MONTGOMERY
& ANDREWS
LAW FIRM

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October 6, 2020

Via Electronic Mail

Melanie Sandoval
Records Bureau
New Mexico Public Regulation Commission
P.O. Box 1269
Santa Fe, NM 87504-1269
prc.records@state.nm.us

Re: Case No. 20-00__-UT
El Paso Electric Company's Application for Approval of Abandonment of Rio Grande Power Plant Unit 6

Dear Ms. Sandoval,

Please find enclosed El Paso Electric Company's Application for Approval of Abandonment of Rio Grande Power Plant Unit 6 and the supporting Direct Testimonies of James Schichtl, Omar Gallegos and Jose Guaderrama. The required filing fee of $25.00 will be mailed.

If you have any questions, please contact our office. Thank you.

Very truly yours,

/s/ Jeffrey J. Wechsler

Enclosures
cc (via email): Service List

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR APPROVAL OF ABANDONMENT OF RIO GRANDE POWER PLANT UNIT 6	**)**	
	)	**Case No. 20-00___-UT**
EL PASO ELECTRIC COMPANY, Applicant.	**)**	

EL PASO ELECTRIC COMPANY'S APPLICATION FOR APPROVAL OF ABANDONMENT OF RIO GRANDE POWER PLANT UNIT 6

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 Rio Grande Power Plant Unit 6 ("Application"), which seeks all necessary regulatory approvals for EPE to abandon its Rio Grande Power Plant Unit 6 ("RG6" or "Rio Grande Unit 6") after the end of EPE's 2021 summer peak season and no later than October 1, 2021. 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 ("NMPUA").

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 approximately 101,000 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. RG6 is a natural gas-fired Babcock and Wilcox-El Paso design boiler. The steam turbine is a Westinghouse Frame 486 with a gross electrical output of 50 MWs. RG6 was commissioned in 1957.

5. 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.

6. 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.

7. EPE's testimonies and exhibits provide substantial factual evidence that abandonment of RG6 is in the public interest under New Mexico law and the *Commuters' Committee* factors, including that:

a. RG6 is past the end of its useful life, and the continued operation of RG6 is not required to reliably serve New Mexico customers.

b. RG6 was retired from regular service in 2015 when it was placed in Inactive Reserve.[1] Its use has been limited to contingency purposes since that time.

c. The costs associated with RG6 have been excluded from EPE's base rates since June 2016, pursuant to the Commission's Final Order in EPE's last general rate case NMPRC Case No. 15-00127-UT.

d. The capacity of RG6 has been replaced by the capacity of Montana Power Station Units 1 through 4, which were granted certificates of public convenience and necessity by Commission Final Orders in NMPRC Case Nos. 13-00297-UT and 12-00137-UT.

e. RG6 capacity has been removed from EPE's current Load and Resource Analysis, which shows a sufficient planning reserve without RG6. Given existing resources and planned resource additions in 2022, RG6 will no longer be required for contingency purposes after the 2021 peak months.

f. An order authorizing the abandonment of RG6 will have no impact of EPE's cost of service because the plant is not included in EPE's cost of service.

[1] 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."

g. Abandonment at this time is in the normal course of business for a fully depreciated generation unit that is well past its useful life and where generation capacity from the unit is not needed to serve load or for reserve requirements.

h. RG6 had a total company net book value of negative $270,113 as of December 31, 2019, the negative book value reflects the depreciation reserve required to offset the future cost of removal of the unit from service, and EPE seeks no ratemaking treatment associated with the plant in this case.

i. In connection with its 2018 IRP and as ordered by the Commission in NMPRC Case No. 18-00293-UT, EPE conducted a life extension analysis of RG6. The 2018 analysis **showed that the total capital and maintenance costs would be significant to extend the useful service life of the unit, with a total cost of $42.4 million for a 5-year extension and a total cost of $91.4 million for a 10-year extension.**

8. EPE's Application is supported by the pre-filed direct testimony and exhibits of James Schichtl, Vice President of Regulatory Affairs; Omar Gallegos, Senior Director of the Resource Planning and Management Department; and Jose L. Guaderrama, Senior Director of Operations.

> <u>James Schichtl</u> addresses statutory and regulatory requirements for abandonment and the current regulatory treatment of the unit which EPE proposes to abandon, including recent Commission orders associated with RG6. He explains that costs associated with the generating unit have been excluded from EPE's base rates since June 2016, and that EPE is seeking no rate treatment associated with the proposed abandonment.
>
> <u>Omar Gallegos</u> 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 RG6.

Jose L. Guaderrama addresses the physical condition of RG6, as well as the relevant operational considerations and concerns, in light of the proposed abandonment. He also presents a Lawrence Berkeley National Laboratory study which reports on the average age of natural gas steam generating units in the United States, as well as 2010, 2012 and 2018 Burns & McDonnell studies commissioned by EPE to evaluate the economics of extending the operations of RG6.

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

Judith Parsons Regulatory Case Manager El Paso Electric Company 100 N. Stanton Street El Paso, Texas 79901 (915) 543-5777	Jeffrey J. Wechsler Matthew Zidovsky Montgomery & Andrews. P.A. Post Office Box 2307 Santa Fe, New Mexico 87504-2307 (505) 982-3873

10. Electronic service should be made as follows:

Judith.parsons@epelectric.com; jwechsler@montand.com; mzidovsky@montand.com; nancy.burns@epelectric.com; tpacheco@montand.com; and partricia.griego@epelectric.com.

11. As indicated on the Certificate of Service attached hereto, EPE has mailed a copy of its Application and supporting Direct Testimonies and Exhibits to parties to EPE's most recent general rate case (NMPRC Case No. 15-0027-UT). EPE's proposed form of Notice is also attached hereto as Attachment A.

12. EPE seeks timely treatment of its Application, in order to meet the proposed October 1, 2021 abandonment date.

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 RG6 no later than October 1, 2021; and

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

Respectfully submitted,

Nancy B. Burns
Senior Attorney
New Mexico 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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mzidovsky@montand.com

ATTORNEYS FOR
EL PASO ELECTRIC COMPANY

EXHIBIT A

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR APPROVAL OF ABANDONMENT OF RIO GRANDE POWER PLANT UNIT 6	)	
	)	**Case No. 20-00___-UT**
EL PASO ELECTRIC COMPANY, Applicant.	)	

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 the Rio Grande Power Plant Unit 6 ("RG6") no later than October 1, 2021.

2. EPE's Application states that: (a) RG6 is past the end of its useful life; (b) the present and future public convenience and necessity do not require the service or use of RG6, and (c) an order authorizing the abandonment of RG6 will have no impact on EPE's rates because RG6 capital and operation and maintenance costs are not included in EPE's base rates. EPE's Application requests that the Commission issue a final order approving abandonment of RG6 no later than October 1, 2021.

3. The Commission has assigned Case No. 20-_____-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. 20-_____-UT.

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

(A) Pursuant to 17.1.2.26 NMAC, any person desiring to become a party to this case shall file a Motion for Leave to Intervene on or before _________, 2020;

(B) The Commission Staff shall, and any Intervenors may file Direct Testimony on or before _________, 2020;

(C) Rebuttal Testimony may be filed on or before ________, 2020;

(D) A public hearing shall be held beginning on _________, 2020, commencing at ____a.m. M.T. and shall continue as necessary through _____, 2020. The hearing will be held either in person at a location to be determined, or via the Zoom platform in whole or in part depending on potential COVID-19 restrictions and guidelines and related safety concerns. 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 ______, 2020. 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 depending on potential COVID-19 restrictions and guidelines and related safety concerns. The purpose of the prehearing is to discuss whether to hold the evidentiary hearing in person or via the Zoom platform in whole or in part.

6. 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.

7. Any interested person may submit written or oral comments during the hearing without becoming an intervenor. Written comments, which shall reference Case No. 20-_____-UT, may also be sent to the Commission at the following address: New Mexico Public Regulation Commission (ATTN: Records management Bureau), P.E.R.A. Building, P.O. Box 1269, Santa Fe, New Mexico 87504-1269. Pursuant to 1.2.2.23(F) NMAC, written and oral comments shall not be considered evidence.

8. Anyone filing pleadings, testimony and other documents shall follow the Commission's Temporary NMPRC Filing Policy, available at http://nmprc.state.nm.us, toward the top of the page and to the right of "NEW!". Pleadings, testimony and other documents shall also be served on all parties of record and Staff in the way or ways specified in the most recent Certificate of Service issued in this case by the Hearing Examiner. Copies

of all filings shall also be sent by email on the date of filing with the Commission to the Hearing Examiner at _____________ in PDF and MS Word or other native formats.

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

10. Interested persons should contact the Commission at 505-690-4191 for confirmation of the hearing dates, times and places, since hearings are occasionally rescheduled.

11. Any person with a disability requiring special assistance in order to participate in this proceeding should contact the offices of the Commission at 505-827-4500 at least 24 hours prior to the commencement of the hearing.

ISSUED at Santa Fe, New Mexico, this _____ day of _________, 2020.

New Mexico Public Regulation Commission

Hearing Examiner

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR APPROVAL OF ABANDONMENT OF ITS RIO GRANDE POWER PLANT UNIT 6	)	
	)	**Case No. 20-00___-UT**
EL PASO ELECTRIC COMPANY, Applicant.	)	

DIRECT TESTIMONY OF

JAMES SCHICHTL

ON BEHALF OF

EL PASO ELECTRIC COMPANY

OCTOBER 6, 2020

TABLE OF CONTENTS

SUBJECT	PAGE
I. INTRODUCTION AND QUALIFICATIONS	1
II. PURPOSE OF TESTIMONY AND RECOMMENDATIONS	4
III. REGULATORY STANDARD FOR ABANDONMENT OF RG6	6
IV. FACTORS TO BE EVALUATED IN ABANDONMENT	8
V. COST OF SERVICE IMPACTS OF ABANDONMENT OF RG6	12
VI. SUMMARY AND CONCLUSION	13

EL PASO ELECTRIC COMPANY
DIRECT TESTIMONY OF
JAMES SCHICHTL

I. INTRODUCTION AND QUALIFICATIONS

Q. 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.

Q. HOW ARE YOU EMPLOYED?

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

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

A. I have been employed by EPE since February 2012. In June 2016, I was promoted from Director of Regulatory Affairs to Vice President. Prior to becoming Director, I was 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. Prior to that, I was 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").

Prior to joining EPE in February 2012, I spent eighteen years in various regulatory positions 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 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 statutes, rules, and regulations and managing regulatory efforts at the California Public Utilities Commission ("CPUC").

I graduated with a Bachelor of Science in Mechanical Engineering in 1987 from the University of Texas at El Paso, where I also studied graduate level 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.

Q. **WHAT ARE YOUR CURRENT RESPONSIBILITIES WITH EPE?**

A. As Vice President of Regulatory Affairs, I am responsible for the oversight and direction of EPE's Economic Research, Rate Research, and Regulatory Accounting groups, as well as EPE's Regulatory Case Management group. Economic Research performs EPE's 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 EPE's retail rate schedules and charges. The Regulatory Accounting group is responsible for the scheduling, preparation, and review of jurisdictional regulatory accounting and reporting. 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 Texas municipal regulators.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE UTILITY REGULATORY BODIES?

A. Yes, I have previously testified before the PUCT, NMPRC, FERC, and the CPUC.

Q. ARE YOU SPONSORING EXHIBITS TO YOUR TESTIMONY?

A. No, I am not.

II. PURPOSE OF TESTIMONY AND RECOMMENDATIONS

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

A. My testimony supports EPE's Application to Abandon Rio Grande Unit 6. I address statutory and regulatory requirements for abandonment and the current regulatory treatment of the unit which EPE proposes to abandon, including recent Commission orders associated with RG6. I explain that costs associated with the generating unit have been excluded from EPE's base rates since the Commission's Final Order in EPE's last general rate case, effective June 2016, and that EPE is seeking no rate treatment associated with the proposed abandonment. I also introduce the other EPE witnesses presenting supporting testimony in this case.

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

A. EPE is requesting Commission approval to abandon RG6 after the end of EPE's 2021 summer peak season pursuant to NMSA 1978, § 62-9-5 (2005) — Abandonment of Service. No further operation of RG6 for service to New Mexico customers will occur after the effective date of abandonment approved by the Commission.

Q. WHAT IS YOUR RECOMMENDATION IN THIS CASE?

A. I recommend the Commission approve EPE's Application to abandon RG6 effective October 1, 2021, as consistent with the present and future public interest. EPE's direct testimony supporting the Application demonstrates that continued operation of RG6 is not required for EPE to continue to provide, safe, reliable and economic service to customers. The abandonment of the unit will benefit customers economically by permanently removing one of EPE's oldest and least-efficient gas-fired generation units from service to New Mexico customers. In addition, the abandonment of RG6 will maintain the environmental benefits obtained through retirement for customers and the region by permanently eliminating associated excess pollution and water use.

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

A. Omar Gallegos, EPE's Senior Director of Resource Planning and Management Department, addresses how the proposed abandonment supports and is consistent with EPE's long-term generation resource planning.

Jose L. Guaderrama, Senior Director of Operations, discusses the operational history and current condition of RG6, as well as considerations associated with any ongoing operation.

III. REGULATORY STANDARD FOR ABANDONMENT OF RG6

Q. 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.

Q. 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 RG6. In fact, abandonment of the facility will maintain the benefits that have already accrued to customers and region as a result of EPE's retirement of RG6 in 2015, and the limited use of the unit for contingency purposes since then.

Q. IS OPERATIONAL USE OF RG6 BEING DISCONTINUED IN THE NORMAL COURSE OF BUSINESS?

A. Yes. RG6 will be 64 years old at the time of formal abandonment. It has already been retired from regular service for several years and was removed from base rates in 2016. RG6 is currently in Inactive Reserve[1] status. Abandonment at this time is in the normal course of business for a fully depreciated generation unit that is well past its useful life and where generation capacity from the unit is not needed to serve load or for reserve requirements.

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

A. Over the last several years, RG6 has been transitioned (from both an operational and ratemaking perspective) from normal operation to retirement and now to abandonment. In addition, the Commission order closing EPE's 2018 Integrated Resource Plan ("IRP") Docket required EPE to "include the full capacity of Rio Grande 6 in all future loads and resource tables until the projected year of an abandonment filing." NMPRC Case No. 18-00293-UT Order Closing Docket; Issuing Variance from 17.7.3.12 NMAC (Sept. 18, 2019) ¶ A ("2018 IRP Final Order"). Based on its retired status and current age and condition, EPE's 2019 load and resource table ("L&R analysis") does not include RG6 capacity for

[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.

planning purposes beginning in 2020. Accordingly, EPE's application is made consistent with the Commission's 2018 IRP Final Order.

IV. FACTORS TO BE EVALUATED IN ABANDONMENT

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

A. The abandonment 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.

Q. IS THE ABANDONMENT OF RG6 CONSISTENT WITH THESE FACTORS?

A. Yes, given the totality of the circumstances. Although each factor is not directly applicable in the present case because the unit has already been retired for operational and ratemaking purposes, the abandonment of RG6 is consistent with the public interest.

Q. REGARDNG THE FIRST OF THE *COMMUTERS' COMMITTEE* FACTORS, HOW WILL EPE SUFFER FINANCIAL HARM IF ABANDONMENT OF RG6 IS NOT ALLOWED?

A. The Commission's Final Order in EPE's last general rate case, NMPRC Case No. 15-00127-UT, approved the removal of RG6 capital and O&M costs from EPE's base rates. EPE has not recovered RG6 costs from customers in rates since June 2016. Over that period, EPE has incurred capital and other expenses in maintaining the unit. EPE has not operated the unit for any purpose since November 2018 but continues to incur costs associated with unit maintenance. While the extent of the current loss to EPE is not significant when compared with the Company's operations as a whole, the potential exists for significant increased costs as the unit continues to age, as discussed by EPE witness Guaderrama.

If the unit is not abandoned and is instead overhauled and returned to service, additional costs will be imposed on EPE that are not currently included in base rates. As EPE witness Guaderrama explains in his testimony, the age of the unit puts it at risk for failure without extensive evaluation and investment, irrespective of near-term maintenance. Such a failure could also result in financial harm to customers, as EPE would seek to include both current operating costs and costs necessary to bring RG6 up to reliability standards in base rates with limited offsetting benefits. Absent abandonment, continued reliance on RG6 also introduces the likelihood of increased replacement power costs when the unit fails, and the increased risk of outages.

Q. WITH RESPECT TO THE SECOND OF THE *COMMUTERS' COMMITTEE* FACTORS, WHY IS RIO GRANDE UNIT 6 NOT NEEDED TO SERVE EPE'S PRESENT CUSTOMERS?

A. RG6 has been a part of EPE's local generation fleet since 1957 and is among the oldest and least efficient units in EPE's fleet. As discussed by EPE witness Gallegos, RG6 was placed into Inactive Reserve in 2015, and its capacity and load serving responsibilities were replaced by new generation when EPE placed Montana Units 1–4 into service. As EPE witness Gallegos explains, since that time its use has been limited to contingency purposes. The four new Montana units fully offset the nameplate capacity of RG6 in load serving capability, are more efficient than RG6, and their quick start and load ramping capability allows for better integration of renewable resources.

Q. 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 is no inconvenience or hardship to the public that results from the abandonment of RG6. To the contrary, hardship for the public would result from the return to operation of RG6 if abandonment is not granted. As discussed by EPE witness Gallegos, EPE has performed unit life extension analyses that demonstrate that the provision of service through the recommissioning of RG6 at 5-year and 15-year extensions would be an uneconomic alternative for EPE's customers. Conversely, the Company incurs, at a financial loss, all non-fuel operation and maintenance costs and risks from maintaining the plant for contingency purposes.

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

A. No. As discussed by EPE witness Gallegos, EPE has adequate electrical supplies and facilities to assure it continues to provide reliable service without RG6.

Q. CONSIDERING ALL FACTORS, DOES THE PUBLIC INTEREST REQUIRE CONTINUING USE OF RG6 BY EPE'S CUSTOMERS?

A. No, the public interest is best served by the abandonment of this retired generating unit. Return of RG6 to operations, if even feasible from a technical perspective, would essentially erase the benefits that customers have realized since the unit was retired in 2015.

Q. WILL EPE'S CUSTOMERS BENEFIT FROM COMMISSION APPROVAL OF THE ABANDONMENT OF RG6?

A. Yes. Not only will customers avoid the costs associated with overhauling and operating RG6, abandonment will eliminate all risks associated with potential future operation of the unit.

V. COST OF SERVICE IMPACTS OF ABANDONMENT OF RG6

Q. WHAT ARE THE COST OF SERVICE IMPACTS OF THE

ABANDONMENT OF RG6?

A. Because RG6 was removed from cost of service and base rates in 2016, there will be no impacts on cost of service from the abandonment of RG6, and EPE will not seek stranded cost recovery for any recently incurred costs associated with RG6. This retired unit is being abandoned in the normal course of business, and rates have reflected the retirement of the unit since 2016. As shown in the table below, RG6 had a net book value of negative $270,113 as of December 31, 2019.

Rio Grande Unit 6 – Plant Balances

Electric Plant	Accumulated Depreciation	Net Plant
$10,097,472	($10,367,585)	($270,113)

Q. SHOULD THE NEGATIVE NET BOOK VALUE BE CHARGED TO COST OF SERVICE?

A. No. EPE has depreciated RG6 in order to provide 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

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Approval of EPE's Application is consistent with the present and future public interest, satisfies 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 RG6 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 exist such that load serving capability and reserves are not impacted by the permanent loss of RG6. The abandonment of the unit will benefit customers economically by permanently removing of one of EPE's oldest and least-efficient gas-fired generation units from service to New Mexico customers.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR APPROVAL OF ABANDONMENT OF ITS RIO GRANDE POWER PLANT UNIT 6	)	
	)	**CASE NO. 20-00___-UT**
EL PASO ELECTRIC COMPANY, Applicant.	)	

DECLARATION OF JAMES SCHICHTL IN SUPPORT OF THE FOREGOING DIRECT TESTIMONY IN EL PASO ELECTRIC'S APPLICATION FOR APPROVAL OF ABANDONMENT OF ITS RIO GRANDE POWER PLANT UNIT 6

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 the *Vice President of Regulatory 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 of Abandonment of its Rio Grande Power Plant Unit 6.***

FURTHER, DECLARANT SAYETH NAUGHT.

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

Executed on October 6, 2020.

_/s/_*James Schichtl*

JAMES SCHICHTL

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC	**)**	
COMPANY'S APPLICATION FOR APPROVAL	**)**	
OF ABANDONMENT OF ITS	**)**	
RIO GRANDE POWER PLANT UNIT 6	**)**	**Case No. 20-00____-UT**
	)	
EL PASO ELECTRIC COMPANY,	**)**	
Applicant.	**)**	
____	**)**	

DIRECT TESTIMONY OF

OMAR GALLEGOS

ON BEHALF OF

EL PASO ELECTRIC COMPANY

OCTOBER 6, 2020

TABLE OF CONTENTS

SUBJECT **PAGE**

I. INTRODUCTION AND QUALIFICATIONS 1

II. PURPOSE AND SUMMARY OF TESTIMONY AND RECOMMENDATIONS...3

III. RIO GRANDE GENERATION UNIT 6..5

IV. CONCLUSION..12

EL PASO ELECTRIC COMPANY
DIRECT TESTIMONY OF
OMAR GALLEGOS

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Omar Gallegos, and my business address is 100 N. Stanton Street, El Paso, Texas 79901.

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

A. I am employed by El Paso Electric Company ("EPE" or "the Company") as Senior Director of the Resource Planning and Management Department.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from the University of Texas at El Paso with a Bachelor of Science degree in Mechanical Engineering in 1995, and a Master of Business Administration degree in 2006. In 2014, I completed a Graduate Certificate in Public Utility Regulation and Economics from New Mexico State University.

From 1995 to May 2009, I was employed by Delphi Corporation in product engineering. During my final eight years at Delphi Corporation, I was Supervisor for Product Engineering, where my responsibilities included design development, product validation, cost estimating, and project management.

In May 2009, I accepted a position with EPE as a Real-Time Scheduler. In that capacity, I was responsible for managing energy transfer schedules over the Company's transmission lines in accordance with Federal Energy Regulatory Commission ("FERC") requirements and North American Electric Reliability Corporation ("NERC") reliability standards. From September 2010 to May 2013, I was an Associate - Business Development working as a Project Manager for renewable energy projects and new generation projects. My responsibilities in that position included financial analysis, business process flows, and evaluation of emerging technologies. In May 2013, I was promoted to System Operations Outage Coordinator where I coordinated EPE's transmission, generation, and system outages in adherence with reliability requirements. In March 2014, I was promoted to Manager-Asset Management Services. During that time, I was responsible for Transmission and Distribution project management initiatives, budgeting, asset management, and support of regulatory permitting for transmission assets. In February 2016, I was promoted to Director of the Resource Planning Department. In July 2016, I assumed responsibility of EPE's Resource Planning and Management Department. In August 2020, I was promoted to Senior Director of Resource Planning and Management.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES WITH EPE.

A. As Senior Director of EPE's Resource Planning and Management Department, I manage and supervise the Company's generation and resource planning, renewable energy procurement, long-term planning/acquisition of interstate gas pipeline transport capacity, intrastate gas pipeline transport/storage, fuel oil supply/transport, wholesale power transactions, fuel supply planning and procurement, and real-time market operations. In particular, this includes development of EPE's annual Loads and Resources ("L&R") analysis, Integrated Resource Plan ("IRP"), New Mexico Renewable Portfolio Standard ("RPS") plan, and selection of resources via competitive Requests for Proposals. In this capacity I supervise and confirm the input and analysis of the Company's modeling through the programs PROMOD, STRATEGIST, and AURORA.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE ANY UTILITY REGULATORY AGENCIES?

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

II. PURPOSE AND SUMMARY OF TESTIMONY AND RECOMMENDATIONS

EL PASO ELECTRIC COMPANY
DIRECT TESTIMONY OF
OMAR GALLEGOS

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

A. My Direct Testimony supports EPE's request to abandon its Rio Grande Unit 6 ("RG6"). Specifically, I address how the proposed abandonment is consistent with EPE's long-term generation resource planning. I also discuss the findings of EPE's life extension analyses, which demonstrate that it is uneconomic to further extend the life of RG6.

Q. PLEASE SUMMARIZE THE MAIN POINTS OF YOUR TESTIMONY.

A. EPE's proposal to abandon RG6 is consistent with EPE's long term generation resource planning as reflected in EPE's Commission-approved 2006, 2009 and 2015 Integrated Resource Plans ("IRPs"). The capacity of RG6 has been replaced by the capacity of Montana Power Station ("MPS") Units 1 through 4, which were granted certificates of public convenience and necessity ("CCNs") by Commission Final Orders in NMPRC Case Nos. 13-00297-UT and 12-00137-UT, and the continued operation of RG6 is not required to serve New Mexico customers. A recent life extension analysis of RG6 conducted by EPE in conjunction with its 2018 IRP found that RG6 does not offer cost-effective capacity to serve current and future load. I recommend that the Commission authorize EPE to abandon RG6 because continued operation is no longer warranted or required by the present or future public convenience and necessity.

III. SUPPORT FOR THE ABANDONMENT OF RIO GRANDE GENERATION UNIT 6

Q. PLEASE PROVIDE PERTINENT INFORMATION ABOUT RG6.

A. Table OG-1 provides pertinent information about the unit.

Table OG-1

Location	Sunland Park, New Mexico
Type of Facility	Steam Turbine
In-Service Date	June 1957
Net Capacity Approx. Jurisdictional Allocation	45 MW (Total Company) 8 MW (New Mexico)
Initial Expected Retirement Date	2007
Date Unit Costs Removed from EPE's Base Rates	June 8, 2016
Date Placed on Inactive Reserve	May 26, 2015
Date of Last Contingency Operations	November 8, 2018
Age at Abandonment	63

Q. WHEN DID EPE ORIGINALLY PLAN TO RETIRE RG6?

A. RG6's initial projected retirement date was in 2007. EPE has therefore extended RG6 operations approximately 13 years past its original service life.

Q. CAN YOU DESCRIBE THE RESOURCE PLANNING DECISIONS SINCE 2010 TO EXTEND THE LIFE OF RG6?

A. In 2010, EPE commissioned a Burns & McDonnell ("BMcD") study ("2010 BMcD Study") to evaluate whether it would be cost-effective to extend the useful life of RG6 beyond the then-current 2012 retirement date (see the direct testimony of EPE witness Jose L. Guaderrama, Exhibit JG-2). The 2010 BMcD Study assessed the condition of the unit and estimated costs to further extend the life of RG6. The 2010 BMcD Study evaluated the Levelized Cost of Energy ("LCOE") for RG6 extensions versus the LCOE of newer, more efficient generation and concluded that an RG6 extension beyond two years was not cost effective. The 2010 BMcD Study concluded that an extension of RG6 became more costly than new generation at the two-year to four-year mark. EPE therefore extended the retirement date from 2012 to 2014 only.

In 2012, EPE again commissioned BMcD to re-assess RG6 ("2012 BMcD Study") and to determine if RG6 should again be extended beyond the then-current December 2014 retirement date. A similar assessment was performed as in 2010, and the cost of an RG6 extension was compared to new generation (reference

Exhibit JG-3). The 2012 B&McD Study concluded that EPE should not further extend the life/retirement date because there were no lower costs available by doing so.

Q. HAS EPE CONSISTENTLY PLANNED FOR THE RETIREMENT OF RG6 SINCE THAT TIME?

A. Yes. EPE's 2012, 2015 and 2018 IRPs reflect the planned retirement of RG6 from serving customer load, and the associated removal of RG6 capacity from EPE's loads and resources analyses necessitated (in part) the addition of Montana Units 1 through 4. Also, as addressed by EPE witness James Schichtl, RG6 was removed from EPE's base rates by Commission Final Order in EPE's 2015 Rate Case.

Q. WHAT PURPOSE HAS RG6 SERVED FOR EPE'S CUSTOMERS SINCE 2015?

A. For several years after placing the unit in Inactive Reserve in 2015, EPE has utilized the unit to meet peak demands when unplanned outages occurred at other generating units. EPE has not operated RG6 for this or any other purpose since November 8, 2018.

Q. WHAT IS INACTIVE RESERVE 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. EPE maintains retired units in Inactive Reserve in order to enhance reliability, and has maintained RG6 on Inactive Reserve since 2015 for this reason. Units on Inactive Reserve, including RG6, provide an additional resource 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. EPE has maintained RG6 on Inactive Reserve since 2015 for this reason.

Q. HAS RG6 BEEN USED DURING OR SINCE 2015 FOR CONTINGENCY PURPOSES?

A. Yes. Table OG-3 below shows the generation in megawatt-hours ("MWh") of RG6 from May 2015 through the date of filing in 2020.

Table OG-3

Rio Grande Unit 6	
Year	Generation (MWh)
2015	52,532
2016	62,154
2017	60,221
2018	56,425
2019	0
2020	0

Q. AT WHAT CAPACITY FACTOR HAS RG6 BEEN OPERATING?

A. RG6 performed at less than a 16 percent capacity factor each year from 2015 through 2018. Although it was designed and built for base load, RG6 was used as a load following unit during those years. As addressed in the Direct Testimony of EPE witness Louie Guaderrama, continued operation of RG6 in this manner has a potential to further impact its reliability and safe operation.

Q. IN YOUR OPINION, IS IT REASONABLE AND PRUDENT TO CONTINUE TO MAINTAIN RG6 IN INACTIVE RESERVE FOR THIS PURPOSE?

A. No. RG6 has served its purpose during the construction and approval of replacement resources including Montana Units 1 through 4 and planned renewable resource additions in 2022 approved in NMPRC Case No. 19-00348-UT and pending in Case No. 19-00099-UT. Both reliability concerns, as well as the results of life extension analyses, indicate that additional life extensions (whether on a short- or long-term basis) are not a feasible or economic option for RG6.

Q. DOES EPE REQUIRE THE CONTINGENT USE OF RG6 TO PROVIDE SAFE, RELIABLE AND ECONOMIC SERVICE?

A. No. As discussed previously, keeping RG6 in Inactive Reserve status has served its purpose during EPE's construction of new units. EPE's current L&R shows a sufficient planning reserve of 15% minimum without RG6. EPE did experience an unprecedented peak load growth in 2020, perhaps in part due to the anomalies of the COVID-19 shutdowns and work from home. Given the planned resource additions in 2022, RG6 will no longer be required for contingency purposes after the 2021 peak months.

Q. HAS EPE ANALYZED WHETHER IT IS ECONOMIC TO FURTHER EXTEND THE SERVICE LIFE OF RG6?

A. Yes. As addressed by EPE witness Schichtl, the Commission ordered EPE to conduct further analysis of RG6 in its 2018 IRP consistent with life extension analysis for other units slated for retirement in the planning period. EPE commissioned BMcD to assess RG6's condition and to estimate costs for bringing

RG6 out of Inactive Reserve and extending its operating life by five and fifteen years ("2018 BMcD Study"). As stated above, the 2012 BMcD Study analysis supported the retirement of the unit in 2014, and EPE placed the unit in Inactive Reserve in 2015. The 2018 BMcD Study and EPE's 2018 IRP analysis did not support bringing the unit out of inactive reserve and extending its life. Finally, the Company used the costs of a life extension from the 2018 BMcD Study in the 2017 All Source RFP, to analyze a life extension as a potential resource option for its future needs.

Q. WHAT WAS THE OUTCOME OF THE 2018 IRP WITH RESPECT TO RG6?

A. The results of the 2018 analysis concluded that the total capital and maintenance costs would be significant to extend the useful service life of the unit. EPE would have to incur the expenditures reflected in Table OG-4 below based on the 2018 B&McD study. Strategist runs of the 5-year and 15-year extension of RG6 for EPE's 2018 IRP resulted in neither option being selected as the number one portfolio.

Table OG-4

	5-Year Extension		15-Year Extension	
RG6	**Total ($000)**	**Total ($/kW)**	**Total ($000)**	**Total ($/kW)**
Capital expenditures	$26,320	$548	$57,620	$1,200
Maintenance	$16,121	$336	$34,375	$716

Total	$42,441	$884	$91,995	$1,917

Q. WHAT DID THE 2017 ALL SOURCE RFP ANALYSIS CONSIST OF WITH RESPECT TO RG6?

A. EPE included the 15-year extensions and associated costs from the 2018 BMcD study for RG6 in the Strategist runs for the 2017 RFP selection in direct competition with new resource additions.

Q. WHAT WAS THE OUTCOME OF THE 2017 ALL SOURCE RFP WITH RESPECT TO RG6?

A. RG6's 15-year extension was not selected for inclusion in the most reliable and economic portfolio as part of the 2017 All Source RFP.

IV. CONCLUSION

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

A. EPE has planned for the removal of RG6 from its system for many years. 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 placed the unit in Inactive Reserve for contingency purposes while its Commission-approved replacement resources were brought on line. The unit was removed from rates while being used at times for contingency purposes at no cost to customers aside from unit fuel usage. This resource has been replaced with new and efficient generation with no inconvenience or hardship to the public. It would be costlier for EPE’s customers for EPE to extend the life of RG6 compared to other generation alternatives.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR APPROVAL OF ABANDONMENT OF ITS RIO GRANDE POWER PLANT UNIT 6	**)**	
	)	**CASE NO. 20-00___-UT**
EL PASO ELECTRIC COMPANY, Applicant.	**)**	

DECLARATION OF OMAR GALLEGOS IN SUPPORT OF THE FOREGOING DIRECT TESTIMONY IN EL PASO ELECTRIC'S APPLICATION FOR APPROVAL OF ABANDONMENT OF ITS RIO GRANDE POWER PLANT UNIT 6

I ***Omar Gallegos***, 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 the *Senior Director of the Resource Planning and Management Department.*

3. The foregoing Direct Testimony of Omar Gallegos, 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 of Abandonment of its Rio Grande Power Plant Unit 6.***

FURTHER, DECLARANT SAYETH NAUGHT.

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

Executed on October 6, 2020.

_/s/_*Omar Gallegos*

OMAR GALLEGOS

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR APPROVAL OF ABANDONMENT OF ITS RIO GRANDE POWER PLANT UNIT 6	**)**	
	)	**Case No. 20-00___-UT**
EL PASO ELECTRIC COMPANY, Applicant.	**)**	

DIRECT TESTIMONY

OF

JOSE L. GUADERRAMA

ON BEHALF OF

EL PASO ELECTRIC COMPANY

OCTOBER 6, 2020

TABLE OF CONTENTS

SUBJECT **PAGE**

I. INTRODUCTION AND QUALIFICATIONS 1

II. PURPOSE OF TESTIMONY...3

III. PHYSICAL CONDITION AND OPERATIONS OF RG 6...........................4

V. SUMMARY AND CONCLUSION 14

EXHIBITS

JLG-1 - Lawrence Berkeley National Laboratory Study
JLG-2 - 2010 Burns & McDonnell Study
JLG-3 - 2012 Burns & McDonnell Study
JLG-4 - 2018 Burns & McDonnell Study

EL PASO ELECTRIC COMPANY
DIRECT TESTIMONY OF
JOSE L. GUADERRAMA

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Jose L. Guaderrama, and my business address is 100 N. Stanton Street, El Paso, Texas 79901-1341.

Q. HOW ARE YOU EMPLOYED?

A. I am employed by El Paso Electric Company ("EPE" or "Company") as Senior Director of Operations.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND BUSINESS BACKGROUND.

A. I graduated from New Mexico State University with a Bachelor of Science degree in Mechanical Engineering in 1975 and received a Master of Science degree in Mechanical Engineering from the University of Texas-El Paso in 1987. I obtained my Professional Engineering license in 1980 in the State of New Mexico. After graduating in June 1975, I was employed by Southern California Edison Company in San Bernardino, California as an Assistant Plant Engineer at the San Bernardino Generating Station. My job duties included plant betterment projects, thermal performance oversight of the unit operations, and fuel inventory level and quality reviews.

In May 1976, I began working for EPE as a Mechanical Engineer, where my duties were very similar to those at SCE but with a larger focus on the EPE generating fleet unit betterment projects as required to support maintenance, operations and unit performance. During my tenure as a plant engineer I was promoted through the various engineering positions as senior and principal engineer. In September 1990, I was promoted to Manager of Engineering and Maintenance in support of the EPE generating fleet. My job duties included supervision of the EPE engineering and maintenance staff for the generation fleet. This included negotiation of maintenance contracts, long term service agreements, plant capital projects, and maintenance activities in support of unit reliability and performance. I also represented EPE on the Palo Verde Nuclear Engineering and Operating Committee for several years. In December 2000, I was promoted to Newman Station Plant Manager where I assumed the responsibilities of operations, maintenance and engineering for the Newman Plant. In March 2004, I was assigned to the Rio Grande Plant as Plant Manager with the responsibility for the operations, maintenance and engineering of the Rio Grande Plant, including the plant review and oversight of the construction and startup of Rio Grande Unit 9. In September 2014, I was assigned to the position of Manager –

Generation Integration, where my responsibilities included working with the EPE Generation Planning group in the technical support of future generation reviews and planning.

In February 2018, I was promoted to Director of Operations with responsibilities including the oversight of the local generation fleet, including the Newman, Rio Grande and Montana Power Stations. My responsibilities include the process reviews and improvement of generation fleet engineering, maintenance and operations process improvements, outage management oversight, implementation of programs to enhance the training of staff and employees, and performance monitoring and improvement of generation assets in all areas of the generation fleet. In February 2019, I was promoted to Senior Director of Operations with the same responsibilities along with supporting the Vice President–Generation, System Planning and Dispatch regarding the generating fleet.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony supports EPE's Application to Abandon Rio Grande Unit 6 ("Rio Grande Unit 6" or "RG6"). My testimony specifically addresses the physical condition of RG6, as well as the relevant operational considerations and concerns in light of the proposed abandonment.

Q. ARE YOU SPONSORING EXHIBITS TO YOUR TESTIMONY?

A. Yes. I am sponsoring Exhibit JG-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. I am also sponsoring Exhibit JG-2, which is a 2010 Burns & McDonnell study commissioned by EPE. This 2010 study assessed whether RG6 could operate reliably until both a December 2012 retirement date and up to another six years beyond that date. Additionally, I am also sponsoring Exhibit JG-3 and Exhibit JG-4, which are additional Burns & McDonnell studies commissioned by EPE in 2012 and 2018 to evaluate the economics of extending the operations of RG6.

III. PHYSICAL CONDITION AND OPERATIONS OF RG6

Q. PLEASE DESCRIBE RG6 GENERALLY.

A. RG6 is a natural gas-fired Babcock and Wilcox-El Paso design boiler. The steam turbine is a Westinghouse Frame 486 with a gross electrical output of 50 MWs.

Q. WHEN WAS RG6 BROUGHT ONLINE?

A. RG6 was commissioned in 1957.

Q. HOW DOES THE AGE OF RG6 COMPARE TO OTHER GAS-FIRED GENERATING UNITS OF THIS AGE OPERATING IN THE UNITED STATES?

A. RG6 is the oldest unit in EPE's generating fleet. The removal of RG6 from service for New Mexico customers after 64 years is consistent with industry practice, and 64 years is above the average age of recently retired natural gas steam units (40 to 50 years) as documented in Exhibit JG-1, which is a Lawrence Berkeley National Laboratory study that was supported by the Department of Energy. The same report estimates the upcoming retirements of the remaining older natural gas steam units to be under 60 years of age. Again, RG6's retirement age of 64 is on the higher end of the age and retirement spectrum of natural gas steam units of its vintage. Importantly, the age of a unit should not be viewed in isolation from its operations and physical condition.

Q. WHAT STEPS HAS EPE TAKEN TO EVALUATE THE PHYSICAL CONDITIONS OF THE UNIT AND THE COSTS TO EXTEND ITS OPERATIONS?

A. EPE routinely 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 2010, EPE commissioned a Burns & McDonnell ("BMcD") study ("2010 BMcD Study") to evaluate whether it would be cost-effective to extend the useful life of RG6 beyond the then-current 2012 retirement date. *See* Exhibit JG-2. The 2010 BMcD Study also concluded that an extension of RG6 became more costly than new generation at the two to four-year mark. EPE did extend the retirement date from 2012 to 2014.

In 2012, EPE commissioned BMcD to re-assess RG6 ("2012 BMcD Study") and determine if RG6 should be further extended beyond the then retirement date of 2014. A similar assessment was performed as in 2010, and the cost of extension was compared to new generation. As with the 2010 BMcD Study, the 2012 BMcD Study concluded that the cost of further extension would not be justified and that other considerations, including specifically safety considerations, weighed against attempting to extend the useful life at this time.

In 2018, EPE again commissioned BMcD to re-assess the potential life extension of RG6 as part of its 2018 Integrated Resource Plan ("2018 IRP"). As EPE witness Omar Gallegos describes, the RG6 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.

Q. HAS EPE EVALUATED THE PHYSICAL CONDITION OF RG6 IN OTHER NEW MEXICO PUBLIC REGULATION COMMISSION ("NMPRC" OR COMMISSION) PROCEEDINGS?

A. To my knowledge, the physical condition of the unit has not been previously evaluated for the purpose of NMPRC proceedings. EPE evaluated the physical condition as early as 2004, and the more recent BMcD assessments included engineering evaluations intended to determine suitability for continued operations.

Q. WHAT WERE THE FINDINGS OF THOSE EVALUATIONS?

A. As described by EPE witness Gallegos, it was not cost-effective to extend the life of RG6 given the costs identified by the BMcD assessments.

Q. ARE THE RESULTS OF THE ASSESSMENTS CONSISTENT WITH THE AGE, OPERATION AND CONDITION OF THE UNIT?

A. Yes. The results of the assessments are consistent with RG6's operating characteristics, age, and operating history.

Q. PLEASE DESCRIBE THE OPERATIONS OF RG6.

A. RG6 has operated for 61 years. It was originally built as a base load unit and was then transitioned into load following and seasonal operations. For the past 35 years, it has operated primarily as a load following unit during the summer peak season and to support system needs during planned maintenance outages and during unplanned transmission or generation outages. As discussed by EPE witness Gallegos, since the unit was placed on inactive reserve in 2015, its operation has been limited to contingency load support as its replacement generation has been brought on line.

Q, HAVE THE OPERATIONS OF RG6 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.

Q. HOW HAS THE OPERATIONS OF RG6 IMPACTED ITS 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 unit 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. These mechanisms are beginning to appear on many of the different parts of the boiler pressure components and heat transfer surfaces. The turbine developed casing cracks in the early 1990's and has been mechanically stitched in some sections to prevent steam leakage. There are several auxiliary components that would need to be replaced if the unit were to continue operations, i.e. the cooling tower requires significant repair and was operated with two of the cooling cells out of service in its last two operating cycles. Additionally, the feedwater heaters are in need of retubing, the generator is in need of a complete inspection and electrical condition testing, and the steam turbine and generator are due for a complete inspection and repair if identified.

Q. HOW DOES THE PHYSICAL CONDITION OF RG6 IMPACT THE RELIABILITY OF OPERATIONS?

A. The physical condition does impact reliable operation of the unit. As indicated, with several of the key elements of the unit either in need of major inspection, repair or replacement, the threat to reliable operation during the peak season is significant. In addition, the unit is one of EPE's least efficient generating units, not only due to its age, but also due to its original design which was pre-advancements in efficiency improvements in the industry.

Q. HOW DOES THE EFFICIENCY OF RG6 COMPARE TO THE EFFICIENCY OF EPE'S OTHER THERMAL GENERATION UNITS?

A. As seen on Table JG-1, between 2015 and 2017, RG6 had an average actual Net Heat Rate of 13,804 Btu/kWh, which makes it one of the least efficient generating units operated by EPE.

Table JG-1

Unit Historical Net Average Heat Rate 2015-2017 Btu/kWh

Unit	AVG
RG 6	13,804
RG 7	12,453
RG 8	12,298
RG 9	9,367
NM 1	11,806
NM 2	12,197
NM 3	12,265
NM 4	9,975
NM 5	9,480
Copper	17,707
MPS 1	9,034
MPS 2	9,180
MPS 3	9,641
MPS 4	9,143

Q. WHAT SAFETY CONCERNS EXIST?

A. The primary safety risk facing the unit's continued operation 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. Another concern is the condition of the steam turbine shell casing and the risk of shell cracking during operation.

Q. WHAT OTHER EFFICIENCY CONSIDERATIONS EXIST?

A. Currently there are issues with the cooling tower that impact unit cycle cooling effectiveness. There are issues with corrosion and erosion and resulting tube degradation in the boiler walls and other heat transfer zones of the furnace part of the boiler. These issues have the effect of lowering the boiler thermal performance and increasing fuel consumption for the same quality and quantity of steam production. As mentioned previously, there are cycle feedwater heaters that need to be retubed. This degradation impacts thermal cycle efficiency, resulting in increased fuel consumption in order to maintain unit output.

Q. WHAT ADDITIONAL RELIABILITY CONCERNS EXIST?

A. Due to the overall age of the elements that make up the generating unit, 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 unit are aged, there is inherent risk to continued reliable operation of the unit. Over the years, the unit's 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. These include the boiler and other high-pressure components discussed previously.

Q. WHAT ENVIRONMENTAL CONSIDERATIONS EXIST?

A. Many if not all of the concerns about RG6's physical condition 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 required to compensate and achieve the same unit electrical output.

An additional environmental consideration is the impact due to the necessary water consumption that an older steam unit requires. Modern generating units require less water demand per unit of electrical generation.

Q. WHAT TYPE OF POLLUTION CONTROL TECHNOLOGY DOES RG6 HAVE?

A. RG6 has no pollution controls. The construction, permitting and initial operation of RG6 predates emissions limitations and the pollution control requirements inherent in the Prevention of Significant Deterioration (PSD) requirements of the Clean Air Act. Newer units, such as Rio Grande Unit 9, Montana Units 1 through 4, and the proposed Newman Unit 6, have modern pollution control equipment.

Q. WHAT IS THE CURRENT STATUS OF THE ENVIRONMENTAL (AIR) PERMIT THAT ALLOWS FOR THE OPERATION OF RG6?

A. RG6 is covered under the Rio Grande Generating Station Operating Permit No. P127-R3, issued by the New Mexico Environment Department. That permit expires in November of 2022. If the Commission authorizes abandonment of the unit, EPE will not include RG6 in its renewal application.

Q. DO ANY OTHER CONCERNS ARISE FROM RUNNING A GENERATING UNIT OF THIS AGE?

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.

IV. SUMMARY AND CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. There is no doubt that RG6 has been a workhorse for EPE during its operating history. The unit has undergone sound maintenance under well defined programs, has been operated within well managed operating parameters, and has been available when needed. However, due to the factors discussed previously, its continued suitability for service, in a reliable, safe mode can no longer be supported without extensive evaluation and investment. Though these evaluations and investments can be made, it would not be a sound investment, as it would certainly lead to undesirable stranded costs for EPE and its customers. 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. As described, 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 the unit. RG6 has no pollution controls and consumes more water relative to other newer units, which is a reality that cannot be mitigated in a cost-effective manner.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Power Plant Retirements:
Trends and Possible Drivers

Authors:

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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.

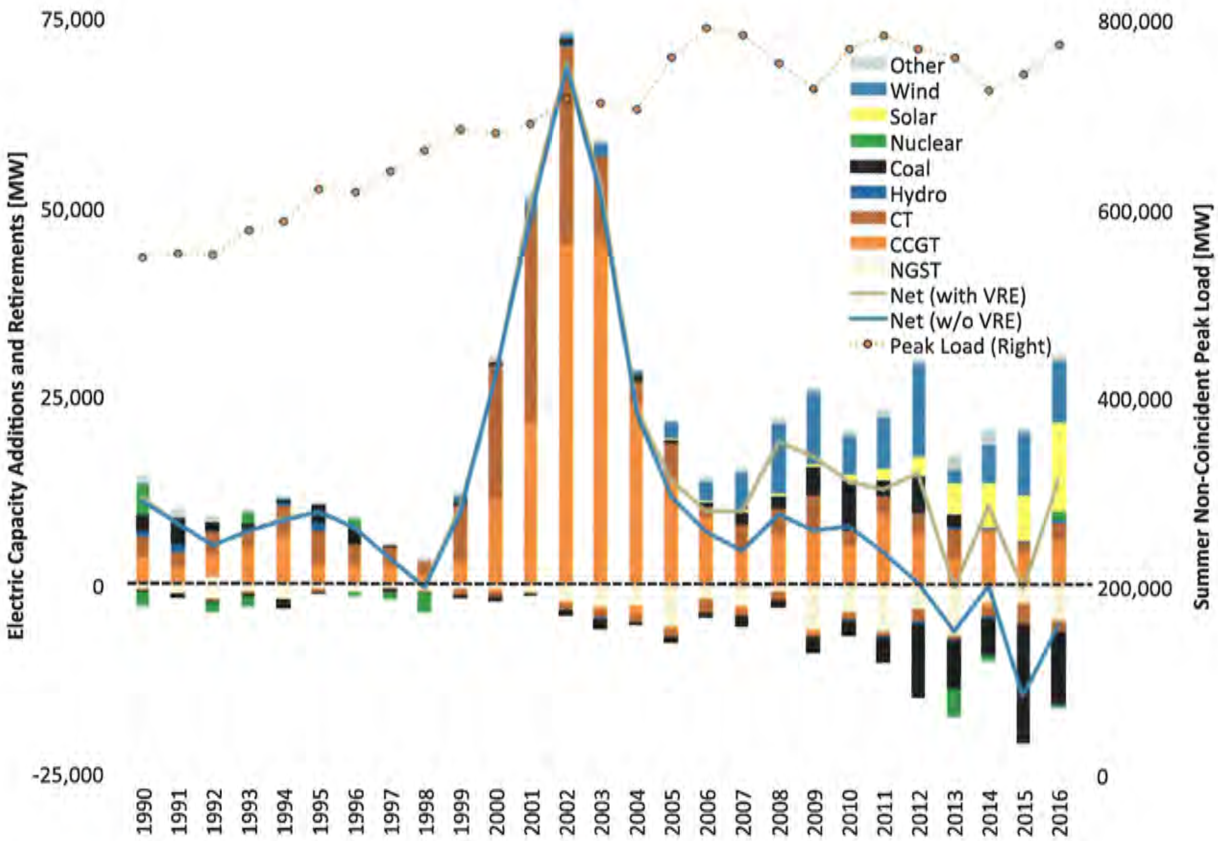
Several observations are apparent from these charts:

- 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

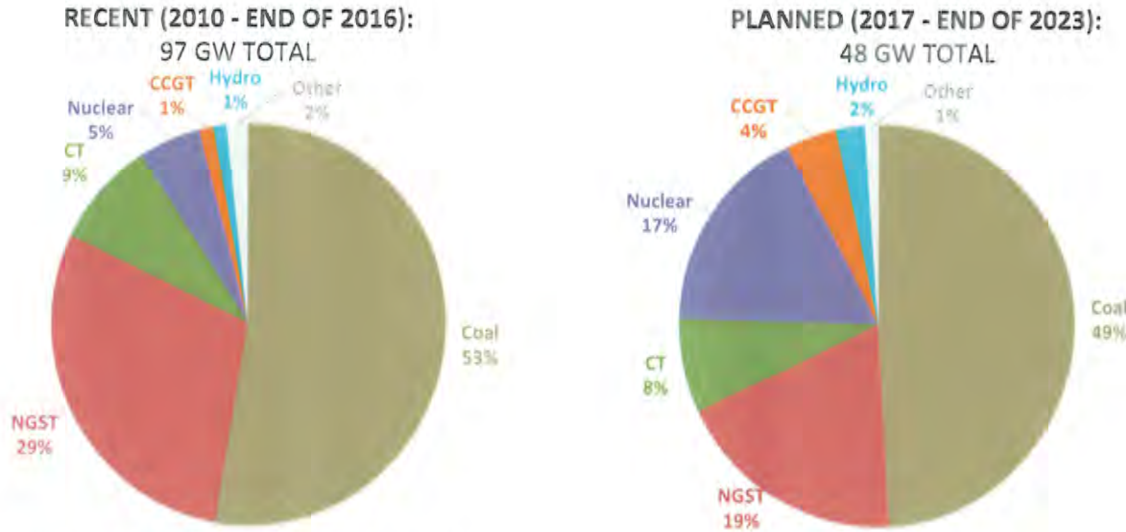
As a result of all of these trends, excess generation capacity exists nationally and regionally.[10]

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

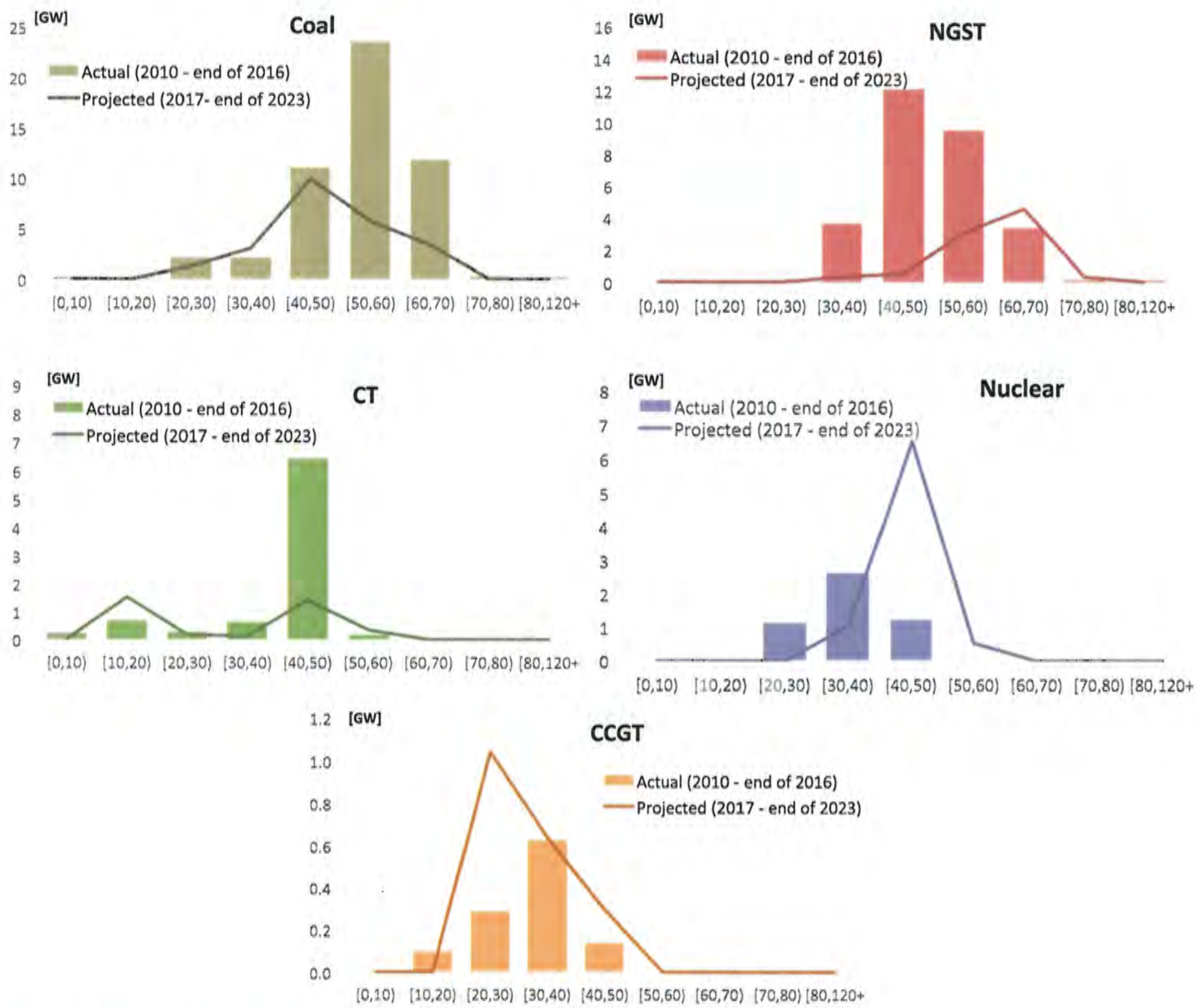
Figure 2. Plant Type Distribution for Recent and Planned Retirements

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.

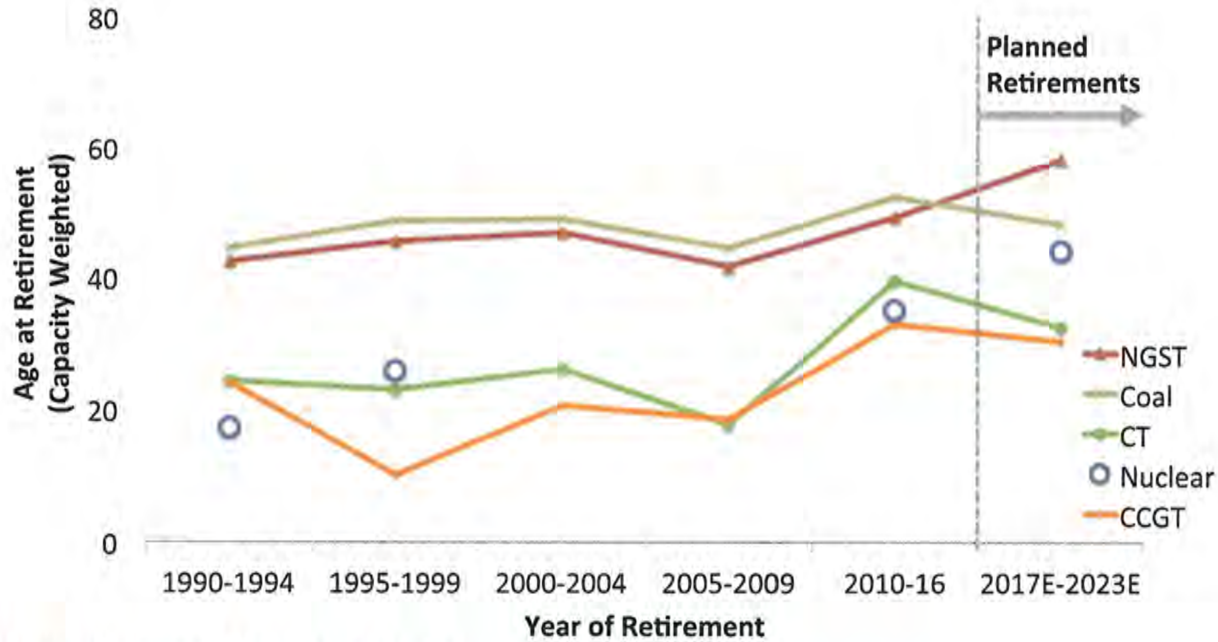
Several observations are apparent from these charts:

- 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.

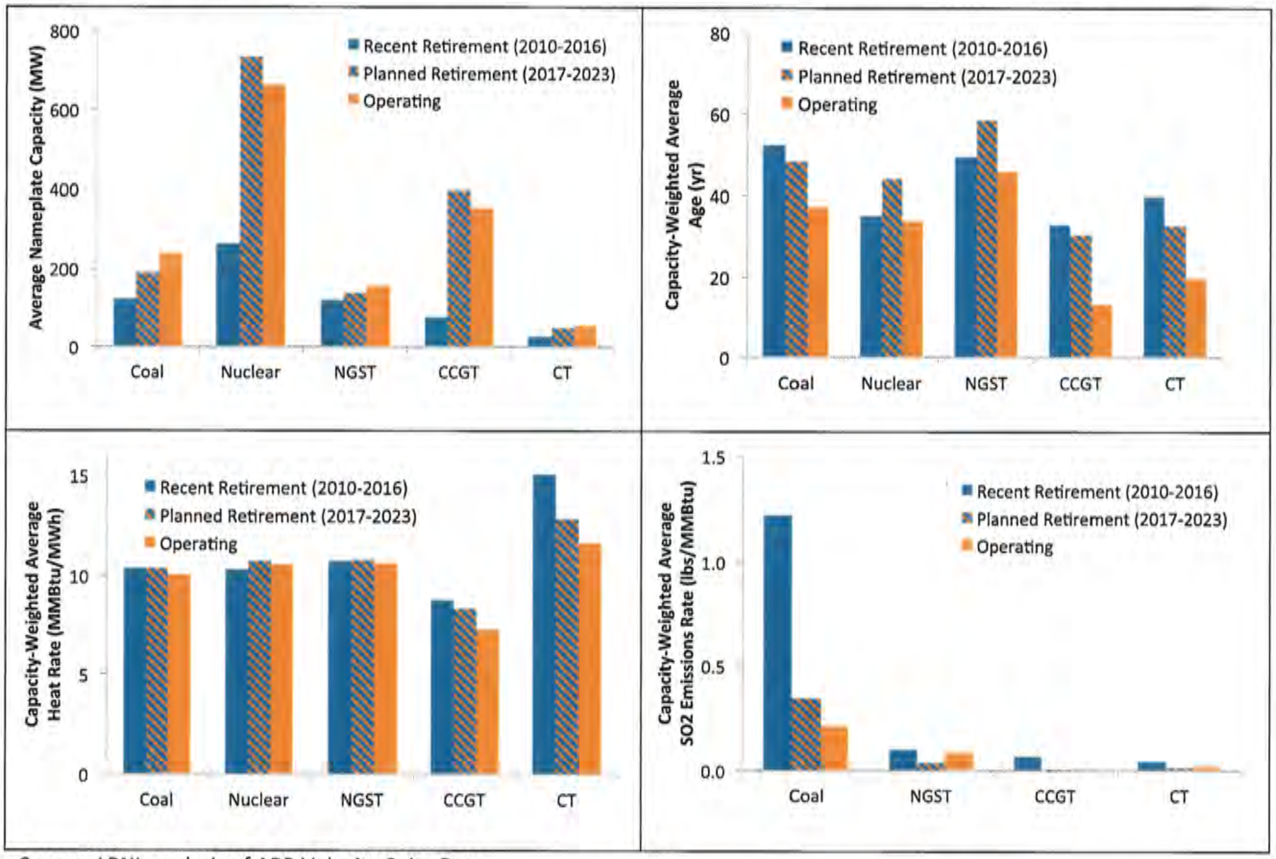
5 Comparison of Recently Retired Plants to Operating Plants

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

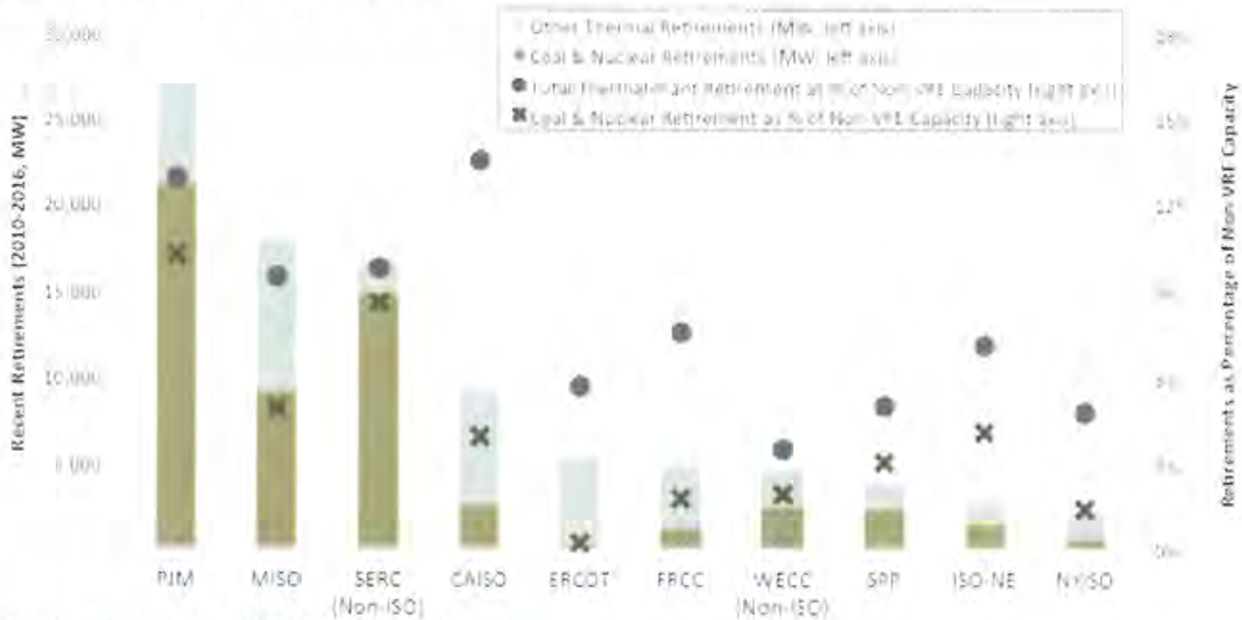
Figure 5. Comparison of Recently Retired or Planned Retirements to Operating Plants

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

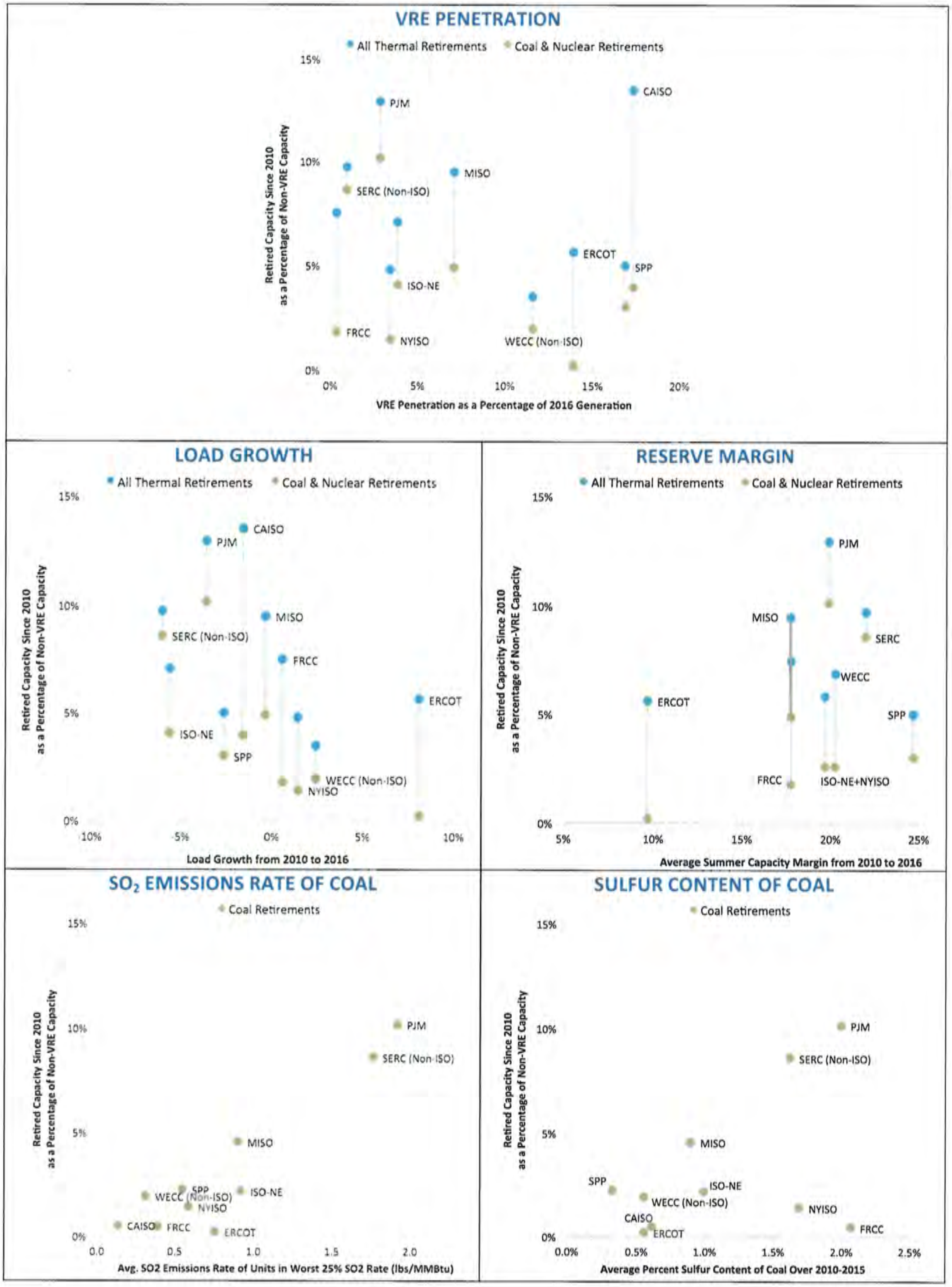
Visual inspection of these figures does not offer perfect clarity on the core drivers for regional retirement trends. Nor do historical trends necessarily tell us what might drive retirement decisions on a going-forward basis. However, we observe the following based on these graphics:

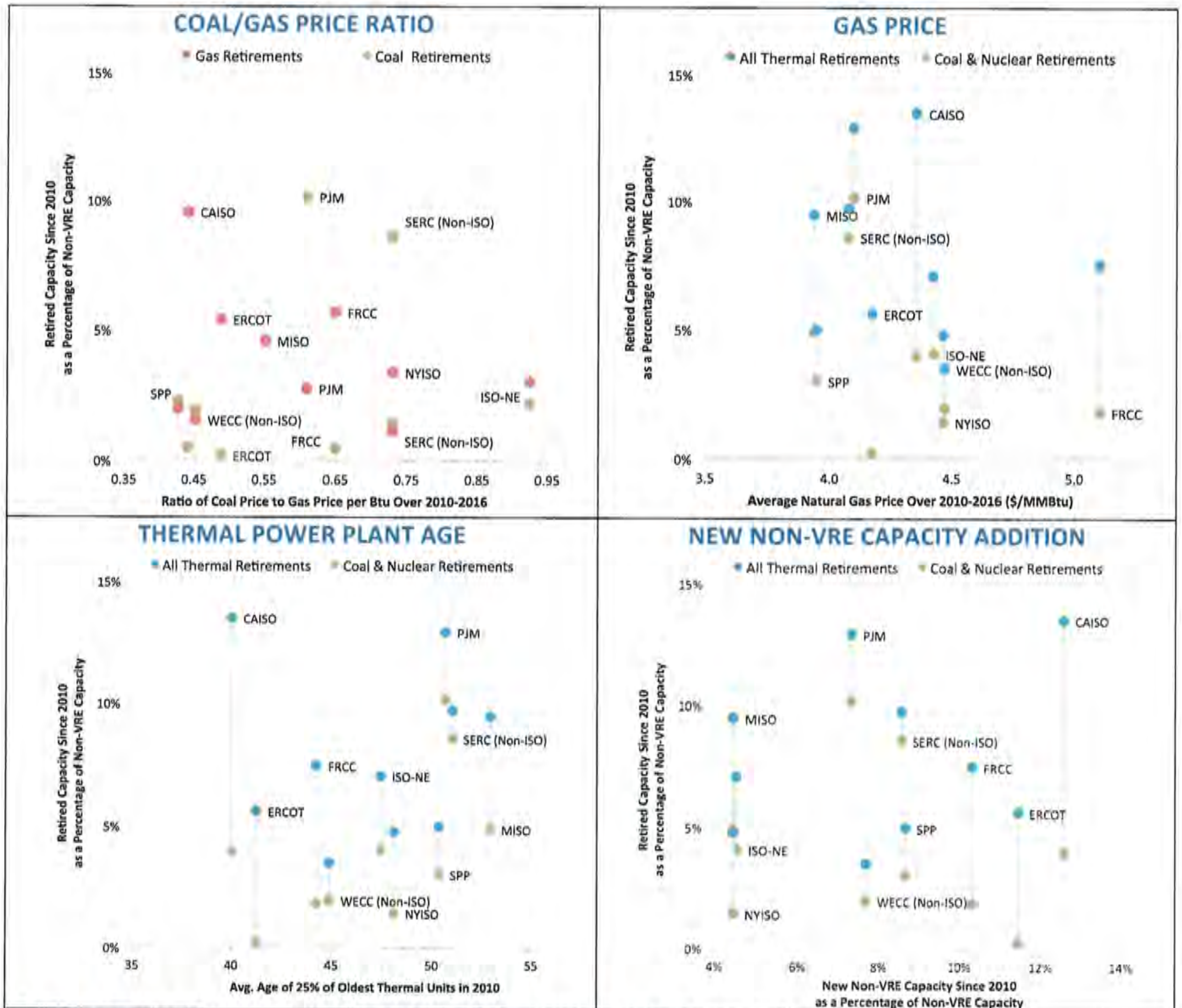
- *VRE Penetration:* There does not appear to be any obvious widespread relationship between VRE penetration and recent historical regional retirement decisions. PJM and SERC, both with very low

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
All Thermal Retirements
Coal & Nuclear Retirements
Retired Capacity Since 2010 as a Percentage of Non-VRE Capacity
VRE Penetration as a Percentage of 2016 Generation
PJM
CAISO
SERC (Non-ISO)
MISO
ERCOT
SPP
ISO-NE
FRCC
NYISO
WECC (Non-ISO)
LOAD GROWTH
All Thermal Retirements
Coal & Nuclear Retirements
Load Growth from 2010 to 2016
RESERVE MARGIN
All Thermal Retirements
Coal & Nuclear Retirements
Average Summer Capacity Margin from 2010 to 2016
ISO-NE+NYISO
SERC
WECC
SO2 EMISSIONS RATE OF COAL
Coal Retirements
Avg. SO2 Emissions Rate of Units in Worst 25% SO2 Rate (lbs/MMBtu)
SULFUR CONTENT OF COAL
Coal Retirements
Average Percent Sulfur Content of Coal Over 2010-2015



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.

Rio Grande Station Units 6 and 7 Condition Assessment Report

prepared for

El Paso Electric, Inc.
El Paso, TX

April 2010

Project No. 53549

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INDEX AND CERTIFICATION

Rio Grande Station Units 6 and 7
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Project 53549

Report Index

Chapter Number	Chapter Title	Number of Pages
--	Executive Summary	3
1	Introduction	3
2	Boiler	9
3	Boiler Auxiliary Systems	3
4	Turbine Generator	5
5	High Energy Piping Systems	5
6	Balance of Plant	8
7	Electrical Systems	8
8	External and Environmental Factors	3
9	New Generation	6
10	Recommendations and Conclusions	8

Certification

We hereby certify, as a Professional Engineers in the state of Texas, that the information in the document was assembled under our direct personal charge. This certification is made in accordance with the provisions of the laws and rules of Texas Board of Professional Engineers under the Texas Engineering Practice Act.

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Michael Frudil

TABLE OF CONTENTS

Page No.

EXECUTIVE SUMMARY **1**

1.0 INTRODUCTION **1-1**
1.1 General Description 1-1
1.2 Project Overview 1-1
1.3 Study Contents 1-2
1.4 Limitation of Liability 1-3

2.0 BOILER **2-1**
2.1 Unit 6 Boiler 2-1
2.1.1 Introduction 2-1
2.1.2 Waterwalls 2-1
2.1.3 Superheater 2-2
2.1.4 Drums and Headers 2-2
2.1.5 Safety Valves 2-3
2.1.6 Burner Control System 2-3
2.2 Unit 7 Boiler 2-4
2.2.1 Introduction 2-4
2.2.2 Waterwalls 2-4
2.2.3 Superheater 2-5
2.2.4 Reheater 2-6
2.2.5 Economizer 2-7
2.2.6 Drums and Headers 2-7
2.2.7 Safety Valves 2-9
2.2.8 Burner Control System 2-9

3.0 BOILER AUXILIARY SYSTEMS **3-1**
3.1 Unit 6 Boiler Auxiliary Systems 3-1
3.1.1 Fans 3-1
3.1.2 Air Heater 3-1
3.1.3 Flues & Ducts 3-1
3.1.4 Stack 3-1
3.1.5 Blowdown System 3-1
3.2 Unit 7 Boiler Auxiliary Systems 3-2
3.2.1 Fans 3-2
3.2.2 Air Heater 3-2
3.2.3 Flues & Ducts 3-2
3.2.4 Stack 3-3
3.2.5 Blowdown System 3-3

4.0 TURBINE GENERATOR 4-1
4.1 Unit 6 Turbine Generator 4-1
4.1.1 Introduction 4-1
4.1.2 Turbine 4-1
4.1.3 Turbine Valves 4-2
4.1.4 Generator 4-2
4.2 Unit 7 Turbine Generator 4-3
4.2.1 Introduction 4-3
4.2.2 Turbine 4-3
4.2.3 Turbine Valves 4-3
4.2.4 Generator 4-4

5.0 HIGH ENERGY PIPING SYSTEMS 5-1
5.1 Unit 6 High Energy Piping Systems 5-1
5.1.1 Main Steam Piping 5-1
5.1.2 Extraction Piping 5-2
5.1.3 Feedwater Piping 5-2
5.2 Unit 7 High Energy Piping Systems 5-3
5.2.1 Main Steam Piping 5-3
5.2.2 Hot Reheat Piping 5-3
5.2.3 Cold Reheat Piping 5-4
5.2.4 Extraction Piping 5-4
5.2.5 Feedwater Piping 5-5

6.0 BALANCE OF PLANT 6-1
6.1 Unit 6 Balance of Plant Systems 6-1
6.1.1 Condensate System 6-1
6.1.2 Feedwater System 6-2
6.1.3 Condensate and Boiler Feed Pumps 6-2
6.1.4 Circulating Water System 6-3
6.2 Unit 7 Balance of Plant Systems 6-3
6.2.1 Condensate System 6-3
6.2.2 Feedwater System 6-4
6.2.3 Condensate and Boiler Feed Pumps 6-5
6.2.4 Circulating Water System 6-5
6.3 Water Treatment, Chemical Feed, & Sample Systems 6-6
6.4 Fire Protection Systems 6-7
6.5 Plant Structures 6-8

7.0 ELECTRICAL SYSTEMS 7-1
7.1 Unit 6 Electrical Systems 7-1
7.1.1 Transformers 7-1
7.1.2 Cable Bus 7-2
7.1.3 Medium Voltage Switchgear 7-2

7.1.4 480 V Load Centers, Switchgear, and Motor Control Centers 7-3
7.1.5 2400 Volt Motors 7-3
7.2 Unit 7 Electrical Systems 7-3
7.2.1 Transformers 7-3
7.2.2 Cable Bus 7-5
7.2.3 Medium Voltage Switchgear 7-5
7.2.4 480 V Load Centers, Switchgear, and Motor Control Centers 7-5
7.2.5 2400 Volt Motors 7-6
7.3 Station Emergency Power Systems 7-6
7.4 Electrical Protection 7-6
7.5 2.4 kV Cable 7-7
7.6 Grounding & Cathodic Protection 7-7
7.7 Substation & Transmission Systems 7-7
7.8 Control Systems 7-8
7.9 Miscellaneous Electrical Systems 7-8

8.0 EXTERNAL AND ENVIRONMENTAL FACTORS 8-1
8.1 Introduction 8-1
8.2 Fuel Supply 8-1
8.3 Water Supply 8-1
8.4 Air Emissions & Environmental Issues 8-2
8.5 Wastewater Discharge 8-2
8.6 Odor, Visibility, & Noise 8-2
8.7 Work Force 8-3

9.0 NEW GENERATION 9-1
9.1 Assumptions 9-1
9.1.1 General Assumptions and Clarifications 9-1
9.1.2 Project Indirect Costs 9-2
9.1.3 Evaluation 9-4

10.0 RECOMMENDATIONS AND CONCLUSIONS 10-1
10.1 General Recommendations 10-1
10.2 Unit 6 Recommendations 10-1
10.3 Unit 7 Recommendations 10-3
10.4 Analysis 10-5
10.5 Conclusions 10-6

APPENDIX A – Rio Grande Unit 6 Economic Analysis

APPENDIX B – Rio Grande Unit 7 Economic Analysis

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LIST OF TABLES

Table No. **Page No.**

Table 10-1: Implementation Schedule for B&McD Recommendations on Rio Grande Unit 6 10-2
Table 10-2: Implementation Schedule for B&McD Recommendations on Rio Grande Unit 7 10-4
Table 10-3: Net Present Value of Total Estimated Costs for Rio Grande 6 10-5
Table 10-4: Total Cost Comparison on a $/Nominal Capacity Basis for Rio Grande 6............ 10-5
Table 10-5: Total Cost Comparison on a $/MWhr Basis for Rio Grande 6 10-5
Table 10-6: Net Present Value of Total Estimated Costs for Rio Grande 7 10-5
Table 10-7: Total Cost Comparison on a $/Nominal Capacity Basis for Rio Grande 7............ 10-5
Table 10-8: Total Cost Comparison on a $/MWhr Basis for Rio Grande 7 10-6

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EXECUTIVE SUMMARY

El Paso Electric (EPE) retained the services of Burns & McDonnell (B&McD) to perform a study to assess whether Rio Grande Unit 6 and 7 could operate reliably until their desired retirement dates (December 2012 and December 2013, respectively) and potentially up to six additional years. This study includes a review of the current condition of the plant, current plant maintenance and operations practices, and a review of external factors influencing this retirement date. The unit remaining life was based on plant maintenance data and historical operations data provided by EPE, maintenance and operating practices of units similar to Rio Grande, and Burns & McDonnell's professional opinion regarding the expected remaining life of the facilities. B&McD has estimated capital and incremental O&M costs for any recommendations made to maintain unit reliability. In addition, B&McD has provided a "screening level" estimate of the capital and O&M cost for new generation.

The project approach used for this study was to review plant documentation, interview plant personnel, and conduct a walk-down of the plant to obtain information to complete the Rio Grande Units 6 and 7 plant condition assessments. As a result of our review of the design, condition, operations and maintenance records, and long-range capital plan it is B&McD's opinion that Rio Grande Units 6 and 7 are capable of extending their scheduled retirement by 6 years to December 2018 and December 2019, respectively. This assumes that the recommended inspections and assessments do not discover any significant findings. However, comparing the capital and incremental O&M cost estimated to extend the life of the three units against the estimated cost for new generation, it is B&McD's opinion that it is not economically justified to extend the life of the existing units the full six years. As indicated in Table 10-5, the equivalent new unit is less expensive, on a cost per MW-hr basis, during any extension period for Rio Grande Unit 6. As indicated in Table 10-8, the equivalent new unit becomes less expensive sometime between the two and four year extension periods for Rio Grande Unit 7.

The Rio Grande units were placed into commercial service June 1957 and June 1958, respectively. Although the units are nearing the end of their anticipated life cycle, they have yet to show the characteristic upswing in Equivalent Forced Outage Rate (EFOR) that is indicative of general degradation of the major components. This is due to a number of factors including:

- Avoidance of cycling operation during the majority of their life,
- Proper attention to water chemistry, and
- An aggressive Predictive Maintenance (PdM) program

Across the industry, external factors, such as availability of fuel, water, or environmental factors have been the cause of generating units being taken out of service. There are no current external or environmental factors detected which would limit or restrict the operation of Rio Grande units in the foreseeable future. There is a good potential for NOx emissions regulations that may require the addition of control technology to the units, or the purchase of emissions allowances.

Based on the information acquired and presented in this report, the following conclusions have been made:

1. The overall condition of the Rio Grande units appears to be good considering their age. There are no conditions that have been identified as being detrimental to achieving the desired retirement date, plus up to six additional years. In general, operational and maintenance problems which could affect operation are actively being addressed. However, the metallurgical condition of critical components is unknown at this time due to the lack of an ongoing Non-Destructive Examination (NDE) program. Consequently, in providing this relatively clean bill of health, our confidence level is moderated by this unknown condition (see further discussion in item 7 below).

2. Operations and maintenance are generally well planned and carried out in a manner consistent with or exceeding utility industry standards.

3. The predictive maintenance program used throughout the EPE system has been highly successful in minimizing forced outages in the rotating equipment area. This program has received industry recognition and, where feasible, should be extended to other critical equipment, such as control valves, and certain heat exchangers.

4. Certain conditions on major unit components may develop in the future, and the cost of repairing or replacing such components would make the continued operation of a generating unit imprudent. The end of the expected useful life of any of the Rio Grande units may occur upon the failure, or prediction of eminent failure, of the steam drum or the concurrent failure of one or more simultaneous major plant components.

   Based on the information provided by EPE, there were no reported indications or predictions of potential failure of these major unit components anticipated in the foreseeable future. However, there is no NDE program in place to monitor the condition of these major components.

5. Economic pressure to cycle the unit at night and on weekends is currently present and will continue to grow as the fuel price disparity between gas and coal / nuclear

becomes greater. With the addition of Newman Unit 5, EPE has been forced to cycle the less efficient units. As new failure trends are established, a new end-of-life determination will need to be made.

6. The Rio Grande units have typically achieved better than average plant availability, and equivalent forced outage rates. This results from a combination of the predictive maintenance program, coupled with proper attention to water chemistry and the aforementioned dispatch philosophy intended to minimize cycling. As EPE is forced to cycle the units, existing metallurgical weak points that may be lurking unseen within the steam cycle components will become more evident. In addition, oxygen infiltration into the steam cycle during shutdowns will introduce not only general corrosion, but oxygen pitting. In those areas that are highly stressed, these pits serve as initiation points for cracks that, through repeated cycles, could grow to failure points. Therefore, to minimize the impact of cycling, we recommend inerting the steam cycle components during shutdowns.

7. EPE is currently operating its system with little reserve margin during peak seasons. Given this, EPE should closely scrutinize the vulnerabilities of these units, and by extension the rest of its generating fleet. Several vulnerabilities that we have observed at the Rio Grande units are:

   a. The unknown metallurgical condition of the unit's critical components. Given the age of the units, we believe that implementation of an NDE program would be prudent in order to provide early warning of major component deterioration. We recommend that this be made part of EPE's existing PdM program in order to translate the findings into maintenance planning.

   b. The unit has virtually no protection against Turbine Water Induction. While these incidents do not occur frequently, when they do, they can be quite damaging to the turbine and result in lengthy outages. We recommend that EPE review the ASME TWIP guidelines (ASME TDP-1-2006) and develop a cost effective modification plan for these units.

   c. Monitor the auxiliary transformer for combustible gas due to age to provide early warning of component failure.

* * * * *

1.0 INTRODUCTION

1.1 GENERAL DESCRIPTION

El Paso Electric (EPE) is an investor-owned electrical utility responsible for supplying power through an interconnected system to a service territory encompassing approximately 334,000 customers in the Rio Grande Valley in west Texas and southern New Mexico. EPE has interests in Palo Verde Nuclear Plant and Four Corners Station to supply its base load. Both Rio Grande and Newman stations provide load following services. Located in Sunland Park, New Mexico (a suburb of El Paso, Texas), Rio Grande Unit 6 began commercial operation in 1957 and Unit 7 in 1958.

The Unit 6 major plant equipment include a natural circulation steam generator style boiler designed by Babcock and Wilcox for 450,000 $^{lb}/_{hr}$ steam flow at 875 psig outlet pressure and 910°F superheater outlet temperatures. Unit 6 does not have a reheater. The boiler has a pressurized furnace, and a single regenerative Ljungstrom air preheater. The Westinghouse steam turbine is a preferred standard, two cylinder machine with a double flow low pressure condensing turbine. The generator is currently rated at 58.8 MVA. Cooling water is circulated through a counter-flow cooling tower with makeup water provided from off site wells. Boiler makeup water is also supplied from the off site well water system.

The Unit 7 major plant equipment include a natural circulation steam generator El Paso style boiler designed by Babcock and Wilcox for 350,000 $^{lb}/_{hr}$ 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 General Electric steam turbine is a tandem compound, double-flow condensing unit. The generator is currently rated at 56.8 MVA. Cooling water for Unit 7 is also 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.

1.2 PROJECT OVERVIEW

EPE retained the services of Burns & McDonnell (B&McD) to perform a study to assess whether Rio Grande Units 6 and 7 could operate reliably until their desired retirements in December 2012 and December 2013, respectively and potentially up to six additional years in two year increments. This condition assessment study includes a review of the current condition of the plant, current plant maintenance and operations practices, and a review of external factors influencing these retirement dates. The remaining life was based on plant maintenance data and historical operations data provided by EPE, maintenance and operating practices of units similar to Rio Grande Units 6 and 7 and Burns & McDonnell's professional opinion regarding the expected remaining life of the facilities. B&McD has estimated capital and incremental O&M costs for any recommendations made to maintain unit reliability. In addition, B&McD has provided a "screening level" estimate of the capital and O&M cost for new generation.

To complete this assessment, Burns & McDonnell engineers reviewed plant documentation, interviewed plant personnel, and conducted a walkdown of the plant to obtain information on the condition of Rio Grande Units 6 and 7.

1.3 STUDY CONTENTS

The following report details the current condition of the plant, its future operating capability, and recommendations for improvements and additional testing or inspections. This information was compiled based on existing plant records, general plant and equipment observations, comparison to similar units and equipment, and in-house expertise.

Since virtually any single component within a power plant can be replaced, the remaining life of a plant is typically driven by the economics of replacing the various components as necessary to keep the plant operating economically versus shutting it down and either purchasing power or building a replacement facility. For this reason, it is important for EPE to periodically update the condition assessment of the Rio Grande Units 6 and 7 to project the major future expenditures that will be required to maintain the facility. Specifically, the critical components that will likely determine the facility's remaining life include the following:

- Steam generator drum, headers, and downcomers.
- High energy piping systems.
- Steam turbine rotor shaft, valves, and steam chest.
- Main generator rotor shaft, stator windings, stator insulator, 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:

- Steam generator tubing, ductwork, air preheater and FD fan.
- Steam turbine blades, diaphragms, nozzle blocks, and casing and shells.
- Generator stator-winding bracing, DC exciter, and voltage regulator.
- Balance of plant condenser, feedwater heaters, feedwater pumps & motors, controls, and auxiliary switchgear.

- Cooling tower structure, structural steel, stack, concrete structures, and station main GSU and auxiliary transformers.

External influences that will probably be the major determinant of the future life of the unit include:

- Environmental influences; including water availability and future environmental compliance requirements such as NOx and CO_2 emissions.
- Economics; including fuel costs, comparative plant efficiency, and system needs.
- Obsolescence such as the inability to obtain replacement parts and supplies.

1.4 LIMITATION OF LIABILITY

In the preparation of this Report, the information provided to us by EPE was used by B&McD to make certain assumptions with respect to conditions which may exist in the future. While B&McD believes the assumptions made are reasonable for the purposes of this Report, B&McD makes no representation that the conditions assumed will, in fact, occur. In addition, B&McD has no reason to believe that the information provided by EPE, and on which this Report is based, is inaccurate in any material respect. However, B&McD has not independently verified such information and cannot guarantee its accuracy or completeness. To the extent that actual future conditions differ from those assumed herein or from the information provided to B&McD, the actual results will vary from those forecast.

Estimates, forecasts, projections, and schedules prepared by B&McD relating to costs, quantities, demand or pricing (including, but not limited to, property costs, construction, operations or maintenance costs, and/or energy or commodity demand and pricing), are opinions based on B&McD's experience, qualifications, and judgment. B&McD 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 or projections. EPE acknowledges that actual results may vary significantly from the representations and opinions herein, and nothing herein shall be construed as a guarantee or warranty of conclusions, results, or opinions. B&McD makes no guarantee or warranty (actual or implied) that actual rates, demand, pricing, costs, performance, schedules, quantities, technology, and related items will not vary from the opinions contained in the estimates, forecasts, projections, schedules, results, or other statements or opinions prepared by B&McD.

* * * * *

2.0 BOILER

2.1 UNIT 6 BOILER

2.1.1 Introduction

Boiler No. 6 at the Rio Grande Station is a natural circulation, radiant heat, pressurized unit designed to burn natural gas and fuel oil in nine wall-mounted burners. This unit includes a horizontal, drainable superheater, one steam drum, and an elevated mud drum. The unit was originally designed for a maximum continuous rating (MCR) of 450,000 $^{lb}/_{hr}$ main steam at a superheater outlet condition of 875 psig and 910°F. The unit does not have a reheater. The superheater outlet temperature is controlled by desuperheater sprays. The boiler design also includes Ljungstrom type tri-sector air heater for flue gas heat recovery.

The unit has been operated on natural gas for a significant portion of its life except for short periods of fuel oil operation in the 1970's. Boiler chemical cleaning frequency is on a five year cycle with the last cleaning occurring in January 2004. No further boiler chemical cleaning is scheduled due to the imminent retirement of the unit. Should the life of the unit be extended, another boiler chemical cleaning is recommended. In addition, EPE takes tube samples periodically in high heat flux areas of the boiler to evaluate the extent of boiler tube scaling to evaluate the need for chemical cleaning of the boiler.

EPE has not instituted a condition assessment program for the critical boiler components. There were no non-destructive examination (NDE) or physical examination reports available to assess the condition of the critical boiler components. However, EPE has reported there is no ASTM A335-P11 seamed piping in the boiler.

2.1.2 Waterwalls

EPE has reported that the boiler waterwall tubes appear to be in good condition. Relatively few waterwall leaks have occurred over the life of the unit due to the proven design of the boiler and the clean fuel. Because of this fact, the station currently has no tube mapping program in place, nor does it have a regular NDE program established.

In general, the overall condition of the furnace is reported to be good. However, since there is no regular NDE program to identify weakened tubes, our confidence in this assessment is moderated. Typically, the most common damage mechanisms that force replacement of the waterwall tubes are thermal fatigue, and fire side corrosion. Eventually, a tube wall thickness (NDE) inspection program, followed by spot replacements, as needed, will likely be necessary to prevent tube rupture related outages.

2.1.3 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 between the sections. The Rio Grande Unit 6 boiler design allows for draining of both stages of the superheaters during outages and/or startup.

EPE replaced four superheat pendants in the past and one superheat pendant has been capped off. EPE has experienced very few superheater tube leaks and the superheater is believed to be in good condition. However, our confidence in this assessment is moderated by the fact that there is no regular NDE program established.

Future inspection should focus on identifying signs of creep, fatigue, and corrosion, as they are the most common damage mechanisms in superheater tubes. If tube failures become a problem or if future NDE programs reveal a significant amount of deterioration, higher grade material (if signs of creep or fatigue are identified) should be considered on future tube replacements to prolong the life of the replacement tubes. A tube wall thickness (NDE) inspection program may be advisable to identify thinned or weakened tubes or tube sections to be replaced.

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.

2.1.4 Drums and Headers

There is one 60 inch diameter steam drum, one 42 inch mud drum, and a lower waterwall header on the unit. While a visual inspection is occasional performed, there are no records indicating that the drums have been inspected with all internals removed. It is recommended that the steam drum be inspected, with all internals removed, in the near future. Since the drum is most susceptible to fatigue and corrosion damage, the inspection methods should include a detailed visual inspection, magnetic particle examination of all girth, socket, and nozzle, and ultrasonic inspection of the welds and thickness readings at the water level.

The high temperature headers include the primary and secondary superheater outlet headers. 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. These headers should be regularly inspected to determine their condition and assess their remaining life using the following non-destructive testing methods:

- Full borescope examination of the headers.
- Acid etching of the headers to determine whether longitudinal seam welds exist in the headers.
- 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.
- All girth welds, socket welds, and longitudinal welds (if applicable) should be inspected using magnetic particle examination to detect surface discontinuities in the metal.
- Replications should be performed at the welds in the hottest locations along the headers. These replications should be taken across the weld, base metal, and heat affected zone for best results. The replications should then be sent out to a professional materials testing laboratory for analysis by professional metallurgical engineers to examine the pipe material's grain structure and determine if heat has affected its metallic properties and if the pipe has been exposed to extreme temperatures.
- Hardness tests should be completed at all replication locations to assess the material's ultimate tensile strength and determine if the material has undergone a reduction of its metallic properties.
- Pi Measurement tests, used as a gauge to detect long term creep by identifying pipe swelling, should be performed along the headers.
- A header straightness examination should also be performed to identify any signs of sagging associated with long term creep damage.

2.1.5 Safety Valves

There is no indication that there is an ongoing plan in place to test the safety valves. At a minimum, the valves should be tested in accordance with ASME code requirements, but it is not uncommon to test more frequently if required by the facility's insurance company. Annual inspections by the safety valves' Original Equipment Manufacturer (OEM) are recommended to determine if refurbishment or replacement is required.

2.1.6 Burner Control System

The existing Unit 6 Boiler has no Flame Safety Shutdown and Startup Furnace Purge System (FSSS). This boiler was constructed before the NFPA Codes required all boilers to have FSSS systems to prevent furnace explosions. It has continued to operate as a "grandfathered" unit, depending on the operators to implement appropriate burner ignition practices, which have been successful to date. However, for continued operation, addition of a FSSS system is recommended. Such a recommendation is particularly emphasized if the future operation of the unit will include seasonal or peak load operation, or major turnover of the current experienced staff.

2.2 UNIT 7 BOILER

2.2.1 Introduction

Boiler No. 7 at the Rio Grande Station is a natural circulation, radiant heat, pressurized unit designed to burn natural gas and fuel oil 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 1000°F. The reheater is designed for an operating temperature of 1000°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.

Boiler chemical cleaning frequency is on a five year cycle with the last cleaning occurring in April 2004. No further boiler chemical cleaning is scheduled due to the imminent retirement of the unit. Should the life of the unit be extended, another boiler chemical cleaning is recommended. In addition, EPE takes tube samples periodically in high heat flux areas of the boiler to evaluate the extent of boiler tube scaling to evaluate the need for chemical cleaning of the boiler.

2.2.2 Waterwalls

EPE has reported that the boiler waterwall tubes appear to be in good condition. Relatively few waterwall leaks have occurred over the life of the unit due to the proven design of the boiler and the clean fuel. Because of this fact, the station currently has no tube mapping program in place, nor does it have a regular NDE program established.

In general, the overall condition of the furnace is reported to be good. However, since there is no NDE program to identify weakened tubes, our confidence in this assessment is moderated. However, the plant records indicate that EPE contracted with an NDE inspection firm to perform a one day inspection of the boiler in 2001. A summary of the results of this report are indicated below. Typically, the most common damage mechanisms that forces replacement of the waterwall tubes are thermal fatigue, and fire side corrosion. Eventually, spot replacements, as needed, will likely be necessary to prevent tube rupture related outages. A tube wall thickness (NDE) inspection program may be advisable to identify thinned or weakened tubes or tube sections to be replaced.

United Dynamics Corporation (UDC) performed a one day inspection of the Unit 7 boiler on April 16, 2001. There were a limited number of water wall tubes that revealed excessive attachment damage, bulged tubes, and minor refractory repairs were required near the burners. There was limited access available to the front wall, the rear portion of the right and left side walls. No findings were observed in the secondary superheater; however, there was limited access to the bottom of the secondary superheater. Many bowed tubes were observed in the reheater due to overheating. Some reheater circuits have been discontinued; UDC recommended these tubes should be monitored to ensure they don't abrade adjacent tubes. The bottom of the front bank of the primary superheater tubes were noted to be thinning and were recommended to be monitored by EPE for future abrasion. Economizer required some attachment lug repairs. No repair recommendations were made for the penthouse area. The steam drum was noted for excessive debris in the bottom of the drum; no serious corrosion was noted.

Unit 7 boiler experienced a combustion explosion on April 17, 2003. As a result of this explosion, seven of the eight buckstays were damaged and had to be replaced. There was only a minimal amount of waterwall tubing replacement required to allow maintenance access into certain furnace locations as a result of this explosion. Some boiler asbestos abatement was done during the boiler repair. Not all boiler asbestos was abated in the 2003 forced outage repair.

In 2004, the boiler furnace roof section tubing was replaced due to excessive tube leaks. Future roof section tubing replacements should consider the use of rifled tubing which will minimize the tube overheating problem that caused the leaks.

2.2.3 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 six sections or stages of the superheater are as follows, starting at the steam drum and progressing towards the superheater outlet header:

- The backpass wall and roof section, which form the sides and roof of the vertical gas path and part of the horizontal gas path.

- The low temperature horizontal sections, located above the economizer in the rear backpass of the boiler.
- The low temperature pendant section, located in the furnace rear backpass above the low temperature horizontal sections.
- The division panel section, located directly above the furnace, between the front wall and the pendant platen section.
- The pendant platen section, located directly above the furnace in front of the furnace arch.
- The finishing section, located in the horizontal gas path in the back of the screen wall tubes.

A report reviewed by B&McD stated, "Testing of the superheat and reheat sections of Unit #7 boiler done in 1996 resulted in the determination that the remaining creep-rupture lives of these three sections was, at that time, 200,000 hours [or about 20 years from that time]". This would indicate a need to perform further inspections of the boiler components prior to any final decision to extend the life of the unit.

Future inspection should focus on identifying signs of creep, fatigue, and corrosion, as they are the most common damage mechanisms in superheater tubes. If tube failures become a problem or if future NDE programs reveal a significant amount of deterioration, higher grade material (if signs of creep or fatigue are identified) should be considered on future tube replacements to prolong the life of the replacement 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.

2.2.4 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 Rio Grande Unit 7, the design of the reheater allows for draining the reheater during outages and/or startup.

Future inspections should focus on identifying signs of creep, fatigue, and corrosion, as they are the most common damage mechanisms in reheater tubes. If tube failures become a problem or if future NDE programs reveal a significant amount of deterioration, higher grade material (if signs of creep or fatigue are identified) should be considered on future tube replacements to prolong the life of the replacement tubes.

2.2.5 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.

The economizer inlet header is always a source of concern for plants, as it is subject to considerable thermal stresses during startups and shutdowns. Thus, the inlet header should be inspected for signs of creep and fatigue as they are the most common damage mechanisms in the economizer section. Flow-accelerated corrosion (FAC) has also been an industry wide problem in many economizers. Since it is composed of carbon steel tubes and headers (FAC only affects carbon steels, typically with inadequate levels of chromium, copper, or molybdenum) and typically operates near the 250°F to 350°F temperature range where FAC is most prevalent, the economizer tubes and headers are particularly susceptible to FAC and ultrasonic thickness inspections should be used to monitor for any signs of this damage mechanism.

2.2.6 Drums and Headers

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

In April 2001, UDC inspected the steam drum and reported excessive debris and chemical buildup in the drum internals. It is recommended that the drums be NDE inspected in the near future. Since the drums are most susceptible to fatigue and corrosion damage, the inspection methods should include a detailed visual inspection, magnetic particle examination of all girth, socket, and nozzle, and ultrasonic inspection of the welds and thickness readings at the water level.

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 in the near future and then periodically (based on the findings of the initial examination) to monitor for signs of this type of damage and, if present, may need to be replaced at some point over the remaining plant life. The low temperature headers should be inspected using the following non-destructive methods:

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

The high temperature primary and secondary superheater outlet and reheat outlet 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. These headers, not having been inspected in the past, should be inspected to determine their condition and assess their remaining life using the following non-destructive testing methods:

- Full borescope examination of the headers.
- Acid etching of the headers to determine whether longitudinal seam welds exist in the headers.
- 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.
- All girth welds, socket welds, and longitudinal welds (if applicable) should be inspected using magnetic particle examination to detect surface discontinuities in the metal.
- Replications should be performed at the welds in the hottest locations along the headers. These replications should be taken across the weld, base metal, and heat affected zone for best results. The replications should then be sent out to a professional materials testing laboratory for analysis by professional metallurgical engineers to examine the pipe material's grain structure and determine if heat has affected its metallic properties and if the pipe has been exposed to extreme temperatures.
- Hardness tests should be completed at all replication locations to assess the material's ultimate tensile strength and determine if the material has undergone a reduction of its metallic properties.
- Pi Measurement tests, used as a gauge to detect long term creep by identifying pipe swelling, should be performed along the headers.

- A header straightness examination should also be performed to identify any signs of sagging associated with long term creep damage.

2.2.7 Safety Valves

There should be an ongoing plan in place to test the safety valves. At a minimum, the valves should be tested in accordance with ASME code requirements, but it is not uncommon to test more frequently if required by the facility's insurance company. Annual inspections by the safety valves' Original Equipment Manufacturer (OEM) are recommended to determine if refurbishment or replacement is required.

2.2.8 Burner Control System

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

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3.0 BOILER AUXILIARY SYSTEMS

3.1 UNIT 6 BOILER AUXILIARY SYSTEMS

3.1.1 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. The inlet guide vanes are cleaned and inspected annually. The Bailey inlet guide vane positioners have been replaced once during the life of the plant. In addition, vibration readings are taken 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.

3.1.2 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 air heater baskets have not been replaced in the last 10 years.

3.1.3 Flues & Ducts

The ductwork transports combustion air to the boiler and also 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.

3.1.4 Stack

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

3.1.5 Blowdown System

Unit 6 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 on to the continuous blowdown flash tank.

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

3.2 UNIT 7 BOILER AUXILIARY SYSTEMS

3.2.1 Fans

Similar to Unit 6, Unit 7 is provided with 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.

3.2.2 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 air heater baskets have not been replaced in the last 10 years. The inspection by UDC on April 16, 2001 revealed a few cracked welds which were repaired. These cracked welds were not a significant concern. EPE replaced the radial seals during the fall 2005 outage. Air heater lagging was replaced at the time when the boiler buckstays were replaced after the boiler explosion.

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

3.2.3 Flues & Ducts

The ductwork transports combustion air to the boiler and also 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

3.2.4 Stack

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

3.2.5 Blowdown System

Similar to Unit 6, the Unit 7 design includes an intermediate pressure blowdown tank and another continuous blowdown flash tank which are controlled in a similar manner to Unit 6. 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.

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4.0 TURBINE GENERATOR

4.1 UNIT 6 TURBINE GENERATOR

4.1.1 Introduction

In general, the turbine has exhibited good operation and vibration levels. The last major turbine-generator overhaul took place in the 2006 outage. Consequently, the internal condition is presumed to be in good condition because there have been no outward signs of significant damage beyond that indicated in item 4.1.2 below. Water chemistry is well maintained at the station and the unit has not been cycled excessively. Therefore, it is assumed that the turbine will only have 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.

4.1.2 Turbine

The HP and LP turbines were last overhauled by Siemens Power Generation during the spring 2006 outage extending from March 27, 2006 to May 26, 2006. The HP and LP turbine sections were disassembled, inspected and reassembled. Non-destructive examinations (NDE) were performed on the HP, LP, and generator rotors and HP and LP rotor blades by Siemens NDE Group. Siemens Turbine Services machined the journals of the HP rotor, and LP rotor,. They also performed weld repairs on the nozzle block, #1 water gland sealing diaphragm, blended indications on the HP and LP rotor blades, and re-tapped cracked thrust bearing foundation studs. There were no major repair recommendations made by Siemens.

In general, the turbine has exhibited good operation and vibration levels. Consequently, the internal condition is presumed to be in good enough shape that it shows no outward signs of damage. Therefore, the turbine will likely exhibit minor solid particle erosion (SPE) and insignificant deposits, as it has in past overhauls.

Turbine overhauls are scheduled on an 8 year cycle. EPE has not scheduled another turbine inspection, due to the intended unit retirement in 2012. Should EPE decide to continue operation of Unit 6 through 2018, another turbine inspection would be required.

4.1.3 Turbine Valves

The turbine valves, consisting of the main steam stop and control valves, are maintained on a four year cycle, which has proven to be adequate. In general, they usually exhibit minor SPE when inspected. Should EPE decide to continue operation of Unit 6 through 2017, additional valve inspections would be required.

4.1.4 Generator

The main generator is a 1955 vintage Westinghouse unit rated 58.822 MVA at 13.8kV. The stator output is 2460 amps at a 0.85 power factor. The rotor and stator windings are hydrogen cooled. The exciter is a 1955 vintage DC generator exciter rated 700 amps at 250VDC. The voltage regulator is a Westinghouse 1955 vintage electro-mechanical type located on the ground level under generator.

Generator protection consists of the following microprocessor relays:

- Distance backup (21) -GPU2000R-589W
- Volts/hertz (24) -GPU2000R-589W
- Voltage Supervised Overcurent backup (51V) -GPU2000R-589W
- Generator Differential (87G) -GPU2000R-589W
- Synchronizing (25/25A) -GPU2000R-589W
- Undervoltage Alarm (27) -GPU2000R-589W
- Reverse Power (32) -GPU2000R-589W
- Loss of Excitation (40) -GPU2000R-589W
- Unbalance (46) -GPU2000R-589W
- Overvoltage (59) -GPU2000R-589W
- Loss of Potential (fuse) (60) -NA
- Stator Ground (59GN or 64G) -GPU2000R-589W
- 100% Stator Ground (27TN) -GPU2000R-589W
- Frequency (81) -GPU2000R-589W
- Inadvertent Energizing (50/27) -GPU2000R-589W

The main generator was last inspected in 2006. Siemens Generator Services cleaned, electrically tested, and checked the core through bolt torque on the generator stator. Siemens Turbine Services machined the journals of the generator rotor, and collector rings. The following tests were performed:

- Insulation resistance (megger)
- Dielectric absorption
- El Cid (stator iron)
- Retaining ring ultrasonic inspection

The testing indicates that the generator is in good condition.

4.2 UNIT 7 TURBINE GENERATOR

4.2.1 Introduction

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

Similar to Unit 6, 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 Unit 7 turbine is also a major focus of the EPE predictive maintenance program and undergoes the same vibration and oil analysis as is performed for the Unit 6 turbine generator as indicated above.

4.2.2 Turbine

The HP and LP turbines were last overhauled by GE Energy Service during the fall 2005 outage extending from September 19, 2005 to December 10, 2005. The HP and LP turbine sections were disassembled, inspected and reassembled. The Stage 6 turbine buckets were replaced and the Stage 6 diaphragms were repaired. The nozzle plates were also repaired. The turbine shell had two major indications that were repaired.

GE's report noted that the turbine shell is nearing the end of its useful life.

Should EPE decide to continue operation of Unit 7 through 2019, another turbine inspection would be required.

4.2.3 Turbine Valves

The turbine valves, consisting of the main steam stop and control valves, are maintained on a four year cycle, which has proven to be adequate. In general, they usually exhibit minor SPE when inspected. Should EPE decide to continue operation of Unit 7 through 2019, additional valve inspections would be required.

4.2.4 Generator

The main generator is a 1956 vintage GE unit rated at 56.82 MVA at 13.8kV. The stator output is 2461 amps at 0.85 power factor. The rotor and stator windings are hydrogen cooled. The exciter is a 1956 vintage DC generator exciter rated 596 amps at 250VDC. The voltage regulator is a GE 1956 vintage electro-mechanical type located on the ground level under generator.

Generator protection consists of the following microprocessor relays:

- Distance backup (21) -GPU2000R-589W
- Volts/hertz (24) -GPU2000R-589W
- Voltage Supervised Overcurent backup (51V) -GPU2000R-589W
- Overall Differential (87O) - Not Included
- Generator Differential (87G) -GPU2000R-589W
- Synchronizing (25/25A) -GPU2000R-589W
- Undervoltage Alarm (27) -GPU2000R-589W
- Reverse Power (32) -GPU2000R-589W
- Loss of Excitation (40) -GPU2000R-589W
- Unbalance (46) -GPU2000R-589W
- Overvoltage (59) -GPU2000R-589W
- Stator Ground (59GN or 64G) -GPU2000R-589W
- 100% Stator Ground (27TN) -GPU2000R-589W
- Frequency (81) -GPU2000R-589W
- Inadvertent Energizing (50/27) -GPU2000R-589W

The main generator was last inspected in 2005. The following tests were performed:

- Insulation resistance (megger)
- Power factor
- El Cid (stator iron)
- 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 this age of generator. A recommendation was made to add a permanent partial discharge monitoring system, or at the least perform on-line partial discharge testing.

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5.0 HIGH ENERGY PIPING SYSTEMS

5.1 UNIT 6 HIGH ENERGY PIPING SYSTEMS

5.1.1 Main Steam Piping

The main steam piping consists of 12 inch schedule 100 pipe manufactured of seamless ASTM A335 P-22 material. The steam line transfers steam from the boiler superheater outlet header to the HP steam turbine. The system operates at approximately 875 psig at 910°F.

Since this operating temperature is within the creep range (greater than 800°F), this piping system is of particular concern. Creep is a high temperature, time dependant phenomenon that can progressively occur at the highest stress locations within the piping system.

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. EPE has reported there is no P11, P12, or P22 seamed piping in Unit 6.

Hardness testing, which allows approximation of the material ultimate strength, and pi examination, which is also a useful indication of the onset of creep damage, are both also useful NDE methods that should be employed routinely on the main steam line, particularly at the highest stress locations within the system.

Furthermore, B&McD recommends that the piping and 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. It is recommended that the spring hangers be load tested to determine their actually current loading and a stress analysis should be completed to verify that all loads and stresses are within the allowable limits.

EPE contracted with Aptech Engineering Services, Inc (APTECH) to perform an inspection of the main steam piping in 2006. APTECH performed a hot and cold visual examination, a detailed stress analysis and NDE of select locations. In general, APTECH found no serious defects. APTECH recommended several piping and pipe support modifications and re-examination using NDE in 12,000 operating hours (for certain weld locations) or 50,000 operating hours (for the remainder of the weld locations).

5.1.2 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 of the main steam system.

B&McD recommends that the piping and support system be visually inspected on a regular basis as indicated above for the main steam line.

B&McD observed during the plant walkdown that this system is not in compliance with ASME TDP-1-2006, "Recommended Practices for the Prevention of Water Damage to Steam Turbines Used for Electric Power Generation". These practices are not requirements, but recommendations. Therefore, EPE should decide, in conjunction with their insurance carrier, whether they should implement any or all of the recommendations. 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, EPE should consider implementation of 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.

5.1.3 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 drum. Although this piping operates 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.

To date, there is no record indicating that the feedwater lines have been thoroughly inspected for signs of flow accelerated corrosion (FAC). This type of inspection should be completed by the plant in the near future. FAC has been an industry wide problem, and special attention should be given to the first elbows and fittings downstream of the boiler feedwater pumps. During this inspection, a permanent grid should be marked on the piping at the inspection locations so that future inspections can track the rate of deterioration.

5.2 UNIT 7 HIGH ENERGY PIPING SYSTEMS

5.2.1 Main Steam Piping

The main steam piping, composed of a 10-inch O.D. ASTM A335-51T, P-22, 1.125 inch minimum wall thickness seamless steam line, transfers steam from the boiler superheater outlet header to the HP steam turbine. The system operates at approximately 1,510 psig and 1000°F.

Since this operating temperature is within the creep range (greater than 800°F), this piping system is of particular concern. Creep is a high temperature, time dependant phenomenon that can progressively occur at the highest stress locations within the piping system.

Hardness testing, which allows approximation of the material ultimate strength, and pi examination, which is also a useful indication of the onset of creep damage, are both also useful NDE methods that should be employed routinely on the main steam line, particularly at the highest stress locations within the system.

EPE contracted with Thielsch Engineering to perform an inspection of the Unit 7 main steam piping system in November 2005. This NDE testing did not reveal any significant concerns for these lines. The visual examination did find one damaged riser clamp clevis and a procedure for its replacement was given to EPE.

5.2.2 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 piping. The system operates at approximately 550 psig and 1,005°F.

Since this operating temperature is within the creep range (greater than 800° F), this piping system is of particular concern.

EPE contracted with Thielsch Engineering to perform an inspection of the Unit 7 hot reheat piping system in November 2005. This NDE testing did not reveal any significant concerns for these lines.

B&McD 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 / 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.

EPE currently has no regular NDE program to monitor this piping system. Therefore, before the expected life of this system can be evaluated with any confidence, we also recommend that NDE be performed in the high stress areas of the system. This will also establish a baseline for future monitoring.

5.2.3 Cold Reheat Piping

The cold reheat piping, consisting of two 10 inch seamless A106, Grade B schedule 40 steam lines, transfers steam from the discharge of the HP steam turbine to the desuperheater and then into the boiler reheater inlet header connections.

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 system should not require the level of examination recommended on the main steam and hot reheat system. B&McD recommends inspecting only the highest stress weld locations using replication examinations to determine the extent of any carbide graphitization from high temperature operation that may have occurred.

EPE contracted with Thielsch Engineering to perform a hanger walkdown of the Unit 7 cold reheat piping system in November 2005. No indications were found.

B&McD recommends that the piping and support system be visually inspected annually.

EPE currently has no regular NDE program to monitor this piping system. Therefore, before the expected life of this system can be evaluated with any confidence, we recommend that NDE be performed in the high stress areas of the system. This will also establish a baseline for future monitoring.

5.2.4 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.

B&McD recommends that the piping and support system be visually inspected on a regular basis as indicated above for the main steam piping.

Similar to Unit 6, B&McD observed during the plant walkdown that this system is not in compliance with ASME TDP-1-2006, "Recommended Practices for the Prevention of Water Damage to Steam Turbines Used for Electric Power Generation". B&McD recommends that EPE should consider implementation of 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.

5.2.5 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.

To date, there is no record indicating that the feedwater lines have been inspected for signs of flow accelerated corrosion (FAC). This type of inspection should be completed by the plant in the near future. FAC has been an industry wide problem, and special attention should be given to the first elbows and fittings downstream of the boiler feedwater pumps. During this inspection, a permanent grid should be marked on the piping at the inspection locations so that future inspections can track the rate of deterioration, if present.

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6.0 BALANCE OF PLANT

6.1 UNIT 6 BALANCE OF PLANT SYSTEMS

6.1.1 Condensate System

6.1.1.1 System Overview

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

6.1.1.2 Condenser

Unit 6 is provided with a two pass tube and shell condenser with divided water boxes. It consists of 25,000 square foot of 90-10 copper nickel alloy tubes. The condenser has never been retubed and experiences very few tube failures. There are no plans to retube the Unit 6 main condenser.

6.1.1.3 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 backed up by one 100% liquid ring Nash vacuum pump. The pumps are in good condition.

6.1.1.4 Low Pressure Feedwater Heaters

There are two low pressure (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 low pressure 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 low pressure heaters. Since the feedwater heaters are the original equipment and are approaching 48 years of age, it would be prudent to monitor the tubing condition. The feedwater heaters should be inspected by eddy current testing at each unit annual planned outage, as necessitated by past feedwater heater failures.

6.1.2 Feedwater System

6.1.2.1 System Overview

The feedwater system is a closed-loop system that 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 drum.

6.1.2.2 High Pressure Feedwater Heaters

There are two high pressure (HP) closed feedwater heaters installed downstream of the feedwater pumps. These heaters were manufactured by Yuba Heat Transfer Corporation. 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 feedwater heaters should be inspected by eddy current testing at each unit planned outage, as necessitated by past feedwater heater failures. The 1st point feedwater heater (highest pressure) was replaced by Senior Engineering in 1993. It is expected to operate to the end of unit life. The 2nd point feedwater heater is the original 1956 vintage Griscom-Russel unit which is in average condition.

6.1.2.3 Deaerator Heater & Storage Tank

The open, tray type deaerator consists of a single vertical 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.

The plant has performed an magnetic particle (MT) inspection of the deaerator tank head welds during the Fall 2004 outage. No relevant indications were found.

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

6.1.3 Condensate and Boiler Feed Pumps

The two electric driven vertical condensate pumps manufactured by Byron Jackson are each rated at 920 gpm and supply 100-percent of the full load condensate system demand. The condensate pumps are considered to be in good condition. There are no indications that the condensate pumps, with regular maintenance, can not continue to operate throughout the study period.

The two main 100-percent capacity boiler feed pumps are motor-driven barrel type Ingersoll Rand pumps rated at 1120 gpm. The pumps and motors are reportedly in good condition. EPE experienced a broken shaft on boiler feed pump #6A in 2004. Both pumps were overhauled in 2004. Spare motors exist for both pumps.

6.1.4 Circulating Water System

The circulating water system is used to reject heat from the condenser to the atmosphere. The system utilizes two 50% 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 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 are refurbished at the major unit overhaul outages.

The circulating water piping is carbon steel. The lines under the powerhouse are encased in concrete. EPE reported that the circulating water piping has been inspected and it was reported to be in average condition. Some of the 48 inch offsets have been replaced due to erosion. The section of piping from the CW pump to the condenser was unable to be inspected.

The cooling tower is 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 a Marley, 4-cell, cross-flow induced draft tower handling 33,610 gpm. It is designed for a range of 20°F with a 12°F approach at a 67.5°F wet bulb. The original cooling tower casings, gearboxes, and fans were replaced in outages in the late 1990's. The cooling tower is operated at 4.5 cycles of concentration. It is inspected annually, and the plant has expressed concern regarding the structural integrity. B&McD recommends a structural assessment be made to the cooling tower.

6.2 UNIT 7 BALANCE OF PLANT SYSTEMS

6.2.1 Condensate System

6.2.1.1 System Overview

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

6.2.1.2 Condenser

Unit 7 is provided with a two pass tube and shell condenser with divided water boxes. The condenser was retubed in the 1970's. EPE has experienced cracks in the condenser shell and are working on that problem. We do not expect this to affect the operation of the unit for the extent of the study period. No condenser tube leaks have been experienced. The condenser tubing should be eddy current tested to assure it is suitable for the remaining continued unit operation.

6.2.1.3 Condenser Vacuum System

Similar to Unit 6, the Unit 7 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 backed up by one 100% liquid ring Nash vacuum pump. The pumps are in good condition.

6.2.1.4 Low Pressure Feedwater Heaters

There are two low pressure (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 low pressure 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 low pressure heaters. The feedwater heaters should be inspected by eddy current testing at each unit annual planned outage, as necessitated by past feedwater heater failures.

6.2.2 Feedwater System

6.2.2.1 System Overview

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

6.2.2.2 High Pressure Feedwater Heaters

There are two high pressure (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. The feedwater heaters should be inspected by eddy current testing at each unit planned outage, as necessitated by past feedwater heater failures.

6.2.2.3 Deaerator Heater & Storage Tank

The open, tray type deaerator consists of a single vertical 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.

The plant has performed a magnetic particle (MT) inspection of the deaerator tank welds during the spring 2004 outage. No relevant indications were found.

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

6.2.3 Condensate and Boiler Feed Pumps

The two electric driven vertical condensate pumps manufactured by Flowserve are each rated at 650 gpm and supply 100-percent of the full load condensate system demand. The Unit #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 in good condition. The Unit #7A boiler feedwater pump and motor were removed and sent out for refurbishment in the fall 2005 outage. Spare motors exist for both pumps.

6.2.4 Circulating Water System

The circulating water system is used to reject heat from the condenser to the atmosphere. The system utilizes two 50% capacity Westinghouse 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 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. EPE reported that the circulating water piping has been inspected and it was reported to be in average condition. EPE has reported that the 36 inch and 42 inch 45 degree fittings of the circulating water system piping were replaced in the late 1990's. The section of piping from the pumps to the condenser was unable to be inspected.

The Unit 7 cooling tower was replaced in 1997 with a Hamon 8-cell, counter-flow induced draft tower handling 33,610 gpm. The cooling tower consists of two 4-cell blocks with back to back arrangement. It is designed for a range of 20°F with a 12°F approach at a 67.5°F wet bulb. The old Marley cooling tower was demolished and a new tower was built over the same foundation. Structural members of the original Marley cooling tower were eroded and the tower structure was weakening and risking collapse. 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. It is inspected annually, and the plant has expressed concern regarding the structural integrity. B&McD recommends a structural assessment be made to the cooling tower.

6.3 WATER TREATMENT, CHEMICAL FEED, & SAMPLE SYSTEMS

These systems serve both Units 6 and 7. 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 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.

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 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% 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 1-2 million gallons between regenerations. Cleaning of the RO membranes is conducted annually which is a manual process utilizing temporary hoses.

Rio Grande Units 6 and 7 use 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 average condition.

Circulating water treatment consists of injection of sodium bi-sulphite and ammonia which is occasionally supplemented with bromine powder. Plans are to replace and combine the ammonia chlorinators for Units 6 and 7.

The plant contracts with Nalco to advise them 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 average condition and, with continued attention and proper maintenance, are expected to operate satisfactorily to the end of 2019.

6.4 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.

6.5 PLANT STRUCTURES

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

* * * * *

7.0 ELECTRICAL SYSTEMS

7.1 UNIT 6 ELECTRICAL SYSTEMS

7.1.1 Transformers

7.1.1.1 Startup Transformer

The startup source consists of two transformers in series located in the substation. One transformer, T3, is a 25MVA unit that converts 66kV to 13.8kV. The second transformer, T8, is a 3 MVA unit that converts 14.4kV to 2.4kV. A cable bus connects the second startup transformer to the switchgear terminals. The cable is rated at 3.3 kV and 382 Amps.

The startup transformer protection consists of ABB TPU microprocessor relays.

The following readings were recorded on both transformers, while unit was running, during the inspection:

- Oil Level = Acceptable
- No active leaks were observed.

The startup transformers are rarely heavily loaded and should have a long life. Due to the age of the transformer, monitoring should include dissolved gas analysis on a quarterly basis at a minimum.

7.1.1.2 Main Transformer (Generator Step-up Transformer)

The main generator step-up (GSU) transformer is a three-phase unit located outdoors near the turbine building. The main unit transformer is rated at 95 MVA with a rise of 55 °C with an impedance of 11.1% at 95 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.

GSU protection consists of the following microprocessor relays:

- Transformer differential (87) -TPU2000R
- Transformer overcurrent (51) -TPU2000R
- Transformer neutral overcurrent (51N) -TPU2000R

There are many factors such as exposure to through-faults, lightning strikes, and synchronizing mismatch that reduce the theoretical insulation life. However, it is not unusual to find transformers with 50+ years of service. Therefore, with the present testing and maintenance regiment, the transformer should have 10 years or more remaining life before a rewind is required. No modifications to the GSU are recommended. However, due to the transformer's age, it is recommended that, as a minimum, dissolved gas analysis be performed on a quarterly basis.

7.1.1.3 Auxiliary Transformer

The unit auxiliary transformer is a 1960 vintage three phase unit located outside near the turbine building. The unit auxiliary transformer is rated at 5600 KVA with a rise of 55/65°C. The transformer impedance is 5.5% at 5 MVA. The oil preservation system is a nitrogen blanket type. A deluge system and oil containment is provided. A cable bus connects the auxiliary transformer to the switchgear terminals. The cable bus is rated at 3 kV and 1340 Amps. The bus is naturally cooled.

The auxiliary transformer protection consists of the following microprocessor relays:

- Transformer differential (87) -TPU2000R
- Transformer overcurrent (51) -TPU2000R and CO

7.1.2 Cable Bus

Cable bus connects the main transformer to the generator terminals. The cable bus is rated at 15 kV and 5000 Amps. The bus is naturally cooled and is considered in average condition.

7.1.3 Medium Voltage Switchgear

The original 1955 vintage 2.4kV switchgear consists of Westinghouse 150MVA air magnetic circuit breakers rated at 5 kV installed on the ground floor of turbine building in an open area. The main breaker is a Westinghouse model 50-DH-150 rated at 1200 amps, 24 kA symmetrical interrupting, and 39kA close and latch. The feeder breakers are 50-DH-150 model air magnetic rated at 1200 amps, 24 kA symmetrical interrupting, and 39 kA close and latch. The control power is 125 VDC.

The unit has two (2) three-phase, 2.4/480V, indoor and outdoor, VPI dry-type load center transformers in a free-standing configuration. The main load center transformer is rated 750kVA, while the cooling tower load center is rated 500kVA.

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

Assuming normal maintenance is performed, the switchgear should be serviceable for the next 10 years.

7.1.4 480 V Load Centers, Switchgear, and Motor Control Centers

The 1955 vintage 480V switchgear is equipped with Westinghouse 25kA air-magnetic circuit breakers. The main breakers are Westinghouse DB-25 breakers rated at 800 amps and 25 kA interrupting with 125 VDC control power. The switchgear is located indoors.

No 480V motor control centers are installed. The starters are located in individual enclosures and located near the load.

The two load center transformers that feed the 480 V switchgear 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 7 480V switchgear which allows operation of the plant until the failed transformer is replaced.

7.1.5 2400 Volt Motors

The 2.4 kV motors consist of the following:

- Circulating Water Pump Motors – two 450 hp
- Forced draft fan – one 800 hp
- Boiler feed water pumps – two 900 hp
- Condensate pumps – two 150 hp

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

7.2 UNIT 7 ELECTRICAL SYSTEMS

7.2.1 Transformers

7.2.1.1 Startup Transformer

The startup source consists of two transformers in series located outside in the substation. One transformer, T3, is a 25MVA unit that converts 66kV to 13.8kV. The second transformer, T8, is a 3 MVA unit that converts 14.4kV to 2.4kV. A cable bus connects the second startup transformer to the switchgear terminals. The cable is rated at 3.3 kV and 382 Amps.

The startup transformer protection consists of ABB TPU microprocessor relays.

The following readings on both transformers were recorded, while the unit was running, during the inspection:

- Oil Level = Acceptable
- No active leaks were observed.

The startup transformers are rarely heavily loaded and should have a long life. However, due to the transformer's age, it is recommended that, as a minimum, dissolved gas analysis be performed on a quarterly basis

7.2.1.2 Main Transformer (Generator Step-up Transformer)

The main transformer is a 2002 vintage three-phase unit located outdoors near the turbine building. The main unit transformer is rated at 67.2 MVA with a rise of 65 °C with an impedance of 7.5% at 36 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.

GSU protection consists of the following microprocessor relays:

- Transformer differential (87) -TPU2000R
- Transformer overcurrent (51) -TPU2000R
- Transformer neutral overcurrent (51N) -TPU2000R

The transformer was in good condition. The transformer was new in 2002 and should have 30 to 40 years of remaining life.

7.2.1.3 Auxiliary Transformer

A deluge system is installed on and oil containment is provided. A cable bus connects the auxiliary transformer to the switchgear terminals. The cable bus is rated at 3 kV and 1340 Amps. The bus is naturally cooled.

The auxiliary transformer protection consists of the following microprocessor relays:

- Transformer differential (87) -TPU2000R
- Transformer overcurrent (51) -TPU2000R and CO
- Transformer neutral overcurrent (51N) -NA

7.2.2 Cable Bus

The plant has a very competent PDM group that performs comprehensive testing on 2.4kV motors and cables. The motors or cables should be reconditioned or replaced as determined by the PDM testing. The cable bus is considered in average condition.

7.2.3 Medium Voltage Switchgear

The original 1956 vintage 2.4kV switchgear consists of Westinghouse 150MVA air magnetic circuit breakers rated at 5 kV installed on the ground floor of turbine building in an open area. The main breaker is a Westinghouse model 50-DH-150 rated at 1200 amps, 24 kA symmetrical interrupting, and 39kA close and latch. The feeder breakers are 50-DH-150 model air magnetic rated at 1200 amps, 24 kA symmetrical interrupting, and 39 kA close and latch. The control power is 125 VDC.

The unit has two (2) three-phase, 2.4/480V, indoor and outdoor, VPI dry-type, load center transformers in a free-standing configuration. The main load center transformer is rated 750kVA, while the cooling tower load center is rated 500kVA.

Based on wide industry experience, the Westinghouse 50-DH-150 breakers have good reliability if kept free from moisture and normal preventative maintenance is performed. The breakers were inspected, refurbished, and tested (hipot, megger, contact resistance, etc.) by a contractor in December of 2003. Spare breakers are available. The 2.4kV system is an ungrounded delta system and the indicating voltmeters showed a balanced voltage to ground which indicates that there are no ground faults present.

Assuming normal maintenance is performed, the switchgear should be serviceable for the next 10 years.

7.2.4 480 V Load Centers, Switchgear, and Motor Control Centers

The 1955 vintage 480V switchgear is equipped with Westinghouse 25kA air-magnetic circuit breakers. The main breakers are Westinghouse DB-25 breakers rated at 800 amps and 25 kA interrupting with 125 VDC control power. The switchgear is located indoors.

No 480V motor control centers are installed. The starters are located in individual enclosures and located near the load.

The two load center transformers that feed the 480 V switchgear 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

480V switchgear which allows operation of the plant until the failed load center transformer is replaced.

7.2.5 2400 Volt Motors

The 2.4 kV motors consist of the following:

- Circulating Water Pump Motors – two 300 hp
- Forced draft fan – one 700 hp
- Boiler feed water pumps – two 1000 hp
- Condensate pumps – two 100 hp

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

7.3 STATION EMERGENCY POWER SYSTEMS

One station battery is provided to supply critical plant systems. The battery is located in a dedicated room ventilated by plant area ventilation. The battery is an Exide model FTA-21P flooded-cell lead-acid type rated at 1520 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. The new battery should have a life of 10 to 15 years.

The protective devices in the DC panels are operated infrequently and, along with the DC panel itself, typically has 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.

The emergency diesel generator (EDG) is a 480V Cummins unit rated for 175kW. The diesel generator starting power is supplied by a dedicated battery rated 48 VDC. The EDG is located on ground floor of the Unit 4 turbine building.

7.4 ELECTRICAL PROTECTION

The Unit 6 and 7 generator and transformer protection was upgraded in 2004 to microprocessor based relaying. The 2.4kV switchgear is protected with electromechanical relays that are nearing the end of their useful life. In the next 10 years replacements relays may become difficult to find. Microprocessor based replacements are readily available.

7.5 2.4 KV CABLE

Unit 6 and 7 plant medium voltage cables are primarily Kerite unshielded type. The plant has a very competent PdM group that performs comprehensive testing on 2.4kV cables. The cables should be replaced as determined by the PdM testing.

7.6 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 were grounded by connection to the plant structure at routine intervals.

The plant is located in an average isokeraunic area with an average of 40 thunderstorm days/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 a rectifier type system and is installed to protect the underground gas lines.

7.7 SUBSTATION & TRANSMISSION SYSTEMS

The plant substation is owned by El Paso Electric and maintained by El Paso Electric. The Units supply the grid at 66 kV through the substation. Four 66 kV transmission lines connect the Rio Grande substation to the transmission system. 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, recently replaced, sealed lead acid battery located in the switchyard. 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 has experienced one sustained outage in the past due to a maintenance-induced loss of breaker pressure. The units typically provide minimal MVARs out to the system.

The 66 kV portion of the plant substation has a number of dead-tank, oil and SF6 circuit breakers. Although the breakers are obsolete, spare parts are available from the original supplier or third parties. The substation protection and control is powered from a new sealed lead acid battery located in the switchyard. There are no upgrades planned for the substation.

The most recent blackout condition was in 2005 due to a substation maintenance error while filling an SF6 breaker.

7.8 CONTROL SYSTEMS

The Unit 6 and 7 plant controls are Allen Bradley PLCs. No burner management system is provided on Unit 6. A Forney electronic burner management system is provided for Unit 7. PLC's used to control the water treatment systems. The plant annunciator is a Panalarm system. No sequence of events recorder function is provided. Bentley Nevada vibration monitoring systems are installed on the Unit 6 and 7 turbine generator systems. Plant revenue metering is electromechanical type located in the control room and fed from instrument transformers located on the low side of the main transformers.

7.9 MISCELLANEOUS ELECTRICAL SYSTEMS

General plant lighting typically consists of the following fixtures:

- General plant lighting-incandescent
- Turbine bay lighting-incandescent
- Maintenance shop lighting-flourescent
- Office lighting-incandescent
- Emergency lighting-station battery

No areas were identified with lighting problems.

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8.0 EXTERNAL AND ENVIRONMENTAL FACTORS

8.1 INTRODUCTION

External factors, such as availability of fuel or water, or environmental factors have been the cause of other generating units to be taken out of service in the past. Transmission congestion is another potential problem that can lead to costly transmission upgrades in some cases.

8.2 FUEL SUPPLY

EPE employs a full time fuel resource planning department for management of reliable fuel sources for the Rio Grande station. Rio Grande Units 6 and 7 burn an average of approximately 3,300 mmcf of natural gas annually. The Rio Grande station has been served by both intrastate and interstate pipelines since the 1970's. The plant is fed by two fuel supply sources: natural gas supplies delivered over the El Paso Natural Gas (EPNG) interstate pipeline and an on-site emergency fuel oil supply. EPE purchases only firm natural gas supplies for the Rio Grande plant. One five year, long term fuel contract is held with ONEOK intrastate pipeline and the remaining gas supply is met by short term, firm fuel contracts which are transported through the EPNG under long term, firm transportation agreements. Fuel reliability is maintained through fuel supply diversity through the redundant fuel supply sources to the plant. Each fuel supply tap has two meters and flow regulators which further improves the fuel reliability to the plant. The natural gas supplies to the Rio Grande station are properly managed and provide a reliable and continuous fuel supply to the plant.

8.3 WATER SUPPLY

Water to the plant for the various users, including demineralized water, service water, and cycle water is currently supplied from deep well pumps that are owned by El Paso Water Utilities (EPWU). The water source consisting of off site wells is owned by EPE. The ground water source to the wells is allocated by the State of New Mexico which is dedicated for power generation. There are concerns related to degradation of water well capacity. Water quality from the wells is declining but is being closely monitored by EPE. A smaller water supply line from the City of El Paso is available to EPE for demineralizer makeup and emergency makeup to the cooling tower. EPE indicated that their water rights were recently reduced, but they retain sufficient capacity (maximum expected demand plus 25 percent margin) to service the plant. EPE has reported there does not appear to be any water supply concerns over the next ten years that would prevent the continued operation of Rio Grande Units 6 and 7.

8.4 AIR EMISSIONS & ENVIRONMENTAL ISSUES

EPE has renewed and received approval of its Federal Operating Air Permit from the New Mexico Environmental Department (NMED) on September 22, 2005 and is currently active. The permit must be renewed every five years. EPE has submitted the renewal application and does not anticipate any problem with the renewal.

Two environmental regulations are considered in this report; the Clean Air Interstate Rule (CAIR) and the Regional Haze Rule (RHR). Regarding CAIR, Rio Grande Units 6 and 7 are not applicable CAIR units due to their geographic location in far southeastern New Mexico, which is outside the boundaries identified in the CAIR. However, NMED has designated Dona Ana County as a PM-10 non-attainment area and has recommended it as an 8-hour ozone non-attainment area. NO_x is a pre-curser to both as it can lead to both $PM_{2.5}$ and O_3 formation. As such, there is a potential for future regulations on NOx emissions. For O_3, the NAAQS was revised in March 2008. Final designations are due from the EPA in March 2010. New Mexico will then have until 2013 to develop State Implementation Plans (SIPs) to bring non-attainment areas back into attainment. Attainment must be achieved by 2013 – 2030, depending on how severe the problem is in the area. However, the EPA is now reconsidering the O_3 standard set in 2008, which will delay this whole process.

8.5 WASTEWATER DISCHARGE

Wastewater from the boiler blowdown, laboratory drains, sampling streams, and floor drains is routed through an oil/water separator to the lower canal. Cooling tower blowdown is routed to the upper canal. Wastewater from the demineralizer and reverse osmosis equipment is neutralized and pumped to the lower canal. Sanitary waste is discharged to the El Paso city sewer.

The Rio Grande station is subject to the National Pollution Discharge Elimination System (NPDES) since it discharges waste water into navigable waters of the Rio Grande River. The current NDPES permit became effective on September 30, 2008. The permit must be renewed every five years. EPE does not anticipate any problem with future renewals. EPE reported that the Rio Grande station does not have water discharge permitting issues that will prevent its continued operation for the foreseeable future provided there are no changes in the discharge regulations.

8.6 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 their closest residential U. S. neighbor is less than a mile away. This distance provides a buffer zone and minimizes the potential for complaints from disgruntled neighbors. There have been no complaints from the plant neighbors regarding odor, visibility, or noise from the plant.

8.7 WORK FORCE

EPE indicated that the plant staff is evenly split between highly experienced employees (25 years or more) and relatively new employees (5 years or less) with few employees in between these extremes. They are concerned that the majority of the highly experienced employees will retire in three to five years and taking much of the organization's memory with them. EPE should consider implementing a training plan for the less experienced staff members.

* * * * *

9.0 NEW GENERATION

EPE has also retained B&McD to assess the option of building new generation to replace Rio Grande units 6 and 7. For this assessment, EPE requested B&McD evaluate a greenfield combined cycle gas turbine (CCGT) arrangement that includes two (2) General Electric 7EA frame gas turbines, two (2) heat recovery steam generators (HRSGs) and one (1) steam turbine. This evaluation includes "screening-level" estimated capital & operations and maintenance (O&M) costs and estimated performance.

It should be noted that the information presented is screening level in nature and intended to allow for general evaluation of whether additional studies are merited. Additional studies will be required to fully define the selected option to support budgeting and develop a defined scope and execution plan.

This assessment provides a "screening-level" comparison of technical features, costs and performance. The costs presented are based upon preliminary proposals received from suppliers. As such, information contained herein may not reflect actual firm bid proposals that will be received during execution of the project. This study provides comparative information, but a vendor selection cannot be made until firm proposals have been received.

9.1 ASSUMPTIONS

This section provides overall assumptions used in developing the capital cost estimates, performance estimates, and O&M estimates for this study.

9.1.1 General Assumptions and Clarifications

- Plant site is a relatively level greenfield site, clear of trees and wetlands. There are no existing structures or underground utilities.
- Site elevation is assumed to be 4000 feet above sea level.
- Sufficient area to receive, assemble and temporarily store construction materials is available.
- Piling is included under heavily loaded foundations.
- Construction costs are based on a multiple contract contracting philosophy.
- Capital cost estimates do not include escalation.
- Sufficient housing is available to support construction labor.
- Performance estimates are based on new and clean equipment. Degradation is not included.
- Wet cooling is used for the base estimate, but an alternate for dry cooling is included.

- Gas turbine technologies include an evaporative cooler that is on for ambient conditions of 59°F and above.
- Fuel gas pipeline pressure at the site is sufficient. Gas compressors have not been included.
- Duct firing is included in capital costs and performance estimates.
- Emission estimates are shown to provide the basis for O&M costs and to provide a basis for the required air pollution control equipment included in the capital cost estimates. These emissions represent Burns & McDonnell's best estimate of required BACT emission limits at this time. However, actual BACT requirements will not be fully realized until the permitting process is complete.

9.1.2 Project Indirect Costs

The following project indirects are included in capital cost estimates:

- Construction power.
- Performance testing and CEMS/stack emissions testing (where applicable).
- Initial fills and consumables, preoperational testing, startup, startup management, and calibration.
- Construction/startup technical service.
- Site surveys and studies.
- Engineering and construction management.
- Construction testing.
- Operator training.

9.1.2.1 Owner Indirect Costs

The following Owner indirects are included in capital cost estimates:

- Project development.
- Owner's operations personnel prior to commercial operating date (COD).
- Owner's legal costs.
- Owner construction management.
- Owner start-up engineering.
- Owner construction power and water.

- Permitting and licensing fees.
- Site security.
- Fuel, water, chemicals and power used during startup and testing.
- Permanent plant equipment & furnishings.
- Builder's risk insurance.
- Onsite switchyard.
- Owner's contingency (5%).

9.1.2.2 Capital Cost Exclusions

The following costs are excluded from the capital cost estimates:

- Allowance for Funds Used During Construction (AFUDC).
- Financing Fees.
- Natural gas supply pipeline.
- Raw water supply.
- Land.
- Performance and payment bond.
- Financing fees.
- Sales tax.
- Transmission Upgrades.
- Water Rights.
- Off-site Infrastructure.
- Owner's Corporate Staffing.
- Escalation to a COD.
- Spare parts.

9.1.2.3 Operations and Maintenance Assumptions and Exclusions

The following are assumptions and exclusions used for determining the operations and maintenance costs:

- All O&M costs are based on a greenfield facility.
- All O&M cost estimates are in 2010 dollars.

- O&M estimates do not include emissions credit costs, property taxes, or insurance.
- O&M estimates do not include start-up costs.
- Fixed O&M cost estimates include labor, office and administration, training, contract labor, safety, building and ground maintenance, communication, and laboratory expenses.
- Variable O&M costs include makeup water, water treatment, water disposal, ammonia, SCR replacements, and other consumables not including fuel. Variable O&M costs also include maintenance on equipment.
- Gas turbine spare parts (combustion spares, hot gas path spares, and major spares) are not included in the O&M cost.
- O&M estimates are based on a 50 percent capacity factor.
- Gas turbine major maintenance is based on third party services; not a long term services agreement (LTSA) with the OEM.

9.1.3 Evaluation

The results of this new generation evaluation can be seen in the table below. An optional cost section is also included for dry cooling. Based on the previously mentioned assumptions, the 2x2x1 7EA combined cycle with wet cooling has an estimated construction capital cost of $1,000/kW. The owner's cost for this new generation is estimated to be $140/kW. The fixed O&M costs are estimated to be $20.29/kW-yr and variable O&M (excluding major maintenance) is estimated to be $1.73/MWh. Third party gas turbine major maintenance for this plant is estimated to be $185/GT-hr. The 2x2x1 7EA combined cycle arrangement with wet cooling is predicted to provide a net output of 302 MWs and have a heat rate of 8690 Btu/kWh (HHV) at the assumed site conditions (59°F, 60% RH, 4000 ft elevation) with full duct firing.

EL PASO ELECTRIC COMPANY
COMBINED CYCLE GAS TURBINE SCREENING INFORMATION
BMcD Project 53549

PROJECT TYPE	**2x2x1 Fired 7EA CCGT**
BASE PLANT DESCRIPTION	
Number of Gas Turbines	2
Number of HRSGs	2
Number of Steam Turbines	1
Steam Conditions (Main Steam / Reheat)	1050 F/1050 F
Main Steam Pressure	1905 psia
Steam Cycle Type	Subcritical
Capacity Factor (%)	Intermediate (50%)
Fuel Design	Natural Gas
Heat Rejection	Wet Cooling
NOx Control	DLN/SCR
SO2 Control	N/A
Particulate Control	Good Combustion Practice
Base Load Unfired Performance @ 59F, 60% RH	
Unfired Net Plant Output, kW	221,300
Unfired Net Plant Heat Rate, Btu/kWh (HHV)	8,070
Unfired Heat Input, MMBtu/h (HHV)	1,786
Base Load Fired Performance @ 59F, 60% RH	
Fired Net Plant Output, kW	302,000
Fired Net Plant Heat Rate, Btu/kWh (HHV)	8,690
Fired Heat Input, MMBtu/h (HHV)	2,624
Procurement Costs, $/kW	$470
Construction Costs, $/kW	$350
Project Indirects, $/kW	$180
Owner's Costs, $/kW	$140
Project Total, $/kW	**$1,140**
Fixed O&M Cost, $/kW-Yr	$20.29
GTG Major Maintenance, $/GTG-hr	$185
GTG Major Maintenance, $/GTG-start	$5,700
Variable O&M Cost (Excluding GTG Major Maintenance), $/MWh	$1.73
ESTIMATED BASE LOAD OPERATING CONDITIONS, lb/MMBtu	
NO_X	0.011
SO_2	< 0.0051
CO	0.056
CO_2	118
PM/PM_{10}	0.02

PERFORMANCE AND COSTS FOR DRY COOLING	
Performance @ 59F, 60% RH	
Unfired Net Plant Output, kW	214,900
Unfired Net Plant Heat Rate, Btu/kWh (HHV)	8,310
Unfired Heat Input, MMBtu/h (HHV)	1,786
Base Load Fired Performance @ 59F, 60% RH	
Fired Net Plant Output, kW	293,200
Fired Net Plant Heat Rate, Btu/kWh (HHV)	8,868
Fired Heat Input, MMBtu/h (HHV)	2,600
Project Total, $/kW	**$1,246**
Fixed O&M Costs, $/kW-yr	$20.74
Variable O&M Costs (Excluding GTG Major Maintenance), $/MWh	$1.67

CCGT SCREENING INFORMATION NOTES

The following assumptions, in conjuction with those stated in the report, govern this analysis:

General
- All estimates in this table are "screening-level" and are not to be guaranteed.
- Fuel is pipeline quality natural gas with less than 3 grains Sulfur/100 scfm.
- Option includes an SCR to achieve NOx emissions down to 3 ppm.
- Option does not include a CO catalyst.
- All emissions limits are subject to the BACT process.

Capital Cost Estimates
- A multiple contracting method is assumed for this project, using open shop labor.
- Capital costs provided do not include escalation.
- Owner's costs do not include financing fees, IDC, transmission upgrades and interconnects.
- Plant capital cost ($/kW) is based on fired plant performance at 59F ambient condition.
- The plant site is a greenfield site that is clear of trees, structures and wetlands and is reasonably level.
- Sufficient laydown area is available.
- Piling is included under heavily loaded foundations.
- Typical buildings are included.
- Off-site pipeline costs are excluded.

Tie-Ins
- Raw water supply tie in is at the site boundary. No additional costs for wells or water pipeline have been included.
- Natural gas is available at the site boundary at adequate pressure, flow, and quality.
- Base plant costs include switchyard. Transmission lines or transmission upgrades are not included.

Performance Estimates
- Performance estimates provided are based on a site elevation of 4000 ft.
- Performance assume evaporative cooling is installed and operating at 59°F/60%RH.
- Output and heat rate estimates assume new and clean equipment.

O&M Estimates
- O&M Costs are in current year (2009) dollars.
- GTG Major Maintenance is based on third party services; not an LTSA with the OEM.
- O&M Costs do not include emissions allowances.
- O&M is estimated at 59F ambient condition.
- Estimated staff requirements and salaries are included in the fixed O&M analysis.

* * * * *

10.0 RECOMMENDATIONS AND CONCLUSIONS

10.1 GENERAL RECOMMENDATIONS

The following is a summary of the recommended actions suggested to maintain the reliability of Rio Grande Units 6 and 7 and reduce the potential for extended unit forced outages. The following recommendations are presented herein:

- External & Environmental Factors:
  - Continue to monitor changing air emissions regulations (CAIR and RHR).

10.2 UNIT 6 RECOMMENDATIONS

The following is a summary of the recommended actions suggested to maintain the reliability of Rio Grande Unit 6 and prevent the potential for extended forced unit outages.

- Boiler:
  - Conduct non-destructive examination of selective areas of water wall tubing, steam drum and connections to the steam drum, and superheater inlet and outlet header and its branch connections.
  - Inspect the superheater attemperator(s) and downstream piping.
  - Add a flame safety startup and shutdown system.
- Steam Turbine-Generator:
  - Continue steam turbine-generator inspections on an 8-year schedule.
  - Perform boroscopic examination of the turbine rotor.
  - Continue steam turbine valve inspections on a 4-year schedule.
- High Energy Piping Systems:
  - Visually inspect the main steam and feedwater piping hangers on a regular basis.
  - Perform piping non-destructive examinations as detailed in Section 5.0 of this report.
  - 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.
  - Inspect the feedwater piping downstream of the boiler feed pumps for signs of flow accelerated corrosion.
- Balance of Plant:
  - Conduct eddy current testing of low pressure and high pressure feedwater heater tubing.

- Conduct deaerator and storage tank non-destructive testing on a periodic basis.
- Continue inspection of the carbon steel portions of the circulating water piping.
- Schedule an inspection of the stack.
- Perform a structural assessment on the cooling tower.

- Electrical:
  - Perform quarterly dissolved gas analysis on the transformers.
  - Conduct a study of high energy electrical equipment arc-flash potential in compliance with OSHA standards.

Table 10-1 indicates a schedule for the implementation of the above recommendations.

Table 10-1: Implementation Schedule for B&McD Recommendations on Rio Grande Unit 6

	2011	2012	2013	2014	2015	2016	2017	2018
Boiler								
Conduct non-destructive examination of selective areas	X				X			
Inspect superheater attemperator(s) and downstream piping	X				X			
Test safety valves	X	X	X	X	X	X	X	
Chemically clean boiler	X							
Turbine-Generator								
Perform turbine inspection				X				
Perform boroscopic examinations of turbine rotor				X				
Perform turbine valve inspection	X							
High Energy Piping								
Inspect main steam and feedwater piping hangers	X				X			
Conduct non-destructive examination of selected areas of main steam and feedwater piping	X				X			
Inspect boiler feed pump discharge piping for FAC	X				X			
Balance of Plant								
Conduct eddy current testing of feedwater heater tubing	X	X	X	X	X	X	X	
Conduct non-destructive examination of deaerator and storage tank	X				X			
Conduct visual inspection of circ water piping	X		X			X		
Conduct inspection of stack	X							
Comply with ASME TDP-1-2006	X							
Perform structural assessment of cooling tower	X							
Electrical and Controls								
Monitor auxiliary transformer for combustible gas	X	X	X	X	X	X	X	X
Inspect, adjust and test medium-voltage switchgear			X					
Conduct high energy arc-flash potential	X							

	2011	2012	2013	2014	2015	2016	2017	2018
study								
				Planned Retirement				

10.3 UNIT 7 RECOMMENDATIONS

The following is a summary of the recommended actions suggested to maintain the reliability of Rio Grande Unit 7 and reduce the potential for extended unit forced outages.

- Boiler:
  - Conduct non-destructive examination of selective areas of water wall tubing, steam drum and connections to the steam drum, superheater inlet and outlet header and branch connections to the superheater outlet header, reheater inlet and outlet header and branch connections to the reheater outlet header, and economizer inlet header.
  - Inspect the superheater and reheater attemperator(s) and downstream piping.
- Steam Turbine-Generator:
  - Continue steam turbine-generator inspections on an 8-year schedule.
  - Continue steam turbine valve inspections on a 4-year schedule.
  - Perform boroscope examination of the turbine rotor.
- High Energy Piping Systems:
  - Visually inspect the main steam, hot reheat, cold reheat, and feedwater piping hangers on a regular basis.
  - Perform piping non-destructive examinations as detailed in Section 5.0 of this report.
  - Inspect the feedwater piping downstream of the boiler feed pumps for signs of FAC.
  - 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.
- Balance of Plant:
  - Conduct eddy current testing of low pressure and high pressure feedwater heater tubing.
  - Conduct deaerator and storage tank non-destructive testing on a periodic basis.
  - Conduct flow accelerated corrosion testing of the feedwater pump discharge piping.
  - Schedule an inspection of the stack.
  - Perform a structural assessment on the cooling tower.
- Electrical:

- Perform quarterly dissolved gas analysis on the transformers.
- Conduct a study of high energy electrical equipment arc-flash potential in compliance with OSHA standards.

Table 10-2 indicates a schedule for the implementation of the above recommendations.

Table 10-2: Implementation Schedule for B&McD Recommendations on Rio Grande Unit 7

	2011	2012	2013	2014	2015	2016	2017	2018	2019
Boiler									
Conduct non-destructive examination of selective areas	X				X				
Inspect superheater attemperator(s) and downstream piping	X				X				
Test safety valves	X	X	X	X	X	X	X	X	
Chemically clean boiler	X				X				
Turbine-Generator									
Perform turbine inspection			X						
Perform boroscopic examinations of turbine rotor			X						
Perform turbine valve inspection	X						X		
High Energy Piping									
Inspect main steam, hot reheat, cold reheat and feedwater piping hangers	X				X				
Conduct non-destructive examination of selected areas of main steam, hot reheat, cold reheat, and feedwater piping	X				X				
Inspect boiler feed pump discharge piping for FAC	X				X				
Balance of Plant									
Conduct eddy current testing of feedwater heater tubing	X	X	X	X	X	X	X	X	
Conduct non-destructive examination of deaerator and storage tank	X				X				
Conduct visual inspection of circ water piping	X		X			X			
Conduct inspection of stack	X								
Comply with ASME TDP-1-2006	X								
Perform a structural assessment of cooling tower	X								
Electrical and Controls									
Monitor auxiliary transformer for combustible gas	X	X	X	X	X	X	X	X	X
Inspect, adjust and test medium-voltage switchgear			X						
Conduct high energy arc-flash potential study	X								
				Planned Retirement					

10.4 ANALYSIS

To properly compare the cost of extended operation of Rio Grande units 6 and 7 compared to new generation, B&McD estimated the cost for the recommendations list above and developed an implementation schedule. El Paso furnished other proposed life extensions cost and operating cost. Details can be found in Appendix A and Appendix B. The following assumptions were made:

- Generation, Fixed O&M Costs, Variable O&M Costs, and Fuel Costs for existing units for the years 2010 through the expected retirement date were pulled from ProdMOD data provided by El Paso. Where no ProdMOD data was available, the average of the previous three years was used.
- NOx emissions are based on 2008 data provided by El Paso.
- The capacity factor for the equivalent new unit is 50 percent.
- Cost for the equivalent new unit was based on a 50,000 kW portion of the GE 7EA 2 x 1 combined cycle unit described in Section 10.

The results of the analysis are shown below in Tables 10-3, 10-4, and 10-5

Table 10-3: Net Present Value of Total Estimated Costs for Rio Grande 6

	2-year Extension	4-year Extension	6-year Extension
Rio Grande Unit 6	$66,227,500	$101,776,800	$136,219,200
Equivalent New Unit	$91,763,100	$110,452,100	$163,034,800

Table 10-4: Total Cost Comparison on a $/Nominal Capacity Basis for Rio Grande 6

	2-year Extension	4-year Extension	6-year Extension
Rio Grande Unit 6	$1325/kW	$2036/kW	$2724/kW
Equivalent New Unit	$1835/kW	$2209/kW	$3261/kW

Table 10-5: Total Cost Comparison on a $/MWhr Basis for Rio Grande 6

	2-year Extension	4-year Extension	6-year Extension
Rio Grande Unit 6	$111/MWhr	$114/MWhr	$115/MWhr
Equivalent New Unit	$105/MWhr	$84/MWhr	$93/MWhr

Table 10-6: Net Present Value of Total Estimated Costs for Rio Grande 7

	2-year Extension	4-year Extension	6-year Extension
Rio Grande Unit 7	$64,010,500	$89,643,600	$115,166,100
Equivalent New Unit	$119,024,900	$148,089,800	$185,393,900

Table 10-7: Total Cost Comparison on a $/Nominal Capacity Basis for Rio Grande 7

	2-year Extension	4-year Extension	6-year Extension
Rio Grande Unit 7	$1280/kW	$1793/kW	$2303/kW
Equivalent New Unit	$2380/kW	$2962/kW	$3708/kW

Table 10-8: Total Cost Comparison on a $/MWhr Basis for Rio Grande 7

	2-year Extension	4-year Extension	6-year Extension
Rio Grande Unit 7	$105/MWhr	$106/MWhr	$105/MWhr
Equivalent New Unit	$109/MWhr	$97/MWhr	$94/MWhr

10.5 CONCLUSIONS

Based on the information acquired and presented in this report, the following conclusions have been made:

1. The overall condition of the Rio Grande Units 6 and 7 appears to be good considering their age. In general, operational and maintenance problems which could affect operation are actively being addressed. However, the metallurgical condition of critical components is unknown at this time due to the lack of an ongoing NDE program. Consequently, in providing this relatively clean bill of health, our confidence level is moderated by this unknown condition (see further discussion in item 7 below).
2. Unit operations and maintenance are generally well planned and carried out in a manner consistent with or exceeding utility industry standards.
3. The predictive maintenance program used throughout the EPE system has been highly successful in minimizing forced outages in the rotating equipment area. This program has received industry recognition and, where feasible, should be extended to other critical equipment, such as control valves, and certain heat exchangers.
4. Certain conditions on major unit components may develop in the future, and the cost of repairing or replacing such components would make the continued operation of a generating unit imprudent. The end of the expected useful life of any of the Rio Grande units may occur upon the failure, or prediction of eminent failure, of the steam drum or the concurrent failure of one or more simultaneous major plant components.

   Based on the information provided by EPE, there were no reported indications or predictions of potential failure of these major unit components anticipated in the foreseeable future. However, currently there is no NDE program in place to monitor the condition of these major components.

5. Economic pressure to cycle the unit at night and on weekends is currently present and will continue to grow as the fuel price disparity between gas and coal / nuclear

becomes greater. With the addition of Newman Unit 5, EPE has been forced to cycle the less efficient units. As new failure trends are established, a new end-of-life determination will need to be made.

6. The Rio Grande Units have typically achieved better than average plant availability, and equivalent forced outage rates. This results from a combination of the predictive maintenance program, coupled with proper attention to water chemistry and the aforementioned dispatch philosophy intended to minimize cycling. As EPE decides to cycle the units, existing metallurgical weak points that may be lurking unseen within the steam cycle components will become more evident. In addition, oxygen infiltration into the steam cycle during shutdowns will introduce not only general corrosion, but oxygen pitting. In those areas that are highly stressed, these pits serve as initiation points for cracks that, through repeated cycles, grow to failure points. Therefore, to minimize the impact of cycling, we recommend inerting the steam cycle components during shutdowns.

7. EPE is currently operating its system with little reserve margin during peak seasons. Given this, EPE should closely scrutinize the vulnerabilities of these units, and by extension the rest of its generating fleet. Several vulnerabilities that we have observed at the Rio Grande units are:

   a. The unknown metallurgical condition of the unit's critical components. Given the age of the units, we believe that implementation of an NDE program would be prudent in order to provide early warning of major component deterioration. We recommend that this be made part of EPE's existing PdM program in order to translate the findings into maintenance planning.

   b. The units have virtually no protection against Turbine Water Induction. While these incidents do not occur frequently, when they do, they can be quite damaging to the turbine and result in lengthy outages. We recommend that EPE review the ASME TWIP guidelines (ASME TDP-1-2006) and develop a cost effective modification plan for these units.

   c. Monitor transformers for combustible gas due to age to provide early warning of component failure.

   d. If future operating modes of the unit include on-off cycling of the unit, or if future operations consider staffing the plant only with a skeleton crew, supplemented with temporary staff during peak seasons only, modifications are recommended to increase the safe starting operations of the unit. These include the installation of FSSS (Flame Safety Shutdown and Furnace Purge System) on Unit No. 6, and TWIP (Turbine Water Induction Prevention) equipment on both units.

As a result of our review of the design, condition, operations and maintenance procedures, long-range planning, availability of consumables, and programs for dealing with environmental considerations, it is B&McD's opinion that Rio Grande Units 6 and 7 are capable of extending their scheduled retirement by 6 years to December 2018 and December 2019, respectively. This assumes that the recommended inspections and assessments do not discover any significant findings. However, comparing the capital and incremental O&M cost estimated to extend the life of the three units against the estimated cost for new generation, it is B&McD's opinion that it is not economically justified to extend the life of the existing units the full six years. As indicated in Table 10-5, the equivalent new unit is less expensive, on a cost per MW-hr basis, during the any extension period for Rio Grande Unit 6. As indicated in Table 10-8, the equivalent new unit becomes less expensive sometime between the two and four year extension periods for Rio Grande Unit 7.

* * * * *

APPENDIX A - Rio Grande Unit 6
Economic Analysis

El Paso Electric Company, Inc.
Newman 1, 2, & 4 and Rio Grande 5 & 6 Condition Assessment
B&McD Project No. 53549
Condition Assessment Recommendation Implementation Timetable for Rio Grande Unit 6

		2011	2012	2013	2014
B&McD Recommended Expenditures					
Conduct non-destructive examination of selective areas		$180,000			
Inspect superheater and reheater attemperators and downstream piping		$40,000			
Test safety valves		$10,000	$10,000	$10,000	
Chemically clean boiler		$1,250,000			
Perform turbine inspection					
Perform boroscope examinations of turbine rotor					
Perform turbine valve inspection		$500,000			
Inspect main steam, hot reheat, cold reheat and feedwater piping hangers		$50,000			
Conduct non-destructive examination of selected areas of main steam, hot reheat, cold reheat, and feedwater piping		$100,000			
Inspect boiler feed pump discharge piping for FAC		$20,000			
Conduct eddy current testing of feedwater heater tubing		$20,000	$20,000	$20,000	
Conduct non-destructive examination of deaerator and storage tank		$20,000			
Conduct visual inspection of circ water piping		$5,000		$5,000	
Conduct inspection of stack		$25,000			
Comply with ASME TDP-1-2006		$250,000			
Perform structural assessment on cooling tower		$25,000			
Monitor auxiliary transformer for combustible gas					
Inspect, adjust, and test medium voltage switchgear				$10,000	
Conduct high energy arc-flash potential study		$35,000			
Add boiler FSSS system		$50,000			
Total B&McD Recommendations		$2,580,000	$30,000	$45,000	$0
Owner Planned Expenditures					
Boiler SH/RH/Econ Replacements				$400,000	
Boiler Waterwall Replacements				$400,000	
Boiler SH/RH/Econ Header Replacements (partial)				$500,000	
Turbine Shell Repairs				$500,000	
MS/HRH/CRH/BF Piping Replacement (partial)				$500,000	
Feedwater Heater Replacements					
Condenser Retubing					
Cooling Tower Repairs					
Condensate Pump/Motor Repairs/Replacement					
Boiler Feed Pump/Motor Repairs/Replacement					
Circulator Pump/Motor Repairs/Replacement					
Voltage Regulator Repairs/Replacement					
Switchgear Repairs/Replacement					
Instrumentation Replacement					
Total Owner Planned Expenditures		$0	$0	$2,300,000	$0
Operating Costs					
Net Generation, MWhr		154,058	143,100	148,579	148,579
NOx Emissions, tons		165.00	153.26	159.13	159.13
Variable O&M Cost-Non-fuel-related, $/MWhr		$1.71	$1.49	$1.60	$1.60
Fixed Operating Cost		$2,439,006	$2,356,022	$2,397,514	$2,397,514
Variable O&M Cost, Non-fuel-related		$263,439	$213,219	$237,726	$237,726
NOx Emissions Allowance Purchases		$98,998	$91,956	$95,477	$95,477
Fuel Cost		$12,337,000	$11,349,000	$11,843,000	$11,843,000
Total Operating Cost		$15,138,443	$14,010,197	$14,573,717	$14,573,717
Net Present Value	$66,227,500	$19,135,918	$16,376,486	$21,312,711	$19,827,381
Nominal Rating in kW	50,000				
Estimate Cost per kW	$1,324.55				
Estimated Cost per MWhr	$111.43			Projected Retirement Date	
New Generation					
Net Generation, MWhr		219,000	219,000	219,000	219,000
Capital cost		$50,000,000			
Fixed Operating Cost		$1,014,500	$1,014,500	$1,014,500	$1,014,500
Variable Operating Cost		$378,870	$378,870	$378,870	$378,870
Fuel Cost		$11,475,888	$11,475,888	$11,475,888	$11,475,888
Net Present Value	$91,763,100	$62,869,258	$12,869,258	$12,869,258	$12,869,258
Estimated Cost per kW	$1,835.26				
Estimated Cost per MWhr	$104.75				

NOx emissions =	0.001071	tons/MWhr
Escalation Rate =	6%	
NOx Allowances =	600	$/ton
Discount Rate =	6%	

Capacity Factor =	50%		
Fuel Cost =	6.03E-06	$/Btu	
Capital Cost =	1000	$/kW	1000
Fixed O&M =	20.29	$/kW	
Variable O&M =	1.73	$/MWhr	
Heat Rate =	8690	Btu/kWhr	

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B&McD Project No. 53549
Condition Assessment Recommendation Implementation Timetable for Rio Grande Unit 6

		2011	2012	2013	2014	2015	2016
B&McD Recommended Expenditures							
Conduct non-destructive examination of selective areas		$180,000					
Inspect superheater and reheater attemperators and downstream piping		$40,000					
Test safety valves		$10,000	$10,000	$10,000	$10,000	$10,000	
Chemically clean boiler		$1,250,000					
Perform turbine inspection					$2,000,000		
Perform boroscope examinations of turbine rotor					$50,000		
Perform turbine valve inspection		$500,000					
Inspect main steam, hot reheat, cold reheat and feedwater piping hangers		$50,000					
Conduct non-destructive examination of selected areas of main steam, hot reheat, cold reheat, and feedwater piping		$100,000				$100,000	
Inspect boiler feed pump discharge piping for FAC		$20,000				$20,000	
Conduct eddy current testing of feedwater heater tubing		$20,000	$20,000	$20,000	$20,000	$20,000	
Conduct non-destructive examination of deaerator and storage tank		$20,000				$20,000	
Conduct visual inspection of circ water piping		$5,000		$5,000			
Conduct inspection of stack		$25,000					
Comply with ASME TDP-1-2006		$250,000					
Perform structural assessment on cooling tower		$25,000					
Monitor auxiliary transformer for combustible gas							
Inspect, adjust, and test medium voltage switchgear				$10,000			
Conduct high energy arc-flash potential study		$35,000					
Add boiler FSSS system		$50,000					
Total B&McD Recommendations		$2,580,000	$30,000	$45,000	$2,080,000	$170,000	$0
Owner Planned Expenditures							
Boiler SH/RH/Econ Replacements				$400,000			
Boiler Waterwall Replacements				$400,000			
Boiler SH/RH/Econ Header Replacements (partial)				$500,000			
Turbine Shell Repairs				$500,000			
MS/HRH/CRH/BF Piping Replacement (partial)				$500,000			
Feedwater Heater Replacements						$300,000	
Condenser Retubing					$250,000		
Cooling Tower Repairs						$250,000	
Condensate Pump/Motor Repairs/Replacement							
Boiler Feed Pump/Motor Repairs/Replacement							
Circulator Pump/Motor Repairs/Replacement						$200,000	
Voltage Regulator Repairs/Replacement							
Switchgear Repairs/Replacement							
Instrumentation Replacement							
Total Owner Planned Expenditures		$0	$0	$2,300,000	$250,000	$750,000	$0
Operating Costs							
Net Generation, MWhr		154,058	143,100	148,579	148,579	146,753	147,970
NOx Emissions, tons		165.00	153.26	159.13	159.13	157.17	158.48
Variable O&M Cost, $/MWhr		$1.71	$1.49	$1.60	$1.60	$1.56	$1.59
Fixed Operating Cost		$2,439,006	$2,356,022	$2,397,514	$2,397,514	$2,383,683	$2,392,904
Variable O&M Cost, Non-fuel-related		$263,439	$213,219	$237,726	$237,726	$229,423	$234,944
NOx Emissions Allowance Purchases		$98,998	$91,956	$95,477	$95,477	$94,303	$95,086
Fuel Cost		$12,337,000	$11,349,000	$11,843,000	$11,843,000	$11,678,333	$11,788,111
Total Operating Cost		$15,138,443	$14,010,197	$14,573,717	$14,573,717	$14,385,743	$14,511,044
Net Present Value	$101,776,800	$19,135,918	$16,376,486	$21,312,711	$22,997,321	$22,489,158	$23,027,204
Nominal Rating in kW	50,000						
Estimated Cost per kW	$2,035.54						
Estimated Cost per MWhr	$114.48			Projected Retirement Date			
New Generation							
Net Generation, MWhr		219,000	219,000	219,000	219,000	219,000	219,000
Capital cost		$50,000,000					
Fixed Operating Cost		$1,014,500	$1,014,500	$1,014,500	$1,014,500	$1,014,500	$1,014,500
Variable Operating Cost		$378,870	$378,870	$378,870	$378,870	$378,870	$378,870
Fuel Cost		$11,475,888	$11,475,888	$11,475,888	$11,475,888	$11,475,888	$11,475,888
Net Present Value	$110,452,100	$62,869,258	$12,869,258	$12,869,258	$12,869,258	$12,869,258	$12,869,258
Estimated Cost per kW	$2,209.04						
Estimated Cost per MWhr	$84.06						

NOx emissions =	0.001071	tons/MWhr
Escalation Rate =	0%	
NOx Allowances =	600	$/ton
Discount Rate =	6%	
Capacity Factor =	50%	
Fuel Cost =	6.03E-06	$/Btu
1000 Capital Cost =	1000	$/kW
Fixed O&M =	20.29	$/kW
Variable O&M =	1.73	$/MW-hr
Heat Rate =	8690	Btu/kWhr

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Newman 1, 2, & 4 and Rio Grande 5 & 6 Condition Assessment
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		2011	2012	2013	2014	2015	2016	2017	2018
B&McD Recommended Expenditures									
Conduct non-destructive examination of selective areas		$180,000				$180,000			
Inspect superheater and reheater attemperators and downstream piping		$40,000				$40,000			
Test safety valves		$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	
Chemically clean boiler		$1,250,000							
Perform turbine inspection					$2,000,000				
Perform boroscope examinations of turbine rotor					$50,000				
Perform turbine valve inspection		$500,000							
Inspect main steam, hot reheat, cold reheat and feedwater piping hangers		$50,000							
Conduct non-destructive examination of selected areas of main steam, hot reheat, cold reheat, and feedwater piping		$100,000				$100,000			
Inspect boiler feed pump discharge piping for FAC		$20,000				$20,000			
Conduct eddy current testing of feedwater heater tubing		$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	
Conduct non-destructive examination of deaerator and storage tank		$20,000				$20,000			
Conduct visual inspection of circ water piping		$5,000		$5,000			$5,000		
Conduct inspection of stack		$25,000							
Comply with ASME TDP-1-2006		$250,000							
Perform structural assessment on cooling tower		$25,000							
Monitor auxiliary transformer for combustible gas									
Inspect, adjust, and test medium voltage switchgear				$10,000					
Conduct high energy arc-flash potential study		$35,000							
Add boiler FSSS system		$50,000							
Total B&McD Recommendations		$2,580,000	$30,000	$45,000	$2,080,000	$390,000	$35,000	$30,000	$0
Owner Planned Expenditures									
Boiler SH/RH/Econ Replacements				$400,000					
Boiler Waterwall Replacements				$400,000					
Boiler SH/RH/Econ Header Replacements (partial)				$500,000					
Turbine Shell Repairs				$500,000					
MS/HRH/CRH/BF Piping Replacement (partial)				$500,000					
Feedwater Heater Replacements						$300,000			
Condenser Retubing					$250,000				
Cooling Tower Repairs						$250,000			
Condensate Pump/Motor Repairs/Replacement							$100,000		
Boiler Feed Pump/Motor Repairs/Replacement							$300,000		
Circulator Pump/Motor Repairs/Replacement						$200,000			
Voltage Regulator Repairs/Replacement							$200,000		
Switchgear Repairs/Replacement							$50,000		
Instrumentation Replacement							$80,000		
Total Owner Planned Expenditures		$0	$0	$2,300,000	$250,000	$750,000	$730,000	$0	$0
Operating Costs									
Net Generation, MWhr		154,058	143,100	148,679	148,679	146,753	147,970	147,767	147,497
NOx Emissions, tons		165.00	153.26	159.13	159.13	157.17	158.48	158.26	157.97
Variable O&M Cost, $/MWhr		$1.71	$1.49	$1.60	$1.60	$1.56	$1.59	$1.58	$1.58
Fixed Operating Cost		$2,439,006	$2,356,022	$2,397,514	$2,397,514	$2,383,683	$2,392,904	$2,391,367	$2,389,318
Variable O&M Cost, Non-fuel-related		$263,439	$213,219	$237,726	$237,726	$229,423	$234,944	$234,020	$232,790
NOx Emissions Allowance Purchases		$98,998	$91,956	$95,477	$95,477	$94,303	$95,086	$94,955	$94,781
Fuel Cost		$12,337,000	$11,349,000	$11,843,000	$11,843,000	$11,678,333	$11,788,111	$11,769,815	$11,745,420
Estimated Operating Expenditures		$15,138,443	$14,010,197	$14,573,717	$14,573,717	$14,385,743	$14,511,044	$14,490,157	$14,462,309
Net Present Value	$136,219,200	$19,135,918	$16,376,486	$21,312,711	$22,997,321	$22,812,410	$24,241,163	$24,884,997	$26,768,725
Nominal Rating in kW	50,000								
Estimated Cost per kW	$2,724.38								
Estimated Cost per MWhr	$115.02			Projected Retirement Date					
New Generation									
Net Generation, MWhr		219,000	219,000	219,000	219,000	219,000	219,000	219,000	219,000
Capital cost		$50,000,000							
Fixed Operating Cost		$1,014,500	$1,014,500	$1,014,500	$1,014,500	$1,014,500	$1,014,500	$1,014,500	$1,014,500
Variable Operating Cost		$378,870	$378,870	$378,870	$378,870	$378,870	$378,870	$378,870	$378,870
Fuel Cost		$11,475,888	$11,475,888	$11,475,888	$11,475,888	$11,475,888	$11,475,888	$11,475,888	$11,475,888
Net Present Value	$163,034,800	$67,898,799	$15,010,702	$16,211,559	$17,508,483	$18,909,162	$20,421,895	$22,055,646	$23,820,098
Estimated Cost per kW	$3,260.70								
Estimated Cost per MWhr	$93.06								

NOx emissions =	0.001071 tons/MWhr
Escalation Rate =	8%
NOx Allowances =	600 $/ton
Discount Rate =	6%

Capacity Factor =	50%
Fuel Cost =	6.03E-06 $/Btu
1000 Capital Cost =	1000 $/kW
Fixed O&M =	20.29 $/kW
Variable O&M =	1.73 $/MWhr
Heat Rate =	8690 Btu/kWhr

APPENDIX B - Rio Grande Unit 7
Economic Analysis

El Paso Electric Company, Inc.
Newman 1, 2, & 4 and Rio Grande 5 & 6 Condition Assessment
B&McD Project No. 53549
Condition Assessment Recommendation Implementation Timetable for Rio Grande Unit 7

		2011	2012	2013	2014	2015
B&McD Recommended Expenditures						
Conduct non-destructive examination of selective areas		$160,000				
Inspect superheater and reheater attemperators and downstream piping		$40,000				
Test safety valves		$10,000	$10,000	$10,000	$10,000	
Chemically clean boiler		$1,250,000				
Perform turbine inspection				$2,750,000		
Perform boroscope examinations of turbine rotor				$50,000		
Perform turbine valve inspection		$500,000				
Inspect main steam, hot reheat, cold reheat and feedwater piping hangers		$50,000				
Conduct non-destructive examination of selected areas of main steam, hot reheat, cold reheat, and feedwater piping		$100,000				
Inspect boiler feed pump discharge piping for FAC		$20,000				
Conduct eddy current testing of feedwater heater tubing		$20,000	$20,000	$20,000	$20,000	
Conduct non-destructive examination of deaerator and storage tank		$20,000				
Conduct visual inspection of circ water piping		$5,000		$5,000		
Conduct inspection of stack		$25,000				
Comply with ASME TDP-1-2006		$250,000				
Perform structural assessment on cooling tower		$25,000				
Monitor auxiliary transformer for combustible gas						
Inspect, adjust, and test medium voltage switchgear				$10,000		
Conduct high energy arc-flash potential study		$35,000				
Total B&McD Recommendations		$2,530,000	$30,000	$2,845,000	$30,000	$0
Owner Planned Expenditures						
Boiler SH/RH/Econ Replacements (partial)						
Boiler Waterwall Replacements (partial)					$400,000	
Boiler SH/RH/Econ Header Replacements (partial)					$700,000	
Turbine Shell Repairs					$500,000	
MS/HRH/CRH/BF Piping Replacement (partial)					$700,000	
Feedwater Heater Replacements					$500,000	
Condenser Retubing						
Cooling Tower Repairs						
Condensate Pump/Motor Repairs/Replacement						
Boiler Feed Pump/Motor Repairs/Replacement					$300,000	
Circulator Pump/Motor Repairs/Replacement					$200,000	
Voltage Regulator Repairs/Replacement						
Switchgear Repairs/Replacement					$50,000	
Instrumentation Replacement						
Total Owner Planned Expenditures		$0	$0	$0	$3,150,000	$0
Operating Costs						
Net Generation, MWhr		141,776	105,815	120,789	122,793	116,466
NOx Emissions, tons		90.74	67.72	77.30	78.59	74.54
Variable Operating Cost, $/MWhr		$1.71	$1.50	$1.53	$1.58	$1.54
Fixed Operating Cost		$2,465,193	$2,301,822	$2,345,879	$2,370,965	$2,339,655
Variable Operating Cost, Non-fuel-related		$242,437	$158,723	$184,807	$194,013	$178,969
NOx Emissions Allowances		$54,442	$40,633	$46,383	$47,153	$44,723
Fuel Cost		$9,471,000	$6,382,000	$7,854,000	$7,902,333	$7,379,444
Estimated Operating Expenditures		$12,233,072	$8,883,177	$10,431,069	$10,514,464	$9,942,692
Net Present Value	$64,010,500	$15,944,118	$10,390,330	$16,724,024	$18,631,167	$14,609,076
Nominal Rating in kW	50,000				Projected Retirement Date	
Estimated Cost per kW	$1,280.21					
Estimated Cost per MWhr	$105.34					
New Generation						
Net Generation, MWhr		219,000	219,000	219,000	219,000	219,000
Capital cost		$50,000,000				
Fixed Operating Cost		$1,014,500	$1,014,500	$1,014,500	$1,014,500	$1,014,500
Variable Operating Cost		$378,870	$378,870	$378,870	$378,870	$378,870
Fuel Cost		$11,475,888	$11,475,888	$11,475,888	$11,475,888	$11,475,888
Net Present Value	$119,024,900	$67,898,799	$15,010,702	$16,211,559	$17,508,483	$18,909,162
Estimated Cost per kW	$2,380.50					
Estimated Cost per MWhr	$108.70					

NOx emissions =	0.00064 tons/MWhr
Escalation Rate =	8%
NOx Allowances =	600 $/ton
Discount Rate =	6%
Capacity Factor =	23%

Capacity Factor =	50%
Fuel Cost =	6.03E-06 $/Btu
Capital Cost =	1000 $/kW
Fixed O&M =	20.29 $/kW
Variable O&M =	1.73 $/MW-hr
Heat Rate =	8690 Btu/kWhr

El Paso Electric Company, Inc.
Newman 1, 2, & 4 and Rio Grande 5 & 6 Condition Assessment
B&McD Project No. 53549
Condition Assessment Recommendation Implementation Timetable for Rio Grande Unit 7

		2011	2012	2013	2014	2015	2016	2017
B&McD Recommended Expenditures								
Conduct non-destructive examination of selective areas		$180,000				$180,000		
Inspect superheater and reheater attemperators and downstream piping		$40,000				$40,000		
Test safety valves		$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	
Chemically clean boiler		$1,250,000				$1,250,000		
Perform turbine inspection				$2,750,000				
Perform boroscope examinations of turbine rotor				$50,000				
Perform turbine valve inspection		$500,000						
Inspect main steam, hot reheat, cold reheat and feedwater piping hangers		$50,000						
Conduct non-destructive examination of selected areas of main steam, hot reheat, cold reheat, and feedwater piping		$100,000				$100,000		
Inspect boiler feed pump discharge piping for FAC		$20,000				$20,000		
Conduct eddy current testing of feedwater heater tubing		$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	
Conduct non-destructive examination of deaerator and storage tank		$20,000				$20,000		
Conduct visual inspection of circ water piping		$5,000		$5,000			$5,000	
Conduct inspection of stack		$25,000						
Comply with ASME TDP-1-2006		$250,000						
Perform structural assessment on cooling tower		$25,000						
Monitor auxiliary transformer for combustible gas								
Inspect, adjust, and test medium voltage switchgear				$10,000				
Conduct high energy arc-flash potential study		$35,000						
Total B&McD Recommendations		$2,530,000	$30,000	$2,845,000	$30,000	$1,640,000	$35,000	$0
Owner Planned Expenditures								
Boiler SH/RH/Econ Replacements (partial)								
Boiler Waterwall Replacements (partial)					$400,000			
Boiler SH/RH/Econ Header Replacements (partial)					$700,000			
Turbine Shell Repairs					$500,000			
MS/HRH/CRH/BF Piping Replacement (partial)					$700,000			
Feedwater Heater Replacements					$300,000			
Condenser Retubing							$250,000	
Cooling Tower Repairs								
Condensate Pump/Motor Repairs/Replacement								
Boiler Feed Pump/Motor Repairs/Replacement					$300,000			
Circulator Pump/Motor Repairs/Replacement					$200,000			
Voltage Regulator Repairs/Replacement							$200,000	
Switchgear Repairs/Replacement					$50,000			
Instrumentation Replacement						$80,000		
Total Owner Planned Expenditures		$0	$0	$0	$3,150,000	$80,000	$450,000	$0
Operating Costs								
Net Generation, MWhr		141,776	105,815	120,780	122,793	116,466	120,016	119,758
NOx Emissions, tons		90.74	67.72	77.30	78.59	74.54	76.81	76.65
Variable Operating Cost, $/MWhr		$1.71	$1.50	$1.53	$1.58	$1.54	$1.55	$1.56
Fixed Operating Cost		$2,465,193	$2,301,822	$2,345,879	$2,370,965	$2,330,555	$2,352,133	$2,354,218
Variable Operating Cost, Non-fuel-related		$242,437	$158,723	$184,807	$194,013	$178,969	$185,892	$186,246
NOx Emissions Allowances		$54,442	$40,633	$46,383	$47,153	$44,723	$46,086	$45,987
Fuel Cost		$9,471,000	$6,382,000	$7,854,000	$7,902,333	$7,379,444	$7,711,926	$7,664,568
Estimated Operating Expenditures		$12,233,072	$8,883,177	$10,431,069	$10,514,464	$9,942,692	$10,296,037	$10,251,019
Net Present Value	$89,643,600	$15,944,118	$10,396,330	$16,724,024	$18,631,167	$17,136,320	$17,106,150	$17,568,445
Nominal Rating in kW	50,000				Projected Retirement Date			
Estimated Cost per kW	$1,792.87							
Estimated Cost per MWhr	$105.78							
New Generation								
Net Generation, MWhr		219,000	219,000	219,000	219,000	219,000	219,000	219,000
Capital cost		$50,000,000						
Fixed Operating Cost		$1,014,500	$1,014,500	$1,014,500	$1,014,500	$1,014,500	$1,014,500	$1,014,500
Variable Operating Cost		$378,870	$378,870	$378,870	$378,870	$378,870	$378,870	$378,870
Fuel Cost		$11,475,888	$11,475,888	$11,475,888	$11,475,888	$11,475,888	$11,475,888	$11,475,888
Net Present Value	$148,089,800	$67,898,799	$15,010,702	$16,211,559	$17,508,483	$18,909,162	$20,421,895	$22,055,646
Estimated Cost per kW	$2,961.80							
Estimated Cost per MWhr	$96.60							

NOx emissions =	0.00064 tons/MWhr
Escalation Rate =	8%
NOx Allowances =	600 $/ton
Discount Rate =	6%

Capacity Factor =	50%
Fuel Cost =	6.03E-06 $/Btu
Capital Cost =	1000 $/kW
Fixed O&M =	20.29 $/kW
Variable O&M =	1.73 $/MW-hr
Heat Rate =	8690 Btu/kWhr

El Paso Electric Company, Inc.
Newman 1, 2, & 4 and Rio Grande 5 & 6 Condition Assessment
B&McD Project No. 53549
Condition Assessment Recommendation Implementation Timetable for Rio Grande Unit 7

		2011	2012	2013	2014	2015	2016	2017	2018	2019
B&McD Recommended Expenditures										
Conduct non-destructive examination of selective areas		$180,000				$180,000				
Inspect superheater and reheater attemperators and downstream piping		$40,000				$40,000				
Test safety valves		$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	
Chemically clean boiler		$1,250,000				$1,250,000				
Perform turbine inspection				$2,750,000						
Perform boroscope examinations of turbine rotor				$50,000						
Perform turbine valve inspection		$500,000						$500,000		
Inspect main steam, hot reheat, cold reheat and feedwater piping hangers		$50,000								
Conduct non-destructive examination of selected areas of main steam, hot reheat, cold reheat, and feedwater piping		$100,000				$100,000				
Inspect boiler feed pump discharge piping for FAC		$20,000				$20,000				
Conduct eddy current testing of feedwater heater tubing		$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000	
Conduct non-destructive examination of deaerator and storage tank		$20,000				$20,000				
Conduct visual inspection of circ water piping		$5,000		$5,000			$5,000			
Conduct inspection of stack		$25,000								
Comply with ASME TDP-1-2006		$250,000								
Perform structural assessment on cooling tower		$25,000								
Monitor auxiliary transformer for combustible gas										
Inspect, adjust, and test medium voltage switchgear				$10,000						
Conduct high energy arc-flash potential study		$35,000								
Total B&McD Recommendations		$2,530,000	$30,000	$2,845,000	$30,000	$1,640,000	$35,000	$530,000	$30,000	$0
Owner Planned Expenditures										
Boiler SH/RH/Econ Replacements (partial)								$500,000		
Boiler Waterwall Replacements (partial)					$400,000					
Boiler SH/RH/Econ Header Replacements (partial)					$700,000					
Turbine Shell Repairs					$500,000					
MS/HRH/CRH/BF Piping Replacement (partial)					$700,000					
Feedwater Heater Replacements					$300,000					
Condenser Retubing							$250,000			
Cooling Tower Repairs								$250,000		
Condensate Pump/Motor Repairs/Replacement								$100,000		
Boiler Feed Pump/Motor Repairs/Replacement					$300,000					
Circulator Pump/Motor Repairs/Replacement					$200,000					
Voltage Regulator Repairs/Replacement							$200,000			
Switchgear Repairs/Replacement					$50,000					
Instrumentation Replacement						$80,000				
Total Owner Planned Expenditures		$0	$0	$0	$3,150,000	$80,000	$450,000	$850,000	$0	$0
Operating Costs										
Net Generation, MWhr		141,776	105,815	120,789	122,790	116,466	120,016	119,758	118,747	119,507
NOx Emissions, tons		90.74	67.72	77.30	78.59	74.54	76.81	76.65	76.00	76.48
Variable Operating Cost, $/MWhr		$1.71	$1.50	$1.53	$1.58	$1.54	$1.56	$1.56	$1.55	$1.55
Fixed Operating Cost		$2,465,193	$2,301,822	$2,345,879	$2,370,965	$2,339,555	$2,352,133	$2,354,218	$2,348,635	$2,351,662
Variable Operating Cost, Non-fuel-related		$242,437	$158,723	$184,807	$194,013	$178,969	$186,892	$186,246	$183,691	$185,275
NOx Emissions Allowances		$54,442	$40,633	$46,383	$47,153	$44,723	$46,086	$45,987	$45,599	$45,891
Fuel Cost		$9,471,000	$6,382,000	$7,854,000	$7,902,333	$7,379,444	$7,711,926	$7,664,568	$7,585,313	$7,653,936
Estimated Operating Expenditures		$12,233,072	$8,883,177	$10,431,069	$10,514,464	$9,942,692	$10,296,037	$10,251,019	$10,163,238	$10,236,763
Net Present Value	$115,166,100	$15,944,118	$10,396,330	$16,724,024	$18,631,167	$17,136,320	$17,108,150	$19,933,523	$18,666,972	$20,463,338
Nominal Rating in kW	50,000				Projected Retirement Date					
Estimated Cost per kW	$2,303.32									
Estimated Cost per MWhr	$106.08									
New Generation										
Net Generation, MWhr		219,000	219,000	219,000	219,000	219,000	219,000	219,000	219,000	219,000
Capital cost		$57,000,000								
Fixed Operating Cost		$1,014,500	$1,014,500	$1,014,500	$1,014,500	$1,014,500	$1,014,500	$1,014,500	$1,014,500	$1,014,500
Variable Operating Cost		$378,870	$378,870	$378,870	$378,870	$378,870	$378,870	$378,870	$378,870	$378,870
Fuel Cost		$11,475,888	$11,475,888	$11,475,888	$11,475,888	$11,475,888	$11,475,888	$11,475,888	$11,475,888	$11,475,888
Net Present Value	$185,393,900	$75,458,799	$15,010,702	$16,211,559	$17,508,483	$18,909,162	$20,421,895	$22,055,646	$23,820,098	$25,725,706
Estimated Cost per kW	$3,707.88									
Estimated Cost per MWhr	$94.06									

NOx emissions =	0.00064 tons/MWhr
Escalation Rate =	0%
NOx Allowances =	600 $/ton
Discount Rate =	6%

Capacity Factor =	50%
Fuel Cost =	6.03E-06 $/Btu
Capital Cost =	1000 $/kW
Fixed O&M =	20.29 $/kW
Variable O&M =	1.73 $/MW-hr
Heat Rate =	8690 Btu/kWhr

Rio Grande Units 6 and 7
Condition Assessment Report

prepared for

El Paso Electric, Inc.
El Paso, Texas

December 2012

Project No. 68127

prepared by

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

Burns & McDonnell
SINCE 1898

December 21, 2012

Mr. Ricardo Acosta
Manager, Resource & Delivery Planning
El Paso Electric Company
P.O. Box 982
El Paso, TX 79960

Re: El Paso Electric Company
Burns & McDonnell Project No. 68127
Subject: Rio Grande Station Units 6 and 7 Condition Assessment

Dear Mr. Acosta:

We are pleased to submit the final Condition Assessment Report for Rio Grande Units 6 and 7.

El Paso Electric (EPE) retained the services of Burns & McDonnell (B&McD) to perform a study to assess whether Rio Grande Unit 6 and 7 could operate reliably until their scheduled retirement dates (December 2014 and December 2020, respectively). This study includes a review of the current condition of the plant, current plant maintenance and operations practices, and a review of broad external factors influencing this retirement date. The unit remaining life was based on plant maintenance data and historical operations data provided by EPE, maintenance and operating practices of units similar to Rio Grande, and Burns & McDonnell's professional opinion regarding the expected remaining life of the facilities. B&McD has estimated capital and incremental O&M costs for any recommendations made to maintain unit reliability. In addition, B&McD has provided a screening level estimate of the capital and O&M cost for new generation. The levelized busbar costs for new generation were compared to the existing Rio Grande units.

The project approach used for this study was to review plant documentation, interview plant personnel, and conduct a walk-down of the plant to obtain information to complete the Rio Grande Units 6 and 7 plant condition assessments.

Based on the screening level economic evaluation, it appears that a new combined cycle gas turbine or simple cycle gas turbine resource will provide a similar levelized busbar cost compared to Rio Grande Units 6 and Unit 7. B&McD recommends further economic evaluation is conducted within a detailed dispatch model.

As a result of our review of the design, condition, operations and maintenance procedures, long-range planning, availability of consumables, and programs for dealing with environmental considerations, it is B&McD's opinion that Rio Grande Units 6 and 7 are capable of operating to their scheduled retirement of December 2014 and December 2020, respectively.

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Burns & McDonnell
SINCE 1898

It appears that the Rio Grande plant staff understands that achieving the desired useful life of the units is dependent upon the useful life of the common facilities. While age is beginning to show minor cosmetic needs, the Rio Grande plant common facilities appear well maintained and operated.

The positive attitude reflected between El Paso Electric's home office and plant personnel is reflective of a strong team effort. This "work together attitude" will contribute immensely toward achieving the remaining life of units and the common facilities.

We would like to express our appreciation to El Paso Electric and specifically the Rio Grande plant staff for their assistance in providing the necessary data to support this report effort. If you have any questions or comments, please do not hesitate to contact ne at 816-822-3450.

Sincerely,

Michael Friedel

Michael Friedel
Project Manager

Enclosure

cc: File

INDEX AND CERTIFICATION

Rio Grande Station Units 6 and 7 Condition Assessment Report

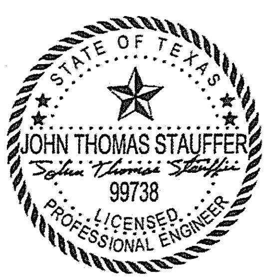
Project 68127

Report Index

Chapter Number	Chapter Title	Number of Pages
--	Executive Summary	2
1	Introduction	4
2	Boiler	8
3	Boiler Auxiliary Systems	3
4	Steam Turbine	2
5	High Energy Piping Systems	6
6	Balance of Plant	8
7	Electrical Systems	12
8	External and Environmental Factors	7
9	New Generation	7
10	Levelized Busbar Cost Analysis	5
11	Recommendations and Conclusions	4

Certification

We hereby certify, as a Professional Engineers in the state of Texas, that the information in the document was assembled under our direct personal charge. This certification is made in accordance with the provisions of the laws and rules of Texas Board of Professional Engineers under the Texas Engineering Practice Act.



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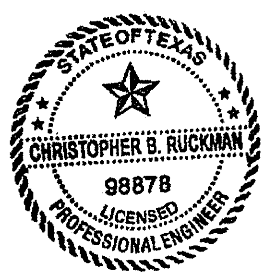

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TABLE OF CONTENTS

Page No.

EXECUTIVE SUMMARY **1**

1.0 INTRODUCTION **1-1**
1.1 General Description 1-1
1.2 Project Overview 1-1
1.3 Study Contents 1-2
1.4 Limitation of Liability 1-3

2.0 BOILER **2-1**
2.1 Unit 6 Boiler 2-1
2.1.1 Introduction 2-1
2.1.2 Waterwalls 2-1
2.1.3 Superheater 2-1
2.1.4 Drums and Headers 2-2
2.1.5 Safety Valves 2-2
2.1.6 Burner Control System 2-3
2.2 Unit 7 Boiler 2-3
2.2.1 Introduction 2-3
2.2.2 Waterwalls 2-3
2.2.3 Superheater 2-4
2.2.4 Reheater 2-5
2.2.5 Economizer 2-5
2.2.6 Drums and Headers 2-6
2.2.7 Safety Valves 2-8
2.2.8 Burner Control System 2-8

3.0 BOILER AUXILIARY SYSTEMS **3-1**
3.1 Unit 6 Boiler Auxiliary Systems 3-1
3.1.1 Fans 3-1
3.1.2 Air Heater 3-1
3.1.3 Flues & Ducts 3-1
3.1.4 Stack 3-2
3.1.5 Blowdown System 3-2
3.2 Unit 7 Boiler Auxiliary Systems 3-2
3.2.1 Fans 3-2
3.2.2 Air Heater 3-2
3.2.3 Flues & Ducts 3-3
3.2.4 Stack 3-3
3.2.5 Blowdown System 3-3

4.0 STEAM TURBINE **4-1**
4.1 Unit 6 Steam Turbine 4-1

4.1.1 Introduction....4-1
4.1.2 Turbine....4-1
4.1.3 Turbine Valves....4-1
4.2 Unit 7 Steam Turbine....4-2
4.2.1 Introduction....4-2
4.2.2 Turbine....4-2
4.2.3 Turbine Valves....4-2

5.0 HIGH ENERGY PIPING SYSTEMS....5-1
5.1 Unit 6 High Energy Piping Systems....5-1
5.1.1 Main Steam Piping....5-1
5.1.2 Extraction Piping....5-2
5.1.3 Feedwater Piping....5-2
5.2 Unit 7 High Energy Piping Systems....5-3
5.2.1 Main Steam Piping....5-3
5.2.2 Hot Reheat Piping....5-3
5.2.3 Cold Reheat Piping....5-4
5.2.4 Extraction Piping....5-5
5.2.5 Feedwater Piping....5-5

6.0 BALANCE OF PLANT....6-1
6.1 Unit 6 Balance of Plant Systems....6-1
6.1.1 Condensate System....6-1
6.1.2 Feedwater System....6-2
6.1.3 Condensate and Boiler Feed Pumps....6-2
6.1.4 Circulating Water System....6-3
6.2 Unit 7 Balance of Plant Systems....6-3
6.2.1 Condensate System....6-3
6.2.2 Feedwater System....6-4
6.2.3 Condensate and Boiler Feed Pumps....6-5
6.2.4 Circulating Water System....6-6
6.3 Water Treatment, Chemical Feed, & Sample Systems....6-6
6.4 Fire Protection Systems....6-8
6.5 Plant Structures....6-8

7.0 ELECTRICAL SYSTEMS....7-1
7.1 Unit 6 Electrical Systems....7-1
7.1.1 Generator....7-1
7.1.2 Transformers....7-2
7.1.3 Cable Bus....7-3
7.1.4 Medium Voltage Switchgear....7-3
7.1.5 480 V Load Centers, Switchgear, and Motor Control Centers....7-4
7.1.6 2400 Volt Motors....7-4
7.2 Unit 7 Electrical Systems....7-5
7.2.1 Generator....7-5
7.2.2 Transformers....7-6
7.2.3 Cable Bus....7-8
7.2.4 Medium Voltage Switchgear....7-8

7.2.5 480 V Load Centers, Switchgear, and Motor Control Centers 7-8
7.2.6 2400 Volt Motors 7-9
7.3 Station Emergency Power Systems 7-9
7.4 Electrical Protection 7-10
7.5 2.4 kV Cable 7-10
7.6 Grounding & Cathodic Protection 7-10
7.7 Substation & Transmission Systems 7-10
7.8 Control Systems 7-11
7.9 Miscellaneous Electrical Systems 7-11

8.0 EXTERNAL AND ENVIRONMENTAL FACTORS 8-1
8.1 Introduction 8-1
8.2 Fuel Supply 8-1
8.3 Water Supply 8-1
8.4 Wastewater Discharge 8-2
8.5 Environmental Issues 8-2
8.5.1 Cross State Air Pollution Rule 8-2
8.5.2 Regional Haze Rule 8-2
8.5.3 National Ambient Air Quality Standards 8-3
8.5.4 Greenhouse Gas Regulations and Legislation 8-4
8.5.5 Clean Energy Standard Act of 2012 8-4
8.5.6 Greenhouse Gas Endangerment Finding, Tailoring Rule, and NSPS 8-5
8.5.7 CWA 316(a) and (b) and Water Discharge Limitations 8-6
8.5.8 Other Permitting Issues 8-7
8.6 Odor, Visibility, & Noise 8-7
8.7 Work Force 8-7

9.0 NEW GENERATION 9-1
9.1 Assumptions 9-1
9.1.1 General Assumptions and Clarifications 9-1
9.1.2 Project Indirect Costs 9-2
9.2 Evaluation 9-4

10.0 LEVELIZED BUSBAR COST ANALYSIS 10-1
10.1 Assumptions 10-1
10.2 Economic Analysis 10-3
10.2.1 Sensitivity Analysis 10-4
10.3 Conclusions 10-5

11.0 CONCLUSIONS AND RECOMMENDATIONS 11-1
11.1 Conclusions 11-1
11.2 Recommendations 11-1
11.3 External & Environmental Factors: 11-1
11.4 Unit 6 Recommendations 11-2
11.5 Unit 7 Recommendations 11-2
11.5.1 Boiler: 11-2
11.5.2 Steam Turbine-Generator: 11-2

11.5.3 High Energy Piping Systems: 11-2
11.5.4 Balance of Plant: 11-3
11.5.5 Electrical: 11-3

APPENDIX A – Rio Grande Unit 7 Additional Maintenance Expenditures

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LIST OF TABLES

Table No. **Page No.**

Table 9-1: New Generation Screening Information 9-6
Table 10-1: Cost and Performance Parameters 10-2
Table 10-2: Financing Assumptions 10-2
Table 10-3: Natural Gas Forecast 10-3
Table 11-1: Implementation Schedule for B&McD Recommendations on Rio Grande Unit 7 11-3

LIST OF FIGURES

Figure No. **Page No.**

Figure 10-1: Levelized Busbar Cost 10-4

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EXECUTIVE SUMMARY

El Paso Electric (EPE) retained the services of Burns & McDonnell (B&McD) to perform a study to assess whether Rio Grande Unit 6 and 7 could operate reliably until their scheduled retirement dates (December 2014 and December 2020, respectively). This study includes a review of the current condition of the plant, current plant maintenance and operations practices, and a review of broad external factors influencing this retirement date. The unit remaining life was based on plant maintenance data and historical operations data provided by EPE, maintenance and operating practices of units similar to Rio Grande, and Burns & McDonnell's professional opinion regarding the expected remaining life of the facilities. B&McD has estimated capital and incremental O&M costs for any recommendations made to maintain unit reliability. In addition, B&McD has provided a screening level estimate of the capital and O&M cost for new generation.

The project approach used for this study was to review plant documentation, interview plant personnel, and conduct a walk-down of the plant to obtain information to complete the Rio Grande Units 6 and 7 plant condition assessments.

The Rio Grande units were placed into commercial service June 1957 and June 1958, respectively. Although the units are nearing the end of their anticipated life cycle, they have yet to show the characteristic upswing in Equivalent Forced Outage Rate (EFOR) that is indicative of general degradation of the major components. This is due to a number of factors including:

- Avoidance of cycling operation during the majority of their life,
- Proper attention to water chemistry, and
- An aggressive Predictive Maintenance (PdM) program

Across the industry, external factors, such as availability of fuel, water, or environmental factors have been the reasons many generating units are being taken out of service. Plant staff has expressed concerns about well water capacity and quality, which is being investigated separately by a third party. Permitting for the new Rio Grande Unit 9 will result in a restriction in operating hours for Unit 6. However, there are no other current external or environmental factors that have been detected that would limit or restrict operation of the Rio Grande Units 6 & 7 in the foreseeable future.

Based on the information acquired and presented in this report, the following conclusions have been made:

- The overall condition of the Rio Grande Units 6 & 7 appears to be good. There are no conditions which have been identified as being detrimental to achieving the planned unit life. Operational and maintenance problems which could affect operation are actively being addressed.

- Unit operations and maintenance are generally well planned and carried out in a manner consistent with utility industry standards.

- The predictive maintenance program used throughout the EPE system has been highly successful in minimizing forced outages in the rotating equipment area. This program has received industry recognition and, where feasible, should be extended to other critical equipment, such as control valves, and certain heat exchangers.

- Although the available operating time for Unit 6 will be reduced as part of the operating permit for the new Unit 9, there are no identifiable external or environmental factors that will prevent continued operation through the scheduled retirement dates.

- Based on the screening level economic evaluation, it appears that a new combined cycle gas turbine or simple cycle gas turbine resource will provide a similar levelized busbar cost compared to Rio Grande Units 6 and Unit 7. B&McD recommends further economic evaluation is conducted within a detailed dispatch model.

As a result of our review of the design, condition, operations and maintenance procedures, long-range planning, availability of consumables, and programs for dealing with environmental considerations, it is B&McD's opinion that Rio Grande Units 6 and 7 are capable of operating to their scheduled retirement of December 2014 and December 2020, respectively.

* * * * *

1.0 INTRODUCTION

1.1 GENERAL DESCRIPTION

El Paso Electric (EPE) is an investor-owned electrical utility responsible for supplying power through an interconnected system to a service territory encompassing approximately 334,000 customers in the Rio Grande Valley in west Texas and southern New Mexico. EPE has interests in Palo Verde Nuclear Plant and Four Corners Station to supply its base load. Both Rio Grande and Newman stations provide load following services. Located in Sunland Park, New Mexico (a suburb of El Paso, Texas) Rio Grande Unit 6 began commercial operation in 1957 and Unit 7 in 1958.

The Unit 6 major plant equipment includes a natural circulation steam generator style boiler designed by Babcock and Wilcox for 450,000 $^{lb}/_{hr}$ steam flow at 875 psig outlet pressure and 910°F superheater outlet temperatures. Unit 6 does not have a reheater. The boiler has a pressurized furnace, and a single regenerative Ljungstrom air preheater. The Westinghouse steam turbine is a preferred standard, two cylinder tandem compound, double flow exhaust, condensing extraction turbine. The generator is currently rated at 58.8 MVA. Cooling water is circulated through a cross-flow cooling tower with makeup water provided from off-site wells. Boiler makeup water is also supplied from the off-site well water system.

The Unit 7 major plant equipment include a natural circulation steam generator El Paso style boiler designed by Babcock and Wilcox for 350,000 $^{lb}/_{hr}$ 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 General Electric steam turbine is a tandem compound, double-flow condensing unit. The generator is currently rated at 56.8 MVA. Cooling water for Unit 7 is also 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.

1.2 PROJECT OVERVIEW

EPE retained the services of Burns & McDonnell (B&McD) to perform a study to assess whether Rio Grande Units 6 and 7 could operate reliably until their scheduled retirement in December 2014 and December 2020, respectively. This condition assessment study includes a review of the current condition of the plant, current plant maintenance and operations practices, and a review of external factors influencing these retirement dates. The remaining life was based on plant maintenance data and historical operations data provided by EPE, maintenance and operating practices of units similar to Rio Grande

Units 6 and 7 and Burns & McDonnell's professional opinion regarding the expected remaining life of the facilities. B&McD has estimated capital and incremental O&M costs for any recommendations made to maintain unit reliability. In addition, B&McD has provided a "screening level" estimate of the capital and O&M cost for new generation.

To complete this assessment, Burns & McDonnell engineers reviewed plant documentation, interviewed plant personnel, and conducted a walkdown of the plant to obtain information on the condition of Rio Grande Units 6 and 7.

1.3 STUDY CONTENTS

The following report details the current condition of the units, their predicted future operating capability, and recommendations for improvements and additional testing or inspections. This information was compiled based on existing plant records, general plant and equipment observations, comparison to similar units and equipment, and in-house expertise.

Since virtually any single component within a power plant can be replaced, the remaining life of a plant is typically driven by the economics of replacing the various components as necessary to keep the plant operating economically versus shutting it down and either purchasing power or building a replacement facility. For this reason, it is important for EPE to periodically update the condition assessment of the Rio Grande Units 6 and 7 to project the major future expenditures that will be required to maintain the facility. Specifically, the critical components that will likely determine the facility's remaining life include the following:

- Steam generator drum, headers, and downcomers.
- High energy piping systems.
- Steam turbine rotor shaft, valves, and steam chest.
- 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:

- Steam generator tubing, ductwork, air preheater and FD fan.

- Steam turbine blades, diaphragms, nozzle blocks, and casing and shells.
- Generator stator-winding bracing, DC exciter, and voltage regulator.
- Balance of plant condenser, feedwater heaters, feedwater pumps and motors, controls, and auxiliary switchgear.
- Cooling tower structure, structural steel, stack, concrete structures, and station main GSU and auxiliary transformers.

External influences that will probably be the major determinant of the future life of the unit include:

- Environmental influences; including water availability and future environmental compliance requirements such as NO_x and CO_2 emissions.
- Economics; including fuel costs, comparative plant efficiency, and system needs.
- Obsolescence such as the inability to obtain replacement parts and supplies.

1.4 LIMITATION OF LIABILITY

In the preparation of this Report, the information provided by EPE was used by B&McD to make certain assumptions with respect to conditions which may exist in the future. While B&McD believes the assumptions made are reasonable for the purposes of this Report, B&McD makes no representation that the conditions assumed will, in fact, occur. In addition, B&McD has no reason to believe that the information provided by EPE, and on which this Report is based, is inaccurate in any material respect. However, B&McD has not independently verified such information and cannot guarantee its accuracy or completeness. To the extent that actual future conditions differ from those assumed herein or from the information provided to B&McD, the actual results will vary from those forecast.

Estimates, forecasts, projections, and schedules prepared by B&McD relating to costs, quantities, demand or pricing (including, but not limited to, property costs, construction, operations or maintenance costs, and/or energy or commodity demand and pricing), are opinions based on B&McD's experience, qualifications, and judgment. B&McD 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 or projections. EPE acknowledges that actual results may vary significantly from the representations and opinions herein, and nothing herein shall be construed as a guarantee or warranty of conclusions, results, or opinions. B&McD makes no guarantee or warranty (actual or implied) that actual rates, demand, pricing, costs, performance, schedules, quantities, technology, and related items will not vary from the opinions contained in the estimates, forecasts, projections, schedules, results, or other statements or opinions prepared by B&McD.

* * * * *

2.0 BOILER

2.1 UNIT 6 BOILER

2.1.1 Introduction

Boiler No. 6 at the Rio Grande Station is a natural circulation, radiant heat, pressurized unit designed to burn natural gas and fuel oil in nine wall-mounted burners. This unit includes a horizontal, drainable superheater, one steam drum, and an elevated mud drum. The unit was originally designed for a maximum continuous rating (MCR) of 450,000 $^{lb}/_{hr}$ main steam at a superheater outlet condition of 875 psig and 910°F. The unit does not have a reheater. The superheater outlet temperature is controlled by desuperheater sprays. The boiler design also includes a Ljungstrom type tri-sector air heater for flue gas heat recovery.

The unit has been operating on natural gas for a significant portion of its life except for short periods of fuel oil operation in the 1970's. Boiler chemical cleaning frequency is on a five year cycle with the last cleaning occurring in January 2011. No further boiler chemical cleaning is scheduled due to the scheduled retirement of the unit.

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

2.1.2 Waterwalls

BPI reported that the boiler waterwall tubes appear to be in good condition. Original tube thickness, per the Plant Data Book, was 0.150-inch. Tube thicknesses were taken with the lowest reading of 0.146-inch or 97-percent of the original tube thickness.

2.1.3 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 between the sections. The Rio Grande Unit 6 boiler design allows for draining of both stages of the superheaters during outages and/or startup.

BPI found several burned out secondary superheater tubes and severe bowing in both the secondary superheater and primary superheater. Original tube thickness, per the Plant Data Book, was 0.180-inch. Tube thicknesses were taken with the lowest reading of 0.179-inch or 99-percent of the original tube thickness.

2.1.4 Drums and Headers

There is one 60 inch diameter steam drum, one 42 inch mud drum, and a lower waterwall header on the unit. BPI's inspection of the steam and mud drums showed them to be in good condition overall. Some minor issues were noted.

There are no records indicating that the drums have been inspected with all internals removed. B&McD would normally recommend an inspection of the boiler drum with all internals removed. However, due to the imminent retirement of the unit, B&McD would not consider further inspection of the drum of particular importance.

The high temperature headers include the primary and secondary superheater outlet headers. 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. BPI performed a visual inspection (using fiberoptics), metallographic replication, and hardness testing on the secondary superheater outlet header. The visual inspection found no evidence of erosion, cracking, or corrosion. They did find some moderate to heavy scale buildup in areas. Two locations adjacent to the girth weld on the secondary superheater outlet header were examined using metallographic replication. Neither location showed evidence of micro-cracking or creep damage. Based on the examinations, BPI considered the header to be in good condition.

2.1.5 Safety Valves

There is no indication that there is an ongoing plan in place to test the safety valves. At a minimum, the valves should be tested in accordance with ASME code requirements, but it is not uncommon to test more frequently if required by the facility's insurance company. Annual inspections by the safety valves' Original Equipment Manufacturer (OEM) are recommended to determine if refurbishment or replacement is required.

2.1.6 Burner Control System

The existing Unit 6 Boiler has no Flame Safety Shutdown and Startup Furnace Purge System (FSSS). This boiler was constructed before the NFPA Codes required all boilers to have FSSS systems to prevent furnace explosions. It has continued to operate as a "grandfathered" unit, depending on the operators to implement appropriate burner ignition practices, which have been successful to date.

2.2 UNIT 7 BOILER

2.2.1 Introduction

Boiler No. 7 at the Rio Grande Station is a natural circulation, radiant heat, pressurized unit designed to burn natural gas and fuel oil 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.

Boiler chemical cleaning frequency is on a five year cycle with the last cleaning occurring in March 2011. Based on the scheduled retirement date of December 2020, another boiler chemical cleaning is recommended. In addition, EPE takes tube samples periodically in high heat flux areas of the boiler to evaluate the extent of boiler tube scaling to evaluate 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.

2.2.2 Waterwalls

BPI reported that the boiler waterwall tubes appear to be in good condition. A visual inspection of the furnace found all four waterwalls straight and aligned. Tube thicknesses were taken, but there was no original tube thickness to compare them to. A regular tube wall thickness (NDE) inspection program is recommended to monitor boiler waterwall condition and prevent tube rupture related outages.

2.2.3 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 six sections or stages of the superheater are as follows, starting at the steam drum and progressing towards the superheater outlet header:

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

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.

A report, reviewed during the previous condition assessment, stated, "Testing of the superheat and reheat sections of Unit #7 boiler done in 1996 resulted in the determination that the remaining creep-rupture life of these three sections was, at that time, 200,000 hours [or about 2016]". As the current scheduled retirement date is beyond this timeframe, B&McD would recommend further inspections of these components to determine if full or partial replacement is warranted to maintain reliable operation of the unit.

Future inspection should focus on identifying signs of creep, fatigue, and corrosion, as they are the most common damage mechanisms in superheater tubes. If tube failures become a problem, or if NDE inspections reveal a significant amount of deterioration, EPE will need to evaluate whether the cost of replacement supports continued operation or warrants early retirement.

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.

2.2.4 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 Rio Grande Unit 7, the design of the reheater allows for draining the reheater during outages and/or startup.

BPI's 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.

A report, reviewed during the previous condition assessment, stated, "Testing of the superheat and reheat sections of Unit #7 boiler done in 1996 resulted in the determination that the remaining creep-rupture life of these three sections was, at that time, 200,000 hours [or about 2016]". As the current planned retirement date is beyond this timeframe, there is a need to perform further inspections of these components to determine if full or partial replacement is warranted to maintain reliable operation of the unit.

Future inspection should focus on identifying signs of creep, fatigue, and corrosion, as they are the most common damage mechanisms in reheater tubes. If tube failures become a problem, or if NDE inspections reveal a significant amount of deterioration, EPE will need to evaluate whether the cost of replacement supports continued operation or warrants early retirement.

2.2.5 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. They found the tubes relatively well aligned with only minor bowing in a few tubes. They did note several plugged tubes.

2.2.6 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, B&McD 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.

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

The visual inspection secondary superheater outlet header found no evidence of erosion, cracking, or corrosion. They did find some 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 examinations, BPI considered the header to be in good condition.

The visual inspection reheat outlet header found no evidence of erosion, cracking, or corrosion. They did find some 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. 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 examinations, BPI considered the 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:

- Acid etching of the headers to determine whether longitudinal seam welds exist in the headers.
- 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.
- All girth welds, socket welds, and longitudinal welds (if applicable) should be inspected using magnetic particle examination to detect surface discontinuities in the metal.
- Pi Measurement tests, used as a gauge to detect long term creep by identifying pipe swelling, should be performed along all the headers.
- 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 in the near future 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:

- Ultrasonic thickness inspections to monitor for signs of flow-accelerated corrosion (FAC).
- Full borescope examination of the headers.

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

2.2.7 Safety Valves

There should be an ongoing plan in place to test the safety valves. At a minimum, the valves should be tested in accordance with ASME code requirements, but it is not uncommon to test more frequently if required by the facility's insurance company. Annual inspections by the safety valves' Original Equipment Manufacturer (OEM) are recommended to determine if refurbishment or replacement is required.

2.2.8 Burner Control System

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

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3.0 BOILER AUXILIARY SYSTEMS

3.1 UNIT 6 BOILER AUXILIARY SYSTEMS

3.1.1 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 recorded. The inlet guide vanes are cleaned and inspected annually. The Bailey inlet guide vane positioners have been replaced once during the life of the plant. In addition, vibration readings are taken 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.

3.1.2 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.

The air heater baskets have not been replaced in the last 10 years.

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

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

3.1.3 Flues & Ducts

The ductwork transports combustion air to the boiler and also 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.

3.1.4 Stack

The stack has not been inspected in recent years. B&McD would normally recommend an inspection, particularly for structural integrity. However, due to the imminent retirement of the unit, B&McD does not consider this of particularly importance.

3.1.5 Blowdown System

Unit 6 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 on to the continuous blowdown flash tank.

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

3.2 UNIT 7 BOILER AUXILIARY SYSTEMS

3.2.1 Fans

Similar to Unit 6, Unit 7 is provided with 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.

3.2.2 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.

3.2.3 Flues & Ducts

The ductwork transports combustion air to the boiler and also 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

3.2.4 Stack

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

3.2.5 Blowdown System

Similar to Unit 6, the Unit 7 design includes an intermediate pressure blowdown tank and another continuous blowdown flash tank which are controlled in a similar manner to Unit 6. 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.

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4.0 STEAM TURBINE

4.1 UNIT 6 STEAM TURBINE

4.1.1 Introduction

In general, the turbine has exhibited good operation and vibration levels. The last major turbine-generator overhaul took place in the 2006 outage. Consequently, the internal condition is presumed to be in good condition because there have been no outward signs of significant damage beyond that indicated in item 4.1.2 below. Water chemistry is well maintained at the station and the unit has not been cycled excessively. Therefore, it is assumed that the turbine will only have 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.

4.1.2 Turbine

The HP and LP turbines were last overhauled by Siemens Power Generation during the spring 2006 outage. The HP and LP turbine sections were disassembled, inspected, and reassembled. Non-destructive examinations (NDE) were performed on the HP, LP, and generator rotors and HP and LP rotor blades by Siemens NDE Group. Siemens Turbine Services machined the journals of the HP rotor, and LP rotor. They also performed weld repairs on the nozzle block, #1 water gland sealing diaphragm, blended indications on the HP and LP rotor blades, and re-tapped cracked thrust bearing foundation studs. There were no major repair recommendations made by Siemens.

Turbine overhauls are scheduled on an 8 year cycle. EPE has not scheduled another turbine inspection, due to the intended unit retirement in 2014.

4.1.3 Turbine Valves

The turbine valves, consisting of the main steam stop and control valves, are maintained on a four year cycle, which has proven to be adequate. In general, they usually exhibit minor SPE when inspected. EPE has not scheduled another turbine valve inspection, due to the intended unit retirement in 2014.

4.2 UNIT 7 STEAM TURBINE

4.2.1 Introduction

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

Similar to Unit 6, 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 Unit 7 turbine is also a major focus of the EPE predictive maintenance program and undergoes the same vibration and oil analysis as is performed for the Unit 6 turbine generator as indicated above.

4.2.2 Turbine

The HP and LP turbines were last overhauled by GE Energy Service during the fall 2005 outage. 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.

GE's report noted that the turbine shell is 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, which Unit 7 is approaching.

Continued operation of Unit 7 through 2020 will warrant another turbine inspection. Further NDE of the turbine shell and specifically the crack repairs should be performed to determine remaining life of the shell.

4.2.3 Turbine Valves

The turbine valves, consisting of the main steam stop and control valves, are maintained on a four year cycle, which has proven to be adequate. In general, they usually exhibit minor SPE when inspected. Continued operation of Unit 7 through 2020 may warrant another turbine valve inspection depending upon actual operating hours and/or unit starts.

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5.0 HIGH ENERGY PIPING SYSTEMS

5.1 UNIT 6 HIGH ENERGY PIPING SYSTEMS

5.1.1 Main Steam Piping

The main steam piping consists of 12 inch schedule 100 pipe manufactured of seamless ASTM A335 P-22 material. The steam line transfers steam from the boiler superheater outlet header to the HP steam turbine. The system operates at approximately 875 psig at 910°F.

Since this operating temperature is within the creep range (greater than 800°F), this piping system is of particular concern. Creep is a high temperature, time dependant phenomenon that can progressively occur at the highest stress locations within the piping system.

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. EPE has reported there is no P11, P12, or P22 seamed piping in Unit 6.

BPI performed metallographic replications, magnetic particle testing, ultrasonic testing, and diametric measurements on several welds of the main steam line. 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 meets the original ASME requirements. Magnetic particle testing was performed at ten locations along the main steam line without any relevant indications found. Ultrasonic shear phased array testing was performed on the same ten locations without any relevant indications found. Diametric measurements were taken at six weld locations on the main steam line. All were within the allowable creep swell tolerance. Based on their findings, BPI considered the main steam line to be in good condition.

B&McD would normally recommend an annual visual inspection of the main steam pipe supports. However, due to the imminent retirement of the unit, B&McD does not consider this of particular importance.

5.1.2 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 of the main steam system.

B&McD would normally recommend an annual visual inspection of the main steam pipe supports. However, due to the imminent retirement of the unit, B&McD does not consider this of particular importance.

B&McD observed during the plant walkdown that this system is not in compliance with ASME TDP-1-2006, "Recommended Practices for the Prevention of Water Damage to Steam Turbines Used for Electric Power Generation". These practices are not requirements, but recommendations. While EPE may wish to consider implementation of these ASME recommendations, non-compliance does not affect continued operation to the scheduled retirement date.

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.

5.1.3 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 drum. Although this piping operates 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 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 downstream of the two boiler feed water pumps during the February 2011 inspection. All four test points were found to have uniform thickness readings throughout the elbows. No indications of FAC were found.

5.2 UNIT 7 HIGH ENERGY PIPING SYSTEMS

5.2.1 Main Steam Piping

The main steam piping, composed of a 10-inch O.D. ASTM A335-51T, P-22, 1.125 inch minimum wall thickness seamless steam line, 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 within the creep range (greater than 800°F), this piping system is of particular concern. Creep is a high temperature, time dependent phenomenon that can progressively occur at the highest stress locations within the piping system.

BPI performed metallographic replications, magnetic particle testing, ultrasonic testing, and diametric measurements on several welds of the main steam line. 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 meets 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 were within the allowable creep swell tolerance. Based on their findings, BPI considered the main steam line to be in good condition.

B&McD 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, B&McD recommends that the spring hangers be load tested to determine their actual current loading and a stress analysis should be completed to verify that all loads and stresses are within the allowable limits.

5.2.2 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 within the creep range (greater than 800° F), this piping system is of particular concern.

BPI performed metallographic replications, magnetic particle testing, ultrasonic testing, and diametric measurements on several welds of the main steam 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 were within the allowable creep swell tolerance. Based on their findings, BPI considered the main steam line to be in good condition.

B&McD 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.

5.2.3 Cold Reheat Piping

The cold reheat piping, consisting of two 10 inch seamless A106, Grade B schedule 40 steam lines, 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 system should not require the level of examination recommended on the main steam and hot reheat system. B&McD recommends inspecting only the highest stress weld locations using replication examination to determine the extent of any carbide graphitization from occasional high temperature operation that may have occurred.

B&McD 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.

5.2.4 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.

B&McD 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.

B&McD observed during the plant walkdown that this system is not in compliance with ASME TDP-1-2006, "Recommended Practices for the Prevention of Water Damage to Steam Turbines Used for Electric Power Generation". These practices are not requirements, but recommendations. Therefore, EPE should decide, in conjunction with their insurance carrier, whether they should implement any or all of the recommendations. 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. EPE should consider implementation of 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.

5.2.5 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.

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

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6.0 BALANCE OF PLANT

6.1 UNIT 6 BALANCE OF PLANT SYSTEMS

6.1.1 Condensate System

6.1.1.1 System Overview

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

6.1.1.2 Condenser

Unit 6 is provided with a two pass tube and shell condenser with divided water boxes. It consists of 25,000 square foot of 90-10 copper nickel alloy tubes. The condenser has never been retubed and experiences very few tube failures. There are no plans to retube the Unit 6 main condenser.

6.1.1.3 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 backed up by one 100% liquid ring Nash vacuum pump. The pumps are in good condition.

6.1.1.4 Low Pressure Feedwater Heaters

There are two low pressure (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 low pressure 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 low pressure heaters. Since the feedwater heaters are the original equipment and are approaching 55 years of age there is some concern about their condition. However, due to the imminent retirement of the unit, no further monitoring is recommended.

6.1.2 Feedwater System

6.1.2.1 System Overview

The feedwater system is a closed-loop system that 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 drum.

6.1.2.2 High Pressure Feedwater Heaters

There are two high pressure (HP) closed feedwater heaters installed downstream of the feedwater pumps. These heaters were manufactured by Yuba Heat Transfer Corporation. 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 by Senior Engineering in 1993. It is expected to operate to the end of unit life. The 2nd point feedwater heater is the original 1956 vintage Griscom-Russel unit which is in average condition. However, due to the imminent retirement of the unit, no recommendation for further monitoring is needed.

6.1.2.3 Deaerator Heater & Storage Tank

The open, tray type deaerator consists of a single vertical 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 the long seam welds, circumferential welds, and accessible penetrating welds during their 2011 inspection. No service-related indications were found.

The plant should continue visual inspections of the deaerator vessel at each unit planned outage. Due to the imminent retirement of the unit, no further NDE testing is recommended.

6.1.3 Condensate and Boiler Feed Pumps

The two electric driven vertical condensate pumps manufactured by Byron Jackson are each rated at 920 gpm and supply 100-percent of the full load condensate system demand. The condensate pumps are considered to be in good condition. There are no indications that the condensate pumps, with regular maintenance, cannot continue to operate to the scheduled retirement date.

The two main 100-percent capacity boiler feed pumps are motor-driven barrel type Ingersoll Rand pumps rated at 1120 gpm. The pumps and motors are reportedly in good condition. EPE experienced a broken shaft on boiler feed pump #6A in 2004. Both pumps were overhauled in 2004. Spare motors exist for both pumps.

6.1.4 Circulating Water System

The circulating water system is used to reject heat from the condenser to the atmosphere. The system utilizes two 50% 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 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 are refurbished at the major unit overhaul outages.

The circulating water piping is carbon steel. The lines under the powerhouse are encased in concrete. EPE reported that portions of the circulating water piping has been inspected and it was reported to be in average condition. Some of the 48 inch offsets have been replaced due to erosion. The section of piping from the CW pump to the condenser could not be inspected.

The cooling tower is 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 a Marley, 4-cell, cross-flow induced draft tower handling 33,610 gpm. It is designed for a range of 20°F with a 12°F approach at a 67.5°F wet bulb. The original cooling tower casings, gearboxes, and fans were replaced in outages in the late 1990's. The cooling tower is operated at 4.5 cycles of concentration. It is inspected annually, and the plant has expressed concern regarding the structural integrity. B&McD recommends continued monitoring of structural integrity of the cooling tower. EPE may want to consider an inspection for structural integrity by the cooling tower manufacturer.

6.2 UNIT 7 BALANCE OF PLANT SYSTEMS

6.2.1 Condensate System

6.2.1.1 System Overview

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

6.2.1.2 Condenser

Unit 7 is provided with a two pass tube and shell condenser with divided water boxes. The condenser was retubed in the 1970's. EPE has experienced cracks in the condenser shell and are working on that problem. B&McD does not expect this to affect the operation of the unit to the scheduled retirement date. No condenser tube leaks have been experienced. The plant proposes retubing the condenser to support continued operation through December 2020. B&McD recommends performing eddy current testing on the condenser tubes to determine if replacement is required.

6.2.1.3 Condenser Vacuum System

Similar to Unit 6, the Unit 7 condenser vacuum system is intended to maintain a negative pressure, or vacuum, in the condenser by removing all non-condensible 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% liquid ring Nash vacuum pump. The pumps are in good condition.

6.2.1.4 Low Pressure Feedwater Heaters

There are two low pressure (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 low pressure 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 low pressure heaters. B&McD recommends the feedwater heater tubes be inspected by eddy current testing to establish a baseline.

6.2.2 Feedwater System

6.2.2.1 System Overview

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

6.2.2.2 High Pressure Feedwater Heaters

There are two high pressure (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 high pressure heaters. B&McD recommends the feedwater heater tubes be inspected by eddy current testing to establish a baseline.

6.2.2.3 Deaerator Heater & Storage Tank

The open, tray type deaerator consists of a single vertical 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 the long seam welds, circumferential welds, and accessible penetrating welds during their 2011 inspection. No service-related indications were found. BPI did find minor pitting throughout the storage vessel. They recommended 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 3-5 years, with special attention being paid to the water level in the storage tank where cracks have been a problem industry wide.

6.2.3 Condensate and Boiler Feed Pumps

The two electric driven vertical condensate pumps manufactured by Flowserve are each rated at 650 gpm and supply 100-percent of the full load condensate system demand. The Unit #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 in good condition. The Unit #7A boiler feedwater pump and motor were removed and sent out for refurbishment in the fall 2005 outage. Spare motors exist for both pumps.

6.2.4 Circulating Water System

The circulating water system is used to reject heat from the condenser to the atmosphere. The system utilizes two 50% capacity Westinghouse 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 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. EPE reported that portions of the circulating water piping have been inspected and it was reported to be in average condition. EPE has reported that the 36 inch and 42 inch 45 degree fittings of the circulating water system piping were replaced in the late 1990's. The section of piping from the pumps to the condenser could not be inspected.

The Unit 7 cooling tower was replaced in 1997 with a Hamon 8-cell, counter-flow induced draft tower handling 33,610 gpm. The cooling tower consists of two 4-cell blocks with back to back arrangement. It 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. It is inspected by plant personnel annually. B&McD recommends a structural assessment be made to the cooling tower by a third party inspector.

6.3 WATER TREATMENT, CHEMICAL FEED, & SAMPLE SYSTEMS

These systems serve both Units 6 and 7. 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% 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 1-2 million gallons between regenerations. Cleaning of the RO membranes is conducted annually which is a manual process utilizing temporary hoses.

Rio Grande Units 6 and 7 use 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 average condition.

Circulating water treatment consists of injection of sodium bisulfite and ammonia which is occasionally supplemented with bromine powder. Plans are to replace and combine the ammonia chlorinators for Units 6 and 7.

The plant contracts with Nalco to advise them 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 average condition and, with continued attention and proper maintenance, are expected to operate satisfactorily to the end of 2020.

6.4 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.

6.5 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.

* * * * *

7.0 ELECTRICAL SYSTEMS

7.1 UNIT 6 ELECTRICAL SYSTEMS

7.1.1 Generator

The generator is a 1955 vintage Westinghouse unit rated 58.822MVA at 13.8kV. The stator output is 2,460A at a 0.85 power factor. The rotor and stator windings are hydrogen cooled. The exciter is a 1955 vintage DC generator exciter rated 700A at 250VDC. The voltage regulator is a Westinghouse 1955 vintage electromechanical type located on the ground level under the generator.

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

- Distance backup (21)
- Volts/hertz (24)
- Voltage Supervised Overcurent backup (51V)
- Generator Differential (87G)
- Synchronizing (25/25A)
- Undervoltage Alarm (27)
- Reverse Power (32)
- Loss of Excitation (40)
- Unbalance (46)
- Overvoltage (59)
- Loss of Potential (60)
- Stator Ground (59GN)
- 100% Stator Ground (27TN)
- Frequency (81)
- Inadvertent Energizing (50/27)

The generator was last inspected in 2006. Siemens Generator Services cleaned, electrically tested, and checked the core through bolt torque on the generator stator. Siemens Turbine Services machined the generator rotor journals and collector rings. The following tests were performed:

- Insulation resistance (megger)
- Dielectric absorption
- El CID (stator iron)
- Retaining ring ultrasonic inspection

The testing indicates that the generator is in good condition. Since Unit 6 is expected to retire in 2014, no further testing is recommended.

7.1.2 Transformers

7.1.2.1 Main Transformer (Generator Step-up Transformer)

The main generator step-up (GSU) transformer is a 2007 vintage, three-phase unit located outdoors near the turbine building. The main unit transformer is rated 45/60MVA with a temperature rise of 55/65°C and an impedance of 9.9% at 45MVA. 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:

- Transformer differential (87)
- Transformer neutral overcurrent (51N)

There are many factors that reduce a transformers theoretical insulation life such as exposure to through-faults, lightning strikes, ambient temperatures, etc. However, it is not unusual to find transformers with more than 50 years of service. Therefore, with the present testing and maintenance practices, the transformer should have 10 or more years of remaining life before significant maintenance or replacement is required. Even though the unit is due to retire in 2014, it is recommended that the plant continue its current maintenance and testing plan. As a minimum, however, it is recommended that dissolved gas analysis be performed on a quarterly basis.

7.1.2.2 Auxiliary Transformer

The unit auxiliary transformer is a 2001 vintage, ABB, three-phase unit located outdoors near the turbine building. The unit auxiliary transformer is rated 3,750/4,200kVA at 14.4-2.4KV with a temperature rise of 55/65°C and an impedance of 5.78% at 3,750KVA. The oil preservation system is a nitrogen blanket type. A deluge system 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 3KV and 1,340A and is naturally cooled.

The auxiliary transformer protection consists of an ABB TPU2000R microprocessor relay and an electromechanical CO relay with these functions:

- Transformer differential (87)
- Transformer overcurrent (51)

Even though the unit is due to retire in 2014, it is recommended that the plant continue its current maintenance and testing plan. As a minimum, however, it is recommended that dissolved gas analysis be performed on a quarterly basis.

7.1.2.3 Startup Transformer

The startup source consists of one transformer, T3, located in the substation which is rated 7.5MVA and 66-2.4KV. A naturally cooled cable bus, rated 3.3KV and 382A, connects the secondary of the startup transformer to a lineup of 5KV 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 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. Even though the unit is due to retire in 2014, it is recommended that the plant continue its current maintenance and testing plan. As a minimum, however, it is recommended that dissolved gas analysis be performed on a quarterly basis.

7.1.3 Cable Bus

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

7.1.4 Medium Voltage Switchgear

The original 1955 vintage Westinghouse 2.4KV 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 1,200A, 24KA interrupting and 39KA close and latch. The feeder breakers are air magnetic Westinghouse model 50-DH-150 rated 1,200A, 24KA interrupting and 39KA close and latch. The control power for the breakers is 125VDC.

Based on wide industry 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 2.4KV system is an ungrounded delta system and the indicating voltmeters showed a balanced voltage to ground which indicates that there were no ground faults present at the time.

Assuming normal maintenance is performed, the switchgear should be serviceable through the 2014 retirement date.

7.1.5 480 V Load Centers, Switchgear, and Motor Control Centers

The 1955 vintage 480V switchgear is equipped with Westinghouse 25KA airmagnetic circuit breakers. The main breakers are Westinghouse DB-25 breakers rated 800A and 25KA interrupting with 125VDC control power. The switchgear is located indoors.

The unit has two three-phase, 2.4-0.48KV, VPI dry-type load center transformers in free-standing enclosures. The main load center transformer is rated 750KVA, while the cooling tower load center is rated 300KVA.

The load center transformers that feed the 480V 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 7 480V main switchgear which allows operation of the plant until the failed transformer is replaced. The two cooling tower switchgear lineups do not have this tie feature.

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

7.1.6 2400 Volt Motors

The 2.4KV motors consist of the following:

- Circulating Water Pump Motors – two 450 hp

- Forced draft fan – one 800 hp
- Boiler feed water pumps – two 900 hp
- Condensate pumps – two 150 hp

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

7.2 UNIT 7 ELECTRICAL SYSTEMS

7.2.1 Generator

The generator is a 1956 vintage GE unit rated at 58.824MVA at 13.8KV. The stator output is 2,461A at 0.85 power factor. The rotor and stator windings are hydrogen cooled. The exciter is a 1956 vintage DC generator exciter rated 596A at 250VDC. 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:

- Distance backup (21)
- Volts/hertz (24)
- Voltage Supervised Overcurent backup (51V)
- Generator Differential (87G)
- Synchronizing (25/25A)
- Undervoltage Alarm (27)
- Reverse Power (32)
- Loss of Excitation (40)
- Unbalance (46)
- Overvoltage (59)
- Stator Ground (59GN)
- 100% Stator Ground (27TN)
- Frequency (81)

- Inadvertent Energizing (50/27)

The generator was last inspected in 2005. The following tests were performed:

- Insulation resistance (megger)
- Power factor
- El CID (stator iron)
- 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. To date this system has not been implemented nor has the testing been performed. It is recommended that as a minimum partial discharge testing be performed at the next outage in 2012. It is further recommended that an El CID test be performed in 2017.

7.2.2 Transformers

7.2.2.1 Main Transformer (Generator Step-up Transformer)

The main generator step-up (GSU) transformer is a 2002, Waukesha, three-phase unit located outdoors near the turbine building. The main unit transformer is rated 45/60MVA at 66/13.8KV with a temperature rise of 55/65 °C and an impedance of 9.9% at 45MVA. 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:

- Transformer differential (87)
- Transformer neutral overcurrent (51N)

The transformer was in good condition and with the present testing and maintenance practices, should have 30 to 40 years of remaining life. Even though the unit is due to retire in 2020, it is recommended that the plant continue its current maintenance and testing plan. As a minimum, however, it is recommended that dissolved gas analysis be performed on a quarterly basis.

7.2.2.2 Auxiliary Transformer

The unit auxiliary transformer is a three-phase unit located outdoors near the turbine building. The unit auxiliary transformer is rated 3,750/5,000KVA at 14.4-2.4KV with a temperature rise of 55/65°C and an impedance of 5.50% at 3,750KVA. 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 3KV and 1,340A and is naturally cooled.

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

- Transformer differential (87)
- Transformer overcurrent (51)

Even though the unit is due to retire in 2020, it is recommended that the plant continue its current maintenance and testing plan. As a minimum, however, it is recommended that dissolved gas analysis be performed on a quarterly basis.

7.2.2.3 Startup Transformer

The startup source consists of one transformer, T3, located in the substation which is rated 7.5MVA and 66-2.4KV. A naturally cooled cable bus, rated 3.3KV and 382A, connects the secondary of the startup transformer to a lineup of 5KV 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 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. Even though the unit is due to retire in 2020, it is recommended that the plant continue its current maintenance and testing plan. As a minimum, however, it is recommended that dissolved gas analysis be performed on a quarterly basis.

7.2.3 Cable Bus

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

7.2.4 Medium Voltage Switchgear

The original 1956 vintage Westinghouse 2.4KV 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 1,200A, 24KA interrupting and 39KA close and latch. The feeder breakers are air magnetic Westinghouse model 50-DH-150 rated 1,200A, 24KA interrupting and 39KA close and latch. The control power for the breakers is 125VDC.

Based on wide industry 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 2.4kV system is an ungrounded delta system and the indicating voltmeters showed a balanced voltage to ground which indicates that there were no ground faults present at this time.

Assuming normal maintenance is performed, the switchgear should be serviceable through the 2020 retirement date.

7.2.5 480 V Load Centers, Switchgear, and Motor Control Centers

The 1955 vintage 480V switchgear is equipped with Westinghouse 25KA air-magnetic circuit breakers. The main breakers are Westinghouse DB-25 breakers rated 800A and 25KA interrupting with 125VDC control power. The switchgear is located indoors.

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

The load center transformers that feed the 480V 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 480V 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 480V motor control centers installed at the plant. The motor starters are located near the loads in individual enclosures.

7.2.6 2400 Volt Motors

The 2.4KV motors consist of the following:

- Circulating Water Pump Motors – two 300 hp
- Forced draft fan – one 700 hp
- Boiler feed water pumps – two 1000 hp
- Condensate pumps – two 100 hp

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

7.3 STATION EMERGENCY POWER SYSTEMS

The Unit 6 and 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 given ideal conditions. With continued regular maintenance and testing, the batteries should remain functional until the Unit 7 retirement date of 2020.

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.

The emergency diesel generator (EDG) is a 480V Cummins unit rated for 175KW. The diesel generator starting power is supplied by a dedicated set of batteries rated 48VDC. The EDG is located on the ground floor of the Unit 4 turbine building. With regular exercising and fluid changes, the EDG should last 40-50 years. However, controls may become an issue with age and obsolescence. The starting batteries will probably have to be changed out occasionally as well.

7.4 ELECTRICAL PROTECTION

As detailed in Sections 7.1.1, 7.1.2.1, and 7.2.2.1, the Unit 6 and 7 generator and transformer protection was upgraded in 2004 to microprocessor based relaying. The 2.4KV 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.

7.5 2.4 KV CABLE

Unit 6 and 7 plant medium voltage cables are primarily Kerite unshielded type. The plant has a very competent PdM group that performs comprehensive testing on 2.4KV cables. The cables should be replaced as determined by the PdM testing.

7.6 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/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.

7.7 SUBSTATION & TRANSMISSION SYSTEMS

The plant substation is owned and maintained by El Paso Electric. The Units each connect to the substation via the GSU transformers. Four 66KV 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, recently replaced, 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 66KV plant substation has a number of 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.

7.8 CONTROL SYSTEMS

Unit 6 and 7 are controlled via Allen Bradley programmable logic controllers (PLCs). Units 6 and 7 were constructed prior to the formation of NFPA 85 burner management requirements. Unit 6 has a manually supervised burner system with some fuel supply interlocks and trips. 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. Bentley Nevada vibration monitoring systems are installed for both turbine generators.

Even though Unit 6 is due to retire in 2014 and its Panalarm system is obsolete, it is recommended that the plant continue its current maintenance and testing plan. With this maintenance, the Unit 6 plant control system should function until retirement.

The Unit 7 Panalarm system is obsolete and parts may be difficult to obtain. It is recommended that a PLC system be installed that would provide alarming and sequence of events recording capabilities.

7.9 MISCELLANEOUS ELECTRICAL SYSTEMS

Plant lighting typically consists of the following fixture types:

- General plant lighting-incandescent
- Turbine bay lighting-incandescent
- Maintenance shop lighting-flourescent
- Office lighting-incandescent

- 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 systems should function until retirement.

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8.0 EXTERNAL AND ENVIRONMENTAL FACTORS

8.1 INTRODUCTION

External factors, such as availability of fuel or water, or environmental factors have been the cause of other generating units to be taken out of service in the past. Transmission congestion is another potential problem that can lead to costly transmission upgrades in some cases.

8.2 FUEL SUPPLY

EPE employs a full time fuel resource planning department for management of reliable fuel sources for the Rio Grande station. Rio Grande Units 6 and 7 burn an average of approximately 3,300 mmcf of natural gas annually. The plant is fed by a single source over the El Paso Natural Gas (EPNG) interstate pipeline. EPE purchases only firm natural gas supplies for the Rio Grande plant. One five year, long term fuel contract is held with ONEOK intrastate pipeline and the remaining gas supply is met by short term, firm fuel contracts which are transported through the EPNG under long term, firm transportation agreements. The fuel supply tap has two meters and flow regulators which further improve the fuel reliability to the plant. EPE is studying the addition of a second tap into the EPNG intrastate pipeline and a separate lateral to the plant as a redundant supply of gas. The natural gas supplies to the Rio Grande station are properly managed and provide a reliable and continuous fuel supply to the plant.

Historically, EPE has maintained a small supply of fuel oil as a backup fuel supply. However, as part of the permitting process for Unit 9, the ability to burn fuel oil in Unit 6, 7, & 8 was eliminated. Thus, EPE removed fuel oil storage from the site.

8.3 WATER SUPPLY

Water to the plant for the various users, including demineralized water, service water, and cycle water is currently supplied from deep well pumps that are owned by El Paso Water Utilities (EPWU). The water source, consisting of off site wells, is owned by EPE. The ground water source to the wells is allocated by the State of New Mexico which is dedicated for power generation. Water quality from the wells is declining but is being closely monitored by EPE. EPE recently converted an existing 1MM gallon tank to well water storage to act as surge capacity for the plant (primarily for Unit 9, but available to the other units). A smaller water supply line from the City of El Paso is available to EPE for demineralizer makeup and emergency makeup to the cooling tower.

EPE indicated that their water rights have been reduced, but they retain sufficient capacity (maximum expected demand plus 25 percent margin) to service the plant. There are concerns related to degradation of water well capacity. EPE is currently studying the well water system for the plant due to concerns about availability and quality. Results of the study are not currently available.

8.4 WASTEWATER DISCHARGE

Wastewater from the boiler blowdown, laboratory drains, sampling streams, and floor drains is routed through an oil/water separator to the lower canal. Cooling tower blowdown is routed to the upper canal. Wastewater from the demineralizer and reverse osmosis equipment is neutralized and pumped to the lower canal. Sanitary waste is discharged to the El Paso city sewer.

The Rio Grande station is subject to the National Pollution Discharge Elimination System (NPDES) since it discharges waste water into navigable waters of the Rio Grande River. The current NDPES permit became effective on September 30, 2008. The permit must be renewed every five years. EPE does not anticipate any problem with future renewals. EPE reported that the Rio Grande station does not have water discharge permitting issues that will prevent its continued operation for the foreseeable future provided there are no changes in the discharge regulations.

8.5 ENVIRONMENTAL ISSUES

This section of the report describes the environmental regulations that could impact the Rio Grande Station 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 also depend on individual plant impacts. Therefore, no control requirements can be determined until the state and 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.

8.5.1 Cross State Air Pollution Rule

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

8.5.2 Regional Haze Rule

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

8.5.3 National Ambient Air Quality Standards

The EPA is required to set limits on ambient air concentrations for each criteria pollutant (SO_2, NO_2, CO, O_3, lead, and PM) to protect the public's health and welfare. 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_x and SO_2 air dispersion modeling was performed to estimate the level of control that may be required to meet NO_x and SO_2 NAAQS. Since the Rio Grande units are gas-fired, there is no concern about the SO_2 NAAQS, however, there could be NOx impacts. Without modeling, no determination can be made on what, if any NOx emission reductions will be required.

Attainment with the new SO_2 and NO_2 NAAQS are expected to be required by 2017 and 2021, respectively. In order to meet the new SO_2 and NO_2 NAAQS by these timeframes, action may be required sooner at sources found to impact concentrations of these pollutants in non-attainment areas. Demonstrating compliance is based on 3 years' worth of monitoring data, so states may require emissions controls several years before the compliance date. Under the new standards, modifications to the SO_2 and NO_2 monitoring networks are required by January 1, 2013. Once three years of data have been collected, a state may decide to start taking action to achieve attainment. Note that the NO_2 standard is expected to be re-reviewed in January 2015, so states may wait until after this review to take action.

In addition to the new NO_2 and SO_2 NAAQS discussed above, the EPA is also proposing to tighten the NAAQS for O_3 and $PM_{2.5}$. On January 19, 2010, the EPA proposed to revise the 8-hour primary NAAQS for O_3 from 75 ppb to a level in the range of 60 to 70 ppb. EPA expected to finalize the new standard by July 2011. In September 2011, the EPA withdrew its proposed changes to the 2008 O_3 NAAQS. The EPA intends to reconsider the 2008 standard in 2013. Ozone formation is impacted by emissions of volatile organic compounds and NO_x. Therefore, some form of NO_x control (i.e. Reasonably Available Control Technology, RACT) could be required for Rio Grande Station. However, absent any detailed regional air dispersion modeling results, it is impossible to determine what, if any, additional controls will be required. If the EPA proposes a new O_3 standard in 2013 as expected, attainment with the new standard is expected to be required between 2017 and 2034, depending on the severity of the non-attainment issue.

Dona County is listed as a PM-10 non-attainment area. Gas-fired generation is a low emitter of particulate matter. No specific controls are proposed for the Rio Grande Station due to the PM-10 non-attainment status.

The EPA set the current $PM_{2.5}$ standard on September 21, 2006. At this time, the EPA revised the 24-hour standard, but made no changes to the previous annual standard. However, a decision by the D.C. Court of Appeals now requires the EPA to review the annual $PM_{2.5}$ standard. EPA expected to finalize the reconsideration of the 2006 standard by July 2011, but this has not been done as of the writing of this report. $PM_{2.5}$ 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 the Rio Grande Station. However, it is impossible to determine what, if any, additional controls will be required without any detailed air dispersion modeling results. Attainment with the new standard is expected to be required between 2014 and 2031, depending on the severity of the non-attainment issue.

8.5.4 Greenhouse Gas Regulations and Legislation

There was significant Congressional activity related to energy and climate legislation in the 111th Congress (i.e., years 2009 and 2010), but few bills were passed. A new congressional session (the 112th) began in January 2011. Any bill from the 111th Congress that was not passed will have to be reintroduced into the new Congress in order to be considered. A description of significant climate change legislation introduced in the 112th Congress is described below.

8.5.5 Clean Energy Standard Act of 2012

Senate Bill S2146 was introduced by Senator Jeff Bingaman on March 1, 2012. Beginning in 2015, electric utilities would be required to have 24 percent of their carbon emissions from clean energy sources. Electric utilities that could not meet this level would be required to buy clean energy allowances and/or pay a 3 cent per kilowatt hour fee. Each year, the clean energy percentage requirement would be increased up to a maximum of 84 percent by 2035. Under this bill, clean energy generators, defined as sources with carbon intensity rates less than a modern coal-fired plant, are given clean energy credits based on their carbon intensity. Lower emitting carbon emitting sources are given more energy credits.

Initially, smaller utilities, with annual energy sales less than 2 million MWh would be exempt from the clean energy standard. However, each year, the small utility exemption would be decreased until 2025, at which point the threshold would be 1 million MWh in annual sales. However, in the future, the utility could be subject to this bill if enacted into law without revisions.

8.5.6 Greenhouse Gas Endangerment Finding, Tailoring Rule, and NSPS

In addition to the climate change legislation being debated in Congress, the EPA is also working to regulate GHGs through the existing Clean Air Act. This section addresses three key GHG rulemakings by the EPA: the EPA's Endangerment Finding for GHGs, the EPA's GHG Tailoring Rule, and the EPA's New Source Performance Standard for GHG.

On December 15, 2009, EPA finalized an Endangerment Finding for GHGs in response to the U.S. Supreme Court's ruling in Massachusetts v. EPA on April 2, 2007. In this decision, the Supreme Court found that GHGs were air pollutants covered by the Clean Air Act. Based on Section 202(a) of the Clean Air Act, the Supreme Court held that EPA must determine whether or not emissions of GHGs from new motor vehicles cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare. On September 28, 2009, the EPA proposed GHG emission standards for light-duty vehicles in conjunction with the Department of Transportation's Corporate Average Fuel Economy (CAFE) standards. The December 2009 Endangerment Finding allowed EPA to finalize these standards on May 7, 2010.

The EPA's Endangerment Finding itself does not impose any requirements on industry. However, it sets in motion the regulation of GHGs from all sources, not just motor vehicles. Because of the broad impact of this ruling, the EPA finalized a GHG Tailoring Rule on June 3, 2010. The Tailoring Rule attempts to temporarily reduce the scope of the New Source Review (NSR), Prevention of Significant Deterioration (PSD), and Title V permit programs to include only larger emission sources of GHGs (sources that emit at least 75,000 tons/year of GHG). The final rule establishes a multi-step schedule for incorporating GHG limits into PSD and Title V permit programs.

The current CAA permitting program sets emissions thresholds for criteria pollutants (SO_2, NO_2, etc.) of either 100 or 250 tons/year, depending on the source's industrial category. These thresholds are not appropriate for GHGs which are emitted in much higher volumes. The final GHG Tailoring Rule "tailors" the requirements to limit which facilities will be required to obtain NSR and PSD construction permits and Title V operating permits. Without the tailoring rule, the lower emissions thresholds would have taken effect automatically for GHGs on January 2, 2011. This would have dramatically increased the number of permits needed and overwhelm state, local, and tribal permitting authorities.

For an existing source, PSD requirements would not be triggered unless a "non-routine" physical or operational change is made which results in a significant emissions increase. Under the Tailoring Rule, a significant increase in GHG emissions is currently defined as 75,000 tons/year CO_2e for a PSD major source and 100,000 tpy CO_2e for a PSD minor source. Please note that for PSD, GHG are measured in English short tons, not metric tons. It is possible that activities that industry sees as routine maintenance activities could be considered by the EPA to trigger PSD requirements.

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

There are three major water regulations that are currently being 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 potential 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. 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.

EPA plans to propose the Effluent Limitations Guidelines (ELG) rulemaking for the steam electric power generating industry in November 2012 and take final actions by April 2014. The implementation of the final rule will occur over a five year period from 2014 to 2019 with the final rule being applicable to any new or renewal NPDES permit application. Discharges from ponds and other wastewater streams will be addressed in this rulemaking.

Rio Grande uses well water for cooling tower makeup. The plant discharges blowdown to a series of canals that eventually discharge to the Rio Grande River. It unlikely that CWA 316(a) or (b) issues will be significant. Effluent discharge limits may be changed in the future but at this point, there are no specific impacts.

8.5.8 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.

8.6 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 their 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.

8.7 WORK FORCE

EPE indicated that the plant staff is evenly split between highly experienced employees (25 years or more) and relatively new employees (5 years or less) with few employees in between these extremes. They are concerned that the majority of the highly experienced employees will retire in three to five years and taking much of the organization's memory with them. EPE should consider implementing a training plan for the less experienced staff members.

* * * * *

9.0 NEW GENERATION

EPE has also retained B&McD to assess the option of building new generation to replace the previously mentioned units. For this assessment, EPE instructed B&McD to evaluate a greenfield combined cycle gas turbine (CCGT) arrangement consisting of two (2) General Electric 7EA frame gas turbines, two (2) heat recovery steam generators (HRSGs) and one (1) steam turbine and a greenfield simple cycle gas turbine (SCGT) option that includes one (1) General Electric LMS100 aeroderivative gas turbine. This evaluation includes screening-level estimated capital & operations and maintenance (O&M) costs and estimated performance.

It should be noted that the information presented is screening level in nature and intended to allow for general evaluation of whether additional studies are merited. Additional studies will be required to fully define the selected option to support budgeting and develop a defined scope and execution plan.

This assessment provides a comparison of technical features, costs and performance. The costs presented are based upon preliminary proposals received from suppliers. As such, information contained herein may not reflect actual firm bid proposals that will be received during execution of the project. This study provides comparative information, but a vendor selection cannot be made until firm proposals have been received.

9.1 ASSUMPTIONS

This section provides overall assumptions used in developing the capital cost estimates, performance estimates, and O&M estimates for this study.

9.1.1 General Assumptions and Clarifications

- Plant site is a relatively level greenfield site, clear of trees and wetlands. There are no existing structures or underground utilities.
- Site elevation is assumed to be 4000 feet above sea level.
- Sufficient area to receive, assemble and temporarily store construction materials is available.
- Piling is included under heavily loaded foundations.
- Construction costs are based on a multiple contract contracting philosophy.
- Capital cost estimates do not include escalation.
- Sufficient housing is available to support construction labor.

- Performance estimates are based on new and clean equipment. Degradation is not included.
- Wet cooling is used for the base estimate, but an alternate for dry cooling is included for the CCGT option.
- The SCGT LMS100 option assumes a water injected unit for NO_x control with wet, mechanical draft cooling for the Intercooler heat rejection.
- Gas turbine technologies include an evaporative cooler that is on for ambient conditions of 59°F and above.
- Fuel gas supply pressure at the site is sufficient for the CCGT option. Gas compressors have not been included.
- Due to the relatively high gas pressure requirements for the LMS100, this evaluation includes fuel gas compressors to take the fuel gas from approximately 425 psig to 925 psig.
- Duct firing is included in capital costs and performance estimates for the CCGT option.
- Both options include a SCR system to achieve NO_x emissions of 3 ppm.
- The CCGT option excludes CO catalyst, but does have space for future inclusion. The SCGT option does include CO catalyst to achieve CO emissions of 3 ppm.
- Emission estimates are shown to provide the basis for O&M costs and to provide a basis for the required air pollution control equipment included in the capital cost estimates. These emissions represent Burns & McDonnell's best estimate of required BACT emission limits at this time. However, actual BACT requirements will not be fully realized until the permitting process is complete.

9.1.2 Project Indirect Costs

The following project indirects are included in capital cost estimates:

- Construction power.
- Performance testing and CEMS/stack emissions testing (where applicable).
- Initial fills and consumables, preoperational testing, startup, startup management, and calibration.
- Construction/startup technical service.
- Site surveys and studies.
- Engineering and construction management.
- Construction testing.
- Operator training.

9.1.2.1 Owner Indirect Costs

The following Owner indirects are included in capital cost estimates:

- Project development.
- Owner's operations personnel prior to commercial operating date (COD).
- Owner's legal costs.
- Owner construction management.
- Owner start-up engineering.
- Owner construction power and water.
- Permitting and licensing fees.
- Site security.
- Fuel, water, chemicals and power used during startup and testing.
- Permanent plant equipment & furnishings.
- Builder's risk insurance.
- Onsite switchyard.
- Owner's contingency (5%).

9.1.2.2 Capital Cost Exclusions

The following costs are excluded from the capital cost estimates:

- Allowance for Funds Used During Construction (AFUDC); while excluded from capital cost estimates, this is included in the economic analysis.
- Financing Fees; while excluded from capital cost estimates, this is included in the economic analysis.
- Natural gas supply pipeline.
- Raw water supply.
- Land.
- Performance and payment bond.
- Sales tax.

- Transmission Upgrades.
- Water Rights.
- Off-site Infrastructure.
- Owner's Corporate Staffing.
- Escalation to a COD.
- Spare parts.

9.1.2.3 Operations and Maintenance Assumptions and Exclusions

The following are assumptions and exclusions used for determining the operations and maintenance costs:

- All O&M costs are based on a greenfield facility.
- All O&M cost estimates are in 2012 dollars.
- O&M estimates do not include emissions credit costs, property taxes, or insurance.
- O&M estimates do not include start-up costs.
- Fixed O&M cost estimates include labor, office and administration, training, contract labor, safety, building and ground maintenance, communication, and laboratory expenses.
- Variable O&M costs include makeup water, water treatment, water disposal, ammonia, SCR and CO catalyst replacements, and other consumables not including fuel. Variable O&M costs also include maintenance on equipment.
- Gas turbine spare parts (combustion spares, hot gas path spares, and major spares) are not included in the O&M cost.
- O&M estimates are based on a 50 percent capacity factor for the CCGT option and 15 percent for the SCGT option.
- Gas turbine major maintenance is based on third party services; not a long term services agreement (LTSA) with the OEM.

9.2 EVALUATION

The results of this new generation evaluation can be seen in Table 9-1. An optional cost section is also included for dry cooling for the CCGT option. Based on the previously mentioned assumptions, the 2x1 7EA combined cycle with wet cooling has an estimated construction capital cost of $1,060/kW and the 1xLMS100 SCGT option has an estimated construction cost of $1,230/kW. The owner's cost is estimated to be $120/kW and $170/kW for the CCGT and SCGT options, respectively.

The CCGT fixed O&M costs are estimated to be $20.00/kW-yr and variable O&M (excluding major maintenance) is estimated to be $1.60/MWh. The SCGT fixed O&M costs are estimated to be $12.10/MWh and variable O&M (excluding major maintenance) is estimated to be $3.60/MWh. Third party gas turbine major maintenance for the CCGT plant is estimated to be $195/GT-hr while the SCGT plant is estimated to be $310/GT-hr.

The 2x2x1 7EA combined cycle arrangement with wet cooling is predicted to provide a net output of 228 MW and have a heat rate of 7,700 Btu/kWh (HHV) at the assumed site conditions (59°F, 60% RH, 4000 ft elevation) with no duct firing (unfired). Net output would be 310 MW with a heat rate of 8,310 Btu/kWh (HHV) at the assumed site conditions with full duct firing. The LMS100 SCGT arrangement with wet cooling is predicted to provide a net output of 93 MW and have a heat rate of 9,010 Btu/kWh (HHV) at the assumed site conditions (59°F, 60% RH, 4000 ft elevation).

Table 9-1: New Generation Screening Information

EL PASO ELECTRIC COMPANY
NEW GENERATION SCREENING INFORMATION
BMcD Project 68127

PROJECT TYPE	2x2x1 Fired 7EA CCGT	1 x LMS100 SCGT
BASE PLANT DESCRIPTION		
Number of Gas Turbines	2	1
Number of HRSGs	2	0
Number of Steam Turbines	1	0
Steam Conditions (Main Steam / Reheat)	1050 F/1050 F	N/A
Main Steam Pressure	1905 psia	N/A
Steam Cycle Type	Subcritical	N/A
Capacity Factor (%)	Intermediate (50%)	Peaking (15%)
Fuel Design	Natural Gas	Natural Gas
Heat Rejection	Wet Cooling	Wet Cooling
NOx Control	DLN/SCR	Water Injection/SCR
SO2 Control	N/A	N/A
Particulate Control	Good Combustion Practice	Good Combustion Practice
Base Load Unfired Performance @ 59F, 60% RH		
Unfired Net Plant Output, kW	228,400	93,100
Unfired Net Plant Heat Rate, Btu/kWh (HHV)	7,700	9,010
Unfired Heat Input, MMBtu/h (HHV)	1,760	840
Base Load Fired Performance @ 59F, 60% RH		
Fired Net Plant Output, kW	310,200	N/A
Fired Net Plant Heat Rate, Btu/kWh (HHV)	8,310	N/A
Fired Heat Input, MMBtu/h (HHV)	2,580	N/A
Procurement Costs, $/kW	$450	$610
Construction Costs, $/kW	$330	$280
Project Indirects, $/kW	$160	$170
Owner's Costs, $/kW	$120	$170
Project Total, $/kW	**$1,060**	**$1,230**
Fixed O&M Cost, $/kW-Yr	$20.00	$12.10
Incremental Duct Fired Fixed O&M Cost, $/kW-Yr	$0.00	$0.00
Major Maintenance, $/GTG-hr	$195	$310
Major Maintenance, $/GTG-start	$4,000	$0
Incremental Duct Fired Major Maintenance, $/GTG-hr or $/GTG-start	$0.00	$0.00
Variable O&M Cost (Excluding Major Maintenance), $/MWh	$1.60	$3.60
Incremental Duct Fired Variable O&M Cost, $/MWh	$1.30	$0.00
ESTIMATED BASE LOAD OPERATING CONDITIONS, lb/MMBtu (HHV)		
NO_X	0.011	0.011
SO_2	< 0.0051	< 0.0051
CO	0.056	0.0067
CO_2	118	118
PM/PM_{10}	0.01	0.01

PERFORMANCE AND COSTS FOR DRY COOLING		
Performance @ 59F, 60% RH		
Unfired Net Plant Output, kW	221,800	N/A
Unfired Net Plant Heat Rate, Btu/kWh (HHV)	7,935	N/A
Unfired Heat Input, MMBtu/h (HHV)	1,760	N/A
Base Load Fired Performance @ 59F, 60% RH		
Fired Net Plant Output, kW	301,200	N/A
Fired Net Plant Heat Rate, Btu/kWh (HHV)	8,566	N/A
Fired Heat Input, MMBtu/h (HHV)	2,580	N/A
Project Total, $/kW	**$1,160**	**N/A**
Fixed O&M Costs, $/kW-yr	$20.60	N/A
Variable O&M Costs (Excluding Major Maintenance), $/MWh	$1.50	N/A

NEW GENERATION SCREENING INFORMATION NOTES

The following assumptions, in conjuction with those stated in the report, govern this analysis:

General
- All estimates in this table are "screening-level" and are not to be guaranteed.
- Fuel is pipeline quality natural gas with less than 3 grains Sulfur/100 scfm.
- Options include an SCR to achieve NOx emissions down to 3 ppm.
- Simple cycle option includes a CO catalyst to achieve CO emissions of 3 ppm.
- CCGT option does not include a CO catalyst, but does include space for future installation.
- All emissions limits are subject to the BACT process.
- Costs originally presented to EPE have been updated to reflect current market conditions, as of October 2012.
- LMS100 option is based on a water injected unit for NOx control with wet Intercooler cooling.

Capital Cost Estimates
- A multiple contracting method is assumed for this project, using open shop labor.
- Capital costs provided do not include escalation.
- Owner's costs do not include financing fees, IDC, transmission upgrades or interconnects.
- Plant capital cost ($/kW) is based on fired plant performance for the CCGT option and baseload performance for the simple cycle option, at 59F ambient condition.
- The plant site is a greenfield site that is clear of trees, structures and wetlands and is reasonably level.
- Sufficient laydown area is available.
- Piling is included under heavily loaded foundations.
- Typical buildings are included, but a fully enclosed plant is not.
- Off-site pipeline costs are excluded.

Tie-Ins
- Raw water supply tie in is at the site boundary. No additional costs for wells or water pipeline have been included.
- Natural gas is available at the site boundary at adequate pressure, flow, and quality.
- Base plant costs include switchyard. Transmission lines or transmission upgrades are not included.

Performance Estimates
- Performance estimates provided are based on a site elevation of 4000 ft.
- Performance assume evaporative cooling is installed and operating at 59°F/60%RH.
- Output and heat rate estimates assume new and clean equipment.

O&M Estimates
- O&M Costs are in current year (2012) dollars and do not include escalation.
- GTG Major Maintenance is based on third party services; not an LTSA with the OEM.
- Major maintenance for GE frame units will be dependent on hours per start. If there are more than 27 operating hours per start, the maintenance will be hours based. If there are less than 27, the maintenance will be starts based.
- Major maintenance for GE aero units is hours based.
- O&M Costs do not include emissions allowances.
- O&M is estimated at the 59F ambient condition.
- Estimated staff requirements and salaries are included in the fixed O&M analysis.

* * * * *

10.0 LEVELIZED BUSBAR COST ANALYSIS

B&McD conducted an economic evaluation of the cost of continued operation of the existing units. The economic evaluation consisted of a levelized busbar cost evaluation of the target units compared against the levelized busbar cost of a new 2x1 7EA combined cycle gas turbine (CCGT) facility. The following summarizes the assumptions utilized within the economic evaluation as well as the overall results of the levelized busbar analysis.

The following summarizes the units evaluated:

- Rio Grande Unit 6 – 45 MW
- Rio Grande Unit 7 – 46 MW
- Combined cycle gas turbine 2x1 7EA (unfired) – 228 MW
- Simple cycle gas turbine LMS100 – 93 MW

The purpose of the economic evaluation is to determine if a new CCGT unit or a new SCGT unit could be constructed and operated at a lower levelized busbar cost than the existing units. The existing units are not as efficient as a new CCGT or SCGT facility; therefore more fuel is consumed as they operate. The analysis will determine the capacity factors at which a new CCGT or SCGT facility would be a lower cost alternative than the existing units. The analysis does not include an evaluation of potential revenue streams such as capacity value or ancillary services.

10.1 ASSUMPTIONS

EPE provided operating cost and performance information for the existing units. B&McD reviewed this information and identified additional operation and maintenance (O&M) costs that may be required to continue to operate the units due to the age of the units. The additional costs were included in the analysis. All maintenance costs associated with the existing units were assumed to be O&M costs, not capital expenditures for the purpose of this evaluation. B&McD developed screening level capital cost, O&M cost, and performance estimates for the CCGT and SCGT alternatives.

Table 10-1 presents the capital costs, fixed and variable O&M costs, and unit performance parameters for each alternative evaluated. Table 10-2 presents the financing and economic assumptions that were used within the analysis. Table 10-3 presents the natural gas forecast that was utilized within this analysis. The natural gas forecast is based on EPE's forecast used within its integrated resource planning efforts.

Table 10-1: Cost and Performance Parameters

	Rio Grande Unit 6	Rio Grande Unit 7	2x1 7EA CCGT	LMS100 SCGT
ESTIMATED PERFORMANCE				
Base Net Plant Output, kW	45,000	46,000	228,400	93,100
Base Net Plant Heat Rate, Btu/kWh (HHV)	11,770	10,389	7,700	9,010
ESTIMATED CAPITAL AND O&M COSTS (2013$)				
EPC Project Capital Cost w/o Owner's Costs ($, Millions)			$290	$99
Owner's Costs ($, Millions)			$38	$16
Total Capital Cost			$328	$115
Base Fixed O&M Cost, $/kW-Yr	$54.99	$49.34	$20.00	$12.10
Levelized Major Maintenance Cost, $/MWh			$1.70	$3.30
Variable O&M Cost, $/MWh (excl. major maint.)	$2.09	$2.09	$1.60	$3.60
Additional O&M Costs	N/A	N/A	N/A	N/A

Table 10-2: Financing Assumptions

Financing Assumptions	
Debt	
% Financed	46.91%
Interest Rate	6.74%
Equity	
% Financed	53.09%
Interest Rate	10.13%
Discount Rate / WACC	7.34%
Contruction Financing Fees	0.50%
Permanent Financing Fees	1.00%
Debt Financing Term (Years)	40
Book Depreciation Term (Years)	40
Rate Assumptions	
General Escalation Rate	2.50%
Insurance Rate	0.25%
Income Tax Rate	35.00%

Table 10-3: Natural Gas Forecast

Year	Fuel Cost $/MMBtu
2013	3.36
2014	3.84
2015	3.99
2016	4.21
2017	4.42
2018	4.55
2019	4.61
2020	4.70
2021	4.82
2022	4.94
2023	4.97
2024	5.16
2025	5.46
2026	5.74
2027	5.86
2028	5.98
2029	6.18
2030	6.39
2031	6.62
2032	6.79

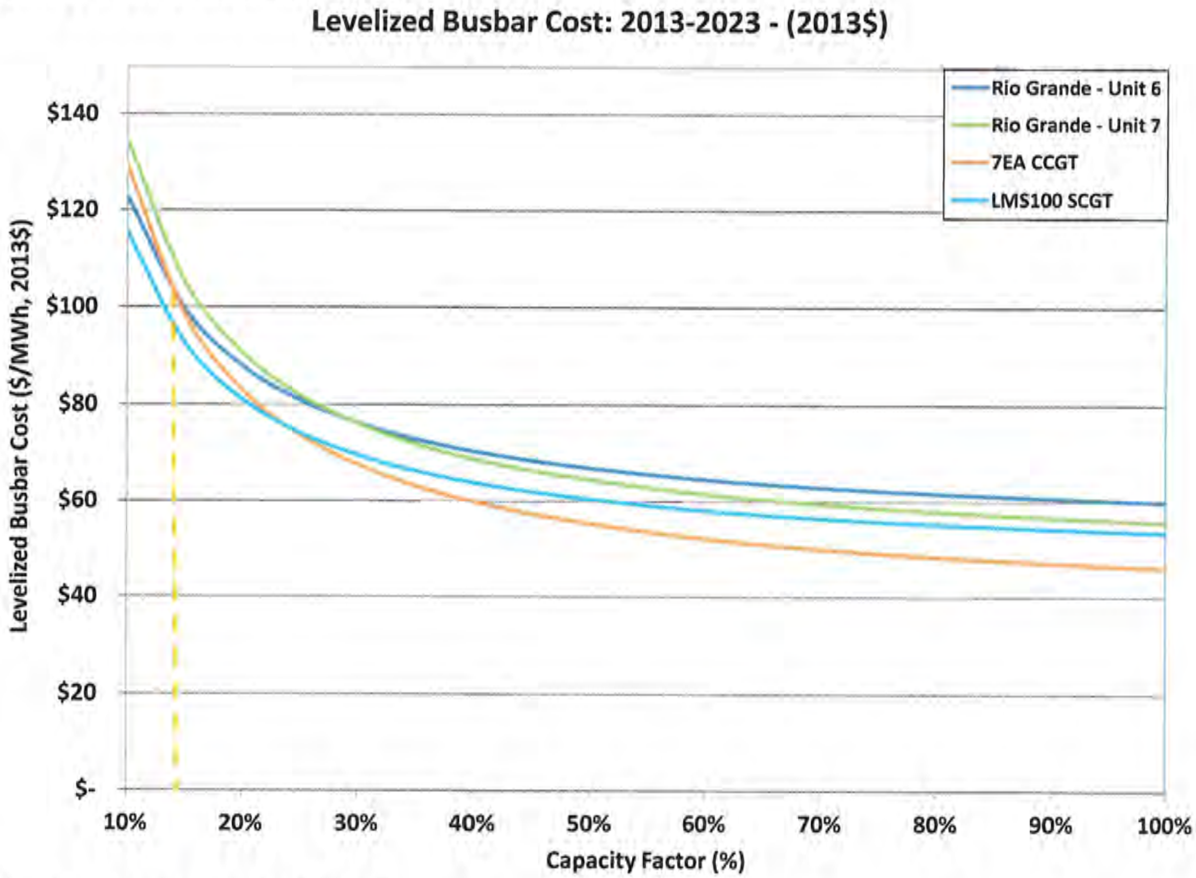
Note: Forecast in nominal dollars

10.2 ECONOMIC ANALYSIS

Using these assumptions, B&McD developed a levelized busbar cost for each option over varying capacity factors. The levelized busbar cost represents the fixed energy cost of the unit accounting for fuel, interest, depreciation, O&M, return, and taxes over the study period from 2013 to 2023. The existing units were assumed to be fully depreciated, therefore costs for those units only consisted of fuel and O&M costs. All maintenance costs associated with the existing units were assumed to be O&M costs, not capital expenditures.

Figure 10-1 presents the levelized busbar cost analysis for Rio Grande Unit 6, Rio Grande Unit 7, the 7EA CCGT, and the LMS100 SCGT. As presented in Figure 10-1, the CCGT has a lower levelized busbar cost compared to Rio Grande Unit 6 for capacity factors greater than 10 percent and Unit 7 for capacity factors greater than approximately 15 percent. The SCGT has a lower levelized busbar cost compared to both Rio Grande Unit 6 and Unit 7 for all capacity factors 10 percent and greater.

Figure 10-1: Levelized Busbar Cost



10.2.1 Sensitivity Analysis

A sensitivity analysis was performed for the capital cost of the CCGT and SCGT options. The sensitivity analysis was utilized to determine how much higher the capital cost for the CCGT and the SCGT would need to be to result in an equivalent busbar cost compared to the Rio Grande units at selected capacity factors. The capital cost for the CCGT ($328,000,000) was increased until the busbar cost of the CCGT unit was higher than that of the Rio Grande units for capacity factors of 20 percent and 30 percent. The capital cost for the SCGT ($115,000,000) was increased until the busbar cost of the SCGT unit equal to that of the Rio Grande units. The results are as follows:

- At a CCGT capital cost of $377,200,000, the Rio Grande units have a lower busbar cost for capacity factors 20 percent and less.
- At a CCGT capital cost of $459,200,000, the Rio Grande units have a lower busbar cost for capacity factors 30 percent and less.

- At a SCGT capital cost of $149,500,000, the Rio Grande units' busbar costs are nearly equal to the levelized busbar cost of the SCGT.

10.3 CONCLUSIONS

Based on the screening level economic evaluation, it appears that a new CCGT or SCGT will provide a lower levelized busbar cost compared to Rio Grande Unit 6 for nearly all capacity factors greater than 10 percent. Furthermore, it appears that a new resource will provide a lower levelized busbar cost compared to Rio Grande Unit 7 for capacity factors greater than 15 percent (for the CCGT) and 10 percent (for the SCGT).

B&McD would recommend EPE evaluate the existing units, CCGT, and SCGT alternative within its integrated resource plan. Depending on the energy and capacity needs of EPE's system, the existing units, CCGT, or SCGT may provide different value to EPE. If EPE only needs the existing units for capacity obligations and would only operate the existing units at lower capacity factors, the existing units may provide the most economic benefit to EPE. However, if EPE's system needs significant energy, then supplementing the Rio Grande units with a new CCGT or SCGT alternative may provide economic benefit. However, that analysis should be further evaluated within a resource optimization or hourly dispatch model to determine how each unit operates within the EPE system.

* * * * *

11.0 CONCLUSIONS AND RECOMMENDATIONS

11.1 CONCLUSIONS

Based on the information acquired and presented in this report, the following conclusions have been made:

- The overall condition of the Rio Grande Units 6 & 7 appears to be good. There are no conditions which have been identified as being detrimental to achieving the intended unit life. Operational and maintenance problems which could affect operation are actively being addressed.
- Unit operations and maintenance are generally well planned and carried out in a manner consistent with utility industry standards.
- The predictive maintenance program used throughout the EPE system has been highly successful in minimizing forced outages in the rotating equipment area. This program has received industry recognition and, where feasible, should be extended to other critical equipment, such as control valves, and certain heat exchangers.
- Although the available operating time for Unit 6 will be reduced as part of the operating permit for Unit 9, there are no identifiable external or environmental factors that will prevent continued operation through the scheduled retirement dates.
- Based on the screening level economic evaluation, it appears that a new CCGT or SCGT will provide a lower levelized busbar cost compared to Rio Grande Unit 6 for nearly all capacity factors greater than 10 percent. Furthermore, it appears that a new resource will provide a lower levelized busbar cost compared to Rio Grande Unit 7 for capacity factors greater than 15 percent (for the CCGT) and 10 percent (for the SCGT).

As a result of our review of the design, condition, operations and maintenance procedures, long-range planning, availability of consumables, and programs for dealing with environmental considerations, it is B&McD's opinion that Rio Grande Units 6 and 7 are capable of operating to their scheduled retirement of December 2014 and December 2020, respectively.

11.2 RECOMMENDATIONS

The following is a summary of the recommended actions suggested to maintain the reliability of Rio Grande Units 6 and 7 and reduce the potential for extended unit forced outages. The following recommendations are presented herein:

11.3 EXTERNAL & ENVIRONMENTAL FACTORS:

- EPE should continue to monitor changing air emissions regulations (NAAQS).
- EPE should continue to monitor well water capacity and quality.

11.4 UNIT 6 RECOMMENDATIONS

Due to the impending retirement of Unit 6 in December 2014, B&McD does not recommend additional actions beyond EPE's current operating and maintenance activities.

In previous reports, B&McD has recommended the addition of a Flame Safety Shutdown and Startup Furnace Purge System to the boiler and Prevention of Water Damage to Steam Turbine equipment to the steam piping. Based on EPE's operating history (and the lack of events these systems are designed to prevent) and the impending retirement of Unit 6, B&McD does not consider the installation of these systems of particular importance.

11.5 UNIT 7 RECOMMENDATIONS

The following is a summary of the recommended actions suggested to maintain the reliability of Rio Grande Unit 7 and reduce the potential for extended unit forced outages through the scheduled retirement date in December 2020.

11.5.1 Boiler:

- Repeat previously performed 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, and reheater outlet header and branch connections to the reheater outlet header. This testing should be expanded to the superheater and reheater inlet headers and branch connections to the headers.
- Inspect the superheater and reheater attemperator(s) and downstream piping. This testing was not done during the NDE testing in 2011.
- Perform annual testing of the safety relief valves.
- Continue boiler chemical cleanings on a 5-year schedule.

11.5.2 Steam Turbine-Generator:

- Continue steam turbine-generator inspections on an 8-year schedule.
- Continue steam turbine-generator valve inspections on a 4-year schedule.
- Perform boroscope examination of the turbine rotor.

11.5.3 High Energy Piping Systems:

- Repeat previously performed non-destructive examination of selective areas of main steam, hot reheat, and boiler feedwater piping. This testing should be expanded to the cold reheat piping.

- Repeat the inspection of the feedwater piping downstream of the boiler feed pumps for signs of FAC.
- Visually inspect the main steam, hot reheat, cold reheat, extraction, and feedwater piping supports on an annual basis.

11.5.4 Balance of Plant:

- Conduct eddy current testing of low pressure and high pressure feedwater heater tubing. The results of this testing can be used to evaluate the need for feedwater heater replacement, which EPE has tentatively scheduled for 2014.
- Repeat previously performed non-destructive testing of the deaerator and storage tank. This testing should be expanded to include ultrasonic thickness testing of the storage tank shell at the normal water level.
- Continue visual inspections of the circulating water piping on a regular basis.
- Inspect the structural integrity of the stack.
- 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.
- Perform a structural assessment on the cooling tower. This assessment may be use to determine the extent of repairs EPE has tentatively scheduled for 2014.

11.5.5 Electrical:

- Perform quarterly dissolved gas analysis on the main, auxiliary, and start-up transformers.
- Continue regular inspection, adjusting, testing, and refurbishing of medium voltage switchgear.
- Perform El CID testing on the generator.
- Perform partial discharge testing on the generator.
- Install a PLC system on Unit 7 for alarming and sequence of events recording.

Table 10-1 indicates a schedule for the implementation of the above recommendations.

Table 11-1: Implementation Schedule for B&McD Recommendations on Rio Grande Unit 7

	2013	2014	2015	2016	2017	2018	2019	2020
Boiler								
Conduct non-destructive examination of selective areas				X				
Inspect superheater attemperator(s) and downstream piping	X			X				
Test safety valves	X	X	X	X	X	X	X	
Chemically clean boiler				X				
Turbine-Generator								
Perform turbine inspection		X						

	2013	2014	2015	2016	2017	2018	2019	2020
Perform boroscopic examinations of turbine rotor		X						
High Energy Piping								
Inspect main steam, hot reheat, cold reheat and feedwater piping hangers	X							
Conduct non-destructive examination of selected areas of main steam, hot reheat, cold reheat, and feedwater piping				X				
Inspect boiler feed pump discharge piping for FAC				X				
Balance of Plant								
Conduct eddy current testing of feedwater heater tubing	X							
Conduct non-destructive examination of deaerator and storage tank				X				
Conduct visual inspection of circ water piping	X			X				
Conduct inspection of stack	X							
Comply with ASME TDP-1-2006	X							
Perform a structural assessment of cooling tower	X							
Electrical and Controls								
Monitor quarterly the main, auxiliary, and start-up transformers for dissolved gases	X	X	X	X	X	X	X	X
Inspect, adjust, test, and refurbish the medium-voltage switchgear on the current schedule			X					
Perform El CID test on the generator					X			
Perform partial discharge test on the generator	X							
Install PLC alarming and sequence of events recording	X							

* * * * *

APPENDIX A - Rio Grande Unit 7
Additional Maintenance Expenditures

El Paso Electric Company, Inc.
Rio Grande 6 & 7 Condition Assessment
B&McD Project No. 68127
Maintenance Expenditures for Rio Grande Unit 7

B&McD Recommended Expenditures	2013	2014	2015	2016	2017	2018	2019	2020
Conduct non-destructive examination of selective areas				$110,000				
Inspect superheater and reheater attemperators and downstream piping	$41,000							
Test safety valves	$10,000	$11,000	$11,000	$11,000	$11,000	$12,000	$12,000	
Chemically clean boiler				$1,104,000				
Perform turbine and generator inspection					$3,111,000			
Perform boroscope examinations of turbine rotor		$53,000						
Perform turbine valve inspection		$525,000						
Inspect main steam, hot reheat, cold reheat and feedwater piping hangers	$51,000							
Conduct non-destructive examination of selected areas of main steam, hot reheat, cold reheat, and feedwater piping				$55,000				
Inspect boiler feed pump discharge piping for FAC				$22,000				
Conduct eddy current testing of feedwater heater tubing	$21,000							
Conduct non-destructive examination of deaerator and storage tank				$22,000				
Conduct visual inspection of circ water piping	$5,000			$6,000				
Conduct inspection of stack	$26,000							
Comply with ASME TDP-1-2006	$256,000							
Perform structural assessment on cooling tower	$26,000							
Monitor quarterly the main, auxiliary, and start-up transformers for dissolved gases								
Inspect, adjust, test, and refurbish the medium voltage switchgear on the current schedule								
Perform EI CID test on the generator					$50,000			
Perform partial discharge test on the generator	$41,000							
Total B&McD Recommendations	$477,000	$589,000	$11,000	$1,330,000	$3,172,000	$12,000	$12,000	$0

Owner Planned Expenditures (See Note 1)	2013	2014	2015	2016	2017	2018	2019	2020
Boiler Waterwall Replacements (partial)		$420,000						
Turbine Shell Repairs/Replacement		$525,000						
High Energy Piping Repairs/Replacement		$735,000						
Condenser Retubing				$276,000				
Cooling Tower Repairs					$283,000			
Condensate Pump/Motor Repairs/Replacement					$113,000			
Boiler Feed Pump/Motor Repairs/Replacement		$315,000						
Circulator Pump/Motor Repairs/Replacement		$210,000						
Fire Protection Upgrades		$84,000						
Water Treatment Upgrades			$135,000					
Cooling Water Delivery Upgrades		$315,000						
Switchgear Repairs/Replacement		$53,000						
Instrumentation Upgrade/Replacement		$84,000						
Voltage Regulator Upgrade/Replacement				$110,000				
Total Owner Planned Expenditures	$0	$2,741,000	$135,000	$386,000	$396,000	$0	$0	$0

Notes:
1. Owner planned life extension projects in addition to B&McD discussed and recommended projects.

Rio Grande Unit 6 Condition Assessment

El Paso Electric, Inc.

Life Extension & Condition Assessment
Project No. 101995

Revision 2
7/17/2018

Rio Grande Unit 6 Condition Assessment

prepared for

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

Project No. 101995

Revision 2
7/17/2018

prepared by

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

TABLE OF CONTENTS

Page No.

1.0 EXECUTIVE SUMMARY 1-1
1.1 Objective & Background 1-1
1.2 Results 1-1
1.2.1 Capital Expenditures and O&M Costs 1-1
1.3 Conclusions 1-2

2.0 INTRODUCTION 2-1
2.1 General Plant Description 2-1
2.2 Study Objectives & Overview 2-1
2.3 Study Contents 2-2

3.0 SITE VISIT 3-1

4.0 BOILER 4-1
4.1 Waterwalls 4-1
4.2 Superheater 4-2
4.3 Drums 4-3
4.4 Safety Valves 4-3
4.5 Burner Control System 4-3

5.0 BOILER AUXILIARY SYSTEMS 5-5
5.1 Fans 5-5
5.2 Air Heater 5-5
5.3 Flues, Ducts, Casing, & Structure 5-6
5.4 Stack 5-6
5.5 Blowdown System 5-6

6.0 STEAM TURBINE 6-1
6.1 Turbine 6-1
6.2 Turbine Valves 6-2

7.0 HIGH ENERGY PIPING SYSTEMS 7-3
7.1 Main Steam Piping 7-3
7.2 Extraction Piping 7-4
7.3 Feedwater Piping 7-4

8.0 BALANCE OF PLANT 8-1
8.1 Condensate System 8-1
8.1.1 Condenser 8-1
8.1.2 Condenser Vacuum System 8-1
8.1.3 Low Pressure Feedwater Heaters 8-1

8.2 Feedwater System 8-2
8.2.1 High Pressure Feedwater Heaters 8-2
8.2.2 Deaerator Heater & Storage Tank 8-2
8.3 Condensate and Boiler Feed Pumps 8-3
8.4 Circulating Water System 8-3
8.5 Water Treatment, Chemical Feed, & Sample Systems 8-4
8.6 Fire Protection Systems 8-6
8.7 Bridge Crane 8-6
8.8 Plant Structures 8-6

9.0 ELECTRICAL AND CONTROLS 9-1
9.1 Unit 6 Electrical Systems 9-1
9.1.1 Generator 9-1
9.1.2 Transformers 9-2
9.1.3 Cable Bus 9-4
9.1.4 Medium Voltage Switchgear 9-4
9.1.5 480 V Load Centers, Switchgear, and Motor Control Centers 9-4
9.1.6 2400 V Motors 9-5
9.2 Station Emergency Power Systems 9-5
9.3 Electrical Protection 9-6
9.4 2.4 kV Cable 9-6
9.5 Grounding & Cathodic Protection 9-7
9.6 Control Systems 9-7
9.7 Miscellaneous Electrical Systems 9-7

10.0 OPERATION AND MAINTENANCE 10-1
10.1 Reliability and Performance 10-1
10.2 Capital Expenditures Estimate 10-2
10.2.1 Life Extension through 2027 10-2
10.2.2 Life Extension through 2037 10-4
10.3 Operations & Maintenance Forecast 10-5
10.4 Summary 10-9

11.0 CONCLUSIONS & RECOMMENDATIONS 11-1
11.1 Conclusions 11-1
11.2 Recommendations 11-2
11.3 External & Environmental Factors 11-3
11.3.2 Boiler 11-4
11.3.3 Steam Turbine-Generator 11-4
11.3.4 High Energy Piping Systems 11-4
11.3.5 Balance of Plant 11-4
11.3.6 Electrical 11-4

APPENDIX A - COST FORECASTS THROUGH 2027
APPENDIX B - COST FORECASTS THROUGH 2037

LIST OF TABLES

Page No.

Table 1-1: Cumulative Capital and Maintenance Costs (2018$) 1-2
Table 10-1: Benchmark Units 10-8
Table 10-2: Cumulative Capital and Maintenance Costs (2018$) 10-9

LIST OF FIGURES

Page No.

Figure 10-1: Equivalent Availability Factor (%) 10-1
Figure 10-2: Equivalent Forced Outage Rate (%).......... 10-2
Figure 10-3: Capital Expenditures Forecast through 2027 10-4
Figure 10-4: Capital Expenditures Forecast through 2037 10-5
Figure 10-5: Maintenance Cost Trend Evaluation 10-6
Figure 10-6: Maintenance Cost Trend Evaluation (X-Y Scatter) 10-7
Figure 10-7: Maintenance Cost Forecast for Unit 6.......... 10-9

LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
A	Amperes
ASME	American Society of Mechanical Engineers
AVR	Automatic Voltage Regulator
BFP	Boiler Feedwater Pump
BPI	Babcock Power, Inc.
BTU/kWh	British Thermal Unit per Kilowatt Hour
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
ºC	Degrees Celsius
DC	Direct Current
DCS	Distributed Control System
EAF	Equivalent Availability Factor
EDG	Emergency Diesel Generator
EFOR	Equivalent Forced Outage Rate
EPE	El Paso Electric, Inc.
EPRI	Electric Power Research Institute
°F	Degrees Fahrenheit
Facility	Rio Grande Power Station
FD	Forced Draft
FSSS	Flame Safety Shutdown and Startup Furnace Purge System
FWH	Feedwater Heater
GADS	Generator Availability Database System

Abbreviation	Term/Phrase/Name
gpm	Gallons per Minute
GSU	Generator Step-Up
HP	High Pressure
hp	Horsepower
in	Inch
kA	kiloamperes
kV	Kilovolt
kW	Kilowatt
lb/hr	pounds per hour
LP	Low Pressure
MCR	Maximum Continuous Rating
MVA	Megavolt Amperes
MW	Megawatts
NAAQS	National Ambient Air Quality Standards
NDE	Nondestructive Examination
NERC	North American Electric Reliability Corporation
NFPA	National Fire Protection Association
NOx	Nitrogen Oxide
O&M	Operation and Maintenance
OEM	Original Equipment Manufacturer
PdM	Predictive Maintenance
Plant	Rio Grande Power Station

Abbreviation	**Term/Phrase/Name**
PLC	Programmable Logic Controller
PSS	Power System Stabilizer
psig	Pound Per Square Inch Gauge
PVC	Polyvinyl Chloride
Rio Grande	Rio Grande Power Station
RO	Reverse Osmosis
SJAE	Steam Jet Air Ejector
SPE	Solid Particle Erosion
STG	Steam Turbine Generator
Study	Rio Grande Unit 6 Condition Assessment
Unit	Rio Grande Unit 6
Unit 6	Rio Grande Unit 6
VDC	Volt Direct Current

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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 6 (Unit or Unit 6) at the Rio Grande Power Station (Plant, Rio Grande, or Facility) The Unit was retired in 2014 but operates in inactive reserve (serves as a contingency reserve Unit). The objective of this assessment is to analyze the current condition of the Unit and estimate the cost of repairing, replacing, maintaining, and operating the Unit through 2027 and 2037 (Study). Burns & McDonnell has included estimated capital and incremental operation and maintenance (O&M) costs associated with operating the Unit safely and reliably for the two life extensions scenarios of 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 as part of past condition assessments, updated information provided by EPE, information obtained during a site interview with plant personnel, and observations from a walkdown of the Unit. Inspections have been performed based on the Unit's inactive reserve designation and much of the previous inspection information was not available for review. Therefore, this assessment is based on the information obtained during the site interviews, a 2006 steam turbine and generator inspection report and the previous condition assessments.

1.2 Results

1.2.1 Capital Expenditures and O&M Costs

Due to the age and condition of the Unit, much of the major equipment and components will need to be replaced or refurbished to continue to operate the Unit safely until 2027 or 2037. Overall, the total capital and maintenance costs for each extended life scenario will be significant. Table 1-1 presents the cumulative capital expenditures and maintenance costs for the time periods from 2018 to 2027 and 2018 to 2037in 2018 dollars. As seen in the table Unit 6 will cost approximately $1,002/kilowatt (kW) for the 2018 to 2027 time period and $2,134/kW for the 2018 to 2037 time period.

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

Time Period	Total ($000)	Capital ($/kW)	Maintenance ($/kW)	Total ($/kW)
2018 to 2027	$48,081	$666	$336	$1,002
2018 to 2037	$102,445	$1,418	$716	$2,134

1.3 Conclusions

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

1. Rio Grande Unit 6 was placed into commercial service in June 1957. The Unit has reached 60 years of service and appears to be in fair condition considering its age. 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. Despite its age, the Unit has generally not exhibited a significant loss of reliability, which would be indicative of degradation of the major components. This is likely due to several factors including:
   a. Minimal cycling operation
   b. Proper attention to water chemistry
   c. Early adoption of a predictive maintenance program
   d. An arid climate
3. The Unit has performed reliable considering the Unit's retirement designation and age, however, many of the major components and equipment will need to be repaired or replaced to extend the service life of the Unit to nearly 70 or 80 years. Rio Grande Unit 6 could be capable of reliable 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.
4. Unit operations appeared to be well planned and carried out in a manner consistent with utility industry standards before the Unit was retired. Since retirement, only critical maintenance items have been performed. Burns & McDonnell believes that the maintenance budget will have to be increased from current levels to actively address issues which could affect operation and reliability of the unit.
5. With the increased penetration of renewable resources, traditional fossil-fueled generation need to provide greater flexibility to system operators to better optimize the power supply resources and costs to account for the variability and uncertainty associated with renewable resource generation.

Rio Grande Unit 6 is a base load unit and does not provide much flexibility regarding ramp rates, start times, or part load operation compared to newer generating resources.

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 West Texas and Southern New Mexico. EPE has interests in the 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), Unit 6 began commercial operation in 1957.

Unit 6 utilizes a natural circulation steam generator boiler designed by Babcock and Wilcox for 450,000 pounds per hour (lb/hr) of steam flow at an outlet pressure of 875 pounds per square inch gauge (psig) and outlet temperature of 910 degrees Fahrenheit (°F). Unit 6 does not have a reheater. The boiler has a pressurized furnace, and a single regenerative Ljungstrom air preheater. Unit 6 also includes a Westinghouse steam turbine, which is a standard two-cylinder machine with a double flow low pressure (LP) condensing unit. The generator is currently rated at 58.8 megavolt amperes (MVA). Cooling water for Unit 6 is circulated through a counter-flow cooling tower with makeup water provided from off-site wells. Boiler makeup water for Unit 6 is also provided from the off-site well water system.

Since retiring in 2014, Unit 6 has operated in inactive reserve (serves as a contingency reserve Unit). Since this retirement, EPE has performed only critical maintenance activities, therefore, the Unit will require a significant amount of investments to operate reliably until 2027 or 2037.

2.2 Study Objectives & Overview

EPE retained the services of Burns & McDonnell to perform a study to assess the condition of Rio Grande Unit 6, and to assess the costs of operating and maintaining this Unit until 2027 or 2037.This Study takes into consideration both the current condition of the Unit as well as operation and maintenance factors that would impact the Plants operating and capital costs. 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 Unit 6 and Burns & McDonnell's professional opinion. Burns & McDonnell has also estimated capital expenditures and incremental O&M costs associated with operating the Unit until 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.

2.3 Study Contents

The following assessment details the current condition of the Unit and presents the capital expenditures and ongoing operations and maintenance costs that would be incurred with continued operation of this Unit 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 at industry standards versus shutting it down and either purchasing power or building a replacement facility. The critical physical components that will likely determine the Facility's remaining useful life include the following:

1. Steam generator drum, headers, and tubing
2. High energy piping systems
3. Steam turbine shell, rotor shaft, valves, and steam chest
4. Main generator rotor shaft, stator and rotor windings, stator and rotor insulation, and retaining rings
5. Cooling tower structure and underground circulating water piping
6. Control and electrical system obsolescence

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 ductwork, air preheater and FD fan
2. Steam turbine blades, diaphragms, nozzle blocks, and casing
3. Generator stator-winding bracing, direct current (DC) exciter, and voltage regulator
4. Condenser, feedwater heaters, balance of plant pumps and motors, controls, and auxiliary switchgear

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

3.0 SITE VISIT

Representatives from Burns & McDonnell, along with EPE staff, visited the Plant on May 14^{th} and 15^{th} of 2018. The purpose of the site visit was to gather information to conduct the life extension condition assessment by interviewing plant management, operations staff, and conducting an on-site review of the Unit.

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

1. Manuel Gomez, Senior Engineer
2. David Aranda, Plant Manager
3. Ronal Heckman, Principle Electrical Engineer
4. Ron Lamontine, Principle Maintenance Planner
5. Jesus Jimenez, Mechanical Engineer
6. Jorge Garcia, Operations Superintendent
7. T.B. Milikien, Maintenance Planner
8. Micah Manns, Maintenance Support
9. Orly Lujan, Maintenance Support
10. Jim Moyer, Maintenance Support
11. Paul Jordan, Preventative Maintenance Technician

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

1. Kyle Haas, Lead Project Analyst and Mechanical Engineer
2. Sandro Tombesi, Mechanical Engineer
3. Thomas Ruddy, Project Analyst

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

During the site visit, some items were identified to likely require replacement due to age including the controls and electric systems, boiler/high energy piping components, steam turbine components, cooling tower, motors, fans, and pumps.

4.0 BOILER

Rio Grande Unit 6 utilizes a natural circulation, radiant heat, pressurized boiler designed to burn natural gas in nine wall-mounted burners. This boiler includes a horizontal drainable superheater, one steam drum, and an elevated mud drum. The boiler was originally designed for a maximum continuous rating (MCR) of 450,000 lb/hr of steam at a superheater outlet condition of 875 psig and 910°F. The boiler does not have a reheater. The superheater outlet temperature is controlled by desuperheater sprays. The boiler design also includes a Ljungstrom type tri-sector air heater for flue gas heat recovery.

Unit 6 has utilized natural gas as the primary fuel source with the exception being in the 1970's when fuel oil was used for operation. Unit 6 is normally dispatched at 20 MW and is rarely ramped to meet demand. Boiler chemical cleaning was performed on a five-year cycle before the Unit was retired and last occurred in January 2011. EPE also takes tube samples periodically in high heat flux areas of the boiler to evaluate the extent of boiler tube scaling and determine the need for chemical cleaning of the boiler. Burns & McDonnell recommends chemical cleaning the boiler every five years if it is to operate until 2027 or 2037.

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

4.1 Waterwalls

The inner walls of the boiler are made up of vertical boiler waterwall tubes that are not connected with a membrane. Subcritical fluid is supplied from the steam drum to the waterwalls and is heated by the furnace flames before recirculating back to the steam drum.

BPI reported that the boiler waterwall tubes appear to be in good condition. Original tube thickness, per the Plant Data Book, was 0.150-inch (in). Tube thickness measurements were taken with the lowest reading of 0.146-in or 97 percent of the original tube thickness

Plant personnel reported that there have been several external tube ruptures at the bottom of the boiler near the mud drum. Furthermore, the waterwall tubes were reported to be blistering in several location which indicates potential overheating. Typically, the most common damage mechanisms that force replacement of the waterwall tubes are thermal fatigue and fire side corrosion. As plant personnel reported blistered tubes, Burns & McDonnell believes that the tubes are nearing end of life and should be replaced if the Unit is to operate until 2037.

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 superheater is divided into two stages, primary and secondary, with attemperators positioned between the sections. The Rio Grande Unit 6 boiler design allows for draining of both stages of the superheaters during outages and/or startup.

In 2011, BPI found several burned out tubes in the secondary superheater and severe bowing in both the primary and secondary superheater. Original tube thickness, per the Plant Data Book, was 0.180-in. The tube thickness measurements were taken with the lowest reading of 0.179-in or 99 percent of the original tube thickness. Furthermore, based on the 2009 condition assessment report, EPE replaced four superheater pendants in the past and one superheater pendant has been capped off. EPE has experienced very few superheater tube leaks.

Plant personnel reported that the attemperators have not been serviced and need an overhaul. Plant personnel also believe that the superheater is at the end of its useful life and should be replaced.

Burns & McDonnell recommends replacing the primary and secondary superheaters as well as overhauling the attemperator valves.

The high temperature headers include the primary and secondary superheater outlet headers. These headers operate under severe conditions and are particularly susceptible to localized overheating. These conditions can lead to creep damage and other stress related cracks caused by temperature imbalances side-to-side across the headers. BPI performed a visual inspection (using fiber optics), metallographic replication, and hardness testing on the secondary superheater outlet header. The visual inspection found no evidence of erosion, cracking, or corrosion. They did find some moderate to heavy scale buildup in areas. Two locations adjacent to the girth weld on the secondary superheater outlet header were examined using metallographic replication. Neither location showed evidence of micro-cracking or creep damage. Based on the examinations, BPI considered the header to be in good condition. Plant personnel reported ligament cracks in the secondary superheater outlet header.

Burns & McDonnell recommends replacing the secondary superheater outlet header when the secondary superheater is replaced.

4.3 Drums

The boiler mud drum receives feedwater from the boiler feed system and distributes it to the waterwall tubes. The steam/water mixture from the waterwalls then travels through the steam drum, which separates the steam from the saturated mixture, before being sent to the superheater. There is one 60-in diameter steam drum, one 42-in mud drum, and a lower waterwall header on the unit.

In 2011, BPI’s inspection of the steam and mud drums showed them to be in good condition overall with some minor issues being noted. There are no records indicating that the drums have been inspected with all internals removed.

Since the steam and mud drum are 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; and ultrasonic inspection of the welds and thickness readings at the normal water level.

4.4 Safety Valves

The safety valves are tested and recertified every five years by a third party as required by the facility’s insurance company. Also, 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.

4.5 Burner Control System

Unit 6 has no Flame Safety Shutdown and Startup Furnace Purge System (FSSS). This boiler was constructed before the National Fire Protection Association (NFPA) Codes required all boilers to have FSSS systems to prevent furnace explosions. It has continued to operate as a “grandfathered” unit, dependent on operators implementing appropriate burner ignition practices, which have been successful to date.

During the site visit, plant personnel also mentioned several issues associated with the gas interrupting valve.

Burns & McDonnell recommends installing new burners that comply with current NFPA standards and replacing the gas interrupting valve if the Unit is to operate until 2027 or 2037.

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 was visually inspected every year during the summer preparation outages with no significant problems being recorded. The inlet guide vanes were cleaned and inspected annually. The Bailey inlet guide vane positioners were replaced once during the life of the plant. In addition, vibration readings are taken monthly and trended as part of the predictive maintenance (PdM) program for rotating equipment. Oil samples are also taken monthly.

Plant personnel reported that the fan appears to be in good condition based on past inspections and on-going maintenance. A rub was reported to occur when the fan starts. Plant personnel also reported that the motor has never been pulled and would need to be cleaned, dipped, and baked or rewound.

Burns & McDonnell recommends inspecting and overhauling the FD fan for both life extension scenarios. Furthermore, Burns & McDonnell recommends pulling the motor and sending it to a shop to be rewound or clean, dipped, and baked if the Unit is to operate until 2027 or 2037.

5.2 Air Heater

Air heating is accomplished by one Ljungstrom type regenerative air heater. This heater was inspected by plant personnel during each annual outage with minor repairs done immediately. Based on the 2012 condition assessment report, the air heater baskets have not been replaced since 2002. BPI performed a limited visual inspection of the air heater from the cold gas discharge during the 2011 inspection. They found the baskets free of debris and the seals in good condition.

Plant personnel reported that the cold end baskets deteriorated when the Unit was tuned to operate with lower nitrogen oxide (NOx). By decreasing the firing temperature, the back-end temperatures were also lowered. Plant personnel also indicated that the hot and cold side lube oil pumps should be replaced, and the entire air heater should be thoroughly inspected.

Burns & McDonnell recommends inspecting the air heater. Furthermore, to operate reliably until 2027 and 2037, Burns & McDonnell recommends that the lube oil pumps and the cold end baskets be replaced.

If the Unit is to operate until 2037, it is also recommended that EPE replace the hot end and intermediate end baskets.

5.3 Flues, Ducts, Casing, & Structure

The ductwork transports combustion air to the boiler and transports hot flue gas away from the boiler, through the air heater, and onto the stack. Since the boiler has operated on natural gas for most of its life, the ducts and flues are 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.

Plant personnel reported a significant amount of casing leaks throughout the boiler and specifically in the roof/penthouse. There have been a higher number near the bottom of the boiler where the waterwall tube failure occurred. During the site visit, Burns & McDonnell also noticed several locations where the casing insulation was discolored indicating a hot spot.

Burns & McDonnell recommends taking a wholistic approach and replacing entire sections of boiler casing in problematic locations as well as continuing to inspect the ducts and flues for continued degradation if the Unit is to operate until 2027 or 2037.

During the site visit, it was also noted that EPE has never inspected the penthouse boiler supports. Burns & McDonnell recommends inspecting these supports for integrity when the casing is repaired in the penthouse.

5.4 Stack

The stack has not been inspected in recent years. Burns & McDonnell recommends inspecting the stack, particularly for structural integrity, as lower exhaust gas temperatures from tuning the boiler to operate with lower NOx increases the likelihood of corrosion in the backend.

5.5 Blowdown System

Unit 6 utilizes an intermediate pressure blowdown tank and a continuous blowdown flash tank to control 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.

In the 2012 condition assessment, it was reported that the blowdown tanks were visually inspected. There were no reports of significant problems with either tank or the ancillary equipment. During the site visit, a significant amount of corrosion was noted on the continuous blowdown tank. Burns & McDonnell recommends replacing the blowdown tanks if the Unit is to operate until 2027 or 2037.

6.0 STEAM TURBINE

Based on the 2012 condition assessment and site visit, the turbine has exhibited good operation and vibration levels. The last major turbine-generator overhaul took place during the 2006 outage. Water chemistry is well maintained at the Station and the Unit has not been cycled excessively.

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 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 HP and LP turbines were last overhauled by Siemens Power Generation during the spring 2006 outage. The HP and LP turbine sections were disassembled, inspected, and reassembled. A nondestructive examination (NDE) was performed on the HP, LP, and generator rotors and HP and LP rotor blades by Siemens NDE Group. Siemens Turbine Services machined the journals of the HP rotor and LP rotor. They also performed weld repairs on the nozzle block, No. 1 water gland sealing diaphragm, blended indications on the HP and LP rotor blades, and re-tapped cracked thrust bearing foundation studs. Siemens recommended replacing the HP and LP rotor and blade radial seals, replacing the No. 1 water gland sealing bellow diaphragm, and installing a new LP blade ring during the next outage.

Information provided by EPE for review shows the Unit heat rate has increased from ~11,700 British Thermal Unit (BTU)/kWh in 2014 to ~12,800 BTU/kWh in 2017. This increase could be attributed to several factors associated with the balance of plant equipment, mainly the condenser, but may also be associated with degradation of steam turbine performance. The 2012 condition assessment mentioned issues with solid particle erosion (SPE). SPE could be affecting the HP turbine which would increase the flow area in the turbine and decrease HP turbine efficiency. Furthermore, the machine may also be experiencing a significant amount of seal wear which would also impact performance. Since the turbine has not been overhauled since 2006, it is likely that there are several seal wear issues and potential SPE issues.

Plant personnel also indicated that the LP shell had a large crack that was repaired using a metal stitch process during the last outage. It is unclear what the condition of the stitch repair is or if the shell continues to expand which would require the LP turbine case to be replaced. Siemens did not mention this as an issue in the 2006 inspection report. Plant personnel also indicated that the water gland seals are leaking and would need to be overhauled. Finally, the seal oil gearbox is at the end of its life and requires replacement.

Burns & McDonnell recommends performing two major overhauls for the Unit if it is to operate until 2027 and three major overhauls if it is to operate until 2037. There may be a significant amount of discovery work during the initial overhaul as the Unit was last inspected in 2006. Burns & McDonnell recommends performing a steam path audit and borescope inspecting before the next outage to understand what issues may be present. Furthermore, Burns & McDonnell recommends inspecting the LP turbine shell to understand if it has reached end of life and whether the turbine can be disassembled and assembled without any issues. Burns & McDonnell believes there will be discovery costs associated with repairing the casing and has included costs to stitch weld the casing during the next turbine overhaul if the Unit is to operate until 2037. Finally, Burns & McDonnell recommends replacing the rotor and blade ring seals per Siemens recommendation in 2006 during the next outage.

6.2 Turbine Valves

The turbine valves, consisting of the main steam stop and control valves, were maintained on a four-year cycle, which proved to be adequate. In general, they have exhibited minor SPE when inspected. Information provided by EPE shows that there are no work order numbers associated with inspecting and overhauling the turbine valves since 2007.

Burns & McDonnell recommends overhauling the steam turbine valves per the OEM’s recommendations if the Unit is to operate until 2027 or 2037.

7.0 HIGH ENERGY PIPING SYSTEMS

7.1 Main Steam Piping

The main steam piping consists of 12-in schedule 100 pipe manufactured of seamless ASTM A335 P-22 material. The steam line transfers steam from the boiler superheater outlet header to the HP steam turbine. The system operates at approximately 875 psig and 910 ^{o}F.

Since this operating temperature is within the creep range (greater than 800°F), this piping system is of concern. Creep is a high temperature, time dependent phenomenon that can progressively occur at the highest stress locations within the piping system.

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. EPE has reported there is no P11, P12, or P22 seamed piping in Unit 6.

In 2011, BPI performed metallographic replications, magnetic particle testing, ultrasonic testing, and diametric measurements on several welds of the main steam line. 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 meets the original ASME requirements. Magnetic particle testing was performed at ten locations along the main steam line without any relevant indications found. Ultrasonic shear phased array testing was performed on the same ten locations without any relevant indications found. Diametric measurements were taken at six weld locations on the main steam line. All were within the allowable creep swell tolerance. Based on their findings, BPI considered the main steam line to be in good condition. Based on the age of the Unit, however, EPE should consider replacing the main steam line if the Unit is operated until 2037.

Burns & McDonnell recommends that the pipe support system continue to be visually inspected annually. The hangers should be inspected to verify they are operating within the indicated travel range, 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 another high energy piping condition assessment be performed in 2021 and every five years thereafter for both retirement scenarios.

7.2 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 of the main steam system.

During the site walkdown, it was noted that there did not appear to be any modifications to the extraction system regarding the ASME guidelines to prevent water induction into the steam turbine. 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).

However, the Unit does employ traditional level gauging and optical methods with alarms and sensors along with extraction steam non-return valve maintenance for protection.

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 recommended that EPE evaluate whether the Facility follows the ASME recommendations at Rio Grande Unit 6.

7.3 Feedwater Piping

The feedwater piping system transfers water from the deaerator storage tank to the boiler feedwater pumps, through the HP feedwater heaters, and eventually to the boiler drum. Although this piping operates 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.

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

Burns & McDonnel recommends performing testing on the extrados of the sweeping elbows, where turbulence can occur, causing excessive erosion/corrosion every five years for both retirement scenarios.

8.0 BALANCE OF PLANT

8.1 Condensate System

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

8.1.1 Condenser

Unit 6 is provided with a two-pass tube and shell condenser with divided water boxes. It consists of 25,000 square feet of 90-10 copper nickel alloy tubes. The condenser has never been retubed and experiences very few tube failures. Plant personnel reported no other issues. Burns & McDonnell recommends inspecting the condenser and hydrostatically testing both the hotwell and circulating water sides during the next outage. Based on the age of the Unit, Burns & McDonnell also recommends retubing the condenser if the Unit is to operate until 2037.

8.1.2 Condenser Vacuum System

The condenser vacuum system is used 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, a Westinghouse Steam Jet Air Ejector (SJAE), and by one 100 percent liquid ring Nash vacuum pump. Plant personnel reported that the hogging and vacuum pumps are in poor condition and should be replaced. Burns & McDonnell recommends replacing these pumps if the Unit is to operate until 2027 or 2037.

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 map data was available for the LP heaters. Plant personnel reported no issues with the feedwater heaters (FWHs). Since the feedwater heaters are the original equipment and are approaching 55 years of age there is some concern about their condition.

Burns & McDonnell recommends performing an eddy current test of the FWHs to understand if the tube bundles are at the end of life for both retirement scenarios. Burns & McDonnell also recommends performing NDE around the extraction inlet to each LP FWH to understand if there is any erosion caused by two phase flow for both retirement scenarios.

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 FWHs installed downstream of the feedwater pumps. These heaters were manufactured by Yuba Heat Transfer Corporation. 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 first point FWH (highest pressure) was replaced by Senior Engineering in 1993. The second point FWH is the original 1956 vintage Griscom-Russel unit which is in average condition.

Burns & McDonnell recommends performing an eddy current test of the FWHs to understand if the tube bundles are at the end of life for both retirement scenarios. Furthermore, as the first point heater operated 36 years before being replaced, indicates that EPE will have to replace a FWH tube bundle if the Unit is to operate until 2027 or 2037.

8.2.2 Deaerator Heater & Storage Tank

The open, tray type deaerator consists of a single vertical 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 the long seam welds, circumferential welds, and accessible penetrating welds during their 2011 inspection. No service-related indications were found. Plant personnel did report that the last time the internals were inspected, over 15 years ago, that there were several tray issues.

Burns & McDonnell recommends that the plant continue to perform visual inspections of the deaerator vessel at each unit planned outage.

8.3 Condensate and Boiler Feed Pumps

The two electric driven vertical condensate pumps manufactured by Byron Jackson are each rated at 920 gallons per minute (gpm) and supply 100 percent of the full load condensate system demand. Plant personnel reported that the condensate pumps are in good condition but that the motors would have to be rebuilt if the Unit is to operate until 2027 or 2037. Burns & McDonnell recommends that EPE send the motors out to be refurbished.

The two main 100 percent capacity boiler feed pumps (BFPs) are motor-driven barrel type Ingersoll Rand pumps rated at 1120 gpm. Both pumps were overhauled in 2004. Spare motors exist for both pumps. Plant personnel reported that the “A” BFP was replaced with a salvaged pump that is larger than originally designed. This pump has issues with cavitation due to its larger size versus system requirements. Plant personnel also indicated that the “B” BFP needs to be refurbished and that the recirculation valves are obsolete and replacement parts cannot be easily sourced. Burns & McDonnell recommends that both BFPs and BFP motors be refurbished and the recirculation valves be replaced if the Unit is to operate until 2027 or 2037.

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 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 motor driven horizontal centrifugal circulating water pumps were manufactured by Westinghouse. Each 50 percent capacity pump is direct driven by a Westinghouse electric motor. The circulating water piping is carbon steel. The lines under the powerhouse are encased in concrete.

Plant personnel reported that the circulating water pumps were refurbished in approximately 2011 and were installed with the wrong specification of oil. EPE decided to remove the oil skids and run the pumps with grease rather than correct the oil issue. This caused the pump bearings to run at higher than designed temperature. EPE believes that if the Unit is to operate until 2027 and 2037 then the pumps/motors should be refurbished, and the oil systems should be put back into service. Plant personnel also reported that the circulating water lines need to be relined. Additionally, if the Unit is to operate until 2027, some of the circulating water line would have to be replaced in sections and to operate until 2037, a significant portion of the circulating water line, especially the soil to air interface, would have to be replaced.

Burns & McDonnell recommends sending the circulating water pumps and motors out to be refurbished as well as commissioning the lube oil system. Burns & McDonnell also recommends inspecting the circulating water line to understand the overall integrity of the system. A large portion of the circulating water system may have to be replaced if the Unit continues to operate to 2027 or 2037.

The cooling tower is erected over a concrete basin having a clearwell at one end from which a 48-in effluent cooling water line gravity feeds over the Montoya canal to the horizontal circulating water pumps. The cooling tower is a Marley, 4-cell, cross-flow induced draft tower handling 33,610 gpm. It is designed for a range of 20°F with a 12°F approach at a 67.5°F wet bulb. The original cooling tower casings, gearboxes, and fans were replaced in outages in the late 1990s. The cooling tower is operated at 4.5 cycles of concentration. It is inspected annually, and the plant has expressed concern regarding the structural integrity. The fill in two cells was destroyed during winter due to icing.

Based on the site visit and information provided by plant personnel, Burns & McDonnell recommends replacing the cooling tower if the Unit is to operate until 2027 or 2037.

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 regeneration wastewater is directed to a polyvinyl chloride (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-in 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 from 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 6 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) are injected into the boiler steam drums for boiler water treatment. The cycle water treatment equipment is in adequate condition.

Circulating water treatment consists of the injection of sodium bisulfite and ammonia which is occasionally supplemented with bromine powder.

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.

Rio Grande Unit 6 does not incorporate a deluge system for the generator step-up transformer.

8.7 Bridge Crane

During the site visit, plant personnel reported several issues with the bridge crane. Based on its age and the recent failures, Burns & McDonnell recommends overhauling the crane, replacing the motors, and replacing the controls if the Unit is to operate until 2027 or 2037.

8.8 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 6 Electrical Systems

9.1.1 Generator

The generator is a 1955 Westinghouse unit rated 58.822 MVA at 13.8 kilovolt (kV). The stator output is 2,460 amperes (A) at a 0.85 power factor. The rotor and stator windings are hydrogen cooled. The exciter is a 1955 vintage direct current generator exciter rated 700 A at 250-volt direct current (VDC). The voltage regulator is a Westinghouse 1955 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. Loss of Potential (60)
12. Stator Ground (59GN)
13. 100 percent Stator Ground (27TN)
14. Frequency (81)
15. Inadvertent Energizing (50/27)

The generator was last inspected in 2006. Siemens Generator Services cleaned, electrically tested, and checked the core through bolt torque on the generator stator. Siemens Turbine Services machined the generator rotor journals and collector rings. The following tests were performed:

1. Insulation resistance (megger)
2. Dielectric absorption
3. El CID (stator iron)
4. Retaining ring ultrasonic inspection

The testing indicates that the generator is in good condition. Plant personnel indicated that the generator has never been rewound. Plant personnel also reported that the hydrogen cooling pumps need to be replaced with in kind spares that are at site. Plant personnel also believe that the original exciter should be upgraded to a static exciter. Finally, plant personnel indicated that the automatic voltage regulator should be upgraded to a system that includes a power system stabilizer.

Burns & McDonnell recommends replacing the hydrogen cooling pumps and the original exciter with a static exciter if the Unit is to operate until 2027 or 2037. In Burns & McDonnell's experience, EPE should also expect to rewind the generator if the Unit is to operate until 2037. Finally, Burns & McDonnell recommends that the EPE should replace the automatic voltage regulator with one that includes a power system stabilizer if the Unit is to operate until 2037.

9.1.2 Transformers

During the site visit, Facility representatives reported that all the transformers are maintained by the substation group.

9.1.2.1 Main Transformer (Generator Step-up Transformer)

The main generator step-up (GSU) transformer is a 2007, three-phase unit located outdoors near the turbine building. The GSU is rated at 45/60 MVA with a temperature rise of 55/65 degrees Celsius (ºC) 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.

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

1. Transformer differential (87)

2. Transformer neutral overcurrent (51N)

There are many factors that reduce a transformers theoretical insulation life such as exposure to through-faults, lightning strikes, ambient temperatures, etc. However, it is not unusual to find transformers with more than 50 years of service. Therefore, with the present testing and maintenance practices, the transformer should have enough remaining life to operate until 2027 or 2037 before significant maintenance or replacement is required. Burns & McDonnell recommends continuing the current inspection, maintenance and testing plan, including a dissolved gas analysis performed on a quarterly basis.

9.1.2.2 Auxiliary Transformer

The auxiliary transformer is a 2001, ABB, three-phase unit located outdoors near the turbine building. The unit auxiliary transformer is rated at 3,750/4,200 kVA at 14.4-2.4 kV with a temperature rise of 55/65 ºC and an impedance of 5.78 percent at 3,750 kVA. The oil preservation system is a nitrogen blanket type. 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 electromechanical circuit opening relay with these functions:

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

There are many factors that reduce a transformers theoretical insulation life such as exposure to through-faults, lightning strikes, ambient temperatures, etc. However, it is not unusual to find transformers with more than 50 years of service. Therefore, with the present testing and maintenance practices, the transformer should have enough remaining life to operate until 2027 or 2037 before significant maintenance or replacement is required. Burns & McDonnell recommends continuing the current inspection, 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 at 7.5 MVA and 66-2.4 kV. A naturally cooled cable bus rated at 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 runs from a load break switch to its associated unit medium voltage switchgear terminals.

The startup transformer is rarely heavily loaded and should have a long life. Burns & McDonnell recommends continuing the current inspection, 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 average condition.

9.1.4 Medium Voltage Switchgear

The original 1955 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 wide industry 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 unground delta system and the indicating voltmeters showed a balanced voltage to ground which indicates that there were no ground faults present at the time.

Plant personnel indicated that the switchgear was last cleaned and tested in 2016. Due to its age, Burns & McDonnell believes that the medium voltage switchgear is at the end of its life and should be replaced if the Unit is to operate until 2027 or 2037.

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.

The unit has two three-phase, 2.4-0.48 kV, vacuum pressure impregnated 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 300 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 7 480V main switchgear which allows operation of the plant until the failed transformer is replaced. The two cooling tower switchgear lineups do not have this tie feature. As the switchgear and load center transformer have already operated beyond the designed useful life, it is recommended that they are replaced if the Unit is to operate until 2027 or 2037.

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 V Motors

The 2.4 kV motors consist of the following:

1. Circulating Water Pump Motors – two 450 horsepower (hp)
2. Forced draft fan – one 800 hp
3. Boiler feed water pumps – two 900 hp
4. Condensate pumps – two 150 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. Plant personnel indicated that these motors should be sent out for refurbishment if the Unit is to operate until 2027 or 2037.

9.2 Station Emergency Power Systems

The Unit 6 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 was installed in 2005. Station batteries are designed for a 20-year life given ideal conditions meaning the batteries will have to be replaced if the Unit is to operate until 2027 or 2037.

The protective devices in the DC panels are operated infrequently and along with the DC panel itself. They 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 meaning the battery chargers will also need to be replaced if the Unit operates until 2027 or 2037.

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 last 40-50 years. 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

The Unit 6 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. These electromechanical relays will need to be replaced if the Unit is to operate until 2027 or 2037.

Furthermore, based on information supplied by plant personnel, the substation breaker is obsolete and should be replaced. Burns & McDonnell recommends replacing this breaker if the Unit is to operate until 2027 or 2037.

9.4 2.4 kV Cable

Unit 6 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. Burns & McDonnell recommends replacing the underground cabling if the Unit is to operate until 2037.

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 and repaired as a minimum.

9.6 Control Systems

Unit 6 is controlled via an Allen Bradley programmable logic controller (PLC). Unit 6 was constructed prior to the formation of NFPA 85 burner management requirements. Unit 6 has a manually supervised burner system with some fuel supply interlocks and trips. The Plant has a Panalarm annunciator system, but no sequence of events recorder function is provided. Bently Nevada vibration monitoring systems is installed on the turbine generator.

The continuous emissions monitoring system has not been upgraded or replaced since commissioned. As such, the system is becoming obsolete and should be replaced if the Unit is to operate until 2027 or 2037.

Burns & McDonnell recommends upgrading the burner management system to comply with NFPA 85 as well as upgrade the PLC system to a distributed control system (DCS) if the Unit is to operate until 2037.

The Unit 6 Panalarm system is obsolete and parts may be difficult to obtain. Upgrading the plant controls to a DCS will make the Panalarm system obsolete, as alarming and sequence of events recording capabilities will be included in the DCS.

9.7 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 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 steam turbine generator (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, Unit 6 has operated reliably given its age and the recent decline in maintenance expenditures. The Unit was designated to be in inactive reserve status (serves as a contingency reserve) in 2014. The 5-year average for EAF for the Unit is higher (or better) than the fleet benchmark and the 5-year average for EFOR is considerably lower (or better) compared to the fleet benchmark.

Figure 10-1: Equivalent Availability Factor (%)

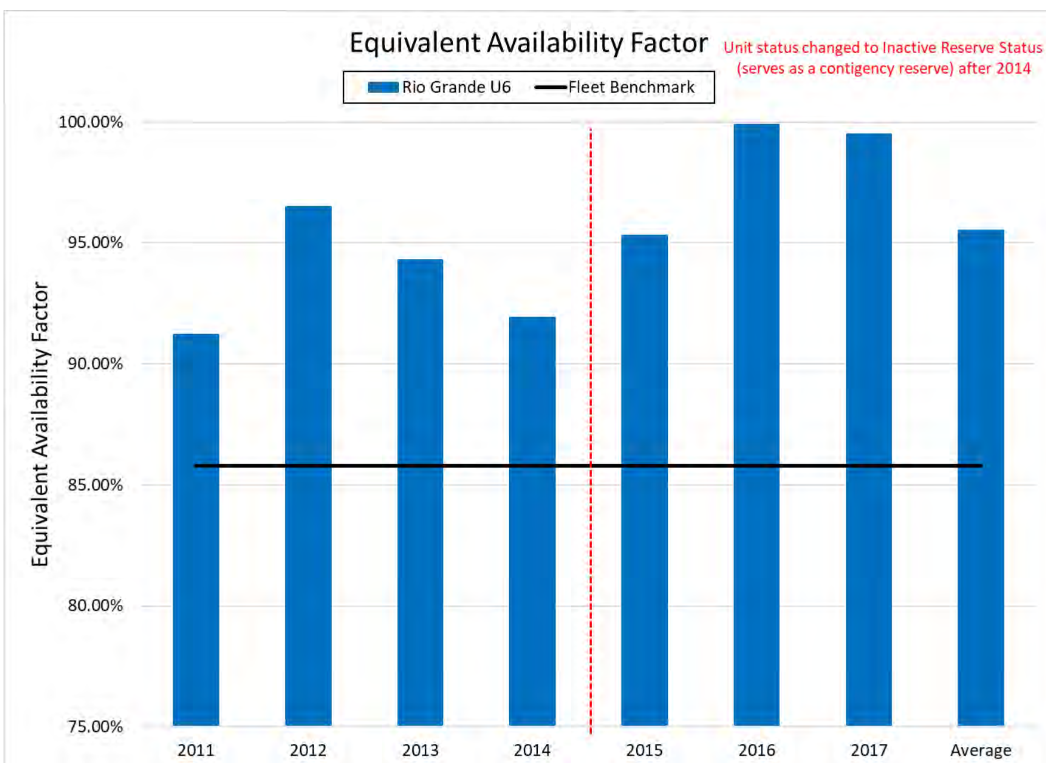
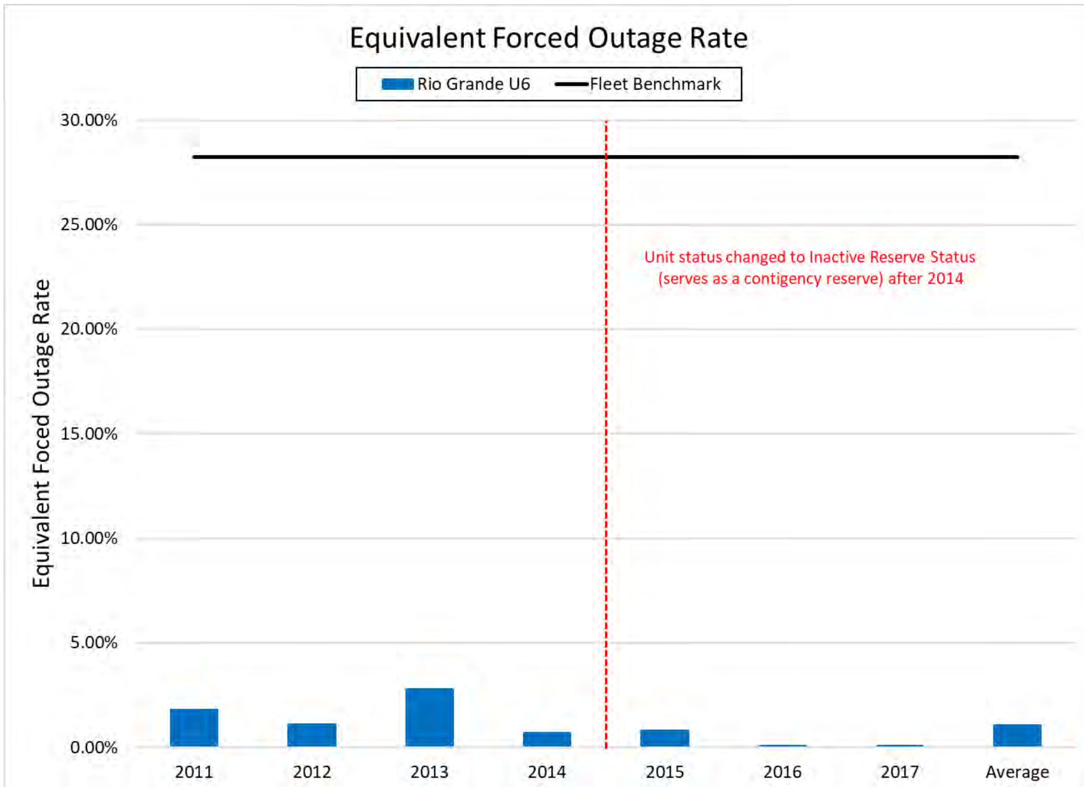


Figure 10-2: Equivalent Forced Outage Rate (%)



10.2 Capital Expenditures Estimate

The Unit was retired in 2014 but continues to operate in inactive reserve (serves as a contingency reserve Unit). 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. Perform STG major inspection and overhaul
3. Install new burners with FSSS standards

4. Comply with TDP-1

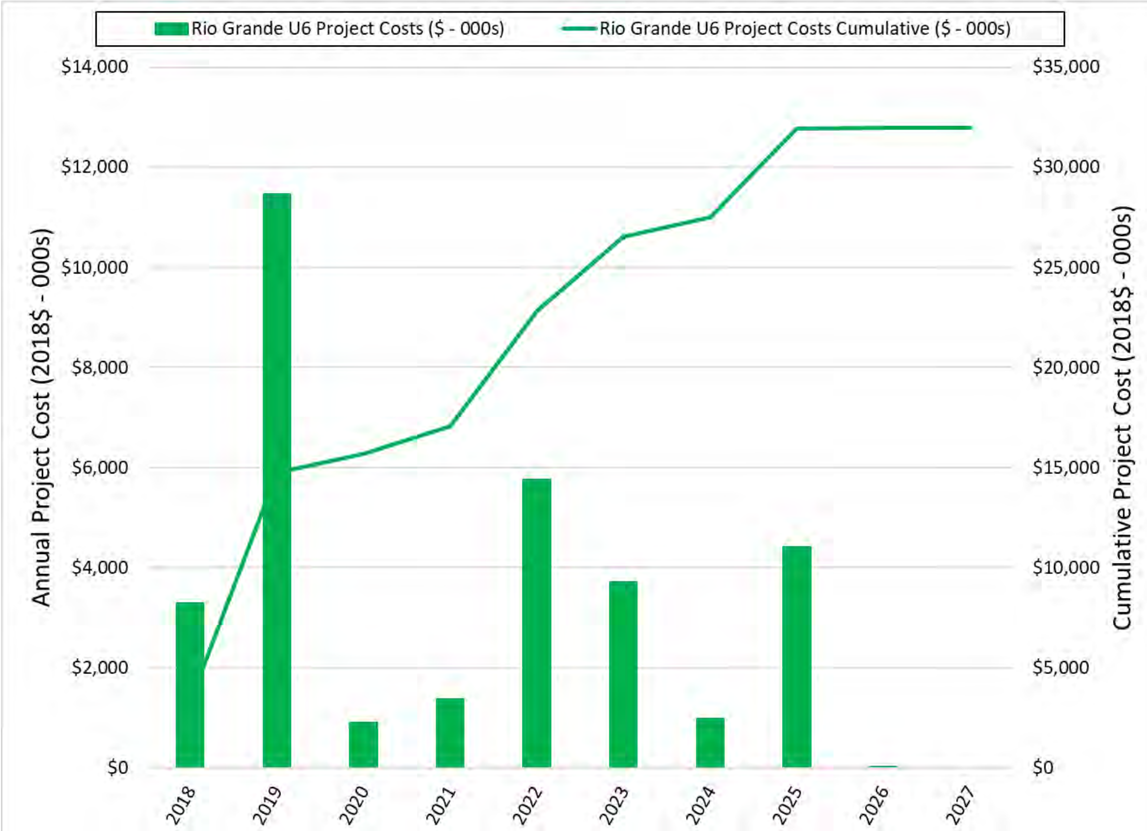
Likewise, the following non-recurring repairs and replacements are highly likely to be required within the next five years.

1. Overhaul of the superheater steam attemperators
2. Replace the air heater lube oil pumps
3. Replace the continuous blowdown tank
4. Inspect and overhaul of the FD fan
5. Replace sections of the boiler casing that are leaking
6. Replace the steam turbine rotor seals and blade ring seals
7. Replace the BFP recirc valves
8. Refurbish the circulating water pumps
9. Install a new liner in the circulating water pipes
10. Replace the cooling tower
11. Replace one FWH
12. Overhaul the crane and replace all motors and controls
13. Replace the switchgear and switchgear protection relays
14. Replace the original exciter with a static exciter
15. Refurbish the BFP, circulating water pump, condensate pump, and FD fan motors

Additionally, recurring maintenance events will need to occur, such as boiler cleanings, NDE inspections, STG major inspections, turbine valve inspections, and replacement of station batteries. 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 6 in 2018 dollars with no inflation included. Assuming the Unit is in service through 2027, infrastructure replacements and equipment upgrades would be required. For Unit 6, at a nominal capacity of 48 MW, a cost of nearly $32 million will be required to cover capital and maintenance expenditures through 2027, or $666/ kW.

Figure 10-3: Capital Expenditures Forecast through 2027



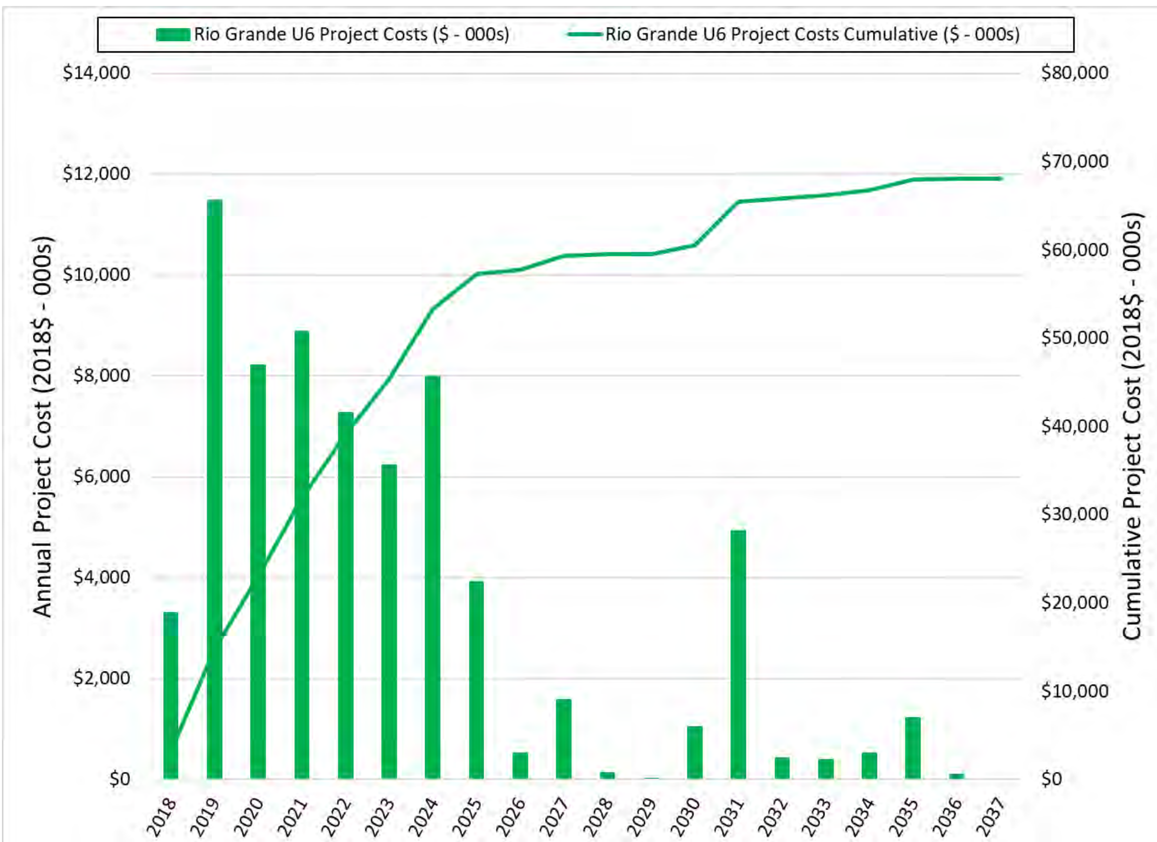
10.2.2 Life Extension through 2037

To extend the useful service life for the Unit until 2037, the projects listed in 2027 should be performed in addition to the projects listed below.

1. Replace the primary and secondary superheaters
2. Replace the waterwall tubes
3. Replace the circulating water bearings and re-commission the lube oil system
4. Replace the underground circulating water pipes
5. Inspection of the condenser and test it hydrostatically
6. Replace the hogger and vacuum pumps
7. Investigate feedwater heater tube life and the possibility of extraction inlet erosion
8. Replace the automatic voltage regulator (AVR) with a new system that includes power system stabilizer (PSS)
9. Upgrade the plant controls to a DCS

Additionally, recurring maintenance events will need to continue, such as boiler cleanings, NDE inspections, air heater cold basket replacements, STG major inspections, turbine valve inspections, and replacement of station batteries. 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 6 in 2018 dollars with no inflation included. Assuming the Unit is in service through 2037, infrastructure replacements and equipment upgrades would be required. For Unit 6, at a nominal capacity of 48 MW, a cost of approximately $68 million will be required to cover capital and maintenance expenditures through 2037, or $1,418/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). Units with capacity factors lower than 5 percent were excluded from the comparison since those units are used during large peaking loads only. The analysis indicates an upward trend of maintenance costs of approximately 1.25 percent per year. Figure 10-5 and Figure 10-6 present the fixed O&M costs for similar natural gas-fired steam generating power plants with Unit 6 highlighted.

Figure 10-5: Maintenance Cost Trend Evaluation

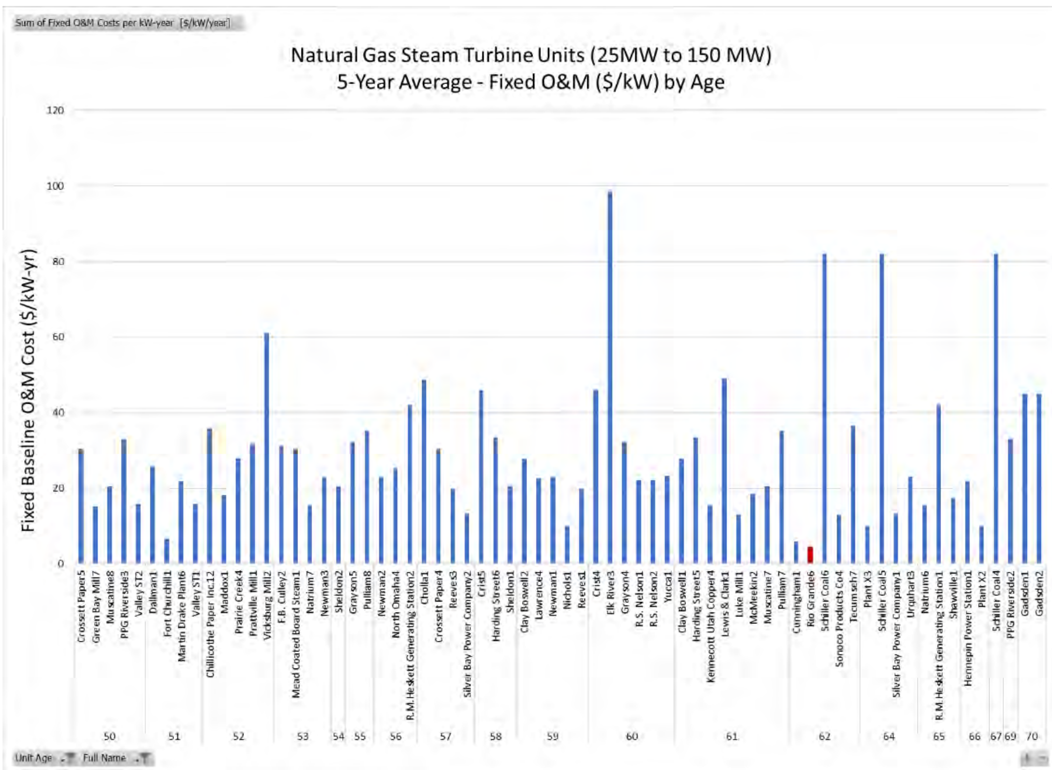
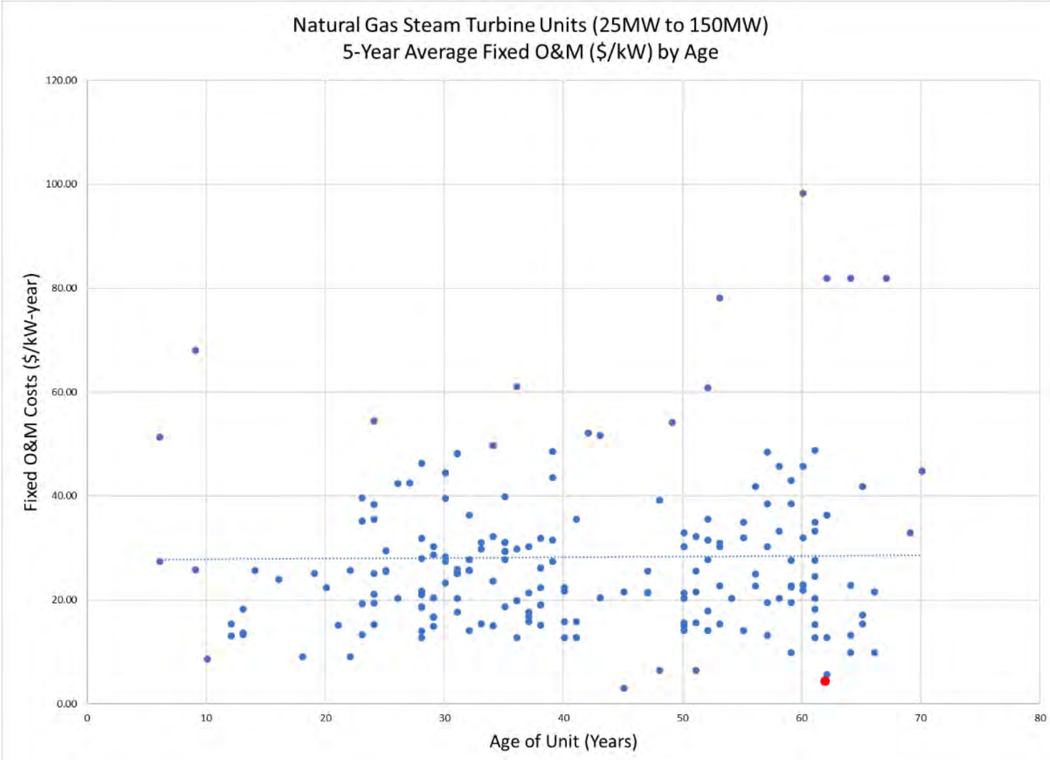


Figure 10-6: Maintenance Cost Trend Evaluation (X-Y Scatter)



In Figure 10-6 the two styles of operating older natural gas units can be distinguished. Units that fall near or below the trend line are being run until failure with limited capital investment and fixed maintenance spend. Units that are significantly above the trendline have taken proactive steps to extend the unit's life by heavily investing in capital upgrades and maintenance activities.

As discussed above, as power plants age the overall cost of maintenance increases at a rate of approximately 1.25 percent but Burns & McDonnell does not anticipate the Unit to maintain low fixed O&M costs of approximately $4.53/kW-year. Burns & McDonnell narrowed the benchmark to determine a more accurate estimate future fixed O&M maintenance cost. A narrowed benchmark analysis was performed on the units having similar natural gas-fired steam turbine generators in the 25 MW to 75 MW range. As of 2018, these units had reached a service life of 60 years or older and had an average capacity factor of at least five percent. A total of 14 power plants, consisting of 15 units, formed the basis of this focused benchmark. Characteristics of these units are provided in Table 10-1.

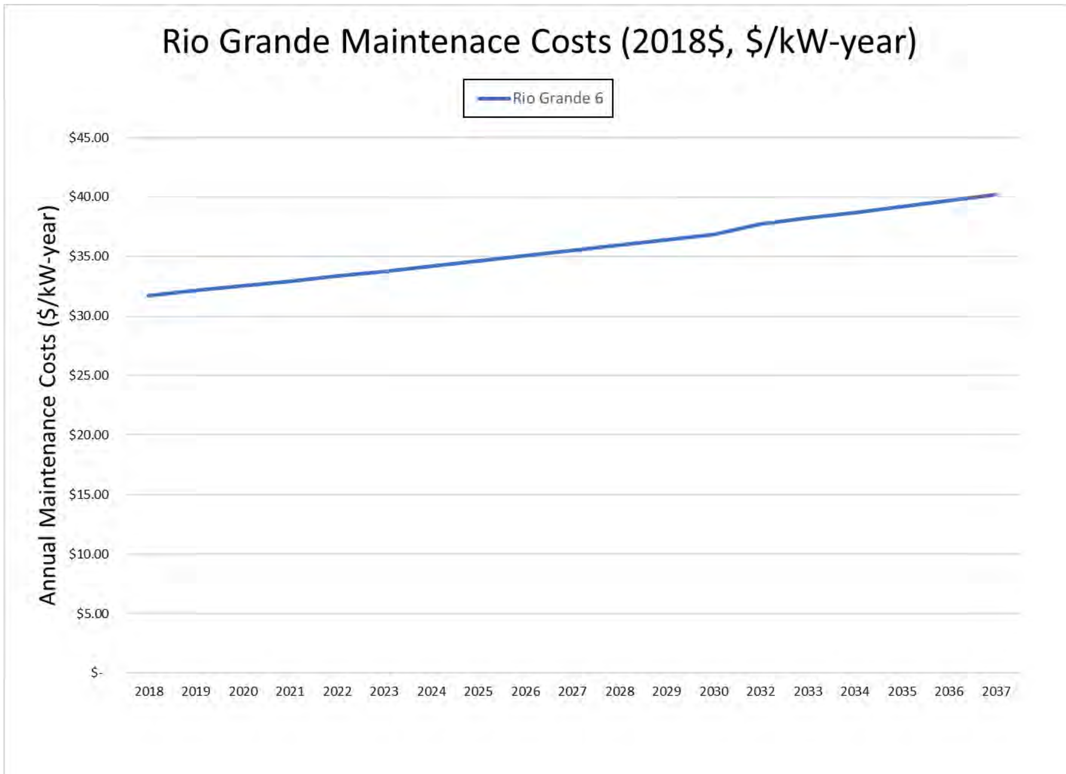
Table 10-1: Benchmark Units

Natural Gas-Fired STG Power Plants between 25 MW to 75 MW and at least 60 Years Old

Power Plant	Age of Unit 2018 (Years)	Operating Capacity (MW)	Fixed O&M ($/kW)	5-Yr Capacity Factor
Clay Boswell 1	61	75	27.81	78%
Cunningham 1	62	75	5.83	26%
Elk River 3	60	25	98.48	51%
Gadsden 1	70	69	45.06	24%
Gadsden 2	70	69	45.06	11%
Grayson 4	60	50	32.22	12%
Hennepin Power Station 1	66	75	21.85	64%
Lewis & Clark 1	61	50	49.06	56%
Luke Mill 1	61	35	13.01	47%
Muscatine 7	61	25	20.56	16%
Natrium 6	65	26	15.57	71%
PPG Riverside 2	69	45	33.09	28%
R.M.Heskett Generating Station 1	65	40	42.05	33%
Silver Bay Power Company 1	64	50	13.38	56%
Sonoco Products Co 4	62	28	13.01	32%
Average	64	49	31.74	39%

Using the average of the benchmarked units in Table 10-1, Burns & McDonnell assumes the Unit will require fixed O&M maintenance costs of $31.74/kW-year. At a rate of 1.25 percent, the maintenance costs would continue to increase for Unit 6 over time from approximately $31.74/kW-year in 2018 to nearly $40.19kW-year in 2037, excluding inflation increases. Figure 10-7 presents the maintenance cost projections for Unit 6. The costs presented in Figure 10-7 are presented in real, constant dollars (2018 dollars) without including inflation.

Figure 10-7: Maintenance Cost Forecast for Unit 6



10.4 Summary

Overall, the total capital and maintenance costs will be significant to extend the useful service life of the Unit. Table 10-2 presents the cumulative capital expenditures and maintenance costs over the periods from 2018 to 2027 and 2018 to 2037The costs do not include inflation. As presented in Table 10-2, Unit 6 will incur costs of approximately $1,002/kW for the 2018 to 2027 life extension scenario and $2,134/kW (2018 dollars) for the 2018 to 2037 life extension scenario.

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

Time Period	Total ($000)	Capital ($/kW)	Maintenance ($/kW)	Total ($/kW)
2018 to 2027	$48,081	$666	$336	$1,002
2018 to 2037	$102,445	$1,418	$716	$2,134

11.0 CONCLUSIONS & RECOMMENDATIONS

11.1 Conclusions

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

1. Rio Grande Unit 6 was placed into commercial service in June 1957. The Unit has reached 60 years of service and appears to be in fair condition considering its age. 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. Despite its age, the Unit has generally not exhibited a significant loss of reliability, which would be indicative of degradation of the major components. This is likely due to several factors including:
   a. Minimal cycling operation
   b. Proper attention to water chemistry
   c. Early adoption of a predictive maintenance program
   d. An arid climate
3. The Unit has performed reliable considering the Unit's retirement designation and age, however, many of the major components and equipment will need to be repaired or replaced to extend the service life of the Unit to nearly 70 or 80 years. Rio Grande Unit 6 could be capable of reliable 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.
4. Unit operations appeared to be well planned and carried out in a manner consistent with utility industry standards before the Unit was retired. Since retirement, only critical maintenance items have been performed. Burns & McDonnell believes that the maintenance budget will have to be increased from current levels to actively address issues which could affect operation and reliability of the unit.
5. With the increased penetration of renewable resources, traditional fossil-fueled generation need to provide greater flexibility to system operators to better optimize the power supply resources and costs to account for the variability and uncertainty associated with renewable resource generation.

The overall condition of Rio Grande Unit 6 appears to be in fair condition considering its age. 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 6 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.

11.2 Recommendations

The following is a summary of the recommended actions suggested to maintain the safe and reliable operation of Rio Grande Unit 6 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. Inspect the boiler safety valves and team valves
2. Inspect the penthouse boiler supports
3. Install new burners that comply with FSSS standards
4. Perform a boiler chemical clean and drum inspection
5. Clean, dip and bake the FD fan motor
6. Replace sections of the boiler casing in problematic locations
7. Perform a steam path audit and borescope inspection, including the LP shell, before a major overhaul
8. Inspect the main steam pipe support system
9. Perform NDE condition assessment of the high energy piping
10. Replace the cooling tower
11. Replace the gas interrupting valve
12. Investigate feedwater heater tube life and the possibility of extraction inlet erosion
13. Investigate if voids around drains may cause safety concerns

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

1. Overhaul superheater attemperators
2. Replace boiler piping
3. Replace the air heater lube oil pumps
4. Replace the continuous blowdown tank
5. Inspect and overhaul the FD fan
6. Replace the steam turbine rotor seals and blade ring seals
7. Make modifications to comply with highest value ASME TDP-1 guidelines

8. Replace the BFP recirculation valves
9. Refurbish circulating water pumps
10. Replace the circulating water pump bearings and re-commission the lube oil system
11. Inspect the condenser and test it hydraulically
12. Replace the hogger and vacuum pumps
13. Overhaul the crane and replace all motors and controls
14. Replace the medium voltage switchgear protection relays
15. Replace the switchgear
16. Replace the original exciter with static exciter
17. Refurbish the BFP, circulating water pump, condensate, and FD fan motors

The following is a summary of the recommended actions suggested to maintain the safe and reliable operation of Rio Grande Unit 6 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 the primary and secondary superheaters
2. Replace the secondary superheater header
3. Replace the waterwall tubes
4. Replace the hot and intermediate end baskets within the air heater
5. Replace the circulating water pipes
6. Replace the underground circulating water pipes
7. Consider adding Bentley Nevada vibration monitoring system
8. Replace the AVR with new system that includes PSS
9. Upgrade the plant controls to DCS
10. Replace the battery charger
11. Rewind the generator

Other recommended practices are described in the subsequent sections.

11.3 External & Environmental Factors

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

11.3.2 Boiler

1. Conduct regular 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 5-year schedule

11.3.3 Steam Turbine-Generator

1. Conduct steam turbine-generator inspections per OEM recommendations
2. Perform regular borescope examinations of the turbine

11.3.4 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. Perform testing on the extrados of the sweeping elbows, where turbulence can occur, causing excessive erosion/ corrosion
3. Visually inspect the main steam, hot reheat, cold reheat, extraction, and feedwater piping supports on an annual basis

11.3.5 Balance of Plant

1. Conduct eddy current testing of low pressure and high-pressure feedwater heater tubing.
2. Conduct regular non-destructive examination of the feedwater heaters, deaerator and deaerator 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

11.3.6 Electrical

1. Perform quarterly dissolved gas analysis on the main, auxiliary, and start-up transformers
2. Continue testing of the rectifier system and integrity of the anodes

APPENDIX A - COST FORECASTS THROUGH 2027

El Paso Electric, Inc.
Rio Grande Unit 6
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

CONFIDENTIAL

CAPITAL EXPENDITURES (Presented in $000)

DESCRIPTION	CATEGORY	LAST	FREQUENCY	NEXT	TOTAL	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
4. BOILER															
Inspect boiler safety valves regularly	Safety	Unknown	3	ASAP	$300	$100			$100			$100			
Inspect penthouse boiler supports	Industry Practice	Never	Once	ASAP	$200	$200									
Install new burners with FSSS standards	Safety	Never	Once	ASAP	$480	$480									
Overhaul superheater attemperators	Required	Never	Once	Within 5 years*	$600		$600								
Perform boiler chemical cleaning	Industry Practice	2011	6	ASAP	$1,200	$600						$600			
Perform regular drum inspections	Industry Practice	Unknown	3	ASAP	$300	$100			$100			$100			
Replace boiler tubing on an as needed basis	Required	N/A	3	Within 5 years*	$3,000		$1,000			$1,000			$1,000		
5. BOILER AUXILIARY SYSTEMS															
Replace air heater cold end baskets	Industry Practice	2002	10	2022	$400					$400					
Replace air heater lube oil pumps	Required	Never	Once	Within 5 years*	$80			$80							
Replace continuous blowdown tank.	Required	Never	Once	Within 5 years*	$500				$500						
Inspect and overhaul FD fan	Industry Practice	Unknown	Once	Within 5 years*	$150		$150								
Replace entire sections of boiler casing in problematic locations	Safety	Never	Once	ASAP	$800	$800									
Inspect stack	Industry Practice	Unknown	10	ASAP	$100	$100									
6. STEAM TURBINE															
Overhaul steam turbine	Industry Practice	2006	6	ASAP	$6,400		$3,200						$3,200		
Perform steam path audit & borescope inspection including LP shell	Required	Unknown	Once	ASAP	$300	$300									
Replace rotor and blade ring seals at next overhaul	Required	Unknown	Once	Within 5 years*	$1,000		$1,000								
Overhaul steam valves	Industry Practice	2007	4	ASAP	$2,400		$1,200				$1,200				
7. HIGH ENERGY PIPING SYSTEMS															
Inspect main steam pipe support system	Industry Practice	Unknown	1	ASAP	$180	$20	$20	$20	$20	$20	$20	$20	$20	$20	
Make modifications to comply with highest value ASME TDP-1 guidelines	Industry Practice	Unknown	Once	Within 5 years*	$300			$300							
Perform NDE condition assessment of energy piping	Industry Practice	2011	3	ASAP	$330	$110			$110			$110			
Test extrados of feedwater piping sweeping elbows	Industry Practice	2011	3	ASAP	$150	$50			$50			$50			
8. BALANCE OF PLANT															
Refurbish BFP A	Required	2004	15	2019	$250		$250								
Refurbish BFP B	Required	2004	15	2019	$250		$250								
Replace BFP recirculation valves	Required	Never	Once	Within 5 years*	$60			$60							
Refurbish circulating water pumps	Required	2011	Once	Within 5 years*	$300				$300						
Re-line circulating water pipes	Required	Never	Once	Within 5 years	$1,000					$1,000					
Replace bearing and re-commission lube oil system	Required	Never	Once	Within 5 years*	$250					$250					
Replace the cooling tower	Safety	Never	Once	ASAP	$3,000		$3,000								
Inspect the condenser and test it hydrostatically	Industry Practice	Unknown	Once	Within 5 years*	$200		$200								
Replace hogger and vacuum pump	Required	Never	Once	Within 5 years*	$250			$250							
Replace gas interrupting valves and regulators	Safety	Never	Once	ASAP	$250	$250									
Investigate tube life and possibility of extraction inlet erosion	Industry Practice	Unknown	Once	ASAP	$150	$150									
Replace one FWH tube bundles	Required	Never	Once	Within 10 years*	$1,500						$1,500				
Investigate if voids around drain may cause problems	Required	Never	Once	ASAP	$30	$30									
Overhaul crane and replace all motors and controls	Required	Never	Once	Within 5 years*	$500					$500					
9. ELECTRICAL AND CONTROLS															
Replace medium voltage switchgear protection relays	Industry Practice	Never	Once	Within 5 years*	$400		$400								
Replace station batteries	Industry Practice	2005	20	2025	$200								$200		
Replace switchgear	Industry Practice	Never	Once	Within 5 years*	$2,000					$2,000					
Replace original exciter with static exciter	Industry Practice	Never	Once	Within 5 years*	$500					$500					
Refurbish BFP motors	Industry Practice	Unknown	Once	Within 5 years*	$200		$200								
Refurbish circulating water pump motors	Industry Practice	Unknown	Once	Within 5 years*	$200			$200							
Refurbish condensate pump motors	Industry Practice	Unknown	Once	Within 5 years*	$200				$200						
Refurnish FD fan motor	Industry Practice	Unknown	Once	Within 5 years*	$100					$100					
Upgrade CEMS	Industry Practice	Unknown	Once	Within 10 years*	$500						$500				
Upgrade substation breaker	Required	Unknown	Once	Within 5 years*	$500						$500				
TOTAL															
TOTAL					$31,960	$3,290	$11,470	$910	$1,380	$5,770	$3,720	$980	$4,420	$20	$0

*Distributed over years to spread out expense

APPENDIX B - COST FORECASTS THROUGH 2037

El Paso Electric, Inc.
Rio Grande Unit 6
Burns & McDonnell Project No. 101955
Condition Assessment & Life Extension Assessment - 2037

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

CONFIDENTIAL

CAPITAL EXPENDITURES (Presented in $000)

DESCRIPTION	CATEGORY	LAST	FREQUENCY	NEXT	TOTAL	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
4. BOILER																									
Inspect boiler safety valves regularly	Safety	Unknown	3	ASAP	$700	$100			$100			$100			$100			$100			$100			$100	
Inspect penthouse boiler supports	Industry Practice	Never	Once	ASAP	$200	$200																			
Install new burners with FSSS standards	Safety	Never	Once	ASAP	$480	$480																			
Overhaul superheater attemperators	Required	Never	Once	Within 5 years*	$600		$600																		
Perform boiler chemical cleaning	Industry Practice	2011	6	ASAP	$1,800	$600						$600						$600							
Perform regular drum inspections	Industry Practice	Unknown	3	ASAP	$600	$100			$100			$100			$100			$100			$100				
Replace boiler tubing on an as needed basis	Required	N/A	5	Within 10 years*	$1,000									$500					$500						
Replace main steam piping	Required	Never	Once	Within 10 years*	$2,000							$2,000													
Replace primary and secondary superheaters	Required	Never	Once	Within 5 years*	$5,000			$5,000																	
Replace secondary superheater header when replacing secondary superheater	Required	Never	Once	Within 5 years*	$2,000			$2,000																	
Replace waterwall tubes	Required	Never	Once	Within 5 years*	$4,000				$4,000																
5. BOILER AUXILIARY SYSTEMS																									
Replace air heater cold end baskets	Industry Practice	2002	10	2022	$800					$400										$400					
Replace air heater hot and intermediate end baskets	Industry Practice	Never	Once	Within 5 years*	$1,000		$1,000																		
Replace air heater lube oil pumps	Required	Never	Once	Within 5 years*	$80			$80																	
Replace continuous blowdown tank.	Required	Never	Once	Within 5 years*	$500				$500																
Inspect and overhaul FD fan	Industry Practice	Unknown	Once	Within 5 years*	$150		$150																		
Replace entire sections of boiler casing in problematic locations	Safety	Never	Once	ASAP	$800	$800																			
Inspect stack	Industry Practice	Unknown	10	ASAP	$200	$100										$100									
6. STEAM TURBINE																									
Overhaul steam turbine	Industry Practice	2006	6	ASAP	$9,600		$3,200						$3,200						$3,200						
Perform steam path audit & borescope inspection including LP shell	Required	Unknown	Once	ASAP	$300	$300																			
Repair turbine casing	Required	2006	Once	Within 10 years*	$500								$500												
Replace rotor and blade ring seals at next overhaul	Required	Unknown	Once	Within 5 years*	$1,000		$1,000																		
Overhaul steam valves	Industry Practice	2007	4	ASAP	$6,000		$1,200				$1,200				$1,200				$1,200				$1,200		
7. HIGH ENERGY PIPING SYSTEMS																									
Inspect main steam pipe support system	Industry Practice	Unknown	1	ASAP	$360	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20	$20		
Make modifications to comply with highest value ASME TDP-1 guidelines	Industry Practice	Unknown	Once	Within 5 years*	$300			$300																	
Perform NDE condition assessment of energy piping	Industry Practice	2011	3	ASAP	$660	$110			$110			$110			$110			$110			$110				
Test extrados of feedwater piping sweeping elbows	Industry Practice	2011	3	ASAP	$300	$50			$50			$50			$50			$50			$50				
8. BALANCE OF PLANT																									
Refurbish BFP A	Required	2004	15	2019	$500		$250															$250			
Refurbish BFP B	Required	2004	15	2019	$500		$250															$250			
Replace BFP recirculation valves	Required	Never	Once	Within 5 years*	$60			$60																	
Refurbish circulating water pumps	Required	2011	Once	Within 5 years*	$300				$300																
Replace bearing and re-commission lube oil system	Required	Never	Once	Within 5 years*	$250					$250															
Replace the cooling tower	Safety	Never	Once	ASAP	$3,000		$3,000																		
Replace underground circulating water pipes	Required	Never	Once	Within 5 years*	$3,000					$3,000															
Inspect the condenser and test it hydrostatically	Industry Practice	Unknown	Once	Within 5 years*	$200		$200																		
Retube condenser	Required	Never	Once	Within 10 years*	$1,500							$1,500													
Replace hogger and vacuum pump	Required	Never	Once	Within 5 years*	$250			$250																	
Replace gas interrupting valves and regulators	Safety	Never	Once	ASAP	$250	$250																			
Investigate tube life and possibility of extraction inlet erosion	Industry Practice	Unknown	Once	ASAP	$150	$150																			
Replace one FWH tube bundles	Required	Never	Once	Within 10 years*	$1,500						$1,500														
Investigate if voids around drain may cause problems	Required	Never	Once	ASAP	$30	$30																			
Overhaul crane and replace all motors and controls	Required	Never	Once	Within 5 years*	$500					$500															
9. ELECTRICAL AND CONTROLS																									
Replace AVR with new system that includes PSS	Industry Practice	Never	Once	Within 5 years*	$300			$300																	
Upgrade plant control to DCS	Industry Practice	Never	Once	Within 5 years*	$3,500				$3,500																
Replace battery charger	Industry Practice	2005	25	2030	$50													$50							
Replace medium voltage switchgear protection relays	Industry Practice	Never	Once	Within 5 years*	$400		$400																		
Replace station batteries	Industry Practice	2005	20	2025	$200								$200												
Replace switchgear	Industry Practice	Never	Once	Within 5 years*	$2,000					$2,000															
Replace original exciter with static exciter	Industry Practice	Never	Once	Within 5 years*	$500					$500															
Replace UG cabling	Required	Never	Once	Within 10 years*	$3,000						$3,000														
Rewind generator	Industry Practice	Unknown	Once	Within 10 years*	$3,500							$3,500													
Refurbish BFP motors	Industry Practice	Unknown	Once	Within 5 years*	$200		$200																		
Refurbish circulating water pump motors	Industry Practice	Unknown	Once	Within 5 years*	$200			$200																	
Refurbish condensate pump motors	Industry Practice	Unknown	Once	Within 5 years*	$200				$200																
Refurnish FD fan motor	Industry Practice	Unknown	Once	Within 5 years*	$100					$100															
Upgrade CEMS	Industry Practice	Unknown	Once	Within 10 years*	$500						$500														
Upgrade substation breaker	Required	Unknown	Once	Within 5 years*	$500					$500															
TOTAL																									
TOTAL					$68,070	$3,290	$11,470	$8,210	$8,880	$7,270	$6,220	$7,980	$3,920	$520	$1,580	$120	$20	$1,030	$4,920	$420	$380	$520	$1,220	$100	$0

*Distributed over years to spread out expense

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BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR APPROVAL OF ABANDONMENT OF ITS RIO GRANDE POWER PLANT UNIT 6	)	
	)	**CASE NO. 20-00___-UT**
EL PASO ELECTRIC COMPANY, Applicant.	)	

DECLARATION OF JOSE L. GUADERRAMA IN SUPPORT OF THE FOREGOING DIRECT TESTIMONY IN EL PASO ELECTRIC'S APPLICATION FOR APPROVAL OF ABANDONMENT OF ITS RIO GRANDE POWER PLANT UNIT 6

I ***Jose L. Guaderrama***, 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 the *Senior Director of Operations.*

3. The foregoing Direct Testimony of Jose L. Guaderrama, 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 of Abandonment of its Rio Grande Power Plant Unit 6.***

FURTHER, DECLARANT SAYETH NAUGHT.

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

Executed on October 6, 2020.

_/s/_*Jose L. Guaderrama*

JOSE L. GUADERRAMA

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF EL PASO ELECTRIC COMPANY'S APPLICATION FOR APPROVAL OF ABANDONMENT OF RIO GRANDE POWER PLANT UNIT 6	)	
EL PASO ELECTRIC COMPANY, Applicant.	)	**Case No. 20-00___-UT**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on October 6, 2020, **El Paso Electric Company's Application for Approval of Abandonment of Rio Grande Power Plant Unit 6** were emailed to each of the following:

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DATED this 6th day of October, 2020.

/s/ Jeffrey J. Wechsler
Jeffrey J. Wechsler