BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF EL PASO ELECTRIC COMPANY FOR APPROVAL OF ABANDONMENT OF ITS RIO GRANDE POWER PLANT UNIT 7 AND NEWMAN POWER PLANT UNIT 1 **EL PASO ELECTRIC COMPANY, Applicant.**	**Case No. 23-00___-UT**

EL PASO ELECTRIC COMPANY'S APPLICATION FOR APPROVAL OF ABANDONMENT OF ITS RIO GRANDE POWER PLANT UNIT 7 AND NEWMAN POWER PLANT UNIT 1

El Paso Electric Company ("EPE" or "Company"), pursuant to NMSA 1978, § 62-9-5, hereby files with the New Mexico Public Regulation Commission ("NMPRC" or "Commission") this Application for Approval of Abandonment of its Rio Grande Power Plant Unit 7 and Newman Power Plant Unit 1 ("Application"), which seeks all necessary regulatory approvals for EPE to abandon its Rio Grande Power Plant Unit 7 ("RG 7" or "Rio Grande Unit 7") and its Newman Power Plant Unit 1 (“NM 1” or “Newman 1”) (collectively RG 7 and NM 1 are referred to as the “Units”). EPE seeks authorization to abandon the Units effective January 1, 2026, subject to confirmation by EPE that it has a sufficient planning reserve margin in place. In support of this Application, EPE states the following:

SUPPORT FOR APPLICATION

1. EPE is certified and authorized to conduct the business of providing public utility service within the State of New Mexico and is a public utility subject to the jurisdiction of the Commission under the New Mexico Public Utility Act ("PUA").

2. EPE generates, transmits and distributes electricity through an interconnected system to customers in southern New Mexico and Texas. EPE owns, operates, leases or controls the plant, property and facilities used by it for the generation, transmission, distribution, sale or furnishing of electricity to or for the public within New Mexico and Texas. EPE provides retail electric service to over 100,000 customers within its New Mexico service area.

3. EPE's principal business address and telephone number for its New Mexico service area are:

El Paso Electric Company
100 N. Stanton Street
El Paso, Texas 79901
(915) 543-5711

4. RG 7 is a natural gas-fired Babcock and Wilcox-El Paso design boiler. The steam turbine was manufactured by General Electric with a nameplate capacity of 50 MWs. RG 7 was commissioned in 1958.

5. NM 1 is also a natural gas-fired Babcock and Wilcox-El Paso design boiler. The steam turbine was manufactured by Allis Chalmers with a nameplate capacity of 81.6 MWs. NM 1 was commissioned in 1960.

6. Section 62-9-5 provides that the Commission may approve abandonment of a utility facility if the present and future public convenience and necessity do not otherwise require the continued use of the facility. The Commission has held that there must be a showing of a net benefit in order to approve a utility plant's abandonment.

7. Historically, the Commission has been guided by the four-factor test set out in *Commuters' Committee v. Pennsylvania Public Utility Commission*, 88 A.2d 420, 424 (Pa. Super. Ct. 1952) and adopted by the New Mexico Supreme Court in *Public Service*

Company of N.M. v. N.M. Public Service Commission, 1991-NMSC-083, 112 N.M. 379 in determining if an abandonment results in a net benefit. These factors examine: (1) the extent of the utility's loss on the particular service and the relation of that loss to the utility's operation as a whole; (2) the use of the service by the public and prospects for future use; (3) a balancing of the utility's loss with the inconvenience and hardship to the public upon discontinuance of service; and (4) the availability and adequacy of substitute service.

8. EPE's testimonies and exhibits provide substantial factual evidence that abandonment of RG 7 and NM 1 is in the public interest under New Mexico law and the *Commuters' Committee* factors, including that:

a. RG 7 and NM 1 have been part of EPE's local generation fleet since 1958 and 1960, respectively, and are the oldest and least efficient units in EPE's fleet.

b. RG 7 and NM 1 are past the end of their useful lives, and the continued operation of the Units is not required to reliably serve New Mexico customers.

c. The Units are no longer suitable for service in a reliable and safe manner without extensive evaluation and investment.

d. EPE's analysis shows that extending the life of the Units will cost over $20,000,000 for each unit, and there are other more cost effective resources available.

e. The Units are not equipped with pollution control for nitric oxide or carbon monoxide. Therefore, abandoning the Units will have significant environmental benefits.

f. In light of approved new resources, EPE anticipates it will have adequate electrical supplies and facilities to continue to provide reliable service to its customers. To prevent potential shortfalls, EPE proposes that abandonment be contingent on EPE confirming to the Commission prior to abandonment that it has sufficient planning reserve margin in place.

g. EPE is not seeking any relief related to rates or the cost of service in this proceeding. Instead, EPE will address rate-related issues in its next base rate proceeding following this proceeding.

h. Abandonment at this time is in the public interest.

9. EPE's Application is supported by the pre-filed direct testimony and exhibits of James Schichtl, Vice President of Regulatory and Governmental Affairs; David Hawkins, Vice President of Systems Operations and Resource Strategy; and J. Kyle Olson, Director of Power Generation and Asset Management.

> James Schichtl addresses statutory and regulatory requirements for abandonment and the current regulatory treatment of the units which EPE proposes to abandon. He explains that EPE is seeking no rate treatment associated with the proposed abandonments at this time.
>
> David Hawkins addresses how the proposed abandonment supports and is consistent with EPE's long-term generation resource planning. He also addresses the findings of EPE's life extension analyses that it is uneconomic to further extend the life of RG 7 and NM 1.
>
> J. Kyle Olson addresses the physical condition of the Units, as well as the relevant operational considerations and concerns, in light of the proposed abandonment.

10. Service of all notices, pleadings and other documents related to this Application should be made as follows:

Tania Reichsfeld Regulatory Case Manager El Paso Electric Company 100 N. Stanton Street El Paso, Texas 79901 (915) 543-5727	Jeffrey J. Wechsler Kari E. Olson Montgomery & Andrews. P.A. Post Office Box 2307 Santa Fe, New Mexico 87504-2307 (505) 982-3873

11. Electronic service should be made as follows:

tania.reichsfeld@epelectric.com;
EPE_Reg_Mgmt@epelectric.com;
jwechsler@montand.com;
kolson@montand.com
nancy.burns@epelectric.com;
tpacheco@montand.com; and
partricia.griego@epelectric.com.

12. As indicated on the Certificate of Service attached hereto, EPE has emailed a copy of its Application and supporting Direct Testimonies and Exhibits to parties to EPE's most recent general rate case (NMPRC Case No. 20-00104-UT). EPE's proposed form of Notice is also attached hereto as Attachment A.

WHEREFORE, EPE respectfully requests that the Commission, after such notice and hearing as it deems necessary, issue a Final Order in this case that:

A) Approves abandonment of RG 7 and NM 1 effective January 1, 2026, subject to confirmation by EPE in December 2025 that it has sufficient planning reserve margin; and

B) Grants such other approvals, authorizations and relief as may be necessary or appropriate.

Respectfully submitted,

Nancy B. Burns
Deputy General Counsel
New México Bar No. 7538
El Paso Electric Company
300 Galisteo Street, Suite 206
Santa Fe, New Mexico 87501
Telephone (505) 982-4713
nancy.burns@epelectric.com

MONTGOMERY & ANDREWS, P.A.

/s/Jeffrey J. Wechsler

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ATTORNEYS FOR
EL PASO ELECTRIC COMPANY

EXHIBIT A

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF EL PASO ELECTRIC COMPANY FOR APPROVAL OF ABANDONMENT OF ITS RIO GRANDE POWER PLANT UNIT 7 AND NEWMAN POWER PLANT UNIT 1 **EL PASO ELECTRIC COMPANY, Applicant.**	**Case No. 23-00___-UT**

PROPOSED FORM OF NOTICE

NOTICE is hereby given of the following matters pertaining to the above captioned case pending before the New Mexico Public Regulation Commission ("Commission" or "NMPRC"):

1. In accordance with the Public Utility Act ("PUA"), NMSA 1978, § 62-9-5, on October 6, 2020, El Paso Electric Company ("EPE") filed an Application and Supporting Direct Testimony with the Commission requesting that the Commission enter an order authorizing EPE to abandon its Rio Grande Power Plant Unit 7 ("RG 7" or "Rio Grande Unit 7") and its Newman Power Plant Unit 1 ("NM 1" or "Newman 1") effective January 1, 2026.

2. EPE's Application states that: (a) RG 7 and NM 1 are past the end of their useful lives; (b) the present and future public convenience and necessity do not require the service or use of RG 7 and NM 1, and (c) EPE is not seeking any relief related to rates in this proceeding.

3. The Commission has assigned Case No. 23-_____-UT to this Application, and all correspondence, pleadings, comments, inquiries and other communications shall refer to that case number.

4. EPE is certified and authorized to conduct the business of providing public utility service within the State of New Mexico, and is a public utility subject to the jurisdiction of the Commission under the PUA. Interested persons may examine the Application and the pre-filed testimonies, exhibits, pleadings and other documents filed in the case online at http://nmprc/state.nm.us under "Case Lookup Edocket", or by making arrangements for an in-person viewing at the Commission offices by calling 1-505-827-6968 during normal business hours, or at EPE's offices, 201 N. Water, Las Cruces, New Mexico, telephone number (575) 526-5551, or at EPE's website http://epelectric.com. All inquiries or written comments concerning this matter should refer to Case No. 23-_____-UT.

5. The procedural schedule established in this case is as follows:

(A) Pursuant to 17.1.2.26 NMAC, any person desiring to intervene in this proceeding must file a Motion for Leave to Intervene on or before _________, 2024;

(B) The Commission Staff shall, and any Intervenors may, file Direct Testimony on or before _________, 2024;

(C) Rebuttal Testimony may be filed on or before ________, 2024;

(D) A public hearing shall be held beginning on _________, 2024, commencing at ____a.m. M.T. and shall continue as necessary through _____, 2024. The hearing will be held either in person at a location to be determined, or via the Zoom platform in whole or in part. The hearing will be held to hear and receive testimony, exhibits, arguments, and any other appropriate matters pertaining to the case; and

(E) A prehearing shall be held at ___a.m., on ______, 2024. The prehearing will be held either (i) in person at a location to be determined; or via the Zoom platform in whole or in part.

The procedural dates and requirement provided herein are subject to further order of the Commission or Hearing Examiner. The Commission's Rules of Practice and Procedure, 1.1.2 NMAC, apply to this case except as modified by Order of the Commission or Hearing Examiner. The Rules of Procedure are available online at http://164.64.110.134/nmac/home.

6. Interested persons who are not affiliated with a party may submit written or oral comments pursuant to Rule 1.2.2.23(F) NMAC. Oral comments shall be taken at the beginning of the public hearing on ______, 2024, and shall be limited to 3 minutes per commenter. Persons wishing to make an oral comment must register in advance no later than 8:30 am MT on ______, 2024 by e-mailing Ana Kippenbrock at ana.kippenbrock@prc.nm.gov. Written comments may also be submitted before the Commission takes final action by sending the comment, which shall reference Case No. 23-_____-UT, to prc.records@prc.nm.gov. Pursuant to 1.2.2.23(F) NMAC, written and oral comments shall not be considered evidence.

7. Anyone filing pleadings, documents, or testimony in this case shall serve copies thereof on all parties of record and Staff via email. Any such filings shall also be sent to the Hearing Examiner by email at ______________________________. All pleadings shall be emailed on the date they are filed with the Commission.

8. Any person whose testimony has been filed will attend the hearing and submit to examination under oath.

9. Any interested person should contact the Commission by e-mail at ana.kippenbrock@prc.nm.gov or by phone at (505) 690-4191 for confirmation of the hearing date, time, and place since hearings are occasionally rescheduled.

10. Any person with a disability requiring special assistance to participate in this proceeding should contact the Commission at 1-888-427-5772 at least 24 hours prior to the hearing.

ISSUED at Santa Fe, New Mexico, this _____ day of ________, 2024.

NEW MEXICO PUBLIC REGULATION COMMISSION

____

Hearing Examiner

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF EL PASO ELECTRIC COMPANY FOR APPROVAL OF ABANDONMENT OF ITS RIO GRANDE POWER PLANT UNIT 7 AND NEWMAN POWER PLANT UNIT 1 EL PASO ELECTRIC COMPANY, Applicant.	)))))))))	Case No. 23-00___-UT

DIRECT TESTIMONY

OF

JAMES SCHICHTL

ON BEHALF OF

EL PASO ELECTRIC COMPANY

DECEMBER 5, 2023

EL PASO ELECTRIC COMPANY
DIRECT TESTIMONY OF
JAMES SCHICHTL

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EL PASO ELECTRIC COMPANY
DIRECT TESTIMONY OF
JAMES SCHICHTL

I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is James Schichtl. My business address is 100 North Stanton Street, El Paso, Texas, 79901.

Q2. HOW ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE") as Vice President of Regulatory and Governmental Affairs.

Q3. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND AND EXPERIENCE.

A. I have been employed by EPE since February 2012. I started at EPE as a Senior Regulatory Case Manager, responsible for the production, filing, and execution of regulatory applications before both the Public Utility Commission of Texas ("PUCT") and the New Mexico Public Regulation Commission ("NMPRC" or "Commission"). After that, I became Manager of EPE's Economic & Rate Research group, responsible for EPE's jurisdictional cost of service, rate design analysis, and developing EPE's retail rate schedules and charges. I then became Director of Regulatory Affairs, and in June 2016, I was promoted from Director of Regulatory Affairs to Vice President and was assigned additional responsibility for Governmental Affairs in 2020. I describe my responsibilities as Vice President of Regulatory and Governmental Affairs below.

Prior to joining EPE in February 2012, I spent 18 years in various regulatory functions at Southern California Edison Company ("SCE"), twelve of those in a managerial capacity. As Manager of Pricing Design and Research, I was responsible for SCE's rates and tariffs during deregulation and changes required in following the California power crisis in 2001. I was subsequently promoted to Manager of Tariffs and Advice Letters, with broad responsibility within regulatory for evaluating California statute, rules, and regulations and managing regulatory efforts at the California Public Utilities Commission ("CPUC"). Those efforts included significant involvement in the transition back to a deregulated generation market as well as significant expansion of distributed generation in California.

I graduated with a Bachelor of Science in Mechanical Engineering in 1987 from The University of Texas at El Paso, where I also studied economics and econometrics. Throughout my career at EPE, I have attended and presented material for numerous seminars and workshops related to cost of service, rate and program design, and regulation.

Q4. PLEASE DESCRIBE YOUR PRINCIPAL AREAS OF RESPONSIBILITY.

A. As Vice President of Regulatory and Governmental Affairs, I am responsible for the oversight and direction of EPE's Economic Research, Rate Research, and Regulatory Case Management groups, as well as EPE's Governmental Affairs organization. Economic Research performs load research and analysis and forecasting functions. Rate Research encompasses EPE's rate research function, jurisdictional and class cost of service studies, rate design analysis, and the development of retail rate schedules and charges. The Regulatory Case Management group coordinates and oversees regulatory filings made by EPE with the PUCT, NMPRC, the Federal Energy Regulatory Commission ("FERC"), and local municipal regulators. Governmental Affairs manages external relations and communications with regulatory authorities, local municipalities, elected officials, community and special interest groups and other stakeholders. The group also oversees and directs EPE's participation in and interests regarding state and federal legislative initiatives. My job duties require knowledge of the statutory and regulatory requirements of each jurisdiction.

Q5. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE ANY REGULATORY AGENCY?

A. Yes. I have testified on behalf of EPE in cases before the NMPRC and the PUCT.

I have also presented testimony and testified before FERC and the CPUC.

Q6. ARE YOU SPONSORING EXHIBITS TO YOUR TESTIMONY?

A. No, I am not.

II. PURPOSE OF TESTIMONY AND RECOMMENDATIONS

Q7. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony supports EPE's Application to Abandon Rio Grande Unit 7 ("RG7") and Newman Power Station Unit 1 (NM1") ("Application"). I address statutory and regulatory requirements for abandonment and the current regulatory treatment of RG7 and NM1. I explain that costs associated with these generating units are currently included in EPE's rates pursuant to the Commission's Final Order in EPE's last general rate case, Case No. 20-00104-UT, effective June 2021, and that EPE is seeking no rate treatment associated with the proposed abandonments at this time. I also introduce the other EPE witnesses presenting supporting testimony in this case.

Q8. WHAT SPECIFIC APPROVAL IS REQUESTED BY EPE IN THIS APPLICATION?

A. EPE is requesting Commission approval to abandon RG7 and NM1 after EPE's 2025 summer peak season pursuant to NMSA 1978, § 62-9-5 (2005) ─ Abandonment of Service. No further operation of RG7 and NM1 will occur after the effective date of abandonment approved by the Commission.

Q9. WHAT IS YOUR RECOMMENDATION IN THIS CASE?

A. I recommend the Commission approve EPE's request to abandon RG7 and NM1 effective January 1, 2026, as consistent with the present and future public interest, with the final timing contingent on future resource adequacy. EPE's direct testimony supporting the Application demonstrates that continued operation of RG7 and NM1 after the abandonment date is not required for EPE to continue to provide, safe, reliable and economic service to customers. The abandonment of these units will benefit customers economically by permanently removing two of EPE's oldest and least-efficient gas-fired generation units from service. In addition, the abandonment of RG7 and NM1 will maintain the environmental benefits obtained through retirement for customers and the region by permanently eliminating associated excess pollution and water use. As EPE demonstrates in this Application, with the addition of new resources over the next several years EPE will have sufficient operating reserves to reliably serve its growing retail load after the abandonment of RG7 and NM1.

Q10. WHAT OTHER EPE WITNESSES ARE PRESENTING TESTIMONY ON BEHALF OF EPE IN THIS CASE?

A. David Hawkins, EPE's Vice President of System Operations and Resource Strategy addresses how the proposed abandonments support and are consistent with EPE's long-term generation resource planning, and that the proposed timing for abandonment coincides with the availability of new generation resource additions to EPE's portfolio and expected load growth. Mr. Hawkins also discuss the findings of EPE's life extension analyses associated with the unit abandonments.

Kyle Olson, Director of Power Generation and Asset Management, discusses the operational history and current physical condition of RG7 and NM1, as well as relevant operational considerations associated with any ongoing operation of these units and which support abandonment as proposed.

III. REGULATORY STANDARD FOR ABANDONMENT OF RIO GRANDE UNIT 7 AND NEWMAN UNIT 1

Q11. WHAT STATUTORY PROVISIONS APPLY TO THE ABANDONMENT OF GENERATION RESOURCES?

A. Abandonment of Service is addressed in NMSA 1978, § 62-9-5. The statute states that:

> "[n]o utility shall abandon all or any portion of its facilities subject to the jurisdiction of the commission, or any service rendered by means of such facilities, without first obtaining the permission and approval of the commission. The commission shall grant such permission and approval, after notice and hearing, upon finding that the continuation of service is unwarranted or that the present and future public convenience and necessity do not otherwise require the continuation of the service or use of the facility; provided, however, that ordinary discontinuance of service or use of facilities for nonpayment of charges, nonuser or other reasons in the usual course of business shall not be considered as abandonment. In considering the present and future public convenience and necessity, the commission shall specifically consider the impact of the proposed abandonment of service on all consumers served in this state, directly or indirectly, by the facilities sought to be abandoned.

Q12. DOES EPE'S APPLICATION MEET THIS REQUIREMENT?

A. Yes. EPE's testimony and exhibits demonstrate that the present and future public convenience and necessity do not require the continuation of the service or use of RG7 and NM1 after the proposed abandonment date. In fact, abandonment of the facilities will maintain and expand the benefits that have already accrued to customers and the region as a result of EPE's retirement and pending abandonment of RG6 and the limited use of that unit for contingency purposes until abandoned. I also address the Commission's Commuter Committee factors.

Q13. IS OPERATIONAL USE OF RIO GRANDE UNIT 7 AND NEWMAN UNIT 1 BEING DISCONTINUED IN THE NORMAL COURSE OF BUSINESS?

A. Yes, RG7 and NM1 will be 67 and 65 years old, respectively, at the time of formal abandonment which is well past their expected useful lives. Prior to abandonment EPE expects the units will have been retired from regular service, moved to Inactive Reserve[1] status and maintained for contingency purposes for summer peak demand service. Abandonment as requested is in the normal course of business for steam generation units that are well past their useful lives and where generation capacity from the units is not needed to serve load or for reserve requirements.

Q14. WHY IS EPE FILING ITS APPLICATION AT THIS TIME?

A. As explained in more detail by EPE witness Hawkins, the Company has consistently planned to retire and abandon these units and has reflected as such in EPE's 2021 and 2022 Loads and Resources Documents ("L&Rs"). The planned retirements are also reflected in EPE's 2021 IRP filed in NMPRC Case No. 21-00242-UT, which was accepted on December 8, 2021. As Mr. Olson discusses in his testimony, RG7 and NM1 are the oldest operating generation units in EPE's portfolio and abandonment as proposed by EPE is consistent with the end of their useful operational lives. In addition, the timing for final

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[1] "Inactive Reserve" status is defined by NERC as a state in which the work involved in bringing the unit into active operation is measured in hours or days.

abandonment of the units coincides with significant new resource additions that are coming into commercial operation prior to the planned abandonment date of January 2026. Finally, as Mr. Hawkins testifies, EPE agreed to file for abandonment of the units to facilitate the Texas Commission on Environmental Quality's approval of EPE's air permit application required for the addition of a new combustion turbine, Newman Unit 6 ("NM6"). EPE is required to file for abandonment of RG7 and NM1 before commercial operation of the new unit, which is now expected to commence December 2023.

Q15. WOULD EPE FILE FOR ABANDONMENT OF RIO GRANDE UNIT 7 AND NEWMAN UNIT 1 ABSENT ITS AGREEMENT TO DO SO AS PART OF THE NM6 APPROVAL?

A. Yes. As EPE supports in testimony, these two units are among the oldest in the EPE generation fleet and the least efficient units operating. They require an increasing investment in dollars and maintenance to keep running and EPE has procured resources to replace them. The agreement to file for abandonment coincident with NM6 COD is simply one factor affecting the timing of this application, not a determinant regarding abandonment.

Q16. IS ABANDONMENT OF RIO GRANDE UNIT 7 AND NEWMAN UNIT 1

CONTINGENT UPON NEW RESOURCE ADEQUACY OR ARE THERE OTHER FACTORS THAT CAN AFFECT THE TIMING?

A. The critical factor related to permanent removal of a generation unit from service is operating reserve margin during the summer peak season. As discussed by Mr. Hawkins, EPE plans for the abandonment and addition of generation resources in its annual resource planning and loads and resources analysis, where the primary measure is planning reserve margin – the capacity of generation available to serve peak demand in excess of expected need based on forecasted customer demand. During the year, the operating reserve margin reflects actual customer demand and real-time availability of resources. In addition to new resources, the availability (or unavailability) of existing generating resources and customer load that exceeds forecasted demand are factors that can determine the ultimate timing of abandonment.

IV. <u>FACTORS TO BE EVALUATED IN ABANDONMENT</u>

Q17. WHAT FACTORS DOES THE COMMISSION USE TO EVALUATE THE ABANDONMENT OF A UTILITY OWNED RESOURCE?

A. Statute requires that the Commission find that the requested abandonment is consistent with the present and future public convenience and necessity and is in the best interest of the public. To comply with this factual showing, and in the absence of more specific guidance, I understand the Commission has previously employed a totality of the circumstances approach using the *Commuters' Committee* factors. These factors are:

- extent of the utility's loss on the particular service and relation of that loss to the utility's operation as a whole;
- use of the service by the public and prospects for future use;
- balancing of the utility's loss with inconvenience and hardship to the public upon discontinuance of service; and
- availability and adequacy of substitute service.

Q18. IS THE ABANDONMENT OF RIO GRANDE UNIT 7 AND NEWMAN UNIT 1 CONSISTENT WITH THESE FACTORS?

A. Yes, given the totality of the circumstances. Although each factor may not be directly applicable in the present case because the units will already be retired for operational purposes, the abandonment of RG7 and NM1 is consistent with the public interest.

Q19. REGARDNG THE FIRST OF THE *COMMUTERS' COMMITTEE* FACTORS, HOW WILL EPE SUFFER FINANCIAL HARM IF ABANDONMENT OF RIO GRANDE UNIT 7 AND NEWMAN UNIT 1 IS

NOT ALLOWED?

A. If the units are not approved for abandonment as proposed and, alternatively, overhauled and retained in active service, significant additional costs will be imposed on EPE that are not currently included in base rates. As EPE witness Olson explains in his testimony, the age of the units puts them at risk for failure without extensive evaluation and investment, irrespective of near-term maintenance. Such an alternative would also result in financial impacts to customers, as EPE would seek to include both current operating costs and investment costs necessary to bring RG7 and/or NM1 up to reliability standards in base rates with limited offsetting benefits. Continued reliance on RG7 and NM1 also introduces the risk of outages and increased replacement power costs if the units fail.

Q20. WITH RESPECT TO THE SECOND OF THE *COMMUTERS' COMMITTEE* FACTORS, WHY ARE RIO GRANDE UNIT 7 AND NEWMAN UNIT 1 NO LONGER NEEDED TO SERVE EPE'S CUSTOMERS?

A. RG7 and NM1 have been part of EPE's local generation fleet since 1958 and

1960, respectively, and are the oldest and least efficient units in EPE's fleet.[2] As discussed by EPE witness Olson, RG7 and NM1 capacity and load serving responsibilities are being replaced by new generation when EPE places NM6 service in 2023, and with the commercial operation of the Buena Vista and other solar generation resources in 2023 and 2025, respectively. NM6 and the solar facilities fully offset the nameplate capacity of RG7 and NM1 in load serving capability. NM6 is also more efficient than RG7 and NM1 and its quick start and load ramping capability allows for better integration of renewable resources.

Q21. REGARDING THE THIRD OF THE *COMMUTERS' COMMITTEE* FACTORS, WHAT IS THE BALANCE OF EPE'S LOSS WITH ANY INCONVENIENCE OR HARDSHIP TO THE PUBLIC RESULTING FROM THE ABANDOMENT OF THE PLANT?

A. There will be no inconvenience or hardship to the public resulting from the abandonment of RG7 and NM1. To the contrary, hardship for the public would result from the continued operation of RG7 and NM1 if abandonment is not granted. As discussed by EPE witness Hawkins, EPE has performed unit life extension analyses that demonstrate that the provision of service through the

[2] EPE's oldest operating unit, Rio Grande Unit 6, was placed into Inactive Reserve in 2015, and abandoned in Case No. 02-00194-UT.

recommissioning and continued operation of RG7 and NM1 at 5-year and 15-year extensions would be an uneconomic alternative for EPE's customers. Conversely, the Company currently incurs, at a financial loss, the increasing non-fuel operation and maintenance costs and risks from maintaining these units for contingency purposes. The probability of public inconvenience or hardship associated with RG7 and NM1 actually increases with delay of their abandonment, as continued operation of the units increases the likelihood of unit outages or catastrophic failure.

Q22. REGARDING THE FOURTH *COMMUTERS' COMMITTEE* FACTOR, IS SUBSTITUTE SERVICE NEEDED IF ABANDONMENT IS AUTHORIZED?

A. No. As discussed by EPE witness Olson, with the addition of new resources and reliable operation of existing generation, EPE will have adequate electrical supplies and facilities to assure it continues to provide reliable service to growing customer load into the future without RG7 and NM1.

Q23. CONSIDERING ALL FACTORS, DOES THE PUBLIC INTEREST REQUIRE CONTINUING USE OF RG7 AND NM1 BY EPE'S CUSTOMERS?

A. No, the public interest is best served by the abandonment of these old generating unit. Continued operation of RG7 and NM1, if even feasible from a technical perspective, would essentially erase the reliability, economic and environmental benefits that customers will realize with abandonment.

Q24. WILL EPE'S CUSTOMERS BENEFIT FROM COMMISSION APPROVAL OF THE ABANDONMENT OF RG7 AND NM1?

A. Yes. Not only will customers avoid the continuing costs associated overhauling and operating RG7 and NM1, but approval for abandonment will also eliminate all risks associated with potential future operation of the units.

V. COST OF SERVICE IMPACTS OF ABANDONMENT OF RIO GRANDE UNIT 7 AND NEWMAN UNIT 1

Q25. WHAT IS THE COST-OF-SERVICE IMPACT OF THE ABANDONMENT OF RG7 AND NM1?

A. Costs associated with generating units RG7 and NM1 are currently included in New Mexico base rates, as approved in the NMPRC's Final Order in Case No. 20-00104-UT. The tables below show net plant balances for the two units as of December 2019, the end of the test year in that case.

Rio Grande Unit 7

Electric Plant	Accumulated Depreciation	Net Plant
$12,787,903	($12,535,898)	$252,004

Newman Unit 1

Electric Plant	Accumulated Depreciation	Net Plant
$27,839,332	($24,359,018)	$3,480,315

In the first base rate proceeding following the abandonment of RG7 and NM1, EPE will remove the net plant balances and O&M expense associated with each unit from the total Company cost of service used to develop jurisdictional costs for New Mexico retail customers. Since retail rates were last set in EPE's 2020 rate case, plant balances have changed to reflect capital additions and provision for accumulated depreciation.

Q26. WHAT ARE THE EXPECTED PLANT BALANCES FOR THE TWO UNITS AT THE TIME OF ABANDONMENT?

A. EPE estimates, based on current rates of depreciation and actual capital investment in the units since the end of 2019, the two units will have the plant balances shown in the tables below at the end of 2025.

Rio Grande Unit 7

Electric Plant	Accumulated Depreciation	Net Plant
$15,850,755	($13,246,473)	$2,604,282

Newman Unit 1

Electric Plant	Accumulated Depreciation	Net Plant
$29,993,912	($30,116,766)	$(122,854)

Q27. ASSUMING A POSITIVE NET PLANT BALANCE FOR RG7 AT THE TIME OF ABANDONMENT, WOULD EPE EXPECT TO REQUEST STRANDED COST RECOVERY FOR THE ACTUAL AMOUNT IN IT'S NEXT BASE RATE PROCEEDING?

A. Yes.

Q28. SHOULD THE NEGATIVE NET BOOK VALUE EXPECTED FOR NM1 BE CHARGED TO COST OF SERVICE?

A. No. EPE's depreciation of NM1 provides for costs associated with physically dismantling and removing the plant upon its retirement from service. The negative book value reflects the depreciation reserve required to offset the future cost of removal of the unit from service.

VI. SUMMARY AND CONCLUSION

Q29. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Approval of EPE's Application for abandonment of RG7 and NM1 is consistent with the present and future public interest, satisfies all statutory requirements, and is consistent with the *Commuters' Committee* factors previously considered by the Commission in abandonment proceedings. EPE's testimony demonstrates that continued use of RG7 and NM1 is not required for EPE to provide, safe, reliable, and economic service to customers. As the result of consistent and careful resource planning, adequate generation resources will exist such that load serving capability and reserves are not impacted by the permanent removal from operations of RG7 and NM1. The abandonment of the units will benefit customers economically by permanently removing EPE's oldest and least-efficient gas-fired generation units from service to New Mexico customers.

Q30. HOW WOULD EPE'S PROPOSAL WORK PROCEDURALLY?

A. EPE proposes that the Commission approve abandonment of the Units effective January 1, 2026, conditioned as follows. If the data on loads and resources in the future indicate that EPE will not have sufficient resources to meet its operating reserve margin, then EPE will file a notice no later than November 1, 2025, updating and informing the Commission. In that event, abandonment would be postponed until January 1, 2027, subject again to the same condition. If EPE does not file a subsequent notice by November 1, 2026 then the abandonment will take effect as scheduled on January 1, 2027.

Q31. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF EL PASO ELECTRIC COMPANY FOR APPROVAL OF ABANDONMENT OF ITS RIO GRANDE POWER PLANT UNIT 7 AND NEWMAN POWER PLANT UNIT 1 **EL PASO ELECTRIC COMPANY,** **Applicant.**	**Case No. 23-00___-UT**

DECLARATION OF JAMES SCHICHTL IN SUPPORT OF THE FOREGOING DIRECT TESTIMONY TO THE APPLICATION OF EL PASO ELECTRIC COMPANY FOR APPROVAL OF ABANDONMENT

I ***James Schichtl***, pursuant to Rule 1-011 NMRA, state as follows:

1. I affirm in writing under penalty of perjury under the laws of the State of New Mexico that the following statements are true and correct.

2. I am over 18 years of age and have personal knowledge of the facts stated herein. I am employed by El Paso Electric Company ("EPE" or "the Company") as *Vice President of Regulatory and Governmental Affairs.*

3. The foregoing Direct Testimony of James Schichtl, together with all exhibits sponsored therein and attached thereto, is true and accurate based on my knowledge and belief.

4. I submit this Declaration, based upon my personal knowledge and upon information and belief, in support of EPE's ***Application for Approval Abandonment.***

FURTHER, DECLARANT SAYETH NAUGHT.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on December 1, 2023.

/s/ James Schichtl
JAMES SCHICHTL

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF EL PASO ELECTRIC COMPANY FOR APPROVAL OF ABANDONMENT OF ITS RIO GRANDE POWER PLANT UNIT 7 AND NEWMAN POWER PLANT UNIT 1 EL PASO ELECTRIC COMPANY, Applicant.	)))))))))	Case No. 23-00___-UT

DIRECT TESTIMONY

OF

DAVID C. HAWKINS

ON BEHALF OF

EL PASO ELECTRIC COMPANY

DECEMBER 5, 2023

EL PASO ELECTRIC COMPANY
DIRECT TESTIMONY OF
DAVID C. HAWKINS

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EL PASO ELECTRIC COMPANY
DIRECT TESTIMONY OF
DAVID C. HAWKINS

I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David C. Hawkins. My business address is El Paso Electric Company, P.O. Box 982, El Paso, Texas 79960.

Q2. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE" or "the Company") as Vice President of System Operations and Resource Strategy.

Q3. PLEASE DESCRIBE YOUR BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold a Master of Science degree and a Bachelor of Science degree in Electrical Engineering from New Mexico State University. I have been with EPE since 2002, where I have held various positions including Vice President of Generation, System Planning and Dispatch and Vice President of Power Marketing, Fuels and Resource Planning. Before joining EPE, I served as a Wholesale Power Marketing Analyst at Public Service Company of New Mexico ("PNM").

Q4. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES AS VICE PRESIDENT OF SYSTEM OPERATIONS AND RESOURCE STRATEGY.

A. I am responsible for the oversight and direction of EPE's System Operations, Resource Management, Resource Planning, Environmental, Western Market Development, and Enterprise Advanced Analytics groups. These departments are responsible for grid reliability, meeting EPE's future jurisdictional resource requirements and required regulatory support, optimizing the dispatch of EPE's gas-fired generation fleet though fuel procurement and wholesale power transactions, compliance with related NERC standards, resource planning, monitoring EPE's water and air emissions for regulatory compliance, EPE's involvement in future organized western markets, and advanced analytics and business improvement for company processes.

Q5. HAVE YOU PRESENTED TESTIMONY BEFORE UTILITY REGULATORY BODIES?

A. Yes. I have presented testimony before the New Mexico Public Regulation Commission ("NMPRC" or "Commission"), Public Utility Commission of Texas ("PUCT") and Federal Energy Regulatory Commission.

II. <u>PURPOSE AND SUMMARY OF TESTIMONY AND RECOMMENDATIONS</u>

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My Direct Testimony supports EPE's request to abandon its Rio Grande Unit 7 ("RG7") and Newman Unit 1 ("NM1") (collectively the "Units"). Specifically, I address how the proposed abandonment of the Units is consistent with EPE's long-term generation resource planning. I also discuss the findings of EPE's life extension analyses for the Units.

Q7. PLEASE SUMMARIZE THE MAIN POINTS OF YOUR DIRECT TESTIMONY.

A. EPE's proposal to abandon RG7 and NM1 is consistent with EPE's long-term generation resource planning as reflected in EPE's Commission-accepted 2021 Integrated Resource Plan ("2021 IRP"). EPE anticipates that additional resources that have or will come online through 2025 will act as replacement energy for the Units being abandoned and will contribute to EPE achieving its reserve margin targets. Once those planned resource additions are in commercial operation, and assuming reserve margins are adequate, the continued operation of the Units are not expected to be required to serve customers. Recent life extension analyses of RG7 (Exhibit DCH-5) and NM1 (Exhibit DCH-6) conducted by Burns & McDonnell ("BMcD") in 2018 ("2018 BMcD Study") and an updated analysis conducted by EPE in 2021 (Exhibit DCH-4) in conjunction with its 2021 IRP found the Units do not offer cost-effective capacity to serve current and future load. Coupled with the additional reasons justifying abandonment offered by EPE witness Kyle Olson, I recommend that the Commission authorize EPE to abandon RG7 and NM1 subject to EPE having sufficient resources to meet its reserve margin. More specifically, EPE is requesting that the Commission authorize abandonment of RG7 and NM1 in January of 2026, subject to EPE confirming that it has adequate system planning reserve requirements to reliably serve EPE's jurisdictional load obligations. EPE witness Mr. Schichtl will describe how this will work procedurally.

Q8. DO THESE UNITS OFFER COST EFFECTIVE CAPACITY FOR EPE'S CUSTOMERS?

A. No. The aforementioned life extension analyses evaluation of new resources for its New Mexico and Texas Customers shows that the Units do not offer cost effective capacity. That conclusion was confirmed by EPE's recent request for proposal processes ("RFPs") in New Mexico and Texas. An analysis of the costs of continuing to operate the Units versus the cost of adding alternative resources supports the plan to retire Rio Grande Unit 7 and Newman Unit 2 (as opposed to Unit 1).

Q9. PLEASE EXPLAIN WHY EPE IS APPLYING FOR THE ABANDOMENT OF NEWMAN UNIT 1 IF IT WAS NOT ORIGINALLY SELECTED FOR PLANNED RETIREMENT THROUGH THE RFP PROCESSES?

A. Following the RFPs, EPE conducted the further evaluation of life extension costs and operating characteristics of both Newman Units 1 and 2 that is discussed by

EPE witness Olson. That information led EPE to conduct additional analysis of retiring Newman Unit 1 in place of Newman Unit 2. Specifically, EPE evaluated the resource portfolio cost impact of substituting a life extension for Newman Unit 1 in place of Newman Unit 2. Taking into account the information discussed by Mr. Olson, EPE decided to seek abandonment for Newman Unit 1.

III. SUPPORT FOR THE ABANDONMENT OF RIO GRANDE UNIT 7 AND NEWMAN UNIT 1

Q10. PLEASE PROVIDE AN OVERVIEW OF THE RG7 AND NM1 GENERATING UNITS.

A. Table DCH-1 provides pertinent information about the Units.

Table DCH-1 Unit Retirements

Description	RG7	NM1
Location	Sunland Park, NM	El Paso, Texas
Type of Facility	Gas Steam Turbine	Gas Steam Turbine
Commercial Operation Date ("COD")	1958	1960
Net Capacity (Total Company)	46 MW	76 MW
Jurisdictional Allocation (New Mexico)	9 MW	15 MW
Expected Abandonment Date[1]	January 2026	January 2026
Age at Abandonment[2]	68 years	66 years

[1] El Paso Electric Company's 2021 IRP anticipated retiring Newman Unit 1 in December 2027 and Newman Unit 2 in December 2022.

[2] Expecting to fully abandon in 2026.

Q11. ARE THE PLANNED RETIREMENTS FOR RIO GRANDE UNIT 7 AND NEWMAN UNIT 1 UNITS REFLECTED IN ANY OF EPE'S PREVIOUS STUDIES OR ANALYSES?

A. Yes. As reflected in EPE's 2021 and 2023 Loads and Resources Documents ("L&Rs"), which are attached as Exhibits DCH-1 and DCH-2 to my Direct Testimony, respectively, the Company has consistently planned to retire these Units. The aforementioned retirements are also reflected in EPE's Commission-accepted 2021 IRP filed in NMPRC Case No. 21-00242-UT.

Q12. PLEASE DESCRIBE THE PLANNING PROCESSES THAT EPE USES TO DEVELOP ITS L&R DOCUMENT.

A. Through its ongoing planning processes, EPE compiles its supply, demand, and planning reserves information into its L&R document on an annual basis. The planning process begins with the development of its 20-year load forecast, together with consideration of planned retirements based in part on the age of existing generating resources, to assess resource needs in a 20-year planning horizon. The L&R document shows the balance or imbalance of EPE generating and purchased power resources versus expected loads and planning reserve criterion, assuming no new capacity is added. The planning reserve margin is necessary to reliably meet the resource needs of customers by taking into consideration transmission import constraints, operational risks of forced generation outages, and unforeseen load growth above the forecasts.

Q13. WHAT IS PLANNING RESERVE MARGIN?

A. Planning reserve margin is the capacity of firm resources above the projected annual firm peak demand necessary to support overall system reliability. Utilities have an obligation to serve and must maintain a positive reserve margin to help ensure service can continue upon the occurrence of certain events such as forced outages during peak times and unexpected increases in demand, which are often due to extremely hot summer conditions. The minimum amount of required planning reserves is determined by the utility's reserve margin criterion. The planning reserve margin is among the tools that utilities use to help plan their power supply system; specifically, to determine how much, if any, additional resources they need and by when.

Q14. WHEN DETERMINING EPE'S PLANNING RESERVE MARGIN, WERE ANY OTHER FACTORS CONSIDERED?

A. Yes. EPE evaluates whether acceptable system reliability will be maintained by modeling the effective load carrying capability ("ELCC") of each resource type and the system's loss of load expectation ("LOLE"). The ELCC method was used to assign capacity contribution toward reliability for each resource type, including the Company's existing gas, renewable, and nuclear resources. The ELCC method is an industry established metric appropriate for measuring resource adequacy contribution toward reliability, given the inherent variability and intermittency of renewable resources such as wind and solar. In addition, EPE implemented the 2-in-10 LOLE, i.e., two loss of load events every 10 years (i.e., 0.2 LOLE), reliability target through 2029 and phase into the industry standard of 1-in-10 LOLE, i.e., one loss of load event every 10 years, in 2030 to maintain best practices in system reliability planning.

Q15. IS EPE USING ANY SOFTWARE THAT UTILIZES THE ELCC AND LOLE METHODOLOGIES?

A. Yes. EPE is currently using PLEXOS which incorporates both methodologies.

Q16. WHAT IS PLEXOS?

A. PLEXOS is EPE's capacity expansion software that selects the lowest cost portfolio of resources from the modeled resources that can safely and reliably meet EPE's capacity needs. PLEXOS is a stochastic tool that runs thousands of Monte Carlo simulations over a multi-year horizon to determine various portfolios of resources that can safely meet EPE's reliability metric. At the same time, PLEXOS runs thousands of hourly dispatch iterations of multiple combinations of resources, keeping track of overall costs during the multi-year horizon, to ultimately select the lowest cost portfolio of resources. PLEXOS is becoming widely used by the electric utility industry for capacity expansion modeling. It is a powerful simulation engine and the best-in-class energy forecasting software, offering both flexible and precise simulations across several markets—electric, water, gas and renewable energy. PLEXOS is capable of modeling and analyzing renewable generation and battery storage resources in detail. It can analyze zonal and nodal energy models ranging from long term investment planning to medium-term operational planning and down to short term, hourly, and intra-hourly market simulations. PLEXOS can simulate time frames that range from as short as one minute up to tens of years. PLEXOS is also able to quickly optimize capacity expansion simulations and capable of running up to three studies simultaneously. In PLEXOS, reliability can be quantitatively parameterized using the LOLE and ELCC metrics.

Q17. WHAT IS EPE'S CURRENT PLANNING RESERVE MARGIN?

A. As mentioned above, EPE uses a 2-in-10 LOLE through 2029, which for EPE equates to a 10.1 percent planning reserve margin. The Company will phase in use of the industry standard of a 1-in-10 LOLE, which for EPE will equate to a 12.9 percent planning reserve margin, from 2030 forward. The Company is using this phasing-in approach to the 1-in-10 LOLE to allow sufficient time to adjust to the increased capacity needed, due to the use of the generating units' ELCC, to meet these planning reserve margins.

Q18. FOR PLANNING PURPOSES, WHEN DID EPE PLAN TO RETIRE RG7 AND NM1?

A. EPE originally planned to retire the Units in December 2022.

Q19. WHAT PURPOSE HAVE THE UNITS SERVED FOR EPE'S CUSTOMERS?

A. EPE has utilized RG7 and NM1 to meet load and peak demands as part of the Company's generating unit mix.

Q20. WHY HAS THE COMPANY NOT SOUGHT TO ABANDON THE UNITS AT AN EARLIER DATE?

A. The Company has experienced a substantial increase in load growth and has relied on the Units to meet load and operating reserve requirements.

Q21. DID THE SYSTEM PEAK LOAD THAT EPE EXPERIENCED IN 2023 REFLECT THE EXPECTED PEAK LOADS REFLECTED IN EXHIBITS DCH-1 AND DCH-2?

A. No. EPE experienced a system peak load of 2,384 MW in July 2023 which is closer to the expected system loads between the years 2028 and 2029.

Q22. GIVEN THE CONTINUOUS LOAD GROWTH, IS EPE COMFORTABLE ABANDONING THE UNITS IN 2026?

A. Yes, cautiously. As I explained above, EPE is expecting new resources to come online through 2025 to meet both its New Mexico and Texas jurisdictional load requirements, which will alleviate the need for the Units; however EPE will further address the proposed date of abandonment in the 2025 IRP process. In addition, EPE agreed to file for abandonment of the Units to facilitate the Texas Commission on Environmental Quality's approval of EPE's air permit application, which was required for the addition of a new combustion turbine, Newman Unit 6, that will provide electric service to EPE's Texas jurisdiction as described in Exhibit DCH-4.

Q23. PLEASE DESCRIBE THE ENVIRONMENTAL BENEFITS OF ABANDONING THESE UNITS.

A. Rio Grande Unit 7 (1958) and Newman Unit 1 (1960) came online before the Clean Air Act was first passed in 1970. Although the Units are subject to state and federal emission standards that are established to protect human health and the environment, the retiring Units are not equipped with pollution control for nitric oxide (NOx) and carbon monoxide (CO). NO_x and CO are criteria air pollutants that are controlled for in the combustion and emissions processes. The abandonment of these Units will secure the benefit of reduced NOx and CO compared to resources EPE has introduced as alternatives.

Q24. HAVE THE PLANNED RESOURCE RETIREMENTS THAT WERE IN PLACE SINCE EPE'S LAST ABANDONMENT FILING CHANGED IN ANY WAY?

A. Yes. As part of the Company's continuous and ongoing resource planning process in 2021 and 2022, it was determined to be in the best interests of EPE customers to plan to extend the retirement of Newman Unit 2 from December 2022 to December 2027. In essence, as discussed above, the retirement dates for NM1 and NM 2 were exchanged. In addition, the retirement dates for Newman Units 3 and 4 were also extended from 2026 to 2031.

Q25. WHY ARE THE CHANGES TO NM1 AND NM2'S RETIREMENT DATES NOT REFLECTED IN EPE'S 2021 IRP AND 2021 L&R?

A. EPE's 2021 IRP, and the 2021 L&R were developed before the decision was made to swap the retirement dates of NM1 and NM2. The updated retirement dates for NM1 and NM2 is reflected in the Company's 2023 L&R (Exhibit DCH-2).

Q26. ARE THE PROJECTED CAPACITIES OF NM1 AND NM2 SIMILAR?

A. Yes.

Q27. CAN YOU BRIEFLY DESCRIBE THE RESOURCE PLANNING

DECISIONS AND PLAN TO ABANDON THE UNITS?

A. Yes. The plan is centered on maintaining reliability as new generating resources are added to the Company's portfolio to account for any unforeseen contingencies that might occur in the construction or operation of the new resources. RG6 is scheduled for retirement in October 2024, and for planning purposes, RG7 and NM1 were originally scheduled for retirement in December 2022. That plan has since been updated to reflect new retirement dates for the Units.

In 2018, EPE commissioned the 2018 BMcD Study to evaluate whether it would be cost-effective and to the benefit of customers to extend the useful life of RG7, NM1 and NM2 beyond the then-current retirement dates. *See* Exhibit DCH-4. The 2018 BMcD Study assessed the condition of the Units and estimated costs to further extend the life of RG7, NM1 and NM2. The 2018 BMcD Study also evaluated the LCOE for the Units' extensions versus the LCOE of newer, more efficient generation and concluded that an extension was not cost effective. Additional details of the 2018 BMcD Study analyses are addressed by EPE witness J Kyle Olson.

Q28. WHAT WERE THE RESULTS OF EPE'S ANALYSIS OF EXTENDING THE UNITS AN ADDITIONAL FIVE YEARS FROM 2022 TO 2027?

A. Please see Table DCH-2

Table DCH-2 EPE 5 Year Life Extension Analysis

Unit	Total ($000)	Total ($/kW)
RG7	22,150	461
NM1	23,098	312
NM2	23,911	315

Q29. DOES THIS ANALYSES SUPPORT EPE'S DECISION AND REASONING TO ABANDON RG7 AND NM1?

A. Yes, this information was utilized in EPE's 2021 (New Mexico) and 2022 (Texas) RFPs for additional resources. The extension of NM1 retirement to 2027 was evaluated as part of the RFP process. In essence, the costs of extending NM1 to 2027 were compared to other resources that were evaluated during the RFP process. The results of the RFP showed that there are more cost-effective options.

Q30. IS THERE A RISK OF RETIRING RG7 AND NM1 BEFORE THE NEW GENERATING RESOURCES ARE OPERATIONAL?

A. There is always some risk in constructing and adding new generating resources to replace retiring units. To mitigate this risk, EPE plans to keep RG7 and NM1 available for service until planned resource additions required to serve load are constructed, completed, and operating. As part of this process, EPE plans to maintain RG7 and NM1 in Contingency Reserve Status, when possible, to be prepared for any contingencies associated with these new resources. So, while NM1 and RG7 were designated for retirement in December 2022 in EPE's 2021 and 2023 L&Rs, in the actual implementation of this plan, there will be a transition period for these Units.

Q31. WHAT IS THE OPERATIONAL STATUS OF RG7 AND NM1?

A. EPE originally planned to place RG7 and NM1 in inactive reserve status in December 2022; however, due to delays in commercial operation of several new generating facilities, both units were operational during the third quarter of 2023. Once the Newman Unit 6 combustion turbine and Buena Vista Solar and Storage facility come online, EPE plans to place RG7 and NM1 in Inactive Reserve Status, or possibly Mothball status.

Q32. PLEASE EXPLAIN INACTIVE RESERVE STATUS AND MOTHBALL STATUS?

A. Inactive Reserve is defined by the Institute of Electrical and Electronics Engineers ("IEEE") Standard 762 and NERC Generating Availability Data System, ("GADS") as "the state in which a unit is unavailable for service but can be brought back into service after some repairs in a relatively short duration of time, typically measured in days."

Placing a unit on Inactive Reserve on a temporary basis allows a utility to maintain reliability as new resources are added, because the unit on Inactive

Reserve will account for any unforeseen contingencies that may occur during the construction or operation of the new resources. Units on Inactive Reserve provide additional resources which can be brought online within a few days or weeks to meet load requirements in the event of any issues with the new resources, multiple outages, or higher than expected load growth.

A unit in Mothball status is defined by IEEE Standard 762 and GADS as "the state in which a unit is unavailable for service but can be brought back into service after some repairs with appropriate amount of notification, typically weeks or months." The difference between Inactive Reserve and Mothball is generally determined by the amount of time it takes to return to service upon notification.

Q33. DOES THAT MEAN THAT EPE PLANS TO UTILIZE RG7 AND NM1 FOR CONTINGENCY PURPOSES?

A. Yes. EPE's plans to place RG7 and NM1 on Inactive Reserve Status focusing on maintaining reliability as new generating resources are added to the Company's portfolio to account for any unforeseen contingencies that might occur in the construction or operation of the new resources.

Q34. IS THIS PLAN PRUDENT AND IN THE BEST INTEREST OF EPE'S CUSTOMERS?

A. Yes. This plan is prudent and in the best interest of EPE's customers because it allows the Company to use existing resources to help ensure safe and reliable service for customers, at minimal cost, as new—more efficient—replacement resources are added.

As I mention above, EPE plans to maintain RG7 and NM1 on Inactive Reserve Status, when possible, to be prepared for any contingencies until the new generating resources come become commercially operational. Given the planned resource additions will come online beginning in 2023 with the BV1 and BV2 projects and continue through May 2025, RG7 and NM1 will no longer be relied on for contingency purposes after the 2025 peak months. Further, RG7 and NM1 will have served their purpose during the construction and approval of replacement resources and planned renewable resource additions in 2022 approved in NMPRC Case Nos. 19-00348-UT, 19-00099-UT and 22-00093-UT. The contingent use of the Units will no longer be required to provide safe, reliable and economic service past those dates.

Q35. DOES EPE HAVE ANY UPCOMING CAPACITY RESOURCES THAT ARE BEING ADDED TO THE COMPANY'S PORTFOLIO?

A. Yes.

Q36. PLEASE DESCRIBE THE UPCOMING CAPACITY ADDITIONS WITHIN EPE'S SERVICE TERRITORY.

A. EPE is currently constructing Newman Unit 6, which has an expected commercial operation date ("COD") of December 2023. EPE plans to allocate 100 percent of the capacity of this unit to Texas customers. I mention it because, even though it will be allocated to Texas, Newman 6 must be considered when evaluating overall system resources.

The next significant capacity additions are the Buena Vista Energy Center 1 ("BV1") and the Hecate Santa Teresa Energy 1 ("Hecate 1") purchased power agreements ("PPAs"). BV1 is a new 100 MW solar PV facility with a 50 MW BESS located in Otero, New Mexico. It became commercially available July 11, 2023. Hecate 1 is a new 100 MW solar PV facility planned in Santa Teresa, New Mexico, with a contracted COD of June 2024. These resources were procured as resources for both Texas and New Mexico jurisdictions and the energy and capacity will be allocated accordingly.

Q37. PLEASE IDENTIFY UPCOMING PLANNED RESOURCES ADDITIONS THAT WILL BE NEW-MEXICO DEDICATED RESOURCES.

A. The Buena Vista Energy Center 2 ("BV2") PPA is a new 20 MW solar PV facility located in the same location and with the same contracted COD as the BV1 project. The Hecate Teresa Energy 2 ("Hecate 2") project is a new 50 MW solar PV facility planned to be located at the same location and with the same COD as the planned Hecate 1 project. EPE has been providing status updates to the Commission for both projects. Both projects are New Mexico-dedicated resources that were contracted to meet New Mexico's Renewable Portfolio Standard requirements. Additionally, pending appeal, EPE recently received approval for a new renewable energy resource selected from EPE's 2021 New Mexico RFP process comprised of a 130 MW solar PV facility and a 65 MW BESS (the "Carne Project") located in Luna County, New Mexico. The Carne Project will be a New Mexico-dedicated resource and has an expected COD of May 1, 2025.

Q38. IS EPE AWARE OF ANY POSSIBLE DELAYS TO THE HECATE 1 AND 2 RESOURCES?

A. As mentioned previously, EPE is providing monthly status updates on the Hecate projects. The Hecate projects are missing milestones identified in the projects' purchased power agreements and are subject to delay damages. EPE has been drawing down on security provided by Hecate as allowed under the PPAs. EPE continues to monitor the progress of the projects.

Q39. HOW CAN EPE RECOMMEND AN ABANDONMENT DATE OF 2026 IF-THERE IS A QUESTION ABOUT THE RESOURCES NECESSARY BEFORE ABANDONMENT CAN OCCUR?

A. It is necessary to set a date based on the projected loads and resources anticipated at the time EPE identified resources through the aforementioned RFP processes.

Similar to the abandonment date of RG6, in which there were resource addition conditions required before the abandonment date could be finalized, the abandonments of RG7 and NM1 should be conditioned on the planning reserve status of EPE's system, and be finalized once planning reserve targets are met. As previously discussed, EPE's IRP in 2025 will bring additional clarity to the final abandonment date of RG7 and NM1.

IV. CONCLUSION

Q40. PLEASE SUMMARIZE THE MAIN POINTS OF YOUR DIRECT TESTIMONY.

A. EPE planned for the removal of RG7 and NM1 from its system as part of its 2021 IRP. After engaging in extensive annual resource planning and IRP processes to ensure that EPE has adequate resources to meet its customers' needs in a reliable and efficient manner, EPE recommends abandoning RG7 and NM1. The reliability concerns, as well as the results of life extension analyses, indicate that additional life extensions (whether on a short- or long-term basis) past 2025 are not the best economic option for RG7 and NM1. EPE will continue to utilize RG7 and NM1 for contingency purposes and place the Units in inactive reserve status while its Commission-approved replacement resources are being brought online. These resources are being replaced with new and efficient generation with no inconvenience or hardship to the public.

Q41. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

El Paso Electric Company
Loads & Resources 2022 - 2041
September 13, 2021

System	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
	100 Sol, 20 Sol, 50 Battery/Sol	100 Sol, 50 Sol, 228 Newman 6		127 Bat, 159 Sol, 203 Wind					283 Bat, 251 Sol		381 Bat, 88 CT, 432 Sol		226 Bat, 52 CT, 256 Sol				107 Bat, 80 CT, 183 Sol, 17 Wind		72 Bat, 54 CT, 123 Sol, 11 Wind	
1.0 GENERATION RESOURCES[1]																				
1.1 RIO GRANDE	244	202	202	202	202	202	202	202	202	202	202	202	74	74	74	74	74	74	74	74
1.2 NEWMAN	654	801	801	801	801	801	733	733	733	733	452	452	452	452	452	452	452	452	452	452
1.3 COPPER	65	65	65	65	65	65	65	65	65	0	0	0	0	0	0	0	0	0	0	0
1.4 MONTANA	331	331	331	331	331	331	331	331	331	331	331	331	331	331	331	331	331	331	331	331
1.5 PALO VERDE	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585	585
1.6 RENEWABLES[2]	4	4	4	3	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2
1.7 STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1.8 POSSIBLE EMERGING TECHNOLOGY EXPANSION[3]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1.9 INTERRUPTIBLE[4]	52	52	52	52	52	55	55	55	55	62	62	62	62	69	69	69	69	69	78	78
1.10 LINE LOSSES FROM OTHERS[5]	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
1.0 TOTAL GENERATION RESOURCES	**1943**	**2048**	**2047**	**2046**	**2046**	**2050**	**1982**	**1982**	**1982**	**1924**	**1642**	**1642**	**1514**	**1521**	**1521**	**1521**	**1520**	**1520**	**1529**	**1529**
2.0 RESOURCE PURCHASES																				
2.1 RENEWABLE PURCHASE[6]	58	53	52	45	44	44	44	44	38	38	24	24	24	10	10	9	2	2	2	2
2.2 NEW RENEWABLE PURCHASE[7]	11	85	83	72	71	71	70	70	62	61	48	48	48	48	47	47	42	42	42	42
2.3 NEW RENEWABLE/ BATTERY PURCHASE[8]	54	49	49	42	42	41	41	41	36	36	28	28	28	28	28	28	25	25	25	25
2.4 NEW BATTERY PURCHASE[9]	50	50	50	50	50	50	50	50	46	46	36	36	36	36	36	36	35	35	35	35
2.5 EDDY TIE PURCHASE[10]	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
2.6 MARKET RESOURCE PURCHASE[11]	230	90	110	0	0	0	80	125	0	20	10	60	0	20	65	130	40	105	25	90
2.0 TOTAL RESOURCE PURCHASES	**438**	**362**	**379**	**243**	**242**	**241**	**320**	**364**	**217**	**236**	**182**	**232**	**171**	**177**	**221**	**284**	**180**	**245**	**165**	**229**
3.0 FUTURE RESOURCES[12]																				
3.1 RENEWABLE / SOLAR	0	0	0	68	67	67	66	66	152	152	249	247	322	321	319	318	335	333	365	363
3.2 RENEWABLE / WIND	0	0	0	52	52	53	53	53	54	54	55	55	55	55	55	55	59	59	62	62
3.3 BATTERY STORAGE	0	0	0	126	126	126	126	126	378	378	567	567	729	729	729	729	796	796	847	847
3.4 GAS GENERATION	0	0	0	0	0	0	0	0	0	0	82	82	130	130	130	130	205	205	255	255
3.0 TOTAL RESOURCE PURCHASES	**0**	**0**	**0**	**246**	**246**	**246**	**246**	**245**	**584**	**584**	**952**	**951**	**1237**	**1235**	**1233**	**1232**	**1395**	**1393**	**1529**	**1527**
4.0 TOTAL NET RESOURCES (1.0 + 2.0 + 3.0)	**2381**	**2409**	**2426**	**2535**	**2534**	**2537**	**2548**	**2592**	**2783**	**2743**	**2776**	**2825**	**2921**	**2932**	**2975**	**3037**	**3096**	**3159**	**3223**	**3286**
5.0 SYSTEM DEMAND[13]																				
5.1 NATIVE SYSTEM DEMAND	**2188**	**2225**	**2252**	**2293**	**2331**	**2372**	**2408**	**2459**	**2506**	**2553**	**2593**	**2650**	**2702**	**2756**	**2804**	**2869**	**2931**	**2996**	**3060**	**3125**
5.2 DISTRIBUTED GENERATION	-14	-18	-23	-25	-30	-34	-39	-43	-48	-46	-51	-55	-59	-50	-53	-56	-60	-63	-60	-63
5.3 ENERGY EFFICIENCY	-15	-23	-31	-38	-46	-54	-62	-69	-77	-85	-92	-100	-108	-115	-123	-131	-138	-146	-154	-162
6.0 TOTAL SYSTEM DEMAND (5.1 - (5.2+5.3))	**2158**	**2184**	**2198**	**2229**	**2255**	**2284**	**2308**	**2347**	**2381**	**2422**	**2450**	**2495**	**2535**	**2591**	**2628**	**2682**	**2733**	**2787**	**2847**	**2901**
7.0 MARGIN OVER TOTAL DEMAND (4.0 - 6.0)	**222**	**226**	**228**	**306**	**279**	**252**	**240**	**245**	**402**	**322**	**326**	**330**	**386**	**342**	**347**	**354**	**363**	**372**	**376**	**385**
8.0 PLANNING RESERVE 10.1% thru 2029 then 12.9%	**219**	**222**	**224**	**228**	**231**	**234**	**237**	**241**	**313**	**318**	**323**	**329**	**335**	**341**	**346**	**353**	**360**	**368**	**375**	**382**
9.0 MARGIN OVER RESERVE (7.0 - 8.0)	**3**	**3**	**4**	**78**	**48**	**18**	**3**	**3**	**88**	**3**	**4**	**1**	**51**	**1**	**2**	**1**	**3**	**4**	**2**	**3**

1. Generation unit retirements are consistent with the 2021 IRP. Rio Grande 6 is classified as inactive reserve.
2. Existing EPE owned solar renewables (27% - 54% ELCC)
3. Emerging technologies may include customer or other distributed resources as well as additional community solar. None were used for the 2021 IRP.
4. Interruptible customer capacity shifted to the resource side of the L&R. Capacity MW contribution per 2021 Load Forecast.
5. Line losses from others shifted to resource side of the L&R and is the typical amount of repayment of transmission wheeling losses from transmission customers with in-kind energy during peak hours.
6. Existing renewable solar PPAs (27% - 54% ELCC)
7. New renewable solar PPAs (27% - 54% ELCC)
8. New solar and battery storage PPAs (27% - 54% ELCC)
9. 50 MW New Battery Purchase reflects the 50 MW battery that is coupled with the 100 MW solar PPA. (71% - 100% ELCC)
10. 35 MW reliability purchase through the Eddy tie.
11. Denotes market purchase either spot market or short-term purchased power. Amounts greater than 645 MW-PV output will need to come into EPE via exchange (Freeport), through the acquisition of additional transmission or on a non-firm path.Also, availability of such power is not guaranteed.
12. Future New Resources from 2025 forward are to address both NM RPS and system capacity needs.
13. System demand is based on the 2021 Long-Term Forecast dated April 2021 with "Native System Demand" adjusted for a fully-managed charging profile for EVs.
14. Effective Load Carrying Capability ("ELCC") is expressed as a percentage of the generators nameplate rating which is the contribution to reliably serve load and is listed here for the peak hour.

Planned Generation Additions
120 MW Solar (27% - 54% ELCC[14]) in 2022
150 MW Solar (27% - 54% ELCC) in 2023
Battery coupled with solar (50 MW) in 2023 (27% - 54% ELCC)
Newman 6 GT5 (228 MW) in 2023 (92% ELCC)
Unit Retirements (86%-94% ELCC)
Rio Grande 6 (45MW) (inactive reserve)
Rio Grande 7 (44MW) - December 2022
Newman 1 (74MW) - Extended to December 2027
Newman 2 (74MW) - December 2022
Newman 3 (93MW) - Extended to December 2031
Newman 4 CC (220MW) - Extended to December 2031
Copper (63MW) - December 2030
Rio Grande 8 (139MW) - December 2033
Company Owned Renewables (27%-54% ELCC)
Line 1.6 consists of EPE Community Solar,
Holloman Solar, EPCC, Stanton, Wrangler,
Rio Grande & Newman Carports and Van Horn
Renewable Purchases
Line 2.1 includes SunEdison, NRG, Macho Springs, Juwi,
and Hatch solar purchases (27% - 54% ELCC)
New Renewable Purchase
Line 2.2 includes Buena Vista and Hecate solar purchases (270 MW)
(27% - 54% ELCC)

Resource Purchase

This purchase is supported by firm transmission through
(i) simultaneous buy/sell with
(i) Freeport McMoRan (formerly Phelps Dodge),
(ii) Four Corners-West Mesa transmission retired
(iii) SPS via the Eddy Tie.
Line 3.0 includes
Battery Resources: 126 MW in 2025, 283 MW in 2030, 381 MW in 2032,
226 MW in 2034, 107 MW in 2038, 72 MW in 2040, and 487 MW in 2045
(71% - 100% ELCC)
Combustion Turbine Resources: 88 MW in 2032, 52 MW in 2034, 80 MW in 2038,
54 MW in 2040, and 108 MW in 2045 (92% ELCC)
Solar Resources: 159 MW in 2025, 251 MW in 2030, 432 MW in 2032,
256 MW in 2034, 183 MW in 2038, 123 MW in 2040, and 624 MW in 2045
(27% - 54% ELCC)
Wind Resources: 203 MW in 2025, 17 MW in 2038, 11 MW in 2040,
and 69 MW in 2045 (27% - 54% ELCC)

Exhibit DCH-1
Page 1 of 1

El Paso Electric Company
System Loads & Resources 2024 - 2043
June 29, 2023

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Retirements				NM2			COPPER	NM3, NM4		RG8										
Additions[14]	HE1 100 Sol, HE2 50 Sol, TX Community 10 Sol, TX Airport 5 Sol, NM Community 20 Sol	CAR 130/65 Sol/Bat, PPA 150/75 Sol/Bat, EPE TX 100 Sol, TX Business 50 Sol, NM Community 10 Sol					250 Sol, 283 Bat		88 CT, 432 Sol, 381 Bat		52 CT, 256 Sol, 226 Bat				80 CT, 183 Sol, 106 Bat, 17 Wind		54 CT, 124 Sol, 72 Bat, 11 Wind			
1.0 GENERATION RESOURCES[1]																				
1.1 RIO GRANDE	202	202	202	202	202	202	202	202	202	202	78	78	78	78	78	78	78	78	78	78
1.2 NEWMAN	772	772	772	772	710	710	710	710	435	435	435	435	435	435	435	435	435	435	435	435
1.3 COPPER	59	59	59	59	59	59	59	0	0	0	0	0	0	0	0	0	0	0	0	0
1.4 MONTANA	331	331	331	331	331	331	331	331	331	331	331	331	331	331	331	331	331	331	331	331
1.5 PALO VERDE[2]	546	546	546	546	546	546	546	546	546	546	546	546	546	546	546	546	546	546	546	546
1.6 RENEWABLE SOLAR (EPE OWNED)[3]	5	5	5	5	5	5	4	4	3	3	3	3	3	3	3	3	3	3	3	3
1.7 BATTERY (EPE OWNED)[3]	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
1.8 INTERRUPTIBLE + SMART THERMOSTATS[4]	35	35	35	38	38	38	38	46	46	46	46	53	53	53	53	53	62	62	62	62
1.9 LINE LOSSES FROM OTHERS[5]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1.0 TOTAL GENERATION RESOURCES	**1,952**	**1,951**	**1,951**	**1,955**	**1,892**	**1,892**	**1,891**	**1,840**	**1,563**	**1,563**	**1,440**	**1,447**	**1,447**	**1,447**	**1,447**	**1,447**	**1,456**	**1,456**	**1,456**	**1,456**
2.0 RESOURCE PURCHASES																				
2.1 RENEWABLE PURCHASE[6]	112	96	96	95	94	94	82	82	59	59	58	44	44	42	33	33	32	32	32	32
2.2 BATTERY PURCHASE[6]	50	50	50	50	50	50	46	46	36	36	36	36	36	36	35	35	35	35	35	35
2.3 NEW RENEWABLE PURCHASE[7]	74	64	63	63	62	62	55	54	43	43	43	42	42	42	38	38	37	37	37	37
2.4 NEW RENEWABLE/ BATTERY PURCHASE[8]	0	55	55	55	54	54	48	47	37	37	37	37	37	36	33	33	33	32	32	32
2.5 NEW BATTERY PURCHASE[9]	0	65	64	64	63	63	58	58	44	44	44	44	43	43	42	42	42	41	41	41
2.6 EDDY TIE PURCHASE[10]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2.7 MARKET RESOURCE PURCHASE[10]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2.0 TOTAL RESOURCE PURCHASES	**235**	**329**	**328**	**326**	**324**	**323**	**288**	**287**	**220**	**219**	**218**	**203**	**202**	**199**	**181**	**180**	**179**	**179**	**178**	**177**
3.0 FUTURE RESOURCES[11]																				
3.1 RENEWABLE / SOLAR	17	147	146	145	144	143	220	219	302	300	375	373	371	369	382	380	411	409	407	405
3.2 BATTERY STORAGE	0	75	74	74	73	73	327	325	524	521	680	675	671	666	730	725	771	766	761	756
3.3 RENEWABLE / WIND	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	5	8	8	8	8
3.4 GAS GENERATION	0	0	0	0	0	0	0	0	82	82	130	130	130	130	205	205	255	255	255	255
3.0 TOTAL RESOURCE PURCHASES	**17**	**221**	**220**	**219**	**217**	**216**	**547**	**544**	**908**	**903**	**1,185**	**1,179**	**1,172**	**1,166**	**1,321**	**1,314**	**1,445**	**1,438**	**1,431**	**1,424**
4.0 TOTAL NET RESOURCES (1.0 + 2.0 + 3.0)	**2,204**	**2,502**	**2,499**	**2,499**	**2,433**	**2,431**	**2,727**	**2,671**	**2,691**	**2,685**	**2,842**	**2,828**	**2,821**	**2,813**	**2,948**	**2,941**	**3,080**	**3,072**	**3,065**	**3,057**
5.0 SYSTEM DEMAND[12]																				
5.1 NATIVE SYSTEM DEMAND	**2,300**	**2,358**	**2,398**	**2,434**	**2,465**	**2,512**	**2,554**	**2,597**	**2,630**	**2,682**	**2,728**	**2,776**	**2,818**	**2,877**	**2,930**	**2,985**	**3,034**	**3,100**	**3,135**	**3,191**
5.2 DISTRIBUTED GENERATION	(19)	(32)	(44)	(56)	(69)	(81)	(93)	(106)	(118)	(130)	(143)	(153)	(163)	(173)	(182)	(192)	(202)	(211)	(221)	(232)
5.3 ENERGY EFFICIENCY	(19)	(29)	(39)	(49)	(58)	(68)	(78)	(87)	(97)	(107)	(117)	(126)	(136)	(146)	(155)	(165)	(175)	(184)	(194)	(204)
5.4 ELECTRIC VEHICLES	3	6	9	14	21	30	42	57	75	96	118	139	158	172	182	188	189	188	184	180
6.0 TOTAL SYSTEM DEMAND (5.1 + 5.2 + 5.3 + 5.4)	**2,264**	**2,304**	**2,325**	**2,343**	**2,359**	**2,393**	**2,425**	**2,460**	**2,490**	**2,541**	**2,587**	**2,635**	**2,676**	**2,730**	**2,775**	**2,816**	**2,847**	**2,892**	**2,904**	**2,935**
7.0 MARGIN OVER TOTAL DEMAND (4.0 - 6.0)	**(60)**	**198**	**174**	**156**	**74**	**38**	**302**	**211**	**201**	**145**	**256**	**193**	**145**	**82**	**174**	**125**	**233**	**180**	**161**	**122**
8.0 PLANNING RESERVE 10.1% thru 2029 then 12.9%	**231**	**236**	**239**	**242**	**245**	**250**	**325**	**331**	**336**	**345**	**352**	**360**	**366**	**375**	**381**	**388**	**393**	**400**	**403**	**409**
9.0 MARGIN OVER RESERVE (7.0 - 8.0)	**(291)**	**(38)**	**(65)**	**(87)**	**(171)**	**(212)**	**(22)**	**(120)**	**(136)**	**(200)**	**(97)**	**(167)**	**(221)**	**(292)**	**(208)**	**(263)**	**(160)**	**(221)**	**(242)**	**(287)**

1 Generation unit retirements are consistent with the 2021 IRP. Rio Grande 6 is classified as inactive reserve.
2 Excludes 19.8% of New Mexico's portion for Palo Verde Unit 3, which was denied by the New Mexico Public Regulatory Commission in the 2020 Rate Case and FPPCAC Continuation Case.
3 Existing EPE owned renewable solar (27% - 49% ELCC) and battery (71% - 100% ELCC).
4 Interruptible customer capacity shifted to the resource side of the L&R. The Interruptible MW capacity is based on the 2022 Long-Term Load Forecast.
5 Placeholder for Line losses from others which shifted to resource side of the L&R.
6 Existing renewable solar PPAs (27% - 49% ELCC) and battery PPA (71% - 100% ELCC), which includes Buena Vista 1 and 2.
7 New renewable solar PPAs (27% - 49% ELCC).
8 New renewable solar coupled with battery storage PPAs (27% - 49% ELCC).
9 New battery storage that is coupled with solar PPA (71% - 100% ELCC).
10 Placeholder for reliability purchase through the Eddy tie and Market Resource Purchases.
11 Future new resources from 2024 forward are to address both NM RPS and system capacity needs. Includes resources projects which have not been filed with the PUCT and NMPRC for approval.
12 System demand is based on the 2023 Long-Term Forecast dated April 5, 2023.
13 Effective Load Carrying Capability ("ELCC") is expressed as a percentage of the generators nameplate rating which is the contribution to reliably serve load and is listed here for the peak hour.
14 Resource capacity additions reflected are nameplate. "HE" and "CAR" are abbreviations for the Hecate and Carne resources, respectively.

Effective Load Carrying Capability ("ELCC")[13]

Approved Generation Additions through 2025[14]

2024
- Hecate 1: 100 MW Solar (27% - 49% ELCC)
- Hecate 2: 50 MW Solar (27% - 49% ELCC)

2025
- Carne: 130 MW Solar (27% - 49% ELCC)
- Carne: 65 MW Battery (71% - 100% ELCC)

Unit Retirements (86% - 94% ELCC)
- Rio Grande 6: 45 MW (inactive reserve)
- Rio Grande 7: 44 MW - December 2022
- Newman 1: 73 MW - December 2022
- Newman 2: 73 MW - Extended to December 2027
- Copper: 63 MW - December 2030
- Newman 3: 90 MW - Extended to December 2031
- Newman 4: 220 MW - Extended to December 2031
- Rio Grande 8: 139 MW - December 2033

EPE Owned Renewables (27% - 49% ELCC)

Line 1.6 consists of EPE owned solar - Texas Community, Holloman, EPCC, Stanton, Wrangler, Rio Grande & Newman Carports, Van Horn, and NMSU.

Line 1.7 consists of EPE owned battery - NMSU.

Resource Purchases

This purchase is supported by firm transmission through:
(i) Tucson / EPE Palo Verde Exchange Agreement,
(ii) Point to Point Transmission Kyrene-Coronado-Springerville,
(iii) Four Corners-West Mesa transmission retired
(iv) Freeport McMoRan (formerly Phelps Dodge).

Renewable Purchases from PPA (27% - 49% ELCC)

Line 2.1 includes SunEdison, NRG, Macho Springs, Juwi (Newsol), Hatch and Buena Vista solar purchases.

Line 2.2 includes Buena Vista battery purchase.

Lines 2.3 through 2.5 include 280 MW of Solar (27% - 49% ELCC) and 65 MW Battery (71% - 100% ELCC) for Hecate and Carne.

Future Resources starting in 2024 (from the IRP, subject to RFP results). Includes future EPE solar projects which have not been filed with the PUCT and NMPRC for approval.

Line 3.0 includes:
- 250 MW of Solar (27% - 49% ELCC) and 75 MW of Battery (71% - 100% ELCC) in 2025 as a result of the 2021 NM and TX RFP.
- 10 MW TX Community Solar, 5 MW TX Airport Solar and 20 MW NM Community Solar in 2024; and 50 MW TX Business Solar and 10 MW NM Community Solar in 2025 (27% - 54% ELCC). These future EPE Solar projects have not been filed with the PUCT and NMPRC for approval.

Combustion Turbine Resources:
88 MW in 2032, 52 MW in 2034, 80 MW in 2038, 54 MW in 2040 (92% - 93% ELCC)

Solar Resources:
250 MW in 2030, 432 MW in 2032, 256 MW in 2034, 183 MW in 2038, 124 MW in 2040 (27% - 38% ELCC)

Battery Resources:
283 MW in 2030, 381 MW in 2032, 226 MW in 2034, 106 MW in 2038, 72 MW in 2040 (71% - 92% ELCC)

Wind Resources:
17 MW in 2038, 11 MW in 2040 (27% ELCC)

SETTLEMENT AGREEMENT

This Settlement Agreement ("Agreement") is made and entered into by and between El Paso Electric Company ("EPE"), Chaparral Community Coalition for Health and the Environment ("Chaparral Community Coalition"), and Sierra Club and institutionally and on behalf of any and all of their representatives individually (collectively "Protestants"). This Agreement is effective upon the latest date of the signatures below (the "Effective Date").

EPE is proposing to modify the existing Newman Generating Station, located at 4900 Stan Roberts Sr. Avenue in El Paso, El Paso County, Texas, by constructing a new Mitsubishi 501G series natural gas 230-Megawatt simple cycle combustion turbine fired by pipeline quality natural gas, referred to as Newman Unit 6, along with ancillary equipment ("Project"), which are more completely described in EPE's permit application ("Application"). To receive authorization for the Project, EPE filed air permit applications, including the Application, with the Texas Commission on Environmental Quality ("TCEQ"). Chaparral Community Coalition for Health and the Environment is an unincorporated neighborhood association based in Chaparral, New Mexico. Protestants have opposed the Application and TCEQ's issuance of the air permits applied for by EPE and were granted party status in State Office of Administrative Hearings ("SOAH") Docket No. 582-21-1740 (TCEQ Docket No. 2021-0314-AIR), which is pending at SOAH.

EPE and Protestants (collectively the "Parties" and individually a "Party") wish to terminate all disputes and administrative challenges related to the authorization, construction, and operation of the Project and avoid further and future litigation regarding the construction and operation of Newman Unit 6, generally, and challenges to TCEQ approval of EPE's air permit applications, including the Application.

With neither Party acknowledging fault, liability, or obligation, other than as described in this Agreement; and in consideration of the promises and covenants set forth in this Agreement; and for other good and valuable consideration, the sufficiency of which is hereby acknowledged, the Parties agree as follows:

1. INCORPORATION OF RECITALS

The above listed recitals and definitions are incorporated to this Agreement by reference.

2. OBLIGATIONS OF PROTESTANTS

2.1. TCEQ Administrative Process

Protestants will immediately file with SOAH a withdrawal of their request for a contested case hearing and objection to issuance of the permit. The Protestants will also join in a motion to remand the Application back to the TCEQ for consideration of the Application by the TCEQ Executive Director as unopposed. Protestants will not file a motion for rehearing or otherwise seek further administrative or judicial review of any TCEQ decision to approve the Application and to issue the draft permit prepared by the Executive Director in this matter ("Permit").

2.2. Future Opposition

As of the Effective Date, Protestants will not challenge the construction or permitting of the Project in any administrative or judicial forum, including by seeking judicial review of TCEQ authorization of the Project or funding any third-party litigation involving any claims settled, released, and waived by this Agreement.

3. OBLIGATIONS OF EL PASO ELECTRIC

3.1. Future Fossil Fuel Generation

With the exception of Newman Unit 6, EPE agrees that it will never construct any new fossil fuel generation units at Newman Generating Station. This restriction shall not apply to the conversions of existing generation units to operate on hydrogen fuel.

3.2. Construction Moratorium

With the exception of Newman Unit 6, EPE agrees to a four-year moratorium on EPE's construction of any additional EPE-owned fossil fuel-fired units to meet EPE's Native System Demand. The four-year moratorium period begins on the date the Permit for the Project is issued.

3.2.1. During the moratorium period, EPE is not prohibited from soliciting and obtaining regulatory approval for additional EPE-owned fossil fuel-fired units.

3.2.2. The moratorium does not include construction of any customer-dedicated resource, i.e. a unit or units dedicated solely for the benefit of a single customer or group of customers that is not a system resource.

3.2.3. The moratorium does not include construction related to any existing units.

3.2.4. The moratorium does not include installation or use of any authorized temporary generation responsive to any emergency or reliability conditions.

3.3. Abandonment of Existing Units

No later than the start of commercial operations date of Newman Unit 6, EPE will file abandonment applications for Newman Unit 1 or Newman Unit 2 and Rio Grande Generation Station Unit 7 with the New Mexico Public Regulation Commission and will use its best efforts in good faith to obtain approval thereof.

3.4. Emission Reductions

Following issuance of the Draft Permit, EPE will immediately seek an alteration of the applicable permits to reduce the allowable tons per year of nitrogen oxides ("NOx") and carbon dioxide ("CO2") emissions from Newman Unit 6 by 40% from the proposed permit. Specifically, EPE will agree to the following allowable tons per year from Newman Unit 6:

3.4.1. 790,000 tons per year of CO2.

3.4.2. 72 tons per year of NOx.

3.4.3. If TCEQ declines to incorporate the limitations in Section 3.4.1and 3.4.2 into the final permit for Newman Unit 6, EPE nevertheless commits to meeting those emission limitations at Newman Unit 6.

3.5. Purchase of VOC Emission Credits

If and when a regional volatile organic compound ("VOC") credit market arises following a final nonattainment designation for El Paso County by the U.S. Environmental Protection Agency ("EPA"), EPE will commit $500,000 to buy VOC emission offset credits to offset 110% of actual VOC emissions from Newman Unit 6.

3.5.1. If the EPA does not designate El Paso County as an ozone nonattainment area by the end of 2022 or a regional credit market fails to develop by the end of 2023, the $500,000 shall be redirected by July 31, 2024, to other emission reduction or energy efficiency projects that shall be jointly selected by the Chaparral Community Coalition and EPE. If the Chaparral Community Coalition and EPE are unable to agree on emission reduction or energy efficiency projects by July 31, 2024, the selection of projects shall be decided through the Dispute Resolution provision in Section 12 below. Sierra Club expressly will not have decision-making authority for how the funds will be spent but may have an advisory role.

3.6. Community Project Fund

Upon issuance of the Permit for Newman Unit 6, EPE will provide $400,000 to a charitable fund (preferably a 501(c)(3) non-profit organization) to be designated and administered by Chaparral Community Coalition as part of a community benefits agreement. The Chaparral Community Coalition will have authority to determine how the funds are spent but shall include pollution reduction or mitigation measures. Sierra Club expressly will not have decision-making authority for how the funds will be spent but may have an advisory role.

3.7. Information pertaining to Newman Unit 6

EPE will create and support a webpage for Newman Unit 6 posting quarterly emission reports filed with regulatory agencies.

3.8. Protestants' Attorney's Fees

Upon issuance of the permit for Newman Unit 6, EPE will provide $40,000 to Protestants for reasonable attorney and expert fees and costs.

4. MULTIPLE ORIGINALS

This Agreement may be executed in any number of identical counterparts, each of which for all purposes is deemed an original, and all of which constitute collectively one agreement. The Parties agree that original signatures are not necessary for this Agreement.

5. AUTHORITY

Each of the undersigned representatives of EPE and Protestants represent that they have the actual and express authority to execute this Agreement for the above-named entities and persons, including representatives, and that by their signature they are binding that Party, its assigns, directors, officers, trustees, employees, representatives, and attorneys to the terms of this Agreement. EPE and Protestants further represent that they will fulfill all of the terms and conditions contained in this Agreement.

6. BINDING ON SUCCESSORS AND ASSIGNS

EPE and Protestants each acknowledge that this Agreement is binding on each of their successors and assigns.

7. FORCE MAJEURE

7.1. No Party shall be liable for any delay or failure of performance under this Agreement if such delay or failure results from a Force Majeure Event. For purposes of this Agreement, a "Force Majeure Event" shall mean an event that has been or will be caused by circumstances beyond the control of the Party that delays compliance with any obligation of this Agreement or otherwise causes a violation of any obligation of this Agreement despite that Party's reasonable and prudent best efforts to fulfill such obligation. The requirement that the Party exercise "reasonable and prudent best efforts to fulfill such obligation" includes using reasonable and prudent best efforts to anticipate any potential Force Majeure Event and to address the effects of such event (i) as it is occurring and (ii) after it has occurred, such that the delay or violation and any adverse environmental effects of the delay or violation is minimized. "Force Majeure" does not include the party's financial inability to perform any obligation under this Agreement.

7.2. If any Party claims a Force Majeure Event, it shall give notice to the other Party within a reasonable time but, in any event, within 30 days after the date the Party-claimant knew or with due diligence should have known of the Event. If the Parties disagree regarding a claim of Force Majeure, the Parties shall attempt to resolve that dispute pursuant to Section 12 of this Agreement. In any such dispute, the Party seeking to invoke Force Majeure shall have the burdens of proof and persuasion to demonstrate that a Force Majeure Event occurred based on the standards set forth above.

7.3. Subject to the provisions of Sections 7.1 and 7.2 above, if a delay or violation is caused by a Force Majeure Event, such delay or violation shall not be considered a breach of this Agreement. The Parties by agreement or the Court by order may modify the obligations and extend the time periods under this Agreement to remedy breaches or delays caused by a Force Majeure Event.

8. NO ADMISSION OF LIABILITY

EPE and Protestants each acknowledge that this Agreement does not constitute an admission of liability by either Party or any recognition of the correctness of their respective positions.

9. NO PARTNERSHIP

This Agreement should not be construed as making EPE and Protestants partners or joint venturers.

10. ENTIRE AGREEMENT

This Agreement embodies and constitutes the entire understanding between EPE and Protestants with respect to the settlement contemplated in this Agreement. All prior contemporaneous agreements, understandings, representations, and statements, oral or written, are merged into this Agreement.

11. NOTICES

Any written notifications required under this Agreement shall be provided by (i) email or fax and (ii) certified mail, return receipt requested or nationally recognized overnight delivery service to the following:

For Sierra Club:
Joshua Smith
2101 Webster Street, Suite 1300
Oakland, CA 94612
Joshua.smith@sierraclub.org:

For Chaparral Community Coalition:
Ida Garcia
300-2 McCombs Road
Personal Mail Box 187

Chaparral, New Mexico 88081
ida88021@yahoo.com

For EPE:
General Counsel
El Paso Electric Company
P.O. Box 982
El Paso, TX 79960
(with copies to EPE Regulatory Affairs, Operations and Environmental Department)

Notices shall be effective upon receipt or refusal. Any Party may update its own notification address(es) and information by providing such information in writing to the other Party.

12. DISPUTE RESOLUTION

In the event that a dispute arises among the Parties related to the terms or enforcement of the provisions of this Agreement, each shall make a good faith effort to settle such dispute by negotiation. In the event the Parties are unable to settle the dispute by negotiation, both shall make a good faith effort to settle the dispute by mediation (with the assistance of a mutually agreed upon mediator) without resorting to litigation. This Agreement has been made under and shall be interpreted and enforced by Texas law, and any causes of action related to this Agreement shall be maintained in Texas courts.

13. MISCELLANEOUS

13.1. If any provision of this Agreement is held to be unenforceable for any reason, it shall be adjusted rather than voided in order to achieve the intent of the Parties to the extent possible. In any event, the invalidity or unenforceability of any provision of this Agreement shall not affect the validity or enforceability of the remainder of this Agreement.

13.2. It is expressly understood and agreed that this Agreement is solely for the benefit of the Parties, and nothing in this Agreement is intended or shall be construed to provide any rights or defenses to any other parties. This Agreement expressly does not create any rights in any entity or individual that is not a party to this agreement

13.3. Headings in this Agreement are provided for convenience only and are not a substantive part of this Agreement.

13.4. This Agreement shall not be modified, altered, or discharged except by a written agreement signed by authorized representatives of the Parties.

13.5. Protestants shall not be liable to EPE for money damages in the event of a breach of their obligations under Section 2, above. If EPE believes Protestants have breached their obligations under Section 2, EPE will provide prompt notice of breach and a reasonable amount of time to cure any breach. The sole remedy for any breach shall be injunctive relief directing Protestants to fulfill the obligations in Section 2.

14. ACKNOWLEDGMENT

EPE and Protestants, by and on behalf of itself and its representatives, acknowledge that they have had adequate opportunity to retain and consult with legal counsel of their choosing to advise them with regard to this Agreement. The Parties expressly warrant and represent to each other that they have reviewed and fully discussed this Agreement with counsel and have satisfied themselves that they fully understand the terms, conditions, contents, and effects of this Agreement and make this Agreement knowingly, voluntarily, and without threat of duress after such consultation.

[*SIGNATURES BEGIN ON NEXT PAGE*]

IN WITNESS WHEREOF, EPE and Protestants have entered into this Agreement, and this Agreement is executed by EPE and Protestants as of the Effective Date.

EL PASO ELECTRIC COMPANY,
A Texas corporation

By: ______________________

Title: SVP - Operations

Date: 8/16/21

Chaparral Community Coalition for Health and the Environment, an unincorporated neighborhood association

By: ______________________

Title: ______________________

Date: ______________________

SIERRA CLUB

By: ______________________

Title: ______________________

Date: ______________________

IN WITNESS WHEREOF, EPE and Protestants have entered into this Agreement, and this Agreement is executed by EPE and Protestants as of the Effective Date.

EL PASO ELECTRIC COMPANY,
A Texas corporation

By: ______________________________

Title: ____________________________

Date: ____________________________

Chaparral Community Coalition for Health and the Environment, an unincorporated neighborhood association
By: Elda Garcia

Title: Chairperson

Date: 08/14/21

SIERRA CLUB
By: ______________________________

Title: ____________________________

Date: ____________________________

IN WITNESS WHEREOF, EPE and Protestants have entered into this Agreement, and this Agreement is executed by EPE and Protestants as of the Effective Date.

EL PASO ELECTRIC COMPANY,
A Texas corporation

By: ______________________________

Title: ____________________________

Date: ____________________________

Chaparral Community Coalition for Health and the Environment, an unincorporated neighborhood association
By: ______________________________

Title: ____________________________

Date: ____________________________

SIERRA CLUB
By: ______________________________
JOSHUA SMITH
Title: STAFF ATTORNEY

Date: 8/15/2021

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 2017$, no inflation is included

CAPITAL EXPENDITURES (Presented in $000)

DESCRIPTION	Type	LAST	FREQUENCY	NEXT	TOTAL	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	CATEGORY
BOILER & HIGH ENERGY PIPING																
Boiler clean	Cap	2012	10 yrs	When due	$600					$600						Industry practice
Regular boiler piping replacements	Cap	2017	3 yrs	When due	$2,000					$1,000			$1,000			Required
Main steam piping replacement	Cap	N/A	Once	Within 5 yrs*	$0											Safety
NDE of selected areas	Cap	N/A	3yrs	ASAP	$220				$110			$110				Industry practice
Replace air heater cold end baskets	Cap	2006	10 yrs	Within 5 yrs*	$400							$400				Industry practice
TURBINE GENERATOR																
STG Major Inspection	Cap	2017	6 yrs	When due	$1,600							$1,600				Industry practice
STG Major Inspection	Exp	2017	6 yrs	When due	$1,600							$1,600				Industry practice
ST blades/valve repl./repairs	Cap	N/A	Once	Next major	$2,000							$2,000				Required
Valve Inspection	Exp	2017	4 yrs	When due	$2,400				$1,200				$1,200			Industry practice
Replace exciter	Cap	N/A	Once	Within 5 yrs*	$0											Required
BALANCE OF PLANT																
Refurbish cooling tower	Exp	1992	30 yrs	Within 5 yrs*	$2,000							$2,000				Required
Add liner to UG circulating water pipe	Exp	N/A	Once	Within 5 yrs*	$1,000							$500	$500			Required
Replace FW heater tube bundles	Cap	N/A	Once	Within 5 yrs*	$1,500							$1,500				Industry practice
Condenser retubing	Cap	N/A	Once	Within 5 yrs*	$1,500							$1,500				Industry practice
Allowance for major pump/fan work	Exp	N/A	Once	Within 5 yrs*	$1,000						$1,000					Required
ELECTRICAL & CONTROLS																
Switchgear upgrade	Cap	N/A	Once	Within 5 yrs*	$1,000						$1,000					Industry practice
Replace station batteries	Cap	2000	20 yrs	When due	$200							$200				Required
Replace unit aux. transformers	Cap	N/A	Once	Within 5 yrs*	$500						$500					Required
TOTAL																
TOTAL - Capital					$11,520				$110	$1,600	$1,500	$7,310	$1,000	$0	$0	
TOTAL - Non Recurring O&M					$8,000				$1,200	$0	$1,000	$4,100	$1,700	$0	$0	
TOTAL					$19,520				$1,310	$1,600	$2,500	$11,410	$2,700	$0	$0	

*Distrubuted over years to spread out expense

FIXED OPERATIONS & MAINTENANCE EXPENDITURES - HISTORICAL BASIS

DESCRIPTION			TOTAL	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Unit Capacity (Net Summer)	74												
FOM ($/kW-yr)	$20.74	$000	$10,745				$1,535	$1,535	$1,535	$1,535	$1,535	$1,535	$1,535

	Total ($000)	Total ($/kW)
Capital Expenditures	$11,520	$264
Maintenance	$10,745	$145
Total	$22,265	$409

FIXED OPERATIONS & MAINTENANCE EXPENDITURES - ADJUSTED FOR AGE BASED DEGRADATION

DESCRIPTION			TOTAL	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Unit Capacity (Net Summer)	74												
Year in Service	1960												
Maintenance Aging Rate per Year	1.25%						$21.53	$21.80	$22.07	$22.34	$22.62	$22.91	$23.19
FOM ($/kW-yr)	$20.74	$000	$11,578				$1,593	$1,613	$1,633	$1,653	$1,674	$1,695	$1,716

	Total ($000)	Total ($/kW)
Capital Expenditures	$11,520	$156
Fixed O&M	$11,578	$156
Total	$23,098	$312

VARIABLE OPERATION & MAINTENANCE EXPENDITURES

DESCRIPTION	UNITS	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Unit Capacity (Net Summer)	74										
Annual Capacity Factor	34.2%										
Variable O&M Costs ($/MWh)	$2.54				$2.54	$2.54	$2.54	$2.54	$2.54	$2.54	$2.54
Annual Variable O&M Costs ($)					$563,607	$563,607	$563,607	$563,607	$563,607	$563,607	$563,607

SUMMARY	UNITS	TOTAL	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
TOTAL - Capital		$11,520	$0	$0	$0	$110	$1,600	$1,500	$7,310	$1,000	$0	$0
TOTAL - Non Recurring O&M		$8,000	$0	$0	$0	$1,200	$0	$1,000	$4,100	$1,700	$0	$0
Fixed O&M (adjusted for age)		$11,578	$0	$0	$0	$1,593	$1,613	$1,633	$1,653	$1,674	$1,695	$1,716
Variable O&M			$0	$0	$0	$563,607	$563,607	$563,607	$563,607	$563,607	$563,607	$563,607

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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 2017$, no inflation is included

CAPITAL EXPENDITURES (Presented in $000)

DESCRIPTION		Type	LAST	FREQUENCY	NEXT	TOTAL	2018	2019	2020	2021	2022	2023	2024	2025	2026
BOILER & HIGH ENERGY PIPING															
	Boiler clean	Cap	2011	10 yrs	When due	$600					$600				
	Regular boiler piping replacements	Cap	2016	3 yrs	When due	$2,000					$1,000			$1,000	
	Main steam piping replacement	Cap	N/A	Once	ASAP	$0									
	NDE of selected areas	Cap	N/A	3yrs	ASAP	$220				$110			$110		
	Replace air heater cold end baskets	Cap	N/A	10 yrs	Within 5 yrs*	$400							$400		
TURBINE GENERATOR						$0									
	STG Major Inspection	Cap	2013	6 yrs	When due	$1,600								$1,600	
	STG Major Inspection	Exp	2013	6 yrs	When due	$1,600								$1,600	
	ST blades/valve repl./repairs	Cap	N/A	Once	Next major	$0									
	Valve Inspection	Exp	N/A	4 yrs	Next major	$2,400					$1,200		$1,200		
	Generator rewind	Cap	N/A	Once	Within 5 yrs*	$3,500					$3,500				
BALANCE OF PLANT															
	Refurbish cooling tower	Exp	N/A	Once	Within 5 yrs*	$2,000								$2,000	
	Add liner to UG circulating water pipe	Exp	N/A	Once	Within 5 yrs*	$500								$500	
	Replace FW heater tube bundles	Cap	N/A	Once	Within 5 yrs*	$500								$500	
	Condenser retubing	Cap	N/A	Once	Within 5 yrs*	$1,500					$1,500				
	Allowance for major pump/fan work	Exp	N/A	Once	Within 5 yrs*	$1,000					$1,000				
ELECTRICAL & CONTROLS						$0									
	Switchgear upgrade	Cap	N/A	Once	Within 5 yrs*	$1,000						$1,000			
	Replace station batteries	Cap	2000	20 yrs	When due	$200							$200		
	Replace GSU	Cap	N/A	Once	Within 5 yrs*	$0									
	Replace unit aux. transformer	Cap	N/A	Once	Within 5 yrs*	$500						$500			
TOTAL															
	TOTAL - Capital					$12,020				$110	$6,600	$1,500	$710	$3,100	$0
	TOTAL - Non Recurring O&M					$7,500				$0	$2,200	$0	$1,200	$4,100	$0
	TOTAL					$19,520				$110	$8,800	$1,500	$1,910	$7,200	$0
	*Distrubuted over years to spread out expense														

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 2017$, no inflation is included

CAPITAL EXPENDITURES (Presented in $000)

DESCRIPTION		TYPE	LAST	FREQUENCY	NEXT	TOTAL	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
BOILER & HIGH ENERGY PIPING																
	Regular boiler piping replacements	Cap	N/A	3 yrs	When due	$2,000					$1,000			$1,000		
	Main steam piping replacement	Cap	N/A	Once	Within 5 yrs*	$0										
	NDE of selected areas	Cap	N/A	3yrs	ASAP	$220				$110			$110			
	Replace air heater cold end baskets	Cap	2011 (insp.)	10 yrs	Within 5 yrs*	$400							$400			
TURBINE GENERATOR																
	STG Major Inspection	Cap	2005	6 yrs	ASAP	$3,200					$1,600		$1,600			
	STG Major Inspection	Exp	2005	6 yrs	ASAP	$3,200					$1,600		$1,600			
	ST blades/valve repl./repairs	Cap	N/A	Once	Next major	$2,000					$2,000					
	Valve Inspection	Exp	2016	4 yrs	When due	$2,400					$1,200		$1,200			
	Generator rewind	Cap	N/A	Once	ASAP	$0				$0						
	Comply with TDP-1	Cap	N/A	Once	ASAP	$0										
BALANCE OF PLANT																
	Reburbish cooling tower	Exp	N/A	Once	Within 5 yrs*	$1,500					$1,500					
	Add liner to UG circulating water pipe	Exp	N/A	Once	Within 5 yrs*	$1,000					$1,000					
	Replace FW heater tube bundles	Cap	N/A	Once	Within 5 yrs*	$1,500					$1,500					
	Condenser retubing	Cap	Unknown	Once	Within 5 yrs*	$1,500					$1,500					
	Allowance for major pump/fan work	Exp	N/A	Once	Within 5 yrs*	$1,000					$1,000					
ELECTRICAL & CONTROLS																
	Switchgear upgrade	Cap	N/A	Once	Within 5 yrs*	$1,000					$1,000					
	Replace station batteries	Cap	2005	20 yrs	When due	$200							$200			
	Replace unit aux. transformers	Cap	N/A	Once	Within 5 yrs*	$500				$500						
TOTAL																
	TOTAL - Capital					$12,520				$610	$8,600	$0	$2,310	$1,000	$0	$0
	TOTAL - Non Recurring O&M					$9,100				$0	$6,300	$0	$2,800	$0	$0	$0
	TOTAL					$21,620				$610	$14,900	$0	$5,110	$1,000	$0	$0
	*Distrubuted over years to spread out expense															

FIXED OPERATIONS & MAINTENANCE EXPENDITURES - HISTORICAL BASIS

DESCRIPTION						TOTAL	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	Unit Capacity (Net Summer)	48														
	Fixed O&M ($/kW-yr)	$26.60			$000	$8,939				$1,277	$1,277	$1,277	$1,277	$1,277	$1,277	$1,277

	Total ($000)	Total ($/kW)
Capital expenditures	12,520	450.42
Maintenance	$8,939	186
Total	$21,459	637

FIXED OPERATIONS & MAINTENANCE EXPENDITURES - ADJUSTED FOR AGE BASED DEGRADATION

DESCRIPTION						TOTAL	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	Unit Capacity (Net Summer)	48														
	Year in Service	1958														
	O&M Aging Rate/year	1.25%								$27.60	$27.95	$28.30	$28.65	$29.01	$29.37	$29.74
	Maintenance ($/kW-yr)	$26.60			$000	$9,630				$1,325	$1,342	$1,358	$1,375	$1,393	$1,410	$1,428

	Total ($000)	Total ($/kW)
Capital expenditures	12,520	261
Maintenance	$9,630	201
Total	$22,150	461

VARIABLE OPERATION & MAINTENANCE EXPENDITURES

DESCRIPTION		UNITS	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	Unit Capacity (Net Summer)	48										
	Annual Capacity Factor	24.2%										
	Variable O&M Costs ($/MWh)	$4.68				$4.68	$4.68	$4.68	$4.68	$4.68	$4.68	$4.68
	Annual Variable O&M Costs ($)					$476,219	$476,219	$476,219	$476,219	$476,219	$476,219	$476,219

SUMMARY

SUMMARY		UNITS	TOTAL	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	TOTAL - Capital		$12,520	$0	$0	$0	$610	$8,600	$0	$2,310	$1,000	$0	$0
	TOTAL - Non Recurring O&M		$9,100	$0	$0	$0	$0	$6,300	$0	$2,800	$0	$0	$0
	Fixed O&M (adjusted for age)		$9,630	$0	$0	$0	$1,325	$1,342	$1,358	$1,375	$1,393	$1,410	$1,428
	Variable O&M			$0	$0	$0	$476,219	$476,219	$476,219	$476,219	$476,219	$476,219	$476,219
			$16,064					FOM (K$)	$7,658	$4,175	$1,393	$1,410	$1,428

FOM Costs - consumables left out since extensions will not be operable until 2023

Non-Reculrring O&M Costs - Omar said to add them all into year 2023 with that year's FO&M Costs

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Life Extension & Condition Assessment for Rio Grande Unit 7

El Paso Electric, Inc.

Life Extension & Condition Assessment
Project No. 101995

Revision 1
7/16/2018

Life Extension & Condition Assessment for Rio Grande Unit 7

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 TABLES

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LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
A	Amperes
ASME	American Society of Mechanical Engineers
BPI	Babcock Power, Inc.
BMS	Burner management system
Btu	British thermal units
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
CCR	Coal combustion residuals
CO	Carbon monoxide
CPP	Clean Power Plan
CWA	Clean Water Act
DA	Deaerator
DCS	Distributed control system
EAF	Equivalent availability factor
EDG	Emergency diesel generator
EFOR	Equivalent forced outage rate
El CID	Electromagnetic Core Imperfection Detection
ELG	Effluent Limitations Guidelines
EPA	Environmental Protection Agency
EPE	El Paso Electric, Inc.
FAC	Flow-accelerated corrosion
Facility	Rio Grande Power Station

Abbreviation	**Term/Phrase/Name**
FD	Forced draft
FSSS	Flame Safety Scanner System
GADS	Generator Availability Database System
GE	General Electric
gpm	Gallons per minute
GSU	Generator step-up
hp	Horse power
HP	High pressure
KA	Kiloamperes
KVA	Kilovolt amperes
KW	Kilowatt
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
NO_2	Nitrogen dioxide
NPDES	National Pollution Discharge Elimination System

Abbreviation	**Term/Phrase/Name**
NSR	New Source Review
O&M	Operation and maintenance
O_3	Ozone
OEM	Original equipment manufacturer
PdM	Predictive maintenance
Plant	Rio Grande Power Station
PLC	Programmable logic controller
PM	Particulate matter
ppb	Parts per billion
PSD	Prevention of Significant Deterioration
psig	Pounds per square inch gauge
RACT	Reasonably available control technology
Rio Grande	Rio Grande Power Station
RO	Reverse osmosis
SJAE	Steam Jet Air Ejector
SO_2	Sulfur dioxide
SPE	Solid particle erosion
STG	Steam turbine generator
Study	Life Extension and Condition Assessment
Unit	Unit 7 of the Rio Grande Power Station
Unit 7	Unit 7 of the Rio Grande Power Station
VDC	Volts DC

Abbreviation	**Term/Phrase/Name**
WQBEL	Water quality-based effluent limits
WQS	Water Quality Standards

STATEMENT OF LIMITATIONS

This report may have been prepared under, and only be available to parties that have executed, a Confidentiality Agreement with El Paso Electric, Inc. Any party to whom the contents are revealed or may come into possession of this document is required to request of El Paso Electric, Inc. if such Confidentiality Agreement exists. Any entity in possession of, or that reads or otherwise utilizes information herein, is assumed to have executed or otherwise be responsible and obligated to comply with the contents of such Confidentiality Agreement. Any entity in possession of this document shall hold and protect its contents, information, forecasts, and opinions contained herein in confidence and not share with others without prior written authorization from El Paso Electric, Inc.

In preparation of this report, Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") has relied upon information provided by El Paso Electric, Inc. and the owners and operators of the Rio Grande Power Station. While there is no reason to believe that the information provided is inaccurate or incomplete in any material respect, Burns & McDonnell has not independently verified such information and cannot guarantee or warranty its accuracy or completeness.

Burns & McDonnell's estimates, analyses, and recommendations contained in this report are based on professional experience, qualifications, and judgment. Burns & McDonnell has no control over weather; cost and availability of labor, material, and equipment; labor productivity; energy or commodity pricing; demand or usage; population demographics; market conditions; changes in technology; and other economic or political factors affecting such estimates, analyses, and recommendations. Therefore, Burns & McDonnell makes no guarantee or warranty (actual, expressed, or implied) that actual results will not vary, perhaps significantly, from the estimates, analyses, and recommendations contained herein.

Burns & McDonnell has not been engaged to render legal services. The services Burns & McDonnell provides occasionally require the review of legal documents, statutes, cases, regulatory guides, and related matters. The opinions, analysis, and representations made in this report should not be construed to be legal advice or legal opinion concerning any document produced or reviewed. These documents and the decisions made in reliance of these documents may have serious legal consequences. Legal advice, opinion, and counsel must be sought from a competent and knowledgeable attorney.

This report is for the sole use, possession, and benefit of El Paso Electric, Inc. for the limited purpose as provided in the agreement between El Paso Electric, Inc. and Burns & McDonnell. Any use or reliance on the contents, information, conclusions, or opinions expressed herein by any other party or for any other use is strictly prohibited and is at that party's sole risk. Burns & McDonnell assumes no responsibility or liability for any unauthorized use.

1.0 EXECUTIVE SUMMARY

1.1 Objective & Background

El Paso Electric, Inc. ("EPE") retained the services of Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") to perform a study to assess the condition of Unit 7 ("Unit") of the Rio Grande Power Station ("Plant", "Rio Grande", or "Facility") and determine the overall costs associated with extending the useful service life of the Unit ("Study"). The Unit is currently scheduled for retirement in 2022. The objective of the condition assessment was to estimate the cost of repairing, replacing, maintaining, and operating this Unit 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 Unit, 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 Unit 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 Rio Grande, 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 walk-down of the Plant to obtain information on Rio Grande Unit 7. Burns & McDonnell also analyzed any necessary updates for the Unit 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 Unit, much of the major equipment and components will need to be replaced and refurbished to continue to operate the Unit 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 Unit was extended to 2027 or 2037.

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 1-1 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 1-1, 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 1-1: 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

1.3 Conclusions & Recommendations

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

1. The 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 need 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 units.

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.
8. 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 life of the Unit, EPE should utilize the capital and O&M costs presented within this report.

2.0 INTRODUCTION

2.1 General Plant Description

El Paso Electric, Inc. ("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 West Texas and Southern New Mexico. EPE has interests in Palo Verde Nuclear Plant, Copper Power Station, Montana Power Station, Rio Grande Power Station, and Newman Power Station. Located in Sunland Park, New Mexico (a suburb of El Paso, Texas), Rio Grande Unit 7 ("Unit", "Unit 7", "Facility", or "Plant") began commercial operation in 1958. The previous condition assessment that Burns & McDonnell provided for EPE also considered Unit 6, which was retired in 2015 and later brought out of retirement due to issues with Newman Unit 5. Unit 7 is scheduled for retirement in 2022. Unit 7 alone is the focus of this assessment.

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

The typical dispatch of Unit 7 has been to baseload the Unit from May through September, during which the Plant is not cycled, but rather is ramped up and down. The Facility runs about seven months out of the year and has not experienced as much cycling in the past compared to the Newman generating station.

During a freeze event in 2011 Unit 7 was offline. However, later in the week when the Unit was starting, plant staff discovered numerous frozen pipes and leaks. There is a major transmission line outage scheduled in October of 2017 for Palo Verde, for which the natural gas-fired units will be dispatched to provide sufficient energy to meet load.

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.

The Unit 7 major plant equipment includes a natural circulation steam generator boiler designed by Babcock and Wilcox for 350,000 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 boiler previously had the ability to fire fuel oil, but this capability has been disabled. Unit 7 also includes a General Electric

("GE") steam turbine, which is a tandem compound, double-flow condensing unit. The generator is currently rated at 56.8 megavolt amperes ("MVA"). Cooling water for Unit 7 is circulated through a counter-flow cooling tower with makeup water provided from off-site wells. Boiler makeup water for Unit 7 is also provided from the off-site well water system.

The steam turbine generator ("STG") was previously on a maintenance cycle of about 8 years and the valves were on a cycle of 3 years, both regardless of dispatch. These maintenance cycles have since become based on hours instead. The steam turbine generator maintenance is now done according to a cycle of 80,000 hours and the maintenance for the valves is done every 30,000 hours.

The Rio Grande facility also employs a predictive maintenance ("PdM") program, which entails continuous monitoring on the 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 utilizes XY probes and thermocouples for the vibration monitoring. 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.

2.2 Study Objectives & Overview

EPE retained the services of Burns & McDonnell to perform a study to assess the condition of Rio Grande Unit 7, and to assess the costs of restoring, operating, and maintaining this Unit to extend its useful service life until 2027 or 2037. 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 its 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 Rio Grande, and Burns & McDonnell's professional opinion. Burns & McDonnell has also estimated capital expenditures and incremental Operation and Maintenance ("O&M") costs associated with operating the unit 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 unit.

2.3 Study Contents

The following report details the current condition of the Unit, and presents the capital expenditures and the ongoing operations and maintenance that would be associated with continued operation of this unit past its 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. Main generator rotor shaft, stator and rotor windings, stator and rotor insulation, and retaining rings

The following items, although not as critical as the above, are also influential components that will also play a role in determining the remaining 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. Generator stator-winding bracing, DC exciter, and voltage regulator
4. Balance of plant condenser, feedwater heaters, feedwater pumps and motors, controls, and auxiliary switchgear
5. 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 Unit 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 14, 2017. The purpose of the site visit was to gather information to conduct the life extension condition assessment, interview the plant management and operations staff, and to conduct an on-site review of the Plant site.

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

1. David Aranda, Plant Manager and former Operator
2. David Barraza, Operations Superintendent

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

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

Through visual observation of the Plant and its operations 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 were identified to likely require replacement due to age and/or obsolescence were the high-pressure piping, boiler, circulating water lines, cooling towers, condenser tubing, fans, and pumps.

4.0 BOILER

The Boiler of Unit 7 at the Rio Grande Station is a natural circulation, radiant heat, pressurized unit designed to burn natural gas in eight wall-mounted burners. This unit includes a horizontal, drainable superheater and reheater, one 60-inch diameter steam drum and a 42-inch elevated mud drum. This boiler design is more commonly known in the industry as the "Babcock & Wilcox El Paso" design. The unit was originally designed for a maximum continuous rating ("MCR") of 350,000 lb/hr main steam at a superheater outlet condition of 1,510 psig and 1005°F. The reheater is designed for an operating temperature of 1005°F. The superheater and reheater outlet temperature is controlled by desuperheater sprays. The boiler design also includes a bare-tube economizer and Ljungstrom type tri-sector air heater for flue gas heat recovery.

Unit 7 frequently sits at minimum load and is ramped up as needed. Boiler chemical cleaning is scheduled on a 4 to 6-year cycle, the last of which occurred this year. In addition, EPE takes tube samples periodically in high heat flux areas of the boiler to evaluate the extent of boiler tube scaling to determine the need for chemical cleaning of the boiler.

EPE hired Babcock Power, Inc. ("BPI") to perform a condition assessment of the boiler and high energy piping in February 2011.

4.1 Waterwalls

BPI reported that the boiler waterwall tubes appeared to be in good condition during the 2011 inspection. At the time, a visual inspection of the furnace found all four waterwalls straight and aligned. Tube thicknesses were also measured, but there was no original tube thickness to compare them to. A regular tube wall thickness nondestructive examination ("NDE") inspection program is recommended to monitor boiler waterwall condition and prevent tube rupture related outages.

4.2 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 ("HP") steam turbine. The six sections or stages of the superheater are as follows, starting at the steam drum and progressing towards the superheater outlet header:

1. The backpass wall and roof section, which form the sides and roof of the vertical gas path and part of the horizontal gas path.
2. The low temperature horizontal sections, located above the economizer in the rear backpass of the boiler.
3. The low temperature pendant section, located in the furnace rear backpass above the low temperature horizontal sections.
4. The division panel section, located directly above the furnace, between the front wall and the pendant platen section.
5. The pendant platen section, located directly above the furnace in front of the furnace arch.
6. The finishing section, located in the horizontal gas path in the back of the screen wall tubes.

During the 2011 inspection, BPI found secondary superheater tubes in tube rows 4, 9, and 31 completely burned out and extensive bowing of the remaining tubes. The primary superheater appeared to be in good condition, although they found tube row 12 missing. Ultrasonic tube thickness measurements were taken, but BPI had no original tube thickness to compare them to.

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.

4.3 Reheater

The reheater section of the boiler increases the superheat of the steam discharged from the HP turbine. Steam exiting the HP 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 Rio Grande Unit 7, the design of the reheater allows for draining the reheater during outages and/or startup.

BPI’s 2011 inspection of the reheater revealed moderate to severe bowing of the tube bundles with several tubes overheated/missing. Ultrasonic tube thickness measurements were taken, but BPI had no original tube thickness to compare them to.

4.4 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 back-pass of the boiler before exiting through the economizer outlet header and traveling to the steam drum.

BPI performed a visual inspection of the economizer tube bundle in 2011. They found the tubes relatively well aligned with only minor bowing in a few tubes. They did note several plugged tubes.

4.5 Drums and Headers

There is one steam drum, and one lower waterwall drum on the unit. The steam drum is visually inspected by plant personnel during each annual outage.

BPI was unable to perform a visual inspection of the steam drum during the 2011 inspection due to an inoperable manway.

Since the drum is susceptible to fatigue and corrosion damage, Burns & McDonnell recommends the steam drum be regularly inspected. The inspections should include a detailed visual inspection, with the internals removed, magnetic particle examination and ultrasonic inspection of girth, socket, and nozzle welds, and thickness readings at the drum water level.

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

In 2011, BPI performed visual inspection (using fiberoptics), metallographic replication, and hardness testing on the secondary superheater outlet header and the reheater outlet header. BPI also performed diametric measurement on the reheat outlet header.

The visual inspection on the secondary superheater outlet header found no evidence of erosion, cracking, or corrosion; yet, it did identify moderate scale buildup in areas. One location on the secondary superheater outlet header was examined using metallographic replication. No evidence of micro-cracking or creep damage was found. Magnetic particle testing was performed on a single nozzle saddle weld. Several small indications were found and repaired. Based on the 2011 examinations, BPI considered the secondary superheater outlet header to be in good condition.

The visual inspection on the reheat outlet header also found no evidence of erosion, cracking, or corrosion; yet, it did identify moderate scale buildup in areas. Two locations on the reheater outlet header were examined using metallographic replication. No evidence of micro-cracking or creep damage was found. Magnetic particle testing was performed on a single nozzle saddle weld and no indications were found. Diametric measurements were taken at one location on the header. Based on an assumed original outside diameter of the header, it was determined to be above its allowable creep swell. However, this finding is moderated due to the assumed outside diameter. Based on the 2011 examinations, BPI considered the reheat outlet header to be in good condition.

The primary and secondary superheater headers and the reheater outlet header should be re-inspected in the future using the following non-destructive testing methods, in addition to those performed by BPI:

1. Acid etching of the headers to determine whether longitudinal seam welds exist in the headers.
2. All girth welds, socket welds, and longitudinal welds (if applicable) should be inspected using ultrasonic thickness examination to determine the integrity of the weld and thickness of the material.
3. All girth welds, socket welds, and longitudinal welds (if applicable) should be inspected using magnetic particle examination to detect surface discontinuities in the metal.
4. Pi Measurement tests should be performed along all the headers, to be used as a gauge to detect long term creep by identifying pipe swelling.
5. A header straightness examination should also be performed to identify any signs of sagging associated with long term creep damage.

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. These headers should be inspected soon and then periodically (based on the findings of the initial examination) to monitor for signs of this type of damage. The low temperature headers should be inspected using the following non-destructive methods:

1. Ultrasonic thickness inspections to monitor for signs of flow-accelerated corrosion (“FAC”).
2. Full borescope examination of the headers.
3. Dimensional analysis of the headers.
4. Magnetic particle examination at all girth and select socket / butt weld locations to detect surface discontinuities in the metal.

4.6 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.

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.

4.7 Burner Control System

The Unit 7 Boiler has a Flame Safety Scanner System ("FSSS"), installed after the 2003 furnace explosion.

5.0 BOILER AUXILIARY SYSTEMS

5.1 Fans

There is one Westinghouse double inlet centrifugal forced draft ("FD") fan that provides 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. 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 Air Heater

Air heating is accomplished by one Ljungstrom type regenerative air heater. This heater is inspected by plant personnel during each annual outage with minor repairs done immediately.

BPI performed a limited visual inspection of the air heater from the cold gas discharge during the 2011 inspection. They found minimal debris and the seals in good condition.

The air heater appears to be in good condition based on inspections and on-going maintenance. It is nevertheless prudent to expect that the cold end baskets will need to be replaced within the next five years.

5.3 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.

5.4 Stack

The stack has not been inspected in recent years. An inspection, particularly for structural integrity, is recommended.

5.5 Blowdown System

Unit 7 design includes 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 flash tank.

The blowdown tanks have been visually inspected. There were no reports of significant problems with either the tanks or the ancillary equipment. The blowdown system appears to be in good condition based on inspections and on-going maintenance.

6.0 STEAM TURBINE

In general, EPE has reported that the Unit 7 turbine has exhibited good operation and vibration levels.

The Unit 7 water chemistry is well maintained; therefore, the turbine can be expected to have only minor solid particle erosion ("SPE") and insignificant deposits, as it has in past overhauls.

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.

6.1 Turbine

The steam turbine generator was previously on a maintenance cycle of about 8 years, regardless of dispatch; however, maintenance is now done according to a cycle of 80,000 hours. A major inspection is scheduled for the turbine in 2022.

During the fall 2005 outage, the HP and low pressure ("LP") turbines were overhauled by General Electric ("GE") Energy Service. The HP and LP turbine sections were disassembled, inspected and reassembled. The sixth stage turbine buckets were replaced and the sixth stage diaphragms were repaired. The nozzle plates were also repaired. The turbine shell had two major indications that were repaired.

At that time, GE's report noted that the turbine shell was nearing the end of its useful life. Plant personnel noted that the turbine shell had cracks repaired by metal lacing in the late 1980's. These repairs are good for approximately 100,000 hours of operation.

Further NDE of the turbine shell and specifically the crack repairs should be performed to determine remaining life of the shell. During the 2016 generator and turbine valve inspection, it was recommended that plans be made to inspect all the turbine sections.

6.2 Turbine Valves

Per OEM recommendation, the turbine valves were previously on a maintenance cycle of 3 years, regardless of dispatch. Currently the turbine valves are maintained on a cycle of 30,000 hours. The turbine valves consist of the main steam stop and control valves. In general, the valves usually exhibit minor SPE when inspected. The most recent inspection on the valves was performed in the beginning of 2016 by the company Turbine Pros. Prior to the 2016 inspection the main stop valve was reopened during the startup outage following the 2005 inspection, otherwise the valves had not been opened since the fall outage of 2004.

From the 2016 inspection, the valves were found to be heavily contaminated with blue blush, and many of the components, particularly on the control valves, had seized, which greatly interfered with disassembly. Turbine Pros recommended that the valves be greased regularly and that valve outages, routine valve stroking, and trip and over-speed testing be performed at more regular intervals as recommended by the OEM. Many components were recommended for repair and replacement at the next outage. Likewise, NDEs were recommended for the control valves for the next outage as cracks were found on a few control valves. Turbine Pros also recommended replacing the studs and nuts on the lower equalizer valve flange of the intercept valve, as several of the nuts are frozen on the studs keeping the studs from being centered in the flange.

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 55/65ºC 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 55/65ºC 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 (%)

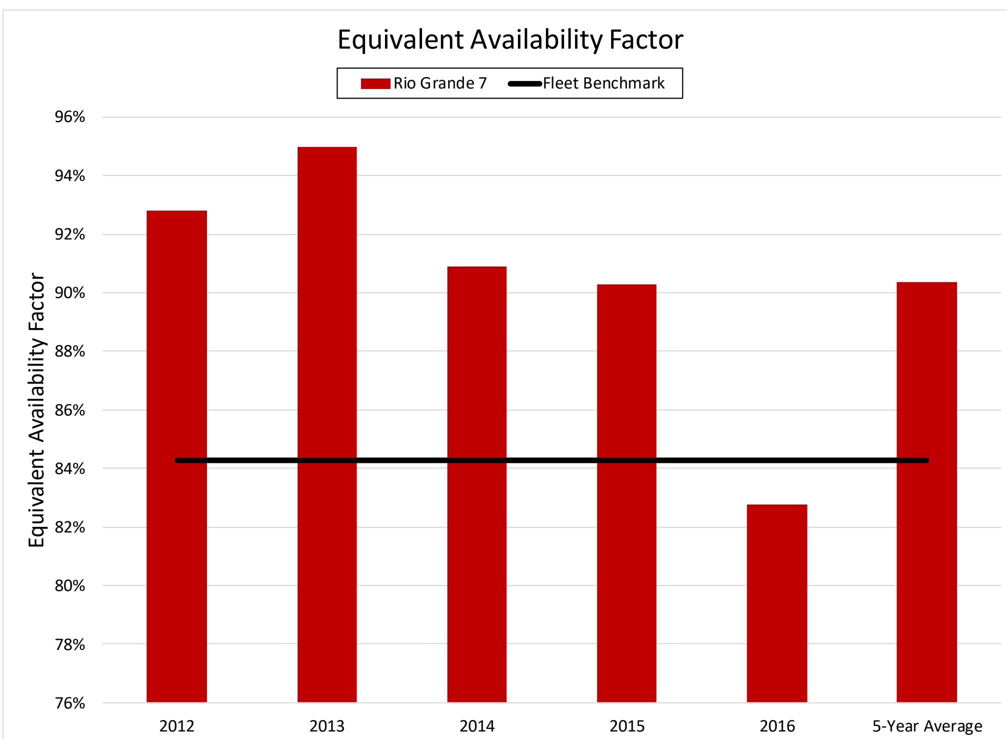
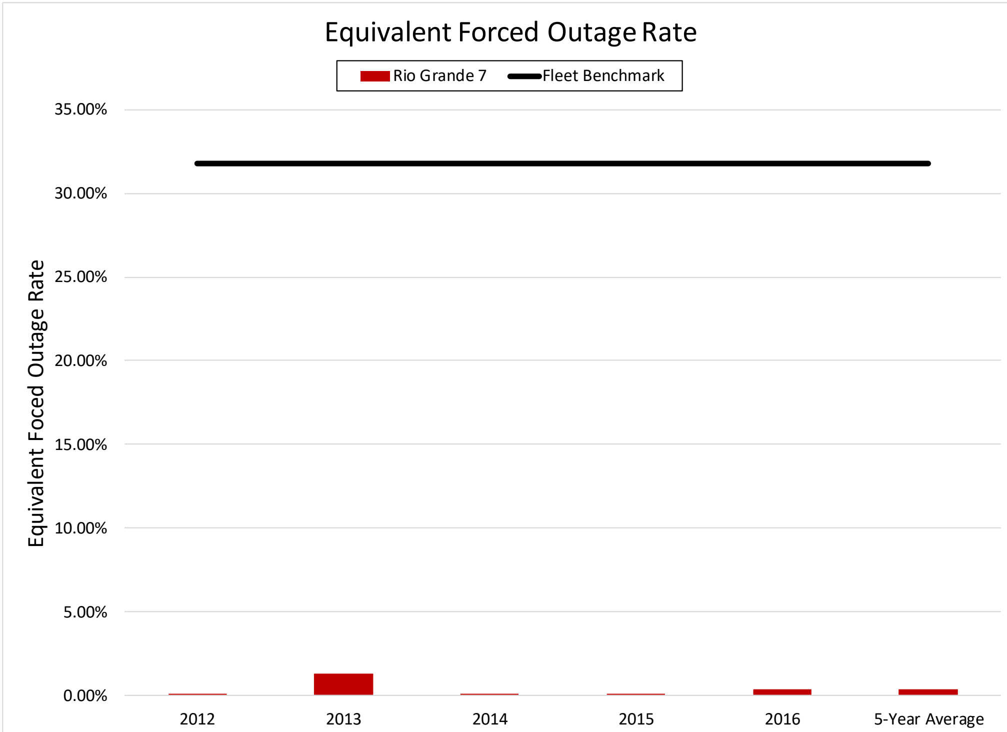


Figure 10-2: Equivalent Forced Outage Rate (%)



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

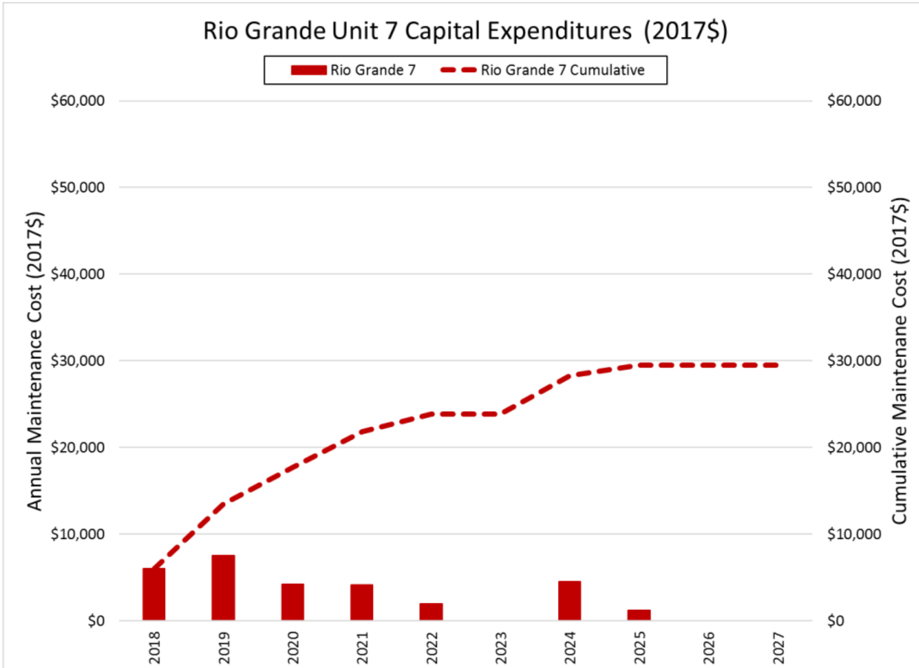
Likewise, the following non-recurring repairs and replacements are highly likely to be required within the next five years.

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.

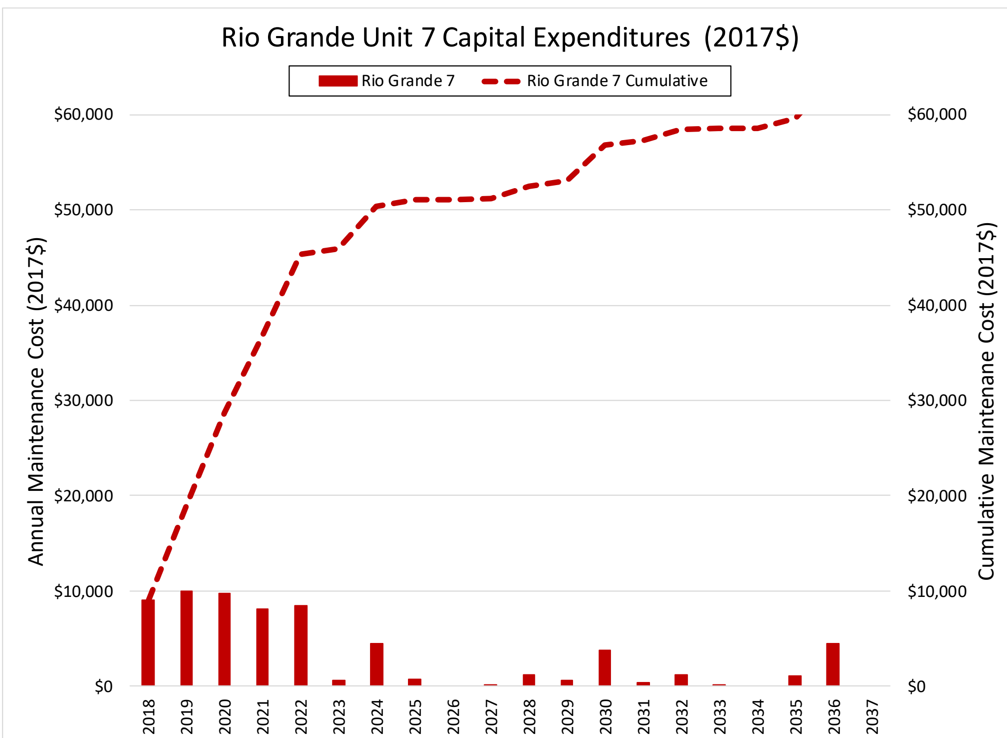
1. Replace primary super heater tubes
2. Replace reheat inlet tubes
3. Replace the main steam piping
4. Replace air heater intermediate and hot end baskets
5. Repair steam turbine blades, rotor, shell, and main valves
6. Rewind the generator
7. Replace the cooling tower
8. Replace the underground circulating 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

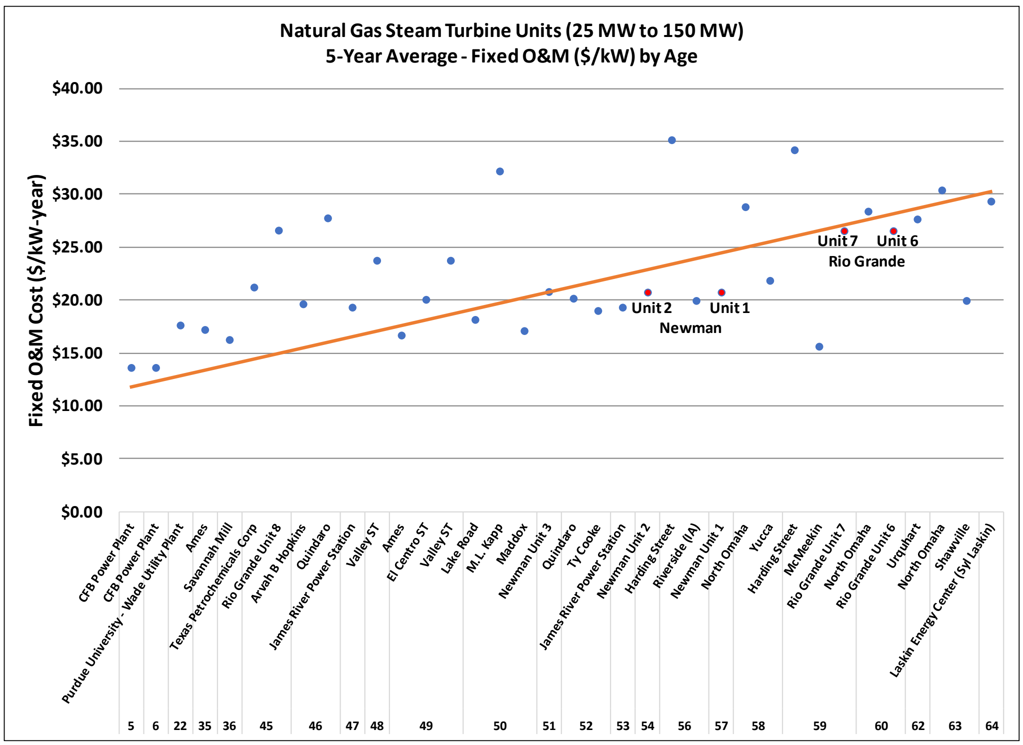
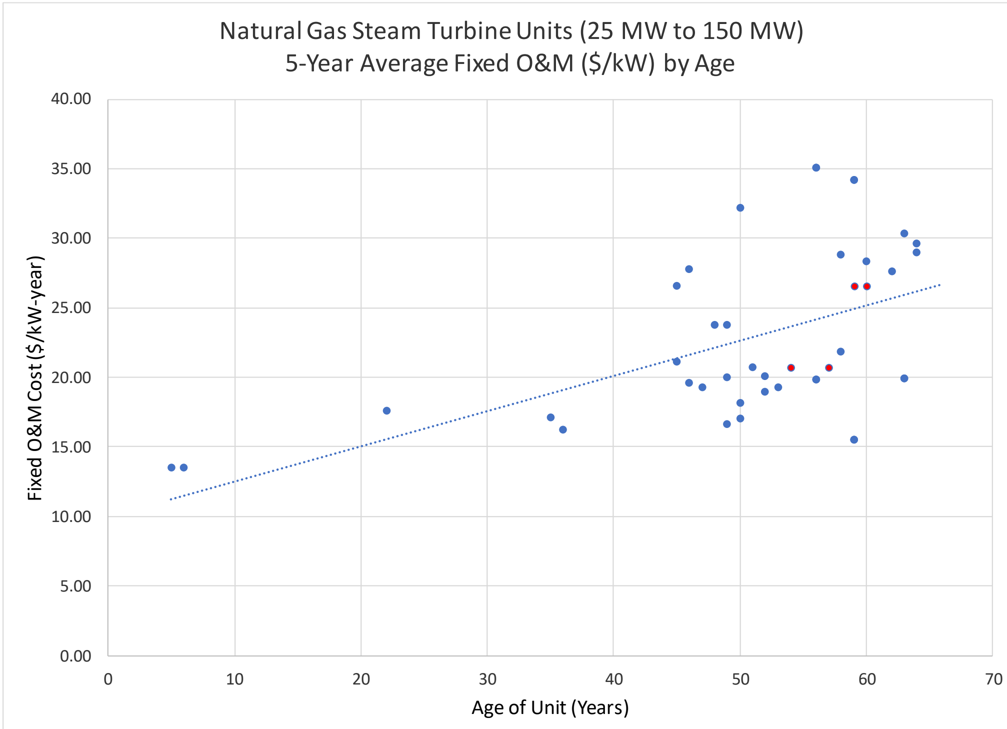
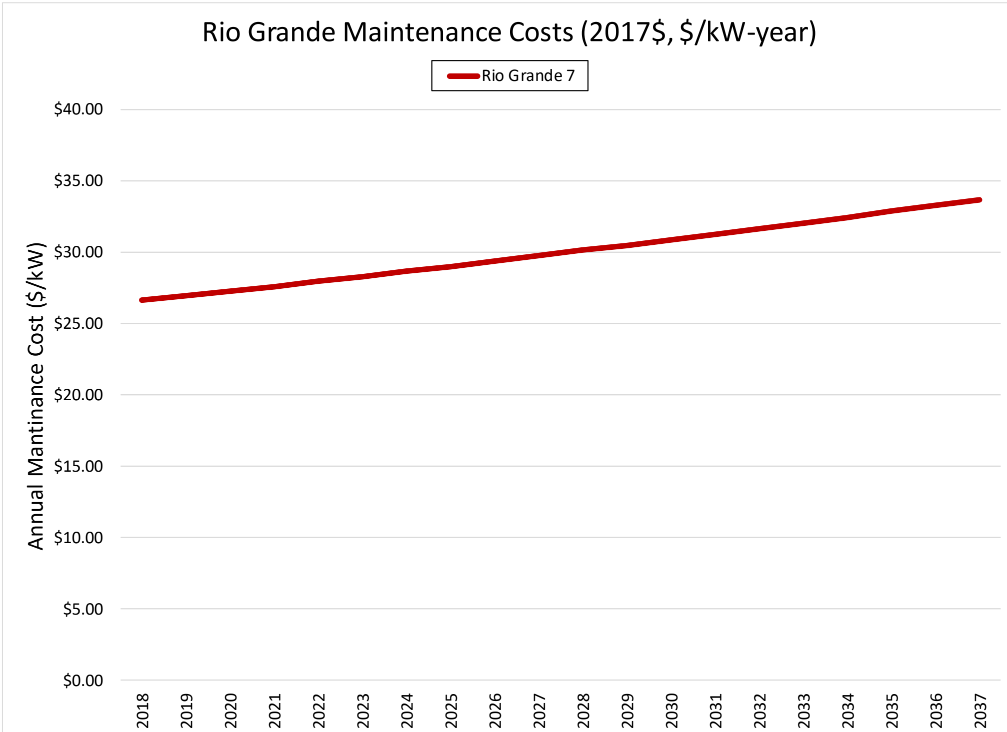


Figure 10-6: Maintenance Cost Trend Evaluation (X-Y Scatter)



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%

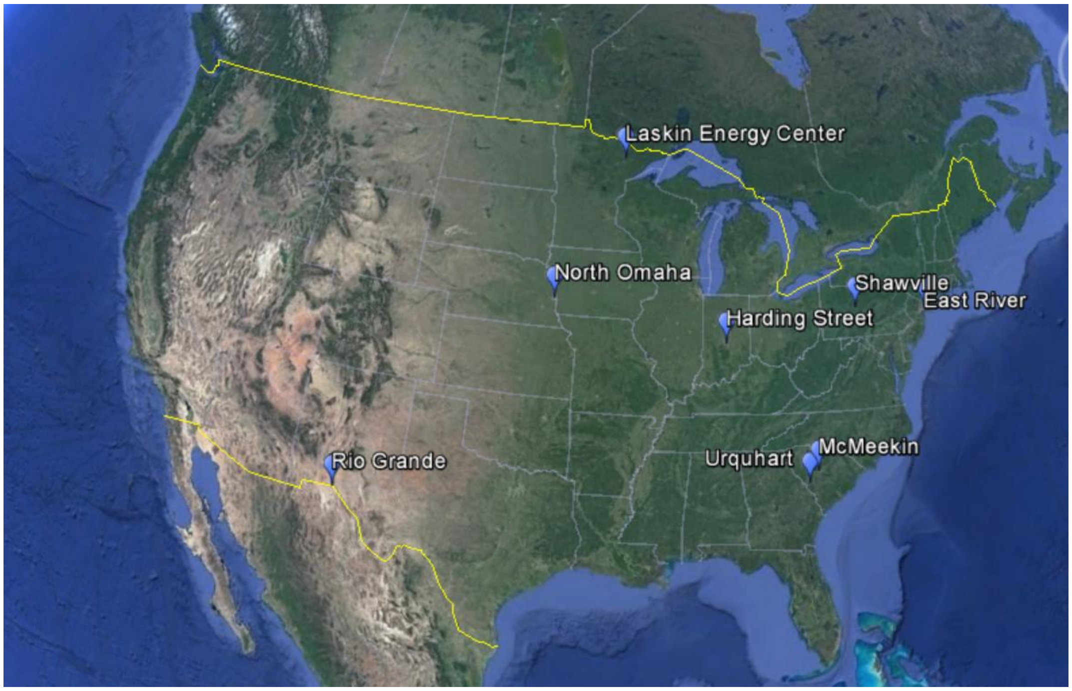
Note: The Average Fixed O&M is representative of all units except East River, which is an outlier.

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

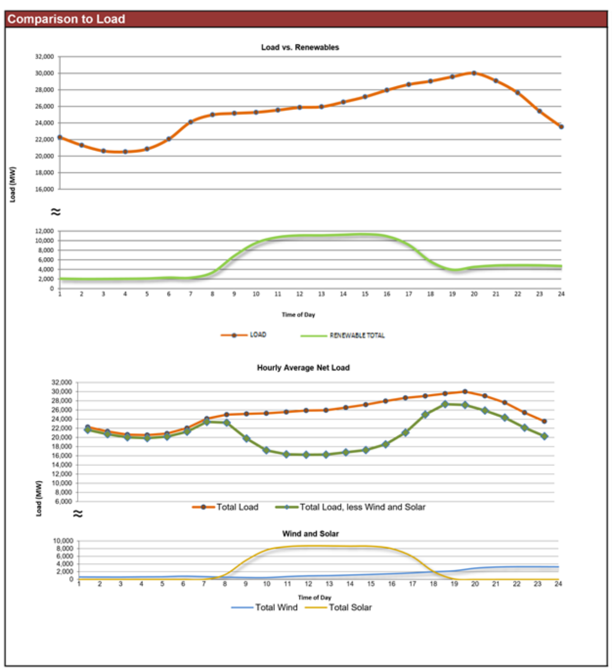
In addition to the costs associated with operating and maintaining the Unit, there are other external factors, such as flexibility or environmental considerations, that may impact the useful service life and long-term viability of the Unit.

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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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 55/65º 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 55/65ºC 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 55/65ºC 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 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 55/65º 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 65ºC 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 55/65ºC 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
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.

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 (%)

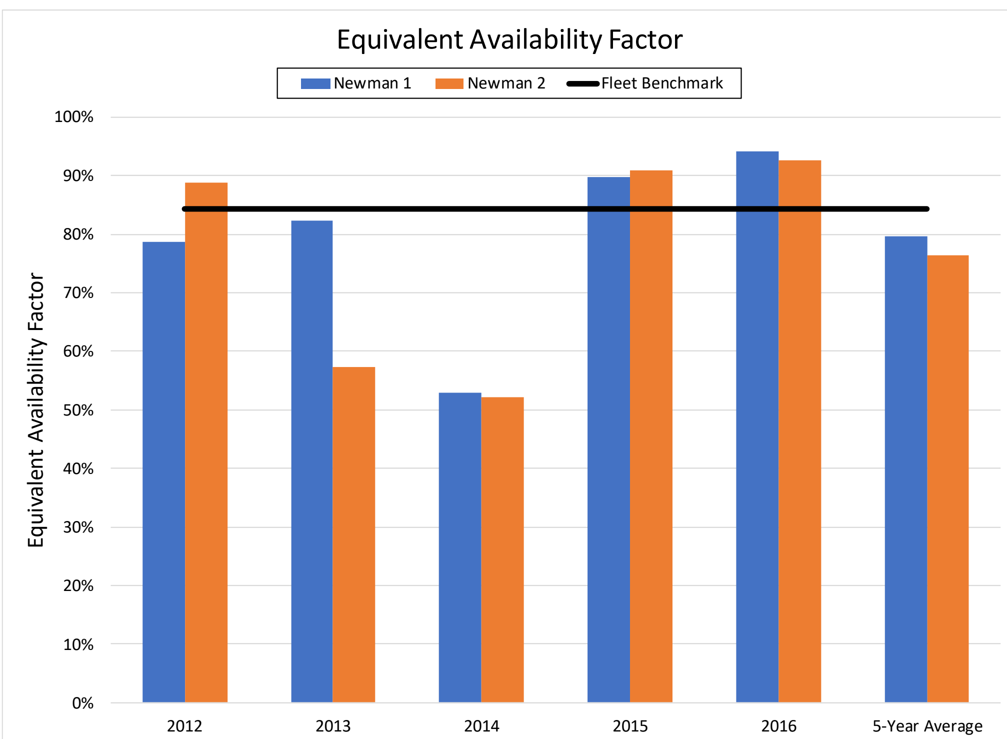
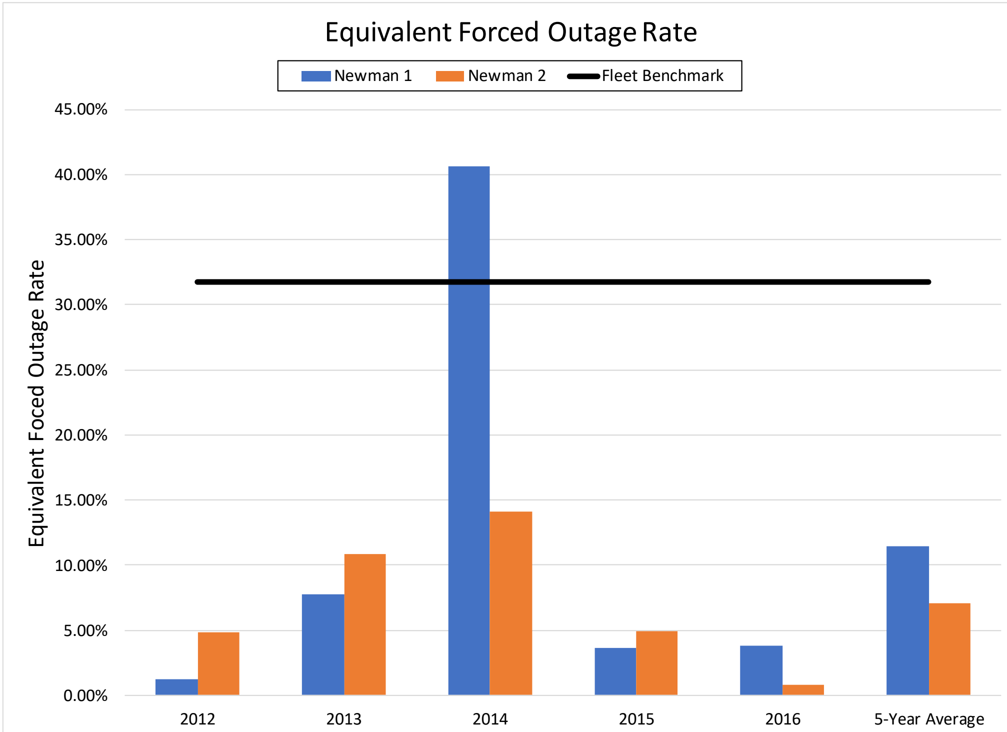


Figure 10-2: Equivalent Forced Outage Rate (%)



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

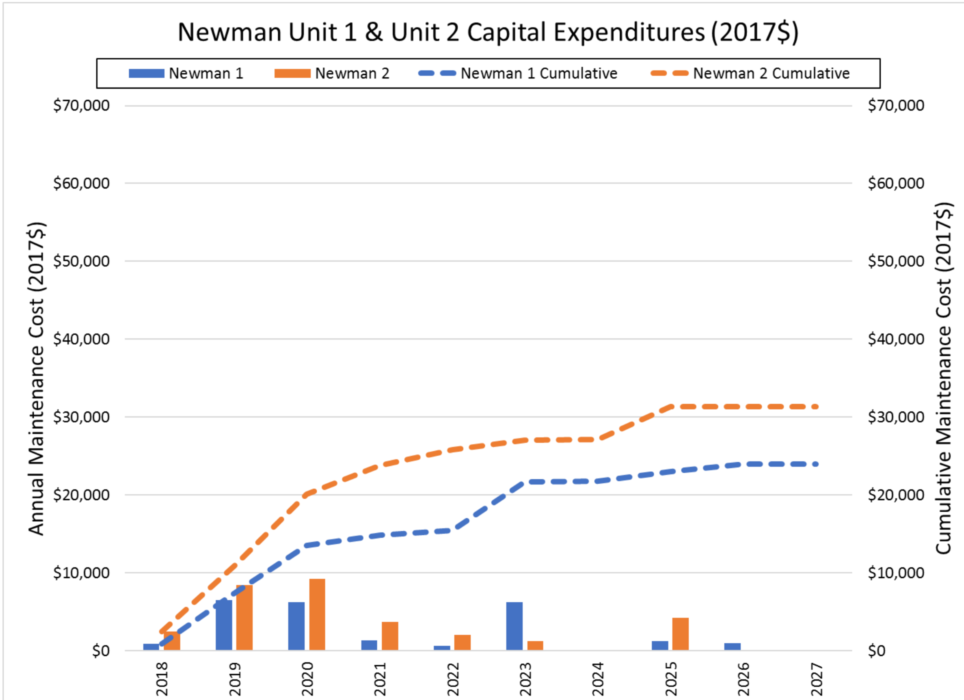
In addition, for Unit 2 only:

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

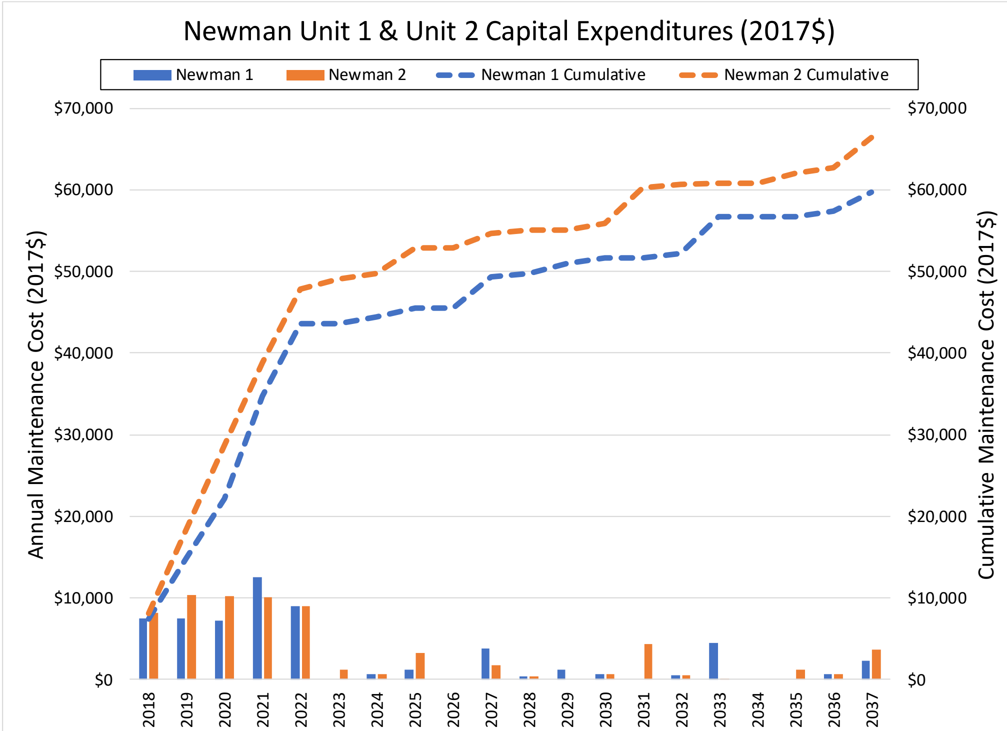
In addition, for Unit 2 only:

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

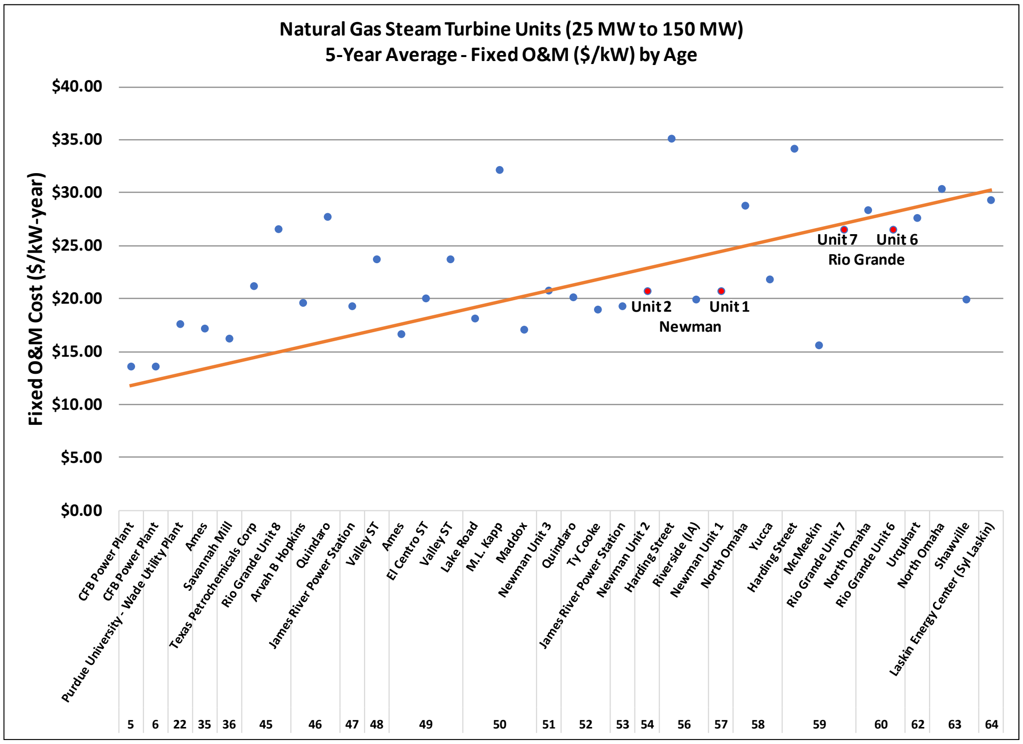
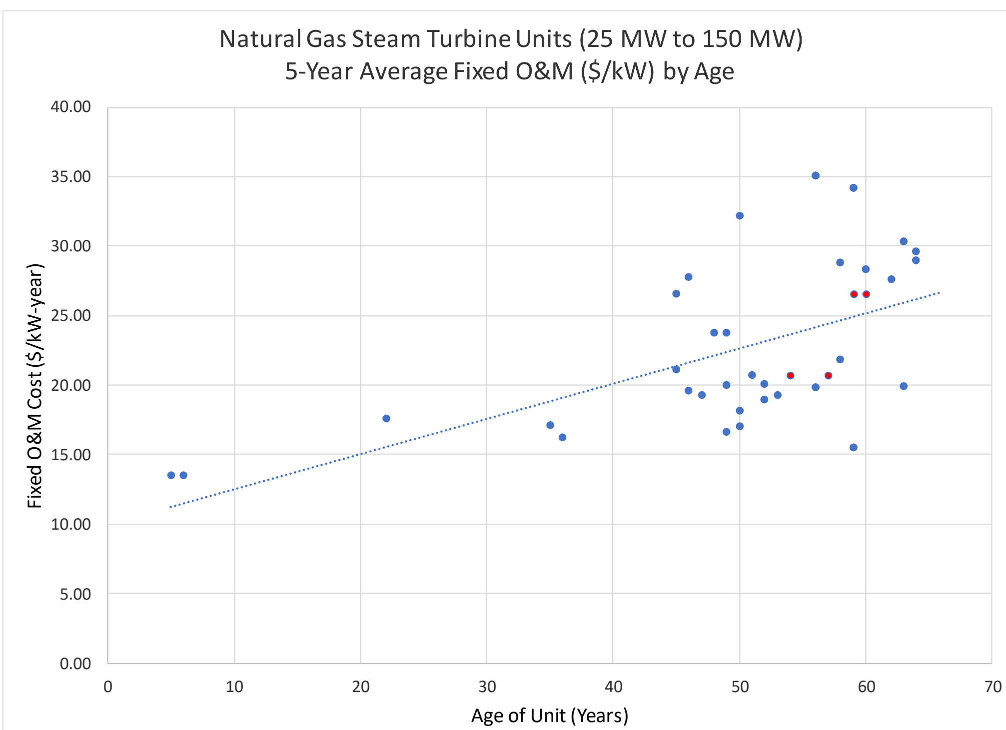
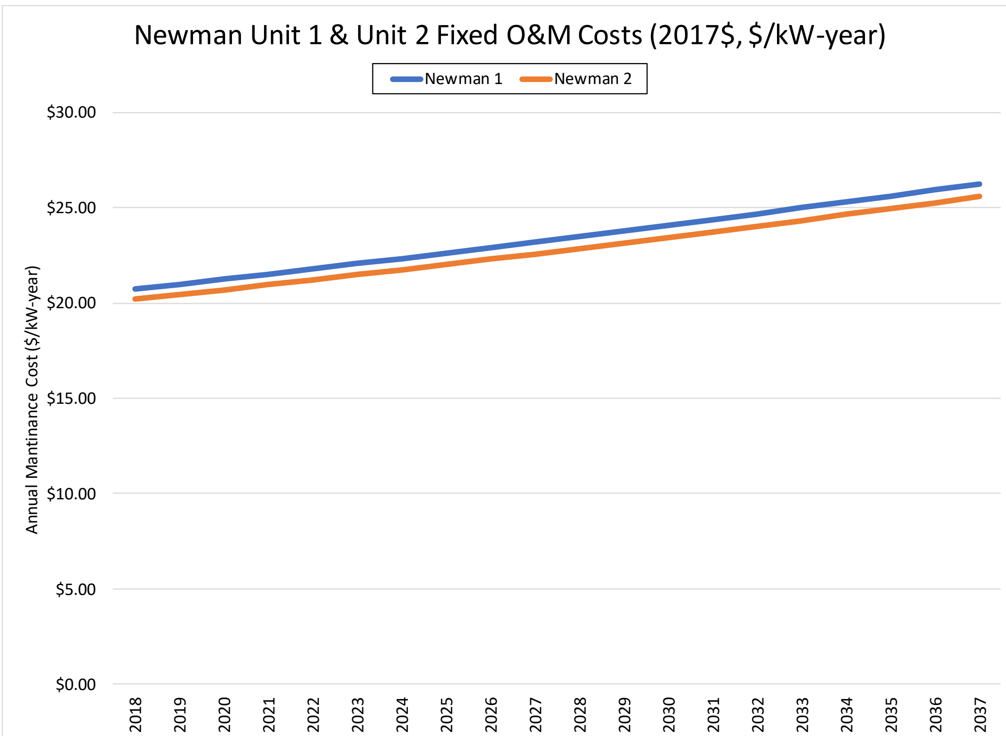


Figure 10-6: Maintenance Cost Trend Evaluation (X-Y Scatter)



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%

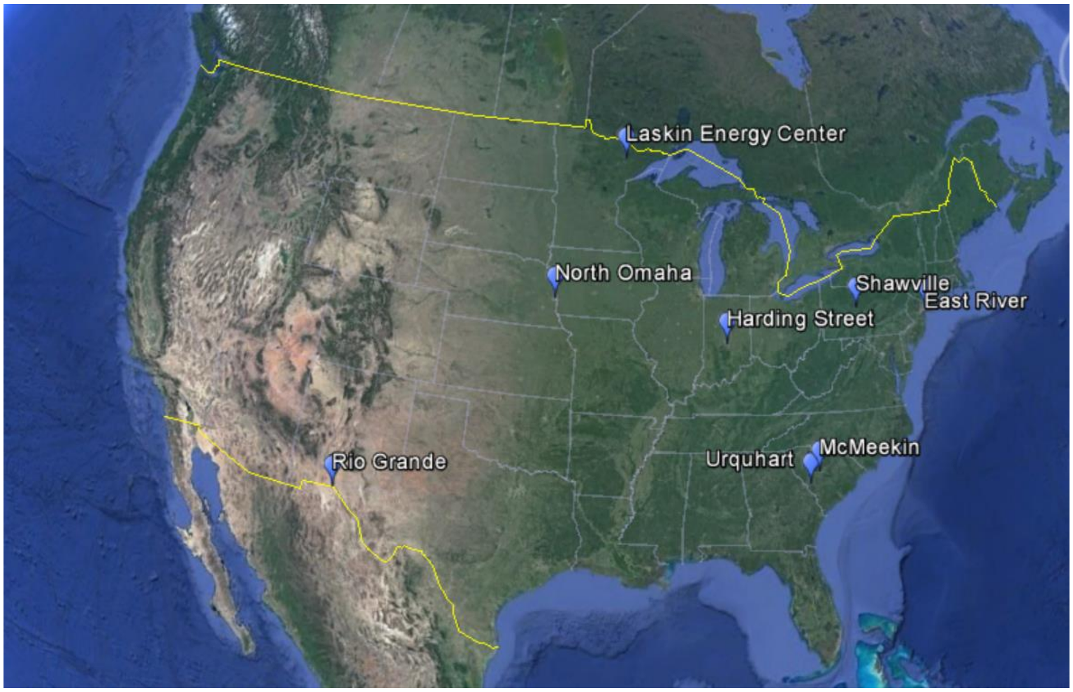
Note: The average fixed O&M is representative of all units excluding East River, which is an outlier.

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

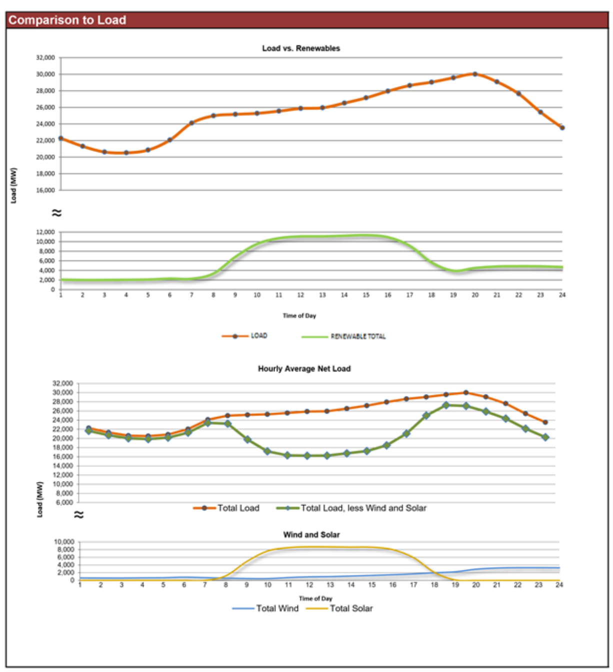
In addition to the costs associated with operating and maintaining the Units, there are other external factors, such as flexibility or environmental considerations, that may impact the useful service life and long-term viability of the Units.

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

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

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	$7,200	$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

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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BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF EL PASO ELECTRIC COMPANY FOR APPROVAL OF ABANDONMENT OF ITS RIO GRANDE POWER PLANT UNIT 7 AND NEWMAN POWER PLANT UNIT 1 **EL PASO ELECTRIC COMPANY,** **Applicant.**	**Case No. 23-00___-UT**

DECLARATION OF DAVID C. HAWKINS IN SUPPORT OF THE FOREGOING DIRECT TESTIMONY TO THE APPLICATION OF EL PASO ELECTRIC COMPANY FOR APPROVAL OF ABANDONMENT

I ***David C. Hawkins***, pursuant to Rule 1-011 NMRA, state as follows:

1. I affirm in writing under penalty of perjury under the laws of the State of New Mexico that the following statements are true and correct.

2. I am over 18 years of age and have personal knowledge of the facts stated herein. I am employed by El Paso Electric Company ("EPE" or "the Company") as *Vice President of System Operations and Resource Strategy..*

3. The foregoing Direct Testimony of David C. Hawkins, together with all exhibits sponsored therein and attached thereto, is true and accurate based on my knowledge and belief.

4. I submit this Declaration, based upon my personal knowledge and upon information and belief, in support of EPE's ***Application for Approval Abandonment.***

FURTHER, DECLARANT SAYETH NAUGHT.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on December 1, 2023.

/s/ David C. Hawkins
DAVID C. HAWKINS

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF EL PASO ELECTRIC COMPANY FOR APPROVAL OF ABANDONMENT OF ITS RIO GRANDE POWER PLANT UNIT 7 AND NEWMAN POWER PLANT UNIT 1 EL PASO ELECTRIC COMPANY, Applicant.	)	Case No. 23-00___-UT

DIRECT TESTIMONY

OF

J KYLE OLSON

ON BEHALF OF

EL PASO ELECTRIC COMPANY

DECEMBER 5, 2023

EL PASO ELECTRIC COMPANY
DIRECT TESTIMONY OF
J KYLE OLSON

TABLE OF CONTENTS

EXHIBITS

EL PASO ELECTRIC COMPANY
DIRECT TESTIMONY OF
J KYLE OLSON

I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is J Kyle Olson, and my business address is 100 N. Stanton Street, El Paso, Texas 79901-1341.

Q2. HOW ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE" or the "Company") as Director-Power Generation and Asset Management.

Q3. PLEASE SUMMARIZE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I graduated from Georgia Tech with a Bachelor of Science degree in Electrical Engineering in 2012. Upon graduation, I was employed by EPE as a Power Plant Engineer at the Newman Power Station. In May 2014, I was laterally moved to the Generation Projects Team to help oversee the design, construction, and commissioning of the Montana Power Station. During this time, I completed my Master of Business Administration degree at The University of Texas at El Paso.

In late June 2016, I was promoted to Assistant Manager at EPE's Newman Power Station. I became a licensed Professional Engineer in New Mexico in March 2017 and in Texas in May 2017.

In April 2019, I was promoted to Manager of Power Generation Engineering. This team is responsible for all capital and large maintenance engineering projects to support all EPE's local generation.

In December of 2021 I was promoted to my current position as Director-Power Generation and Asset Management, where my duties expanded to oversee the capital additions placed in service at Palo Verde Generating Station ("Palo Verde") along with Palo Verde's operations and maintenance ("O&M") expenses. Additionally, I review and approve nuclear fuel contracts and nuclear fuel expenses.

Q4. HAVE YOU PRESENTED TESTIMONY BEFORE A UTILITY REGULATORY BODY?

A. Yes. I have previously presented testimony before the Public Utility Commission of Texas ("PUCT").

II. PURPOSE OF TESTIMONY

Q5. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My direct testimony supports EPE's Application to Abandon Rio Grande Unit 7 ("Rio Grande Unit 7" or "RG7") and Newman Unit 1 ("Newman Unit 1" or "NM1"). My testimony specifically addresses the physical condition of these units, as well as the relevant operational considerations that support abandonment.

Q6. ARE YOU SPONSORING EXHIBITS TO YOUR TESTIMONY?

A. Yes. I am sponsoring Exhibit JKO-1, which is a Lawrence Berkeley National Laboratory study which reports on the average age of natural gas steam generating units in the United States.

While I do not sponsor them, I also refer to two exhibits sponsored by EPE witness David C. Hawkins. First is Exhibit DCH-05, which is a 2018 Burns & McDonnell study commissioned by EPE ("2018 RG7 BMcD Study"). This 2018 study assessed whether RG7 could operate reliably through 2027 and 2037 retirement dates. Additionally, I refer to Exhibit DCH-06 which is the Burns & McDonnell study commissioned by EPE in 2018 which assess the condition and reliability of NM1 through retirement dates 2027 and 2037 ("2018 NM1 BMcD Study").

III. PHYSICAL CONDITION AND OPERATIONS OF RG7 AND NM1

Q7. PLEASE PROVIDE THE GENERAL CHARACTERISTICS OF RG7 AND NM1.

A. General background details for each of the units are described below in Table JKO-1.

Table JKO-1: General Description of RG7 and NM1

Unit	Unit Type	Fuel Source	Boiler Design	Steam Turbine Manufacturer	Year Online	Name Plate Capacity (MW)
RG7	Traditional Steam	Natural Gas	Babcock and Wilcox-El Paso	General Electric	1958	50
NM1	Traditional Steam	Natural Gas	Babcock and Wilcox-El Paso	Allis Chalmers	1960	81.6

As can be seen, RG7 is approximately 65 years old and NM1 is approximately 63 years old.

Q8. HOW DOES THE AGE OF RG7 AND NM1 COMPARE TO OTHER GENERATING UNITS IN EPE'S GENERATING FLEET?

A. Table JKO-2 shows the age of all of EPE's generating units. As the table demonstrates, RG7 and NM1 are among the oldest units in EPE's generating fleet.

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Table JKO-2
Age of EPE Generating Units

Unit Name	COD	Age of Unit
Rio Grande 6	6/15/1957	66
Rio Grande 7	6/12/1958	65
Newman 1	5/1/1960	63
Newman 2	6/1/1963	60
Newman 3	3/16/1966	57
Rio Grande 8	7/31/1972	51
Newman 4GT1	8/1/1975	48
Newman 4GT2	8/1/1975	48
Newman 4ST	8/1/1975	48
Copper 1	7/1/1980	43
Newman 5GT3	5/22/2009	14
Newman 5GT4	5/22/2009	14
Newman 5ST	4/30/2011	12
Rio Grande 9	5/13/2013	10
Montana 1	3/19/2015	8
Montana 2	3/20/2015	8
Montana 3	5/3/2016	7
Montana 4	9/15/2016	7

The only unit older than RG7 and NM1 is Rio Grande Unit 6, which has been approved for abandonment in NMPRC Case No. 20-00194-UT.

Q9. HOW DOES THE AGE OF RG7 AND NM1 COMPARE TO OTHER GAS-FIRED GENERATING UNITS IN THE UNITED STATES?

As documented in Exhibit JKO-1, a Lawrence Berkeley National Laboratory study that was supported by the Department of Energy, the average age of recently retired natural gas steam units in the United States is 40 to 50 years. Thus, both RG7 and

NM1 have been operational longer than the average for similar units. The removal of RG7 and NM1 from service for New Mexico customers after 60 years of service is therefore consistent with industry practice. The same report estimates the upcoming retirements of the remaining older natural gas steam units to be under 60 years of age. RG7 and NM1's retirement age of 63 plus years are on the higher end of the age and retirement spectrum of natural gas steam units of its vintage.

Q10. WHAT IS THE APPROPRIATE WAY TO ASSESS FUTURE RELIABILITY OF EPE'S UNITS?

A. The appropriate way to assess the future reliability of a unit is a physical inspection of the unit combined with a review of the unit's maintenance records and operating history and conditions. During a physical inspection, a team of engineers evaluate the state of the multiple assets making up a generating unit. They determine the risks of catastrophic failures and other types of failures. Nondestructive testing would be performed on steam lines at known high stress points and other areas identified as high-risk based on operating conditions, materials of construction and design factors. Borescope inspections would be performed on the turbine and other assets, along with partial disassembly of some assets to inspect for wear and tear. Much of this is performed during a major maintenance inspection to obtain condition assessment information. Once the physical inspection is complete, the maintenance records and operating conditions would be reviewed. Evaluations would be completed on total run time on parts and time between major repair intervals. All of this accumulated data and inspection findings are required to fully assess a unit's future reliability based on system and asset conditions.

Q11. WHEN WAS THE LAST TIME EPE CONDUCTED SUCH AN INSPECTION OF RG7 AND NM1?

A. EPE conducted nondestructive testing on steam lines at known high stress points and other areas identified as high risk based on operating conditions, materials of construction and design factors in 2018 on NM1 and in 2019 on RG7.

Q12. WHAT DID THE 2018 INSPECTION OF NM1 SHOW?

A. NM1's inspection showed fatigue type damage on the main steam system that required repairs and additional regular inspections.

Q13. HOW MUCH DO THE ADDITIONAL REGULAR INSPECTIONS COST?

A. Each inspection is between $150,000 to $250,000 per unit.

Q14. WHAT DID THE 2019 INSPECTION OF RG7 SHOW?

A. RG7's inspection showed some spheroidization (softening) in the main steam and hot reheat lines as well as the superheat and reheat outlet headers.

Q15. WHAT ARE THE RISKS FROM SPHEROIDIZATION?

A. Spheroidization increases the risk of catastrophic failure due to the softening of the steam lines.

Q16. DOES EPE CONDUCT OTHER ROUTINE INSPECTIONS OR EVALUATIONS OF RG7 AND NM1?

A. Yes. EPE routinely performs turbine and boiler inspections. These inspections usually occur during the spring and are typically conducted in-house as a method of preparing the unit for summer operation.

Q17. DO THESE INSPECTIONS SUPPORT ABANDONMENT OF RG7 AND NM1?

A. Yes, as explained above.

Q18. WHAT OTHER STEPS HAS EPE TAKEN TO EVALUATE THE PHYSICAL CONDITIONS OF THE UNITS AND THE COSTS TO EXTEND THEIR OPERATIONS?

A. EPE periodically commissions engineering studies to evaluate the condition of generation units near the end of their expected lives and the costs associated with the reliable extension of operations. For example, in 2018, EPE commissioned the 2018 BMcD RG7 Study and the 2018 BMcD NM1 Study to evaluate whether it would be cost-effective to extend the useful life of RG7 and NM1 beyond the then-current 2022 retirement date. *See* Exhibit DCH-05 and DCH-06. The 2018 BMcD Studies concluded that an extension of RG7 and NM1 became more costly than new generation at the two to four-year mark, or by 2023. Beyond that period, the 2018 BMCD Studies concluded that the cost of extending RG7 and NM1 would not be justified, and that other considerations, including safety considerations, weighted against attempting to extend the useful life of the units.

As a separate effort, in 2018, EPE commissioned BMcD to again assess the potential life extension of RG7 and NM1 as part of its 2018 Integrated Resource Plan ("2018 IRP"). As EPE witness Hawkins describes, the RG7 and NM1 extension costs identified in 2018 were utilized in its 2018 IRP and 2017 All-Source RFP resource portfolio analysis and were determined not to be cost-effective.

Q19. WHAT WERE THE SPECIFIC FINDINGS OF THOSE EVALUATIONS?

A. To extend the life of RG7 through 2037 would cost $92,978,000, not accounting for inflation. Similarly, to extend the life of NM1 through 2037 would cost $94,349,000, not accounting for inflation. As described by EPE witness Hawkins, it is not cost-effective to extend the life of RG7 and NM1 given the costs identified by the BMcD assessments.

Q20. ARE THE RESULTS OF THE BMCD ASSESSMENTS CONSISTENT

WITH THE AGE, OPERATION AND CONDITION OF THE UNIT?

A. Yes. The results of the BMcD assessments are consistent with RG7 and NM1 operating characteristics, age, and operating history.

Q21. PLEASE DESCRIBE THE CURRENT OPERATIONS OF RG7 AND NM1

A. Both units were used to serve load through the summer of 2023. EPE now plans the units will enter contingency reserve status when no longer needed to support load.

Q22. WHAT IS CONTINGENCY RESERVE STATUS?

A. The term "contingency reserve" was utilized as a descriptor for a resource, such as RG7 and NM1 which may be in "inactive reserve" or "mothball" status but can be utilized in the event of unforeseen multiple contingencies.

Q23. HAS THE OPERATION OF EACH OF THESE UNITS BEEN TYPICAL FOR A UNIT OF ITS VINTAGE?

A. Yes. It was typical for this vintage of generating unit to be transitioned from base load to load following and seasonal operations as thermal performance improvements, newer gas turbine technology and large nuclear units began to penetrate the industry in the early 1970s. However, its operation as a load following, cycling unit has created additional maintenance and planning challenges for the generating unit.

Q24. HOW HAS THE OPERATIONS OF EACH OF THESE UNITS IMPACTED THEIR PHYSICAL CONDITION?

A. Operation as a load following, cycling unit has impacted the unit's components. The boiler, turbine and primary auxiliary components that make up the generating units undergo accelerated wear and thermal creep due to the age and the cyclic nature of the operation. In particular, the boiler high steam pressure parts undergo metal fatigue and begin to lose strength, become eroded and develop stress cracking.

Q25. WHAT ARE THE EXPECTED OPERATIONS OF RG7 AND NM1 AFTER ABANDONMENT?

A. Both units will be retired and decommissioned following abandonment, which, as explained by EPE witness Hawkins, is expected to be in January of 2026. If all goes according to plan, RG7 and NM1 will be a contingent resource available only if needed until December 2025, and will be retired and decommissioned in early 2026.

Q26. HOW DOES THE PHYSICAL CONDITION OF RG7 AND NM1 IMPACT THE RELIABILITY OF OPERATIONS?

A. The current physical condition negatively impacts the reliability and operation of the units. As indicated, with several of the key elements of the units either in need of major inspection, repair or replacement, the threat to reliable operations during the peak season is significant. In addition, RG7 and NM1 are among EPE's least efficient generating units, not only due to their age, but also due to their original design which was before advancements in efficiency in the industry.

Q27. HOW DOES THE EFFICIENCY OF RG7 AND NM1 COMPARE TO THE EFFICIENCY OF EPE'S OTHER NATURAL GAS GENERATION UNITS?

A. As seen on Table JKO-3, between 2020 and 2022, RG7 had an average actual Net Heat Rate of 13,104 and NM1 had an average actual Net Heat Rate of 13,204 Btu/kWh, which makes them two of the least efficient generating units operated by EPE.

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Table JKO-3
Unit Historical Net Average Heat Rate 2020-2022 Btu/kWh

Unit	3 Year Average
Copper	17,926
MPS 1	9,863
MPS 2	9,845
MPS 3	10,542
MPS 4	9,649
NM 1	13,204
NM 2	12,232
NM 3	12,205
NM 4-ST	10,691
NM 5-ST	8,231
Rio 6	14,366
Rio 7	13,104
Rio 8 (A)	11,602
Rio 9	10,012

(A) Rio Grande 8 had low levels of operations in June 2020 due to a forced outage resulting in an inaccurate average heat rate of 13,271 for the year 2020. For analysis purposes, June 2020 heat rate was removed from the 3-year average.

Q28. WHAT IS A NET HEAT RATE?

A. Net heat rate is defined as the amount of fuel energy (measured in British thermal units ("Btu")) used to produce one kilowatt-hour ("kWh") of electricity delivered to the transmission system. This is an industry accepted measurement of generating unit performance which is used to monitor unit thermal efficiency. Net heat rate is one of two key indicators the Company uses to monitor the performance of its local generating units. Efficient power generation equates to less fuel consumed to produce a kWh and therefore lower fuel costs. A lower net heat rate means the turbine generator is more efficient than a unit with a higher net heat rate. The goal is to maintain a reasonable level of efficiency while satisfying system reliability requirements.

Q29. DOES THE INFORMATION IN TABLE JKO-3 SUPPORT ABANDONMENT?

A. Yes, as discussed RG7 and NM1 are among two of the least efficient units with net average heat rates over 13,000 Btu/kWh.

Q30. HOW DOES THE RELIABILITY OF RG7 AND NM1 COMPARE TO THE RELIABILITY OF EPE'S OTHER NATURAL GAS GENERATION UNITS?

A. Figure JKO-1 shows the 3-year average of Net Capacity Factor (NCF) and Peak Equivalent Availability Factor (EAF) for all plants excluding RG6, RG7, and NM1 in comparison to NM1 and RG7. NM1 and RG7 fall below the 3-year average.

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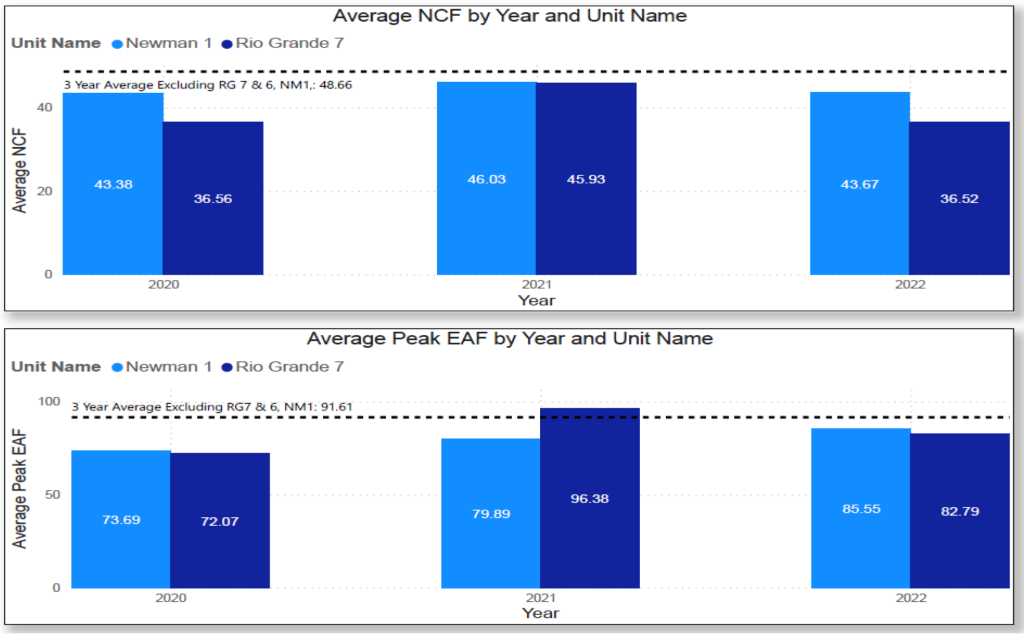
Figure JKO-1

Unit Historical Net Capacity Factor and Peak Equivalent Availability Factor



Q31. Q. WHAT IS A NET CAPACITY FACTOR?

A. Net Capacity Factor is the maximum net energy produced for the period.

Q32. WHAT IS A PEAK EQUIVALENT AVAILABILITY FACTOR ("EAF")?

A. EAF is also an industry accepted measurements of generating unit performance. EAF is used to measure unit availability, based on the percentage of time within a given period that a unit is available to generate electricity. EAF is the second of two key indicators the Company uses to monitor the performance of its local generating units. EPE uses EAF to measure the performance of EPE's local generating units because it provides a clear indication of overall unit availability for a given period.

Q33. WHAT DO YOU CONCLUDE FROM FIGURE JKO-1?

A. Figure JKO-1 supports abandonment because it shows that RG7 and NM1 operate less and are less reliable than the rest of EPE's local generation.

Q34. WHAT ADDITIONAL RELIABILITY CONCERNS EXIST FOR RG7 AND NM1?

A. Due to the overall age of the elements that make up the RG7 and NM1, there are many risks to reliability—some minor with minimal longer-term impact, and others with potentially severe consequences to reliability. Considering that a significant number of the components comprising the units are aged, there is an inherent risk to the continued reliable operation of these units. Over the years, the units' primary elements have been maintained as necessary to achieve a high level of reliable operation, but it is impractical and would be very costly to assume that all components would have been replaced to be able to maintain "like new" reliability. Therefore, as even minor, seemingly insignificant components age or are exposed to heat and electrical cycling, life reduction continues to compound. Subsequently, the overall reliability risk increases. The unseen or inaccessible elements pose the greatest threat to reliability.

Q35. WHAT SAFETY CONCERNS EXIST FOR THESE UNITS?

A. The primary safety risk facing these unit's is catastrophic failure associated with the high pressure/temperature boiler and steam piping pressure components. These components are subject to high thermal stresses during operation, and the metal fatigue is compounded during cycling of the unit.

Q36. ARE THERE ENVIRONMENTAL CONSIDERATIONS?

A. Yes, many of the issues with the physical condition of RG7 and NM1 discussed above lead to increased fuel consumption. As a unit ages, its heat rate begins to increase due to these additive inefficiencies, and additional fuel is needed to compensate and achieve the same unit of electrical output.

An additional environmental consideration is the amount of water these older steam units consume. Modern generating units require less water demand per unit of electrical generation.

Q37. DO RG7 AND NM1 HAVE POLLUTION CONTROL TECHNOLOGY?

A. No, RG7 and NM1 have no pollution controls. The construction, permitting and initial operation of these units predates emissions limitations and the pollution control requirements inherent in the Prevention of Significant Deterioration (PSD) requirements of the Clean Air Act. In contrast, newer units, such as Rio Grande

Unit 9, Montana Units 1 through 4, and the proposed Newman Unit 6, have modern pollution control equipment.

EPE witness Hawkins discusses the current status of the clean air permit covering these units.

Q38. DO ANY OTHER CONCERNS ARISE FROM RUNNING GENERATING UNITS THIS OLD?

A. Yes. One significant factor is the need to reverse-engineer system or component maintenance solutions in order to retrofit newer technology to address the aged systems or components that require maintenance. As a result, maintenance becomes more costly as components for direct replacement, technical support and expertise become limited or non-existent.

Q39. WHY DID EPE DECIDE TO RETIRE NM1 IN DECEMBER 2022 AND EXTEND NM2 TO DECEMBER 2027?

A. As discussed by EPE witness Hawkins, the EPE Power Generation group requested to retire NM1 instead of NM2 as a result of turbine governor issue that arose post 2018 study. These governor issue restricts the unit from operating on Automatic Generation Control ("AGC") and requires operator action to change load.

IV. SUMMARY AND CONCLUSION

Q40. PLEASE SUMMARIZE YOUR TESTIMONY.

A. There is no doubt that RG7 and NM1 have played an integral role in EPE's operating history. These units have undergone sound maintenance under well-defined programs, have been operated within well-managed operating parameters, and have been reliable units. However, due to the factors discussed in my testimony, their continued suitability for service, in a reliable and safe manner, can no longer be supported without extensive evaluation and investment. Though these evaluations and investments can be made, it would not be prudent, as it would certainly lead to undesirable stranded costs for EPE and its customers.

In addition, it would be nearly impossible to perform a complete system-by-system evaluation to help mitigate the risk to reliability and safety. An effort such as this would be very costly and should a component or series of components be missed, the reliability would suffer even after spending the capital and time to accomplish such an evaluation and associated repairs. There are inaccessible areas of the furnace, the boiler and turbine that would need to be inspected and likely repaired or replaced at a high cost in order to continue the operation of these units.

Finally, RG7 and NM1 have no pollution controls and consume more water relative to other newer units, which is a reality that cannot be mitigated in a cost-effective manner.

Q41. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Power Plant Retirements: Trends and Possible Drivers

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Disclaimer

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Abstract

This paper synthesizes available data on historical and planned power plant retirements. Specifically, we present data on historical generation capacity additions and retirements over time, and the types of plants recently retired and planned for retirement. We then present data on the age of plants that have recently retired or that have plans to retire. We also review the characteristics of plants that recently retired or plan to retire vs. those that continue to operate, focusing on plant size, age, heat rate, and SO_2 emissions. Finally, we show the level of recent thermal plant retirements on a regional basis and correlate those data with a subset of possible factors that may be contributing to retirement decisions.

This basic data synthesis cannot be used to precisely estimate the relative magnitude of retirement drivers. Nor do we explore every possible driver for retirement decisions. Moreover, future retirement decisions may be influenced by different factors than those that have affected past decisions. Nonetheless, it is clear that recently retired plants are relatively old, and that plants with stated planned retirement dates are—on average—no younger. We observe that retired plants are smaller, older, less efficient, and more polluting than operating plants. Based on simple correlation graphics, the strongest predictors of regional retirement differences appear to include SO_2 emissions rates (for coal), planning reserve margins (for all thermal units), variations in load growth or contraction (for all thermal units), and the age of older thermal plans (for all thermal units). Additional apparent predictors of regional retirements include the ratio of coal to gas prices and delivered natural gas prices. Other factors appear to have played lesser roles, including the penetration variable renewable energy (VRE), recent non-VRE capacity additions, and whether the region hosts an ISO/RTO.

1 Introduction

There has been a significant amount of retirements of thermal generation assets in recent years, driven by a variety of market, policy, and plant-specific factors. There is uncertainty, however, on which factors have played the largest contributing roles.

- Average wholesale electricity prices have declined which, all else being equal, will erode the revenue possibilities of inflexible generation units (more-flexible units are in a somewhat better position to withstand average price declines, as they are able to dispatch around high- and low-priced periods).[1]
- Wholesale price reductions may be impacted by declining natural gas prices, growth in variable renewable energy (VRE), low load growth and high reserve margins, as well as other factors.
- New power plants may offer advanced technologies that enable improved heat rates, lower operating costs, lower emissions, and/or increased flexibility in operations, putting pressure on the economic position of older plants that use less-advanced technology.
- The operating costs of many existing plants are also rising over time, as those plants age and reach the end of their planned lifetimes and/or face increased regulatory pressures due to environmental regulations (e.g., coal and gas plants) or relicensing needs (nuclear and hydropower).
- A wide array of local, state, ISO/RTO, and federal requirements and incentives directed at power plants of all types and geographic locations also may be influencing retirement decisions.
- Finally, while retirements have increased recently, they have not done so in a vacuum, as generation capacity additions have also occurred, especially of natural gas, wind, and solar.

This paper synthesizes available data on historical and planned retirements. After describing our data sources, we present data on historical generation capacity additions and retirements over time, and the types of plants recently retired and planned for retirement. We then present data on the age of plants that have recently retired or that have plans to retire. We also review the characteristics of plants that recently retired or plan to retire vs. those that continue to operate, focusing on plant size, age, heat rate, and SO_2 emissions. Finally, we present various charts that depict the level of recent thermal plant retirements on a regional basis and correlate those data with a subset of possible factors that may be contributing to retirement decisions.

This basic data synthesis cannot be used to precisely estimate the relative magnitude of retirement drivers. Nor do we explore every possible driver for retirement decisions. Moreover, future retirement decisions may be influenced by different factors than those that have affected past decisions. Nonetheless, it is clear that recently retired plants are relatively old, and that plants with stated planned retirement dates are—on average—no younger. We observe that retired plants are smaller, older, less efficient, and more polluting than operating plants. Based on simple correlation graphics, the strongest predictors of regional retirement differences appear to include SO_2 emissions rates (for coal), planning reserve margins (for all thermal units), variations in load growth or contraction (for all thermal units), and the age of older thermal plans (for all thermal units). Additional apparent predictors of regional retirements include the ratio of coal to gas prices and delivered natural gas prices. Other factors appear to have played lesser roles so far, including VRE penetration, recent non-VRE capacity additions, and whether the region hosts an ISO/RTO or remains traditionally regulated.

2 Data and Methods

The data used in this paper come from several sources, summarized below:

- **Historical and planned retirements and historical additions data** primarily come from ABB's Velocity Suite dataset[2] (which, in turn, sources much of its data from EIA-Form 860M[3]). Historical distributed and utility-scale solar additions, however, come from GTM/SEIA and IREC.[4]
- **Summer non-coincident peak load** is estimated by simply summing the peak load of each region, as reported in ABB's Ventyx Velocity Suite.
- **Summer planning reserve margins** come from EIA-Form 411, updated as of March 2017.[5]
- **Power plant ages** come from ABB's Velocity Suite dataset.
- **VRE regional penetration** estimates come, in part, from annual wind generation reported in ABB's Velocity Suite divided by total generation in the region. For generators that had not yet reported 2016 data, we assumed 2015-level output after accounting for retired units. Since ABB does not include generation <1 MW and since large-scale solar generation data were substantially incomplete for the year 2016, we estimate solar generation based on state-level capacity, and regional capacity factors from NREL.[6] Distributed solar generation also added to total generation when calculating VRE penetrations.
- **Regional demand growth** comes from EIA's dataset of retail sales of electricity by state, with each state assigned to one of the ISO or non-ISO regions.[7]
- **Regional sulfur content** of coal comes from EIA's dataset on the quality of fossil fuels in electricity generation: sulfur content of coal by state.[8]
- **Regional and plant-level SO_2 emissions rates** come from ABB's Velocity Suite dataset.
- **Plant size and heat rate** both come from ABB's Velocity Suite dataset.
- **Delivered gas and coal prices**, by region, come from generation-weighted regional averages of the monthly power plant fuel costs between 2010-2016 reported in ABB's Velocity Suite dataset.

3 Retirements and Additions over Time

Figure 1 presents data on power plant retirements and additions over time, compared to national non-coincident peak load. Figure 2 segments recent retirements (2010-2016) and planned retirements (2017-2023) by generation type: coal plants, natural-gas steam (NGST) plants, combustion turbine (CT) plants, combined-cycle gas turbine (CCGT) plants, nuclear plants, hydropower plants, and other. The NGST category is broadly defined to include both natural gas and oil fired steam plants. Similarly, while most CTs are natural gas fired, some are primarily oil fired.

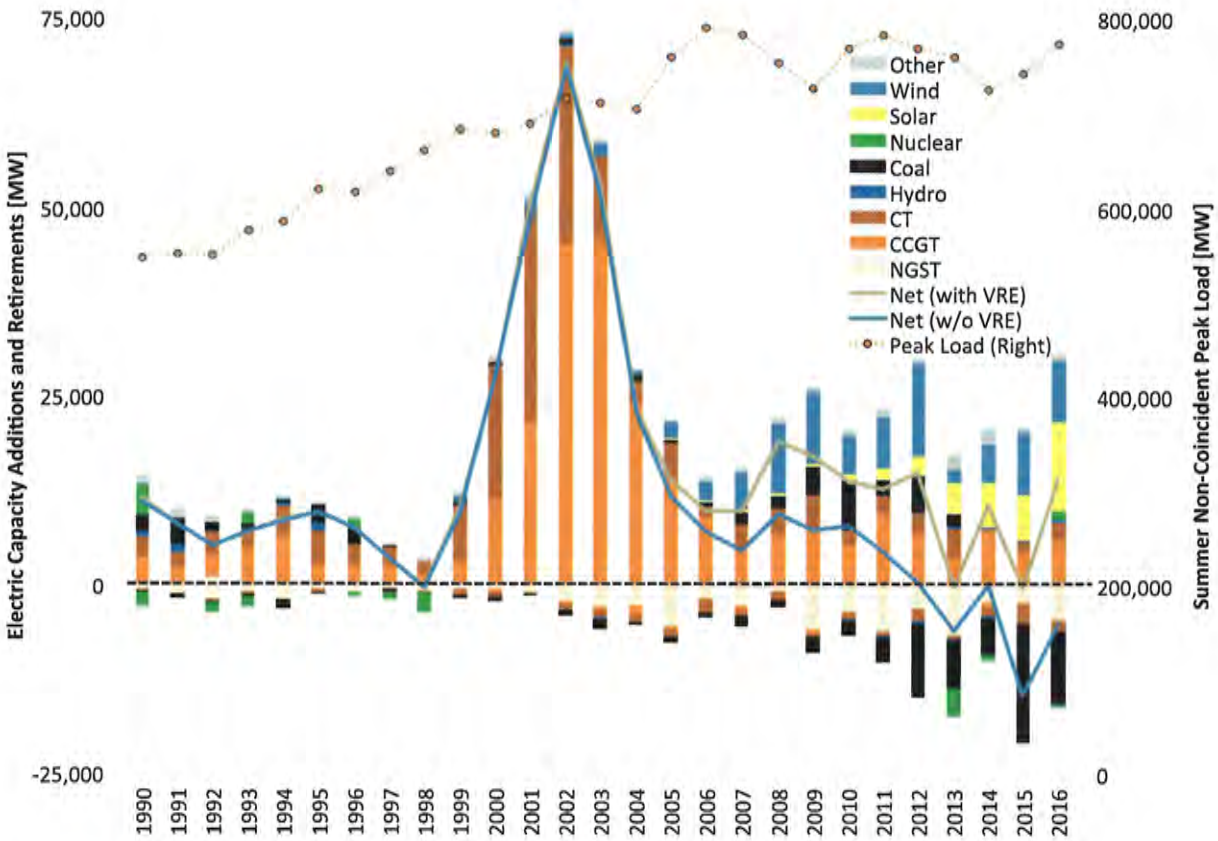
Several observations are apparent from these charts:

- Retirements of thermal plants have occurred throughout history, but have increased since 2010
- Coal & NGST units are the primary recent contributors, with CTs & nuclear a distant third and fourth
- As for planned retirements, coal, NGST, and nuclear plants are dominant
- Disregarding VRE, there has been a net loss of generation capacity nationally since 2012
- If VRE is included, however, net nameplate capacity additions have continued since that time[9]
- Historically significant levels of CCGT and CT additions are apparent from 2000-2005
- Historically significant levels of wind and then solar additions are apparent since 2007

- Non-coincident peak load was highest in 2006 and has not recovered to that peak as of 2016
- A net increase in thermal capacity exists since 2006 notwithstanding the lack of growth in peak load

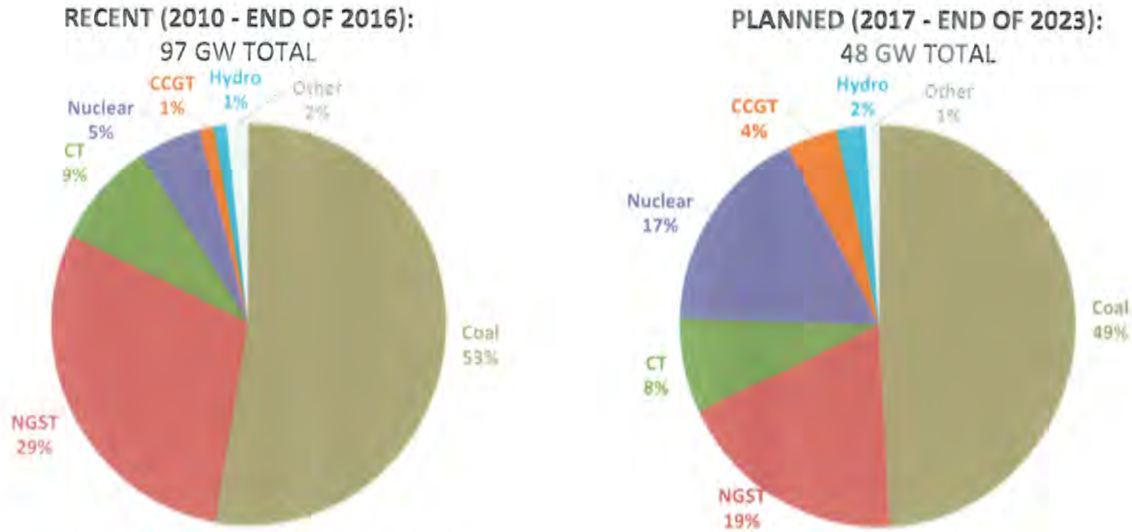
As a result of all of these trends, excess generation capacity exists nationally and regionally.[10]

Some caution should be applied to any interpretation of the planned retirement data, as actual retirements may differ substantially from what is presently planned and reported as such to EIA and other sources.



Source: LBNL analysis of ABB Velocity Suite Data, with solar estimates from IREC and GTM/SEIA

Figure 1. Retirements and Additions to the U.S. Generation Fleet over Time



Source: LBNL analysis of ABB Velocity Suite Data

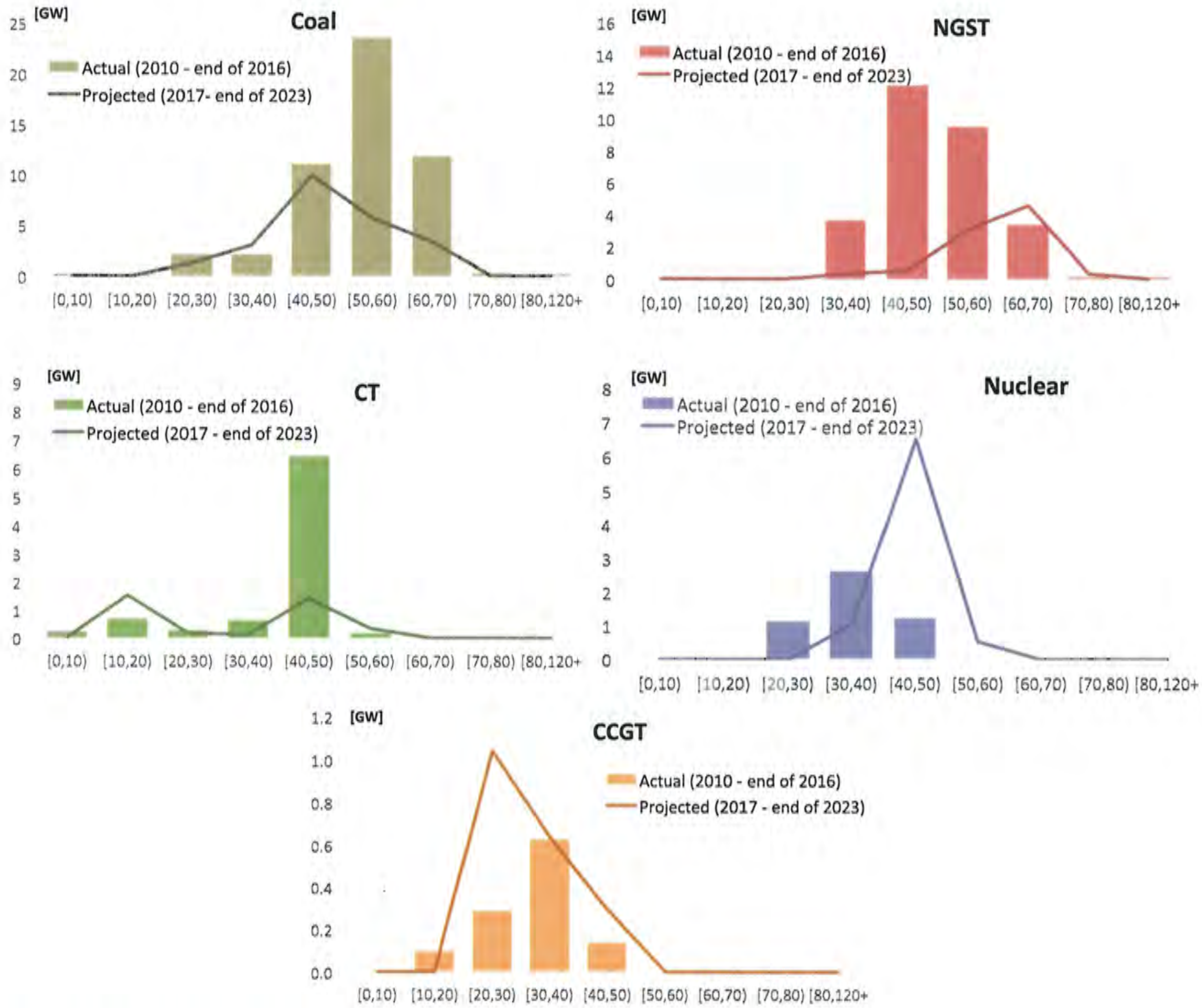
Figure 2. Plant Type Distribution for Recent and Planned Retirements

4 Project Age of Recent and Planned Retirements

Figure 3 presents histograms of project age of recent & planned retirements for coal plants, natural-gas steam (NGST) plants, combustion turbine (CT) plants, nuclear plants, and combined-cycle gas turbine (CCGT) plants.[11] Note the very different scale in each chart, with far larger amounts of retirements for some types of plants than others. Figure 4, meanwhile, presents trend lines for the age of retiring plants over time, while also extending the trend line to consider planned retirements.

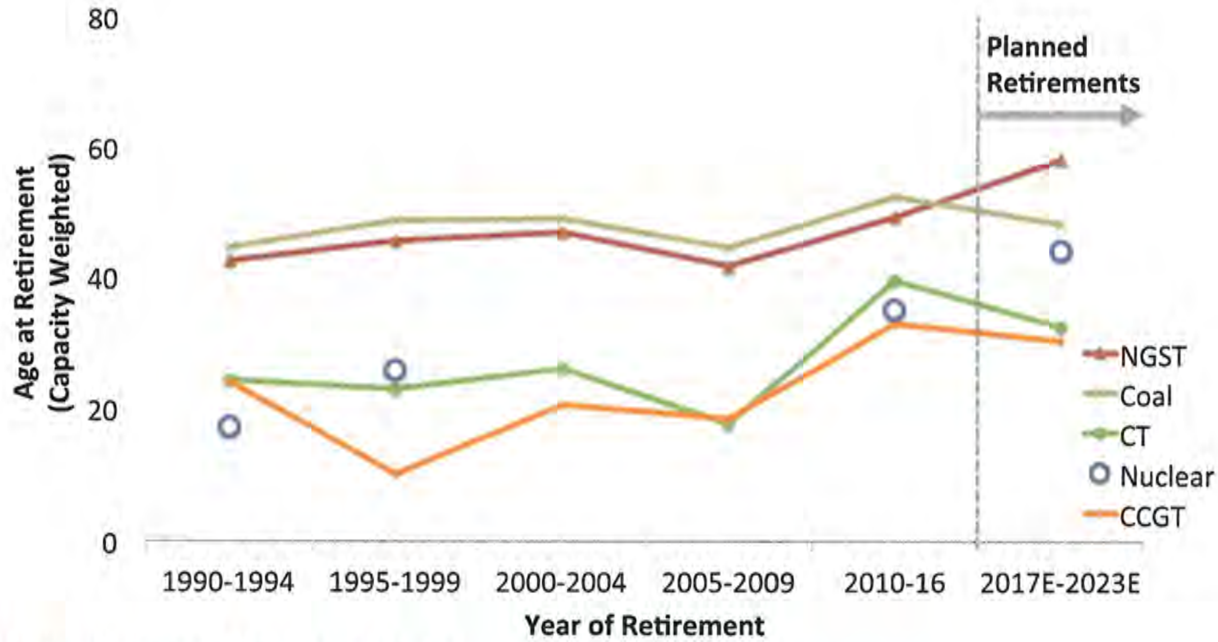
Several observations are apparent from these charts:

- Recently retired plants have been relatively old, across all generation types
  - The most common age of recently retired coal units is 50-60 years
  - The most common age of recently retired NGST units is 40-50 years
  - The most common age of recently retired CT units is 40-50 years
  - The most common age of recently retired nuclear units is 30-40 years
- Plants with announced retirement dates are also relatively old, based on expected age at retirement
  - Nuclear & NGST plants planned for retirement will be older than recently retired plants
  - Coal, CT & CCGT plants planned for retirement will be slightly younger than recently retired plants
- There is no observable broad historical trend towards retiring younger plants



Source: LBNL analysis of ABB Velocity Suite Data

Figure 3. Histograms of Project Age for Recent and Planned Retirements



Source: LBNL analysis of ABB Velocity Suite Data

Figure 4. Trend in Project Age of Past and Planned Power Plant Retirements

As noted earlier, caution should be applied to any interpretation of the planned retirement data, as actual retirements may differ substantially from what is presently planned and reported.

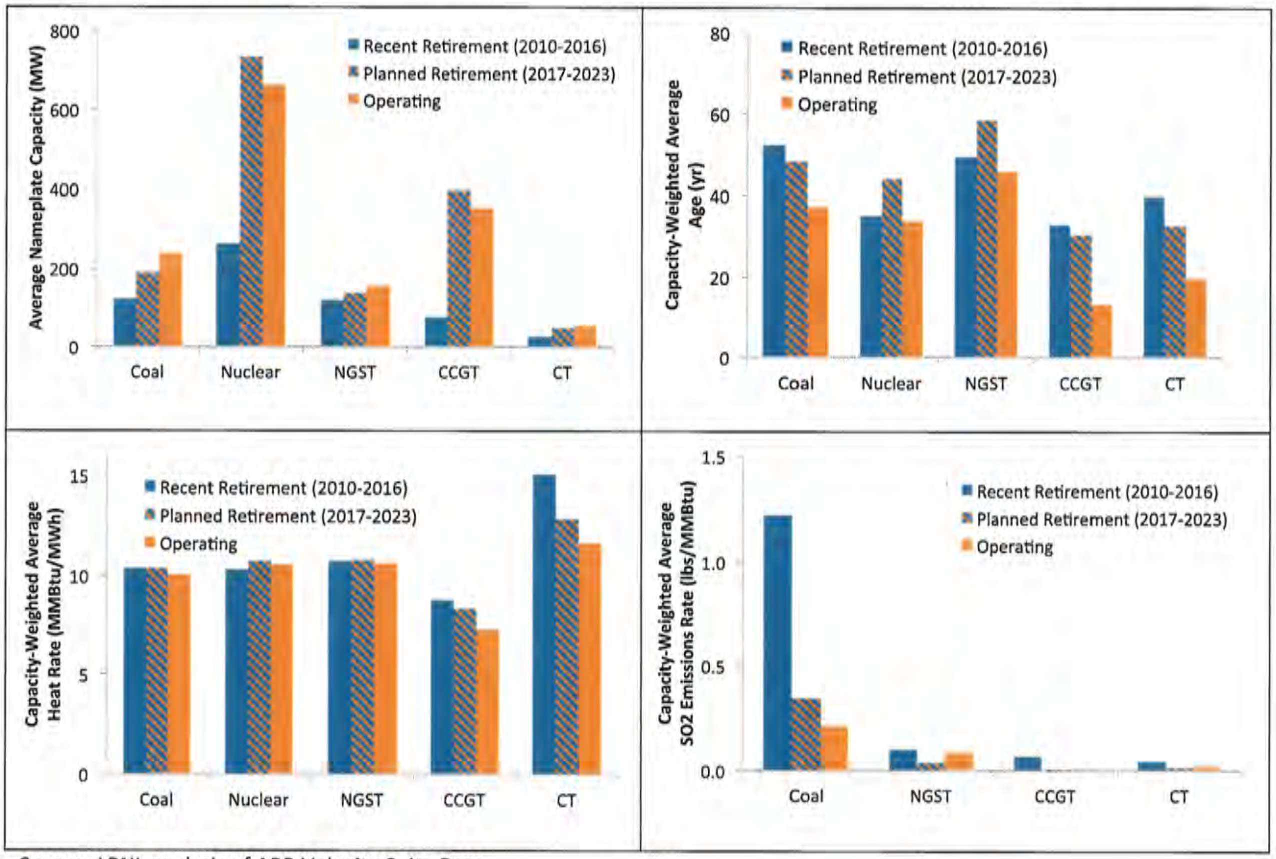
5 Comparison of Recently Retired Plants to Operating Plants

Figure 5 shows that the characteristics of plants that recently retired or that plan to retire are different than for plants that continue to operate with no immediate reported retirement plans. In particular, we observe that retired plants tend to be smaller, older[12], less efficient, and more polluting than operating plants. The figures demonstrate the following:

- Retired plants are smaller: Recently retired coal plants had an average capacity of 122 MW, whereas plants not scheduled for retirement are larger at 239 MW on average. Recently retired nuclear and gas-fired plants are similarly smaller than operating plants. Plants with planned retirement dates over 2017-2023 are larger, on average, than recently retired plants—more comparable to those plants that have not reported plans to retire in the near future.
- Retired plants are older: Coal plants that retired between 2010-2016 had an average age of 52 years while coal plants that did not retire and are not scheduled for retirement had an average age of 37 years in 2016. The recently retired gas plants are similarly older than operating plants. Recently retired nuclear plants, on the other hand, were only slightly older than the age of the operating plants. Plants with near term plans for retirement are also considerably older on average than plants with no such reported plans.
- Retired coal and gas plants are less efficient: The average heat rate of recently retired coal plants (10,386 Btu/kWh) was slightly higher than plants not scheduled for retirement (10,046 Btu/kWh), indicating that the plants that retired were also somewhat less efficient. The heat rate of recently

retired CCGT and CT plants, meanwhile, was considerably higher on average than plants not scheduled for retirement. Plants with near term plans for retirement are also less efficient than those plants with no immediate reported retirement plans.

- Retired coal plants are more polluting: The average emissions rate of coal plants that retired between 2010-2016 was 1.2 lbs SO_2/MMBtu, while the average emissions rate of the plants not scheduled for retirement was 0.2 lbs SO_2/MMBtu. Plants with announced retirements from 2017-2023 have emissions rates more consistent with those plants not reportedly planning to retire.



Source: LBNL analysis of ABB Velocity Suite Data

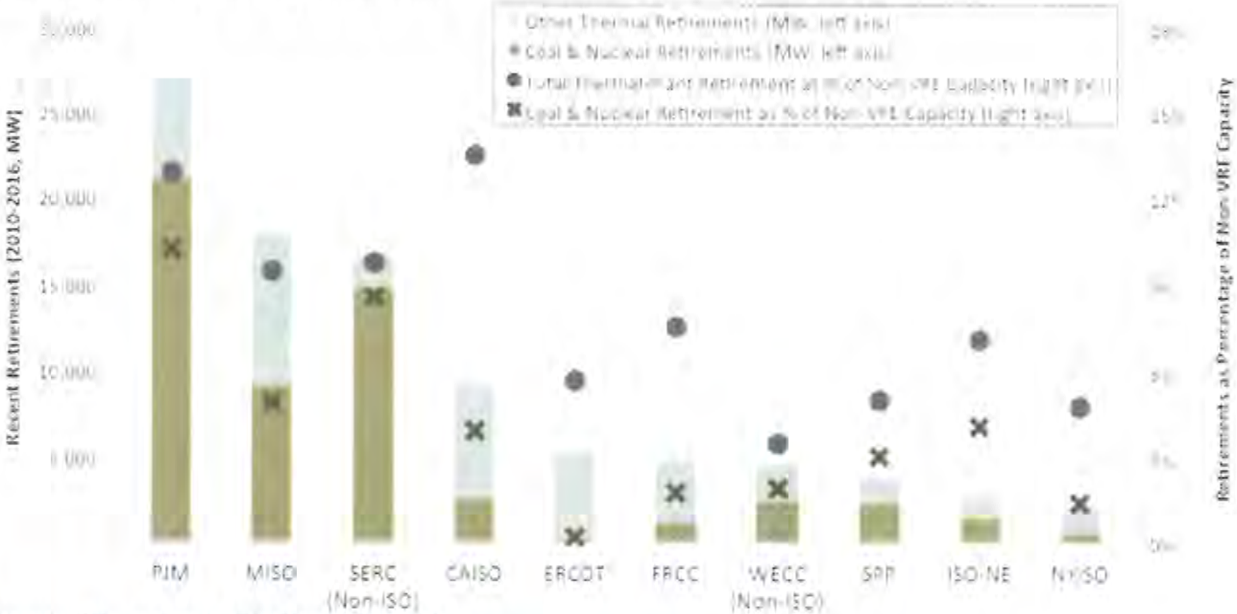
Figure 5. Comparison of Recently Retired or Planned Retirements to Operating Plants

6 Possible Drivers for Varying Levels of Regional Retirement

Figure 6 summarizes the regional distribution of recent retirements both for all thermal units and, of that total, the subset that includes only coal and nuclear units. The total thermal units category includes the NGST, CCGT, CT, Coal, and Nuclear categories used previously, while excluding the VRE, Hydro, and Other categories. The figure also normalizes these absolute sums by presenting them as a percentage of non-VRE capacity as of 2016 in each region.

In absolute magnitude, the largest amount of recent total thermal-plant retirements and coal & nuclear retirements have occurred in PJM, MISO, and the non-ISO portion of SERC. These same regions, along with CAISO, also have the largest amount of retirements on a percentage-of-non-VRE capacity basis.

Notably, natural gas plants dominate the recent retirements in ERCOT, CAISO, FRCC, and NYISO; coal and nuclear make smaller contributions.



Source: LBNL analysis of ABB Velocity Suite Data

Figure 6. Recent Thermal Plant Retirements, by Region

The final set of charts shown in Figure 7 correlate regional retirement percentages with a subset of factors that may be contributing to the strikingly different levels of recent retirement experienced in various regions. Most charts provide data points for both total thermal plant retirements and, separately, only coal and nuclear retirements. In some cases, however, the investigated factors are most likely to affect only coal and/or gas plants; we focus in those instances solely on those plant types.

Nine specific possible explanatory factors are explored:

- VRE penetration in percentage terms, considering utility-scale wind and PV and distributed PV
- Regional growth (or contraction) in electrical load from 2010 to 2016
- Average planning reserve margin (based on summer capacity and peak loads) from 2010 to 2016
- Average SO_2 emissions rates of the 25% of coal plants in each region with the highest emissions
- Average percent sulfur content of coal delivered to the region from 2010 to 2015
- Ratio of delivered coal prices to delivered gas prices in the region from 2010 to 2016
- Average regional delivered natural gas price from 2010 to 2016
- Average age of the oldest 25% of thermal power plants in the region in 2010
- New non-VRE capacity additions since 2010 as a percentage of total non-VRE capacity

Visual inspection of these figures does not offer perfect clarity on the core drivers for regional retirement trends. Nor do historical trends necessarily tell us what might drive retirement decisions on a going-forward basis. However, we observe the following based on these graphics:

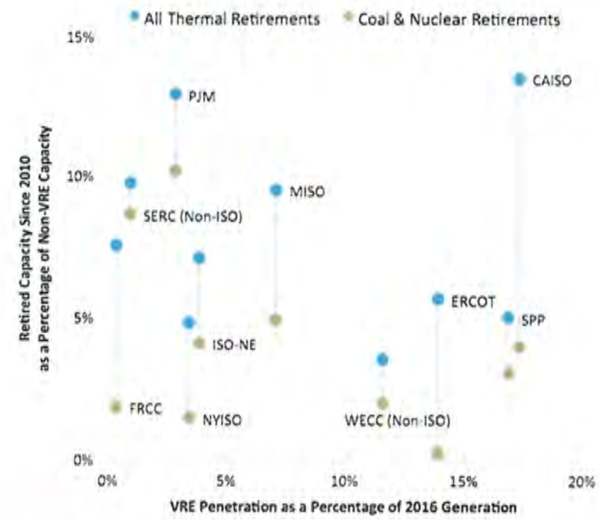
- *VRE Penetration:* There does not appear to be any obvious widespread relationship between VRE penetration and recent historical regional retirement decisions. PJM and SERC, both with very low

VRE penetrations, have among the largest amount of recent total thermal plant and coal & nuclear plant retirement. ERCOT, SPP, and the non-ISO portion of WECC, on the other hand, all have sizable VRE penetrations but low retirement percentages. CAISO has experienced strong growth in VRE and has the highest level of total thermal plant retirements on a percentage basis, most of which are older NGST plants; many of those plants have retired as a compliance mechanism with California's policy to phase out once-through cooling.[13]

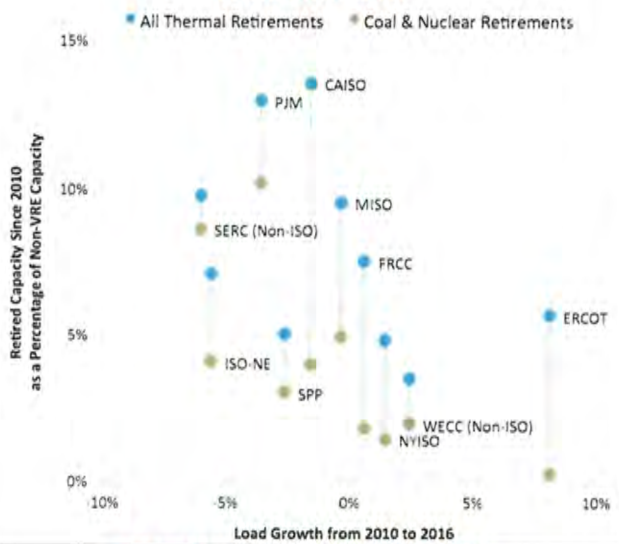
- *Load Growth:* There appears to be a relatively strong inverse relationship between load growth and retirement percentages. Regions that have experienced load contraction from 2010 to 2016 tend to have larger amounts of retirement than those regions that have experienced growth.
- *Reserve Margins:* There appears to be a relatively strong relationship between summer planning reserve margins and retirement percentages. Regions with higher reserve margins from 2010 to 2016 tend to have larger amounts of retirement than those regions with lower reserve margins, perhaps suggesting an ongoing 'market correction' to existing levels of excess capacity.
- *SO_2 Emissions Rate of Coal:* One might anticipate that coal plants with high SO_2 emissions rates may be subject to more stringent environmental upgrade and retrofit needs, which may then drive retirement decisions. This relationship is clearly apparent in the graphic, suggesting that environmental compliance has been a key driver of coal retirements especially in PJM and SERC.
- *Sulfur Content of Coal:* The relationship between the average sulfur content of coal in the region and coal retirements is not as robust as for the SO_2 emissions rate, presumably reflecting adoption of control equipment in areas with high sulfur coal but lower emissions rates.
- *Coal-to-Gas Price Ratio:* Gas and coal compete in the dispatch stack, and there appears to be a weak relationship between the ratio of delivered coal-to-gas prices and the level of regional coal retirement. Some regions that have relatively lower cost coal and/or relatively higher cost natural gas have tended to experience a somewhat lower level of coal retirement. Some regions with inexpensive gas and/or high cost coal, on the other hand, have tended to see more coal retirement.
- *Gas Price:* It is widely recognized that reductions in natural gas prices have been a core driver for lower wholesale prices, and resulting thermal plant retirements. One might also expect that regions with relatively lower delivered gas prices might have experienced greater levels of retirement. A weak relationship of this nature appears to exist.
- *Power Plant Age:* One would expect that regions with older power plants might witness a greater amount of retirement. The graphic suggests that this relationship may exist, especially for coal & nuclear plants, with the notable exception of CAISO having significant retirements with relatively younger plants.
- *Non-VRE Power Plant Additions:* There does not appear to be a clear relationship between growth in non-VRE capacity additions since 2000 and the level of recent retirements.
- *ISO vs. Non-ISO Regions:* It is not obvious that the recent growth in thermal plant retirements is affected by whether the region has a wholesale market overseen by an ISO. SERC is traditionally regulated and has among the highest amount of retirement of all regions. The WECC (not including California) and FRCC also remain under traditional regulation, but have experienced relatively lower levels of retirement so far. Among the many regions with ISOs, retirement percentages vary widely.

Again, visual inspection of these charts is not dispositive in establishing causal relationships. Nor do these charts explore every possible driver for regional retirement variations. Moreover, future retirement decisions may be influenced by different factors than those that have affected past decisions. Nonetheless, based on these simple correlation graphics, the strongest predictors of regional retirement differences appear to include SO_2 emissions rates (for coal), planning reserve margins (for all thermal units), variations in load growth or contraction (for all thermal units), and the age of older thermal plans (for all thermal units). Additional apparent predictors of regional retirements include the ratio of coal to gas prices and delivered natural gas prices. Other factors appear, based on this simple analysis, to play lesser roles; these include VRE penetration, recent non-VRE capacity additions, and whether the region hosts an ISO or remains traditionally regulated.

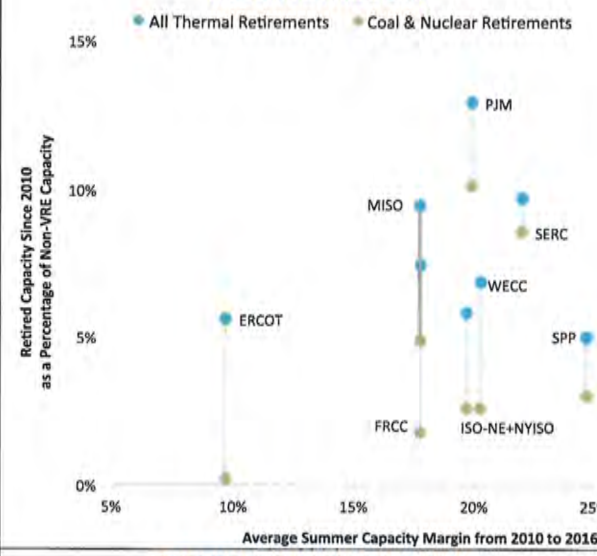
VRE PENETRATION



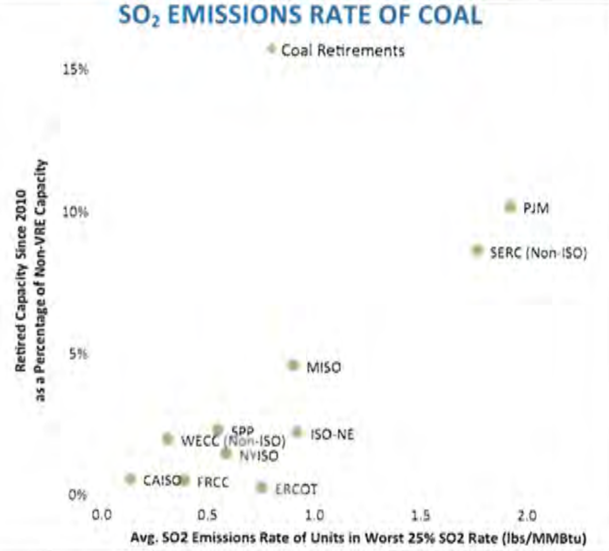
LOAD GROWTH



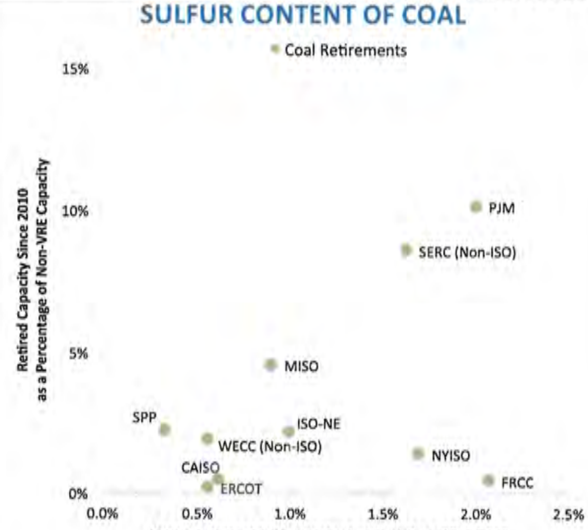
RESERVE MARGIN

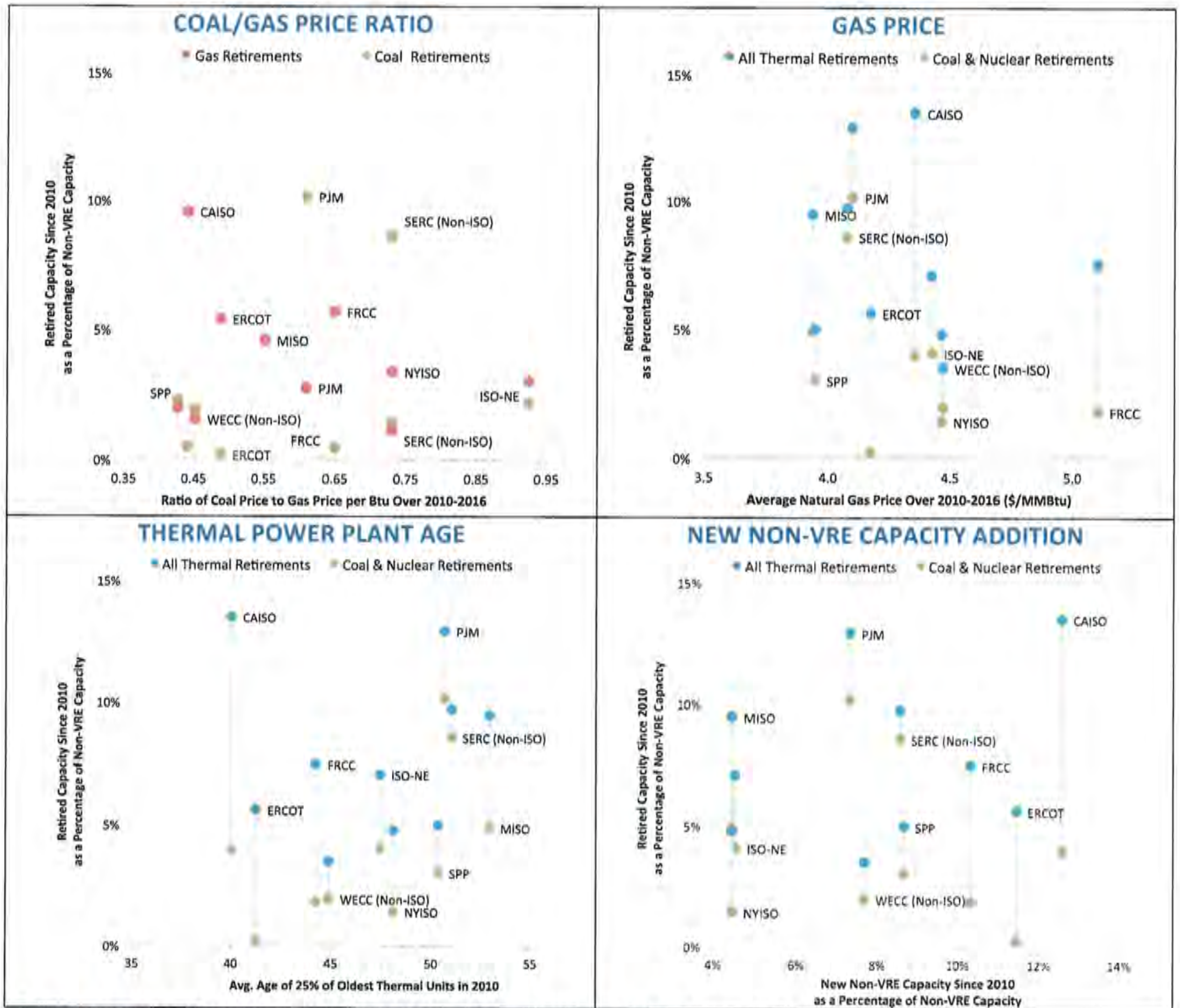


SO_2 EMISSIONS RATE OF COAL



SULFUR CONTENT OF COAL





Source: LBNL analysis of ABB Velocity Suite Data, along with supplemental sources as described earlier

Figure 7. Possible Drivers for Regional Retirement Trends

7 Future Research

This paper provides a cursory look at retirement trends and drivers, but by no means is the final word on the subject. To understand these trends and drivers in more detail would require an understanding of how each possible driver affects plant profitability, an exploration of additional drivers, and a better understanding of interactions among the possible drivers. Such analysis might usefully focus on specific resource types separately (e.g., coal, nuclear, or CCGTs), be conducted on a regional as opposed to solely a national basis, and consider planned as well as recent retirements. It may be useful to consider, for a wider variety of possible drivers, not only regional averages but the distribution of plants within those averages. Assessing retirement drivers over time, not only across regions, may be informative.

In conducting further analysis, additional drivers to consider include: (1) additional existing and prospective state, regional, and federal policies and regulations (e.g., carbon, NO_x, mercury, water, plant relicensing, RPS, etc.); (2) the specific impacts of wear-and-tear, cycling, and other factors on operational costs; (3) regional trends in wholesale energy and capacity prices; (4) the possible differential impacts of wind and PV, as opposed to the combined impact of VRE; and (5) thermal plant heat rates and capacity factors. Regression analysis and reviews of regulatory and financial filings offer useful tools to help better identify the underlying causes of investor decisions.

Endnotes and References

[1] Where active wholesale markets do not exist, the same basic dynamics hold: the declining cost of natural gas, for example, puts economic pressure on inflexible units even in markets that do not feature an ISO/RTO. Generation that is locked into longer term physical or financial contracts may be temporarily isolated from some of these forces, but will still be affected by, e.g., natural gas and wholesale price changes at least over the longer term.

[2] ABB Velocity Suite dataset. Accessed May 2017.

[3] https://www.eia.gov/electricity/data/eia860m/

[4] Specifically, GTM/SEIA data were used to estimate state-level solar capacity additions for the years 2010-2016 (GTM Research, Solar Energy Industries Association (GTM/SEIA). 2017. "U.S. Solar Market Insight, 2016 Year in Review", pp.51-57). State-level data from IREC were used to supplement capacity data for states that were not covered by GTM/SEIA in the years 2010-2013 and for solar capacity data for the years 1996-2009 (personal communication with Larry Sherwood, data are associated with the "U.S. Solar Market Trends" report series, 2006-2013, by the Interstate Renewable Energy Council (IREC)). http://www.irecusa.org/wp-content/uploads/2014/07/Final-Solar-Report-7-3-14-W-21.pdf.

[5] https://www.eia.gov/electricity/data/eia411/

[6] Specifically, we used the solar capacity data from GTM/SEIA and IREC to develop state-level solar generation data based on sector-specific capacity factor estimates reported by NREL (National Renewable Energy Laboratory. 2012. "U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis". http://www.nrel.gov/gis/re_potential.html). State-level solar generation data were then aggregated to ISO regions (future work could refine the state-level assignment to regions). California's solar generation is apportioned among CAISO and non-CAISO WECC based on EIA 861 NEM ratios for distributed solar and ABB's regional generation ratios for large-scale solar. We used ABB data for wind generation and total ISO generation data across all fuel types to calculate ISO-level VRE penetration levels.

[7] https://www.eia.gov/electricity/data/browser/. Future work could refine the state-level assignment to regions, or instead utilize different data sources.

[8] https://www.eia.gov/electricity/data/browser/. Future work could refine the state-level assignment to regions.

[9] Future work could look at net additions based on the estimated capacity credit of each resource type.

[10] See various NERC reports focused on existing, near term, and longer term reserve margins.

[11] We do not analyze hydropower retirements in more detail as some of the capacity categorized as retired is instead part of an uprating of a hydropower facility that continues operations. Overall, hydropower is a very small share of both historical and planned retirements.

[12] The age of plants is based on the age at retirement for plants that retired between 2010-2016, the age in the year that they plan to retire for plants slated to retire between 2017-2023, or the age in 2016 for operating plants that have not reported plans to retire over the timeframe considered here (2017-2023).

[13] California Energy Commission (CEC). 2017. "Once-Through Cooling Phase-Out." California Energy Commission. http://www.energy.ca.gov/renewables/tracking_progress/documents/once_through_cooling.pdf.

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF EL PASO ELECTRIC COMPANY FOR APPROVAL OF ABANDONMENT OF ITS RIO GRANDE POWER PLANT UNIT 7 AND NEWMAN POWER PLANT UNIT 1 **EL PASO ELECTRIC COMPANY, Applicant.**	**Case No. 23-00___-UT**

DECLARATION OF J KYLE OLSON IN SUPPORT OF THE FOREGOING DIRECT TESTIMONY TO THE APPLICATION OF EL PASO ELECTRIC COMPANY FOR APPROVAL OF ABANDONMENT

I ***J Kyle Olson***, pursuant to Rule 1-011 NMRA, state as follows:

1. I affirm in writing under penalty of perjury under the laws of the State of New Mexico that the following statements are true and correct.

2. I am over 18 years of age and have personal knowledge of the facts stated herein. I am employed by El Paso Electric Company ("EPE" or "the Company") as *Director Power Generation and Asset Management.*

3. The foregoing Direct Testimony of J Kyle Olson, together with all exhibits sponsored therein and attached thereto, is true and accurate based on my knowledge and belief.

4. I submit this Declaration, based upon my personal knowledge and upon information and belief, in support of EPE's ***Application for Approval Abandonment.***

FURTHER, DECLARANT SAYETH NAUGHT.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on December 1, 2023.

/s/ J Kyle Olson
J KYLE OLSON

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION OF EL PASO ELECTRIC COMPANY FOR APPROVAL OF ABANDONMENT OF ITS RIO GRANDE POWER PLANT UNIT 7 AND NEWMAN POWER PLANT UNIT 1

Case No. 23-00___-UT

EL PASO ELECTRIC COMPANY,
Applicant.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on December 5, 2023, **El Paso Electric Company's Application for Approval of Abandonment of its Rio Grande Power Plant Unit 7 and Newman Power Plant Unit 1** was emailed to each of the following:

Nancy Burns	nancy.burns@epelectric.com;	Emily Medlyn	emily.w.medlyn.civ@army.mil;
Jeffrey Wechsler	jwechsler@montand.com;	Merrie Lee Soules	mlsoules@hotmail.com;
Linda Pleasant	linda.pleasant@epelectric.com;	Elizabeth Jensen	epjensen@gmail.com;
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DATED this 5th day of December, 2023.

/s/ Jeffrey J. Wechsler
Jeffrey J. Wechsler