XL INSURANCE

Power Generation All-Risk Report
City of Dover
McKee Run and VanSant Generating Stations
Dover, DE 19904, USA.

Date of Survey: March 09, 2017

Inspected by:

Mr. Neal Grabow, N-Tec Services, Energy Loss Prevention Consultant

Participants:

Mr. Jacob Aucoin	**Plant Engineer, NAES**
Mr. Stacy Johnson	**Plant Manager, NAES**
Mr. Daniel Corrigan	**Electrical Superintendent - City of Dover**

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1 Summary

1.1 Introduction

XL Insurance is dedicated to serving the energy industry through world-class engineering knowledge and expertise. We believe the human element aspect of operations and maintenance is most critical for assuring safe, reliable, and productive facilities. We define human element to mean the ability of personnel at a plant to have the training, experience, and support to recognize the incipient signs of equipment failure and to react positively to modify their practice or operation to prevent rather than recover from potential losses. Reacting to and modifying the risk, such that incidents leading to disruption of production are recognized and the root cause eliminated in their earliest phase, defines best practice. To this end, we provide the following assessment report based on guidelines, which we believe to be the best practices for the power generation industry.

The 175 MW City of Dover power plants at McKee Run and VanSant in Delaware, USA, were visited by Mr. Neal Grabow, N-Tec Services, Energy Loss Prevention Consultant on March 09, 2017. This is the ninth visit by XL, the purpose of which is to provide a continuing engineering risk evaluation and loss prevention assessment survey with respects to All Risks and Machinery Breakdown insurance coverage.

The survey included initial discussions as to the purpose of the visit, detailed discussions with respect to recommendations, operation, maintenance and fire systems followed by a walk-around of the McKee Run Generating Station and the VanSant Generating Station. The McKee Run and the VanSant units were off line at the time of this visit. An exit meeting was conducted with Mr. Stacy Johnson, Mr. Jacob Aucoin and Mr. Daniel Corrigan to discuss the status of recommendations, plant conditions observed and power generation industry issues. Units 1,2 and 3 at the McKee Run Station and the one unit at Van Sant were off line at the time of this visit. A routine borescope inspection was being performed on the Van Sant unit at the time of this visit.

Based on a request from the City of Dover during the 2015 visit the previously closed recommendations and the equipment repairs/maintenance history information is located in the appendix section of this report, in an effort to provided easier review of the current conditions.

The City of Dover, Delaware Electric Department

Founded in 1683 by William Penn, the City of Dover is the capital of Delaware and owns its own electricity generating stations at McKee Run and VanSant. The McKee Run generating station consists of three steam turbine/generating units with a total generating capacity of 136 MW (Net). The VanSant generating station consists of a single GE frame 6B gas turbine generating unit with a capacity of 39 MW, this unit operates in simple cycle mode.

The City of Dover electrical department supplies in excess of 23,844 customers within the City and the surrounding area. The whole area is located in the middle portion of the state of Delaware, with the city itself being approximately 70 miles (112.6 km), from Philadelphia, Pennsylvania.

In addition, the City is an associated member and interconnected with the PJM Power Grid where it regularly transacts purchases and sales of electricity to achieve the lowest reasonable cost for its customers.

The McKee Run generating station is a three-unit natural gas/oil fired power plant. Units One and Two are Westinghouse 17 MW net steam turbine generators with associated Babcock & Wilcox 160,000 lb. /hr

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boilers. Unit Three is a 102 MW net GE steam turbine, with reheat, and generator with a Riley Stoker 786,000 lb. /hr boiler.

Power generated from Units 1 and 2 is stepped up to 22.9 kV via separate 25 MVA GE Generator Step Up transformers (GSU). The plant is not responsible for the maintenance of GSU 1&2. Power generated from Unit 3 is stepped up to 69 kV via a 130 MVA McGraw Edison GSU. The plant is responsible to maintain GSUs for Unit 3 and for VanSant Unit 11.

VanSant is an unmanned simple cycle 39MW GE Frame 6 combustion turbine generator. Power generated is stepped up to 69 kV from 13.8 kV via a 46 MVA GE GSU. Operating personnel are dispatched from the McKee Run plant.

The NAES Corporation (NAES), a broad-based provider of services to the power generation industry, was selected by the City of Dover, Delaware Electric Department (City of Dover) as its operations and maintenance provider for the McKee Run and VanSant Electric Generating Stations. NAES' contract is with the City of Dover and they were working very closely with Pace Global Asset Management, LLC (Pace Global), the selected Asset/Energy Manager until their contract expired on June 30, 2011. NAES, in partnership with Pace Global, provided comprehensive operations and maintenance services in support of the City of Dover's 175 MW of power generation assets. On July 1, 2011, The Energy Authority (TEA) assumed the role of the City of Dover’s Asset Manager and is working closely with NAES in this current relationship.

In the previous years the McKee Run and VanSant stations have been in standby mode, with the McKee Run units having a 10 hour recall/start-up time for operation and VanSant having a one-hour time period. Further reduction in operation time was seen in 2008 and 2009, however, in 2010 the hours of operation were increased as a result of economic fuel pricing. The hours of operation for Unit 1 increased in 2011 however the operating hours for Unit 2, Unit 3 and Unit 11 decreased to approximately half of the 2010 hours. (Unit 1 had been in a forced outage in 2010 which limited the number of operating hours as compared to Unit 2. Typically, the units operate the same approximate hours). In 2012, The McKee Run units operated approximately the same number of hours as in 2011. The VanSant unit operating hours decreased to only 22 hours. In 2013, Unit 1 at McKee run was only started twice and operated a total of 74 hours, a decrease of 22 hours from 2012. Unit 2 was started four times with a total of 170 hours, an increase of approximately 100 hours from 2012. Unit 3 was started 13 times in 2013 and operated 183 hours a decrease from 29 starts and 369 hours in 2012. The VanSant unit started 33 times with 479 hours in 2013, a decrease from 2012, when the unit was started 60 times with 561 hours. In 2014 the units operated slightly more than 2013. Unit 1 was started eight times and operated 91. 8 hours. Unit 2 started nine times with 92.8 hours of operation. Unit 3 was started 50 times in 2014 and operated 649.6 hours. The Van Sant unit was started 13 times in 2014 and operated 50 hours. The unit operating time was reduced in 2015 compared to 2014. Unit 1 was only started one time with a total operating time of 7.8 hours. Unit 2 was started three times and operated 10.1 hours. Unit 3 was started 26 times in 2015 with 324 operating hours. The VanSant operations was increased in 2015 compared to 2014. The VanSant unit was started 16 times with 72 hours of operation in 2015. In 2016 the Unit 1 and Unit operating times were again reduced Unit 1 was started on time and operated 6 hours. Unit 2 was started twice with a total of 4.3 hours in 2016. The operating time for Unit 3 increased in 2016 to 791 hours with 37 starts. The Van Sant unit operated 31 hours with 14 starts in 2016, slightly less than in 2015.

The City of Dover is currently planning for the plant to be available for service another 10 -15 years. The City of Dover City Council voted on February 10, 2014 to remove Units 1 and 2 from operating service as of approximately June 30, 2017. Units 1 and 2 are currently expected to be retired on June 01, 2017.

Principal Changes

The station was built in two separate stages with Units 1 and 2 built in the early 1960’s and Unit 3 built in the early 1970’s.

In 1972, Units 1 and 2 were converted to burn #6 fuel oil.

Turbine controls were upgraded in 1997.

NOx reduction work on Unit 3 boiler was carried out in 2003 along with an ABB Net 90 system upgrade producing a 20% reduction in NOx production. A Burner Management upgrade to an ABB Net 90 system was installed to comply with NFPA requirements for burner shutdowns and to interface more readily with the existing turbine control system.

Partial (65%) waterwall replacement carried out in 2000 on Unit 3 boiler.

The VanSant Gas turbine generator was re-wedged and a Hot Gas Path Inspection took place in 2004 (GE).

The McKee Unit 2 steam turbine generator end rings were changed for 18/18 in 1997.

The heat/smoke detection system for each Unit 3 burner deck is now complete and operational.

The McKee Run site which includes Units 1, 2 and 3 was completely changed over from No. 6 oil to No. 2 oil. Included in the modifications were new gas burners and flame eyes installed. Modifications carried out to the BOFA port openings to assist with NOx reduction and redesign of the Unit 3 fuel system at the burner front to allow for better staging of the fuel at the burners.

Unit 11 Stack Repairs, these repairs were made in 2008. Subsequent inspections have not indicated any more degradation of the stack.

A ten kilo-watt solar system was installed on the roof of the turbine building at the McKee Run station in 2010.

The cyclone separators have been removed from all three boilers and the Unit 3 air-side outlet expansion joint has been replaced.

An Arc Flash analysis has been completed. The electrical equipment has been marked and plant policies and practices have been updated. Personnel training and labeling are expected to be completed by May 01, 2011.

The VanSant controls were upgraded to a PLC based control system in 2010.

Fire protection was installed in the Administration Building and the Warehouse in 2010.

Hot water pump and fuel oil transfer pump switches were relocated from Unit 1/2 control panel to Unit 3. This will allow the Unit 3 Control Room Operators to oversee and have direct control of this equipment.

The Unit 1 and Unit 2 boiler combustion controls were upgraded in 2011.
The Unit 1 and Unit 2 turbine valves were disassembled and inspected in 2011. A borescopic inspection of the first stage nozzles was completed at the same time.

The Net 90 control system PCs were upgraded in 2012.

New deck valves and vent valves were installed in the gas train for Unit 3 boiler.

The Unit 3 gas piping was ultrasonically inspected and an orifice plate access platform was installed in 2011.

The 1B circulating water pump was sent out for inspection and repairs in 2011 and was returned in

February 2012.

New gas purge and equipment lay-up procedures were developed and implemented in 2011.

The hydrogen gas fill line was replaced in 2011.

The vibration monitoring display for Unit 3 is slated for an update from a chart recorder to an electronic display in 2012. The recorder has been already been purchased.

A Man-Down alert system was implemented in early 2012.

A plotter/scanner was purchased to allow transferring plant drawings and documents to electronic format.

The plant has a VanSant simulator for training and trouble shooting.

New intake filters for the turbine and generator were installed for the VanSant unit.

New access steps over the dike for the fuel oil tank at VanSant were installed.

New Beck Drives installed on the inlet and outlet dampers of Unit 3 Induced Draft, and Forced Draft fan and on the inlet damper to the BOFA Fan.

Fire barrier walls were installed between the Units 1 and 2 auxiliary transformers and the Unit 3 start-up transformer.

A new governor was purchased for Unit 3 and installed in 2012.

A vacuum-dehydrator skid was also purchased and is expected to be used to condition equipment lubricating oil.

Unit 3 Air Heater sector plates and seals were replaced in 2012.

New portable vibration monitoring equipment was purchased and a vibration monitoring program has been developed.

The warehouse inventory accounting was transferred to the City's accounting system (HTE).

Unit 3 generator dismantle was completed in the Spring 2013.

NAES Maintenance Staff installed modifications to the piping on the Unit 1 & 2 lube oil system storage/transfer system to allow for the connection of a portable Hy-Pro lube oil processing unit. Valving was installed so the conditioning unit could be easily connected to either unit to aid in the cleaning and purifying of the lubricating oil.

A nitrogen generator was installed at the McKee Run Station in 2016 to improve the plant lay-up practices.

A water injection system was installed on the Van Sant Unit in 2015 for power augmentation and NOx control.

The plenum for the Van Sant Unit was replaced in 2016.

1.3 Future Developments

A Capital improvement schedule has been developed and is expected to be implemented as time and budgets allow.

Unit 1 and Unit 2 are scheduled to be retired from service in 2017.

Unit 3 turbine/generator are scheduled for a valve outage in 2018.

The VanSant unit is scheduled for a major outage in 2018.

The Van Sant CO2 fire suppression system will be replaced with a water mist suppression system in 2018.

1.4 Incident Experience & Loss History.

At approximately 6:10 PM on July 06, 2010, the Unit 1 control room operator noticed that there was a rapid drop of boiler steam pressure and drum level, well below their normal operational conditions. During that same period of time a loud “BOOM” sound was heard in the location of Unit 1 boiler. Immediately following the loud noise, thick smoke was seen emanating from Unit 1 boiler and ductwork.

Examination of the boiler revealed that three sides of the boiler casing had expanded outward. The north, east and west walls were all effected. The west wall of the boiler was the worst of the three walls, expanding 18 to 24 inches in some areas and pressing against the I-beam support structure for the unit. A steam generating tube ruptured and was opened wide enough to make it appear flat. The tube rupture would account for the rapid loss of steam pressure and drum level. A section of the ruptured tube measuring approximately 8 feet in length was replaced.

It has been concluded that the sudden release of steam from the boiler tube rupture displaced the oxygen in the furnace causing the flames in the boiler to go out. This sudden release of steam would have occurred in a matter of seconds. During that same period of time the forced draft and induced draft fans were still in operation causing the steam that was released to then be displaced from the furnace area and replaced with fresh air. Because Unit 1 boiler is primarily a manually operated unit the natural gas fuel continued to enter the furnace area after the tube rupture and until the control room operator activated the manual fuel trip button located in the control room and the operators were instructed to secure the manual gas valves. Prior to that activation and securing process it is believed that the natural gas fuel entering the boiler came in contact with an unknown ignition source causing a furnace explosion. It was determined through research that the auto ignition temperature for Natural gas (methane) is 1076 degree F. It was also determined through research that the proper flammable range or explosive range is the range of concentration of a gas or vapor that will burn or explode if an ignition source is introduced. The lower explosive or flammable limit for natural gas (methane) is 5% and the upper explosive or flammable limit is 15%. The assumption can be made that when the concentration of natural gas returned to a level between the lower flammable limit of 5% and the upper flammable limit of 15% and found an ignition source the furnace explosion occurred.

The ignition source remains unknown. When the operators were instructed to secure the natural gas fuel they secured the main gas, pilot gas and all of the igniters. It is unknown if any of the igniters were actually on at the time because they were in such a hurry to get everything secured they didn’t actually take the time to determine if any of the igniters were on prior to selecting the manual off buttons. Because the auto ignition temperature of natural gas is only 1076 degrees F there is a strong probability that there may also have been an area of the boiler furnace that reached that temperature thus providing the source of ignition.

1.5 Significance of Recommendations

The significance of the recommendations is to reduce potential losses. It is believed that standards should comply with “Best Working Practices”, usually operators work to local or national specifications and, where statutory conditions exist, these specifications must be applied. However, these should be considered as minimum requirements and best working practices applied.

1.6 New Recommendations

No new recommendations were made as a result of the 2017 inspection visits. The following observations were discussed during the 2017 site visit.

Battery Capacity Discharge Testing
Direct Current Lube Oil Pump Electrical Breaker ratings/settings.
Hydrogen detectors in Battery rooms
Elevate Acetylene gas in the 460 and 461 Transformers

1.7 Previous Recommendations (Open)

2014-01 Perform ultrasonic testing of the boiler water wall tubes.

Comment: A tube leak occurred in 2012 near one of the burner throats. An analysis of the failed tube concluded that the failure was due to caustic gouging. This condition may have existed for several years, however it is important to evaluate the condition of the boiler tubes to determine if additional areas of deterioration are present.

Status February 18, 2015 – Ultrasonic examination of the Unit 3 boiler tubes is being budgeted for the next major boiler outage. The Unit 3 boiler is scheduled for a major outage 2018.

Status February 24, 2016 – Ultrasonic examination of the Unit 3 boiler tubes is being budgeted for the next major boiler outage. The Unit 3 boiler is currently scheduled for a major outage 2018.

Status March 09, 2017 – Ultrasonic examination is scheduled for the 2018 outage.

2012-02- Dismantle inspections of the Unit 1, Unit 2 and Unit 3 steam turbine-generators should be considered or formal evaluations performed to justify the continued operation of the units.

Comment: Unit 1 steam turbine and generator were last dismantled in 1998.Unit 2 turbine was last dismantled in 1994 and the generator was in 2000. The Unit 3 turbine and generator were last dismantled in 2000. It is understood that the units operate very few hours per year and the typical equivalent operating hours (EOH) dismantle schedule of 40,000 to 50,000 EOH between dismantles would not be practical for these units. Outages extensions for units with low operating hours are common up to ten years. Extension beyond ten years should be validated with a formal evaluation of the unit that provides justification of longer intervals. Plant water chemistry conditions, lay-up practices, interim inspections (Borescope, condenser inspections, online monitoring), past repairs and operating conditions should be included in such an evaluation.

Plant Response: Sectionalized maintenance is planned for Unit 3 over the next few years which at the present time valves are being inspected in 2012, the generator in 2013 and the turbine in 2014. Units 1 and 2 will be reassessed once the study is completed by The Energy Authority (TEA).

Status Feb. 13, 2013 – Units 1 and 2 are in the five year plan for dismantle inspections, however the City of Dover has not committed to a firm date for dismantle. Unit 3 is scheduled for dismantle inspection of the generator in the Spring of 2013 and the turbine in the Spring of 2014. The valves were inspected in 2012.

Status January 29, 2014 – The Unit 3 generator was dismantled in the Spring of 2013 and the Unit 3 turbine is planned for the Spring of 2014. Dismantle inspections of Unit 1 and Unit 2 have not yet been scheduled but are currently budgeted in the Capital plan for Spring of 2018

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Status February 18, 2015 – Unit 1 and Unit 2 are expected to be retired in 2017 and there is currently no plans to perform dismantle inspections on Unit 1 and Unit 2. Unit 3 turbine was dismantled for inspection in 2014.The Unit 3 Generator dismantle inspection was completed in 2013 and the Unit 3 turbine valves were inspected in 2012.

Status February 24, 2016 – Unit 1 and 2 are still expected to be retired in 2017. A valve inspection is scheduled for Unit 3 in 2018.

Status March 09, 2017- Unit 3 is scheduled for a valve inspection in 2018.

2010-06 – A program should be developed and implemented that documents annual hot and cold settings of hangers in the main steam, hot reheat, cold reheat, feedwater and boiler systems.

Comments: Plant piping system, especially high energy piping, support components should be inspected on a regular basis. The piping should be inspected in both the hot position and in the cold position. The results should be properly documented.
Plant Comment: Work order will be put into MAXIMO to track hangers settings. Inspection of hangars currently set up for 2014 on a 5-year basis.

Status 4/21/2011- The plant is currently planning to perform examinations on high energy piping systems in 2014.

Status: 2/1/12 - Plant personnel are in the process of developing a high energy piping examination program. The plant operating structure provides very few opportunities for collection of hot condition readings.

Status Feb. 13, 2013 – An initial study of the high energy piping system was performed. An initial inspection and testing program has been developed. Plant personnel will continue to develop and implement an inspection program

Status January 29, 2014 – Cold and hot walk downs were completed in 2012 and the hanger settings have been documented. Various piping hanger deficiencies were identified which are being addressed by plant personnel.

Status February 18, 2015 –The piping hanger deficiencies identified in 2012 have been corrected. Formal hot and cold walk down inspections are not yet being documented. Plant management is establishing a standard walk-down matrix.

Status February 24, 2015 – A formal program is being developed to document the hanger hot and cold conditions. The plant does not typically operate for periods long enough to establish hot conditions.

Status March 09, 2017 – The hanger inspection program is in the process of being implemented.

2009-01 Removal of Redundant Equipment

As part of the Unit 3 conversion to No 2 oil firing a large amount of redundant equipment has been removed from the station including No 6 oil pumps and heaters.

Comment: The removal of obsolete/redundant used equipment is to be encouraged as left in situ they need to be maintained and remain a potential fire hazard. This should be extended to include the removal of all external coal plant wherever practicable.

Post visit comment 2009: This philosophy was implemented when the oil conversion project started and continues as the plant removes or upgrades equipment.

Status 4/20/10: Plant obsolete/abandoned equipment is being removed as time and budgets allow. The ash recycle system was in the process of being removed during the April 2010 visit.

Status 4/21/2011- Plant personnel continue to remove obsolete and abandoned equipment as time and budgets allow. The majority of the abandoned outside equipment has been removed.

Status: 2/1/2012 – Abandoned and obsolete equipment is being removed as resources become available. Plant management is removing the items based on a hazardous risk priority presented by the obsolete/abandoned components.

Status Feb. 13, 2013 – Abandon and obsoleted equipment continues to be removed as resources allow. The ash removal system controls was recently removed to allow installation of a control panel for the industrial waste water system. The remaining equipment poses a low fire risk and is expected to be removed based plant needs and developments.

Status January 29, 2014 – Abandoned and obsoleted equipment continues to be removed as resources allow.

Status February 18, 2015 – The plant has removed obsolete and abandoned equipment in the past as a needed for safety and plant upgrades/change. A future plan for removal of this equipment has not been developed. Plant management suggested that a more formal approach is being considered with the retirement of Unit 1 and Unit 2 in 2017.

Status February 24 2016 – Unit 1 and Unit 2 are expected to be retired in 2017. Plant management with assess the associated hazards of the obsolete and abandoned equipment as part of the Unit 1 and Unit 2 retirement effort.

Status March 9, 2017 – Equipment that is retired or abandon has been drained of oil/hazardous substances and do not appear to pose any increase risk. Unit 1 and Unit 2 are also expected to be retired in 2017. This recommendation is WITHDRAWN since all of the associated coal handling equipment has been removed.

2 Plant Description

2.1 General

The City of Dover Power Plants are located as follows:

McKee Run: 39° 10' 30''N, 75° 32' 40'' W at an elevation of 19.68 ft (6 meters) and located on a 50 acre (202,342.8 m^2) site. 880 Buttner Place, Dover, Delaware 19904, USA.

The site stretches along the nearby railway line to the west and is roughly triangular in shape. The site is bordered to the east by domestic dwellings, to the north by open land and to the south by a small industrial area.

Access to the plant is via Walker Road.

VanSant: 39° 08' 42.76'' N, 75° 32' 54.66'' W at an elevation of 26.25 ft (8 meters) and located on a 7.4 acre (approx 30,000 m^2) site. 125 Electric Avenue, Dover, Delaware 19904, USA.

The VanSant site is approached from off Kenton Road either via Shinnecock Road or Carnoustie Road. The area is one used for recreational purposes although there are nearby industrial units to the site these are in excess of 1476 ft (450m) to the north.

Units 1 and 2 at the McKee Run station were built and commissioned in 1961 and 1962 respectively initially to burn coal, however in 1972 both were converted to burn #6 fuel oil, with each unit rated at 17MW (net). During 2008 these units were converted to burn No 2 Oil (distillate) to meet the January 2008 new emissions laws.

Unit 3 commenced operation in 1975 and was designed to burn both #6 fuel oil and natural gas. This unit is rated at 110 MW. During 2008 this unit was converted to burn No 2 Oil (distillate) to meet the

January 2008 new emissions laws.

NB: All units are now capable of dual fuel operation (Oil and Natural Gas).

The VanSant gas turbine is utilized in simple cycle mode generating 39/40 MW dependent upon the time of the year.

The McKee Run station is manned 24 hrs/day while the VanSant station is only occupied during start up and is generally unmanned. All units in the early 1990's were operated at base load but now all units are classified as peaking units.

Typically boiler units 1 and 2 are kept dry while unit 3 is maintained (currently) in a warm condition due to water constraints.

2.2 Operating Status and History

The station operates in a peaking mode. The units are test run annually for capacity verification. Unit 1 and Unit 2 are not expected to operate much in 2017 and are scheduled to be retired on June 01, 2017.

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Unit Starts										
Unit 1	3	2	1	2	3	3	2	8	1	1
Unit 2	5	2	2	4	3	2	4	9	3	2
Unit 3	32	24	8	48	22	29	13	50	26	37
VanSant	26	15	6	41	23	26	14	13	16	14
Total	66	43	17	95	51	60	33	80	46	54
Unit Operating Hours										
Unit 1	163.85	53.42	44.167	45.566	89.1	96	74.7	91.8	7.8	6.5
Unit 2	195.09	47.48	33.000	159.447	88.0	71.970	170.3	92.8	10.1	4.3
Unit 3	374.44	323.88	122.850	659.536	321.58	369.930	183.2	649.2	324.21	791.2
VanSant	107.44	57.30	23.393	132.364	80.97	22.986	51.5	50.0	72.78	31.8
Totals	840.82	482.10	223.410	996.913	579.65	561.168	479.7	884.0	414.39	833.8

NB: Hours are through December 31, 2015

Minimum time Unit 3 would be in operation is generally 8 hours and loading is as dispatched. Units 1 and 2 would normally operate a minimum of 12 hours and Unit 11 has a minimum operating time of 2 hours.

	MCKEE RUN STATION		
	Unit 1	**Unit 2**	**Unit 3**
***Cumulative Hours**	180,006.6	185,773.7	152,245.5

* estimated - operating hours before 1981 are not available. Cumulative hours are through 2015.

2.3 Age of Equipment

Units 1 and 2 are 1962 vintage and Unit 3 was commissioned in 1975.

2.4 Turbine Generating Equipment

	TURBINES			
GENERAL	**T/G #1**	**T/G #2**	**T/G #3**	**VanSant**
Service Status	Peaking	Peaking	Peaking	Peaking

TURBINE				
Type	ST	ST	ST	GT
Manufacturer	WHS	WHS	GE	GE
Model #				FR 6
Serial #	13A2482-1	13A2482-2	178864	295627
# Stages			20	
Rating (kW)	16,500	16,500	110,000	40,000 / 45,300
Year	1962	1962	1975	1992
Fuel (GT)				#2 oil
				Natural Gas
	LUBE / SEAL OIL			
System/Type	Below deck	Below deck	Below deck	Within enclosure
Piping	Flanged	Flanged	Flanged	Flanged
Containment	Trenches	Trenches	Curb	Enclosure
Reservoir Location	Basement	Basement	Basement	Within Enclosure
H_2 Detrain Provided	Yes	Yes	Yes	N/a
	GENERATOR			
Manufacturer	**WHS**	**WHS**	**GE**	**GE**
Model #				
Serial #	2S64P963	1S64P963	838428	336x424
Year	1962	1962	1975	1991
Rating (kVA)	22,059@30psi H2	22,059@30psi H2	133,689@30 psi H2	48,706
Rated Voltage (kV)	12,500	12,500	12,500	13,800
Rotor Cooling	H2	H2	H2	Air
Stator Cooling	H2	H2	H2	Air

NB: Generators are not fitted with hydrogen dryers or dew point monitors.

2016 Turbine – Generator Outage Activities

No major activities were performed on the unit turbine -generators during the 2016 outages. Unit 3 is scheduled for a valve inspection in 2018.

The inlet plenum was repaired at the Van Sant unit in 2016, which resulted in additional concerns being identified in the inlet plenum. These concerns were addressed by replacing the entire plenum liner from the rear of the turbine to just upstream of the sound baffles in March 2017.

2015 Turbine – Generator Outage Activities

Unit 1 2015
No inspections, preventive maintenance or major activities were planned on the Unit 1 Turbine/Generator during the Spring and Fall 2015 outages.

Unit 2 2015
No inspections, preventive maintenance or major activities were planned on the Unit 2 Turbine/Generator during the Spring and Fall 2015 outages. There were plans to repair the Turbine Trip Throttle Valve Mechanism during the Fall 2014 outage but never materialized due to a delay in the delivery of some of the parts and the lack of skilled man-power once the parts did arrive. The mechanism was repaired in January 2015.

Unit 3 2015 Outage

Plant outage reports were not available during 2016 visit. There was no Fall outage for Unit 3 so there were no outage reports.

VanSant 2015 Spring Outage

Plant outage reports were not available during 2016 visit. HPI Turbine overhaul was done, new vibration monitoring system was installed, overhaul corrected a previous vibration issue that was from the unit installation. No vibration of any remarkable level occurs since the HPI unit overhaul.

VanSant Fall 2015 Outage

A wet compression upgrade was evaluated and in 2014; and installation was done in the spring of in 2015. The wet compression system was commissioned in June of 2015 and is fully operational. The inlet fogging system and unit capacity test proved a 6.3 MW increase in the unit design generation.

See historical turbine – generator outage information in Attachment 9

2.5 Main & Station Service Transformers

TRANSFORMERS				
Manufacturer	GE	GE	McGraw Edison	GE
Serial No			C0434151	M162149
MVA	25	25	130	46
Cooling	FOA	FOA	FOA	FOA
Voltage (kV)	22.9/12.4	22.9/ 12.4	69/12.5	69/13.8
No. Phase	3	3	3	3
Form (Shell or Core)	Core	Core	Core	Core
Oil Type Oil Capacity	5450	5450	8565	3640

The transformers above share a common switchyard with plant owned and maintained by the City of Dover Electrical department. This is a mainly open yard with little or no fixed fire installation.

Tap changers are not regularly operated so there are no requirements for any specific procedure covering these.

2.6 Boilers

	Boiler Details		
	Unit 1	Unit 2	Unit 3
Manufacturer	Babcock and Wilcox	Babcock and Wilcox	Riley*
Built	1961	1961	1971
Duty	Peaking	Peaking	Peaking
Boiler Type	Natural circulation watertube	Natural circulation watertube	Natural circulation watertube with reheat
Fuel	#6 Oil/natural gas	#6 Oil/natural gas	#6 Oil/natural gas
Steam Flow at MCR	160,000 lbs/hr	160,000 lbs/hr	786,000 lbs/hr
Working pressure (psi)	850	850	1880
Steam Temperature oF	910	910	1005
Reheat pressure (psi)			448
Reheat temperature ºF			1005
Burners	Two, one side by side	Two, one side by side	Nine, three on three levels.
Stack Construction	Common steel stack		Steel stack
Stack height	275 ft (83.8m)		300 ft (91.44m)

Units 1 and 2 are Babcock and Wilcox water tube natural circulation, semi-outdoor dual oil/natural gas fired boilers having a Commercial Operations Date of 1st April 1962. The units are designed to supply 175,000 Lbs/hrs (22.10 kg/s) at 850 psi (58.6 Barg) and 900 °F (454°C). Each boiler is equipped with 4 burners housed within the boiler/turbine hall and 1 forced draft and 1 induced draft fan (Westinghouse Sturtevant) complete with 2 x speed motors for balanced flow operation.

Unit 3 is a Riley Boiler is a top supported water tube natural circulation, semi-outdoor dual oil/gas fired boiler. The unit consists of a superheater, reheater, economizer, air heater, water cooled furnace, Boosted Over-fire Air System, two forced draft fans, two induced draft fans.

Unit 3 is designed to supply 786,000 lbs/hrs (99.24 kg/s) of steam at 1005 °F (540 °C) and (155.1 barg).

NB: In accordance with the data sheet provided by COD.

* Riley is now owned by B&W. Burners have flame monitoring of both fuel oil and gas burners.

Boiler 2015 Outages

Boiler outages were performed in 2015 and the routine maintenance and repairs were completed. A formal boiler outage report was not available during this visit.

Auxiliary Boilers

There are two (2) Continental (Boiler Engineering and Supply Company Hot Water Boilers) each rated at

13.39 MMBTU/hr, which are fired on natural gas only. These are self-contained skid mounted fire tube boilers used for heating the station's #6 fuel oil and for some of the in-house heating.

2.7 Flue Gas Treatment Systems

There are no flue gas treatments at the McKee Run generating station however the VanSant unit is operated with water injection for NOx control. The ash recycle system is no longer used and most of the system has been removed.

2.8 Water Treatment Systems

Unit three is the only one with a deaerator. It was inspected in 2001 with indications found that required repairs. The vessel was re-inspected in 2003, no recordable indications were found. The Unit 3 deaerator was inspected in October 2014 and no cracks were reported, however some pitting was noted. Unit 1 and 2 operate with a hotwell system

The station uses a phosphate/caustic dosing regime for the boiler water chemical control with an oxygen scavenger and a neutralizing amine for condensate system protection. The station did have a Lab technician up until NAES took over plant operation. However, since then the operations staff has continued with those previously shared responsibilities under the guidance of the chemical manufacturer/supplier. Currently this is with Condor Technologies who visits the site each week to check through sample results and advise as required, they are also available again as required. Normal sampling and analysis is carried out by station staff.

The station is equipped with two sets of cooling towers located at the northern end of the site; each unit is of the cross flow design utilizing plastic infill. C/Tower #1 provides cooling for Units 1 and 2 and has 10 cells, with C/Tower #2 providing cooling for Unit 3 and has 5 cells, although C/T#2 is physically the larger unit.

The water requirements for the station are met from dual water treatment trains situated in the station basement consisting of 2 x cation, 2 x anion, and one mixed bed vessel.

The current operating mode of the units makes maintaining the water chemistry levels very difficult. The water chemistry logs were provided for reviewed for the past year for Boilers 1, 2 and 3 and a few readings were noted to be outside the acceptable chemistry limits. Every effort should be made to ensure the water chemistry, lay-up practices and operating conditions prevent additional system deterioration.

NB: There is a standalone facility at the VanSant location providing demineralizer water for the use of the gas turbine.

2.9 Air Compressors

There are a number of compressors at the station some of which are no longer in service, new compressors are of the Ingersoll Rand rotary type GA75 with Hankison Dryers
The two Atlas-Copco compressors that were located on the mezzanine deck have been moved to the ground floor to help reduce the heat concerns associated with the compressors on the mezzanine deck during the summer high heat periods.

During the 2013 Fall outage the NAES IC&E Team removed and replaced the thermostat on Unit 3 main air compressor due to overheating problems. The Compressor was placed in service and cycled several times. Oil temperature reached 195 F without overheating. Normal Compressor oil trip temperature is 248 F. Operations Team secured the Quincy atomizing air compressor and will continue to monitor Unit 3 main air compressor for proper operational temperatures.

NAES IC&E Team completed repairs on the 2B air compressor during the Fall 2013 outage. The compressor would not unload and through the process of troubleshooting determined the unloading valve spring was defective. New ones were ordered,

2.10 Fuel Handling Equipment

The station has 2 tanks for the storage of #6 oil together with heaters and transfer pumps to the station, these are located some distance from the main plant. Tank number 1 has a capacity of approximately 2,500,000 gallons and tank 2 which has been out of service since 1996 has a capacity of 500,000 gallons, each housed in a separate bunded area.

Tank #1 was emptied and inspected on 15th December 2007. The following is a summary:

Containment Area - The containment area is a soil base with a soil dike wall. The foundation is a concrete ring wall with secondary containment and leak detection. The visual inspection found no serious conditions.
Settlement Survey - An out-of-plane settlement survey was performed on the tank.
The out-of-plane settlement is acceptable per API-653.
Fixed Roof - The roof was visually inspected and thickness readings were obtained through the manway. No serious conditions were found.
Shell - The shell was visually inspected and thickness readings were taken internally. One of the were found.
Nozzles - The nozzles were visually inspected and thickness readings were taken. No serious conditions were found.
Chime - The chime is insulated and could not be inspected.
Bottom - The bottom was visually inspected and thickness readings were taken. An MFE bottom scan was also performed, but was limited due to the coils and the configuration of the coils to the bottom seams. 34 indications of soilside corrosion were found and proofed with ultrasound. The maximum soilside pit found was .129" remaining wall thickness. The MRT calculations per API-653 would require that all soilside pits .226" remaining wall thickness or less to be patched to facilitate a next out-of-service inspection interval of 20.0 years. MFE SCANNER - Magnetic Flux Leakage Examination Scanner is set up using MFE Enterprises function test plate. The test plate is 0.25" thickness with two simulated flaws. Flaw #1 is a 3/16" diameter hole and Flaw #2 is a ½" diameter simulated soilside pit stair stepped to 40% wall loss. The unit is then adjusted to bottom actual thickness with coating, if present.
External Deterioration Protection - The insulation is in good condition.
Brittle Fracture - Brittle fracture should not be a concern since the tank is to remain in the same service.
Cathodic Protection - NA.
Internal Lining - NA.
Overfill Prevention - An auto gauge system is installed.
Coils - The hot water coils were visually inspected and thickness readings were taken. No serious conditions were found.
Grounding - The tank is adequately grounded.
Stairway - The spiral stairway was visually inspected. No serious conditions were found.

2.11 DC System & Station Batteries

Units one and two are on a separate set of lead acid batteries, Unit three has its own set of lead acid batteries for DC power. The VanSant gas turbine has its own set of lead acid batteries.

It was noted that the battery systems are tested weekly for voltage and fluid levels but to date no discharge testing has been carried out. Discharge testing is expected to be performed in 2015.

Status 2009: Batteries banks for Units 1, 2 and Unit 3 were replaced in 2009 due to them approaching end of life cycle based on recent load testing. In addition, two new battery chargers were purchased and installed to replace the older model chargers due to equipment failure and lack of replacement parts. Battery discharge testing was discussed during the 2017 site visit. Battery capacity testing is typically performed on a five-year frequency in electrical power plants. Plant management agreed to review the plants battery testing program.

The DC electrical one-line drawings were reviewed in 2013. It appears the Unit 3 DC system is equipped with a fuse (400amp) installed between the DC supply and the DC buss. There is also a 200Amp fuse in the supply to the DC Emergency Seal oil pump. An instantaneous fault could result in de-energizing the DC buss and potentially allowing hydrogen to escape from the generator resulting in a fire. The DC system for all the units should be evaluated to ensure a single fault incident will not de-energize the DC bus. Over time fuses can become deteriorated and the rating affected, which could also prematurely de-energizing the DC buss. In an event where the DC lube oil pump is in service due to no other lube oil supply, then it would be considered better to allow the DC lube oil pump to run until the unit can be shut down to ensure oil is supplied to the turbine bearings, rather than have the breaker protection trip the DC lube oil pump and interrupt the flow of oil to the turbine bearings. The DC breaker for the DC Lube oil pump is usually set higher than the locked rotor amps rating of the DC oil pump. This condition was discussed with plant management during the 2017 visit and plant management agreed to evaluate the breaker arrangement.

General Electric Technical Information Letters 775 and 914 regarding DC Lube oil pump reliability were provided as a reference. The DC electrical supply for Unit 3 was upgraded in 2014 to incorporate a dual contactor arrangement.

2.12 Electrical System (See Attachment 7 for One - Line Diagram)

The electrical system covered by the Insurance policy for the station does not include Unit 1 and 2 GSUs but does cover the Unit 1 12.5/2.4 kV, 12.5/0.48 kV auxiliary transformers, Plant 12.5/2.4 kV, 12.5/0.48 kV auxiliary transformers, Unit 2 12.5/2.4 kV transformer, Unit 3 12.5/4.16 kV Start, 12.5/4.16 Run and Main and LTC 130 MVA 12.5/69 kV transformers and associated station switchboards connected to them.

Units 1 and 2 generally feed through to the 22.9 kV outgoing lines (2) through transformers T1 and T2 and via a step-up 22.9kv to 69kv transformer to the 69kv ring bus for distribution elsewhere in the city electrical system. Unit 3 feeds directly into the 69 kV system.

GSUs 1 and 2 are maintained by the City of Dover. There is adequate distance from the building, approximately 18 ft from each other. There are no concrete walls and no sprinkler protection.

GSU 3 is approximately 30 ft from the building with the station service transformer between itself and the building. The station service unit is approximately 15 ft from the GSU. There are no concrete walls or sprinkler protection.

The VanSant GSU is surrounded on three sides by a concrete wall. There is no sprinkler protection.

3 Construction and Civil Works

3.1 General Construction Features

The powerhouse at the east end has three floors. The control room is on the third floor running along the south end of the building, along with the turbine deck. The boiler fronts make-up the north end of the powerhouse with the backs of the boilers outside.

There are other small buildings onsite but the powerhouse and the two warehouses are the largest structures (steel framed metal clad, with concrete bases).

Still existing on the property are parts of the coal conveyor and other support systems for coal handling plant.

The station has two cooling towers, both are wooden framed with plastic infill on a concrete base.

The VanSant location has a steel framed metal clad demin building which is approximately 3,000 ft^2.

3.2 Powerhouse

This is a substantial building housing the main equipment areas and is of steel supports with infill of brick (cavity) having concrete floors and ceilings. There are numerous window openings around the building. The turbine hall has roof openings and venting.

3.3 Control Rooms

This is located within the main building on the same level as the steam turbines, providing a view of them and the three boiler fronts. The control runs east to west along the south wall of the building and has brick walls with concrete roof under which is a suspended ceiling, the floor is concrete covered with a floor tiling.

Units 1 and 2 are controlled from the east end of the control room and Unit 3 from the west end.

A portion of the control room has been extended to allow the movement of phones and controls to a more central location to provide better access for the operators.

3.4 Building / Equipment Layout & Spacing

The lower floor (basement of the station is slightly congested with BOP items of equipment and pipe work, however unit 3 is slightly better. Upper levels are not so congested.

Layout of the major plant items was generally found to be good.

3.5 Fire Barriers & Penetration Stopping

Overall these were in good condition however there were some exceptions and this area needs to be monitored. XL Insurance and the plant will work together to correct these exceptions. Several areas of wall penetrations have been sealed already. Additional fire barriers and penetration sealing is planned after the completion of controls upgrade.

2012 Status Update: Plant personnel have made significant efforts to seal all cable penetrations in fire barriers.

No fire barrier concerns were noted during the 2017 site visit.

3.6 Drainage, Containment & Spill Control

The station has a drain system however there are no interceptors or separators as would be expected in a modern power plant and all drains have to be sampled frequently. Spill control kits were noted as being available around the station.

4 Plant Dependencies

4.1 Substation / Transmission

The substation is located externally to the station on the Southside, access is from the main building basement. There is joint ownership of the switchyard between the power station and the city electrical department. There are no fixed fire systems and only physical separation between units.

4.2 Fuel Supply

The station has dual fuel capability however the gas contract is interruptible and in the winter there is a restriction on gas supply (pressure) for the VanSant gas turbine which necessitates this unit operating on #2 oil during the peak times of the day. Eastern Shore Natural Gas has been upgrading their distribution system over the past several years which have enabled the VanSant unit to operate more often on gas during the summer peak periods.

Fuel usage is dependent upon economics, however gas is in short supply during the winter but used more on the McKee run units in the summer. During the 2014 visit the units at Mckee Run were being operated on fuel oil. Boilers are typically started up on natural gas although it was recognized that natural gas may not be available during winter periods. Consequently, an atomizing air compressor was installed as part of the Oil Conversion project which would allow Unit 3 to start up on fuel oil by using the higher pressure air from the new compressor to atomize the oil. Units 1 and 2 are mechanically atomized and could be started up on oil if necessary.

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4.3 Raw Water Supply

The station raw water is supplied from the City of Dover water main. The water main in turn is fed from a series of 29 individual wells located throughout the City of Dover. The station is located at a junction of these wells such that water flowing toward the station can come from any of four different supply lines. Raw water is normally fed into the plant through any or all four supply lines located around the station.

5 Equipment Control, Monitoring & Protection Devices

5.1 Control Systems

Units 1 and 2 are manual operation by operations staff, Unit 3 is automatic control from the ABB Net 90 system. The Van Sant gas turbine control package has been upgraded and can be operated remotely.

NB: There is a review process in place considering the replacement of the MKIV GE control system

Status 2009: Project has been approved to replace the Mark IV during the 2009-2010 fiscal year. Plant is investigating replacements systems.

Status: 2010 The control cabinet has been extended and was being prepared for installation of the new control system.

Status: 2012 The VanSant controls upgrade has been completed. A simulator has been purchased and is being utilized for operator training and system trouble shooting.

Status: 2013 Additional control wiring has been installed to upgrade the unit 1 and Unit 2 gas control system.

5.2 Protective Relaying

The units 1 and 2 are protected by hardwire protection systems some of which are manually operated in the trip mode. Unit 3 has both hardwire and software generated trips and alarms.

Protective relays are tested every five years. The relays were last tested in July 2015 by CAMCO. All deficiencies identified were being investigated and repaired though the plant maintenance management program.

5.3 Water Induction Protection

There is some water induction protection covering drum water levels and steam pipe work temperature measurement however the standard of protection is not to ASME Standard TDP-1-2006. Unit 3 has a low point drip pot with redundant level switches which provide an alarm to the control room.

5.4 Combustion Control System

All three boiler units have a burner management system installed. A study of the controls on Unit 1 and 2 boilers was performed and burner management modifications were completed in 2012-2013

5.5 Plant Condition Monitoring Systems

These are somewhat limited on Units 1 and 2 mainly being manual logs and chart recordings of critical parameters. The ABB Net 90 system on units 3 allows for more flexibility in plant condition monitoring. New PCs were installed in the Net 90 control system in 2012. An electronic vibration chart recorder was installed for the Unit 3 turbine in the 2014 Spring Outage.

The VanSant control system was upgraded by ICS which incorporates PLC based controls, Wonderware Software and has data trending capability.

6 Fire Protection / Special Protection Systems

6.1 Designs Used for Systems

The standard of fire protection installed at the station is poor when compared to similar stations of that age and is not in accordance with current NFPA standards. Efforts are being made to upgrade the protection as time and budgets allow. Heat and smoke detection has been installed at the Unit 3 boiler fronts, however there is no protection in this area. There is no fire protection installed at the turbine lube oil reservoirs.

The hose stations no longer have hoses in place. The plant policy is for the plant personnel to only fight incipient fires with fire extinguishers only. The plant personnel are not trained on the hose stations and the fire department uses only their own certified hoses. The plant does not provide certified hoses as the industry standard is fire departments will supply their own firefighting hoses and connect to the fire station.

6.2 Water Supplies for Fire Fighting

Plant service water is received from the city water supply through 4 separate connections around the site, 1 x 8'' (200mm), 2 x 10'' (250mm) and 1 x 12'' (300mm) connections all complete with isolation valves. Two back-flow preventors are installed in parallel to protect the city supply from any contamination coming back from the station.

This system is the normal source of service water for the station and initially supplied water only to unit 3 however this now also supplies units 1 and 2 through a 4'' (100mm) connection. The city water main operates at 60 psig (4.14 barg) however there are 2 service pumps at the plant which provide up to an additional 43 psi boost (3 barg) should the city pressure fall.

NB: The pressure in the service water system is regulated at a maximum of 80 psig (5.52 barg).

The station fire system is supplied from the city main as above from the outside plant fire mains through an 8'' (200mm) main with a 4'' (100mm) crossover to units 1 and 2.

A single 1,000 gpm @100 psi (3784 l/hr @ 6.9 barg), fire pump takes suction from the City of Dover water main outside the station. In the unlikely event that the city water main water pressure is lost, the fire pump can also take suction from an onsite firewater storage tank located adjacent to the fire pump. This tank holds approximately 150,000 gallons of water. The pump is driven by either an electric motor or a gas engine.

NB: The pump is both a manual and automatic start and is currently in the auto start mode. If the protection for the location were upgraded, it would be suggested that the pump arrangement be upgraded.

6.3 Fire Hydrant Systems

There is an extensive external fire hydrant system which covers the whole of the operational area of the station including the fuel oil tank and cooling tower area. The external hydrant ring main has nine hydrant points in total.

In addition, the VanSant location was noted to have a fire hydrant system with two hydrants.

6.4 Sprinkler / Deluge Systems

At McKee Run there is an automatic sprinkler system onsite, this is a dry system protecting the cooling tower for units one/two and a deluge system protecting the cooling tower for unit three.

A number of deluge valves have been replaced with new valves on both cooling towers. Quarterly and annual test are completed by Radius Technologies LLC. The test reports for 2009 were reviewed and some deficiencies were identified which were corrected. The January 2010 quarterly report reported no deficiencies.

The 2011 system inspection results were provided for review and no significant deficiencies were reported.

Inspection of the fire protection system in 2013 was satisfactory with a few minor discrepancies, which included out of date gauges and broke handles on regulators.

Sobieski Life Safety LLC performed the quarterly and annual fire system inspections in 2015. The 2015 fire system inspection reports reviewed did not report any significant deficiencies with the fire protection systems.

The 2016 fire system inspection reports were reviewed and no significant concerns were identified. A few minor discrepancies were identified such as missing signs and identification markers.

6.5 Standpipe & Hose Stations

Each unit has a fire system which extends almost the full height of each unit with Unit 3 in particular having eight fire hose cabinet/fire extinguisher cabinets. Fire hoses have been removed from all fire stations as local fire departments reported they will not use installed equipment as they are not aware of the conditions or the last test dates for fire hoses. They will always bring their own firefighting hoses and make the connection at the plant fire stations.

6.6 Fire / Gas Detection & Alarm Systems

It was noted that the gas turbine has rate of rise, smoke, and heat detection systems installed. Plant management worked with the OEM to install a gas detection system on the Combustion turbine. Heat and smoke detection has been installed at the boiler burner fronts. Heat and smoke detectors were also installed in the warehouse and in the stairways of administration building.

6.7 Portable Fire Extinguishers

Fire extinguishers are located throughout the plant. Regular inspections of the fire extinguishers are performed and documented by plant personnel.

6.8 Special Fire Suppression Systems

The combustion turbine is protected by a CO2 system. The combustion turbine (model GE Frame 6) has a load gear which shares a compartment with the turbine outboard bearing and generator inboard bearing, this area is protected by the CO2 system. The generator outboard bearing was not protected by the system, which is not uncommon. This system is scheduled to be replaced with a water mist system that will allow for the same protection but not be an employee hazard should the fire suppression system be activated while an employee or contractor is in the compartment.

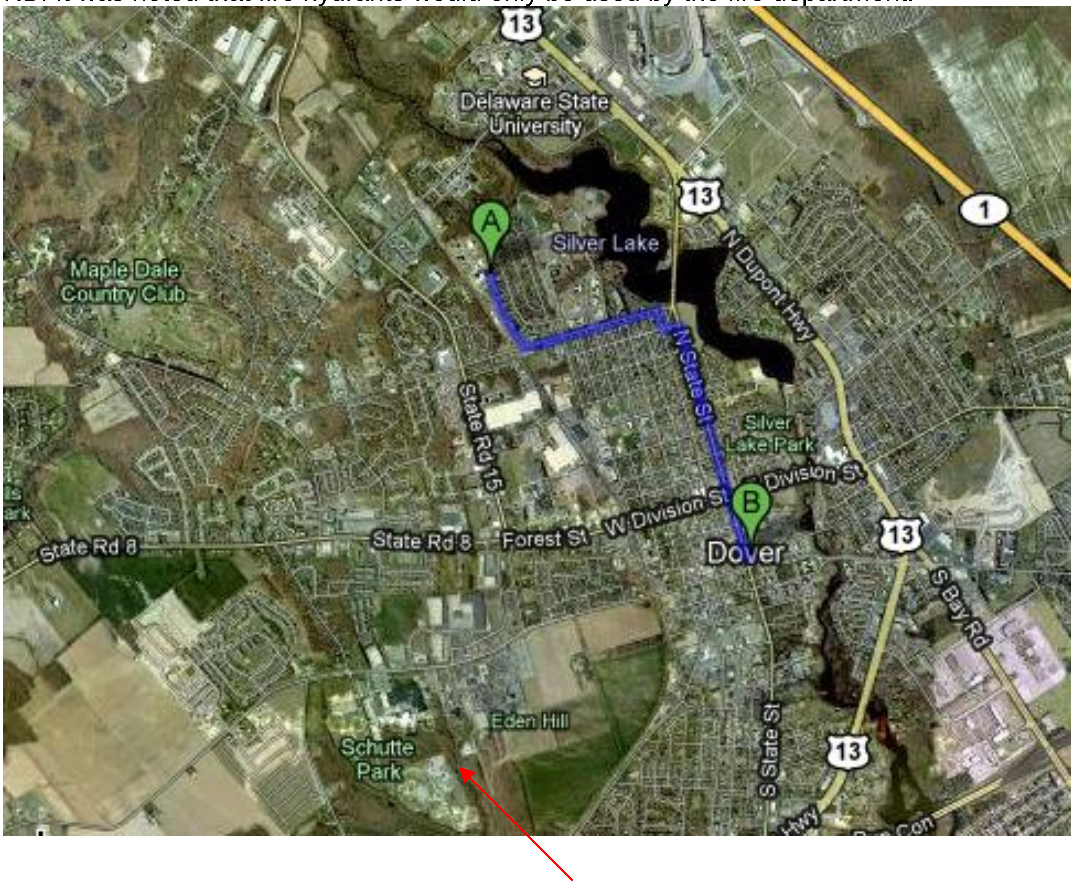
An Ansulite AFFF (Aqueous Film Forming Foam) suppression system has been installed for the Unit 3 turbine bearings. The system is installed to be activated by heat activated wire (such as Protecto-wire). The system is equipped with a water flow alarm, pull station and a tamper switch on the main valve. The system was installed by Radius Technologies in 2010.

A portable foam fire extinguisher is located on the ground floor between Unit 1 and Unit 2 near the lube oil system. This extinguisher has been position to be used in the event of a lube oil fire on Unit 1 or Unit 2.

6.9 Public & Private Fire Brigades

All site staff will attempt to put out a fire the size of a trash can but anything larger will always be left to the fire department. The Dover Fire department is approximately 2.6 miles from the McKee Run Station and approximately 2.7 miles from the VanSant location. The Dover Fire department is a volunteer department, known as the Robbins Hose Company.

NB: It was noted that fire hydrants would only be used by the fire department.



Note: A- McKee Run B- Fire Department, - Red Arrow is to VanSant

6.10 Special Hazard Management & Protection

Special Hazards Fire Protection Summary	
Special Hazard Area	*Fire Protection*
Generator Housing	None
Exciter Housing	None
Turbine Bearings	AFFF Unit 3 only
Sub-Turbine	None Portable foam extinguisher
Lube Oil Reservoir & Bowser	None
Lube Oil Storage	None
Generator Seal Oil	None
Electro-Hydraulic Control System / Governor Oil System	None
Steam or Shaft Driven Boiler Feed Pumps	None
Burner Fronts	None –Smoke and Heat detection
Air Preheaters	None
Electrostatic Precipitators	N/A
Scrubbers	N/A
Bag Houses	N/A

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Control / Computer Room	None
Cable Spreading	None
Relay / Switchgear	None
Transformers	None
Fuel Storage Facilities (Tanks, Bunkers, Silos, Yard, Building, etc.)	Hydrant system
Fuel Conveyors, Pumps, Gas Compressors & Other Fuel Transfer Equipment	None
Fuel Processing Facilities (Crushers, Mills, Shredders, Hoggers)	N/A
Battery Rooms	None
Cooling Tower	Dry sprinkler
Lube oil storage	Detection only

7 Plant Operations

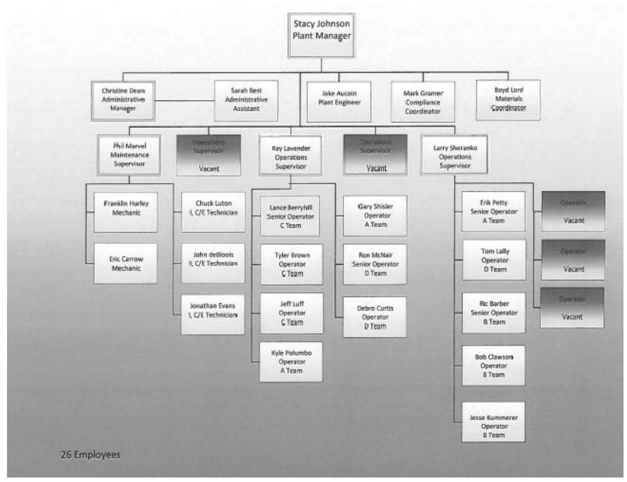
7.1 Operations Staffing

Up to 1996 the two stations were operated and maintained by the City of Dover Electrical department however in that year a contract was placed with Duke/Louis Dreyfus (D/LD). In turn D/LD signed a contract with Duke/Flour Daniels (D/FD) to operate and maintain the two stations. The partnership dissolved in 2004 and the operation and maintenance was taken over by DEOS and this in turn was taken over by the NAES on the July 01, 2006. NAES continues to operate and maintain the two facilities for the City of Dover.

NB: Although the operations and maintenance of the plant has passed through a number of companies, however the plant personnel remain basically the same. Each new operating company has taken on the existing staff. This is considered a plus for the two stations, as there is continuity on both the operational and maintenance fronts.

Currently the McKee Run station operates a 4 shift system one week followed by a 3 shift system the second week. Typically, each shift has 3 operators with an on-call supervisor. Additional shift staff (3) works a flexible day shift together with the normal rotating shift.

In the past year the plant has seen some plant personnel changes. The plant currently has a new plant manager. The plant staffing level has been reduced by the Owner and the plant's current staffing level is 26 employees which is down from the previous 30.



7.2 Operator Training & Certification

The station management have produced a McKee Run/VanSant Generating Station Plant Readiness Plan. The purpose of which is to provide basic training requirements to ensure station Operations and Maintenance Staff are operationally ready to meet unit dispatch demands. The Plant Readiness Plan (ORP) is the blue print for preparing our workforce through a number of training media including videos, class room instruction, On-the-Job Training, Refresher Training, and Computer Based Training (CBT).

The plan covers a full year of training and includes the following (GPT) General Physics Training, (DRS) Dry Run Scenario, (PJM – OL) PJM online training (BOP) Balance of Plant, (SR) System Review, (PR) Procedure Review (DR) Dry Run (WCTR) Water Chemistry Test & Review.

7.3 Plant Operating Regime

Both stations are carrying out peaking duties at this time however prior to 1996 the units were base load units.

7.4 Operations Data

	2008	2009	2010	2011	2012	2013	2014	2015	2016
Unit Starts									
Unit 1	2	1	2	3	3	2	8	1	1
Unit 2	2	2	4	3	2	4	9	3	2
Unit 3	24	8	48	22	29	13	50	26	37
VanSant	15	6	41	23	26	14	13	16	14
Total	43	17	95	51	60	33	80	46	54
Unit Operating Hours									
Unit 1	53.42	44.167	45.566	89.1	96	74.7	91.8	7.2	6.5
Unit 2	47.48	33.000	159.447	88.0	71.970	170.3	92.8	10.1	4.3

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Unit 3	323.88	122.850	659.536	321.58	369.930	183.2	649.2	324.3	791.2
VanSant	57.30	23.393	132.364	80.97	22.986	51.5	50.0	72.8	31.8
Totals	482.10	223.410	996.913	579.65	561.168	479.7	884.0	414.33	833.8

	MCKEE RUN STATION		
	Unit 1	**Unit 2**	**Unit 3**
***Cumulative Hours**	180,006.6	185,773.7	152,245.5

* estimated - figures for operating hours before 1981 are not available. Cumulative hours are through 2016

Capacity Testing information for 2015-2016 were not available during this site visit.

7.5 Plant Availability & Forced Outage Rate

	Unit 1								
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Availability %	71.77	96.38	73.11	67.23	65.85	67.19	58.11	91.8	99.2
Capacity %	0.34	0.26	0.23	0.53	0.42	0.73	0.40	0.11	0.05
Forced Outage %	0.0	0.0	6.6	0.0	0.0	10.9	0.0	2.3	0.0
	Unit 2								
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Availability %	71.77	97.74	79.73	67.23%	65.81	69.01	58.11	91.8	99.2
Capacity %	0.33	0.22	0.9	0.53%	0.37 %	1.36	0.44	0.12	0.04
Forced Outage %	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.2	0.0

	Unit 3								
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Availability %	86.53	83.24	73.27	67.23%	65.82	69.01	55.25	90.9	85.4
Capacity %	1.0	0.90	4.87	2.55%	1.88 %	2.57%	2.30	1.77	3.73
Forced Outage %	0.0	0.0	0.07	0.0	0.0	10.9	0.030	3.99	1.26

	Van Slant Unit 11	

	2008	2009	2010	2011	2012	2013	2014	2015	2016
Availability %	92.56	97.93	92.16	80.45%	66.91	69.01	58.11	93.6	86.2
Capacity %	0.20	0.21	1.37	0.63%	0.21	0.91	0.54	1.18	0.35
Forced Outage %	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.266

7.6 Incident Reporting & Root Cause Analysis

The station has a formal report process of incident reporting including a full review of RCA and associated lessons learned/actions required and personnel responsible to ensure actions are carried out.

8 Equipment Maintenance

8.1 Maintenance Planning & Supervision

This is achieved through the maintenance management system for both short and long term planning. Work orders may be prioritized with a number of different classifications some of which are listed as follows:

Priority 1 - Immediately

2 - Next Day

3 – Next Week

4 – Within a Month

5 – Requires an Outage

6 - Safety

8.2 Maintenance Facilities

These are limited at the station but will accommodate all routine maintenance activities. There is a good size workshop with a good availability of tooling and specialist machine tools.

8.3 Maintenance Management System

The plant has transferred the management of maintenance activities from Maximo to MP2.

MP2 is a completely integrated asset management system used to:

- Organize and track inventory.
- Manage equipment costs.
- Track equipment history.
- Schedule preventive maintenance tasks.
- Maintain confidential labor records.
- Allocate resources.
- Generate work orders.
- Requisition and purchase parts.
- Project equipment failures.

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8.4 Maintenance Staffing & Contractual Arrangements

There is a team of 7 maintenance personnel at the station, 1 supervisor, 2 mechanical craftsmen, 3 - I & C technicians.

OEM/Specialist services are used as required. A compliance specialist position was added and filled in 2013.

8.5 Plant Overhaul Schedule

Plant management has developed a plan in which the units are placed in outage twice a year in order to reduce labor costs and to use available plant staff in outage activities. Unit 1 and Unit 2 are expected to be retired in 2017 and no major outages are scheduled for these units.

Unit 1 turbine and generator was last dismantled in 1993. Unit 2 turbine was last dismantled in 1994 and the generator was last done in 2000. Unit 1 and 2 valve inspections were being performed at time of the 2011 inspection visit. A major overhaul of the Unit 1 and 2 turbine – generators is not currently scheduled.

Unit 3 turbine and generator were dismantled in 2000. The Unit 3 generator was dismantled and inspected in 2013. The Unit 3 turbine was dismantled and inspected in 2014.

A limited inspection of the Unit 3 turbine was performed in 2010. Unit 3 turbine valves were inspected in 2012. Unit 3 has a borescope plug between the L-1 and L-0 rows. Unit 3 is scheduled for a valve outage in 2018.

The VanSant borescope inspection frequency has been changed to every two years. A partial borescope inspection was performed in 2013 of the combustor sections to identify and coking and minimal coking was noted. A Generator Shorted Turn Analysis was performed in 2013 and no concerns were reported. Flux probe inspections are being performed on a five year basis to coincide with Appendix E Testing. The VanSant unit is tentatively scheduled for a major outage in 2018. A borescope inspection was being performed during this visit on March 09, 2017.

8.6 Machinery Condition Monitoring

MP-2 is the computerized maintenance management system used to track and schedule maintenance. The station has some fixed vibration monitoring equipment installed and this is supplemented by portable vibration monitoring on all four units. They utilize a CSI system and have a soft-ware package for ‘expert analyses. Do to the manner in which the plant is now operating this is only occurring once yearly.

Thirty eight samples were collected in 2013. Three were reported to be in the “Alert”, twenty-five were reported to be in the “Caution” range and eleven were reported as “Normal”. The 1FD-0003-IB Forced Draft Fan Inboard bearing was reported to have high sodium level and a potential corrosion concern exists. The 2-FD-001-OB and the 2-ID-001-IB Induced Draft Fan inboard bearing were reported to have abnormal wear metals indicating serious bearing wear.

In 2014, thirty eight samples were again collected and analyzed. Four samples were reported in the “Alert” status and thirteen were reported as “Caution”. The Unit 2 Forced Draft fan out board bearing indicated severe metal wear. The Unit 2 Induced Draft fan inboard bearing analysis indicated increased iron/metal wear. The Unit 3 3B-CWB bottom bearing indicated high moisture content. The Unit 3 3B Forced Draft fan reservoir oil indicated high iron content.

The Unit 3 turbine vibration was analyzed by Mechanical Dynamics and Analysis (MD&A) in 2015 and it was determined that the vibration levels were acceptable and within the normal operating range.

The 2016 vibration reports were reviewed and vibration concerns were being addressed for the 3A Boiler Feed pump, 3A&B EHC pumps, Cooling tower Fan #2 and the two Cooling water pumps at Van Sant.

The 2016 equipment oil samples were also reviewed and the August 01, 2016 sample for the 3B Forced Draft fan indicated a “Critical Condition” due to high particle count. Plant management reported that the analysis referenced the wrong specifications and the resample was satisfactory. A few other lube oil analysis reported increased particle counts.

The 2015 oil samples were provided for the Unit 1 and 3 main turbines, #3A and 3B boiler feed pumps, Units 1, 2 and 3 Forced draft (FD) fans, Units 1 and 3 Induced Draft (ID) fan and the VanSant combustion turbine.

The 3B FD fan motor outboard bearing was rated as CRITICAL due to in correct oil viscosity and elevated particle counts.

The analysis was rated MARGINAL due to high particle count in the oil samples for Unit 1 FD fan motor inboard bearing, Unit 1 ID fan outboard bearing, Unit 2 FD fan motor inboard bearing, Unit 3A ID fan motor inboard bearing, Unit 3 main turbine and the Vansant turbine. Plant personnel have an auxiliary oil filtration system which is being used to filter the oil systems with the high particle count. Unit 3 oil condition was reported to have been corrected.

The 2014 turbine oil samples results were as follows:

Unit 1 turbine oil tank: CAUTION - OBS 1 -- Additive package elements flagged are unusual for this oil. Suspect incorrect lubricant, mix up of oil, or contamination. Verify lubricant in use & advise lab. -- OBS 2 -- Particle count result is above industry guidelines. Acceptable limit is ISO 18/16/12. Check filters for performance. Filter lubricant to remove particulates.

Unit 2 turbine oil tank reservoir: CAUTION - Elevated amounts of ferrous particles are present. Iron is a common wear element and could be coming from sources such as gears, bearings, shafts, housings. Filter lubricant & continue to monitor. -- OBS 2 -- Additive package elements flagged are unusual for this oil. Suspect incorrect lubricant, mix up of oil, or contamination. Verify lubricant in use & advise lab.

Unit 3 Turbine oil tank: CAUTION - Additive package elements flagged are unusual for this oil. Suspect incorrect lubricant, mix up of oil, or contamination. Verify lubricant in use & advise lab.

VanSant Combustion Turbine reservoir: CAUTION - Particle count result is above industry guidelines. Acceptable limit is ISO 18/16/12. Check filters for performance. Filter lubricant to remove particulates.

Transformer oil analysis is performed annually when the units are in service. A previous inspector directed the plant personnel to collect samples only when the unit is under a load. The best practice is to collect transformer oil samples every six months whether the unit is loaded or not. Transformer oil analysis was collected in February 2012 and no significant gassing or oil degradation was noted. In 2013 the transformer oil was tested for and no concerns were identified. Eight transformers were also tested in 2013 for corrosive sulfur per ASTM 1275 and no corrosive sulfur was detected. The 2014 transformer oil analysis results were reviewed and all were reported to be in Condition 1. Three transformers had a slight increase in gases indicating a potential heating condition.

C0434251 - Ethane increased from 58ppm to 63ppm

461901 - The hydrogen increased from 5ppm to22ppm. The carbon Monoxide increased from 1210ppm to 1679ppm and the carbon dioxide increased from 18160ppm to 19373ppm.

05C1528 - The hydrogen level increased from 200ppm to 270ppm and the carbon dioxide increased from 10650ppm to 12563ppm.

The March 2015 and January 2016 transformer oil analysis results were provided for the Unit 3 Start-up transformer, Unit 3 11200Kva transformer, Unit 3 Main130Kva transformer and the VanSant #150 transformer. There were no indications of gassing or oil degradation, all four transformers were rated in Condition 1.

The November 2016 transformer oil analysis were reviewed and concerns with elevated gassing was noted in the Unit 2 -1500KVA transformer Location 460, SN461902. This transformer indicated an increase of acetylene from 0.0ppm to 13.0ppm. The oil sample for Transformer Location 461, SN 461901 also indicated elevated acetylene from 0.0ppm to 80.0ppm. Acetylene in transformer oil is an indication of arcing in the oil. Plant management agreed to evaluate this concern.

A hand held vibration data collection device was purchased in 2012. The plant has established routes for collecting vibration data from the rotating equipment. No significant vibration concerns were reported during the 2015 visit.

A high energy piping evaluation has been completed and some deficiencies were identified and were addressed. The evaluation was performed by Intertek. Both hot and cold walkdowns of the main steam, hot reheat and cold reheat piping systems was conducted in 2012.

The evaluation of the Unit 1 and Unit 2 main steam piping was completed by Intertek and some system interferences and displacements were identified. Intertek also performed an as found stress analysis on the piping systems and selected the critical welds which should be examined based on current piping stresses. Intertek concluded that the Unit 1 and Unit 2 main steam piping sustained loads and thermal stress from the as found analysis are in compliance with the ASME B31.1-1955 code stress allowables.

Intertek identified several deficiencies on the Unit 3 high energy piping system during the 2012 hot and cold walk down inspections. During the Unit 3, 2013 outage several of the hanger deficiencies were corrected. A sag was identified in the Unit 3 main steam piping and Intertek recommended that an additional drain be installed at the low point, which is being reviewed by plant personnel. Five girth welds in the cold reheat piping, six girth welds in the hot reheat piping system and seven main steam piping girth welds were identified for examination during the next outage, to verify if current stresses have degraded the integrity of the weldment.

In December 2014, Babcock Power/Riley Power performed an assessment of the main steam, Hot reheat and cold reheat piping. The assessment included performing magnetic particle examinations, Ultrasonic shear wave and straight beam examination, metallurgical replications and positive material identification. No areas of creep damage were identified and the piping was reported to be in good condition. In the main steam piping the base metal microstructure is highly spheroidized (Stage 6 in certain locations) and this could eventually lead to reduction of tensile strength, below the allowable ASME minimum limit. Currently, the estimated tensile strength of the main steam examined locations is above the minimum ASME specification for new material. Three areas in the hot reheat piping also were reported to have base metal microstructure that is highly spheroidized (Stage 6 in certain locations) and this has lowered the estimated tensile strength of the component in some locations, HRH-L2-9, HRH-L3-E, and HRH-L3-W, close to the allowable ASME minimum limit. Riley Powere recommended that the physical condition of the component at these locations where later stages of spheroidization (Stage 5-6) were observed should be evaluated during next year’s outage, within twelve (12) to eighteen (18) months.

The plant water chemistry, operating conditions and piping configurations were evaluated by Intertek. One hundred seventeen (117) components in the plant piping systems were identified as potentially locations for FAC. A matrix was provided to the plant personnel with an assigned priority of risk, with one being the highest risk and three being the lower risk. There were 74 locations identified as priority one concerns. Follow-up examinations were completed in 2014 and one component was replaced.

8.7 Electrical Equipment Testing

Thermographic surveys in the past were performed annually including back of panel inspections (allowed under the LOTO/Red Tag system. The electrical relays and breakers are tested every three years. Partial discharge testing is performed annually by GENTECH on the Vansant unit generator. One or two shorted turns were identified in Coil 5B of the VanSant combustion turbine Unit 11 generator. This condition was first identified in 2004 and has been three additional times and the condition has remained stable.

Thermography was completed in July of 2013 by Compliance Environmental Inc. when the units were in-service. Two hot spots in the electrical system were identified, which have been repaired. Infrared scans of the VanSant exhaust stack identified potential deterioration of the insulation. No thermography surveys were completed in 2014. A thermographic survey was performed in 2015 and seven Level 3 findings were identified in the VanSant report, which are expected to be repaired in the March, 2016 during the exhaust plenum replacement. The McKee Run report has eight level 1 observations, which were placed in the plants CMMS for follow up investigation.

Thermography survey results for the plant electrical equipment were not readily available for 2016, however a thermal graphic scan of the VanSant plenum was performed before and after the repairs.

Dielectric absorption test are carried out on large motors every 2 years.

Dielectric absorption/polarization index testing was performed in 2016 on the boiler fan motors, boiler feed pump motors, cooling water pump motors and no concerns were reported.

8.8 Non-Destructive Testing

Generally all normal forms of NDT have and are being used at the station as needed:

- Hydraulic testing
- Dye Penetrant
- MPI
- Ultrasonic

The unit 3 boiler tubes are scheduled for examination during the 2018 outage.

- X-ray.
- Eddy current testing of condenser tubing carried out.

8.9 Remnant Life Analysis

An equipment assessment of the McKee Run and VanSant stations were conducted on 22nd to 24th April 2002 by Duke/Flour Daniel Operating Plant Services. Based on a physical inspection of the plant systems, a walk-down of the site, and review of the historical documentation, Duke/Fluor Daniel concluded that the plant and equipment had been well engineered, and that it was considered generally suitable for the purpose for which it was designed.

There were, however, several plant items the assessment team and plant staff have identified which have proven troublesome. These items are noted below with the actions taken to date. These items include:

- Boiler water wall, reheater and superheater tubing failures – sections replaced
- Structural roof deterioration - % year plan, all replaced 1 and 2 units
- Air conditioning system life – All replaced with individual units
- Air heater element deterioration – Replacement of elements done.
- Condenser tubing monitoring – visual carried out, no leaks detected.
- Continued turbine/generator rotor inspections – No casings removed but LP end inspected from Condenser.
- Combustion turbine hot gas path inspections – last inspection in 2002, Borescope carried out.

These items are expected to require close attention while in operation, inspection during outage periods, and regular level of maintenance or repair prior to 2011.

There were additional areas, which Duke/Fluor Daniel recognized as possibly affecting the future plant operations in the time frame until 2011. These items include:

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- Continued routine boiler chemical cleanings – last done in 2001 will not be doing going forward unless tube analysis warrants it.
- Replacement of recorders due to obsolete or replacement parts – ongoing program of replacement in place
- Boiler flue gas duct work expansion joints – some done already metal being replaced with fabric (noted on U3)
- Cooling tower maintenance – annual inspection carried out.
- Digital Control Systems – 2003 changed to ABB INFI 90

Beyond the 2011 time frame the largest item affecting the plant would be to install a new digital control system. The typical cost of this is usually based on input and output points required to operate the units.

The management of the stations have recognized the need to carry-out the majority of the recommendations made following the assessment and these have been active in the Capital Projects and Special Projects listings for the station.

Two failed boiler tubes from the Unit 3 were removed and sent out for analysis. The samples were adjacent tubes removed from a burner nest in Spring 2013. One of the tubes contained two pad welds that were presumably made due to previous failures. Metallurgical examination identified under deposit corrosion in the pad-welded tube, as well as comparable areas in the adjacent tube. The metallurgical report, suggested that the under deposit corrosion appears to have occurred due to caustic gouging. Caustic gouging occurs when caustic in boiler water concentrates to high pH levels within internal deposits resulting in rapid corrosion of the tubing. The report recommends ultrasonic thickness (UT) measurements should be obtained from the fire side of other burner nest tubes. Tube sections with significant wall thinning should be replaced. It was also recommended that UT measurements be obtained from other areas of the boiler susceptible to under deposit corrosion including the furnace nose, horizontal or inclined tubes, and tubes that are vulnerable to flame impingement. A detailed review of the plant cycle chemistry records should be performed to identify if there are currently conditions that may be contributing to under deposit corrosion. The straight sections of tubing, above and below the burner nest, were in acceptable metallurgical condition. The hot-side internal deposit loading ranged from 9 g/ft2 to 13 g/ft2, which is considered relatively clean.

In 2016 one boiler tube failure was reported in the corner area of the boiler.

8.10 Equipment Storage

When not in service the boilers are maintained in a dry condition, or stored wet if under short term outage. U3 has a nitrogen blanket. Turbines are operated on turning gear. The generators are maintained with a positive hydrogen pressure. Motors have heaters. The feedwater heaters were not drained during the 2104 visit; however the unit was just running the day of the site visit. During the 2017 visit, the boilers were drained in preparation for the annual maintenance outage.

In 2016 the plant installed a nitrogen generator so the Unit 3 turbine and boiler could be maintained in a nitrogen environment when not in service.

8.11 Technical Bulletins

With the exception of the gas turbine all other equipment at the station has been well proven and there are no technical bulletins relevant to these outstanding. In the case of the gas turbine however it was noted that these are carried out as required by the OEM and a record maintained. Technical bulletins for the emergency bearing oil pump reliability were provided in 2012 and requested that plant personnel review the plant system to ensure no single failure events would prevent proper operation of the DC lube oil system.

9 Machinery Breakdown

9.1 Plant or Equipment Issues – Technical / Problem Areas, etc.

None known at this time. Other than shown in the previous section

9.2 Unique Equipment

All plant equipment, including the VanSant gas turbine, are well proven.

9.3 Installed Redundancy

The very low utilization factor does allow for some redundancy however if all 3 units were called upon at the same time there is no spare capacity. Units 1 and 2 are supplied with no built in redundancy where fan capacity is concerned, however there is redundancy in some of the auxiliaries. Unit 3 has dual fans and would allow reduce operation if one failed.

9.4 Strategic Spare Parts Inventory

There is no strategic parts inventory maintained for the major components.

9.5 Equipment Contingency Plans

COMPONENT		HP/IP	LP	GENERATOR	PRI VALVES	SEC VALVES	BOILER major	Boiler safety valves	Boiler mini	BORESONIC HP	BORESONIC LP	BORESONIC GEN.
Steam turbine units	Next Major											
MR1		50,000 hrs (3)	50,000 hrs (3)	50,000 hrs (3)	30,000 hrs	30,000 hrs	4 yrs	2 yr	2 yrs.	50,000 hrs (3)	50,000 hrs (3)	50,000 hrs (3)
MR2		50,000 hrs (3)	50,000 hrs (3)	50,000 hrs (3)	30,000 hrs	30,000 hrs	4 yrs	2 yr	2 yrs.	50,000 hrs (3)	50,000 hrs (3)	50,000 hrs (3)
MR3		50,000 hrs (3)	50,000 hrs (3)	50,000 hrs (3)	30,000 hrs	30,000 hrs	4 yrs	2 yr	2 yrs.	50,000 hrs (3)	50,000 hrs (3)	No Inspection (1)
Gas turbines		Major compressor/ turbine	HOT GAS PATH	COMBUSTION inspection	BORESCOPE TURBINE	GENERATOR	BORESONIC GEN.					
VS11		48000/2400 (2)	24000/1200 (2)	12,000/600 (2)	2yr	80,000 hrs	No Inspection (1)					

Note: inspections based on Factored hours or Factored starts divided by the calculated maintenance factor per GE recommendation contained in GER 3620J

The Unit 1 and Unit 2 steam turbines have not been dismantled for several years and are expected to be retired in 2017. It is understood that the units have very few starts and operating hours, however internal conditions identified during the borescope inspection of the Unit 1 and Unit 2 nozzle block area suggest that a dismantle inspection is warranted. Units with few operating hours and start can still be subjected to deteriorating conditions and should be dismantled for inspection, however the units are expected to be retired very soon and it is not likely that borescope inspections will be performed.

Unit 3 turbine was dismantled for inspection in 2014.

9.6 Accessibility of Equipment for Removal and Repairs

There is some congestion within the basement area however major plant items are accessible. Unit 3 boiler does have fans at a high elevation and would require a crane to remove.

10 Risk Management Programs & Procedures

10.1 Emergency Response Pre-Plans

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The station has a set of emergency response plans available within the administration building and in the main control room. In 2008 the plant staff reviewed the emergency response plans and has developed a risk management plan associated with natural gas hazards at both generating stations. All station staff have received training in this process.

10.2 Housekeeping Standards

Plant housekeeping conditions observed during the 2016 and 2017 visits were excellent. The plant was running the morning of the 2015 site visit and the facility housekeeping was above average.

10.3 Fire System Inspection, Testing & Maintenance Standards

The systems protecting the cooling towers are tripped and the fire pump is flow tested annually by a contractor. In 2015 and 2016 the fire pump along with the dry pipe systems, deluge systems and the fire alarms were tested and inspected by Sobieski Life Safety Inc. The results were satisfactory with minor discrepancies and noted.

The fire extinguishers are inspected monthly by plant personnel and annually by a contractor. Fire pumps are tested weekly by plant personnel.

10.4 Cutting & Welding Controls

The plant also utilizes a Hot Work Permit program which identifies possible hazards and incorporates a fire watch.

10.5 Smoking Controls

This is a non-smoking site however there are designated areas near to the main plant building where smoking is permitted.

10.6 Self Inspection Procedures

The station has a number of self-inspection systems in place a typical example of a station report is shown below:

Environmental, Health, and Safety Statistics		
	Month (December)	Fiscal Year to Date (7/1/16-6/30/17)
NOVs	0	1
Opacity Deviations	0	2 - Unit 3
Environmental Deviations	0	0
OSHA Recordable	0	0
OSHA LTA's	0	0
First Aid cases	0	0
Restricted Workday Accident	0	0
Near Miss	0	10
Man Hours Worked	----	----
Date last OSHA Recordable		04/16/15
Date last Lost Time Accident		01/12/15
Days since last OSHA recordable		625
Days since last Lost Time Accident		719

10.7 Fire Protection Training

As noted earlier in the report, station staff will not attempt to extinguish anything larger than a waste bin (trash can) sized fire and will immediately call out the local fire department. The fire department has come to the facility for training and familiarity.

10.8 Safety Management Systems, Training, etc.

New hires and personnel seeking advancement utilize the Employee Development Qualification Program that includes system sign off and oral boards. A refresher- training program is being developed along with procedure upgrades.

10.9 Security

Access to the station is via the electrically operated main gate located at the south end of the site which is controlled from the main control room via an intercom system. The entire site is surrounded by 6 ft high fencing topped with barbed wire.

There are 5 x CCTV facilities:

- 2 at the main gate.
- 2 at the rear of the station looking north.
- 1 at the front of the station looking south. No other form of intruder alarm system is available. All four cameras are viewed from the main control room, station staff carry out perimeter walks throughout the day and night.

10.10 Fire Protection Impairment Procedures

There is a basic system in place and would form part of the LOTO RED TAG system risk assessment.

11 Extraneous Perils

11.1 Subsidence / Settlement / Landslide

There is no evidence or history of subsidence/settlement or landslide at the station.

11.2 Water / Flood

Both sites are located in a FEMA Flood Zone X. See attached drawings.

11.3 Lightning

The City of Dover is located in a Zone 1 area with a likely strike rate of 2 - 6 strikes per km^2 and per year.

11.4 Storm / Windstorm

Zone 1: SS 1 (118-153 km/h) Probable maximum intensity (SS: Saffir-Simpson hurricane scale) with an exceedance probability of 10% in 10 years (equivalent to 'return period' of 100 years)Freeze / Snow Load. Dover is however located in an area known for its high risk of tornado damage.
There is also a low to medium risk of hailstorm damage.

11.5 Aircraft

There are no major commercial airports in the area although there is a number of smaller airports utilizing local and interstate traffic however during the visit not one aircraft was noted as over flying the station. Dover Air Force Base is located just outside city limits.

11.6 Tsunami

Dover is approximately 45 km from the sea and is unlikely to be subjected to any affects from a Tsunami. According to the Munich Re world hazards map there is no threat of a tsunami along the east sea coast in the area of Dover.

11.7 Earthquake

Dover is located in a very stable part of the United States and the area is shown as being Zone 0 MM V and below. Probable maximum intensity (MM: modified Mercalli scale) with an exceedance probability of 10% in 50 years (equivalent to 'return period' of 475 years) for medium subsoil conditions

11.8 Malicious Damage & Theft

Although there had been a number of trespass incidents no major theft or damage has resulted from them.

11.9 Third Party Exposures

The biggest threat would be to nearby resident dwellings running along the east boundary of the station. In addition the west boundary is adjacent to a main railway line.

12 Value breakdown

Date of Values Evaluation / Source:	XL RQR Sheet
Building:	
Machinery & Equipment:	
Inventory:	
Other (Specify):	
Total PD:	
Total BI (12 Month Period):	
Total Insured Value (TIV):	$232,600,000

Comments: The VanSant location has an additional TIV of $19,500,000. The values have not been updated since 2010

These values were previously provided and have not been updated.

13 Loss Estimations

XLI Maximum Foreseeable Loss (MFL) definition

The XLI MFL is the largest monetary loss that may be expected from a single fire, or other peril when the controlling factor, to any given property. The impairment of fire protection that can be visualized on worst case scenario (i.e. free-burn with no intervention whatsoever) should be assumed when calculating the MFL. The MFL will take into consideration plant interdependencies and all coverage's provided including Business Interruption, Extra Expense, Extended Period of Indemnity, etc. No production make-up capacity (internally or externally) is considered in this MFL definition.

MFL scenario:

This would involve the loss Unit 3 boiler which would explode following an accumulation of combustible gases within the furnace into the turbine hall causing a major fire and result in U3 turbine run down without any lube oil and eventual seizure. The resulting fire would also cause extensive damage to the turbine hall roofing turbine pedestal and basement equipment. Major damage to Units 1 and 2 would occur due the significant fire. All the associated controls would need to be replaced and three generators would require rewinding. Extra expense is associated with demolition and disposal of damaged components and unavailable replacement parts and resources. Other would be the additional cleanup cost due to smoke damage and the other areas of the facility and asbestos abatement.

Coverages	***% of TIV***	***Time / Days***	***Monetary Amount / Loss MWH***
Fire / Explosion – PD			$100,000,000
Fire / Explosion – BI		450	
Extra Expense			$5,000,000
Other – Describe			1,000,000
Total MFL		450	$106,000,000

MFL – All Risk

XLI Probable Maximum Loss (PML) definition

The XLI PML is the largest monetary loss that may be expected, originating in the most vulnerable area of a property / critical equipment item, at a time when there exists a major impairment to a fixed protective device / fire protection system, and other reasonable to imagine adverse conditions. Credit for the activation of the fixed protective devices and automatic protection systems in the surrounding areas (if

Coverages	***% of TIV***	***Time / Days***	***Monetary Amount / Loss MWH***
Fire / Explosion – PD			$60,000,000
Fire / Explosion – BI		273	
Extra Expense			$3,000,000
Other – Describe			$500,000
Total PML		273	$63,500,000

any), plus an emergency response from the local fire department/brigade, may be applied.

PML Scenario:

This would involve the loss of blading in Unit 3 turbine with subsequent vibration rupturing a lubricating oil line resulting in a fire which would result in the extensive damage to the turbine building structure, damage to the turbine pedestal and basement equipment. Minor damage to units 1 and 2 would occur due to falling roof debris. The station is equipped with a single overhead crane which would also have been damaged but repairable as a result of the fire. Extra expense is associated with demolition and disposal of damaged components and unavailable replacement parts and resources. Other would be the additional clean-up cost due to smoke damage in the other areas of the facility and possible asbestos abatement.

PML – All Risk

XLI Normal Loss Expectancy (NLE) Definition

The XLI NLE is the largest monetary loss that can be expected from a single loss event to any insured property under normal conditions. All existing protection systems (including but not limited to ; active fire protection systems and protective devices etc.) are in service and perform as designed. In addition, notification to the plant emergency organization and/or the local public fire department is not delayed and they respond as expected. In most cases, the NLE is the highest loss expectancy for an existing recognized deficiency, and is normally aligned to the expected deductibles for the policy.

NLE Scenario:

This would involve a steam turbine blade rub on Unit 3 requiring the turbine to be shut down and opened for inspection and repair. All blades are found intact however some dressing of blade shrouds and seal required. NLE amount includes the opening and closing cost of the unit. Extra expense is expected for expedite the repairs.

NLE – All Risk

Coverages	*% of TIV*	*Time / Days*	*Monetary Amount / Loss MWH*
Fire / Explosion – PD			$1,000,000
Fire / Explosion – BI		45	
Extra Expense			$100,000
Other – Describe			
Total NLE		45	$1,100,000

The Uniform Loss Events/values were discussed with plant management during this visit. No value changes have been provided.

14 Summary of Quality Ratings (Optional)

Rating Standards:

Excellent: The facility has taken measures beyond industry best practices to conserve equipment and property. Loss potential is significantly reduced due the management teams approach and practices as respects the management of risk inherent at the facility.

Acceptable: The facility has taken measures on par with industry standards and best practices to conserve equipment and property. Loss potential is average as compared to other similar risks in consideration of the management teams approach and practices as respects the management of risk inherent at the facility.

Needs Improvement: The facility's practices and standards are less than industry best practices and facility management has not taken acceptable measures to conserve equipment and property. Loss potential is extremely high as compared to other similar risks. The management team's approach and practices as respects the management of risk inherent at the facility are below industry standards and best practices.

Rating Area	*Excellent*	*Acceptable*	*Needs Improvement*
Construction & Civil Works		X	
Plant Dependencies		x	
Equipment Protection		X	
Fire Protection & Special Hazards		X	
Plant Operations		X	
Equipment Maintenance		X	
Machinery Breakdown		X	
Risk Management Programs & Procedures	X		

15 Opinion of Risk

The McKee Run station consists of three units. Units 1 and 2 are over 50 years of age and originally designed for coal firing previously converted to burn #6 fuel oil and now fired on #2 oil and natural gas, unit 3 is approximately 41 years old.

The plant is an older plant and was built to the standards used at the time of construction. Several plant upgrades have been completed, however the plant protection does not meet today's standards in areas such as fire protection and turbine water induction protection. Improvements have been made such as installing an AFFF system on the Unit 3 turbine bearings and smoke and heat detection in the warehouse and administration building as well as installing an industrial waste water system. Several areas of the plant are not equipped with fire detection or protection as described in Section 6 of the report. Based on the plant's current operating schedule additional fire protection is not recommended at this time, however additional detection and protection would improve this risk.

The McKee Run Unit 1 and Unit 2 have operated very little in the past few years and will be retired soon. Unit 3 operations increase significantly in 2016. Plant operators have procedures, however with very little operating time it is difficult to become proficient and stay abreast of plant operations. Plant management has developed a training program to keep operators up to speed which includes having dry run training sessions, there is also a simulator for the Van Sant unit.

Due to the cycling nature of the operating steam units, the plant water chemistry program allows the chemistry limits to consistently be out of the acceptable ranges. Plant lay-up procedures have been developed and implemented. The plant recently installed a nitrogen generator to improve the system layup practices.

Borescope inspection of the Unit 1 and Unit 2 nozzle blocks indicate water chemistry and lay-up practices have been less than adequate in the past based on the pitting and deterioration reported.

The Unit 3 steam turbine was overhauled in 2014. The turbine was reported to be in good condition for its age. The steam packing and oil seals were recommended to be replaced during the next outage. The Unit 3 generator was last dismantled in 2000. The Unit 3 operations have increased in the past few years. Unit 3 operated 791 hours with 37 starts in 2016. The Unit 2 steam turbine has not been dismantled since 1994 (approximately 20 years). Dismantle inspections beyond ten years are not typical even for units with few operating hours and starts, unless an extensive evaluation is completed that reviews all conditions associated with the unit. Unit 1 and Unit 2 are scheduled to be retired in 2017 and no major dismantle inspections are currently scheduled for these units.

Combustion turbine was scheduled to be dismantled for inspection in 2015, however is currently planned for Spring 2018. A borescope inspection was being performed at the time of the 2017 site visit. The operating time for the VanSant unit was slightly increased in 2015 compared to 2014 operating data, however decreased in 2016.

Plant activities appeared to be well documented and tracked. Regular maintenance outages are performed. Capital improvements are ongoing and the plant continues to update controls and software systems. New burner management protection for unit 1 and 2 boilers have been installed. Additional wiring was installed to improve the gas control system for the unit 1 and Unit 2 boilers.

Regular testing of plant equipment is being performed. Annual lube oil testing has been completed every year since 2011. The plant upgraded the DC protection system for the Unit 3 turbine DC lube oil pump providing a dual contactor on the pump for redundant protection. An elevated level of acetylene was noted in two of the plant transformer oil samples in 2016, which plant management agreed to evaluate.

There are no external third party risks and with respect to natural perils the one main risk is connected to tornado damage which is considered to be very high in this location.

Plant management is receptive to the insurance recommendations and has completed several of the previous recommendations. Five recommendations were completed in 2010 and five additional recommendations were completed in 2011. In 2012 four recommendations were completed and one was withdrawn during the 2013 inspection. During the 2014 inspection one recommendation was closed and one new recommendation was issued. No new recommendations were made in 2015 and two recommendations were closed. No new recommendations were made in 2017, one old recommendation was withdrawn due to the decreased risk by removing the old coal equipment. Three recommendations

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remain open for the City of Dover. The plant has action plans in place to address the recommendations.

The personnel at the plant continue to make changes to improve the safety and reliability of the facility. The continued effort to improve plant reliability and comply with recommendations is a testimony to the City and plant personnel's commitment to have a reliable facility. Several of the plant staff are near retirement age and notable personnel turnover is expected. In 2015 a new plant manager and plant engineer were engaged. In 2016 the plant manager was promoted and in 2017 a new plant manager was appointed.

This account was previously rated below average in regards to plant protection systems to include fire protection, and turbine water induction protection, however the significant efforts have improved the plant protections system that are aligned with the operating practices employed at the plant. Economic justification to update to state of the art protection is difficult for a plant operated in peaking mode. Plant operating procedures and operator training programs are in place, and considered to be average to above average. In 2011 efforts to develop and implement lay-up procedures and flammable gas venting and purging procedures are commendable. Significant efforts were also made 2012 to reduce the plant's risk exposure and limit damage. A prime example is the installation of the fire walls between the unit transformers. Since the plant operates such few hours per year and several operators have been employed at the facility for several years, along with the regular maintenance performed this account should be considered as an overall average to above average risk. The rating for Risk Management Programs and Procedures was upgraded during the 2014 inspection due to the continued efforts shown to improve plant conditions, procedures and equipment protection. The housekeeping at the facilities is also excellent. Based on the plants past efforts, it is expected that the combustion turbine will be dismantled and inspected and additional recommendations will be completed in the next few years and will soon be considered an above average facility.

16 APPENDIX Attachment 1 – Water Supply and Sprinkler System Test

Results

Public / Private Water Supplies

Date	By	Source Tested	Flow Location	Pressure Location	Test Data		
					Flow Rate (units)	Static Pressure (units)	Residualr essure (units)
Notes	Water provide by City water system.						

Diesel / Electric Fire Pumps

Pump	100% Rating			Suction	Driver	Pressure Settings			
						Jockey Pump (pressure units)		Fire Pump (pressure units)	
	(gpm)	(pressure units)	(rpm)	SOURCE		Start	Stop	Start	Stop
	1000		1750	City fire main	Electric				
	1000		1750	City fire main	Gasoline				

Diesel / Electric Fire Pump Tests

Date	By	Pump	Flow Location	Test Data					Adjusted Data		Rating
				Flow (gpm)	Speed or Current (rpm / Amps)	Suct. Press. (psi)	Disch. Press. (psi)	Net Press. (psi)	Flow (units)	Net (units)	
04/23/09	Radius Tech	Electric		1012	1773	40	110	95			
				1518	1768	40	100	75			
			Churn	0	1788	50	125	100			
04/23/09	Radius Tech	Gasoline		1012	1647	48	125	73			
				1500	1778	45	110	65			
			Churn		1775	50	125	75			

Sprinkler System Test Results

Date	By	No. of Risers		Test Data			Alarms Rec'd		Valves	
		# On Site	# Tested	Init. Static Press. **(units)**	Resid. Press. (units)	Final Static Press. (units)	Local (Yes / No)	Central (Yes / No)	# On Site	# Tested
Notes										

Dry Pipe Sprinkler System Test Results

System #	Building/Area	System Air Pressure (units)	Static Water Pressure (units)	Trip Point Pressure (Units)	Time to Trip (sec)	Time to ITC (sec)	Comments
CT #1	Cooling tower Unit 1	50	50	7	20		
CT#2	Cooling Tower Unit 2	35	50	5	18		
CT #3	Cooling Tower Unit 3	34	50	6	13		
CT #4	Cooling Tower Unit 3	30	50	8	20		
CT#5	Cooling Tower Unit 3	43	50	8	23		
Deluge #1	Cooling Tower Unit 1	28	50	15	10		
Deluge #2	Cooling Tower Unit 2	30	50	18	9		
Deluge #3	Cooling Tower Unit 3	32	50	19	10		

Sprinkler System Design

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System # / Type	Building / Area	Code	Design Density / Area (units)	Demand (units: Flow @ press.)	Sprinkler Heads (units: Nom.Size, Temp.)	Spacing (units: Area)	Req'd. Density / Area (units)	Avail. Density / Area (units)	Assessment

Attachment 2 - Pictures

View of the Station Cooling Towers

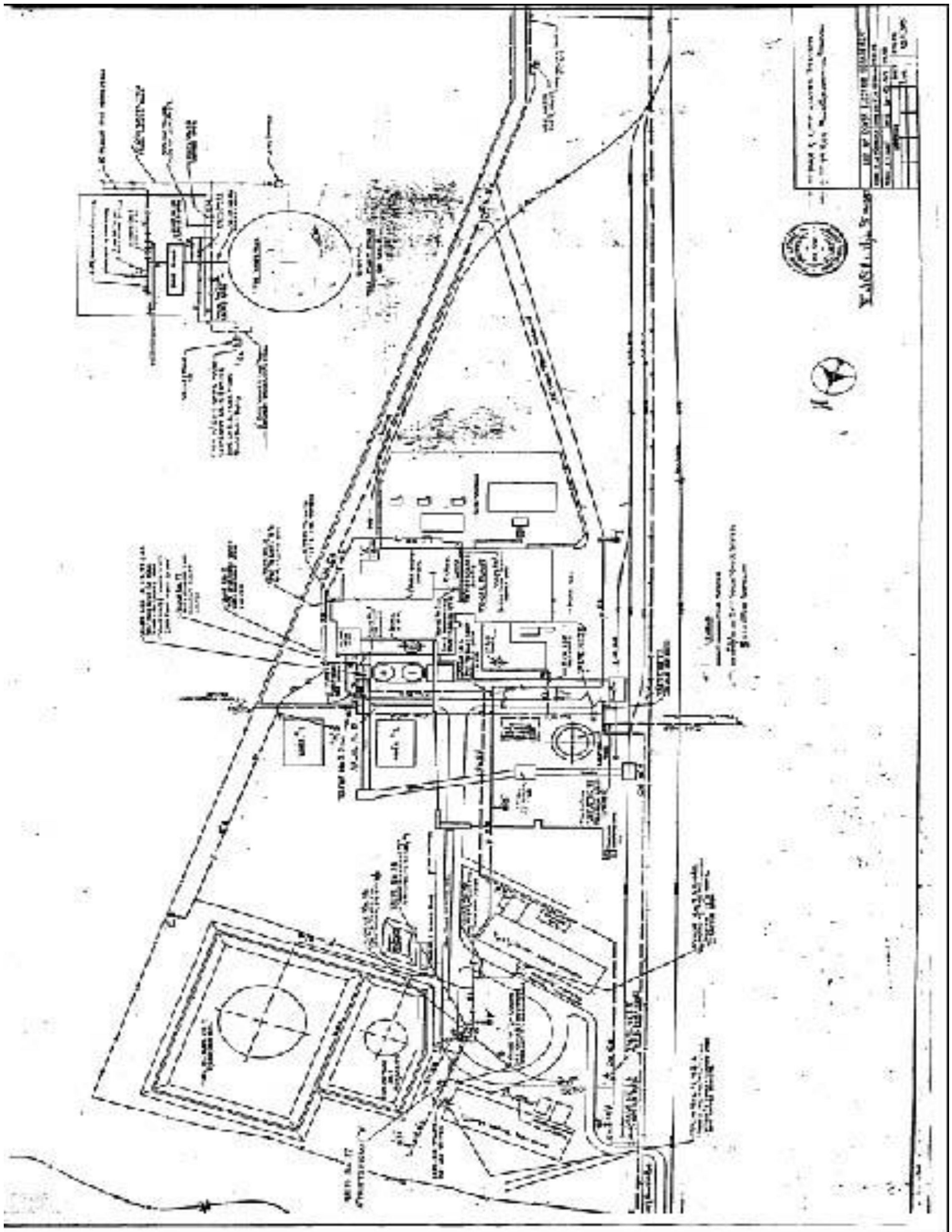
Steam Turbines 1 & 2

Unit 3 Steam Turbine

Unit 3 Boiler

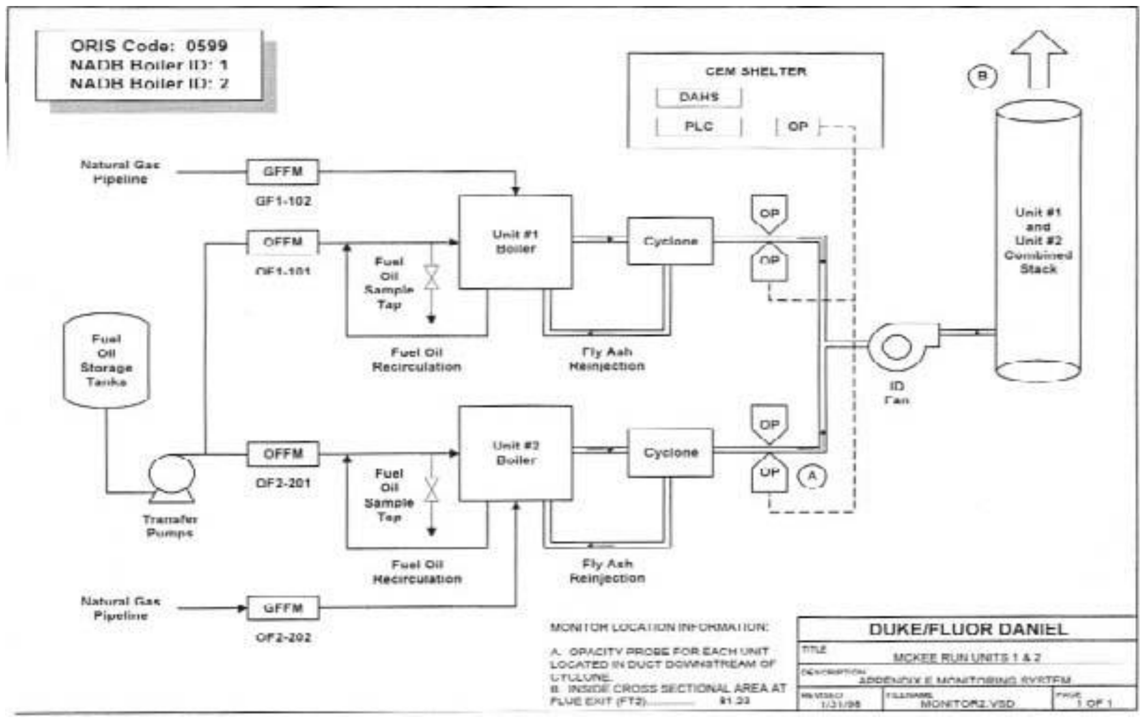
VanSant Gas Turbine

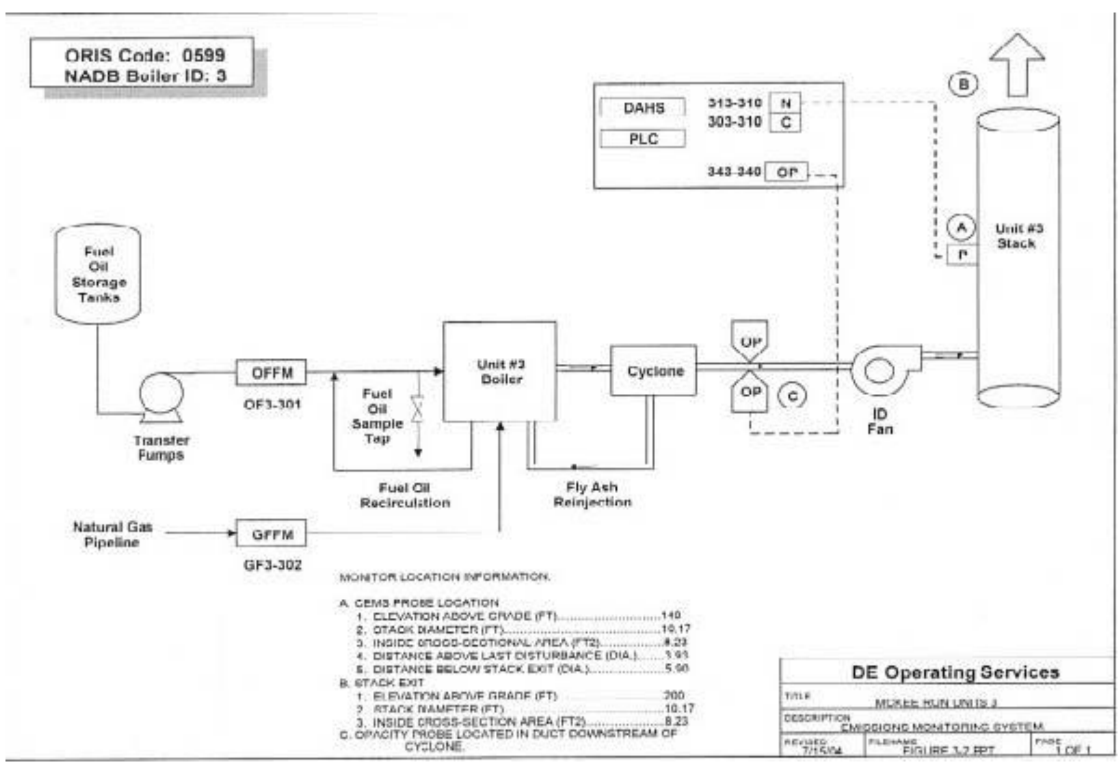
Attachment 3 - Site Plan



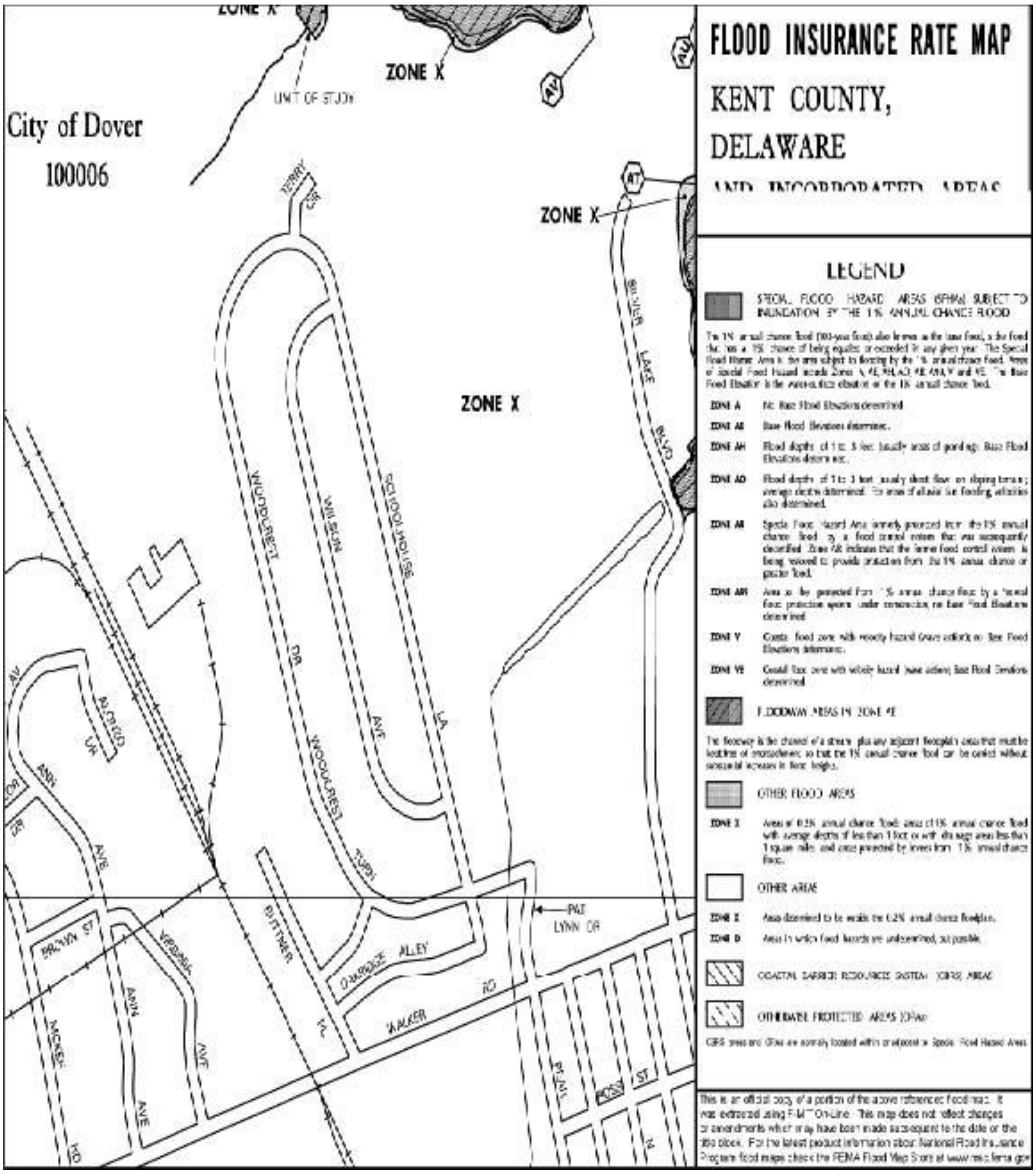
Attachment 4 - Process Flow Diagrams

Units 1 and 2

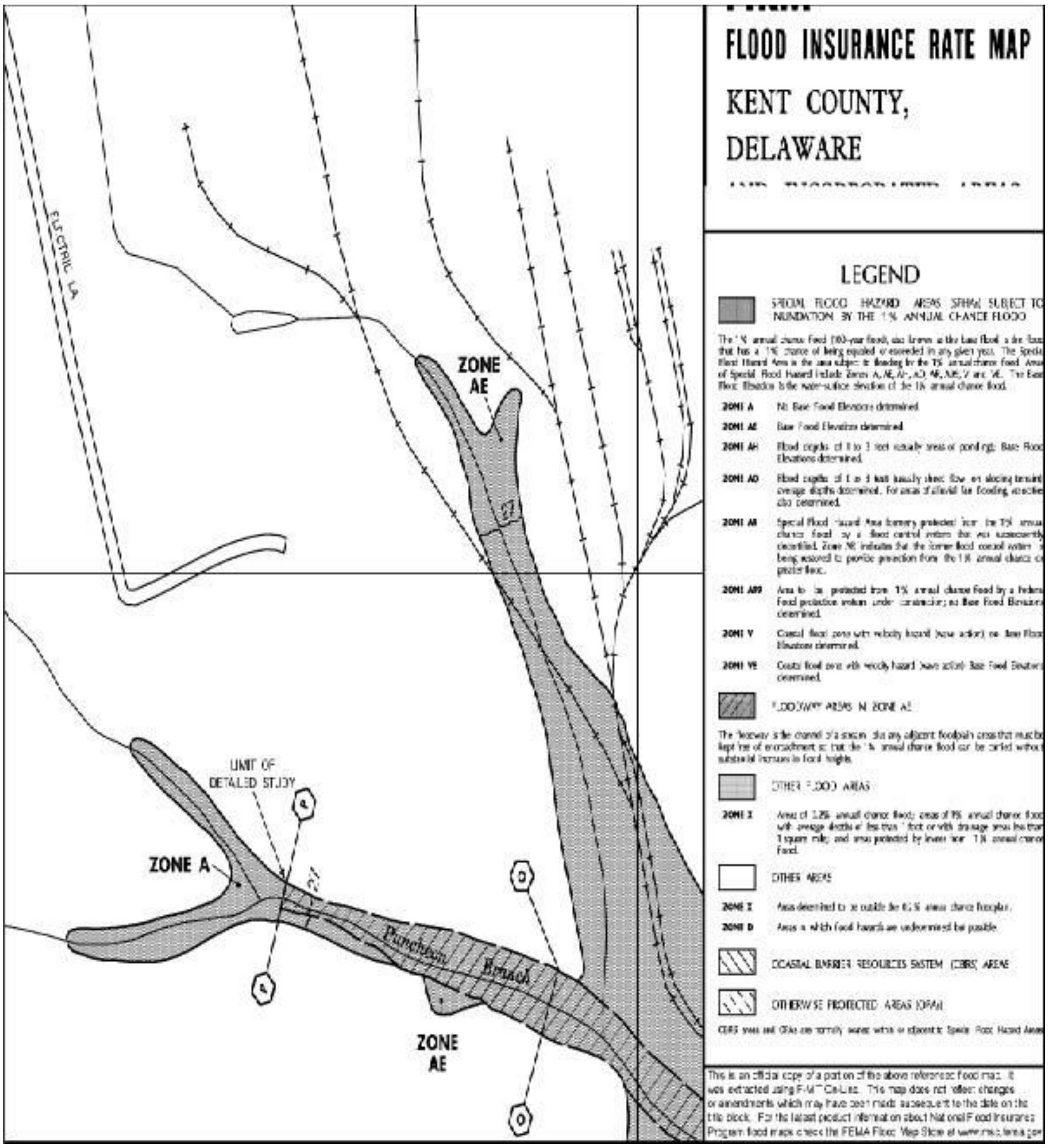




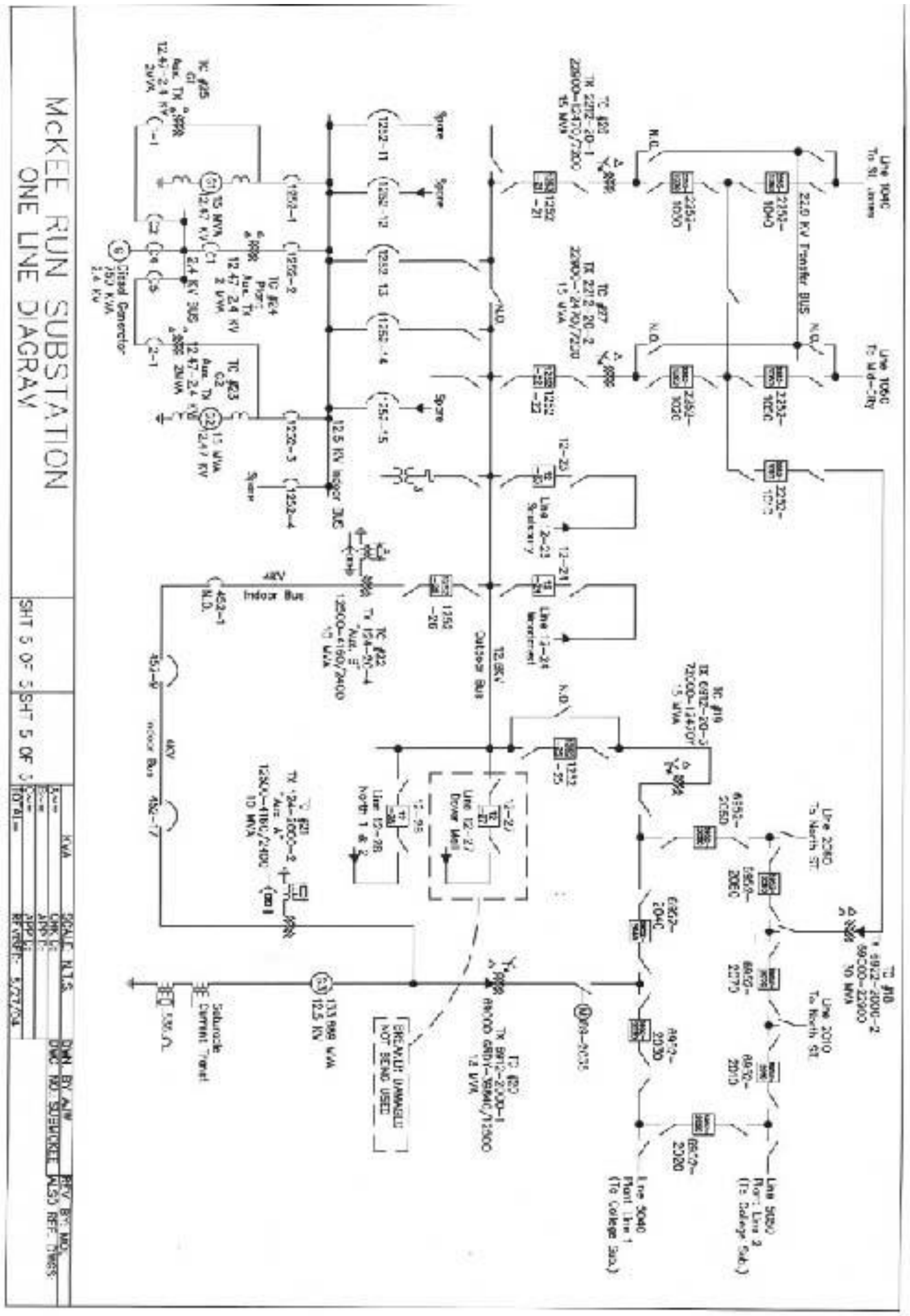
Attachment 5 – Flood Map for McKee Run



Attachment 6 – Flood Map for VanSant



Attachment 7 One line Electrical for McKee Run



Attachment 8- Previously Closed Recommendations

2012-01 – Evaluate the DC system to ensure that the design meets the requirements of GE TIL 775 and TIL 914 to ensure the DC Lube oil and DC seal oil pumps will start and continue to operate even if there is a single point failure in the DC supply. Unit 3 appears to have several redundant DC power supplies however all supplied though a single fuse and transfer switch which could also lead to a single point failure.

Comment: It appears that the DC circuits for Unit 1 and Unit 2 have fuses or breakers between the DC Buss and the DC oil pump motors as well as the batteries. Fuses are not the recommended reliable protection and breakers should be rated at least 150% of the maximum in rush current. A recent industry event resulted in significant turbine damage as a result of an instantaneous fault in the DC system which tripped the breakers preventing the DC lube oil pumps from starting.

Plant Response: The system will be evaluated on how best to implement the suggested design and appropriate action taken to install the system changes.

Status Feb. 13, 2013 – The change is currently being submitted through the approval process. Once the approval process is complete, plant personnel will begin planning the implementation of the changes.

Status January 29, 2014 – A project has been initiated to address this concern. The project is in the bid scope development process at this time.

Status February 18, 2015 – The DC system for Unit 3 has been upgraded to provide a dual contactor for the DC lube oil pump through a separate DC supply. CLOSED

2010-05 - An evaluation should be performed to identify the components that are prone to Flow Accelerated Corrosion.

Comment: Flow Accelerated Corrosion (FAC) has resulted in several plant failures and is a potential safety concern. The plant operating conditions and components should be evaluated to determine areas prone to FAC and an inspection program should be developed if necessary.

Plant Comment: Plans are in place to perform inspections per planning schedule. Mr. Grabow to review to determine if scheduling should be moved up in time.
Status 4/21/2011- The plant is currently planning to perform FAC examinations in 2014**.**

Status 2/1/12 – Plant personnel are in the process of developing an examination program. Previous examination records have been retrieved that provide base line information to assist in the development of the program.

Status Feb. 13, 2013 – An initial study of the high energy piping system was performed. An initial inspection and testing program has been developed. Plant personnel will continue to develop and implement an FAC inspection program

Status January 29, 2014 – Locations of potential FAC have been identified and the plant is in the process of setting up the inspections. Pulse eddy current is being considered for the initial screening of the feedwater heaters and some of the piping systems in 2014.

Status February 18, 2015 – A survey was completed in 2012 by Intertek, which identified the areas prone to FAC. Subsequent inspections of these areas have been completed and one area was identified as an area of concern, which was replaced. Follow up inspections are expected to be conducted based on established thinning rates from the nominal thickness to the measured thickness of each component. CLOSED

2013-01 Test the transformer oil for corrosive sulfurs. The presence of sulfur and/or sulfur

mercaptans should be verified in all critical transformer oil.

Comment: The presence of elemental sulfur and thermally unstable sulfur-bearing compounds in electrical insulating oil can cause corrosion of certain transformer metals such as copper and silver. This is a one-time test which should be performed in accordance with ASTM Standard D-2864.

Status January 29, 2014 – The transformer oil testing was completed and no corrosive sulfur concerns were identified. CLOSED

2012-03 – Overspeed Protection Testing. Testing of the overspeed protection system on the steam turbines should be performed on an annual basis. CLOSED

Comment: Overspeed protection should be tested on a regular basis to ensure the set point has not drifted and the protection is maintained in a good working condition. Overspeed conditions can result in catastrophic failures and present a significant risk to the plant and personnel.

Plant Response: Plant staff will review procedures and implement in 2012. PM Work order is currently in Work Order Management System MP2 to trigger the testing.

Status Feb. 13, 2013 – Overspeed test were performed in 2012 on all three steam units. The overspeed protection activated as designed. The tests were reported to be satisfactorily completed. This recommendation is considered CLOSED.

2012-04 – Overspeed Protection of the Van Slant combustion turbine, Unit 11 should be performed on an annual basis. CLOSED

Comment: Overspeed protection should be tested on a regular basis to ensure the set point has not drifted and the protection is maintained in a good working condition. Overspeed conditions can result in catastrophic failures and present a significant risk to the plant and personnel.

Plant Response: Plant staff is currently performing this test and will ensure it is completed on an annual basis. PM Work order is currently in Work Order Management System MP2 to trigger the testing.

Status Feb. 13, 2013 – Overspeed test were performed in 2012 on the combustion turbine unit. The overspeed protection activated as designed. The tests were reported to be satisfactorily completed. This recommendation is considered CLOSED.

2008-03 VanSant Gas Turbine Gas Detection CLOSED
During the site tour it was noted that the VanSant gas turbine although running predominately on gas was noted as not being fitted with any form of gas detection.

Comment: GE should be contacted and the installation of gas detectors considered. The plant is in the process of contacting GE for this information.

Status 4/20/10: Plant personnel have contacted GE and are waiting for a response.

Status 4/21/2011- Plant personnel are still working with GE regarding this matter.

Status: 2/1/2012 – A gas detection system has been designed and equipment has been ordered. The system is expected to be installed in the Spring of 2012.

Status Feb. 13, 2013 – A gas detection system has been installed. The gas detectors will activate the fire suppression system and alarm to the central control system. This recommendation is considered CLOSED.

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2007-08 Blastwall Protection of Transformers CLOSED

NFPA calls for transformers to be provided with blastwalls to restrict the knock on effect of a transformer explosion and subsequent fire. The transformers in the station are in close proximity to the station walls and other transformers.

Comment: It is recommended that a review be carried out as to the provision of blastwalls on those transformers owned by the McKee Run power station. In addition and in conjunction with the City electrical department a review of all transformers in the switchyard with respect to the installation of blastwalls should be carried out.

Status 2008**:** Still outstanding however site staff will set up team to investigate options. Need to discuss with COD Electric Dept. once all options have been formulated and researched.

Status 2009: Remains open.

Status 4/20/10: Plant management is still researching the installation of the fire barriers.

Status 4/21/2011- Plant management has requested additional information regarding the requirements of the blastwall protection**.**

Status: 2/1/2012 – The design efforts have been completed and the specifications have been released to the bidding process. Blast walls are expected to be installed in 2012.

Status Feb. 13, 2013 – Blast walls have been installed between the Unit three start-up transformer and the Unit 1 and 2 auxiliary transformers. This recommendation is considered CLOSED.

2007-09 Station Windows WITHDRAWN

It was noted that directly above a number of transformers on the south side of the station building are a number of windows.

Comment: It is likely as a result of failure of a transformer the windows directly above will fail and allow hot gases into station with the further risk of fire within the station. It is recommended that these windows be bricked up thereby reducing the risk.

Status 2008: Still investigating options

Status 2009: Remains open

Status 4/20/10: A fire curtain was suggested as an option to sealing the windows. Plant personnel rely on the windows to verify switch positions in the switchyard. Additional information will be provided.

Status 4/21/2011**-** This recommendation is still being considered by plant management.

Status: 2/1/2012 - Plant personnel have budgeted to install fire curtains in 2013 on the three windows directly above the auxiliary transformers on Units 1 and 2 side of the switchyard.

Status Feb. 13, 2013 – The plants has budget approval for the installation of fire curtains over the two windows above the Unit 3 start-up transformer. The windows above the Unit 1 and 2 auxiliary transformers are approximately 25 feet from the top of the transformers. The auxiliary transformers have an oil capacity of 635 gals. NFPA 850 Standard for Fire Protection for Electric Generating Plants and High voltage Direct Current Converter Stations Section 3-2.4.3 suggests that outdoor oil insulated transformers with 500 to 5000 gallon oil capacity should be separated by a minimum of twenty-five feet from adjacent structures and from each other by firewalls, spatial separation, or other approved means for the purpose of limiting the damage and potential spread of fire from a transformer failure. The distance from the top of the auxiliary transformers to the windows is approximately 25 feet, therefore it is considered that fire curtains are not required over the windows above the auxiliary transformers. The Unit 3 start-up transformer is slightly larger and within the 25 foot separation boundary to the windows. This recommendation is WITHDRAWN.

2010-09 – Lay-up practices should be implemented to protect the feedwater heater, deaerator, and condenser from corrosion when expected to be out of service for long periods. COMPLETED

Comment: Corrosion products will develop in metal systems that are exposed to oxygen and water for long periods of time. Draining the components while warm will help dry the components.

Plant Comment: Plant will incorporate recommendations into plant procedures.

Status 4/21/2011- The plant is currently reviewing plant procedures and updating to conform with the NAES procedures standards. The lay-up procedures are expected to be updated as part of this process.

Status: 2/1/12 - Plant personnel have developed and implemented lay-up procedures for the feedwater heaters, boilers and condensers that meet the XL insurance requirements.

Status Feb 13, 2013- It was noted during the plant walk through that the feedwater heater had water in the shell side of the feedwater heater. The heaters should be drained in accordance with the lay-up procedures. The heater was drained the following day by plant staff and will become part of Plant SOP

2010-10 – Develop and implement battery maintenance and testing program in accordance with IEEE STD 450. COMPLETED

Comment: A formal battery maintenance and testing program is necessary to properly maintain batteries. The program should follow the IEEE guidelines.

Plant Comment: Plant has received IEEE Guidelines from Mr. Grabow and will develop battery M/T program based on the information provided.

Status 4/21/2011- The plant has implemented a battery testing program with documented monthly and quarterly inspections. The documents were reviewed and cell temperatures and specific gravity values are not included on the records.

Status: 2/1/2012 - A formal battery maintenance and testing program has been developed and implemented that meets the IEEE Guidelines.

2007-01 Turbine Generator Bearing Protection

There are no systems protecting any of the steam turbine/generator bearings. **COMPLETED**

Comment: NFPA 850 recommends:

'7.7.4.2.1 Turbine-generator bearings should be protected with an automatic closed-head sprinkler system utilizing directional nozzles. Automatic actuation is more reliable than manual action. Fire protection systems for turbine-generator bearings should be designed for a density of 0.25 gpm/ft.^{2} (10.2 mm/min) over the protected area of all bearings.*
7.7.4.2.2 Accidental water discharge on bearing points and hot turbine parts should be considered. If necessary, these areas can be permitted to be protected by shields and encasing insulation with metal covers.'*

However, due to the limited operation and life of the station, it is suggested that consideration be given to the replacement of the water sprinkler system with a simple foam system in accordance with NFPA 16, the Standard for the installation of Foam-Water sprinkler and Foam-water spray systems. The system can be manual or automatic and could be operated from within the main control room if required. This will help the facility move towards the goal of meeting the NFPA standard stated above.

Status 2008: Work Order entered in MAXIMO- Assessing quotes to install system- expect to be installed by 6/30/08.

Status 2009: Previous tasking was incomplete. Plant is in the process of revising task statement/work scope with the help of XL Insurance GAP.

Status 4/20/10: The project was approved by city council; however bids were higher than estimated. Additional funds have been appropriated and the project bid is expected to be awarded by June 30, 2010.

Status 4/21/2011- A fire protection system has been installed over the Unit 3 turbine bearings activated by heat detectors. No additional protection has been installed on the Unit 1 and Unit 2 turbine bearings.

Status: 2/1/2012 – A portable foam extinguisher has been purchased and positioned on the ground floor between Unit 1 and 2. This form of protection is not the recommended standard of protection, however based on the low risk exposure and limited operating time of the units, it is has been accepted as adequate protection.

2007-07 Fire Barriers COMPLETED

The station has a number of fire barriers through which cables pass; some of these were noted as not being sealed. All openings in fire barriers should be provided with fire seals.

Comment: These openings can be sealed with an in tumescent material or as is now common practice with an approved fire rated (2 hrs.) expanding foam.

Status 2008:Work Order entered in MAXIMO- identified openings and in progress of obtaining materials to complete task. Expect to complete 4/30/08. XL Insurance will provide the plant will a list of approved products.

Status 2009: Plant is evaluating materials and pricing for the materials. Expect to complete by end of the year.

Status 4/20/10: Plant management has purchased the fire barrier materials and plans to seal the opening after completion of the Spring 2010 outage.

Status 4/21/2011- Upgrades of boiler controls is being performed. Additional control upgrades and control room modifications are also scheduled. Plant has sealed approximately 20 percent of the identified openings. Plant management intends to seal all openings upon completion of the controls upgrade.

Status: 2/1/2012 – The plant has sealed several through wall penetrations to comply with the intent of this recommendation. No unsealed penetrations were noted during this plant visit. This recommendation is considered closed, however a continued effort should be maintained to keep penetrations through fire barriers sealed.

2007-10 Routine Testing of Safety Features and Standby Equipment COMPLETED

As part of normal routines, modern power stations have procedures in place for the regular testing of equipment safety features and standby plant. These were not noted as being in place at the station.

Comment: All safety features should be catalogued and a routine of testing implemented. Standby plant should have a philosophy agreed and then implemented along with a log of time tests done results and any remedial action required.

Status 2008: Team set up to develop and implement procedures and test schedule. Some procedures are in place but not in a formal program.

Status 2009: Work continues on this project, albeit slow progress due to the work demands which occurred during the oil conversion project.

Status April 2010: Plant management continues to review and update procedures. Operating procedures reviewed during this visit have not been updated to remove direction for operating the ash removal equipment, valve position verifications, and lay-up practices.

Status 4/21/2011- The plant is currently reviewing plant procedures and updating to conform with the NAES procedures standards.

Status: 2/1/2012 – Several testing procedures and tracking documents have been developed and implemented. This recommendation is considered closed, however a continuous effort should be made to identify and test safety systems with applicable procedures and documentation.

2010-02 Maintain a hydrogen usage log - COMPLETED

Comment: A log should be maintained to monitor the use of hydrogen. A hydrogen usage log is essential in identifying a potential hydrogen leak.

Plant Comment: This task has been incorporated into the daily shift(s) log sheet and is compiled in the monthly/yearly results spreadsheet.

Status 4/21/2011-Hydrogen usage is documented on the monthly reports.

2010-01 Weekly -Test Unit 1 & 2 DC driven hydrogen seal oil pump - COMPLETED Comment: Regular testing of the hydrogen seal oil pumps should be performed to ensure the hydrogen is maintained in the generator in the event that the normal seal oil pump fails.

Plant Comment: This task has been added to the weekly weekend checklist.

Status 4/21/2011- The plant has incorporated the testing into the weekly testing regime.

2010 -04 – Battery racks for Unit 1 & 2 are not grounded. COMPLETED

Comment: The battery racks should be properly grounded to ensure plant personnel safety and proper use of the battery system.

Plant Comment: Work order has been entered into MAXIMO to ground the rack.

Status 4/21/2011- The battery racks have been grounded**.**

2010-07 – Weekly testing of the DC lube oil pump should be implemented and documented on Unit 11. Completed

Plant Comment: This task has been added to the weekly weekend checklist.

Status 4/21/2011- Weekly testing of the DC lube oil pumps is performed and documented on the Weekly Operational Checks record.

2010-08 – Amp meters should be installed on the Unit 11 generator strip heaters so the operations of the heaters can be verified. COMPLETED

Comment: In the event the generator strip heaters failed there is no indication provide to identify the heaters are not in service. The strip heaters are used to maintain the generator windings in a dry environment.

Plant Comment: Plant is investigating. Ammeters may be in the GAC building that monitors generator heaters.

Status 4/21/2011- Ammeters have been installed and are included on the operational check sheets.

2009-02 Dual battery System for Diesel Fire Pump - COMPLETED

Although not noted earlier during the site inspection it was found that the diesel fire pump had only a single battery for the purposes of starting the diesel engine.

Comment: NFPA calls for dual battery and dual chargers for all emergency diesels. COD are to implement this recommendation on an urgent basis.

Status 4/20/10: Dual batteries and chargers were installed on the gas driven fire pump.

2008-01 Testing of Station Fire Hydrants - COMPLETED

During the site visit it was learnt that the fire system hydrants are no longer flushed/flow tested by station staff. The following is an extract taken from NFPA 25

The above schedule should be implemented as part of the normal fire system routines.

XL Insurance was to contact the City of Dover to discuss how to implement the site's fire protection equipment under the COD Public Works responsibility in a Test, Flush, and Inspection Program. XL Insurance will also discuss priorities and note standards for checking the fire hydrants on site as well as help to set up a testing schedule.

Status 4/20/10: The hydrant flushing is done by the City of Dover Delaware employees and is not performed by the plant personnel. Quarterly and annual inspections are performed by Radius Technology LLC, which includes sprinkler inspection, fire pump testing, deluge system and fire detection alarms.

2008-02 Gasoline Fire Pump - COMPLETED

When assessing the performance of the gasoline fire pump it was noted that during the test the gasoline was running significantly slower than its rated 1800 rpm rating.

Comment: The diesel should be checked and adjustments made to ensure the driver meets its operating requirements. The gasoline fire pump has a governor which can be regulated for output gpm.

2008 Update: During a pump test, the pump was capable of putting out the desired flow without the need to run up to its maximum rpm rating.

Status 4/20/10: The 2009 pump flow test was satisfactorily completed with rated flow (100gpm) at 1647rpm.

2007-04 Smoke/Heat Detection - COMPLETED

There is no smoke/heat detection in the power station to provide early warning of the onset of any fire.

Comment: It would be suggested that smoke/heat detection be provided in unmanned areas containing combustible materials such as, administration area (overnight Protection), fire pump house, warehouses, workshops, cable runs, and computer room.

Status 2008: Quotes are in and some preliminary work has started. Budgeted for 2009-2010 budget year.

Status 4/20/10: The smoke and heat detectors have been installed in the administration area, fire pump house, warehouses, workshops, cable runs, and computer rooms.

2007-15 Business Recovery Plan CLOSED

The station has considered the loss of major plant items and the effect of such a loss on business, however, this has not been formalized into a Business Recovery Plan.

Comment: A formal plan should be provided whereby the impact on business of the loss of any item of equipment has been considered. The plan would identify plant items and where and how long it would take to obtain replacement parts. This would also assist in recognizing which long lead items need to be purchased as strategic spares.

Status 2008: Work has started spreadsheet/Rest of team to fill applicable data/contacts.

Status: The plan is a work-in-progress that is continually updated whenever plant staff goes out for quotes on projects, equipment purchases, or contract services. In addition, the plant has development a list of plant duties/tasks to aid in the succession planning process and to ensure that there is a qualified back-up in case the primary contact is absent from the plant.

2007-03 Burner Fire Protection. CLOSED

The three boilers burn either fuel oil or natural gas and it was noted that there was no burner front protection on any unit preventing damage from a fire caused by a leak of oil or gas.

Comment: NFPA 850 requires the following for boiler burner fronts:

> *'**7.5.1.2** Boiler front fire protection systems should be designed to cover the fuel oil burners and igniters and adjacent fuel oil piping and cable a 20 ft (6.1 m) distance from the burner and igniter, including structural members and walkways at these levels. Additional coverage should include areas where oil can collect. Sprinkler and water spray systems should be de*signed for a density of 0.25 gpm/ft^2 (10.2 mm/min) over the protected area.'

Due to the boilers age and the limited life of the station it is recommended that a fusible link be attached above each burner and linked through mechanical means (or other) to the fuel isolation valve such that activation by any fusible link would isolate the fuel. This will help the facility move towards the goal of meeting the NFPA standard stated above.

Status 2008: Work Order entered in MAXIMO- Work in Progress-expect to be complete by 2/29/08
Work is complete. Smoke/Heat Detectors were installed on each burner deck that alarm to the control room and cannot be reset until the cause has been investigated.

2008-Oil/Lubrication Schedule CLOSED

A review of the stations recent lubricating oil testing results indicated a high number of alerts and questionable comments with respect to oil quality and type.

Comment: It is recommended that a full review of the stations lubricating oils and greases be carried out, identifying which type should be used where and it's frequency of use.

NB: Since the XL Insurance site visit, the plant discovered that the wrong oil data had been entered by the lube oil analysis vendor which accounted for the numerous alerts in the oil analysis program. This issue has now been resolved and the plant has addressed all subsequent alerts properly. The plant had also updated an equipment list specifying approved oil and grease types for each piece of equipment in the program. This had already been completed at the time of the site visit but had not been brought to insurance auditor's attention.

2007-02 Under Turbine First Floor Fire Protection. CLOSED

There are no systems protecting the lube oil systems on the first floor. Any loss of oil could ignite and cause a pooling fire which could spread to other units.

Comment: NFPA 850 requires that:

'<u>7.7.4.1.1</u> All areas beneath the turbine-generator operating floor that are subject to oil flow, oil spray, or oil accumulation should be protected by an automatic sprinkler or foam-water sprinkler system. This coverage normally includes all areas beneath the operating floor in the turbine building. The sprinkler system beneath the turbine-generator should take into consideration obstructions from structural members and piping and should be designed to a density of 0.30 gpm/ft² (12.2 mm/min) over a minimum application of 5000 ft² (464 m²).'*

The lube oil system for unit 3 is bunded (diked). There is no bunding for units 1 and 2 but a pipe trench surrounding the area. The trench drains to a sump pump pit which is monitored for oil prior to manually pumping out the sump area.

However, due to the limited life of the plant and the economic restraints, this is unlikely to be installed. It is recommended that the maintenance of the bunding be a priority and that additional large capacity portable foam extinguishers be located in this area. This will help the facility move towards the goal of meeting the NFPA standard stated above.

Status 2008: As an alternative a portable foam extinguisher tender was ordered and is now on site.

2007-05 Provision of Second (separate) Fire Pump CLOSED

A single 1,000 gpm @100 psi (3784 l/hr @ 6.9 barg), fire pump takes suction from the City of Dover water main. The pump is driven either by an electric motor or a gas engine.

NB: The pump is a manual start.

Comment: The provision of a second pump should be considered and located away from the current pump.

Post Visit Update: Subsequent to the visit the pump has been set up to start automatically.

Status 2008: Fire Department would respond to any and all fire calls. Dover Fire Department is less than 1 mile away.

2007-06 Emergency Response Plans COMPLETED

The station has a set of emergency response plans available within the administration building and in the main control room.

Comment: These need to be reviewed and updated at this time.

Status 2008**:** The emergency response plan identified in SMP-2 has been updated since the last XL Insurance site visit.

2007-11 Management of Change COMPLETED

There was no procedure in place whereby changes to the plant/equipment is recorded or reviewed.

Comment: A formal Management of Change procedure should be adopted whereby all changes are reviewed, risk assessed, planned and documented including the provision of 'As Built' drawings.

Status 2008: Procedure has been adopted into OP104.

2007-12 Battery Room COMPLETED

Unit 3 battery room was visited during the tour and although the room was ventilated there were no smoke or gas detection systems installed, further it was noted that the electrical installation was of standard design and not explosion proof.

Comment: As the batteries are of the wet type, they are likely to give off Hydrogen from time to time and accumulations of this gas may lead to an eventual explosion/fire. It is recommended that an alarm be fitted to the ventilation fan to warn of failure and that a spare fan be procured as a replacement in the event of failure.

Status 2008: Work Orders entered in MAXIMO and completed on 2/5/08. Spare fan motor on site - Completed

2007-13 Hydrogen Store/CO_2 Purge System COMPLETED

It was noted that the Hydrogen bottle storage and the CO_2 purge systems were located in the same building.

Comment: In the event of a fire it is recommended that the CO_2 purge system be relocated into a secure area away from the Hydrogen bottles.

Status 2008: Completed 12/07, purge station now within the auxiliary boiler building, and separated from the hydrogen bottles.

2007-14 Unit 3 FO Pumping & Heating Set COMPLETED

Unit 3 Fuel oil (FO) Pumping and Heating set is located on the first floor of the station and any leak would allow the spread of hot fuel oil across the turbine hall floor.

Comment: Install a bund (dike) around the pumping and heating unit to prevent the spread of fuel oil.

Status 2008: Completed 2/19/08, new bunding installed with ramped access.

2007-16 Plant Idle Time CLOSED

The station is operating on a much reduce capacity factor and as such there is a considerable time when the unit/s are not running.

Comment: It is recommended that in this idle time station staff are utilized in updating plant operating and maintenance procedures together with a review of ‘as built’ drawing accuracy.

Status 2008: Staff are involved in continuous projects work, EDQP, online training, cross training, Procedure writing, Plant Readiness Plan development, etc.

Unit 1 Turbine – Generator History

In **1987**, Unit 1 turbine was disassembled due to problems with a steam leak at the horizontal joint, near the #1 gland steam seal case.

In **1992,** the turbine was disassembled and seven rows of blades were replaced on the turbine. All diaphragms were removed, repaired for minor cracking, and realigned. New steam packing was also installed.

In **1994,** an unusual vibration occurred and the unit was tripped and restarted several times. The turbine was opened up and revealed the loss of the shroud bands in the LP rotating blades. Stages 2, 3 and 18 and 19, were totally replaced, due to excessive damage. Indications were that a foreign object passed through the turbine, causing the damage. The #1 and #2 bearings were worn excessively and refurbished.

In **1998**, the turbine tripped off line from loss of excitation and high vibration. The unit was disassembled and the generator bearings were completely wiped. When the field was removed and inspected, a bottom turn on coil #7 was found broken at the pole jumper on the zero pole.

September 2006

Unit 1

- The condenser water boxes and the hot well were opened and cleaned. The condenser hot-well was flooded to check for any tube leaks and none were found.
- The turbine exhaust hood was removed and an inspection of the condensate recirculation line was performed and found to be in good condition.

Unit 1 2009 annual Outage

No turbine work was performed. The Hotwell and condenser were drained. After opening the doors, all areas were cleaned and inspected. The condenser inlet tubes did have a small amount of rust flakes stuck in the tubes. The tubes were a little dirty with no major build up. Work order issued to purchase equipment and water blast tubes with condenser darts in the spring. WO#8971. The condenser water boxes were inspected; cleaned and plugged tubes were mapped out for documentation. The recirculation line was inspected and reported OK. Operations flooded the hotwell above the trunk expansion joint and found no leaks.

Unit 1 2010 Annual Outage

There was no turbine work performed in 2010. The "K" feedwater heater insulation and lead paint was removed and abated as necessary to perform non-destructive examinations of the vessel welds and random checks of the vessel walls at one-foot intervals. One crack was found on the third stage extraction steam line. The crack was in the weld and one half inch into the vessel shell. APEX repaired and Lehigh Testing Lab checked the repair. Eddy Current testing was also completed. TesTex checked each tube to the bend area. NAES maintenance employees pressurized the vessel and found two tubes leaking. Both were plugged, along with three other tubes showing wall loss off 80% to 100% from the TesTex summary report.

The Unit 1 and 2 cooling tower basin was drained and cleaned. Miscellaneous lumber was replaced in the tower mechanical area. North and South lower diagonals were replaced with fiberglass. Eight concrete piers were repaired. The 4x4 Douglas fir columns had checks and damaged at the water line. SPIG suggested replacing the upper diagonals due to racking of the tower. Recommendation from SPIG was to repair 168 interiors columns using a fiberglass splice and replace the entire set of outside columns with Douglas Fir. Due to the price and amount of work, an outside cooling tower consultant was hired and inspected the tower. His findings indicated that the columns were in good shape and replacement of two being completed in the fall along with repairs to thirty four columns be made. FRP material has been ordered for the column repairs and will be completed by NAES employees.

Unit 1 2011 Spring Outage

The turbine valves were dismantled by Sulzer Turbo Services. The nozzle block area was inspected with borescope while the valves were removed. Pitting conditions were reported in the nozzle block area.

A Vacuum was pulled with the auxiliary oil pump placed in service. The lockout reset and throttle valve closed to simulate a unit startup. Vacuum reached 25 (condenser vacuum) and the latch dropped allowing the turbine to be reset and check the throttle valve operation. Throttle valve was opening and not reaching its open limit. During testing it was discovered that the throttle valve will trip before reaching the upper limit switch. NAES team reviewed prints and potential problems. Findings were provided to Siemens via teleconference and Siemens agreed to research design drawings and provide dimensional information on the valve and its operating cylinder internals. Throttle valve stops bushings were removed and the distance measured. Bushings were machined and installed for testing. Testing verified full travel of the throttle valve stem without tripping before reaching the upper limit as designed.

NAES operations team transferred oil from the main turbine oil tank and filtered the oil before placing in storage during the outage. Turbine oil filtering unit was drained and cleaned. New filtering bags were installed. Filtered oil was then placed back into the bowser unit and a water seal established. Turbine seal oil unit was drained and two sight port covers removed. Visual inspection of the float ball and mechanical linkage was completed by NAES personnel. Each cover was installed with a new gasket.

NAES operations team degassed the turbine generator and completed a purge of the hydrogen fill piping utilizing the NAES SMP-22 procedure. Hydrogen fill piping was removed and new stainless steel piping was installed. Piping was filled with N2 and checked for leaks. No leaks on piping. With the oil system back in place, hydrogen was placed back into the generator for operational use.

The condenser tubes and the cooling tower basin were cleaned. Various components in the cooling tower were identified as damaged and were replaced.

Unit 1 2012 Fall Outage

NAES Turbine Services came on site and started the repair work for the #1 bearing steam seal leak. Steam seals were removed and sent out for refurbishment by Siemens Energy Services. Bearing #1 was inspected and checked for wear. Bearing did have some wear and did not meet acceptable tolerance, so it was sent out for refurbishment by Fusion Babbiting. Oil deflectors were inspected and found to have excessive clearances. NAES Turbine Services demobilized and was offsite until the returned parts were back on site for installation. NAES Turbine Services remobilized and arrived at McKee Run Generating Station on Monday November 5, 2012. NAES ICE staff unwired the turning gear motor. NAES Turbine Services disassembled the turning gear housing for access to the rotor shaft and completed the removal of the turbine/generator coupling bolts. NAES Turbine Services completed the bearing, oil deflector and steam seal assembly. Each was checked for clearances and rotor manually rotated for rubbing issues. Final assembly of the turbine front standard was completed for alignment checks. Turbine shaft was manually rotated to check generator to turbine alignment. Checks determined the generator will have to be moved. NAES Turbine Services performed a 16 point alignment check on the exciter to generator and corrected the alignment to OME specifications. Generator was found to be .019 out total indicator.

Unit 1Spring 2013 Outage

Cooling Tower outfall piping was measured and a new blank was fabricated for installation. This will be one of the last steps in the Industrial Waste Water project.

NAES Maintenance Staff installed modifications to the piping on the Unit 1 & 2 lube oil system storage/transfer system to allow for the connection of the portable Hy-Pro lube oil processing unit. Valving was installed so the conditioning unit could be easily connected to aid in the cleaning and purifying of the lubricating oil. Electrical connections were made to MCC 6 utilizing a plug type cord and disconnect switch. This activity was completed post outage due to higher outage priorities.

NAES Maintenance Team installed a new coupling on the Unit 2 seal oil AC motor/pump. Coupling was original to the pump and had deteriorated from normal wear.

Unit 1 Fall 2013 Outage

NAES mechanics installed new hand wheel throttle valve mechanical parts. Thereafter, the IC&E Team installed the portable vacuum pump to Unit 1 turbine to simulated vacuum. The turbine was reset and the throttle valve was closed. The throttle valve was then fully opened with no issues and the handle was freewheeling. The Unit was then tripped and the throttle valve closed automatically as part of the trip circuitry. This evolution was completed several times without incident.

NAES Mechanics fabricated and installed a gasket on the Unit 1 lube oil bowser filter housing due to a small oil leak. Bowser was checked out and placed back into service.

2014 Turbine Outage Activities

Unit 1 2014
No inspections, preventive maintenance or major activities were reported on the Unit 1 Turbine/Generator during the Spring and Fall 2014 outages.

Unit 2 Turbine Generator History

In **1985**, a scheduled inspection on Unit 2 turbine was performed.

In **1989**, the turbine generator was disassembled as part of the life extension study that was done by the City of Dover.

In **1991**, the turbine generator was dismantled for the installation of the new turbine end-retaining ring. Damage done during an earlier attempt to remove the retaining ring, made this repair difficult.

In **1994**, the turbine was disassembled for a scheduled outage. The 1st stage Curtis, 4th, 5th, 6th, 7th and 13th stage blading were replaced due to erosion and foreign object damage. Because of broken partitions, the 1st stage nozzle was removed and repaired. 16 rows of diaphragm packing and 8 rows of shaft packing were also replaced. The steam inlet flange on the shell and its mating surface were refaced. The 17th, 18th and 19th stage spill strips were machined out and replaced due to excessive clearances. Minor repairs to the diaphragm partitions on the 2nd through the 13th stage and the 18th and 19th stage were made. The horizontal joints on the 16th and 17th stage were welded up and machined, due to erosion.

October 2005 Unit 2

- The condenser water boxes were opened and cleaned, as well as the hot well. The condenser hot-well was flooded to check for any tube leaks and none were found.
- The turbine exhaust hood was removed and an inspection of the condensate recirculation line was performed and found to be in good condition.

September 2006 Unit 2

- The condenser water boxes and the hot well were opened and cleaned. The condenser hot-well was flooded to check for any tube leaks and none were found. Also the hand actuator for the south outlet valve was found not to be operating and a new brass gear was installed to correct the problem.
- The turbine exhaust hood was removed and an inspection of the condensate recirculation line was performed and found to be in good condition.

Unit 2 2009 Annual Outage

No turbine work was performed. The Hotwell and condenser were drained. After opening the doors, all areas were cleaned and inspected. The condenser inlet tubes did have a small amount of rust flakes stuck in the tubes. The tubes were a little dirty with no major build up. Work order issued to purchase equipment and water blast tubes with condenser darts in the spring. WO#8971. The condenser water boxes were inspected; cleaned and plugged tubes were mapped out for documentation. The recirculation line was inspected and reported OK. Operations flooded the hotwell above the trunk expansion joint and found no leaks. Unit 2 condenser has 11 plugged tubes out of a total of 3606.

Unit 2010 Spring Outage

No turbine work was performed. The “K” feedwater heater insulation and lead paint was removed and abated as necessary to perform non-destructive examinations of the vessel welds and random checks of the vessel walls at one-foot intervals. No cracks were found. Eddy Current testing was completed. TesTex checked each tube to the bend area. NAES maintenance employees pressurized the vessel and found one tube leaking and plugged it.

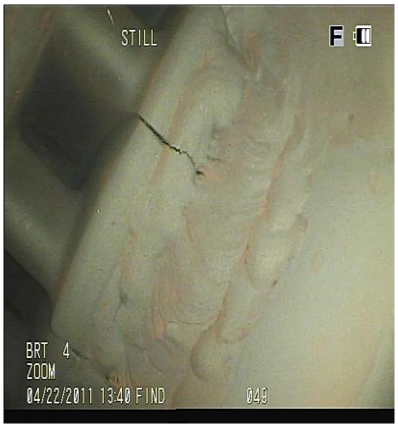
Unit 2 2010 Fall Outage

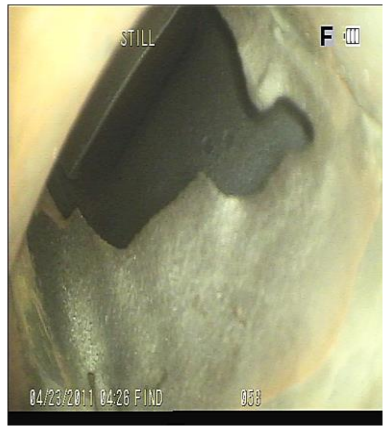
There was no turbine work performed during this outage. The condenser tubes were attempted to be cleaned however the cleaning darts were in effective. Condenser was inspected by NALCO and one recommendation was discussed. NAES installed zinc blocks for corrosion protection. Sixteen zinc blocks were installed to complete this project.

The Unit 1 & 2 Cooling Tower basin was drained for column repairs. FRP was installed on remaining 4x4 columns before actual outage started. Replaced 36 decking joists and removed the remaining plywood from under fan motor supports. Tower fan decking completed with new 1 1/8” plywood installed. Toe boards have been replaced along the tower perimeter. Each fan was test run, checking for blade rub on shrouds. No issues were identified. Decking and fill was cleaned to complete this project. The CWP’s were test run and the trash screens were cleaned.

Unit 2 2011 Spring Outage

The turbine valves were dismantled for inspection. Throttle valve shaft was found to be bent during Sulzers break down and inspection of the assembly. A new shaft was manufactured by DESS machine shop. The new shaft was installed and tested OK. A borescope inspection of the nozzle block area was conducted. Significant pitting, linear indications and deterioration was observed.





NAES IC&E technicians installed a portable vacuum pump at the front standard. Vacuum was pulled, auxiliary pump placed in service, lockout reset and throttle valve closed to simulate a unit startup. Vacuum reached 25 (condenser vacuum) and the latch dropped allowing the turbine to be reset and check the throttle valve operation. It was found during the testing of the throttle valve operation that it spun freely in both directions which indicated the valve is nonoperational. A conference call to Sulzer (mechanical contractor) resulted in their return to the plant site on May 5 to remove the throttle valve assembly. Once apart, a locking key in the lower operating assembly was found to be sheared and a new one was to be manufactured. The lower valve stem key was found to be missing during disassembly (Nothing found in the housing therefore the key parts are presumed to be somewhere in the system oil return). The new key was installed and after making other minor adjustments, the throttle valve mechanism worked satisfactory. Testing verified full travel of the throttle valve stem without tripping before reaching the upper limit as designed.

NAES operations team transferred oil from the main turbine oil tank and filtered the oil before placing in storage during the outage. Turbine oil filtering unit was drained and cleaned. New filtering bags were installed. Filtered oil was then placed back into the bowser unit and a water seal established. Lube oil was transferred back to the main oil tank and the main lube oil pump placed in service checking for leaks. Oil was placed in the seal oil unit and the pumps started. No leaks were discovered on the oil the system piping or seal oil unit.

NAES operations team degassed the turbine generator and completed a purge of the hydrogen fill piping utilizing the NAES SMP-22 procedure. Hydrogen fill piping was removed and new stainless steel piping was installed. Piping was filled with N2 and checked for leaks. No leaks on piping. With the oil system back in place hydrogen was placed back into the generator for operational use.

The condenser tubes were cleaned and inspected for leaks. The cooling tower basin was cleaned and damaged deteriorated components were replaced by SPIG.

Unit 2 Fall 2012 Outage

Siemens Energy INC. representative, Mr. David Donati, was on site to assist with the troubleshooting and repair of the turbine overspeed trip issue. While disassembling the mechanism, measurement readings were taken and compared to the original drawing. It was discovered at this time that the trip arm had an excessive amount of clearance. Solution for the repair was provided by Siemens Engineering who recommended that mechanical milling of the flange face for the overspeed trip mechanism would achieve the proper clearance for the trip arm to activate the bolt mechanism. Machine work was completed Chalmers and Kubeck at an offsite location. Overspeed trip mechanism was reassembled and manually tested for proper operation. Overspeed trip mechanism was found to be in correct working order.

NAES Operations team placed burners into service on the boiler and commenced with the startup procedure to test the repairs. Unit 2 was started, heat soaked and run to full speed no load capacity and then overspeed to 4000 RPM's, which at this time the mechanical bolt trip mechanism was activated and the unit tripped on overspeed. No issues were observed or found at this time.
NAES IC&E staff repaired the lube oil tank low level switch. It was determined that during annual annunciator testing that the low level switch mechanism was defective. New terminal studs were installed and the switch and the alarmed tested successfully. Lube oil was then transferred back to the lube oil tank for future service.

Unit 2 Spring 2013 Outage

NAES Staff installed modifications to the piping on the Unit 1 & 2 lube oil system storage/transfer system to allow for the connection of the portable Hy-Pro lube oil processing unit. Valving was installed so the conditioning unit could be easily connected to aid in the cleaning and purifying of the lubricating oil. Electrical connections were made to MCC 6 utilizing a plug type cord and disconnect switch.

NAES Maintenance Team installed a new coupling on the Unit 2 seal oil AC motor/pump. Coupling was original to the pump and had deteriorated and failed from normal wear. This work was completed as corrective measure due to the coupling failure.

NAES Maintenance Team installed Unit 2 vapor extractor pump. During this event, it was discovered that the new pump wasn't a direct replacement. The electric motor would need to be repositioned. Coupling was sent to the local machine shop for modifications. New base plates were installed and motor repositioned to fit the new vapor extractor pump. Final motor and coupling installation/alignment were completed. Motor was rewired and both bump tested. Both started and ran as designed with no issues.

Summit Mechanical completed work on the condenser tie-in for the Industrial Waste Water Project. (IWW) New valve station was fabricated and installed to the condenser discharge piping. During system testing, it was discovered that the discharge pressure was too low to properly overcome the piping head pressure and provide blow down relief for the tower without additional work. Valve station piping was moved from the discharge side of the condenser to the inlet header. System was tested and worked as designed.

Unit 2 2013 Fall Outage

Condenser

NAES Maintenance & Operation Team opened condensers doors and flooded the hotwell for expansion joint/condenser tube leak inspections. No condenser tube leaks were observed. Each hotwell level was raised above the turbine trunk expansion joint. During this event, it was discovered Unit 2 has several small leaks between the expansion joint and the condenser. NAES Operations Team lowered the hotwell water level and NAES Maintenance Team tightened the expansion joint flange bolts around the entire expansion joint perimeter. The hotwell was flooded again and checked for leaks at the expansion joint. Unit 2 still had several small leaks. During a previous outage, the IMCAS ESP 2, a sealer material, was placed around the perimeter of the expansion joint. NAES staff is researching for this product or one equivalent to it for sealing the expansion joint area. NAES Maintenance Team completed the removal of debris from the condenser tube openings and waterboxes. Condenser waterbox doors were closed.

Cooling Tower

There were no planned Cooling Tower activities conducted during the outage.

Turbine

There were no planned Turbine activities conducted during the outage.

Generator

NAES IC&E Team completed the cleaning and inspection of generator cables, chokes and insulators. Each area was cleaned utilizing low pressure air, dust removal devices and vacuums. Cables and insulators were cleaned, wiped down and inspected. All bolts were checked for tightness. Unit 2 was in good condition with no follow-up items to address.

Unit 2 2014

No inspections, preventive maintenance or major activities were reported on the Unit 2 Turbine/Generator during the Spring and Fall 2014 outages. There were plans to repair the Turbine Trip Throttle Valve Mechanism during the Fall 2014 outage but never materialized due to a delay in the delivery of some of the parts and the lack of skilled man-power once the parts did arrive. The mechanism was repaired in January 2015.

Unit 3 Turbine Generator History

In **1991**, the turbine was disassembled for installation of new 1st stage nozzle, per a GE TIL (1088-2). The High Pressure to Low Pressure Joint was broken during this outage to establish better joint contacts. New spill strips were installed on 17 diaphragms to establish proper clearances. New 1st stage reheat buckets were also installed.

In **1995**, the turbine was disassembled for a scheduled outage. The IP outer upper shell was removed and machined, due to warping.

In **2000**, the turbine was disassembled for a scheduled turbine/generator outage. All of the turbine bearings were machined and returned to the original elliptical design, recommended by GE

March 2006

Turbine/Condenser:

- The turbine exhaust hood diaphragms were inspected from inside the turbine and were found to not require replacement.
- The turbine-to-condenser expansion joint bolts were checked and tightened.
- The condenser was flooded to check for leaking tubes, expansion joint and piping. One leaking tube on the west side of the condenser was plugged.
- The condenser water boxes were checked and cleaned and 20 of the sacrificial anodes replaced.
- The hot well for the condenser was drained, cleaned, and inspected.
- All of the motor operated valves were checked for proper operation.
- The vacuum pump coolers were cleaned.
- The seal oil unit filters were changed.
- The turbine lube oil bowser was drained and cleaned and all of the filters and filter bags were changed.

Unit 3 2009 Annual Outage

The generator was degassed and oil system shut down during the outage because of the work on the Turing Gear. GE Services was contracted to rebuild the turning gear with help from NAES maintenance staff. After tearing the turning gear apart there were two pieces that were found broken. Parts were ordered ahead of time and in house to repair the problems areas during tear down. The parts numbers that were given to the plant by GE and used to purchase engagement parts were the wrong numbers. By the time this was discovered, the correct parts could not be procured in time. The repairs that could be made were completed and front standard was put back together. As of now operators are engaging the turning gear manually.

The Hotwell, condenser, and the DA tank were drained. The trays were removed from the DA Heater tank. Both tanks were inspected and MDT tested. The DA heater and storage tank were inspected by Baker Testing. There were some cracks found in the seam welds. Apex Mechanical ground out the cracks and re-welded the seams. Post tank inspections were completed by Baker Testing, until all cracks were welded up. The SH and RH attachment lugs were inspected and reported in good condition.

Unit 3 2010 Spring Outage

An internal inspection of the turbine hood and last stage blades was completed. The hotwell was flooded and the condenser trunk expansion joint and vacuum piping were checked. No leaks were found. The hotwell and condenser were drained. After opening the doors, all areas were cleaned and inspected. One anode bolt was attached to the condenser wall. New anodes were ordered. No tube leaks were found after flooding the condenser.

The 3A Boiler Feed Pump coupling was disassembled cleaned and grease pack. Pump was re-aligned and checked OK.

SPIG completed miscellaneous repairs to the cooling tower. Five new HWB ladders were installed. Basin repairs were completed and new interior/exterior doors were installed.

Unit 3 2010 Spring Outage

Turbine: Radius Fire Protection was awarded the generator bearing protection project. Radius installed piping, nozzles, air compressor, foam tank and an alarm panel to complete this project. The City of Dover (COD) Fire Marshall was on site to witness the testing of the generator bearing fire protection system. With a successful test demonstration, the COD Fire Marshall certified/passed the system. System was not placed into service until each employee receives training on the system which is now in service.

IC&E: Work orders to check operation of 3A & 3B feed water valves. 3A tested OK. During inspection of 3B a valve linkage arm was found to be off. Linkage was repaired and field tested the valve. Valve tested OK. Eleven relay calibrations were completed on Unit 3 generator by Camco.

Work order to check operation of 600lb steam station. Valve was removed and inspected. Internal seat inspected and OK.

Removed and rebuilt the Pre-air heater primary steam valve. Air was found to be leaking from the valve. Field tested and OK.

Condenser: Doors were opened and temporary scaffolding was installed to use as a working platform. Tube cleaning tarps and hoses were installed to start this project. New condenser cleaning plugs had been purchased for this project. After several trial and error tests were completed, the NAES team began to load and shoot the plugs. Shooting the plugs took several weeks before each tube was done. One tube was found to have the south plug missing; a new brass plug was installed. Ten darts were stuck on the north side, they have been removed. All tarps and plugs were removed and accounted for. Several zinc blocks were replaced in both sides of the condenser. Condenser hot well was flooded to check the hood expansion joint, vacuum pump piping attachment welds and for condenser tube leaks. No leaks were found. Each door was cleaned and closed.

Cooling Tower: Each fan cable was tested then rolled and placed on the south HWB decking. Fire alarm wiring was removed, relocated and temporary installed to keep the tower safe during the outage work. Special procedures were written and followed during this event. Documentation was recorded during this event. Asbestos and wood samples were taken and results received ahead of the project start. CTD removed fan shrouds, decking plywood and wood decking members to begin the mechanical part of this project. Plymouth ES was on site to remove asbestos board from under fan shrouds, cable trays and north/south hand rail decking. Asbestos was removed and properly disposed of. Manifest was returned to NAES. Full access to the tower was given to CTD to remove fan mechanical components and gearboxes. Once removed and placed on ground level. Fan blades were removed and each mechanical support was sent out for cleaning, new galvanized paint was installed. Each gearbox was sent out for cleaning, disassembled, rebuilt with new bearings/seals and epoxy painted. Fan hubs were removed by Power Tech at an added cost, due to length of installation and hub/shaft corrosion. Fan decking plywood was removed and entire first level of decking structure was replaced in kind, this was done as an added cost to NAES. Scope called for up to 30% of the members, but after final inspection it was determined that more needed to be replaced. Safety and structural integrity were at issue. Crossover tubes were removed and replaced with fiberglass tubes per scope. Crossover tube expansion joints were eliminated from the work scope. Due to positioning of the crossover tubes and tower structure members in the intended path, other work was needed. First fire protection water lines to nozzles needed to be reconfigured and moved to make access for the crossover tubes. Each tube needed a special adapter spool piece made, then attached to the main header. CTD had the spool pieces made. Each crossover saddle was removed and replaced in kind per scope. Each main header flow valve was removed and replaced in kind per scope. Each crossover tube was carefully placed back in the tower and set in place. North flow valves were installed and the piping attached to the main header.

Tower cold water basin walkway was removed and replaced in kind. Removed and replaced in kind five hot water basin ladders on the north side per scope.

Set all mechanical supports and gearboxes. Fan hubs and blades were installed on all gearboxes at ground level. All fans blades were pitched to scope spec. All torque tubes set in place and mounted. All motors set in place and mounted. All shrouds set in place and mounted to tower structure.

Ten new water distribution boxes were built and installed. New oil and breather tubing was installed on each gear box. New oil has been added to each unit. Two new blades were installed in number three fan, due to cracking issues. Aligned all torque tubes/gear boxes.

Mid Atlantic unrolled and installed all high voltage wiring. Installed new seal tight conduit to motors and wired each one. Megger tested each motor lead. All the wiring tested OK no issues. Installed the tower lighting, vibration trips and receptacles back on the tower.

Fire protection system shut down removed temporary wiring and reinstalled as built. Proper notification procedure was written, followed and documented to complete this project. Cleanup of hot water basins and cold water basin was completed prior to startup of CW pumps.

Each fan was bump tested for direction. Each fan was run in low and high speed. Fan number three has vibration issues. After further inspection and investigation, one blade was relocated opposite the other new one. Fan tested OK. Oil placed in gearbox and checked OK. All 5 fans were placed in service. Removed and installed twelve new main header saddles.

Staff removed damaged wood from the north and south plenum walls. New material was placed over the entire south wall with repairs made to the north wall.

Test ran the circulating water system found several leaks around crossover piping bolts and main header flow valve bolts also. System shutdown and repairs made. CW pumps in service, leaks in the cross over piping and water distribution box valves have been fixed. Each fan was test run and amperages checked with CW pump in service. Each fan reading was within 5% of last readings taken back in 1996. Ran CWP's and cleaned trash screens.

Unit 3 2011 Spring Outage

A visual inspection of the low pressure turbine was conducted by entering the low pressure turbine hood and observing the last stage blades and diaphragms. No issues were identified. No turbine, condenser or cooling tower work was completed during this outage.

Unit 3 2011 Fall Outage

Maintenance and operations staff removed the Unit 3 Lube Oil Cooler Outlet heads. Some partial fouling/plugging of the heat exchanger tubes were discovered as well as some severe pitting of the Outlet Head gasket surfaces. Inlet side piping and heads were removed for inspection also. Severe pitting of the Inlet Head Facing surfaces was found. The Heat exchanger tubes were cleaned by NAES maintenance and operations employees by first rodding them out. Afterwards, the final cleaning was completed using the plant's Goodway machine in combination with ½" stainless steel brushes. Each tube was flushed, inspected and clean of debris. New gaskets have been made for reinstallation once the head repair is complete. All the Lube Oil Cooler Heads were cleaned and prepared for facing surface restoration. Each head unit was sand blasted, cleaned and had Devcon epoxy material installed to form a new facing surface. Each head was machined down to true the surface and then was reinstalled on the lube oil cooler.

The Lube Oil Cooler Heads were machined by DESS and returned to the plant. Cooler Heads were installed and fit checked. LOTO tags removed and cooling water valved in, no leaks at this time. After the final LOTO tags had been cleared a circulating water pump and booster pump were started, placing full pressure and water flow on the lube oil cooler unit. No leaks were reported.

Maintenance mechanics replaced the five extraction steam drain line traps. New traps and replacement parts were ordered ahead of the outage.

No turbine, condenser or cooling tower work was completed during this outage.

Unit 3 2012 Fall Outage

Advanced Turbine Services (ATS) completed a borescopic inspection of the turbine 1st stage nozzles and blading. Technician reported no issues found. The LP turbine L-1 stage blading and L-O diaphragm were also borescopically inspected with no issues found.

The unit 3 turbine valves were disassembled and inspected during the outage and no significant concerns were identified.

Normal maintenance to include cleaning of the lube oil tank and inspecting the turning gear was completed. The pilot gas regulator was found to have a bad diaphragm. NAES ICE technicians completed the repair.

Unit 3 2013 Spring Outage

Turbine

NAES Turbine Services mobilized and began the process of preparing the generator for inspection and testing. The outside turbine lagging, generator lagging, exciter housing, generator end covers, seals and bearings were removed. Measurements and alignment of the rotor was taken and turbine/generator coupling bolts were removed. All the parts were inspected closely after the cleaning. NAES IC&E Staff worked with NAES Turbine Services to remove instrumentation and electrical equipment from the generator in preparation of the generator testing and inspection. The generator rotor was removed and placed on the turning spindles in the ground floor open bay area. The rotor was tented and heaters installed to keep the rotor moisture free. The testing company, AGT, commenced the generator field testing and took several days to complete. AGT completed the generator field testing and no issues were found. NAES Turbine Services re-installed the generator rotor, generator bearings, seals and end covers. NAES IC&E Team reconnected the RTD's and the generator flex connectors on Unit 3 generator.

NAES Maintenance and Operations Team installed hoses, valves and Y strainers for the Unit 3 Generator lube/seal oil system flush. Both the turbine and the seal oil systems were flushed for approximately ten hours during which the screens were removed, inspected for debris, cleaned and then reinserted for more oil processing. Debris loading on each filter was minor. The oil flush equipment was removed and the seal oil and turbine oil piping systems placed back to normal configuration. Oil systems were placed in service and all fittings were checked for leaks. Air leakage testing of the generator was conducted. The Generator passed this test, was then purged with carbon dioxide and filled with hydrogen in preparation for generator testing.

NAES Turbine Services mobilized to site and observed the startup of Unit 3 turbine-generator. During the testing one small seal oil leak was discovered. Unit 3 was shut down and NAES Turbine Services removed the exciter and seal casing. The oil seal was removed and cleaned to install new gasket material. Unit was assembled; LOTO removed and seal oil system placed in service. No leaks were discovered at this time. Unit 3 was placed on turning gear.

NAES Plant staff started Unit 3 for further testing of the turbine-generator. During the first unit operational hold period; Unit 3 tripped off line due to loss of excitation relay activating (40GF) which in turn tripped the generator lockout relay (86G3). After a lengthy investigation it was discovered that two potential transformer (PT) fuses were improperly placed in their holders. NAES IC&E Technicians cleaned and adjusted the fuse holders. PT fuses were cleaned, tested and found to be in good working order. Fuses were placed in their holders and checked for proper tightness by the IC&E Technicians when the unit LOTO was removed. During the same trip event, the Motor Operated Disconnect switch (MOD) failed to open. NAES IC&E Technicians investigated the switch not opening. After extensive troubleshooting, two wires were found to be terminated in the wrong location. Wires were terminated in the proper location and the MOD switch was tested several times and operated as designed with no further issues. Further research determined that during the fall outage of 2012 City of Dover relay technicians had made repairs to the switch. Unit 3 wasn't scheduled to run during the following months and this problem was just discovered during the generator testing.

Also during the run event, NAES Turbine Services discovered that one hydrogen seal was leaking. Unit 3 was degassed and LOTO was issued ahead of the repair work. Hydrogen seals were removed and inspected for damage. Hydrogen seals were taken to Chalmers and Kubeck. Chalmers and Kubeck machined the seals to manufacture specifications. Seals were returned to Dover and installed. Generator was assembled, placed on turning gear and checked for seal oil leaks. Generator was filled with air and pressure test completed. During this event it was discovered that the Generator busing box had several leaks. NAES Turbine Services tightened all the bushing box bolts and secured the locking tabs. No hydrogen leaks were discovered during the retesting inspection and Generator Hydrogen pressure was increased to fifteen PSI.

NAES Plant Staff started Unit 3 for testing of the turbine-generator. NAES Operations Team completed a normal boiler purge and startup of the natural gas system with no issues. NAES Turbine Services observed the startup of Unit 3 turbine-generator. Generator was placed on line and ramped to full load with no issues. Unit 3 was ramped to max emergency generation (112 Megawatts) with no issues and all systems worked as designed. Unit was ramped down to minimum load and the released for shutdown. Shutdown was completed with no issues.

NAES IC&E Team inspected the shaft voltage monitor wiring on Unit 3 Generator; to ensure the wiring was in good condition and intact.

NAES IC&E and Operations Staff made corrective repairs to the stack lighting protection system. New bonding connectors and rod holders were installed, along with one hundred feet of new bonding cable and one new lighting rod.

NAES IC&E Team installed one new recorder for Unit 3 turbine shell temperatures. Recorder was programmed and was observed for proper operation during the Unit 3 start up. No issues to report.

NAES IC&E Team completed the inspection and system testing of the turbine extraction steam motor operated valves for proper operation and stroke travel. There were no apparent discrepancies and all the valves operated as designed.

NAES IC&E Team completed troubleshooting activities on the 3A substation ground alarm. They were able to find the source of the ground which was due to a shorted motor on the 3A circulating water pump power pack. NAES IC&E Technicians completed removal of the power pack motor off of 3A CWP. Motor was found to be nonoperational and was sent to the local repair shop. Returned motor was installed, tested for proper operation and travel stroke adjusted. Power pack motor was observed for proper operation during the Unit 3 start up. No issues to report.

NAES IC&E Technicians investigated a Net 90 system trouble/failure alarm. They found that a bridge controller card had failed and had signaled an alarm. The alarm card was reset by rebooting the controller. This corrected the problem, the failure/alarm light cleared and the system was placed back into normal operation.

NAES IC&E Technicians investigated the hydrogen seal oil unit flow rate being low. It was determined that the regulator is working properly. NAES IC&E Technicians removed the seal oil flow meter; cleaned the operating mechanism and associated piping. Meter was found to be nonoperational during the last run event. Seal oil unit was observed during unit testing and it was determined that the seal oil unit is working properly. No other issues to report.

NAES IC&E Technicians investigated boiler scanner fans flow issues. Both fans were needed to obtain a purge permissive. Copper tubing was found bent; causing a restriction of air flow to the pressures switches. Tubing was replaced and pressure settings calibrated. Each scanner fan was tested for proper air flow and achieving the purge permissive. No further issues to report.

NAES IC&E Technicians removed and replaced MV-8 extraction steam piping drain valve motor. Motor was found to be in nonworking condition. New motor was installed and adjustments were made to the stem travel limit switches. Several testing cycles were completed and the valve was released for normal operation.

NAES IC&E Technician installed the new power cord for the ultrasonic waste pit level transmitter. During the setup phase of the transmitter, it was discovered that the transmitter was bad and needs replacing. New transmitter was delivered to the plant and installed with no further issues to report.

NAES IC&E Technicians investigated Unit 3 cooling tower level transmitter and indicator reading in control room. Readings between the two components were discovered to be out of reference. Adjustments to the zero reference set point were made and both are reading the same levels of measurement for the tower.

NAES IC&E Technicians investigated the plant air pressure signal on the control room console. Plant air tubing was found to be removed and disconnected. Plant air tubing was repositioned and installed to pressure gauge sensing component. Plant air pressure can now be seen viewed on Unit 3 console.

NAES IC&E Technicians completed the annual calibration of the oil tank level indicators and alarm devices at McKee Run and VanSant locations. All systems and alarms worked as designed.

NAES IC&E Technician replaced the contactor in 2A & 2B air compressors. Both compressors were having tripping events due to the contactors. No further issues to report.

NAES IC&E Technician cleaned and lubricated the main contacts and auxiliaries' contacts on Unit 3 air compressor. Compressor was experiencing trip events also related to the contactors. No further issues to report.

NAES IC&E Technicians and Operations Team investigated #4 AC unit; they discovered one broken heating element wire was bringing in the ground alarm. Heating element was disconnected and the alarm cleared. New heating element was purchased and installed. No further issues to report.

Overhead Crane Services was onsite and completed the turbine overhead crane load test. Both the main hoist (75T) and the auxiliary hoist (15T) were load tested with dry steel weights. There were no issues found during the testing. Preliminary Certificate was issued to NAES for record keeping. The load test was performed in preparation for performing critical lifts associated with the generator inspection.

NAES Maintenance Staff completed the PM service on the gasoline fire pump motor. Documentation of the inspection and service work were completed and filed. Also NAES Maintenance and Operations Team removed the exhaust and intake manifolds on the gas driven fire pump. Manifold gasket surfaces were pitted and deteriorated. Parts were taken to local machine shop for repairs. Manifolds had spray weld buildup applied and machined to accommodate new gaskets. NAES Maintenance and Operations Team completed the exhaust manifold installation for the fire pump motor. PMT performed. No issues observed at this time.

The NAES Maintenance and Operations Team disassembled and removed the south sewage pump. Pump shaft housing and discharge piping have holes in them. Both sections of piping were removed and replaced. Pump shaft and bushing had spray weld buildup applied and machined to accommodate new parts. Parts were taken to local machine shop for repairs. NAES Maintenance and Operations Team completed the final assembly on the sewage sump pump. Pump was installed after piping modifications are made to the IWW system piping. Four new flanges were installed on the IWW system piping for better access to the sewage sump pumps. NAES Maintenance and Operations Team test ran the newly rebuilt sewage pump. It was discovered during normal operation the half horse power (1/2 hp) motor will not start on its own. Sewage pump motors were swapped from one pump to the other; reason being the sister pump has a three quarter horse power (3/4 hp). Sewage pump started and ran as designed. Manufacture prints will be reviewed for identification of the proper motor size. NAES Maintenance and Operations Team removed and replaced the "B" sewage sump pump isolation valve; it was discovered to have a broken valve stem. Also, the check valve was inspected and cleaned.

The NAES Maintenance and Operations Team disassembled and removed 3A Cooling Water Booster (CWB) Pump. It was discovered during the last run event that the pump wasn't operating as designed. Pump was shutdown and a LOTO issued for investigation of the internal parts. Pump impeller has damage beyond repair and will need replacing. A replacement impeller was ordered and installed. Pump shaft had spray weld buildup applied and machined to accommodate new parts. Parts were taken to local machine shop for repairs. NAES Maintenance and Operations Team completed the final assembly on the CWB Pump. CWB Pump was observed during unit scheduled activity and it was determined that the CWB Pump is working properly. No other issues to report.

NAES Maintenance and Operations Team repaired the Unit 3 lube oil over flow sight glass. One small weeping leak was repaired. Sight glass was taken apart, cleaned and resealed. Operations removed the LOTO and filled the sight glass with no leaks observed.

NAES Maintenance and Operations Team removed and replaced one support hanger on the reheat line. Hanger clamp was found to be loose and hanger load device (can) out of specification. New parts were ordered, installed and hanger can loaded to the cold setting. Hanger was observed during unit scheduled activity and it was determined that the hanger had the proper range of movement.

IWW Project:

Summit Mechanical commenced work on Industrial Waste Water (IWW) Project with condenser tie-in for Units 1, 2 & 3 tower blow down control stations. Two stations were fabricated and installed at the condenser inlet piping for units 2 & 3.

Summit Mechanical completed the installation of the IWW Project piping runs with the final tie-in to the plant sewer piping system. New 3" and 4" piping was routed throughout the plant and tied in to the existing sewer piping system. NAES Plant Staff pressure tested the entire system for leaks and a few minor ones were found where the pipe flanges had not been properly tightened. Each connection was re-tightened and the system was retested with no further leaks found.

Preferred Electric commenced work on the IWW Project by installing conduit and cable trays for pulling control wire associated with the IWW Project.

Preferred Electric completed terminating wire connections on the valve controllers at the condenser stations.
NAES Maintenance Team completed the installation of instrument air piping to flow control valves associated with the IWW Project.

NAES IC&E Team completed the installation of two new level indicators for the DI water system acid and caustic tanks.

NAES Maintenance Team installed one new flange on top of the IWW storage tank to allow for the installation of a new level transmitter as part of the IWW system.

NAES IC&E Technicians completed mounting external flow meters for the IWW project and installed the waste water tank level transmitter on the IWW Tank.

NAES IC&E Technicians pulled wire, terminated connections and installed the new power feed from MCC 3G to the IWW control cabinet.

NAES IC&E Technicians completed the IWW project heat tracing installation. New piping was heat traced ahead of insulation and lagging installation. Control boxes were installed and all wiring terminated. System was tested and OK.

NAES IC&E Technicians completed the installation of one thermo-well and thermometer in the recirculation piping for the IWW pit.

NAES Maintenance Team completed the control cabinet installation.

Preferred Electric completed installation of the wire into the PLC cabinet and wire termination at the field devices associated with the IWW Project.

Programming of the PLC program was handled off-site by Marino. NAES Plant staff reviewed proposed PLC program screens and provided recommended changes to the screens to the electrical contractor. NAES Plant staff traveled to the Marino's job site to review logic and operation of the system. Visual inspection of the proposed PLC programs, screens and operating system were previewed. Preferred Electric delivered and installed the new control cabinet backplane. Final wire terminations were completed. NAES IC&E Technicians and Operations Team assisted Marino Industries in the testing of the waste water system. Several start-up issues were discovered with the level transmitters and pump wiring. Issues were assigned to different companies for investigation and repairs. NAES IC&E Technicians completed repairs on the following items; waste water storage tank level transmitter, neutralizing pit level transmitter and the pH probe in the hot water boiler room. Plant staff received updated IWW prints. Test scenarios for the commissioning of the system were developed and have been completed and system checkouts completed also. IWW system has been utilized during scheduled unit run events with no issues. IWW system training programs for both operations and maintenance staff have been completed.

Unit 3 Fall 2013 Outage

Turbine: NAES Mechanics completed the repair of the Unit 3 lube oil bearing enlargement tank. Weld overlay procedure was utilized to complete the repair. During normal operational equipment checks; it was discovered to have one small weeping crack in the sightglass piping. NAES Operations Team removed the turbine LOTO and refilled the lube oil system, lube oil pump was placed in service and no leaks were observed. Lube oil system was left in service.

Condenser: NAES Maintenance & Operation Team opened condenser doors and flooded the hotwell for expansion joint/condenser tube leak inspections. No condenser tube leaks were observed. Hotwell level was raised above the condensate return piping. During this event it was discovered one small leak at the condenser attachment weld. NAES Operations Team lowered the hotwell water level and NAES Maintenance Team completed an overlay weld repair. The hotwell was flooded again and checked for leaks. No leak was observed. NAES Maintenance Team completed the removal of debris from the condenser tube openings and waterboxes. Condenser waterbox doors were closed.

NAES IC&E Team completed repairs to the 480V breaker that was nonoperational during preventive maintenance testing. Several adjustments to the breaker were made; in order to properly operate. Breaker was placed back into the cubical, racked in service and energized. Breaker closed as it should with no issues.

NAES IC&E Team completed repairs to two spare 4160V breakers. Adjustment was made to the floor interlock trip cam. The breaker was placed back into the cubical, racked in service and energized. Breaker closed as it should with no issues. Inspection and repairs of the 480V and 4160V breakers has been completed.

NAES IC&E Team completed the cleaning and inspection of generator saturable reactor and grounding transformer. Each area was cleaned utilizing low pressure air, dust removal devices and vacuums. Saturable reactor and grounding transformer were cleaned, wiped down and inspected. All bolts were checked for tightness. Unit is in good condition with no follow-up items to address.

NAES IC&E Team set up, bench tested, installed condensate flow and main steam flow transmitters for Unit 3.

2B air compressor received its 8000 hour preventive maintenance and was placed back into service.

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NAES IC&E Team completed the Deaerator feed water level controller valve rebuild. Valve was disassembled, cleaned and inspected. New flow control valve trim parts were installed. Valve was field tested for proper stroke travel. NAES IC&E Team removed and replaced one section of control air tubing to the Unit 3 Heater #4 water level alarm column. Alarm column was field tested and worked as planned with no air leaks.

NAES IC&E Team completed the receptacle and conduit installation for the portable lube oil conditioning unit. Permanent electrical connections were placed adjacent to 3C motor control center for ease of use when installing and running the oil conditioning unit on the Unit 3 lube oil system.

Cooling Tower: EVAPTECH (Cooling Tower Contractor) completed the Hot Water Basin Decking Project. New plywood decking and miscellaneous structural framing was removed and replaced. Eight light towers were re-installed to complete the project.

NAES IC&E Team reconnected electrical control wiring for Unit 3 cooling tower lights. Lights were checked for proper operation.

Unit 3 Spring 2014 Outage

A major dismantle inspection was completed on the Unit 3 turbine in the Spring of 2014. The turbine steam inlet control rack, turning gear housing, high pressure (HP), intermediate pressure (IP) and low pressure (LP) casings were removed. The ninth stage blades were discovered to have pitting and erosion of material on several buckets. Also the ninth stage diaphragm has pitting and erosion of material in several areas. The Turbine bearings were rolled out and removed. The thrust bearing was observed to have delamination of the babbit material. As found measurements and alignment readings of the rotor were taken. The turbine rotor was removed shipped to the Century Turbine in Missouri for ninth stage blade replacement and rotor nondestructive testing. The replacement ninth stage blades were previously purchased. The steam path inspection company, Steam Turbine Engineering completed the turbine rotor blade and diaphragm inspections. Major recommendations include the replacement of the 9th stage blades, major refurbishment of the 9th stage and 13th stage diaphragms.

The Hy-Pro oil conditioning machine was installed on the main oil tank for the lube oil flush. Oil circulating through the conditioner was heated and cleaned for optimum flow during the oil flushing process.

It was determined that the number 1, 2, and 3 bearings will need to be sent out and rebabbitted. Also the thrust bearing was identified as having delamination of babbitt material. The babbitt material was removed, bearing housing re-casted with new babbitt and resurfaced for rotor assembly. The diaphragm packing as found conditions was reviewed with NAES staff and multiple sets were ordered for replacement of damaged sets.

Turbine Masters (media blasting contractor) sand blasted packing box parts for HPI. After each part was cleaned, they were UT inspected for cracks and stress failure. The waste material from the sand-blasting process was properly disposed of by plant staff. No issues to report on the packing box parts. The HP, IP and LP shell bolts were UT inspected with no issues to report.

The Turbine rotor was delivered to the HPI repair shop (Century Turbine) in St Louis, Missouri for media blasting and a complete inspection of the turbine blades/diaphragms. The HP and IP/LP rotors underwent a Phased Array Inspection to determine the integrity of the rotor and rotor material. Nondestructive testing of the turbine rotors reported no findings.

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Each diaphragm was laser aligned to the proper elevation of the three new bearings. The upper half diaphragms and packing installation was completed.

During the assembly process it was discovered that the turbine float (thrust) movement wasn't at proper specification (clearance). Shim plates needed 0.019 thousands taken off to achieve the proper clearance (float). During the rotor installation the sensor for differential/rotor expansion was damaged. HPI installed the bearing caps, vibration probes and the lube oil system was placed in service. No lube oil leaks were discovered. The turbine was then placed on turning gear and no rubs or scraps were heard. The turbine was left on turning gear throughout the night and observed by NAES Operations team. No issues were observed during the overnight run.

The unit experienced several issues with vibrations during the start-up process. Twelve starts were conducted in an effort to correct the vibration concerns. The details of the twelve starts are provided below:

1. Mr. Tim McGinley from Industrial Machinery Diagnostics, LLC (IMD) arrived at the McKee Run site on Thursday April 10, 2014 and setup vibration equipment ahead of the planned unit startup. Unit 3 was rolled off turning gear at 0947 hours to 500 RPMs and the vibration readings were continuously taken during the acceleration of the turbine. The vibration readings were reading under normally observed readings. No rubs, scraps or steam leaks were observed. The turbine vibration readings were stable and the decision was made to roll the turbine up to 3600 RPMs. The vibration readings at the two critical points of the roll were reading under normally observed readings. The turbine was held at 5 MWs for half an hour and the decision was made to place the unit on line (1047) and increase the load to 93 MWs. During load pickup (89 MWs) the turbine experienced a rub which caused the turbine #3 bearing to vibrate above the thresh hold; the decision was made to trip the unit. The turbine also experienced high vibration while decelerating down to zero RPMs. The unit was placed on turning gear and the normal shutdown activities completed.

2.The NAES Leadership Team, HPI and IMD reviewed the run data and formulated a plan to allow the turbine to roll on turning gear overnight and attempt to restart the unit in the morning. Startup was Saturday April 12, 2014 however; a severe rub was noticed when the rotor rolled off turning gear. The decision was made to abort the startup and let the turbine cool down to a temperature low enough to allow the unit to be taken off turning gear to investigate the source of the rub and to address the leaking #3 bearing oil seal

The NAES Maintenance Team removed and replaced two diaphragms in the LP hood. The NAES Operations Team completed a Lock Out Tag Out (LOTO) on Unit 3 boiler and the turbine turning gear in order for HPI to inspect the bearing oil seals. HPI (Turbine Contractor) removed vibration probes, #2 and #3 bearing caps, steam packing housings and the oil seals. HPI completed repairs to the oil seals and the steam packing by scraping and adjusting the clearances. The LOTO was removed and the lube oil system placed back in service. No lube oil leaks were observed. The turbine was then placed on turning gear and no rubs or scraps were heard. The turbine was left on turning gear throughout the night and observed by NAES Operations team. No issues during the overnight run.

3. The NAES Operations Team started the unit warm-up process. Unit 3 was rolled off turning gear at 1243 hours to 1000 RPMs and the vibration readings were continuously taken during the acceleration of the turbine. Vibration readings were reading under normally observed readings. No rubs, scraps and steam leaks were observed. The turbine vibration readings were stable and the decision was made to roll the turbine up to 3600 RPMs. The vibration readings at the two critical points of the roll were reading under normally observed readings. The turbine was held at 1000 RPMs for half an hour and the decision was made to place the unit on line (1328) and increase the load to 102 MWs. After reaching 102 MWs the turbine was being held at this load for vibration readings. After fifteen minutes into the hold pattern the turbine experienced a rub which caused the turbine #3 bearing to vibrate just above 5mils. The decision was made to lower the unit load to 40 MWs; at 45 MWs the vibration reached 7 mils. The decision was

made to trip the turbine and take the unit off line. The turbine experienced some vibration (10 mils) while decelerating down to zero RPMs. The unit was placed on turning gear and the normal shutdown activities completed. The NAES Leadership Team, HPI and IMD reviewed the run data and formulated a plan to allow the turbine to roll on turning gear overnight and attempt to restart the unit Thursday April 17, 2014 morning.

4. The startup began with a warm startup acceleration speed input. After rolling off turning gear and reaching 1,000 RPMs the decision was made to accelerate to 3600 RPMs. However, a severe rub (13 mils) was noticed when the rotor rolled up to 1400 RPM's. The decision was made to abort the startup and let the turbine cool down to a temperature low enough to allow the unit to be taken off turning gear and investigate the rub. HPI worked Friday April 18, 2014 and Saturday April 19, 2014 removing the IP and LP shell for the inspection of internal parts and sources of the rub. With the turbine cooled down sufficiently to disassemble. Readings were taken on Monday April 21, 2014 and it was determined the two LP shaft packing boxes would need to be removed and repaired to allow moving the packing boxes axially by 0.060. The packing boxes were removed and sent off site to Chalmers and Kubeck machine shop for modifications. The machine work was completed and the parts returned to the McKee Run site.

HPI commenced reassembly Thursday night April 24, 2014. The shell bolting was tightened on Friday April 25, 2014. Each bolt was heated, stretched and torque tightened.

The NAES Operations Team will place the turbine rotor on turning gear and HPI will observe the operation for rubs. If no rubs are observed or heard, the rotor will continue to rotate until Monday morning April 28, 2014. At that time, Mr. Tim McGinley from Industrial Machinery Diagnostics, LLC (IMD) will be on site and setup vibration equipment ahead of the planned unit startup. The NAES Operations Team will start the unit warm-up process on Sunday night April 27, 2014.

County Insulation installed the HP turbine blankets and will install the IP/LP shell blankets on Sunday April 27, 2014.

Mr. Tim McGinley from Industrial Machinery Diagnostics, LLC (IMD) mobilized to the McKee Run site Monday April 28, 2014 and setup vibration equipment ahead of the planned unit startup. The NAES Operations Team completed the unit warm-up process on Sunday night April 27, 2014 and

5. Unit 3 was rolled off turning gear at 0800am. Unit 3 was rolled to 1000 RPMs and the turbine was observed during the warm-up hold point. No issues with vibration and the decision was made to continue with the startup. Unit 3 was placed on line at 0852 and loaded to 94 MWs. Six mils of vibration were observed and the Unit 3 was backed down to 65 MWs. The turbine rotor was fully axial at this time and showing signs of rub/vibration. Decision was made to drop load to 40mw's. With Unit 3 stable at 40 MWs, the decision was made to go to 70 MWs. More rubs/vibration was observed and the decision was made to go to 40 MWs and complete a shutdown. Vibration of 6.1 mils was observed during the shutdown. The decision was made to restart the Unit 3 Tuesday April 29, 2014 and observe startup vibration readings.

6. The unit warm-up process was completed and Unit 3 rolled off at 0750am and experienced high vibration (7.2 mils). Unit 3 was tripped and turbine controls reset to hold 1000 RPMs for thirty minutes, allowing the rotor to cool down and roll out.

7. Another rollup attempt was made and aborted after high vibration was experienced a second time (7.2 mils). The NAES Leadership Team, Mr. Howard Morgan (HPI Turbine Contractor) and Mr. Tim McGinley (IMD Vibration Specialist) discussed options going forward and the decision was made to restart the Unit 3 turbine at 1500 hours Tuesday and record more vibration analysis data.

8. A successful ramp-up was achieved and the unit was taken to full load. Unit 3 did experience small pockets of rub/vibration but was monitored and below the tripping point. The decision was made to shut down the unit and allow it to cool down for installation of balance weights in the LP section of the rotor. The hood doors and turbine blankets were removed to help aid in the cool down process. HPI installed twelve ounces of weight for a calibration run. The hood doors were installed along with the turbine blankets. Mr. Tim McGinley from Industrial Machinery Diagnostics, LLC (IMD) was on site Friday May 2, 2014 and setup vibration equipment ahead of the planned unit startup.

9. The NAES Operations Team completed the unit warm-up process and Unit 3 was rolled off turning gear at 1445 pm. Unit 3 was rolled to 1000 RPMs and the turbine was observed during the warm-up hold point. The decision was made to roll the turbine to 3600 RPMs. The observed vibration was 7.0 mils and the decision was made to trip the unit. The NAES Leadership Team, Mr. Howard Morgan (HPI Turbine Contractor) and Mr. Tim McGinley (IMD Vibration Specialist) discussed options going forward and the decision was made to rotate the balance weights 180 degrees and lock them in place then run the unit again.

10. The unit was cooled down until Saturday morning May 3, 2014 at which time the balance weights were moved and the unit was started and ramped to full load. Vibration on the #2 bearing was excessive at over 5 mils. The unit was brought back down.

The NAES IC&E Team completed an inspection of the lube oil instrumentation devices for Unit 3 by verifying the set points/calibration of transmitters and switches. No issues to report. The system electrically checked and verified to be in working order.

HPI demobilized on Monday May 5, 2014 and left the McKee Run site. HPI Technical Director Mr. Howard Morgan will return to the McKee Run site when the HP weights are on site and ready for installation. Plans are to have the NAES Maintenance Team install the weights and conduct another unit startup. During the next unit startup additional vibration data will be collected.

The NAES IC&E Team discovered the south thrust bearing thermocouple wasn't reading correctly. One bad terminal strip was found and repaired. Terminal strip reading is correct.

HPI Technical Director Mr. Howard Morgan returned to the McKee Run site on Wednesday May 14, 2014. The NAES Maintenance Team installed four weights in the HP section of the turbine on the #2 bearing side.

11. The NAES Operations completed a unit startup on Thursday May 15, 2014. Unit 3 was rolled (0648) to 1000 RPMs and then rolled (0725) to 3600 RPMs, 5.2 mils of vibration were observed and the decision was made to load the turbine to 18 MWs. During the rollup attempt; high vibration was experienced and the decision was made to abort the startup and consult with Mr. Tim McGinley. During the unit startup, additional vibration data was collected and sent to Mr. Tim McGinley from -IMD. The NAES Leadership Team, Mr. Howard Morgan (HPI Turbine Contractor) and Mr. Tim McGinley (IMD Vibration Specialist) discussed options going forward. The decision was made to remove the four HP weights completely and remove the ten recently installed LP weights. Complete the installation of three tungsten (heavy) weights in the LP section and lock them in place. The unit will continue to cool down until Monday morning May 19, 2014 at which time the LP/HP balance weights will be removed and the new tungsten weights installed prior to a unit start-up on Tuesday May 20, 2014. The NAES Maintenance Team removed four weights in the HP section and ten from the LP section. Three new heavy (tungsten) weights were installed in the LP section with assistance from HPI Technical Director Mr. Howard Morgan.

12. The NAES Operations Team completed a unit startup on Tuesday May 20, 2014. Unit 3 was rolled (0716) to 1000 RPMs and then rolled (0746) to 3600 RPMs and 4.8 mils of vibration were observed. The

decision was made to load the turbine to 18 MWs. The vibration was observed and the decision was made to load the turbine to 102 MWs. The vibration was observed and reading 3.0 mils or less on all bearings. Unit 3 was loaded to 110 MWs and the vibration observed was below 3.0 mils. The decision was made to drop load on Unit 3 and take the unit off line. During the roll down of the unit; 6.1 mils of vibration was observed at 2200 RPMs. During the unit startup, additional vibration data was collected and sent to Mr. Tim McGinley from IMD. The NAES Leadership Team and Mr. Tim McGinley (IMD Vibration Specialist) discussed options going forward and the decision was made to collect more vibration data during the summer run period and address any further issues during the fall outage. Mr. Howard Morgan (HPI Turbine Contractor) was de-briefed and demobilized from the McKee Run site on May 20, 2014.

The NAES Operations Team cleared the PJM outage ticket on Friday May 30, 2014 at 0700 hours. Unit 3 has been walked down and now ready for service, if requested by PJM.

Unit 3 2014 Fall Outage

With the unit in outage, the EHC tank was drained, cleaned and inspected, In addition, the Hy-Pro filtration equipment was installed on the tank for the purpose of improving filtration of particulate and removing moisture from the EHC fluid which could adversely affect performance.

No other turbine activities were reported for the Fall of 2014. No further turbine vibration issues were addressed in the Fall 2014.

No inspections, preventive maintenance or repairs were reported on the Unit 3 generator in 2014.

Unit 11 (VanSant Combustion Turbine) History

Combustion Inspection – 10/10/1994 – 11/11/1994. Work was performed by ECM and the CI revealed the unit to be in a very satisfactory condition. Two TILs were performed during the CI, TIL 1068-2 and 1132-2, both related to IGVs. A borescope showed no blade or spacer movement. Several visible cracks were found on the pressure side of four vane segments of the first stage nozzle. They were not open and did not appear to be a concern. New fuel oil check valves were also installed, along with all related gaskets and bolting.

A Hot Gas Path and Generator Inspection – 9/27/04 – 12/2/04.

The Hot Gas Path (HGP) and Combustion Inspection (CI) were completed in December 2004 with a few discrepancies.

Borescope Inspection March 2005.

The borescope inspection was conducted by Rodney Shidler of Advanced Turbine Support (ATS) on March 17, 2005 which included the compressor, turbine section and the exhaust section of the unit. To a limited extent, combustion hardware was also checked, in chambers five, six, and seven through the turbine case borescope ports. Results of the inspections were as follows:

November 2006

Unit 11 at VanSant Generating Facility was put into a scheduled five day maintenance outage in order to change out the fuel nozzles that had recently been purchased from General Electric.

April 16, 2007 to April 20, 2007.

During the outage, a number of work orders were addressed including inspections, equipment calibrations, preventative maintenance, and TILS. A borescope inspection was also performed on the compressor and turbine sections.

The following TILs and inspections were completed during the annual outage:

1) TIL 1004-2R1, it is recommended that the Inlet Guide Vanes (IGV's) and first stage rotor blades be inspected for corrosion pitting on an annual basis or when the unit is down for a scheduled inspection. All blading should be inspected during a major inspection when the compressor casing is removed. If corrosion pitting is found that exceeds the limits in Table 1 of the TIL, all blades of that stage should be replaced with GTD-450 blades or AISI 403 blades coated with GECC-1 coating.

This TIL includes the inspection techniques, procedures, and guidelines for inspection of variable Inlet Guide Vane inner bushings for all turbines operating at IGV settings of 84 degrees or less and 84 degrees and greater (revision). Additional information regarding the IGV inspection may be found in the Inspection and Maintenance Manual of the Gas Turbine Service Manual provided with the gas turbine. Also TIL's 522B, 5320CR2, 1013-3R3 and 1041-3A should be consulted, as they contain sections addressing the inspection of the VIGV inner bushings.

2) TIL 1132-2, annual inspection for thrust washer corrosion on the variable inlet guide vane assembly. Refer to table in TIL 1132-2 for proper clearances, drawings, and replacement parts.

NOTE: This procedure should be done with the gas turbine shut down and the inlet guide vanes rendered inoperable. Failure to do so could result in injury to personnel.

3) TIL 1146-3, annual Outage Work to be performed to comply with TIL 1146-3 pertaining to bus bar insulation cracking. Bus bar insulation discussed in the TIL is normally red in color and typically used in the following locations in a Gas Turbine-Generator Set:

- Generator Auxiliaries Compartment (GAC)
- Excitation Compartment
- Terminal Enclosure
- Bus Duct

Inspect bus bar on an annual basis for cracking. Clean insulation using a clean cloth dampened with a mild soap solution or ethyl alcohol. Take extra care when cleaning the insulation at bus bar support points.

This particular bus bar insulation is subject to chemical attack from hydrocarbons such as oil and solvents with a result that bus bar insulation may crack. Dirt and moisture can collect in the cracks creating a potential problem of electrical flashover phase-to-phase or phase-to ground.

4) Vibration probes BB4 and BB5 were replaced, due to giving faulty readings during previous runs.

5) We received our annual oil flow meter and transmitter calibrations from RMAX Technologies.

6) The annual gas fuel orifice plate was pulled, inspected, and found to be within specifications.

7) The oil and filters were changed in the starting diesel, along with all of the fuel filters and air filters.

Borescope Report

This report describes and documents the April 18, 2007 borescope examination of the General Electric Frame MS6000B combustion turbine. This inspection included the compressor, the turbine section, and the exhaust section. A limited inspection of the combustion hardware in chambers five, six, and seven was performed through the turbine case borescope ports.

The purpose of this borescope examination was to look for conditions considered to be abnormal to the unit and to gather trending data for future inspections. The machine data taken at the time of the borescope is shown below starts and hours are cumulative values.

Compressor

1. The inlet plenum appears to be clean.
2. The compressor rotor blades and stator vanes are dirty with dark deposits on the stage R-1 through R-2 blades and vanes.
3. The leading edge tips of several of the stage R-1 rotor blades have been blended because of previous

Utility	Inspector		Inspection Date	Serial Number
N.A.E.S.	Robert Burkhart		April 18, 2007	295627
Site Unit No.	**Manufacturer**			**Model**
VanSant Unit-11	General Electric			MS6000B
Type of Fuel	**Inspection Type**			**Contact**
Distillate	Annual Borescope Inspection			Paul Greenage
Fired Hours	**Manual Starts**	**Actual Starts**	**Fired Starts**	**Unit Trips**
3743.9	1400	1153	N/A	N/A

ice damage. There is minor impact damage on several of the first stage rotor blades.

4. There is minor impact damage on several of the rotor blades and stator vanes from stage R-7 through R-11. All of the impact damage identified is within the OEM’s acceptable limits.

Combustion Section

1. The combustion liners, fuel nozzles, and transition pieces appear to be in good condition in chambers 6 and 7.
2. The end of a crossfire tube in liner 7 shows minor wear and material loss.
3. The aft end of combustion liner 5 and the transition piece appear to be in good condition.
4. The inner and outer floating seals were inspected between transition pieces 5, 6, and 7 and the leading edge of the first stage turbine nozzles. The seals appear to be seated correctly.
5. The side-seals were inspected between transition pieces 5-6 and 6-7. The side seals appear to be seated correctly.

Turbine

1. There are minor cracks in platforms at the trailing edge of several of the first stage nozzles that were inspected.
2. The first stage nozzle seal slot grooves appear to be in good condition.
3. The first stage rotor buckets have rubbed against the shroud blocks. This has left the bucket tips discolored and smeared metal on the shroud blocks.
4. There are cracks in the trailing edge of the majority of the second stage nozzles that were inspected. The cracks are approximately ½” to 1” in length and do not appear to increase in length since the inspection in 2006.
5. There is minor damage to one of the discourager seal segments on the trailing edge of the second stage nozzle support ring where the second stage bucket angel wings have rubbed against it.
6. The second stage rotor buckets appear to be in good condition with no signs of any significant off set at the tip shrouds.
7. The second stage seal slot grooves and the knife seals on the shroud blocks appear to be in good condition.
8. There are cracks in the trailing edge of the majority of the third stage nozzles that were inspected. The cracks are approximately ¼” to ½” in length.
9. The third stage seal slot grooves seals, discourager seals, rotor buckets and the knife seals on the shroud blocks appear to be in fair condition.

Exhaust Section

1. The exhaust section appears to be in good condition.

Unit 11 2009 Annual Inspection

An inspection was performed in accordance with the same specifications as the 2007 inspection and no concerns were reported.

Unit 11 2010 Annual Outage

A black start was performed with the no power on the grid. The start was completed successfully.

Unit 11 2011 Spring Outage

The outage preventive maintenance tasks were completed and no major concerns were identified. Staff assisted in completing the testing of CTs, PTs, and DC Control Circuitry for NERC Standard PRC-005 requirements.

Unit 11 2011 Fall Outage

Completed the inspection of the air intake duct work. Duct work was inspected during a rain event and found to be dry and free of any metal fatigue.

JB Testing completed the underground oil piping leak test. Fuel oil was removed from the piping and helium was injected. Leak detection equipment was utilized at specific points. No leakage was reported

Cathodic protection testing was completed by Corrpro on Tuesday November 29th, 2011.

Camco relay contractor completed the inspection and calibration of MW transducers. Meter readings between the CEMS MW readout and the metering computer MW read out often varied and needed calibration. Unit 11 meter was reported to be within manufacturer's specifications.

Plant staff completed the change out of the air intake filters (both Turbine &Generator) before the outage.

2012 Spring Outage

NAES Operations and Maintenance teams completed a turbine water wash, with cleaning detergent. Rinsed several times and ran unit for thirty minutes to dry. No issues during procedure.

Borescope plugs were removed and Advance Turbine Services (ATS) set up for the borescope.
A borescope was completed by Advance Turbine Services. Initial report from the field technician provided no issues found.

Maintenance mechanics completed stack door repairs due to broken bolts and removal of debris from the stack bottom was completed also.

Maintenance mechanics completed the preventative maintenance service on the starting diesel. New oil and filters were installed; also new exhaust manifold gaskets were installed.
Maintenance mechanics removed and replaced one air skid cooling tube.

Mid Atlantic Electrical Services on site and started the installation of conduit for the gas detection system. Conduit runs were completed; new wiring was pulled and terminated at each gas detector to complete this portion of the project. IC&E technicians installed the detectors and Emerson completed a functional test on the operation of the system. During testing, the VanSant turbine compartment combustible gas detection system was found to have defective printed circuit board after power was supplied to unit. Circuit board was replaced and control panel tested OK.

Emerson Process Management completed installation of the VanSant control panel upgrades. The CT was started to check out the logic changes and brought up to full speed no load and heat soaked. During this time Emerson completed more system checks including a check of the startup diesel logic change and the natural gas logic during overspeed trip test conditions. Operations performed the mechanical overspeed trip test on the CT, which was successfully completed when the speed reached 111.6% and the turbine tripped. The mechanical bolt was reset and the test was documented for plant recordkeeping purposes.

IC&E technicians completed calibration and testing of gauges and transmitters. Most were completed ahead of the scheduled outage and completed during the first week. No issues to report.

IC&E technicians completed inspection and calibration of the following recommended GE TILS. Annual TIL1004-2R1 (IGV's and first stage corrosion/pitting inspection), Annual TIL1068-2R1 (IGV's bushing inspection), Annual TIL1132-2 (IGV thrust washer corrosion inspection) and Annual TIL 1049-3R1 (Inspect and measure dovetail material loss).

NAES ICE technicians installed the new DI water skid computer and function testing was completed. NAES ICE technicians with assistance from Rumsey Electric Technical support worked through several DI computer program communication problems.

NAES ICE technicians removed and replaced the cooling tower "A" side fan motor.

2012 Borescope Inspection

A borescope inspection was performed on March 15, 2012 by Advance Turbine Support and the following observations were reported;

Compressor Section
1. There are leading edge blends on several stage R-1 rotor blades.
2. There is impact damage to the leading edge of several stage R-1 rotor blades. IAW GEK107492 no action is necessary for this type of damage.
3. There are deposits on the stage S-1 stator vanes through S-13 stator vanes.
4. There is leading edge impact damage on stage several of the stage R-2, R-4, R-6, R-9, R-11 and R-13 rotor blades. IAW GEK107492 no action is necessary for this type of damage.
5. The stage R-5 through R-10 and R-12 rotor blades have rubbed against the compressor case near the six o'clock position. This has resulted in discoloration along the blade tips.
6. The stages S-5 through S-13 stator vanes near the six o'clock position have rubbed against the rotor shaft. This has resulted in discolored and rolled metal along the vane tips.

Combustion Section
1. The combustion caps, fuel nozzles, crossfire tubes and liners appear to be in good condition with typical carbon buildup on the primary fuel nozzles.
2. There are areas of coating loss from several of the transition pieces. At the majority of these areas only the top coat appears to be missing.
3. The floating seals and side seals on the transition pieces appear to be in good condition.

Turbine Section
1. There is coating loss from the leading edge of the first stage nozzles.
2. There are cracks in the trailing edge and outer platform of several first stage nozzles in the lower half of the unit. The cracks range in length from approximately ¼ inch to 2 inches.
3. The first stage seal slots grooves and discourager seals appear to be in good condition.

4. The first stage buckets have rubbed against the shroud blocks at the five o'clock position. This has resulted in discoloration along the bucket tips. Smeared metal is evident on the shroud blocks in this location.
5. The second stage nozzle seal slots and discourager seals on the trailing edge of the second stage nozzles appear to be in good condition.
6. There are cracks in the trailing edge of the second stage nozzles in the lower half of the unit.
7. The second stage buckets and honeycomb seal on the shroud blocks appear to be in good condition.
8. There is evidence of tip deflection between the inspected second stage bucket tip shrouds. Measurements were taken from each quadrant of the second stage buckets. The offset measurements range from between 0.018 inch to 0.43 inch.
9. Several of the second stage bucket pins are slightly protruding from the second stage buckets.
10. There are deposits located on the leading edge of the third stage nozzles.
11. The third stage seal slots and discourager seals appear to be in good condition.
12. The third stage buckets and bucket tip shrouds appear to be in good condition.

Exhaust Section
1. The exhaust flex seal was inspected and appears to be in good condition.
2. The exhaust section appears to be in good condition.
3. There is loose debris on the exhaust floor located underneath the exhaust diffuser.

Recommendations
1. Have engineering disposition the items listed in the observation section.
2. Borescope the unit on a six-month interval to monitor the conditions identified during this inspection.

2013 Spring Outage

NAES Operations Team completed a successful compressor blade water wash; in which the particulate was removed from the blades. Clean blades allow the unit to run at peak efficiency during times of operation. Operations started the unit and ramped to full speed no load. A brief hold period was completed allowing the turbine to heat soak for proper operating temperatures. Operations Team ran the manual overspeed trip test on the CT, a speed of 111.5% was realized and the mechanical bolt trip test was successful. Unit was shutdown and mechanical bolt reset to complete these activities.

NAES Operations and Maintenance Staff completed a successful Black Start Test on the Unit 11 turbine. Turbine was started from a dead buss and successfully loaded to carry its own auxiliary load for thirty minutes at which time the turbine was shutdown and the station returned to normal status. Unit then was taken out of service for the spring outage maintenance activities.

NAES Operations staff completed the LOTO ahead the scheduled outage work. NAES Maintenance Staff completed the Preventive Maintenance work on the starting diesel. Fuel and oil filters were replaced along with the lubricating oil. One fuel oil fitting was replaced; it was found to be cracked and leaking at time of the inspection. Belts and radiator hoses were inspected with no issues to report.

NAES Maintenance Staff completed the PM task of lubricating each piece of equipment. Several grease fittings were replaced in the process.

NAES Maintenance Staff also inspected the air inlet duct and stack interior with no issues to report.

NAES IC&E Technicians completed calibration of forty electrical and instrumentation transmitters with no issues to report.

NAES IC&E Technicians completed the PM service on the generator field breaker with no issues to report.

NAES IC&E Technicians investigated turbine and generator inlet air filtration puffer systemproblems. During system inspection and checks; one sequencing card was found to be nonoperational for the generator inlet side. Card was changed and the system checked again. System worked as designed with no problems.

NAES IC&E Technicians troubleshot the air inlet trouble alarm. Alarm would annunciate and then clear. Technicians traced it down to a faulty wire. Wire has been removed and replaced with new wire. No follow up trouble alarms have been received.

NAES IC&E Technicians completed four recommended General Electric (GE) TIL PM's for Unit 11 VanSant.

1) Annual TIL1004-2R1 (IGV's and first stage corrosion/pitting inspection)

2) Annual TIL1068-2R1 (IGV's bushing inspection)

3) Annual TIL1132-2 (IGV thrust washer corrosion inspection)

4) Annual TIL1049-3R1 (Inspect and measure dovetail material loss)

NAES IC&E Technicians completed the inspection and PM checks for the exhaust frame blowers. Blowers were inspected, greased and test run for vibration. No issues to report.

NAES IC&E Technicians completed the inlet guide vane calibration. Inlet guide vanes are inspected and calibrated for degrees of opening on the guide vanes. No changes were needed or made.

NAES IC&E Technicians and Operations Team completed the natural gas venting and condensate removal on the natural gas conditioning skid at VanSant. This was ahead of planned isolation and control valve replacements.

NAES IC&E Technicians and Operations Team completed a successful SMP-22 nitrogen gas purge of the natural gas piping system. Natural gas conditioning skid condensate drain line was dismantled and taken to the McKee Run shop. Gas skid piping was modified, new isolation valves and new control dump valve were preassembled. Gas skid piping was installed and pressure tested at 100psi; no leaks were found. Manual operation of the dump valve was completed with no issues to report.

Unit 11 Fall 2013 Outage

NAES Operations staff completed the LOTO ahead the scheduled outage work.

NAES Maintenance Staff inspected the air inlet duct and stack interior with no issues to report. NAES Maintenance Team completed the installation of ten fuel nozzles and respective fuel oil check valves on the combustion turbine. During the installation process, each bolt hole was tapped out, cleaned and inspected. Each fuel nozzle was installed and the bolting torque was properly set.

General Electric (GE) representative Mr. Mike Symons completed a borescope inspection of the internal components which consisted of; combustion cans, crossover tubes, transition pieces and first stage blades. Inspection revealed no issues with any of the internal components.

NAES IC&E Team completed the calibration of gas transmitter (#63 FG) at VanSant. No issues or problems to report.

NAES IC&E Team completed preventive maintenance (PM) on motor control cabinets (MCC), MCC breakers and generator breaker. Each were inspected, cleaned and serviced. No other issues or problems to report.

NAES IC&E Technicians completed the PM service on the generator field breaker with no issues to report.

NAES IC&E Technicians completed four recommended General Electric (GE) TIL PM's for Unit 11 VanSant.

1) Annual TIL1004-2R1 (IGV's and first stage corrosion/pitting inspection)

2) Annual TIL1068-2R1 (IGV's bushing inspection)

3) Annual TIL1132-2 (IGV thrust washer corrosion inspection)

4) Annual TIL1049-3R1 (Inspect and measure dovetail material loss)

NAES IC&E Technicians completed the inspection and PM checks for the exhaust frame blowers. Blowers were inspected, greased and test run for vibration. No issues to report.

NAES IC&E Technicians completed the inlet guide vane calibration. Inlet guide vanes are inspected and calibrated for degrees of opening on the guide vanes. No changes were needed or made.

NAES IC&E Team removed and replaced one (1) malfunctioning wheel space thermocouple. During operational run periods the thermocouple was registering low readings and bringing in a trouble alarm. NAES IC&E Team removed and replaced four (4) flame detector cables. NAES IC&E Technicians completed repairs on the eyewash and shower stand at VanSant. New piping, pedestal foot support and operator foot pedal were installed. The Eyewash and shower were tested and are now working properly. NAES Mechanics and ICE Technicians removed and replaced the lube oil pump motor. Motor was bump tested for proper rotation and then placed in service for further testing. With the pump and motor coupled together and operated, it was determined the lube oil pump has a bad bearing. Pump was removed and replaced with a spare from warehouse inventory. Pump was tested and operated as it should; unit was placed on ratchet for further observation.

NAES Operations Team completed a walk down of Unit 11; preparing the unit for winter mode of operation.
NAES Operations Team cleared the Lock Out Tag Out (LOTO) on outage related equipment.

2013 Borescope Inspection

General Electric performed the Borescope inspection on October 16, 2013 of the Frame 6B Turbine combustion section. The inspection was to check for coking inside the cans. The probe was inserted through the front of the cans and pushed up through the liners and into the transition piece to look for any indications. No concerns were identified. A Borescope of the remaining portion of the unit was not done in 2013.

VanSant 2014 Spring Outage

A compressor water wash was completed during the Spring 2014 outage. The NAES Maintenance Staff also inspected the air inlet duct and stack interior with no issues to report. The NAES IC&E Technicians completed four recommended General Electric (GE) TIL PM's for Unit 11 VanSant.

1) Annual TIL1004-2R1 (IGV's and first stage corrosion/pitting inspection).
   The NAES IC&E Technicians completed the inlet guide vane calibration. Inlet guide vanes are inspected and calibrated for degrees of opening on the guide vanes. No changes were needed or made.

2) Annual TIL1068-2R1 (IGV's bushing inspection)

3) Annual TIL1132-2 (IGV thrust washer corrosion inspection)

4) Annual TIL1049-3R1 (Inspect and measure dovetail material loss)

The NAES IC&E Technicians completed the inspection and PM checks for the exhaust frame blowers. Blowers were inspected, greased and test run for vibration. No issues to report.

Mr. Tom Martin from Philadelphia Gear was on site and completed an inspection of accessary gear box on the VanSant turbine. Tooth profile wear on the mating gear surfaces was observed on several sets of gears. A recommendation was made to re-inspect in 12 months and plan on refurbishing the gearbox in the next year or two.

VanSant Fall 2014 Outage

A wet compression upgrade was initiated; however the project has not yet been completed until 2015 and is fully operational . Repairs were made to the plenum duct during the Fall 2014 outage. The inlet air duct and stack were inspected and no issues were reported.

No inspections, preventive maintenance or repairs were reported on the VanSant generator in 2014.

Attachment 10- – Historical Boiler Maintenance, Inspections and Repairs (noted in previous reports)

Unit 1 Boiler History

October 2005

Received its annual outage inspection during the month of October 2005 and the following items were inspected:

- The station received their annual boiler inspection from Mr. Steve Smith of the ARISE Insurance Company, on October 18, 2005. Also during this outage Joe Hultberg of NALCO and Shane Taylor inspected both drums internally.

September 18 to September 22, 2006

Unit 1 received its annual outage inspection during the month of September, 2006 and the following items were inspected:

- Unit 1 received its annual boiler inspection from Mr. Steve Smith of the ARISE Insurance Company, on September 21, 2006. Also during this outage Joe Hultberg of NORFALCO inspected both drums internally.

October 8, 2007 to October 11, 2007

Received its annual internal boiler inspection from Mr. Steve Smith of the ARISE Insurance Company, on October 9, 2007. Internal inspections of both the steam drum and the mud drums were performed, along with the external boiler inspection. While he was on site, Mr. Smith also inspected both of our hot water Boilers and thirty six vessels here and seven vessels at VanSant, which were due for inspections. No problems or concerns were found by Mr. Smith on any of the boilers.

Unit 1 Annual Outage Work Scope 2008

10/1/08 – 12/31/08 – PJM Ticket #651611
Annual Insurance Inspection - Steve Smith of ARISE – Also inspect the hot water boilers while he is here.Open the mud and steam drums and inspect/clean. Open the ID and FD Fans and inspect/clean. Open the wind box and inspect dampers and linkages. Adjust / repair if required. Open the condenser water boxes and clean. Flood condenser to check for tube leaks. Open the hot well and inspect/clean. Inspect re-circulation line in condenser. Open and inspect ash hoppers. Clean if needed. Clean the air pre-heater steam coils. Inspect air pre-heater soot blower nozzle. Inspect air-preheater radial seals. Check clearances/adjust if required. Also check baskets. Check stroke and operation of ID and FD Fan dampers Inspect / repair ID fan expansion joints. Blow out motors and check contacts. Fuel Oil Conversion Project Pull / inspect main gas line orifice plate. Inspect / Repair Boiler Safety Valves. Check all burner oil and supply hoses for leaks.

Unit 1 2009 Annual Outage

The Arise boiler inspection included inspected of the steam drum, mud drum, and boiler. Unit 1 steam drum was reported to be in good condition. Some pitting was reported on the south side, along with a small amount of accumulation was noted in the mud drum and boiler looked good. Visual inspection of the furnace was done from the ground floor. No scaffolding was placed in the boiler. The Nalco chemical representative also inspected the water side of the boiler and reported the boiler to be in good condition. Safety valve inspection was completed in 2008 by Furmanite American. The valves are due in 2010. Unit one duct work was inspected by plant management to develop a removal plan for the cyclone separators and duct modifications. Operations removed loose ash from two areas and removed rain water from the air heater duct work. Work order issued for repairs to eight duct work ports. Holes in port caps or around piping. WO#8970

The Unit 1 air heater guide bearing cover was broken. The cover was removed and repaired and the bearing was replaced. The hole in cover was allowing water to enter the shaft area and puddle in the duct work. The air heater support bearing oil was replaced. The air pre-heater ductwork and steam coils were cleaned and reported to be in good condition. The air pre-heater soot blower nozzle was inspected and in good condition. The air heater baskets and duct work were reported to be clean and in good condition. The ash hoppers were cleaned, inspected and in good condition. The FD/ID fans were cleaned and inspected. Several holes and cracks on the inside liners of the FD fan were repaired

Unit 1 2010 Annual Outage

Unit one cyclone separators were window paneled by Apex. Holes were cut in the inlet and outlet dust distributors. Two rows of angle stiffeners were welded on the south distributors. Mechanical work was completed by Apex. Duct work, ash hoppers, cyclone area and boiler bottom were cleaned, inspected and in good condition after completion of the project work. Broadbent completed this task. New insulation and lagging was installed on the man way door to complete this project.

Unit 1 boiler Overpressure Excursion Inspection Findings

In July 2010, a boiler furnace pressure excursion occurred. During a visual inspection of the outside of the boiler it was reported that the casing of the boiler had been damaged on the north, east and west sides of the unit. There was also damage to a ductwork door between the boiler exit and air heater that had been blown off during the incident. Each of these areas was addressed during the outage.

Scaffolding was constructed on the outside of the boiler and once the temperatures in the boiler were lowered to a safe level for human entry contractors began building scaffolding inside so members of the plant staff and Babcock and Wilcox could perform an inspection and facilitate repairs.

A steam generating tube ruptured. The rupture would account for the rapid loss of steam pressure and drum level on the day of the incident. The rupture in the tube measured approximately 24 inches in length and was opened wide enough to make the tube appear flat. A section of the ruptured tube measuring approximately 8 feet in length was replaced. It was also determined that several other tubes in the immediate area also needed attention and they were addressed during the outage.

The Babcock and Wilcox Company performed an inspection of Unit 1 boiler that included internal surface deposit weight determination and a metallurgical assessment of an un-failed boiler tube located in Unit 1 boiler adjacent to the tube that did fail. Overall the tubing tested was in fair to good condition. No water wall tubes were below the 70% threshold that would require replacement. Of the super heater tubes tested one tube fell below the 85% threshold and a few others were near that point. The results of the surface deposit and metallurgical assessment showed no evidence of internal corrosion. The results of the metallurgical analysis showed that the tube did conform to ASME SA-178A material specifications and the measurements indicated a localized wall loss of approximately 30% of the external surface possibly associated with erosion.

In addition to the damaged boiler casing, ductwork door and boiler tubes there was also damage to insulation, refractory and insulating tiles located inside the boiler. Boilers 1 and 2 are also equipped with a camera that provides visual indication that a flame is present in the boiler. As a result of the incident the camera on Unit 2 was damaged beyond repair and had to be replaced with a new one. Each of these areas was repaired during the outage.

The boiler has one set of double block and bleed valves installed in the pilot gas line that goes to the left set of burners, and another set of double block and bleed valves that go to the right set of burners. There is also a set of igniter gas supply trip valves. Loss of pilot flame in any burner, should give a flame failure alarm for that burner. There is no pilot trip for loss of flame. When power is applied to the alarm panel all of the flame failure alarms except for the bottom left work properly. The bottom left shows flame failure all the time. A test of the flame scanner indicated that it is bad.

The main gas burner valves are manual and require an operator to open or close them. The same is true for the main oil burner valves. There are no flame scanners for the main gas burners or main oil burners. Therefore they will not trip on loss of flame. According to the drawings, the main oil trip valves and main gas trip valve do not trip on loss of flame. There is an emergency trip button located in the control room on the control panel of each unit. When pressed by the control room operator, the main oil, main gas, pilot gas trip valves, and pilot gas burner trip valves will close. An operator then has to manually close each burner main oil and or gas valve. Loss of either the ID or FD fans on the boiler should trip all the fuel trip valves. This did not work on Unit 1. It was discovered that the FD-2 relay in the purge cabinet would not energize to trip the fuel valves. Replacing the relay cured the problem. All fuel trip valves now trip on loss of either FD or ID fan. The Low oil pressure switch is wired to trip the oil supply and return valves.

This was tested and it works properly. The Low gas pressure switch is wired to trip the main gas supply valve. This was tested and it works properly. The low igniter gas pressure switch is wired to trip the igniter trip valves and the igniter burner trip valves. This was tested and it works properly.

Unit 1 2011 Boiler Spring Outage

The boiler combustion controls upgrade was started on March 28, 2011. NAES mechanics removed all the oil supply and return isolation valves, installed new 750 PSI ball valves recommended by Warren Professionals. It was later discovered that the valves didn't meet the system design and new 1200PSI ball valves were ordered and installed. NAES mechanics installed new limit switches on main gas, pilot gas and oil supply/return valves. NAES mechanics removed sight port covers and installed bell reducers for installation of new flame detectors.

Mid Atlantic Electrical Services (MAES) started installation of overhead cable tray, conduit and pulled wire to each device location. MAES also installed the cable tray, conduit and ran the main cable from the burner front control cabinet to the control room.

NAES IC&E technicians installed the control cabinet, relays, LED lights and terminated all the panel wiring. Boiler front main and pilot gas flame scanners were installed. Boiler front components were wire terminated.

Warren Professionals completed component system checkouts and the boiler was placed in service for final system checkouts. Pilot gas was placed in the boiler, once flame detection was established the scanner was lifted and loss of flame secured the gas system. Each pilot was tested and all checked out as working properly. Main gas was established in each burner, scanners checked and system shutdown tested. Each main flame checked out as planned. Oil burners were placed in the boiler and main flame scanners detected the flame. Next each scanner was lifted and secured the oil system for proper shut down on loss of flame. This completed the system check outs. New pilot and main gas latch/trip valves will be ordered and installed. Also new time delayed spark relays will be installed on the igniter system. Since the outage, these parts have been received and installed.

Unit 1 Fall 2011 Outage

Maintenance completed boiler, mud drum and system component inspections. All were clean and found to be in good condition. Maintenance completed the boiler duct work and wind box inspections. A small amount of ash was removed from the duct work. Air heater, steam coils and ash system were found to be in good condition and clean. The wind box had corner weld cracks that were identified and repaired. Boiler feed pump 1B was removed and replaced with a certified rebuilt pump. Boiler feed pump 1B electric motor was removed and sent out for inspection, cleaning and repairs. Both components were installed. During this event it was found that the pump shaft was longer than the previous one. ISC, the pump repair

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company, was on site to witness the pump install. Mr. Don Johnson and NAES staff reviewed pump manuals and prints and took shaft measurements, pump lift measurements and shaft end play measurements. After reviewing the results and consulting with ISC representatives, it was agreed upon that a motor adapter plate would be manufactured and installed. This will allow for the proper pump lifting height during operation. ISC fabricated the plate and sent the plate to the plant. Final assembly was completed and the pump checked. Flow testing was completed and base line performance numbers documented.

Minor oxidation scale and pitting were observed in the steam drum; no cracks or metal fatigue was reported.

Unit 1 Boiler Spring 2012 Outage

NAES Mechanics removed and replaced top side air heater seals.

APEX mechanical completed the fabrication work on Unit 1 pilot gas orifice plate/flange project. Fabricated piping and installed new orifice plate flanges. Unit 1 pilot gas orifice plate/flange and piping was leak tested and no leaks were found. NAES ICE department installed natural gas (pilot) transmitters for Unit 1 and stainless steel tubing to the new pilot gas transmitters from the outside pilot gas header so that the pilot gas flow may be measured. The conduit and wire for the natural gas (pilot) transmitters on Unit 1 were also installed. Wire termination to the new pilot gas transmitters and the Net 90 system was completed for the final step of this project. Natural gas pilot and main gas line blanks have been removed and orifice plates installed. Primary element inspections for Unit 1 have been completed. The logic needs to be added to complete the project.

Both the ID and FD fans were opened up, cleaned, and inspected. The ID and FD fans inlet and outlet dampers and drives were inspected, lubricated, and stroked for position.

Unit 1 Fall 2012 Outage

NAES Maintenance staff completed the inspection of the following areas; cold air inlet/outlet baskets, hot gas inlet/outlet baskets for the air heater, air heater seals, air preheater steam coils and associated duct work. No issues to report. A new spring loaded check valve was installed.

NAES Maintenance staff completed the installation of two steam piping supports. Two existing steam pipes were identified as needing additional support. MDS designed the new layout and provided NAES management with a mechanical blueprint**.**
International Chimney Company (ICC) was on site to complete an internal and external inspection of the stack. No immediate repairs were identified at this time.

All the safety valves were disassembled, inspected, assembled and final pressure settings completed.
.
Mr. Joe Hultberg Condor Technologies representative was on site to inspect the boiler steam drum and condenser water boxes and no issues were identified

Unit 1 Spring 2013 Outage

No major work or significant inspections were performed on the Unit 1 boiler in the Spring 2013.

Unit 1 Fall 2013 Outage

NAES Maintenance Team opened the boiler and ductwork doors after which they completed internal boiler and ductwork inspections . Air heater upper and lower seals, internal duct work structural steel, boiler burner throats, gas spuds and wind box inspections were completed. No issues or findings were reported. One drum of debris was removed from the hot gas ductwork area. .

NAES Maintenance Team opened mud and steam drum doors ahead of the XL Insurance Inspection. Mr. Charlie Newman from XL Insurance Company completed an internal inspection of the mud-drum and boiler drum. Unit 1 had minor surface rust and pitting. Inspector noted that water chemistry and lay up procedures has improved the boiler conditions. There were no major issues with the boiler inspection to report and no follow-up work to complete.

Unit 1 Boiler 2014 Outages

Inspections of Units 1 ductwork, air preheater steam coils and air heater rotor assemblies (including baskets) were completed during the Spring 2014 outage. As part of the inspection process, debris (ash) was removed from the ductwork. The NAES Maintenance Team removed and replaced one section of drain pipe on the air heater steam piping that had frozen and busted.

The NAES Maintenance Team completed the fabrication of new piping for the boiler drains header. The piping from the DI storage tank to Units and 2 was replaced. .

Two abandoned house heating system pipes that have been out of service for several years were capped to safely secure them from the main system.

In the Fall of 2014, the Unit 1 boiler steam drum and mud drum doors were opened in preparation of the insurance company boiler inspector arriving onsite. Upon completion of the boiler inspection, Mr. Curtis McLaurin, the XL Insurance Company Boiler Inspector, noted the steam drum was clean and free of scale with all internals tight. The mud drum was also clean. The safety valves were checked and noted to be properly sized. No other conditions were noted which required attention.

Unit 2 Boiler History

September 25, to September 28, 2006

Unit 2 received its annual outage inspection during the month of September, 2006 and the following items were inspected:

- Unit 2 received its annual boiler inspection from Mr. Steve Smith of the ARISE Insurance Company, on September 21, 2006. Also during this outage Joe Hultberg of NALCO inspected both drums internally.

October 15, 2007 to October 18, 2007

Received its annual internal boiler inspection from Mr. Steve Smith of the ARISE Insurance Company, on October 18, 2007. Internal inspections of both the steam drum and the mud drums were performed, along with the external boiler inspection. Also during this outage Joe Hultberg of NORFALCO inspected both drums internally.

Unit 2 Annual Outage Work Scope

10/1/08 – 12/31/08 PJM Ticket #651612 Annual Insurance Inspection – Steve Smith of Arise – Also inspects the hot water boilers Open the mud and steam drums and inspect/clean. Open the ID and FD Fans and inspect/clean. Open the wind box and inspect dampers and linkages. Adjust / repair if required. Open the condenser water boxes and clean. Flood condenser to check for tube leaks. Open the hot well and inspect/clean. Inspect re-circulation line in condenser. Open and inspect ash hoppers. Clean if needed. Clean the air pre-heater steam coils. Inspect air pre-heater soot blower nozzle. Inspect air-pre heater radial seals. Check clearances/adjust if required. Also check baskets Check stroke and operation of ID and FD Fan dampers Inspect / repair ID fan expansion joints Blow out motors and check contacts Pull

/ inspect main gas line orifice plate Inspect / Repair Boiler Safety Valves Fuel Oil Conversion Project Check all burner oil and supply hoses for leaks

Unit 2 2009 Annual Outage The Arise boiler inspection included inspected of the steam drum, mud drum, and boiler. Unit 1 steam drum was reported to be in good condition. Some pitting was reported on the south side, along with a small amount of accumulation was noted in the mud drum and boiler looked good. Visual inspection of the furnace was done from the ground floor. No scaffolding was placed in the boiler. The Nalco chemical representative also inspected the water side of the boiler and reported the boiler to be in good condition. Safety valve inspection was completed in 2008 by Furmanite American. The valves are due in 2010. Plant management inspected the duct work to develop a plan to remove the cyclone separators and duct modifications. Operations removed loose ash from the air heater to stack duct work. A work order was issued for repairs to three duct work ports due to holes in port caps or around piping. The duct work expansion joint west of the fan openings rusted out. The expansion joint liner was reported rusted out and missing. Cerwool was placed in the expansion joint gaps and a new liner cover was welded in place. The Unit 2 air heater guide bearing was out of tolerance. The old bearing was replaced. The air heater support bearing oil was replaced. The air pre-heater and steam coils were cleaned and reported in good condition. The air pre-heater soot blower nozzle was inspected and in good condition, however, the steam line was bent and resting on the duct work transition piece. Further inspected revealed that the transition piece was rusted out and weak. The air heater had three sections of damaged seals which were replaced. Further inspection of the air heater soot blower reveled the housing was damaged and would require replacing. The air heater baskets were reported to be clean and in good condition. The ash hoppers were cleaned, inspected, and reported to be in good condition. The ID/FD fans were cleaned and inspected and the FD fan had several holes and cracks on the inside liners, which were repaired.

Unit 2 2010 Spring Outage

Unit two cyclone separators were window paneled by Apex. Holes were cut in the inlet and outlet dust distributors. Two rows of angle stiffeners were welded on the south distributors. Mechanical work was completed by Apex. Duct work, ash hoppers, cyclone area and boiler bottom were cleaned, inspected and in good condition after completion of the project work. New insulation and lagging was installed on the man way door to complete this project. Duct work expansion joint was removed, flanges cleaned and one small hole repair completed by Apex. New EJ was installed and new sector plants installed also. Air heater soot blower was dismantled and the transition piece removed. A new transition piece was welded in place; soot blower was assembled using all new parts. The soot blower was installed on the new transition piece and steam cleaning arm adjusted to achieve maximum coverage.

Unit 2 2010 Fall Outage
Two superheater U-bolt brackets were installed. Two tubes in the superheat header were rolled and new plugs installed. DP testing was done after each pass for the new plug install. All passes tested OK. A Hydro test on Unit 2 boiler was completed at 300 PSI. Apex inspected their work and no leaks at this time. Superheat and water wall tube samples were removed for testing. New tubes were installed. A hydro was completed at near operating pressure and one leak found. The tube was rewelded and retested OK. The water level was taken down to operating level. UT testing on generation tubes was completed and data analyzed. Each tube was identified and marked for pad welding. Specific lengths of pad welding were designated for each tube from UT testing results. No steam generation tubes were removed. Inspected and cleaned out ash hoppers. There was a small amount of ash in the hoppers. Ash was removed, put in the waste rolloff and logged on the profile sheet. The ash hoppers and the air pre-heater steam coils were cleaned. Six relief valves on unit 2 were removed by Chalmers & Kubeck. Each valve was inspected, repaired and pressure set. New internals and seats were installed. Valves were returned to site and installed. The mud drum and steam drum doors on Unit 2 were opened for Arise inspection. Inspection was completed and report sent to NAES. No issues found.

Unit 2 2010 Boiler Control Evaluation
The Unit 2 boiler controls and protection were also evaluated as a result of the Unit boiler excursion. Unit 2 also has very little in the way of burner safety automation. Each boiler has one set of double block and bleed valves installed in the pilot gas line that goes to the left set of burners, and another set of double

block and bleed valves that go to the right set of burners. There is also a set of pilot gas supply trip valves. Loss of pilot flame in each burner should give a flame failure alarm for that burner. Applying power to the alarm panel showed that all burner flame failure alarms came in. Tests were performed on all burners for flame detection and alarms and they all work as per design. The main gas burner valves are manual and require an operator to open or close them. The same is true for the main oil burner valves. There are no flame scanners for the main gas burners or main oil burners. Therefore, they will not trip on loss of flame nor will the main gas or main oil supply valves. There is an emergency trip button located in the control room on the control panel of each unit. When pressed by the control room operator, the main oil, main gas, pilot gas trip valves and pilot gas burner valves will close. The operator then has to manually close each burner main oil and or gas valve. Loss of either the ID or FD fans on the boiler is supposed to trip all the fuel trip valves. When tested this did not happen. It was discovered that the FD-2 relay in the purge cabinet would not energize to trip the fuel valves just like Unit 1. Replacing this relay cured the problem. All fuel trip valves now trip on loss of either FD or ID fan. The Low oil pressure switch is wired to trip the oil supply and return valves. This was tested and it works. The Low gas pressure switch is wired to trip the main gas supply valve. When tested this did not work. The plant I&C group found the switch was wired incorrectly. The wiring was changed and it now works properly. Low igniter gas pressure should trip the igniter gas trip valve, and the igniter burner valves.

Unit 2 2011 Boiler Spring Outage

Unit 2 boiler combustion controls were upgraded during this outage. APEX was contracted to remove all the oil supply and return isolation valves, install new 1200 PSI ball valves. NAES mechanics installed new limit switches on main gas, pilot gas and oil supply/return valves. NAES mechanics removed sight port covers and installed bell reducers for installation of new flame detectors.

Mid Atlantic Electrical Services installed the overhead cable tray, conduit and pulled wire to each device location. MAES also installed the cable tray, conduit and ran the main cable from the burner front control cabinet to the control room. NAES IC&E technicians installed the control cabinet, relays, LED lights and terminated all the panel wiring. Boiler front main and pilot gas flame scanners were installed. Boiler front components were wire terminated. Warren Professionals completed component system checkouts and the boiler was placed in service for final system checkouts. Pilot gas was placed in the boiler, once flame detection was established the scanner was lifted and loss of flame secured the gas system. Each pilot was tested and all checked out as working properly. Main gas was established in each burner, scanners checked and system shutdown tested. Each main flame checked out as planned. Oil burners were placed in the boiler and main flame scanners detected the flame. Each scanner was lifted and secured the oil system for proper shut down on loss of flame. This completed the system check outs. New pilot and main gas latch/trip valves will be ordered and installed. New latch/trip relays will be installed. Also new time delayed spark relays will be installed on the igniter system. Since the outage, these parts have been received and installed.

LRC installed scaffolding in the air heater outlet duct work for safe access to the bottom side air heater radial seals. Several seals were damaged last year when the air heater soot blower transition piece broke and allowed the steam wand to hit several seals causing damage to them. NAES mechanics removed and replaced the entire set of seals. Each one was adjusted for proper clearance.

Unit 2 2011 Fall Boiler Outage

Maintenance completed boiler, mud drum and system component inspections. All were clean and found to be in good condition. Maintenance completed the boiler duct work and wind box inspections. A small amount of ash was removed from the duct work. Air heater, steam coils and ash system were found to be in good condition and clean. Wind box had corner weld cracks that were identified and repaired. Hot gas duct work to air heater was reported to have several small areas of metal fatigue. Plate metal was cut and seam welded in place to complete the repairs.
During the air heater inspection the top side seals were reported to be thin and deteriorating closest to the rotor post. These are scheduled to be replaced in the next outage. APEX mechanical started the

prefabrication work on units 1&2 pilot gas orifice plate/flange project. Prefabricated piping with the new orifice plate flanges will be completed and installed during the spring outage.

Mr. Mike Brewington Nalco representative was on site to inspect our boiler steam drums, mud drums and condenser water boxes. No issues were reported. Mr. Ernest Brantley, the Boiler & Property Consulting, LLC insurance representative, inspected the boiler steam drums, and mud drums. Minor oxidation scale and pitting were observed; no cracks or metal fatigue was reported.

Unit 2 Spring 2012 Outage

NAES mechanical staff completed the repair of Unit 2 Hot gas duct work to the air heater. New sheet metal was installed and sealed to complete the repairs. Small repairs were made to the interior duct breeching

APEX mechanical completed the fabrication work on Unit 2 pilot gas orifice plate/flange project, fabricated piping and installed new orifice plate flanges. Unit 2 pilot gas orifice plate/flange and piping was leak tested and no leaks were found.

NAES ICE department installed natural gas (pilot) transmitters for Unit 2. Installed stainless steel tubing to the new pilot gas transmitters from the outside pilot gas header so that the pilot gas flow may be measured.

Conduit and wire for the natural gas (pilot) transmitters on Unit 2 was installed. Wire termination to the new pilot gas transmitters and the Net 90 system was completed for the final step of this project. Natural gas pilot and main gas line blanks have been removed and orifice plates installed. Primary element inspections for Unit 2 have been completed.

Unit 2 Fall 2012 Outage

NAES Maintenance staff completed the inspection of the following areas; cold air inlet/outlet baskets, hot gas inlet/outlet baskets for the air heater, air heater seals, air preheater steam coils and associated duct work. No issues were identified.

NAES Maintenance staff removed and replaced the indoor condensate piping check valve. A new spring loaded check valve was installed. NAES Maintenance staff inspected air registers and linkages in the wind box.

International Chimney Company (ICC) was on site to complete an internal and external inspection of the stack. No immediate repairs were identified by ICC.

The boiler Safety valves were disassembled, inspected, assembled and final pressure settings completed. During the unit overspeed trip test, two safety valve gaskets were leaking due to miss alignment. Chalmers and Kubeck was notified and returned to site. Each flange was fitted with a new gasket and proper alignment completed. Inspections and certifications are completed every two years.

Mr. Charles Newman, XL Insurance/Boiler & Property Consulting, LLC representative, was on site to inspect the boiler steam drums. Minor oxidation scale and pitting were observed; no cracks or metal fatigue was found. Mr. Joe Hultberg, Condor Technologies' representative, was also on site to inspect the Unit 2 boiler steam drum and condenser water boxes. No issues were found. Water treatment program concerns related to future lay-up of the boiler were identified.

Unit 2 Fall 2013 Outage

NAES ICE technicians removed the main and pilot natural gas piping orifice plates and installed blank plates ahead of boiler ash pit cleanout, duct work, and boiler inspection.

NAES Maintenance Team opened the boiler and ductwork doors after which they completed internal boiler and ductwork inspections. Air heater upper and lower seals, internal duct work structural steel, boiler burner throats, gas spuds and wind box inspections were completed. No issues or findings were reported. One drum of debris was removed from the hot gas ductwork area.

NAES Maintenance Team opened mud and steam drum doors ahead of the XL Insurance Inspection. Mr. Charlie Newman from XL Insurance Company completed an internal inspection of the mud-drum and boiler drum. Unit 2 had no surface rust or pitting. Inspector noted that water chemistry and lay up procedures has improved the boiler conditions. There were no major issues with the boiler inspection to report and no follow-up work to complete.

Unit 2 Boiler 2014 Outages

A routine Unit 2 boiler outage was completed from March 03 to May 30, 2014. The NAES Operations and Maintenance Teams completed inspections of Units 2 ductwork, air preheater steam coils and air heater rotor assemblies (including baskets). As part of the inspection process, debris (ash) was removed from the ductwork. No issues were reported.

One section of drain pipe on the air heater steam piping that had frozen and busted was replaced. The NAES Maintenance Team completed the fabrication of new piping for the boiler drains header. The removal and replacement of the outdoor DI storage tank supply piping to Units 1&2 was replaced. Additional repairs were completed on the same line at a different location closer to the tank.

The NAES Maintenance Team cut and capped two abandoned house heating system pipes. Piping system has been out of service for several years and needed to be safely secured from the main system.

In the Fall of 2014, the Unit 1 boiler steam drum and mud drum doors were opened for the internal boiler inspection. Mr. Curtis McLaurin, the XL Insurance Company Boiler Inspector, noted the steam drum was clean and free of scale with all internals tight. The mud drum was also clean. The safety valves were checked and noted to be properly sized. No control or operational concerns were reported. Once the inspection was complete, the Maintenance Team closed up the boiler doors utilizing new graphite gaskets.

Unit 3 Boiler History

Unit 3 April 2005.

- Boiler Ductwork repairs
- Expansion joints before the ash handling system, in the ductwork before the boiler on the hot air side and in the ductwork after the boiler on the hot gas side.
- Replace atomizing air & oil burner front diaphragms
- Boiler (pressure vessel) inspection by Steven Smith of ARISE Incorporated assisted by NALCO Representative Joseph Hultberg and DE Operating Services Chemistry Technician, Shane Taylor.
- Preventative maintenance on 4160V, 480V and field breakers
- Doble testing on Unit #3 Main Transformer, Starting Transformer and Run Transformer

13th March to 24th March 2006

- The annual internal boiler inspection was done on 3/1/06 by Mr. Steve Smith of the ARISE Insurance Company.
- The steam drum internals were inspected by Joe Hultberg (Calgon representative),
- Burner air registers were inspected and checked for position.
- The Bailey cabinet was cleaned.

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19th March 2007 to 23rd March 2007.

The annual internal boiler inspection was done on 3/20/07 by Mr. Steve Smith of the ARISE Insurance Company. We also received our inspection certificate from him.

The steam drum internals were also inspected by Joe Hultberg (Calgon representative), on 3/21/07

Unit 3 2008 Outage Work Scope

10/1/08 – 12/31/08 PJM Ticket #651613 Boiler Inspection – Don't know if Steve Smith of the Arise Insurance Company will want to inspect again, since he did it in March Open all boiler access doors and steam drum.

Clean out ash pit and boiler. Boiler Inspection: (visual inspection of the boiler, wind box, and all related ducts and expansion joints). Inspect IK Soot blowers Inspect/clean Ash Re-injection System (includes cyclone swirlers) Install Beck Drives Install burner shrouds Repair the turbine turning gear Install new flame scanners Install the CEMS sample line Fuel Oil Conversion Project Check cooling tower fan blades for pitch New CEMS DAHS install - all units Vacuum out all ash hoppers Install over fire air nozzles Clean out turbine lube oil tank.

Lab:

- The neutralizing pit liner was inspected and the pit was cleaned.
- The pre-tech pump and the phosphate pump were inspected, cleaned, and repaired.
- The air operated valves and associated piping on the main train of the demineralizer were inspected and cleaned.
- There are two hot water boilers that are used for building heat and to heat the fuel oil: they are manufactured by Continental and operate at 250 psi, 300 °F having an output of 13,390 MBTU/hrs and where manufactured in 1972 and found to be in good condition. These units are gas fired and unmanned.
- The station stacks are fitted with full CEMS monitoring equipment covering:CO_2, SO_2, and NOx.

Unit 3 2009 Annual Outage

The Dead Air Space (DAS) was inspection of the dead air space was conducted and the flowing conditions were reported:

- The insulation on the south wall of the DAS had fallen down and the lagging had separated from the wall of the dead air space.
- The DAS access doors were loose and looked as if they were not attached to the duct work.
- NAES employees removed the lagging and insulation from the 3 ½ floor to the 5 ½ floor.
- The sheet metal that made up the DAS walls were in need of replacement on the east, west and south sides. Apex Mechanical removed all the damaged sheet metal and replaced with new. The old doors were in good condition so they were reused and reattached to the new duct work.
- After the metal was removed, refractory problems on the boiler south wall was discovered. Apex and Ramco Solution replaced the refractory per specifications in the boiler drawing. Apex also did some refractory work around the access doors in the super heater and reheat sections of the boiler.
- New insulation and lagging was installed on the DAS walls by All-Temp Insulation Co.

All boiler doors were opened. Steve Smith with Arise inspected the drum and boiler. There was one problem in the drum area with a broken support. The support was welded back in place. This was accomplished by Apex Mechanical. Everything else in the boiler and wind box was reported in good condition. Safety valve inspection was completed by Furmanite American. The valves were inspected and reinstalled by Furmanite American. No problems or issues were reported. The air heater was inspected and the outlet expansion joint needed repairs. HMI was contracted to repair the joint.

Unit 3 2010 Spring Outage

Unit three cyclone separators, ash system and conveying line equipment were removed by Apex. Cyclone tube sheet was removed and several rows of tube stiffeners were welded at the cyclone opening. Mechanical work was completed by Apex. Duct work, ash hoppers, cyclone area and boiler bottom were cleaned, inspected and in good condition after completion of the project work. Broadbent completed this task. Dead air space inspection was conducted from the 5 ½ level to the 3 ½ level by Ray Lavender. No problems were found. Work completed by Apex on DAS walls still in place. Boiler side repair work by Apex and Ramco was in good condition and in place. No damage found. All boiler and drum doors were opened. Steve Smith with Arise inspected the drum and boiler. There was one problem in the drum area with a cracked support. The crack was repaired. This was accomplished by Apex Mechanical. Windbox and damper operation were inspected and found to be in good condition.

ID fan expansion joints were removed and replaced with OEM EJ's. One modification was made to each one due to the above breeching sagging. Approximately one inch of the EJ was removed before installation. Angle iron was installed to support the final installation. ID fan outlet dampers were cleaned and manually operated for testing. Grease lines were repaired and bearings checked. No problems. Fans were cleaned out and water washing not needed. One ID fan inlet damper drive unit was rebuilt. Inspected the SH and RH attachment lugs. Everything checked visually OK. Vacuum was pulled on boiler and one reheat tube leak was found to have a small crack. Leak was located on the south side at the lug attachment.

Unit 3 2010 Fall Outage

NewCO/O2 probes were installed. Old probes were removed; new spool pieces were fabricated and installed. New probes set in place. New wires run from the probes to the control boxes. Probe installation completed. Calibration and startup of the analyzers has been completed. All probes tested OK. NAES completed the installation of the new air heater soot blower and drain trap steam piping. New heat tracing, insulation and lagging was installed. NAES installed a new plate on the bottom of Unit 3 stack cone and repaired the drain line that runs to the pit. Outside engineering firm inspected stack area for installation of permanent platform and walkway.

NAES inspected the air heater seals, structural metal and the rotor post seals on unit 3. There are some problems with the seals and support metal. Alstom Power inspected the air heater and provided recommendations to NAES for priority repairs and future repairs. Apex removed the lagging from two areas on East & West gas outlet duct work for Unit 3. There were cracks in two tubes and the breaching wall. Breaching and tubes were removed. New tubes were sent out to be bent. Apex pad welded two holes in the duct work section where the tube leaks were located. Apex welded in four new tubes on Unit 3 and NAES completed a hydro of the boiler near operating pressure. Repairs that Apex had made to the tubes checked out fine. However we did find a small leak on the front wall around B-2 burner. UT readings were taken on the B-2 burner tubes and compared with readings taken on B-3 burner. Apex removed two tubes around (9 to12) B-2 burner. New tubes on site and Apex completed installation. On Hydro one crack was found at the lower attachment point and repaired. Vacuum was placed on RH section and no leaks found. Leaks were repaired by Apex.

Broadbent cleaned the gas outlet duct work, expansion joint, steam coils and bottom of stack on Unit 3. Material is compacted and cement like in the cone bottom. Further outside help will be needed to remove this material. New refractory was placed around the tubes and touched up the burner throat.

Unit 3 2011 Spring Outage

Boiler (crotch) tube area and boiler ash bottom area were cleaned, inspected and reported to be in good condition. Dead air space (DAS) inspection was conducted from the 5 ½ level to the 3 ½ level by plant personnel and no concerns were reported. Work previously completed by Apex on DAS walls was in good condition. Boiler side repairs, work by Apex and refractory work by Ramco was reported in good condition. Steve Smith with Arise inspected the drum and boiler. A cracked support in the drum was identified. The crack was repaired. Chalmers and Kubeck was contracted to complete the bi-ennial safety valve inspection. Seven valves were taken apart and inspected. Internals parts were cleaned, inspected and seats lapped. During the inspection reheat springs were found to be the wrong size for the valves. C and K provided spec information on the proper valve springs. NAES verified the findings and approved a change order for the purchase of the correct springs. Each valve was assembled. C and K returned to the site and pressure set each valve during unit operation on June 8, 2011 to complete this project.

The windbox and dampers were inspected and reported to be in good condition. FD and ID fans were opened and inspected. Each fan was turned by hand for inspection of fouling and blade condition. All fans were reported to be in good condition and no fouling of blades was noted. During the inspection 3A FD fan had one blade with a broken vane attachment. Maintenance removed the vane and installed a new swivel ball attachment. The damper was reinstalled and tested. The SuperHeat and ReHeat attachment lugs were inspected. Vacuum was pulled on boiler reheat section and no leaks were reported.

Apex was awarded the contract to remove and replace the air heater air outlet expansion joint. Operations removed the insulation and lagging. Apex removed the old expansion joint and prepared the breaching duct work for the new install. During the cleanup of the duct work it was discovered that modifications to the adjoining ductwork would be needed to facilitate proper fit-up of the expansion joint. This was completed and the new expansion joint was installed. Early in the process it was discovered that the breaching ductwork to the air heater needed to have its support I beam replaced. Metal delaminating was extensive on the I beam and associated duct work metal. One new I beam was purchased with installation to follow. New insulation and lagging were installed following the I beam work. Insulation clips were installed to help better support of the new insulation and lagging

Apex was awarded the contract for installing the new main gas isolation valves for each burner deck level. NAES operations removed the insulation from the gas piping. Each gas valve location was marked for the install. NAES operations, maintenance and APEX performed a gas line purge utilizing SMP-22. Once completed Apex was cleared to cut and install the new gas isolation valves. New conduit and wiring was installed to each valve on each level. This was completed by Mid Atlantic. Each gas valve was wire terminated and tested for operation by NAES ICE team members. Upon completion the main gas piping was filled with nitrogen and each gas valve area was tested for leaks. None were reported. Unit 3 boiler was placed in service, each valve and control scheme was tested by NAES operations team. Warren Professionals were contracted for the controls upgrade and system testing. Each gas piping section was cleaned of rust and UT testing was completed by NAES Operations Team. Results were recorded and reviewed. Each gas piping section was prepared and painted by NAES Operations Team.

Leak testing utilizing smoke generators was completed on Unit 3 boiler exit ductwork by NAES Operations Team on May 5. No leaks were reported.

Unit 3 2011 Fall Boiler Outage

The air heater expansion joint work started on October 10th. HMI completed the removal of insulation/lagging. HMI completed the removal of the old expansion joint and began prepping for installation of the new joint. The new joint was rigged and moved to the fan deck area and then placed in the duct work breeching, tack welded in place for fitting/final install. HMI completed the hot gas outlet expansion joint work on schedule. Final welding of the joint and installation of the deflector plate (provided by plant) was completed to close out the installation portion of the project. Cleanup of the work area was completed by HMI and final inside ductwork cleanup was completed by NAES operations team. County Insulation the insulation contractor started the new insulation/lagging install. Work was completed on schedule. LRC scaffolding contractor dismantled and removed all the scaffolding for the Unit 3 Boiler Hot Gas Outlet Expansion Joint to close out this project.

Maintenance opened boiler doors for boiler hydro and reheat vacuum inspections.
Operations started vacuum pumps to pull a negative vacuum on boiler. Reheat tubes were checked for leaks. One reheat tube leak was identified for repair. Plant will assess this area to determine what additional work is needed with a thought on future operations. APEX mechanical contractor was awarded the contract. They completed the reheat tube repair. Vacuum was pulled on the boiler to verify leak repair was satisfactory and there were no other leaks.
Operations set up and placed a hydro on the boiler. Maintenance personnel checked the economizer, superheater and water wall tubes for leaks and none were reported. APEX mechanical contractor removed

and replaced two drum vent isolation valves. Maintenance removed each double bleed & block gas burner valve and installed new packing O rings. Main gas system was pressurized with nitrogen and no leaks were detected.

Maintenance and operations staff removed and replaced the inlet damper bearings for 3A & 3B FD Fans. Insulation containing asbestos was abated on the 3A and 3B FD Fans. Insulation removal provided access to the damper guide bearings that were under the outside covering. Damper guide bearings were replaced also. This work was in preparation for new damper drive units that will be installed during our spring outage. The 3A ID fan casing repair was completed. During the inspection of the fan, two 1/4" holes were found in the casing. The area was prepped and then seal welded shut.

Unit 3 Spring 2012 Outage

NAES Maintenance team completed the boiler duct work and wind box inspections. Small amount of ash was removed from the boiler bottom ash pit area. Air heater baskets, steam coils and ash system ductwork were found to be in good condition and clean.

Mr. Ernest Brantley, Boiler & Property Consulting, LLC insurance representative was on site to inspect the boiler steam drums. Minor oxidation scale and pitting were observed; no cracks or metal fatigue was found. One area in the drum was dye checked and verified to have no crack.

Mr. Mike Brewington, Nalco representative, was on site to inspect our boiler steam drum and condenser water boxes. No water treatment issues were identified.

New sector plates were installed in the air heater. EIC removed and replaced top & bottom air heater radial seals.

Hot gas outlet ductwork was found to be separated from the attached I beam. It was discovered that the supporting I beam was delaminated and in poor condition. A new I beam was installed.

The 3A/3B ID/FD fan inlet/outlet damper drive units were replaced. The 3A ID fan insulation and lagging was repaired.

Structural Preservation Systems (SPS) performed an inspection of the stack inner liner at the top stack opening. The gunite liner was found to be missing and cracked thereby exposing the stack inner wall. SPS took pictures and conveyed the findings to the NAES staff. After reviewing the pictures it was agreed to have SPS complete the inspection and cleanout of the cone area at the base of the stack. Future internal repairs were identified and conveyed to NAES staff. Actual repairs will be scoped out and repairs will be bid out. NAES Maintenance team fabricated a stainless steel debris plate and placed in the bottom of the stack cone. Debris was removed from the stack drain and final piping to the neutralizing pit was installed.

Unit 3 Boiler 2012 Fall Outage

NAES Maintenance team completed the inspection of the following areas; cold air inlet/outlet baskets, hot gas inlet/outlet baskets for the air heater, air heater seals, air preheater steam coils and associated duct work. The steam coils were reported to have an average amount of debris and some damaged from outage work. NAES Operations team straightened fouled coil fins and cleaned them to complete this project.

Small amount of ash was removed from the boiler bottom ash pit area. Boiler wind box, air registers and bottom ash area were reported to be in good condition.

Mr. Charles Newman XL Insurance Boiler and Property Consulting, LLC representative, inspected the boiler steam drums. No oxidation, scale or pitting were observed; no cracks or metal fatigue was found. Mr. Joe Hultberg Condor Technologies representative also inspected the boiler steam drum and condenser water boxes. No water treatment issues were reported.

NAES Maintenance team investigated mechanical concerns with 3B FD fan inboard bearing overheating. Inspection revealed that the bearing and the coupling had excessive wear. New bearing was requisitioned from the warehouse and will be installed, in accordance with the manufacture specifications. Local manufacture representative Kaman Industrial, verified measurements on the coupling so that a new one could be obtained. New coupling was purchased and delivered to the plant. NAES Maintenance staff completed the installation of 3B FD Fan bearing and coupling. New bearing was lapped in, new coupling fitted to the shaft and alignment of motor completed. Coupling was greased and manually operated for proper coupling movement.

The hot gas outlet expansion joint was replaced.

APEX Piping completed the removal and dismantling of the condenser condensate return piping tree. APEX Piping also completed the installation of two hangers for the condenser condensate piping header to complete this project.

The reheat tubes were checked for leaks and one leak was discovered. Apex Piping was contracted to complete the repairs. During the repair process it was identified that several waterwall tubes were severely pitted. The top Reheat section bundle was missing tube lugs and front wall support clips. Further loss of lugs and clips could cause damage to the lower bundle. New tube material was purchased and bent to match the existing Reheat tubes. Apex field fitted the new Reheat tubes and completed final weld outs. APEX Piping completed the removal and installation of nineteen Reheat front wall clips. Front wall clips were found to be missing or in poor condition during an earlier inspection. Replacement of the clips helps stabilize the overall Reheat panel sections. Due to parts availability and funding; replacement of Reheat Lugs will be considered for future outage work. Also weld buildup “Pads” were installed on the waterwall tubes as a preventative precaution in the areas of the severe pitting. One additional leak was found on the 15th panel from the east wall; on the outer tube of the outlet tube bundle. This was a vertical tube to tube weld that had failed.
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NAES Maintenance staff completed the inspection, disassembly, removal, cleaning and reassembly of five critical equipment couplings. 3A FD Fan, 3A & 3B ID Fans and 3A & 3B Boiler Feed Pumps were completed. Each coupling was (as found) in good working condition. All were disassembled, cleaned, inspected, reassembled and installed with new grease. Each coupling was manually operated for proper coupling movement.

APEX Piping completed the removal and installation of two high pressure superheat section steam isolation valves. Each valve was leaking by the seat. New valves were purchased and installation by Apex.

Unit 3 Spring 2013 Boiler Outage

NAES IC&E Technicians cleaned the main flame and pilot gas flame detectors on Unit 3 boiler. Each burner was placed into service and checked for proper operation. No issues to report.

NAES IC&E Technicians and Operations Team investigated one problem during the preliminary startup of the boiler while attempting to obtain a boiler purge. The Igniter and main natural gas trip valves did open, however the individual burner level deck isolation valves would not open. It was discovered during troubleshooting process that the Gas Fuel Trip Relay (GFTR) would not reset in the GFTR logic. The main natural gas trip valve needed another switch to open and close GFTR logic. One new relay was added in Forney control cabinet to complete GFTR logic. Operations completed a boiler purge and each natural gas valve was operated and tested OK. The Operations Team completed a normal boiler purge and startup of the natural gas system. Natural gas burners were put into service on each level of the boiler with no issues. All boiler and natural gas systems worked as designed.

NAES IC&E Technicians and Operations Team investigated natural gas flow problems with the minimum flow valve. It was determined that the new natural gas stop valve is allowing more gas pressure at the minimum flow valve. Adjustments to the minimum flow valve were made. Technicians placed control air on the valve and made adjustments to the minimum flow valve set point. Valve is now set at approximately 21% open compared to 25% before. This will help minimize the amount of gas flow during the beginning stages of boiler startups. Valve was observed during unit testing and it was working properly. No other issues to report.

NAES Maintenance Team opened boiler, windbox, ductwork and ash pit doors for inspections. Small amount of ash was removed from the boiler bottom ash pit area. Air heater baskets, steam coils and ash system ductwork were found to be in good condition and clean.

NAES Operations team drained the boiler.

NAES Operations team started vacuum pumps to pull a negative vacuum on reheater; reheat tubes were checked for leaks and none discovered.

NAES Operations Team opened the Deaerator Heater & Storage Tank doors for inspection. NAES Maintenance Team inspected the Unit 3 Deaerator Heater & Storage Tank. There were some trays in the deaerator heater that were misaligned and out of place. The trays were restored to their proper location and the tank inspection doors were closed. No other findings to report.

County I.C. (scaffolding division) mobilized to site and installed scaffolding around Unit 3 A-2 Burner for tube replacement.

Apex Piping Contractors mobilized to site and removed two waterwall tubes on A-2 burner for replacement. The removed tube sections were taken to the contractor's shop so that new tubes could be bent correctly. Apex Piping remobilized on March 25, 2013 and completed the installation of two waterwall tubes around A2 burner. Unit 3 boiler was filled with water and pressurized to check for leaks. The Hydro test was completed and no leaks were found. Apex Piping completed the waterwall tube installation by installing the filler membrane welds and repairing the refractory that had been disturbed when the tubes were removed on the A2 burner. In addition, the removed tubes will be sent out for analysis by a third party vendor. Deposit loading and metallurgical testing will be performed on the pipe and analyzed in order to provide NAES staff with a condition assessment of part of the front wall of the boiler. Apex Piping completed the refractory repairs on A3 burner. During the boiler inspection A-3 was found to have several large cracks and missing refractory. County Scaffolding removed Unit 3 boiler scaffolding. NAES Maintenance and Operations Teams cleaned out the boiler bottom ash pit area and completed closing boiler doors in preparation for unit testing. Operations completed a boiler walk down. LOTO tags were removed. NAES IC&E Technicians removed Unit 3 main natural gas blank plate and installed the main natural gas orifice plate. Chesapeake Utilities placed the natural gas system in service. NAES Plant staff started Unit 3 for testing of the turbine-generator and the boiler (main gas valve). The NAES IC&E Technicians and Operations Team investigated one problem during the ramp up to full load on the unit; while attempting to place B-1 burner in the light off mode it tripped out causing the Net 90 to shut down and trip the boiler. After further investigation B-1 burner actuator was found to have a pinched wire between the cover and the gas valve. The insulation on the wire was damaged (pinched wire) causing a short; leading to the tripping issues. Once the wire was repaired, Operations completed a normal boiler purge and start up of the natural gas system. B-1 burner was placed in service and tested with no further issues. East Coast Valve mobilized to site and completed the break down and removal of the safety valves on Unit 3. Each valve was removed and taken back to their shop for a complete inspection. Two boiler drum safeties and one superheat safety have been identified with operating disc issues. NAES was advised and approved all safety valve repairs that were needed to return them to top condition. East Coast Valve remobilized and returned to the plant to install the safety valves. Each valve was inspected, repaired as needed and tested prior to re-install. Valves were checked for steam leaks during the generator testing. No steam leaks to report. East Coast Valve will be on site August 12, 2013 for final safety valve setting during the State of Delaware RATA testing.

NAES Maintenance Team removed the main gas stop valve and installed a new replacement valve. Summit Mechanical made up a new spool piece and installed it on the natural gas piping. NAES IC&E Team pressure leak tested the main gas piping around the main natural gas stop valve with nitrogen and found no leaks. They also completed the electrical wire termination to the main natural gas stop valve limit switches and connected the instrument air supply tubing to main natural gas stop valve. Testing was performed on the valve to ensure the electrical controls were fully operational. No issues to report.

County Scaffolding Company installed scaffolding around the hot gas outlet ductwork to improve accessibility to the hot gas outlet ductwork for plate steel and drain piping repairs. NAES Maintenance Team removed lagging from the air heater hot gas duct. UT tests were completed on the duct work plate metal to assess the strength and thickness of the metal. The metal was thin in some areas and needed to be replaced along with the duct work drain piping connections. Hot gas ductwork (internal) area was cleared of debris; so material wouldn't fall on workers when the air heater waterwash drain lines are removed. NAES Maintenance and Operations team removed more insulation and lagging from the hot gas outlet ductwork. NAES Maintenance and Operations Team removed the deteriorated duct work drain pipes and one small section of ductwork plate metal. New plate metal panels were installed on the duct work as well as new drain piping.

County Insulation installed new insulation and lagging on the hot gas ductwork and the BOFA fan inlet ductwork. County Scaffolding removed the scaffolding to complete this project.

NAES Mechanical staff removed and replaced one steam piping flange gasket under the turbine that was discovered leaking during generator testing. Removed gasket was wrong size and pressure rating for the steam flange application.

Steam piping gasket was checked during a scheduled capacity run event and no leaks were discovered.

NAES Mechanical Staff completed taking equipment oil samples that were sent out for analysis. Preventive and corrective measures will be taken once the analysis report is received and reviewed.

Unit 3 Fall 2013 Boiler Outage

NAES Maintenance Team opened boiler, windbox, ductwork and ash pit doors for inspections. Air heater baskets, steam coils and ash system ductwork were found to be in good condition and clean. NAES Operations team drained the boiler.

NAES Maintenance Team opened steam drum doors in support of the XL Insurance Inspection. Mr. Charlie Newman from XL Insurance Company completed an internal inspection of boiler drum; drum was clean and free of surface rust. Unit three (3) had no reportable issues. Inspector noted that water chemistry and lay up procedure has improved the boiler conditions. There were no major issues with the boiler drum inspection to report and no follow-up work to complete.

NAES IC&E Team completed the neutralization pit liner water removal ahead of the liner repair work. Hallaton Inc. (liner repair company) completed an inspection of the IWW pit liner. Three areas of previous repairs were identified as needing new repairs. Hallaton removed the old patch repairs and prepared each area for new adhesive and membrane material. Each repaired area was checked for steam leaks. Hallaton requested a two hour curing time schedule before industrial waste water could be added to the pit. No new liner issues were found. No other issues to report or follow-up work to complete. Plant staff requested quote for new liner.

County I.C. (scaffolding division) mobilized to the site and installed scaffolding in several areas around Unit 3 for inspection and adjustments of steam piping hangers.

NAES Maintenance Team completed main steam, cold reheat and hot reheat steam pipe hanger adjustments. Cold setting adjustment was completed to hangers per the inspection report. NAES Maintenance Team removed and replaced the Unit 3 main steam piping sway bar. The sway bar replacement was identified in the high energy piping inspection report.

Apex Power and Heat (mechanical contractor) completed the installation of three root isolation valves on Unit 3 boiler drain header. NAES Mechanics and APEX Power and Heat completed the installation of Unit 3 boiler drain piping and isolation valves to the expansion tank. New heat tracing is on order and will be installed. Insulation and lagging will be installed to complete this project. Apex Power and Heat removed and replaced two valves (isolation and by-pass) on the DA feed water level control piping station. New insulation and lagging was installed to complete this project.

NAES Maintenance Team removed and replaced the DI acid tank drain piping to the industrial waste water pit. New stainless steel piping and fittings were installed.

NAES Maintenance Team removed and replaced Unit 3 cooling tower makeup water bypass isolation valve. It was discovered to be leaking-by during times of normal operation. NAES Maintenance Team closed Unit 3 steam drum doors utilizing new graphite gaskets. NAES Maintenance and Operations Teams cleaned out the boiler bottom ash pit area and completed closing boiler doors in preparation for unit winter boiler layup. Operations completed a boiler walk down. LOTO tags were removed. NAES IC&E Technicians removed Unit 3 main natural gas blank plate and installed the main natural gas orifice plate. Chesapeake Utilities placed the natural gas system (gas yard) in service.

Unit 3 Boiler 2014 Outage

A routine boiler outage was performed from March 03, 2014 to May 30 2014 on the Unit 3 boiler. The NAES Operations Team completed most of the LOTO requirements for planned outage work activities. The NAES Operations Team drained the boiler. The NAES Operations Team started vacuum pumps to pull a negative vacuum on reheater; reheat tubes were checked for leaks and none were reported.

The boiler, windbox, ductwork and ash pit doors were opened for inspections. A small amount of ash was removed from the boiler bottom ash pit area. Air heater baskets, steam coils and ash system ductwork were found to be in good condition and clean.

Inspections were completed on the Unit 3 boiler gas swirlers, gas spuds and burner throats; as part of the inspection process, debris (ash) was removed from the boiler bottom area. No issues were identified.

The 3A & 3B vacuum pumps and Boiler Feed pump lube oil coolers heat exchanger were cleaned and inspected with no issues reported;

The NAES Maintenance Team removed and replaced the EHC unit filters. Varnish, shellac and debris were observed in the filter casings and reservoir tank. The reservoir tank was cleaned, inspected and filled with new Fyrquel fluid. New gaskets were made and installed on the sight glass and inspection door.

Repairs to the soot blowing steam piping were completed. One area was discovered to be leaking during a run event. New piping and elbow were installed, also new insulation and lagging was installed to complete this project.

In the Fall of 2014, the NAES Operations team drained the boiler and Maintenance Team opened the boiler, drums, windbox, and ash pit doors for the certificate inspection. Mr. Curtis McLaren from XL Insurance Company completed an internal inspection of boiler drum; drum was clean and free of surface rust. Unit three (3) had no reportable issues. Inspector noted that water chemistry and lay up procedure has improved the boiler conditions. There were no major issues with the boiler drum inspection to report and no follow-up work to complete.

The Unit 3 boiler neutralization pit liner was replaced using existing brackets which enabled the cost to be substantially less than what a completely new installation would cost. Plant staff then followed up by installing new ballast and reinstalling the pH and level probes to complete the project.

Calibration of the mass flow meter on Unit 3 was completed with with no issues.

Scaffolding was installed in several areas around Unit 3 for insulation/lagging removal and inspection/testing on the High Energy Piping. With the scaffold installed, the NAES Operations team removed insulation and lagging so the test team could have accessibility to the pipe for testing. Babcock Power was contracted to complete the inspection on the High Energy Piping. Upon completion of the inspection, new insulation and lagging was installed. Prior to removal of the scaffold, new Asbestos free and HEP Inspection site labels were installed.

The Deaerator (DA) and Deaerator Storage Tank Inspections were completed by TesTex Inc. As a result of their testing and inspection, minor surface cracks were found in several seam welds which pose no problem to the operation of the equipment. Plant staff had previously removed the DA heater trays and prior to reinstalling them, cleaned and repaired them. No other issues were found at this time.

Prior to the outage, the boiler had experienced a couple of tube leaks that were repaired temporarily until an outage whereby the tube section could be replaced versus having a patch on the tube. There were two locations (west-side 5th floor level and east-side crotch area) where the tubes had been patched and Apex

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was contracted to replace the tube sections. The tube sections were replaced, the boiler was filled with water and the boiler was hydro tested. Unfortunately, additional leaks were identified. Upon completion of the additional repairs a successful hydrostatic test was completed.