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SAN DIEGO GAS & ELECTRIC COMPANY

PREPARED DIRECT TESTIMONY OF

CARL S. LAPETER

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

A Sempra Energy utility®

June 1, 2020

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ACRONYM GLOSSARY

APCD	San Diego Air Pollution Control District
BESS	Battery Energy Storage System
CARB	California Air Resource Board
CEC	California Energy Commission
CMMS	Computerized Maintenance Management System
CPEP	Cuyamaca Peak Energy Plant
CPUC	California Public Utilities Commission
CT	Combustion Turbine
CTG	Combustion Turbine Generator
CUPA	Certified Unified Program Agencies
GE	General Electric
D	Decision
DAQ	Clark County Department of Air Quality
DSEC	Desert Star Energy Center
ERRA	Energy Resource Recovery Account
ESRB	Electric Safety and Reliability Branch
GO	General Order
HRSG	Heat Recovery Steam Generator
MEF	Miramar Energy Center
MW	Megawatt
NDEP	Nevada Division of Environmental Protection
NERC	North American Electric Reliability Corporation
NOx	Nitrous Oxides
OEM	Original Equipment Manufacturer
ORA	Office of Ratepayer Advocates
PEC	Palomar Energy Center
RSEP	Ramona Solar Energy Plant
RWQCB	Regional Water Quality Control Board
SCR	Selective Catalytic Reduction
SDG&E	San Diego Gas & Electric
STG	Steam Turbine Generator
UOG	Utility Owned Generation
US EIA	U.S. Energy Information Administration
WECC	Western Electricity Coordinating Council

PREPARED DIRECT TESTIMONY OF
CARL S. LAPETER
ON BEHALF OF SDG&E

I. INTRODUCTION

This testimony presents San Diego Gas & Electric Company's ("SDG&E") compliance with the California Public Utility Commission's ("Commission") Good Utility Practice, as discussed below, and reasonable manager standards as defined in Decision (”D.") 02-12-069,[1] with respect to Utility Owned Generation ("UOG") resources planned and unplanned outages during the period of January 1, 2019 through December 31, 2019.

II. DESCRIPTION OF SDG&E-OWNED GENERATION

SDG&E owns and operates two combined-cycle generating facilities, the Palomar Energy Center in Escondido, California and the Desert Star Energy Center in Boulder City, Nevada. SDG&E owns and operates two peaking plants, Miramar Energy Facility in San Diego, California and Cuyamaca Peak in El Cajon, California. SDG&E also added two battery energy storage system projects to its fleet in early 2017; a 30 MW/120 MWh Escondido Battery Energy Storage System ("BESS") and a 7.5 MW/30 MWh El Cajon BESS. Lastly, a solar energy project located in Ramona, CA was also added to the portfolio that can produce up to 4.32 MW using smart inverters and fixed photovoltaic panels.[2]

A. Palomar Energy Center ("PEC")

The Palomar Energy Center is a 565 MW gas-fired combined-cycle plant with 2 GE 7FA combustion turbines and a GE steam turbine. The plant is equipped with inlet-air chillers and a thermal energy storage tank that allows the plant to produce energy at its capacity during the summer months. Recycled water is used for cooling of the plant equipment.

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[1] *See* D.02-12-069, Attachment A-3 at 5.

[2] The MW ratings used is this Testimony are electric generation ratings and may differ from plant interconnect ratings used elsewhere.

B. Desert Star Energy Center ("DSEC")

The Desert Star Energy Center, located in Boulder City, Nevada, is a 480 MW gas-fired combined-cycle plant with 2 Siemens 501-FC combustion turbines and a Westinghouse steam turbine. This plant was acquired by SDG&E in October 2011 pursuant to D.07-11-046. This Decision permitted SDG&E to exercise an option to purchase the facility from El Dorado Energy, LLC, a subsidiary of Sempra Energy.

C. Miramar Energy Facility ("MEF")

The Miramar Energy Facility is a peaking plant with two GE LM6000 turbines that together produce 92 MW (MEF-1 and MEF-2). This site also provides black start services used for restoration of the electric grid. Operations and maintenance personnel based out of the Palomar Energy Center provide all plant services to this facility.

D. Cuyamaca Peak Energy Plant ("CPEP")

The Cuyamaca Peak Energy Plant is a peaking plant with a Pratt & Whitney FT8 turbine generator set that produces 45 MW. Operations and maintenance personnel based out of the Palomar Energy Center provide all plant services to this facility.

E. Escondido Battery Energy Storage System ("Escondido BESS")

The Escondido BESS is a 120 MWh energy storage system with a maximum output of 30 MW for up to 4 hours. The energy storage system uses lithium-ion batteries. The project construction began Q4/2016 and began to operate commercially Q1/2017. Pursuant to CPUC Resolution E-4791 on May 26, 2016, SDG&E developed expedited energy storage projects to alleviate reliability issues associated with Aliso Canyon. CPUC approval was requested via Tier 3 Advice Letter 2924-E. The Advice Letter was approved in its entirety in CPUC Resolution E-4798 on August 18, 2016. Operations and maintenance personnel based out of the Palomar Energy Center provide all plant services to this facility. O&M costs for Escondido BESS are included in PEC O&M costs. Such costs are included as part of SDG&E's General Rate Case ("GRC").

F. El Cajon Battery Energy Storage System ("El Cajon BESS")

The El Cajon BESS was developed and constructed under the same authorization as the Escondido battery project and also uses lithium-ion technology. This energy storage system is rated at 30 MWh with a maximum output of 7.5 MW for up to 4 hours. Operations and maintenance personnel based out of the Palomar Energy Center provide all plant services to this facility. O&M costs for El Cajon BESS are included in PEC O&M costs. Such costs are included as part of SDG&E's GRC.

G. Ramona Solar Energy Project ("RSEP")

The Ramona Solar Energy Project, located in Ramona, CA, was developed and constructed pursuant to D.10-09-016 and SDG&E's Advice Letter 2374E-A. The project is built with fixed photovoltaic panels and can produce up to 4.32 MW. Operations and maintenance personnel based out of the Palomar Energy Center provide all plant services to this facility. O&M costs for RSEP are included in PEC O&M costs. Such costs are included as part of SDG&E's GRC.

III. COMMISSION STANDARDS RELATED TO SDG&E-OWNED GENERATION

During the record period, SDG&E operated and maintained its UOG resources (Palomar, Desert Star, Miramar, and Cuyamaca; collectively, SDG&E's "UOG units") in a reasonable and prudent manner, consistent with "Good Utility Practice" and the reasonable manager standard.[3] The Commission defined "Good Utility Practice" in D.02-12-069:[4]

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[3] The Commission has explained the "reasonable manager" standard in ERRA compliance cases, as follows: Under the "reasonable manager standard, utilities are held to a standard of reasonableness based on the facts that are known or should have been known at the time. The act of the utility should comport with what a reasonable manager of sufficient education, training, experience, and skills using the tools and knowledge at his or her disposal would do when faced with a need to make a decision and act." D.14-05-023 at 15. By meeting the "Good Utility Practice" standard and other Commission requirements stated herein, SDG&E maintains that likewise has met the "reasonable manager" standard during the 2018 record period. The Appendices to this testimony further provide SDG&E's primary showing with respect to both standards. In addition, the Commission recently has confirmed that the compliance review to which various SDG&E accounts are subject in ERRA compliance proceedings are not "reasonableness reviews." D.17-03-016 at 3 and Finding of Fact 2.

[4] *See* D.02-12-069, Attachment A-3 at 5.

> [A]ny of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice does not require the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the Western Electric Coordinating Council region.

Consistent with "Good Utility Practice," during 2019, SDG&E followed an established maintenance program to maximize the availability of the units as a primary "desired result." Specifically, this maintenance program factors in a number of considerations, including manufacturer guidelines, appropriate power industry practices, safety considerations, and good engineering and technical judgment to allocate resources most effectively to maximize availability of its UOG resources. Additionally, the SDG&E maintenance program incorporates practices that are generally accepted within the electric power generation industry and the Western Electricity Coordinating Council ("WECC").

Additionally, SDG&E is required to comply with the Commission's General Order ("GO") 167 - Enforcement of Maintenance and Operation Standards for Electric Generating Facilities.[5] Sections 10.0 and 11.0 of GO 167 specifically outline each generator owner's obligation to provide information and cooperate with Commission audits, investigations and inspections. In addition, each outage may warrant the creation of internal documentation, including but not limited to, equipment affected, parts replaced, work required to accomplish outage-related tasks, costs of repairs, other recommended actions that may be taken to mitigate a repeat of the failure, change to operating procedures required to address component or plant issues, changes to maintenance

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[5] Public Utilities Commission of the State of California, General Order No. 167 Enforcement of Maintenance and Operation Standards for Electric Generating Facilities (Effective September 02, 2005). Available at http://docs.cpuc.ca.gov/PUBLISHED/GENERAL_ORDER/108114.htm.

practices to improve reliability, communications with an original equipment manufacturer, and implementation of upgrades to improve reliability. Evidence of the above may be found in parts of the Computerized Maintenance Management System ("CMMS") ordering documents, as well as work orders, vendor invoices, investigation reports, management of change documents, and communications with vendors.

GO 167 also requires SDG&E to meet specific maintenance and operations standards, which also suggest guidance detailed for maintenance and operations programs. These standards and guidance are based on accepted power industry good practices. SDG&E is required to document and certify to these standards every two years and submit the documentation to the Commission Electric Safety and Reliability Branch ("ESRB"). The certification documentation includes a summary list of maintenance, operations and safety procedures that describe the programs and processes used in generation.

IV. ADDITIONAL REVIEW OF UOG OPERATIONS

Additional review of SDG&E's UOG operations is provided through Sempra Energy Internal Audit Department's audits of SDG&E's generating facilities. Consistent with auditing standards and industry best practices, the frequency and nature of such audits is determined based on the Internal Audit Department's annual risk assessment, which determines the areas of the company, including utility operations, to be audited. This risk-based analysis may change from year to year.

Further, SDG&E's Insurance Risk Consultants conduct site inspections to review and evaluate the plant's physical condition, maintenance, and operations processes. These inspections are performed from a risk perspective and cover maintenance practices, operations practices, material condition, and fire protection. The report may offer recommendations for improvement to systems, facilities, and processes.

SDG&E is also required to meet certain electric reliability standards from the North American Electric Reliability Corporation ("NERC") and WECC. NERC and WECC perform periodic audits of SDG&E to ensure compliance with the reliability standards.

Furthermore, SDG&E generation plants are subject to site visits from various regulators concerning implementation of permits. There are periodic onsite inspections and data requests concerning the implementation of requirements for air permits, water permits, and water discharge permits. SDG&E's Palomar Energy Center is also required to meet permit conditions detailed in the California Energy Commission ("CEC") Operating Permit.

SDG&E's Generation personnel have communicated with the following agencies in 2019:

- California Energy Commission ("CEC")
- California Public Utilities Commission ("CPUC")
- California Air Resource Board ("CARB")
- U.S. Energy Information Administration ("US EIA")
- Environmental Protection Agency ("EPA") Region 9
- Clark County Department of Air Quality ("DAQ")
- Nevada Division of Environmental Protection ("NDEP")
- San Diego Air Pollution Control District ("APCD")
- Regional Water Quality Control Board ("RWQCB")
- CA-EPA State Water Board
- City of Escondido
- Western Electricity Coordinating Council ("WECC")
- Certified Unified Program Agencies ("CUPA")

V. OUTAGES - UTILITY OWNED GENERATION

Many preventive and corrective maintenance work activities require planned outages, whereas unplanned corrective maintenance is performed under short-notice or forced outages.

Appendix A, below, provides narratives for forced outages 24 hours or longer for all facilities 25 MW or larger. Appendix B, below, provides narratives for planned outages that are 24 hours or longer for all facilities 25 MW or larger, where the outage was extended by two weeks or fifty percent longer, whichever is greater, from its planned schedule. The narratives address, as applicable, the following points:

1. The nature of the outage.
2. The cause(s) of the outage, if known.
3. Possible steps to prevent similar occurrences.
4. Whether the outage may have prevented (or minimized the duration of) a future outage.

VI. CONCLUSION

My testimony describes SDG&E's UOG resources located in San Diego County and Nevada. SDG&E consistently followed the Commission's guidance and "Good Utility Practice" and met the "reasonable manager" standard during the 2019 record period.

This concludes my prepared direct testimony.

VII. QUALIFICATIONS

My name is Carl S. LaPeter. My business address is 2300 Harveson Place, Escondido, CA 92029. I am currently employed by SDG&E as a Plant Manager for Palomar Energy Center, Miramar Energy Facility and Cuyamaca Peak Energy Plant. My responsibilities include overseeing a staff that operates and maintains these power plants.

I began employment at SDG&E in 2005 as Plant Engineer, and then Maintenance Manager, for Palomar Energy Center and Miramar Energy. My experience prior to employment at SDG&E (approximately 28 years) includes various positions in the US Nuclear Navy, at Palo Verde Nuclear Generating Station and Gila River Power Station.

I hold a Bachelor of Science degree in Nuclear Engineering Technology from Excelsior College in New York State.

I have previously testified before the Commission.

APPENDIX A

SDG&E's 2019 UOG Forced Outages Greater Than 24 Hours
For Facilities 25 MW or Larger

1. Palomar Energy Center ("PEC") Vibration Shutdown on Combustion Turbine Generator 1 ("CTg1") – January 14, 2019 through January 15, 2019 – 1.5 Days

On January 14, 2019 during a plant startup, the plant control system alerted the control room operator that CTG1 had an indication of high vibrations on the turbine bearing #1. The plant control system initiated a controlled shutdown for protection of the turbine; this protection is the intended function for high bearing vibration. Upon investigation the maintenance technician found the signal cable to the vibration instrument was frayed. The cable holder had worked loose allowing the cable to lightly touch the turbine shaft. The technician replaced the cable and properly secured and tightened the cable clamp. The unit was returned to service.

2. Cuyamaca Peak Energy Plant ("CPEP") Ammonia Tank Isolation Valve Failed to Open – January 14, 2019 through January 16, 2019 – 1.7 Days

On January 14, 2019 during a plant startup the ammonia tank isolation valve failed to open; this prevented the ammonia pumps from running. Ammonia is needed for the turbine exhaust catalyst to control Nitrous Oxide ("NOx") stack emissions. Due to the inability to control emissions, the operator shutdown the turbine.

A maintenance technician investigated and found a loose wire in the valve that was preventing it from opening; the technician corrected the problem. Operators started the turbine generator to verify proper operation of the ammonia system. When the ammonia system was verified to operate properly, operators shut down the turbine generator. During the shutdown, the operators saw that the generator breaker did not indicate that it was open. The maintenance technician investigated and identified Mechanism-Operated Control Auxiliary Switch ("MOC"), that provides the generator breaker open indication, did not operate properly. The technician investigated further and found bent linkage to the MOC switch, preventing proper operation. The technician repaired the linkage and restored the generator circuit breaker open indication. The unit was released for service.

3. Cuyamaca Peak Energy Plant ("CPEP") Loose Debris Inside Engine B – February 27, 2019 through March 14, 2019 – 15.2 Days

On February 27, 2019, plant operators were unable to start Engine B at CPEP; the unit was placed in a forced outage to troubleshoot the problem. Troubleshooting led to an inspection of the turbine bleed valves, where the maintenance technician found loose debris in the 3rd stage bleed valve area of Engine B. The maintenance technician was able to remove the debris; which appeared to be part of the 3rd stage bleed valve gasket. This debris prevented the proper operation of the 3rd stage bleed valve and was the cause of the starting problem for Engine B.

As a result of finding debris, Management decided to perform a complete borescope inspection for both Engines A and B. No additional debris was found in Engine B during the borescope inspection.

The borescope technician identified loose debris in the Engine A Power Turbine ("PT") inlet case downstream of High-Pressure Turbine ("HPT") exhaust. In addition, the borescope technician also identified a loose seal ring retaining bolt on Engine A PT Inlet Case.

This borescope technician was able to use special tools to extract two small pieces of metallic debris, without disassembling the turbine. The debris from Engine A was metallic; each part was less than 0.2 inches in size. The parts were sent to a lab for analysis where it was determined to be a nickel base alloy. The OEM was consulted and determined that the metal alloy debris was consistent with rivets used in the HPT exhaust case assembly. The parts did not cause any operating issues with Engine A and no further issues were identified.

The OEM was consulted regarding the loose seal ring bolt inside Engine A; it was determined that the work could be done onsite without removing the engine. Tightening the loose bolt required special tooling and an OEM field technician. The field technician arrived onsite and obtained the special tools from another local power plant with the same model turbine. By slightly separating the turbine case at a flange, the OEM field technician was able to tighten the loose bolt.

The unit was returned to service on March 14, 2019.

4. DSEC unit 2 High Pressure ("HP") economizer tube leak: Combustion Turbine 2 ("CT2") forced outage – March 27, 2019 through March 30, 2019 – 3.0 days

On March 27, 2019, after shutting down Unit #2 for a scheduled economic shutdown, water was discovered leaking from several Heat Recovery Steam Generator ("HRSG") drain penetration seals. A visual inspection from a lower access door determined the leak was located somewhere in an upper region of the high-pressure economizer section. The leak could not be specifically identified or repaired without unit cooldown and HRSG entry. At 13:00 on 3/27, a forced outage was declared. Spin cooling of CT2 began at 15:43 on 3/27 in order to cool the HRSG for safe entry and was completed at 22:30 on 3/27. HRSG entry was performed on 3/28, and the leak was found to be in an upper return bend weld on the HP economizer. Failures of this type are typically attributed to thermal shock during hot/warm starts in cycling plants, but they could also be attributed to steaming or buoyancy instability issues. Due to the difficulty involved in accessing and making a quality repair in an upper return bend, it was decided to plug both the associated upstream and downstream tubes at the bottom headers. The mechanical contractor began work on 3/29 and completed repairs on 3/30. Preparations were made to return HRSG 2 to service and CT2 was made available for dispatch at 13:00 on March 30, 2019.

5. PEC CTG1 Control System Trip – April 3, 2019 through April 4, 2019 – 1.1 Days

Following an outage, during the startup of CTG1, a turbine trip occurred. Plant staff performed troubleshooting to determine the cause of the trip. The CTG1 Control system appeared to be operating normally, and there were no controller logic problems or obvious indications of the cause of the trip. The plant staff decided to perform a redundant controller reset to reload the controller logic. After the reset, the plant operators performed a successful test start for CTG1; showing that the problem was resolved. The plant staff determined that the trip was due to a controller database corruption that was cleared by the controller reset. Following the controller rest, the unit was released and returned to service.

6. Desert Star Energy Center ("DSEC") steam turbine turning gear failure: full plant forced outage – April 23, 2019 through April 25, 2019 – 2.23 days

On April 23, 2019, after shutting down the plant for a scheduled economic shutdown, the steam turbine turning gear failed to engage. After inspection and direction from the turning gear assembly manufacturer, it was determined that the fiber gear located in the gearbox assembly had failed. The gearbox was thoroughly cleaned to remove any debris left behind from the fiber gear, and the fiber gear was replaced. Based on recommendations from the steam turbine manufacturer the turning gear was left off for two days, allowing the steam turbine to soak in the stationary position to avoid binding and possible damage due to distorted components. On April 25, 2019 at 08:48, the steam turbine turning gear was successfully started, and the plant was declared available for dispatch April 25, 2019 at 12:00.

7. DSEC Combustion Turbine 1 ("CT1") generator relay trip – CT1 forced outage April 30, 2019 through May 2, 2019 – 2.26 days

On April 30, 2019 during plant 2x1 operation, the CT1 Beckwith M-3430 generator protection relay tripped CT1 on differential current. Our electrical testing contractor was called out to investigate and troubleshoot the event. Upon inspection, leads from the current transformers were found with chafed insulation from long term vibration and relative movement, causing the leads to short together intermittently. This was determined to be the cause of the relay triggering. All leads were inspected and repaired. CT1 was declared available for dispatch on May 1, 2019 at 16:15.

CT1 was restarted on May 1, 2019 at 19:01, and immediately tripped again on differential current. It was determined that the electrical testing contractor followed plant drawings while repairing the current transformer leads. It was later determined that the plant wiring drawings were incorrect, causing the repaired leads to be landed with reversed polarity. The drawings were revised and the wiring was corrected. CT1 was successfully started May 2, 2019 at 12:07.

8. DSEC CT2 generator ground fault trip: CT2 forced outage May 21, 2019 through May 24, 2019 – 2.64 days

Shortly after CT2 was started, the Beckwith M-3430 relay tripped the unit on Neutral Overvoltage. After initial investigation, DSEC electrical testing contractor was mobilized to site to assist in location the ground fault. Testing and investigating revealed that excitation current transformer wiring became unsecured and contacted the 13.8 KV bus bar to excitation transformer resulting in path to ground, which caused the ground fault trip. The grounded wiring was removed, new wiring was pulled and properly secured away from exposed bus work. CT2 was declared available for dispatch on May 24, 2019 at 09:45.

9. DSEC unit 2 Low Pressure ("LP") preheater tube leak: CT2 forced outage – June 7, 2019 through June 9, 2019 – 2.58 days

On June 6, 2019, after shutting down the plant for a scheduled economic shutdown, water was discovered leaking from the HRSG stack expansion joint. A visual inspection from a stack lower access door determined the leak was located somewhere in an upper region of the low preheater. The leak could not be specifically identified or repaired without unit cooldown and HRSG entry. At 00:00 on 6/7, a forced outage was declared. HRSG entry was performed the morning of 6/7, and the leak was found to be in an upper return bend weld on the LP preheater. Failures of this type are typically attributed to thermal shock during hot/warm starts in cycling plants. Due to the difficulty involved in accessing and making a quality repair in an upper return bend, it was decided to plug both the associated upstream and downstream tubes at the bottom headers. The mechanical contractor performed the repair on 6/8. Preparations were made to return HRSG 2 to service, and CT2 was made available for dispatch at 14:00 on June 9, 2019.

10. DSEC unit 2 Intermediate Pressure ("IP") superheater tube leak: CT2 forced outage – September 9, 2019 through September 10, 2019 – 1.08 days

On September 9, 2019, after shutting down the plant for a scheduled economic shutdown, water was discovered leaking from a HRSG 2 drain penetration seal. A visual inspection from a lower access door determined the leak was located somewhere in a superheater section. At 09:00 on 9/9, a forced outage was declared. HRSG entry was performed on 9/9 and the leak was found to be in a lower tube-to-header weld on the IP Superheater. Failures of this type are typically attributed to incomplete draining of condensate during hot/warm starts in cycling plants. The leak was fixed using a weld repair method. The mechanical contractor performed the repair on 9/10. Preparations were made to return HRSG 2 to service, and CT2 was made available for dispatch at 11:00 on September 10, 2019.

11. DSEC unit 1 main steam boiler stop valve leak: CT1 forced outage September 22, 2019 through September 24, 2019 – 2.22 days

On September 22, 2019 during CT1 startup, the #1 main steam boiler stop valve began leaking large amounts of steam. The unit was shut down and a CT1 forced outage was declared. The DSEC valve maintenance contractor was dispatched to the site to disassemble the valve and make repairs. It was determined that the pressure seal gasket had failed and the contractor installed a new pressure seal gasket and reassembled the valve. CT1 was declared available for dispatch on September 24, 2019 at 19:00.

12. Palomar Energy Center (PEC) Water Hammer Event – December 2, 2019 through December 15, 2019 – 13.8 Days

During a plant startup on December 2, 2019 the Hot Reheat Steam Bypass Valve ("HRH Bypass") failed to operate properly. The HRH Bypass is designed to vary position, as needed, from 0% (closed) to 100% open, to provide the needed amount of steam bypass flow. The HRH Bypass is operated only from the plant control system, usually from the control room; the valve is not operated locally.

Control room operators noticed that the valve position feedback showed the valve at 0% open with a "Bad Quality" indication; the "Bad Quality" indicated a problem with the position signal. An operator was sent to visually check the HRH Bypass valve locally, and to assist the operator in the control room with troubleshooting the problem. The control room operator and local operator attempted to vary the HRH Bypass valve position but determined that the valve would only move to completely open (100%) or completely closed (0%) positions; it was not possible to adjust the valve to any intermediate position.

During the troubleshooting the control room operator noticed an HRH Bypass pipe high energy alarm; this is an early warning to avoid an excessive pipe temperature. The control room operator determined that the HRH Bypass Desuperheater Control Valve ("HRH bypass Spray") was closed; this valve controls water spray into the HRH Bypass to prevent the steam from overheating the pipe. The plant control system logic will close the HRH bypass Spray if the HRH Bypass indicates closed.

While working to regain control and coordination of the HRH Bypass and the HRH bypass Spray the local operator reported hearing a loud noise and seeing the HRH Bypass piping move. The control room operator heard the noise in the control room and noticed a loss of steam turbine condenser vacuum. In response to the loss of vacuum, the operators shut the plant down.

The operators determined that a "water hammer" event occurred in the HRH Bypass piping due to the valve control problem. The follow-up inspection by maintenance and plant management revealed that the HRH Bypass pipe had moved sufficiently to damage part of the HRH Bypass pipe, some pipe supports, and some deck grating around the pipe supports. The HRH pipe movement also damaged the pipe weld attachment to the steam turbine condenser; this damage allowed air to leak into the condenser and caused loss of vacuum.

The repairs were made and the plant restored to availability on December 15, 2019. Evaluation of the event showed that the plant control system logic can be changed to greatly mitigate the occurrence of this type of event. The logic can be altered to provide more assistance to the plant operators if the HRH Bypass valve indication fails. Operations, Engineering, and Management are discussing these control system logic changes. When the change is fully developed and vetted, we will implement it in the plant control system.

13. Miramar Energy Facility (MEF) Generator Breaker Failed to Indicate Open – December 21, 2019 through December 24, 2019 – 3.3 Days

On December 21, 2019 during a shutdown, the Generator Circuit Breaker failed to indicate open. This failure to indicate caused the 69 KV Bank 33 Breaker to open, which is a designed protective function. Technician performed troubleshooting and determined that the contacts in the Mechanism-Operated Control Auxiliary Switch ("MOC") switch were not operating correctly. The MOC was removed from the breaker and sent out for repair. Following the repair, the plant staff successfully completed functional testing of the breaker and released the unit for service.

APPENDIX B

Planned Outages During 2019 That Were 24 Hours or Longer for All Facilities 25 MW or Larger
That Were Extended by Two Weeks or Fifty Percent Longer,
Whichever is Greater, From its Planned Schedule

There were no Appendix B outages in this reporting period.