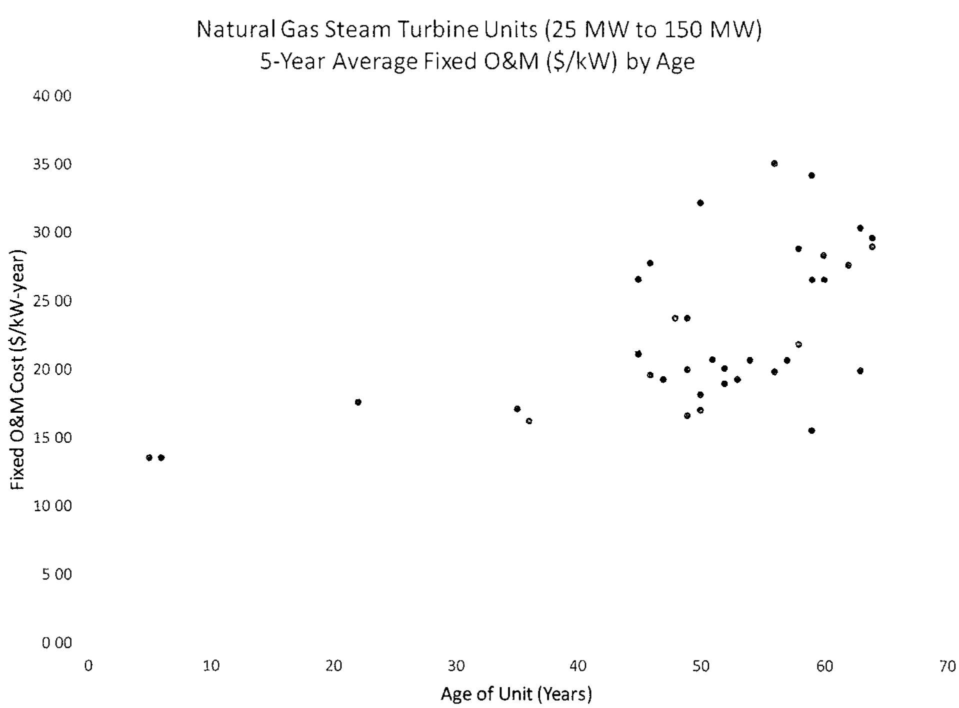
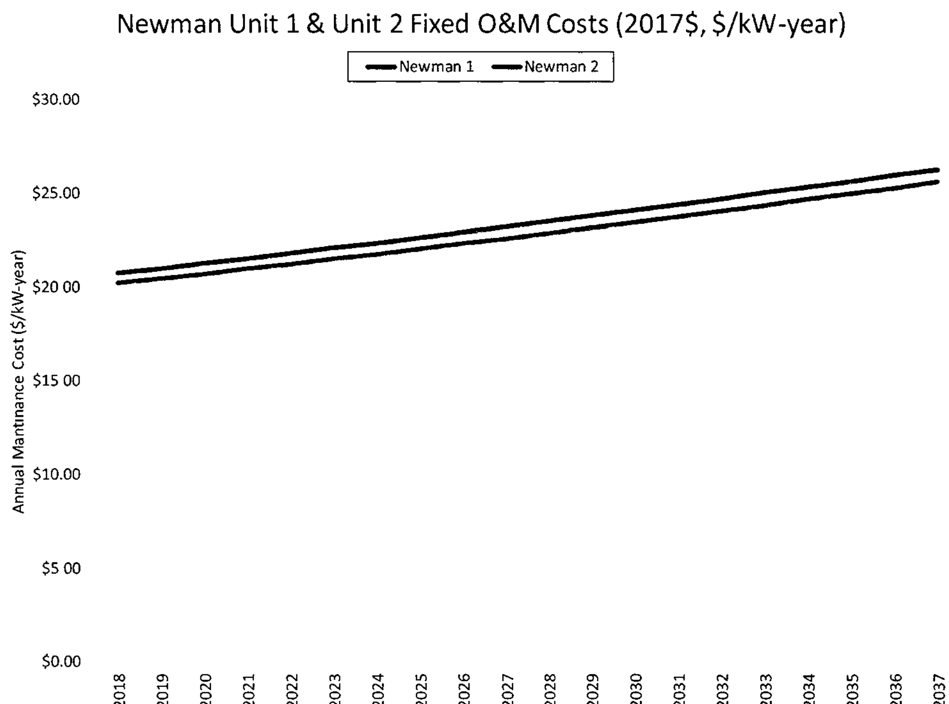


Figure 10-6: Maintenance Cost Trend Evaluation (X-Y Scatter)



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 the Units over time from approximately $21/kW-year in 2018 (2018$) to over $25/kW-year in 2037 (2018$), excluding inflation increases. Figure 10-7 presents the maintenance cost projections for Unit 1 and Unit 2. The costs presented in Figure 10-7 as presented in real, constant dollars (2018$) without including inflation.

Figure 10-7: Maintenance Cost Forecast for Unit 1 and Unit 2



Additionally, the Units will incur a variable O&M cost of approximately $2.54 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 presented 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 excluding 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 benchmark units, only 14 units are still in service today that have an age of 60 years or older. The Newman Units 1 and 2 have an average fixed O&M of approximately $21/kW-year in 2018 (2018$) that is expected to increase to over $25/kW-year in 2037, which is comparable to the units of the narrowed benchmark.

The location of each of the units is presented 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 Units 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 and Table 10-3, 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 10-2: 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 10-3: 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

11.0 EXTERNAL & ENVIRONMENTAL FACTORS

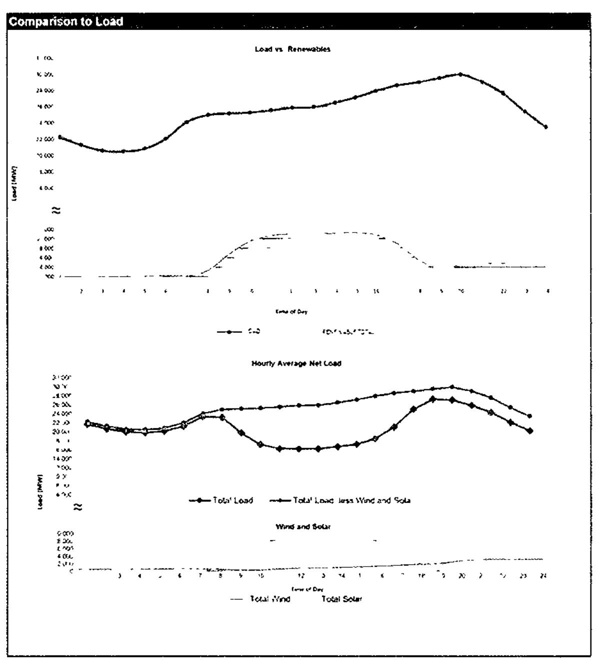
In addition to the costs associated with operating and maintaining the Units, there are other external factors, such as flexibility or environmental considerations, that may impact the useful service life and long-term viability of the Units.

11.1 Flexibility

The value of Units 1 and 2 is less than that of newer generating resources, since through 2027 and further through 2037 the Units will require more repair and replacement of aging systems in addition to the increased, recurring maintenance. These lower values will be further exacerbated by the poor flexibility of these Units 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 1 and Unit 2, 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 1 and Unit 2 compared to those of new generating resources. As presented in the table, the new resources are much more flexible compared to the Newman Units in regard to 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 1	Unit 2	Reciprocating Engine	Aeroderivative SCGT	F-Class SCGT	F-Class CCGT (Fired)
Ramp Rate (MW/min)						
Up	3	3	50	12	40	60
Down	3	3	50	12	40	60
Start Time						
Cold	8 hrs	8 hrs	45 min	45 min	45 min	180 min
Warm	4 hrs	4 hrs	7 min	8 min	10 to 30 min	120 min
Hot	2 hrs	2 hrs	7 min	8 min	10 to 30 min	80 min
Load (MW)						
Minimum	25	25	8	42	95	181
Maximum	84	82	199	169	191	329 (407 Fired)
Heat Rate (BtU/kWh)						
Minimum Load	12,430	12,220	8,990	11,490	12,880	7,370
Base Load	11,330	10,430	8,190	9,270	10,120	6,580

11.2 Environmental Issues

This section of the report describes the environmental regulations that could impact Unit 1 and Unit 2 in the future. As a general summary, the only regulation that may have near term pollution control requirements is the Cross State Air Pollution Rule ("CSAPR") and possibly National Ambient Air Quality Standards ("NAAQS"). For the Units, the most recent emissions from 2015 through 2016 are above the 2017 ozone season NO_X allowances. EPE may have other units in CSAPR that are below the allowance levels, but no evaluation was performed. Assuming that other CSAPR units in the system are at or near allowance levels, EPE can either purchase allowances or install combustion controls or add on equipment. EPE could also reduce operating hours from these Units during the ozone season. NAAQS requirements are area specific and also depend on individual plant impacts. Therefore, no control requirements can be determined until the state of Texas and the 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

In the CSAPR, the EPA's approach is based on state-wide SO_2 and NO_x emission budgets. Each state's budget consists of the emissions that the EPA estimates will remain after the state has made the reductions required to reduce its significant contribution to non-attainment and interference with maintenance of the relevant NAAQS in other states in an average year. The EPA established each state's budget by estimating unit-level allocations and then totaling the unit-level allocations for each state.

In September of 2016, the EPA modified the ozone season allowance budget to incorporate the 2008 ozone standard of 75 parts per billion ("ppb"). In the original CSAPR the ozone season allocation was based on the 1997 ozone standard. The 2008 ozone standard is more stringent than the 1997 ozone standard. As a result, the amount of ozone allowances for facilities has generally been reduced. It should be noted that EPA has finalized a new 2016 ozone standard of 70 ppb. At the time of this report this new ozone standard had not been incorporated into the CSAPR budget yet, but should be in the next few years, and it is likely that the new standard will slightly decrease ozone allowances further. Burns & McDonnell has reviewed the EPA's Clean Air Markets Data ("CAMD") to obtain the 2015 through 2016 ozone season NO_x emissions and annual NO_x and SO_2 emissions for the Units. Allowances can be traded inter-state and intra-state. Burns & McDonnell also reviewed the EPA's new (September 2016) CSAPR allocations under the 2008 ozone standards. The ozone season allowances are presented in Table 11-2.

Table 11-2: CSAPR 2008 Ozone Season Allowances

Unit	Ozone Season Allowances (tons per season)	2015-2016 Average Emissions (tons per season)
Newman Unit 1	73	156
Newman Unit 2	77	135
Total	150	291

As presented in Table 11-2 above, recent operating levels do not have sufficient allowances for the new CSAPR 2008 ozone allocations. There is a robust ozone season trading market. As such, it is expected that allowances can be purchased for only a few hundred dollars per ton deficient. However, EPE should review the total allowances given to the system and compare the total to the assurance provision levels. If total systemwide NO_x ozone season emission exceeds the assurance levels, EPA could fine EPE and take away future allowances if the state of Texas exceeds its total assurance levels during the ozone season.

Assuming that other CSAPR units in the system are at or near allowance levels, EPE can either purchase allowances or install combustion controls or add on equipment. EPE could also reduce operating hours from these units during the ozone season.

For annual SO_2 and NO_x allowances, Texas recently was removed from the annual program as addressed in the September 21, 2017 Federal Register.

11.2.2 Regional Haze Rule

On July 1, 1999, the EPA issued a Regional Haze Rule (40 CFR Part 51, Subpart P) aimed at protecting visibility in 156 Federal Class I areas. Subsequently, the EPA issued proposed guidelines for determining Best Available Retrofit Technology ("BART"), which provides guidance to the states in determining the air pollution controls needed to reduce visibility-impairing pollutants. On July 6, 2005, the EPA finalized amendments to its Regional Haze Rule and its BART Guidelines.

BART is defined as "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant." BART requirements will apply to facilities that were not yet operating on August 7, 1962 but were in existence on August 7, 1977 (the date of enactment of the Clean Air Act Amendments of 1977) and that have the potential to emit more than 250 tons per year of any visibility-impairing pollutant, such as Sulfur dioxide ("SO_2"), NO_x, or particulate matter ("PM"). If any visibility-impairing pollutant is emitted above this threshold level, then that source is BART-eligible. Next, it must be determined whether emissions from a BART-eligible facility are reasonably anticipated to contribute to, or cause, visibility impairment in any Federal Class I area. A BART review is required for each visibility-impairing pollutant.

Under the Regional Haze Rule, states must determine which sources will have to install BART controls and then must submit a state implementation plan ("SIP").

Newman Unit 2 is BART eligible. The Texas Regional SIP proposal did not require additional controls on Unit 2. Also, by virtue of CSAPR requirements being more stringent than BART, no new emissions limits are expected.

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

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

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 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 Newman units are natural gas-fired, there is no concern about the SO_2 NAAQS, however, there could be NO_x 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 $PM_{2.5}$. 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 Newman, 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 Newman. However, it is impossible to determine what, if any, additional controls will be required without any detailed air dispersion modeling results.

El Paso 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 ("EGU"), 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 Newman 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 the discharge 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 under 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 the Newman facility since it burns only natural gas.

The Newman plant uses effluent from the local waste water treatment district as makeup to their cooling towers. The Plant recently installed a zero-discharge system to treat cooling tower blowdown. So, it is unlikely that future changes to CWA will significantly impact the Facility.

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 Wastewater Discharge

Wastewater from the boiler blowdown, laboratory drains, sampling streams, and floor drains is routed through an oil/water separator which is discharged to on-site sumps. Cooling tower blowdown is routed to separate sumps without treatment.

The Plant installed a zero-liquid discharge system in the 2007 timeframe, with the addition of Unit 5. It is possible that the Plant was required to install a partial zero-liquid discharge system since the permits would not allow any additional discharge with the addition of Unit 5. All wastewater is pumped to the zero-discharge wastewater system. This wastewater treatment system effluent is of better quality than the existing cooling tower makeup feed, and is utilized as makeup to the cooling tower. The new wastewater treatment is essentially zero-discharge and the concentrated solids are landfilled.

11.4 Odor, Visibility, & Noise

The Plant did not report any significant issues with odor or visibility. The Plant does not have residential neighbors within three miles. This distance provides a buffer zone and minimizes the potential for complaints from disgruntled neighbors; however, continued urban growth may bring residential neighborhoods closer to the Plant. There have been no complaints of noise from Newman. Noise compliance may currently be an issue with the El Paso Municipal Code and the current operations at Newman. EPE is evaluating noise compliance alternatives for the Newman station.

11.5 Water Quality Standards

The Water Quality Standards 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 EPA to review, approve, disapprove and promulgate water quality standards pursuant to section 303(c) of the Clean Water Act. A Water Quality Standard ("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. Aantidegradation requirements
4. WQS variances
5. Provisions authorizing the use of schedules of compliance for water quality-based effluent limits in NPDES permits

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

11.6 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 EGU under Section 112 of the Clean Air Act. This regulation is also known as the National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units, or the Utility MACT. Since these are natural gas-fired units, it is not subject to this MACT.

11.7 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. These units burn natural gas and/or fuel oil and do 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. 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 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 in order 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. EPE should perform a boiler and high energy piping condition assessment on a regular basis. The implementation of a regular NDE program would be prudent to provide early warning of major component deterioration.

The overall condition of the Newman units appears to be reasonably fair to good considering their age, and the units could achieve the planned useful service 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. 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 Newman Unit 1 and Unit 2 should be capable of technical operations until 2027 or 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. In evaluating the economics of extending the lives of the Units, 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 Newman Unit 1 and Unit 2 should the Units' useful service life be extended through 2027. These recommendations would help maintain the safety, reliability, and reduce the potential for extended unit forced outages. Burns & McDonnell's major recommendations for both units are:

1. Replace air heater cold end baskets
2. Refurbish cooling tower
3. Add liner to UG circulating water pipe
4. Replace FW heater tube bundles
5. Condenser retubing
6. Allowance for major pump/fan work
7. Switchgear upgrade

8. Replace unit auxiliary transformers

In addition, for Unit 1 only:

9. Main steam piping replacement
10. Replace the generator exciter

In addition, for Unit 2 only:

11. Rewind the generator
12. Replace the GSU transformer

The following is a summary of the recommended actions suggested to maintain Newman Unit 1 and Unit 2 should the Units' useful service life be extended through 2037. These recommendations would help maintain the safety, reliability, and reduce the potential for extended unit forced outages. Burns & McDonnell's major recommendations for both units 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. Replace the cooling tower
7. Replace the underground circulating water piping
8. Replace the feedwater heater tube bundles
9. Re-tube the condenser
10. Carry out major repair work on primary pumps and fans
11. Complete the conversion to a distributed control system ("DCS")
12. Upgrade the electrical switchgear
13. Replace the startup and unit transformers
14. Replace the underground cabling

In addition, for Unit 1 only:

1. Replace the generator exciter

In addition, for Unit 2 only:

1. Rewind the generator
2. Replace the GSU transformer

12.2.2 External & Environmental Factors

Continue to monitor changing air emissions regulations (CSAPR and NAAQS).

12.2.3 Additional Recommendations

The following is a summary of additional recommended actions suggested to maintain the safe and reliable operation of both Units and prevent the potential for extended forced unit outages. The following recommendations are presented herein:

12.2.3.1 Boiler

1. Conduct regular non-destructive examination 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, superheater and reheater attemperator(s) and downstream piping.
2. Perform annual testing of the safety relief valves.
3. Continue boiler chemical cleanings on a 6-year schedule.

12.2.3.2 Steam Turbine-Generator

1. Conduct steam turbine-generator inspections on a 6-year schedule.
2. Conduct steam turbine valve inspections on a 4-year schedule.
3. Perform regular borescope examinations of the turbine rotor.
4. Replace the turbine valve studs and nuts as recommended by the OEM, if not done already.

12.2.3.3 High Energy Piping Systems

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

12.2.3.4 Balance of Plant

1. Conduct regular eddy current testing of low pressure and high pressure feedwater heater tubing.

2. Conduct non-destructive examination testing 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. Regularly inspect the structural integrity of the stack.

12.2.3.5 Electrical

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

APPENDIX A - COST FORECASTS THROUGH 2027

El Paso Electric, Inc.
Newman Unit 1
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															
Boiler clean	Industry practice	2012	10 yrs	When due	$600					$600					
Regular boiler piping replacements	Required	2017	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	2006	10 yrs	Within 5 yrs*	$400	$400									
TURBINE GENERATOR															
STG Major Inspection	Industry practice	2017	6 yrs	When due	$3,200						$3,200				
ST blades/valve repl /repairs	Required	N/A	Once	Next major	$2,000						$2,000				
Valve Inspection	Industry practice	2017	4 yrs	When due	$2,400				$1,200				$1,200		
Replace exciter	Required	N/A	Once	Within 5 yrs*	$350	$350									
BALANCE OF PLANT															
Refurbish cooling tower	Required	1992	30 yrs	Within 5 yrs*	$2,000			$2,000							
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	N/A	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	2000	20 yrs	When due	$200			$200							
Replace unit aux transformers	Required	N/A	Once	Within 5 yrs*	$500		$500								
TOTAL															
TOTAL				$000	$23,980	$860	$6,500	$6,200	$1,310	$600	$6,200	$110	$1,200	$1,000	$0

*Distributed over years to spread out expense

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El Paso Electric, Inc.
Newman Unit 2
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															
Boiler clean	Industry practice	2011	10 yrs	When due	$600				$600						
Regular boiler piping replacements	Required	2016	3 yrs	When due	$3,000		$1,000			$1,000			$1,000		
Main steam piping replacement	Safety	N/A	Once	ASAP	$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	N/A	10 yrs	Within 5 yrs*	$400	$400									
TURBINE GENERATOR															
STG Major Inspection	Industry practice	2013	6 yrs	When due	$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	N/A	4 yrs	Next major	$2,400		$1,200				$1,200				
Generator rewind	Required	N/A	Once	Within 5 yrs*	$3,500			$3,500							
BALANCE OF PLANT															
Refurbish cooling tower	Required	N/A	Once	Within 5 yrs*	$2,000				$2,000						
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	N/A	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					$0										
Switchgear upgrade	Industry practice	N/A	Once	Within 5 yrs*	$2,000			$2,000							
Replace station batteries	Required	2000	20 yrs	When due	$200			$200							
Replace GSU	Required	N/A	Once	Within 5 yrs*	$1,000		$1,000								
Replace unit aux transformer	Required	N/A	Once	Within 5 yrs*	$500			$500							
TOTAL															
TOTAL				$000	$31,330	$2,510	$8,400	$9,200	$3,710	$2,000	$1,200	$110	$4,200	$0	$0

*Distributed over years to spread out expense

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APPENDIX B - COST FORECASTS THROUGH 2037

El Paso Electric, Inc
Newman Unit 1
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	2012	6 yrs	When due	$3,000	$600						$600						$600						$600	$600
Regular boiler piping replacements	2017	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	2006	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	2017	4, then 6 yrs	When due	$9,600				$3,200						$3,200						$3,200				
ST blades/rotor/shell/valve repl /repairs	N/A	Once	Next major	$5,000				$5,000																
Valve Inspection	2017	4 yrs	When due	$6,000				$1,200				$1,200				$1,200				$1 200				$1,200
Replace exciter	N/A	Once	Within 5 yrs*	$350	$350																			
BALANCE OF PLANT																								
Replace cooling tower	1992	30 yrs	Within 5 yrs*	$4,000			$4,000																	
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	N/A	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	2000	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			$000	$59,720	$7,460	$7,500	$7,700	$12,510	$9,000	$0	$710	$1,200	$0	$3,810	$400	$1,200	$710	$0	$500	$4,510	$0	$0	$710	$2,300

*Distrubuted over years to spread out expense

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El Paso Electric, Inc
Newman Unit 2
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	2011	6 yrs	When due	$2,400	$600						$600						$600						$600	
Regular boiler piping replacements	2016	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	ASAP	$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	N/A	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	2013	6 yrs	When due	$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	N/A	4 yrs	Next major	$6,000		$1,200				$1,200				$1,200				$1,200				$1,200		
Generator rewind	N/A	Once	Within 5 yrs*	$3,500			$3,500																	
BALANCE OF PLANT																								
Replace cooling tower	N/A	Once	Within 5 yrs*	$4,000				$4,000																
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	N/A	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				$0																				
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	2000	20 yrs	When due	$200			$200																	
Replace GSU	N/A	Once	Within 5 yrs*	$1,000		$1,000																		
Replace unit aux transformer	N/A	Once	Within 5 yrs*	$500			$500																	
Replace UG cabling	N/A	Once	Within 5 yrs*	$3 000				$3,000																
TOTAL																								
TOTAL			$000	$66,470	$8,110	$10,400	$10,200	$10,110	$9,000	$1,200	$710	$3,200	$0	$1,810	$400	$0	$710	$4,400	$500	$110	$0	$1,200	$710	$3,700

*Distrubuted over years to spread out expense

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SOAH Docket No 473-21-2606
PUC Docket No 52195
CEP's 1st, Q No CEP 1-27
Attachment 5
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BURNS & McDONNELL

CREATE AMAZING.

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9400 Ward Parkway
Kansas City, MO 64114
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CEP 1-27 Attachment 6 is a VOLUMINOUS attachment.

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
CITY OF EL PASO'S FIRST REQUEST FOR INFORMATION
QUESTION NOS. CEP 1-1 THROUGH CEP 1-28

CEP 1-28:

Please provide the number of hours during each of the last three calendar years and during the test year that the delivery of energy produced from EPE's ownership share of the PVNGS units to EPE's Texas service area was limited by transmission constraints and explain the primary reasons for these constraints.

RESPONSE:

During periods of transmission constraints, EPE seeks to utilize other ways to import EPE's least cost resources, such as through the Freeport-McMoRan agreement or interruptible transmission. Outside of the two mentioned import alternatives, EPE does not track whether EPE could not import energy from its remote generation due to transmission constraints. Should there be a transmission constraint wherein EPE was not able to import energy from its remote generation and was required to make off-system sales, EPE would engage in off-system sales and increase local natural gas generation to meet load requirements; the increased natural gas costs would be assigned to off-system sales and the cost of energy generated at Palo Verde would be assigned to native load customers. From an accounting perspective, EPE's customers would receive the benefit of the lower fuel prices from EPE's remote generation.

Preparer: Jesus S. Gonzalez — Title: Manager – Day Ahead & Long-Term Trading

Sponsor: David C. Hawkins — Title: Vice President – Strategy & Sustainability

SOAH DOCKET NO. 473-21-2606
DOCKET NO. 52195

APPLICATION OF EL PASO	§	BEFORE THE STATE OFFICE
ELECTRIC COMPANY TO	§	OF
CHANGE RATES	§	ADMINISTRATIVE HEARINGS

CONFIDENTIALITY STATEMENT UNDER SECTION 4 OF THE PROTECTIVE ORDER

The undersigned attorney for El Paso Electric Company (EPE) submits this statement under the section 4 of the Protective Order entered in this case. Materials provided in the responses to CEP 1-5 (Attachment 1), CEP 1-13 (Attachment 1), and CEP 1-21 (Attachment 1) are exempt from public disclosure pursuant to sections 552.101 and 552.110 of the Public Information Act and section 418.181 of the Texas Government Code.

The responses contain information on business operations and financial information that is commercially sensitive and not otherwise readily available to the public. Moreover, the documents contained within the responses include information that qualifies as trade secrets, as the information is not generally known and provides a commercial advantage to its owner. Public release of this information would also cause substantial competitive harm to EPE and the other companies that are owners in the Palo Verde Generating Station. Finally, some of the documents contained within the response contain information on highly sensitive, confidential critical infrastructure that EPE is required to keep confidential and the public release of which could jeopardize the security of EPE's system.

The undersigned counsel for EPE has reviewed the information described above sufficiently to state in good faith that the information is exempt from disclosure under the PIA and merits the confidential designation given to it.

Respectfully Submitted,

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