UTILITY COMMITTEE
A G E N D A

JUNE 9, 2014 - 6:00 P.M.

CITY HALL COUNCIL CHAMBERS
15 LOOCKERMAN PLAZA
DOVER, DELAWARE

Public comments are welcomed on any item and will be permitted at appropriate times. When possible, please notify the City Clerk (736-7008 or e-mail at CityClerk@dover.de.us) should you wish to be recognized.

AGENDA ADDITIONS/DELETIONS

1. **Annual Engineering Consultant's Report on the Operation and Maintenance of the Electric System - Fiscal Year 2013**
   (Staff recommends acceptance of the report)

2. **TEA/NAES Report (*April*)**
   (Staff recommends acceptance of the report)

3. **Updates**
   (Committee action not required on the below items)
   - **A. Garrison Oak Technical Park Project Updates**
     - **a-1. City Infrastructure**
     - **a-2. Calpine Energy Center**
     - **a-3. Dover Sun Park**
   - **B. Progress Update on Purchase Power Agreement**

4. **Adjournment by 7:00 p.m.**

/tm
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THE AGENDA ITEMS AS LISTED MAY NOT BE CONSIDERED IN SEQUENCE. THIS AGENDA IS SUBJECT TO CHANGE TO INCLUDE THE ADDITION OR THE DELETION OF ITEMS, INCLUDING EXECUTIVE SESSIONS.

Annual Engineering Consultant's Report

on the

Operation and Maintenance of the Electric System Fiscal Year 2013

City of Dover, Delaware

Project No. 78609
June 2014

Annual Engineering Consultant's Report

on the

Operation and Maintenance
of the Electric System
Fiscal Year 2013

prepared for

City of Dover, Delaware
Dover, Delaware

June 2014

Project No. 78609

prepared by

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

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June 4, 2014

Ms. Donna S. Mitchell, CPA
Controller/Treasurer
City of Dover
5 East Reed Street
Weyandt Hall, Suite 300
Dover, Delaware 19901

RE: Annual Engineering Consultant's Report
Project No. 78609

Dear Ms. Mitchell:

In compliance with the requirements of Section 705 and Section 504 of the City of Dover, Delaware Resolution Authorizing and Securing Electric Revenue Bonds, adopted December 23, 1985 (Resolution), Burns & McDonnell submits this Annual Engineering Consultant's Report for the fiscal year ended June 30, 2013. This report summarizes our review and assessment of the City of Dover's (City) Electric System, its existing retail electric rates, its insurance coverage in effect, and its reserve funds. Financial, statistical, and operating data used in preparing the report were initially reported in the City's annual financial statements and accounting records. Additional information was furnished by City and Electric Division staff.

In the preparation of this Engineering Consultant's Report, Burns & McDonnell completed assessments of the electric generating stations and the transmission and distribution system of the City's Electric Division. Assessments involved interviews, observations, and review of fiscal year 2013 expenditures and fiscal year 2014 budgets. In addition, an analysis of the balances of the Improvement and Extension Fund as well as other funds supporting the Electric Division was performed. Burns & McDonnell also reviewed the adequacy of revenues provided by current retail rates in relation to the requirements of the Resolution. Finally, a high-level assessment of the City's insurance coverage related to the Electric Division was completed.

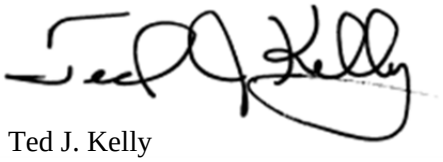
Based on these reviews and assessments, it is the opinion of Burns & McDonnell that the Electric System is being operated and maintained, including replacements and upgrades as appropriate, in a manner that is consistent with current electric utility practices. In addition, the current retail rates have provided sufficient revenues to satisfy the debt service coverage requirement in the Resolution.

Further, it is the opinion of Burns & McDonnell that the balances in the various reserve funds maintained by the City for the Electric Division are sufficient for their intended purposes.

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We appreciate the cooperation and assistance provided by the City and the Electric Division staff in the preparation of this report. We will be happy to discuss the report with you at your convenience.

Sincerely,
BURNS & McDONNELL



Ted J. Kelly
Principal & Senior Project Manager
Business & Technology Services

TJK/pcf

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
City	City of Dover, Delaware
DCS	distributed control system
EDQP	Employee Development and Qualification Program
EIA	U.S. Energy Information Administration
FY	Fiscal Year
GWh	gigawatt-hour
I&E Fund	Electric Improvement & Extension Fund
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
LAN	local area network
McKee Run	McKee Run Generating Station
MW	megawatt
MWh	megawatt-hour
NAES	North American Energy Services Corporation
NERC	North American Electric Reliability Corporation
NRG	NRG Energy Center
Ohm	standard unit of electrical resistance
PJM	Pennsylvania New Jersey Maryland Interconnection
Report	2014 Engineering Consultant's Report on the Operation and Maintenance of the Electric System
Resolution	Resolution Authorizing and Securing Electric Revenue Bonds, adopted December 23, 1985

VanSant	VanSant Generating Station
TEA	The Energy Authority, Inc.

STATEMENT OF LIMITATIONS

In preparation of the 2014 Engineering Consultant's Report on the Operation and Maintenance of the Electric System (the Report), Burns & McDonnell relied upon information provided by the City of Dover, Delaware (the City). The information included various analyses, computer-generated information and reports, audited financial reports, and other financial and statistical information, as well as other documents such as operating budgets and current retail electric rate schedules. While Burns & McDonnell has no reason to believe that the information provided, and upon which Burns & McDonnell has relied, is inaccurate or incomplete in any material respect, Burns & McDonnell has not independently verified such information and cannot guarantee its accuracy or completeness. In addition, Burns & McDonnell has used the information provided to make certain assumptions with respect to conditions that may exist in the future. While Burns & McDonnell believes the assumptions made are reasonable for the purposes of the Report, it makes no representation that the conditions assumed will occur.

1.0 – EXECUTIVE SUMMARY

1.0 EXECUTIVE SUMMARY

1.1 Introduction

The 2014 Engineering Consultant's Report on the Operation and Maintenance of the Electric System (Report) has been prepared in compliance with the requirements of the City of Dover, Delaware Resolution Authorizing and Securing Electric Revenue Bonds, adopted December 23, 1985 (Resolution). Burns & McDonnell was retained as the Engineering Consultant by the City of Dover, Delaware (City) to complete an inspection of the Electric System and prepare a report on findings. The Resolution requires that the Engineering Consultant complete the following:

> *"The City covenants that it will cause the Engineering Consultants employed under the provisions of Section 705 of this Resolution . . . to make an inspection of the Electric System at least once each fiscal year and . . . to submit to the City Manager a report setting forth (a) their findings whether the properties of the Electric System have been maintained in good repair, working order and condition and whether they have been operated efficiently and economically and (b) their recommendation as to*
>
> *(i) the proper maintenance, repair and condition of the Electric System during the ensuing fiscal year and an estimate of the appropriations which should be made for such purposes,*
>
> *(ii) the insurance to be carried under the provisions of Article VII of this Resolution,*
>
> *(iii) the amount that should be deposited during the ensuing fiscal year to the credit of the Improvement and Extension Fund for the purposes set forth in Section 510 of this Article,*
>
> *(iv) the extensions, improvements, renewals and replacements which should be made during the ensuing fiscal year, and*
>
> *(v) any necessary or advisable revisions of the electric rates."*

This is the eleventh annual Engineering Consultant's Report prepared for the City by Burns & McDonnell.

1.2 Electric System Overview and Assessment

The Electric Division served 23,446 customers at the end of fiscal year (FY) 2013, 19,993 of which were residential customers. Four of the Electric Division customers take service from the 69-kV transmission system. These customers include the Dover Air Force Base, Kraft, Proctor & Gamble, and NRG Energy

Center (NRG). NRG is an exempt wholesale generator that sells power that must be transmitted through the City's transmission system to third party purchasers. When the NRG plant is not operational, the Electric Division provides power for the plant site.

1.2.1 General Plant

General plant facilities consist primarily of Electric Division administrative and operations facilities and pollution control related equipment on McKee Run Generating Station (McKee Run) and VanSant Generating Station (VanSant). Other types of general plant include office furniture and equipment, transportation and power-operated equipment, and communication equipment.

Effective July 1, 2011, the City entered into an Energy Management Agreement with The Energy Authority, Inc. (TEA) to assist the City with its energy procurement, energy sale, purchase of fuels, establishment and management of risk policies, and the development and management of hedging protocols and related energy procurement challenges. Headquartered in Jacksonville, Florida, TEA is a non-profit energy manager owned by seven public utility systems operating across the nation.

1.2.2 Production Plant

The City owns two generating plants, the McKee Run and VanSant generating stations. McKee Run consists of three steam turbine generating units with a total combined capacity of 136 megawatts (MW). VanSant is a 39 MW simple-cycle combustion turbine unit. North American Energy Services Corporation (NAES Corporation) operates the generating plants. The agreement between the City and NAES Corporation has been in effect since July 1, 2006. The various systems and components of the generating plants reviewed by the Engineering Consultant are listed below:

Major Equipment

- Steam turbines/generators
- Boilers and auxiliaries
- Station cooling water systems
- Fuel handling systems
- Water treatment systems
- Station electrical systems
- Station control systems
- General facilities

Management and Organization

- Safety
- Training
- Staffing

Based on statements and information provided by the City, as well as the observations and reviews performed, it is the Engineering Consultant's opinion that the City's power generation facilities are being operated and maintained consistent with generally accepted electric utility practice in the United States. In general, the performance, operation, maintenance, staff, planning, and training aspects for the McKee Run and VanSant were found to be above average. Specifically, the generation facilities have demonstrated a high level of availability despite the dispatching of the units primarily for peak demand.

1.2.3 Transmission and Distribution Plant

The transmission and distribution network includes 44 miles of overhead transmission lines, 0.12 miles of underground transmission lines, 190 miles of overhead distribution lines and 268 miles of underground distribution lines. Four Electric Division customers take service off of the 69-kV transmission system. The following list includes areas of the transmission and distribution system that were considered and reviewed.

- System reliability
- Power quality
- Operations and maintenance
- Design standards and specifications
- Transmission and distribution improvements

It is the Engineering Consultant's opinion that the design, construction, operation, and maintenance of the City's electric transmission and distribution system and the associated facilities are consistent with current generally accepted electric utility standards. In recent years, the City has made appropriate upgrades and improvements which the Engineering Consultant has observed while conducting the reviews and assessments to complete the annual reports.

1.3 Financial Assessment

The level of revenues required from the retail electric rates for the Electric Division were determined through the analysis of the financial results and net income or net margins for FY 2013. The Resolution requires that the Electric Division maintain a debt service coverage ratio of 1.25.

Customers of the Electric Division of the City were charged for the electric service they received based on the City's rate schedules and contracts that were in place in FY 2013. A comprehensive cost-of-service and rate design study was completed in 2006 and subsequent rate analyses were completed in 2007, 2008, 2012, and 2013 to examine revenue requirements and revenue generation. Specifically, the 2006 rate study was conducted to address increased costs associated with a new power supply contract that became effective on July 1, 2006. The rate study recommended combining a number of rate classes and implementing rate increases on July 1, 2006. The 2006 rate study also recommended an additional increase be implemented on January 1, 2007 to cover increased costs associated with operating the generating station. The 2007 and 2008 rate analyses re-examined Electric Division revenues and expenses and recognized additional revisions to power supply costs. As a result of these analyses, additional rate increases were implemented on July 1, 2007, July 1, 2008, and July 2012. The July 2013 rate adjustments established the rate schedules utilized by the Electric Division today.

Total energy sales increased from 710.3 GWh in FY 2012 to 723.1 GWh in FY 2013, an increase of 1.8 percent. Total revenue from sales to electric customers in FY 2013 was $88.3 million, representing a decrease of $3.6 million from FY 2012 rate revenue of $91.9 million. In FY 2013, the average revenue per kWh for residential customers was 14.00 cents and the system-wide average price was 12.22 cents per kWh.

The Electric Division's largest cost in providing electric service to its customers is the wholesale cost of power purchased from the Pennsylvania New Jersey Maryland Interconnection (PJM) marketplace through its energy manager, TEA. From FY 2012 to FY 2013, the cost of power increased from $58.9 million to $65.4 million. Net income decreased from $8.5 million in FY 2012 to $6.2 million in FY 2013. The net income decrease in FY 2013 was due in large part to the increase in transfers out of the Electric Revenue Fund.

Following is an excerpt from Section 502(c) of the Resolution.

> *"(c) The total amount of the Revenues of the Electric System during the preceding fiscal year shall have been not less than the total of the following:*
>
> *The Current Expenses of the Electric System during the current fiscal years shown by the Annual Budget . . . for such fiscal year, and*

One hundred twenty-five percent (125%) of the maximum amount of the Principal and Interest Requirements for any fiscal year thereafter on account of all bonds then Outstanding under the provisions of this Resolution."

The Resolution requires that annual revenues of the Electric Division be no less than the total current expenses plus 125 percent of the greatest remaining annual debt service. The Electric Division achieved debt service coverage ratios for FY 2011, FY 2012, and FY 2013 of 5.45, 6.48, and 6.56 respectively; therefore, the revenues generated by the current electric rates have been sufficient to meet the applicable covenant of the Resolution.

The City maintains a comprehensive insurance program to cover varying types of liabilities, as well as significant losses related to various Electric Division properties. It is the opinion of Burns & McDonnell as Engineering Consultant, and not as insurance counselor, the insurance in full force and affect appears to satisfy the requirements of Section 706 of the Resolution.

The City established the Electric Revenue Fund and the Electric Improvement & Extension (I&E) Fund to make moneys available for specific purposes when they are needed. The following is a list of these funds' respective cash accounts:

Electric Revenue Fund

- Insurance Reserve Account
- Contingency Reserve Account
- Electric Rate Stabilization Reserve Account
- Interest and Sinking Account

Electric Improvement and Extension Fund

- Depreciation Reserve Account
- Future Capacity Reserve Account

The Engineering Consultant reviewed activity information on the accounts listed above and found that the balances in those accounts as of June 30, 2013, were consistent with the required or target balances.

1.4 Conclusions

Based on the reviews and assessments completed, it is the opinion of Burns & McDonnell that:

1. The City's power generation facilities are being operated and maintained consistent with generally accepted electric utility practice in the United States.
2. The design, construction, operation, and maintenance of the City's electric transmission and distribution system and the associated facilities are consistent with current generally accepted electric utility standards and over the past few years, the system has been upgraded in order to improve operation and service to customers.
3. The Electric Division capital projects included in the City's Capital Investment Plan and the FY 2014 Operating Budget are necessary and should provide improved reliability and power quality for the Electric System.
4. The cash balances as of June 30, 2013 for the various accounts maintained by the City for the Electric Division appear to be sufficient for their defined purposes.
5. The insurance coverage in full force and effect as maintained by the City related to the various assets of the Electric Division appears to satisfy the requirements of Section 706 of the Resolution.
6. The electric revenues generated by the City's current retail rates are more than sufficient to fulfill the debt service coverage requirement (125 percent of current expenses) defined in Section 502(c) of the Resolution.

2.0 – INTRODUCTION

2.0 INTRODUCTION

The City of Dover, Delaware (City) operates a municipally-owned electric utility system that served 23,446 customers within the City and surrounding areas at the end of fiscal year (FY) 2013. The service area of the electric utility is located in central Delaware; with the City itself located approximately 70 miles south of Philadelphia, Pennsylvania.

2.1 Purpose of Report

This 2014 Annual Engineering Consultant's Report (Report) has been prepared in compliance with the requirements adopted December 23, 1985 of the City of Dover Electric Bond Resolution (Resolution). Burns & McDonnell was retained by the City as the Engineering Consultant defined in Section 705 of the Resolution, as follows.

> *"The City covenants that it will, for the purpose of performing and carrying out the duties imposed on the Engineering Consultants under the provisions of this Resolution, employ an independent engineer or engineering firm or corporation having a nationwide and favorable repute for skill and experience in such work."*

The required scope of the Report is described in Section 504 of the Resolution, as follows.

> *"The City covenants that it will cause the Engineering Consultants employed under the provisions of Section 705 of this Resolution . . . to make an inspection of the Electric System at least once each fiscal year and . . . to submit to the City Manager a report setting forth (a) their findings whether the properties of the Electric System have been maintained in good repair, working order and condition and whether they have been operated efficiently and economically and (b) their recommendation as to*
>
> *(vi) the proper maintenance, repair and condition of the Electric System during the ensuing fiscal year and a estimate of the appropriations which should be made for such purposes,*
>
> *(vii) the insurance to be carried under the provisions of Article VII of this Resolution,*
>
> *(viii) the amount that should be deposited during the ensuing fiscal year to the credit of the Improvement and Extension Fund for the purposes set forth in Section 510 of this Article,*
>
> *(ix) the extensions, improvements, renewals and replacements which should be made during the ensuing fiscal year, and*

(x) any necessary or advisable revisions of the electric rates."

2.2 Organization

The Electric Utility Director is responsible for the overall management of the Electric Utility Division. ***(The Electric Utility Director position is currently vacant.)*** The Electric Director oversees the day-to-day operations of the Electric Division and manages the Division's staff. The Director also provides oversight of the Power Plant budget, monitors the contracts of the energy coordinator and the power generation operator/manager, and is responsible for North American Energy Services Corporation (NAES Corporation) contracts and oversight. The Electric Division is organized into four separate operating sections. Descriptions of the current Electric Division sections are provided below.

Administration Section – Administration provides the overall management of the Electric Division's Engineering and Transmission & Distribution Sections. This section performs all planning and budgeting, monitors all construction projects, administers all power supply and generating station operations agreements, and coordinates with customer service and public relations for the Electric Division.

System Operations Section – System Operations is responsible for the operation of a 24/7 system operations control center. This section was formally a part of the Electric Engineering Section, but now has been identified as its own section comprising of the System Operators Crew Leader and the Operators.

Electric Engineering Section – Electric Engineering provides design, specifications, construction management, and project inspection for all capital investment projects of the Electric Division. This section also develops and maintains maps, plans, and specifications, as well as engineering standards for construction and maintenance of the Electric System.

Transmission & Distribution Section – Transmission & Distribution constructs, operates, and maintains the overhead and underground electric systems and fiber optic communication facilities. This section installs and maintains all electric metering, as well as street and security lighting. This section also investigates and resolves customers' power problems and oversees the work of tree trimming contractors.

Figures 2-1 through 2-4 provide organizational charts illustrating the staffing hierarchies of the various sections in the Electric Division. The number of individuals in each position was indicated as appropriate. Electric Division staff totaled 38 at the time the FY 2014 budget was issued.

The subsequent sections of the Report provide a discussion of the required reviews and inspections conducted pursuant to Section 504 of the Resolution. Section 3 describes the assessment of the Electric System and its condition. Section 4 presents the financial results for the Electric Division, including an analysis of the adequacy of revenues provided by the electric rates. Section 5 summarizes the conclusions of Burns & McDonnell regarding the operation and maintenance of the Dover Electric System.

Figure 2-1: Organization

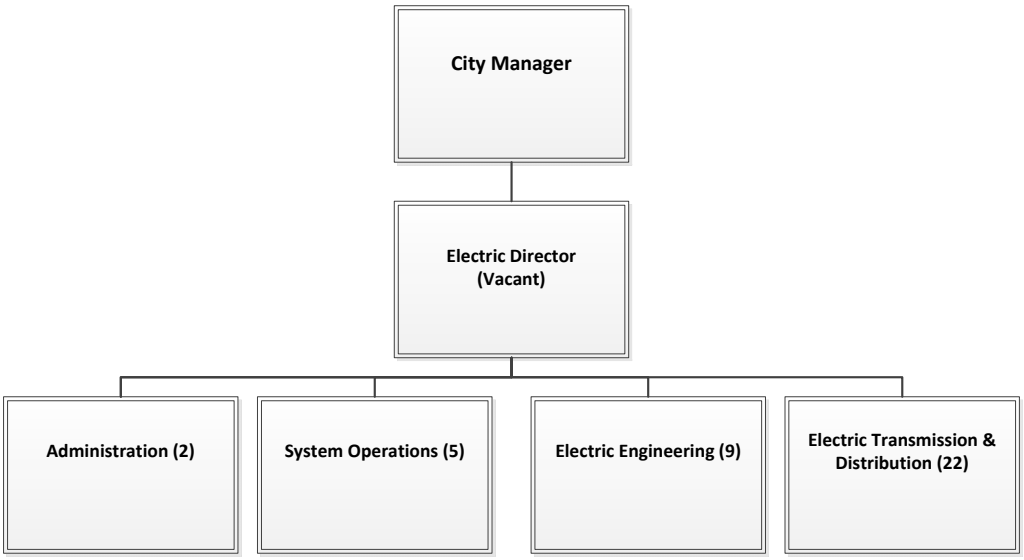


Figure 2-2: Administration



Figure 2-3: System Operations

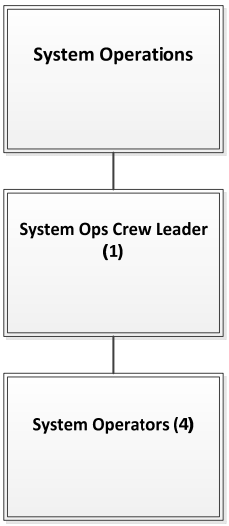


Figure 2-4: Electric Engineering

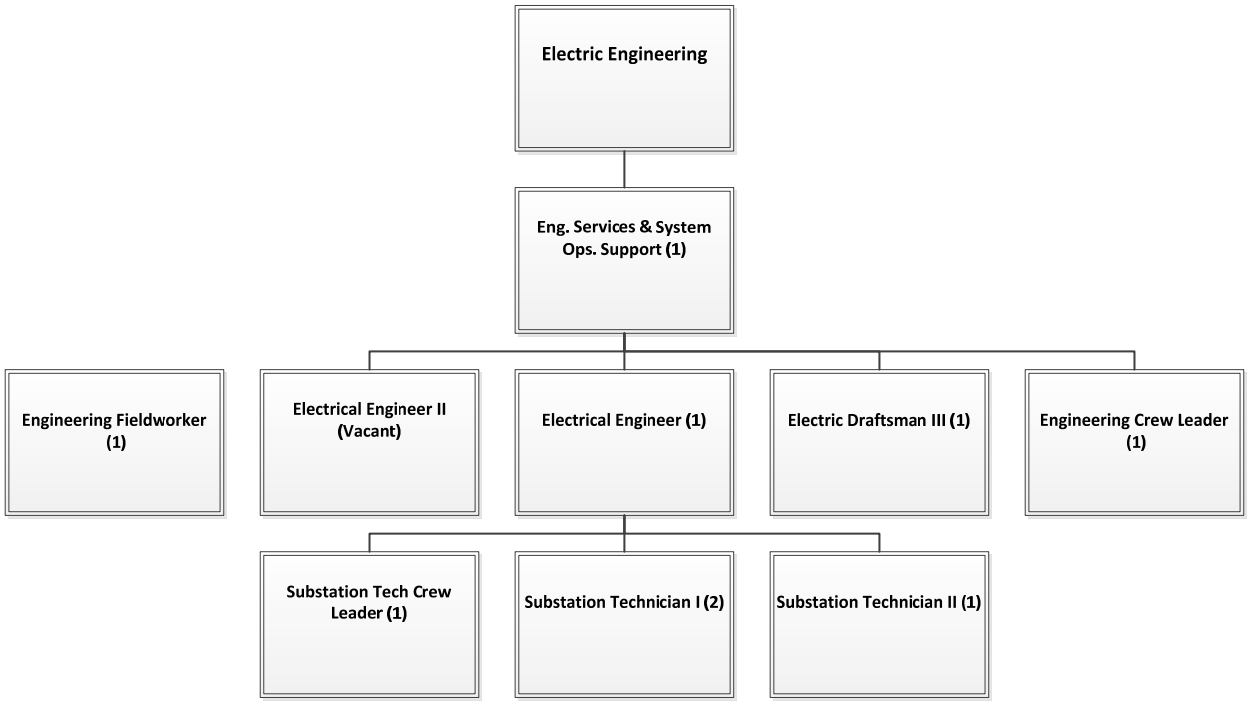
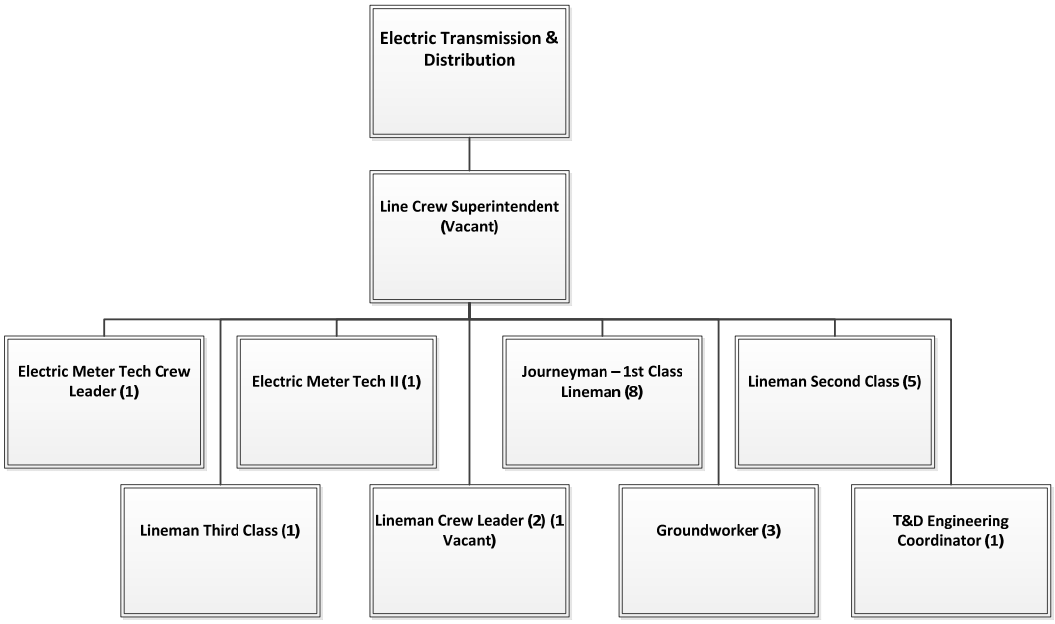


Figure 2-5: Electric Transmission and Distribution



3.0 – ELECTRIC SYSTEM OVERVIEW AND ASSESSMENT

3.0 ELECTRIC SYSTEM OVERVIEW AND ASSESSMENT

3.1 Electric System Overview

The Electric System owned by the City primarily consists of production plant, transmission plant, distribution plant, and general plant facilities, and construction work in progress. Table 3-1 displays the year-end balances of the various plant components for FY 2011 through FY 2013. Table 3-2 itemizes the specific capital investment plan projects and anticipated expenditures included in the FY 2014 budget.

Table 3-1: Year-End Plant in Service

	FY 2011	FY 2012	FY 2013
Capital assets, not being depreciated			
Land	$ 1,458,066	$ 1,458,066	$ 1,458,066
Construction in progress	424,809	789,014	1,338,909
Total capital assets, non-depreciable	$ 1,882,875	$ 2,247,080	$ 2,796,975
Capital assets, being depreciated			
Buildings	$ 17,383,566	$ 17,456,628	$ 17,619,349
Production	63,408,937	64,610,399	65,040,049
Transmission	32,558,944	33,106,748	34,010,686
Distribution	59,824,248	60,680,365	61,752,469
Administration	1,551,280	1,634,017	1,743,754
Vehicles	622,236	640,096	625,876
Total capital assets, being depreciated	$ 175,349,211	$ 178,128,253	$ 180,792,183
Less accumulated depreciation for:			
Buildings	$ (10,992,065)	$ (11,400,308)	$ (11,795,879)
Production	(39,931,442)	(41,416,622)	(42,682,428)
Transmission	(9,206,982)	(10,344,554)	(11,537,017)
Distribution	(23,817,302)	(25,322,267)	(26,832,246)
Administration	(1,102,778)	(1,196,545)	(1,316,532)
Vehicles	(435,188)	(464,219)	(481,527)
Total accumulated depreciation	$ (85,485,757)	$ (90,144,515)	$ (94,645,629)
Total capital assets, being depreciated, net	89,863,454	87,983,738	86,146,554
Total capital assets, net	$ 91,746,329	$ 90,230,818	$ 88,943,529

In FY 2013, the Electric System experienced a decrease in the annual system peak demand and an increase in annual energy sales from the previous year. The Electric System experienced its peak at 2 p.m. on July 8, 2012 of 171.6 MW. For the year, 723.1 GWh of energy were sold, an increase of 1.8 percent from the preceding year. The Electric Division projects energy sales in FY 2014 to total 721.2 GWh, a decrease of 0.3 percent. The Electric Division expects annual energy sales to remain relatively constant from FY 2014 through FY 2018.

Table 3-2: Fiscal Year 2014 Planned Capital Expenditures

Electric Engineering Projects:		
General Scott Switchgear	$	800,000
Air Conditioner Replacement/Monitors		12,000
Substation Battery Replacement		24,500
Distribution Upgrades		400,000
Lighting Project and Rehabilitation		50,000
Distribution Feeder Replacement Program		277,500
Distribution Capacitors and Controls		60,000
Transmission Line Maintenance Program		75,000
69 kV Substation Switch Replacement		80,000
Horsepond Substation Reliability Upgrade		591,800
Subtotal Electric Engineering Division	$	2,370,800
Electric Transmission & Distribution Projects:		
New Developments	$	600,000
Advanced Metering Infrastructure		150,000
Subtotal Electric Transmission Division	$	750,000
Electric Generation Projects:		
Unit 3 Cooling Tower Repairs	$	42,000
McKee Run Unit 3 Auxiliary System Components		116,000
VanSant Unit 11 Component Replacements		32,000
McKee Run High Energy Piping Repairs		80,000
Metering Systems Upgrades		25,000
McKee Run & VanSant Safety & Compliance Improvemetns		86,000
McKee Run Natural Gas System Block/Bleed Valves		65,000
McKee Run & VanSant Mobile Crane Repair/Replace		125,000
McKee Run & VanSant Preservation of Structures		42,000
McKee Run Unit 3 Turbine Repairs		1,149,800
McKee Run Units 1 & 2 Component Repairs		105,000
Van Sant Capacity Increase		250,000
Subtotal Electric Generation Division	$	2,117,800
Total Planned Capital Investment Projects	$	5,238,600

3.1.1 Production Plant

The City owns two plants, the McKee Run and VanSant generating stations. McKee Run consists of three steam turbine generating units with a total combined capacity of 136 megawatts (MW). VanSant is a 39-MW simple-cycle combustion turbine unit.

North American Energy Services Corporation (NAES Corporation) operates the generating plants. The agreement between the City and NAES Corporation has been in effect since July 1, 2006. The Engineering Consultant's observations regarding the generating stations and units are described later in this section of the Report.

Effective July 1, 2011, the City entered into an Energy Management Agreement with The Energy Authority, Inc. (TEA) to assist the City with its energy procurement, energy sales, purchase of fuels, establishment and management of risk policies, the development and management of hedging protocols and related energy procurement challenges.

3.1.2 Transmission and Distribution Plant

The service area includes 44 miles of overhead transmission lines, 0.12 miles of underground transmission lines, 190 miles of overhead distribution lines and 268 miles of underground distribution lines. Four Electric Division customers take service off of the 69-kV transmission system. These customers include the Dover Air Force Base, Kraft, Proctor & Gamble, and NRG Energy Center (NRG). NRG is an exempt wholesale generator that sells power that must be transmitted through the City's transmission system to third party purchasers. When the NRG plant is not operating the Electric Division provides power for the plant site.

The Electric Division has two contracts for providing transmission service through the Electric System. The Electric Division provides transmission service to NRG for the output of its 16 MW electric generator. The Electric Division also has a point-to-point contract for the output of an NRG Combustion Turbine which ties directly to the Kent Substation and is not part of the Dover transmission system.

3.1.3 General Plant

The general plant category consists primarily of Electric Division administrative and operations facilities, and pollution control-related equipment at McKee Run and VanSant. The agreement with NAES Corporation stipulates NAES Corporation manage the operation and maintenance of the facilities while the City funds all replacements and upgrades required to maintain the capability of the two generating stations. The City is also responsible for the costs of compliance with new regulations promulgated. Other types of items included in the general plant category include office furniture and equipment, computer-related equipment, transportation and power-operated equipment, and communication equipment. Burns & McDonnell did not specifically assess the items in the general plant category for the Report.

3.2 Electric System Assessment

Burns & McDonnell made observations and conducted assessments of the Electric System assets in support of the development of this annual Engineering Consultant's Report. The findings of Burns & McDonnell from the review of the City's Electric System are documented herein.

3.2.1 Electric Generating Stations

On April 17, 2014, Mr. Ted Kelly of Burns & McDonnell met with representatives of NAES Corporation to discuss the condition of the McKee Run and VanSant generating stations. Mr. Kenneth Beard, the Plant O&M Manager, coordinated the visit along with Mr. Vince Scire, the Plant Manager.

3.2.1.1 Description

McKee Run consists of three units. Units 1 and 2 were originally coal-fired units, which began operations in 1961 and 1962, respectively. In 1972, these units were converted to burn No. 6 fuel oil. Units 1 and 2 each have rated capacities of 17 MW. Unit 3 began operations in 1975 and was designed to fire No. 6 fuel oil and natural gas. Unit 3 has a rated capacity of 102 MW. In FY 2008, the City began work to convert all three units at McKee Run to burn No. 2 fuel oil in order to reduce pollution from the plant. To date, the necessary upgrades and new equipment had been installed allowing each of the units to burn both natural gas and No. 2 fuel oil.

VanSant consists of a simple cycle combustion turbine with a rated capacity of 39 MW. This unit commenced operation in 1991. VanSant remains unmanned, except when it is dispatched into service. On the occasions when the unit is dispatched, personnel from McKee Run are transferred to VanSant to startup and operate the unit.

3.2.1.2 Management and Organization

Station management is very well organized and knowledgeable. Personnel take a logical approach to the operation and maintenance of the generation facilities. Mr. Vince Scire serves as the Plant Manager. The management/leadership team consists of eight positions including Mr. Scire's position. The Administrative Manager, O&M Manager, Compliance Coordinator, and Materials Coordinator, all report directly to Mr. Scire. One Operations Supervisor and two Day Shift Operator positions are currently open at the plant. The open Operations Supervisor position is part of the management/leadership team.

The O&M Manager oversees a Maintenance Supervisor and four Operations teams. Each operations team consists of two supervisors and three operators working 12-hour rotating shifts. Two operators work eight-hour flex time shifts Monday through Friday, and fill in as needed. The maintenance team consists of a planner, a supervisor and five employees working eight-hour shifts. The operations and maintenance personnel are all union employees. The relationship between the union and management was reported to be excellent. McKee Run is currently at a staff level of 29 employees, with 32 approved positions.

3.2.1.3 Safety

"Safety First" is an overall theme and attitude of the Electric Division. Near-miss incidents are documented, reviewed, and corrective follow-up actions are taken as required with an employee-run safety committee actively in place. This committee conducts monthly safety meetings, completes safety equipment inspections, and defines and implements tasks to improve safety in all areas. Members of the safety committee complete periodic visual inspections of employee work activities utilizing an observation checklist to detail their findings. Recorded observations are discussed and infractions corrected. Safety is the first topic discussed at all meetings at the generating plant. An indoctrination video emphasizing safety is shown to all visitors when entering the Station.

There were no restricted work days or lost time accidents reported in FY 2013. NAES ended the year with 51,786 man-hours worked with no OSHA recordable accidents.

3.2.1.4 Training

The required annual OSHA compliance training is completed and documented for each employee. A formal two-day employee orientation program is required for all new employees. This orientation covers a multitude of subjects from employee benefits to a review of the various Station operating manuals.

For operator training, the Employee Development and Qualification Program (EDQP) has been established. EDQP is a formal program for training operators to progressively advance to positions with additional responsibilities. In addition to the above programs, cross training of various disciplines also occurs. An example of cross training would be plant operators training with maintenance staff.

Plant staff receive environmental and safety training online via the GPi Learning website. The training includes tutorials and exams to ensure comprehension of the subject matter. Plant manuals, meetings, etc. offer additional safety training.

Plant staff continues to receive appropriate operator certification training for the Pennsylvania New Jersey Maryland Interconnection (PJM) market. This training should continue in the future. The plant also completes planning and scheduling training on a regular basis for plant operators.

3.2.1.5 Major Equipment Operation and Maintenance

In general, the generation facilities appear to have been properly operated and maintained, and in good condition as evidenced by the high availability of the units. The generation facilities are dispatched sparingly and operate primarily as peaking units. As such, the individual units incur a relatively large

number of starts per year and low annual capacity factor. Table 3-3 summarizes the major FY 2013 operating statistics.

The large amount of time that units are not operating allows for maintenance and repair of the units. As a result, the FY 2013 overall equivalent availability factor for the generation facilities averaged 58.99 percent. Low net capacity factors are partially offset by PJM capacity credits. In FY 2013, $14.3 million of PJM capacity credits helped cover the fixed operating and maintenance costs of the Electric System. PJM capacity credits are expected to continue to provide similar benefits in FY 2014 and beyond.

3.2.1.6 Electronic Management System

Maintenance activities are organized, planned, and managed using MP2[tm] by CMMS Data Group, a computer-based management system. All three major categories of maintenance activities (corrective, preventative, and predictive) are electronically managed by MP2[tm].

Table 3-3: FY 2013 Generating Plant Operating Statistics

Unit Number	Rated Capacity - MW	Net Production - MWh	Net Capacity Factor	Net Heat Rate Btu/kWh	Number of Starts
VanSant	39	1,568.4	0.46%	12,096	8
McKee Run					
Unit 1	17	545.5	0.37%	15,866	2
Unit 2	17	1,024.4	0.69%	14,812	4
Unit 3	102	12,692.5	1.42%	11,715	18
Total	175	15,830.7	1.03%		32

Unit Number	Forced Outage Hours	Operating Hours	Service Factor	Equivalent Availability Factor
VanSant	-	52.1	0.59%	59.45%
McKee Run				
Unit 1	80.0	74.8	0.85%	57.62%
Unit 2	-	170.3	1.94%	59.45%
Unit 3	-	201.8	2.30%	59.45%
Total	80.0	499.0	5.70%	

For corrective maintenance activities, any station operator or mechanic can enter a work order into the system at any terminal on the Station local area network (LAN). A supervisor reviews the request, turns it into a work order, and assigns a priority according to a predetermined categorization. The work order is planned, parts are ordered, and then the work order is assigned to an operator or maintenance technician for completion once the material has been received.

This system is also used to manage and track preventative maintenance activities that follow a schedule. Changing filters, and turning on and off heat tracing are examples of preventative maintenance. Predictive maintenance activities practiced include oil analyses, vibration testing, and infrared surveys. Portable vibration testing equipment is used at the Stations to improve the frequency of and capabilities to trouble-shoot rotating equipment. The technology allows personnel to identify problems and take corrective actions before equipment failure occurs.

3.2.1.7 Electric Generation Improvements

The following describes completed, on-going, and planned improvements to the City's generation assets:

Recently Completed:

- DOE Grant - Photovoltaic Panels
- McKee Run & VanSant Arc Flash
- McKee Run Driveway Repaving
- Unit 3 Fire Protection System
- Unit 3 Cooling Tower Life Extension
- Unit 1 Outage FY 2011
- Unit 2 - Boiler Inspection & Repair
- VanSant CT Mark IV Upgrades
- Work Management Software Replacement
- Unit 3 - Gas Modification
- Unit 3 Air Heater Expansion Joint
- Units 1 and 2 Control Modifications
- Units 1 and 2 Stack Repairs Inspection
- Unit 3 - Stack Repairs Inspection
- Unit 3 Boiler Air Heater
- Unit 3 FD and ID Fan Controller Upgrade
- Unit 3 DCS Computers & Software Upgrades
- Units 1 and 2 Component Repairs
- VanSant Component Replacements
- Unit 3 Auxiliary System Components
- Industrial Wastewater Discharge System
- Unit 3 Air Heater Expansion Joint
- Unit 3 Generator Repairs

- Units 1 & 2 Stack Repairs
- Unit 1 Gasket Leak Repair

On-Going:

- McKee Run Preservation of Structures
- Unit 3 Boiler Systems
- Unit 3 Auxiliary System Components
- Unit 3 Turbine Outage – Inspections & Repairs
- Units 1 & 2 Component Repairs

Planned:

- McKee Run Building Equipment Replacements
- McKee Run High Energy Piping
- McKee Run Natural Gas System Block/Bleed Valves
- McKee Run Fuel Oil System Refurbishment
- Unit 3 – Stack Repairs
- Unit 3 – Cooling Water Line Replacement
- Unit 3 – Cooling Tower Life Extension
- Units 1, 2 & 3 Hydrogen Purity Analyzers
- VanSant Capacity Increase
- VanSant Major Overhaul & Inspection
- VanSant Component Replacements
- Metering System Upgrades
- Safety & Compliance Improvements
- Vehicles, Trucks & Equipment

3.2.1.8 Condition Assessment

The following is a summary of the condition assessment of major equipment at McKee Run and VanSant as presented by the NAES corporation staff. Burns & McDonnell made no internal assessments of equipment during the facility tour.

3.2.1.9 Steam Turbines/Generators

The steam turbines and generators for VanSant and McKee Run Units 1 and 2 were reported to be in satisfactory condition with no major problems. McKee Run Unit 3 turning gear engagement problems were reported in the summer 2010 outage report and repairs were completed in FY 2012.

XL Insurance completes inspections of the Electric Division production facilities on an annual basis. After each inspection the insurance provider issues a report detailing its risk reduction recommendations. A recommendation following the FY 2011 inspection addressed safety. XL Insurance recommended the installation of a permanent fire protection system for the turbine generator bearings at McKee Run. The City completed the installation of the system in FY 2011 for Unit 3. The City and XL Insurance agree that portable foam generating carts are sufficient fire protection for Units 1 and 2, due to their light use.

For FY 2012, Unit 1 conducted turbine generator checks and found a bearing steam seal leak. Steam seals were removed and sent out for refurbishment by Siemens Energy Services during the fall 2012 outage. Bearing 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. Turbine condition assessment was conducted during the fall outage and the Units were found to be in satisfactory working condition.

For Spring 2013, an extensive inspection and testing was performed on Unit 3's turbine and generator. The inspection showed signs of seam oil, hydrogen, and busing box leakages. All issues were fixed and brought to acceptable operating standards. NAES Instrument, Control and Electrical (IC&E) Technicians completed four recommended General Electric Technical Information Letters (TIL) projects for VanSant Unit 11 in both spring and fall 2013 outages as shown below:

1. Annual TIL 1004-2R1 (IGV's and first stage corrosion/pitting inspection)
2. Annual TIL 1068-2R1 (IGV's bushing inspection)
3. Annual TIL 1132-2 (IGV thrust washer corrosion inspection)
4. Annual TIL 1049-2R1 (Inspect and measure dovetail material loss)

During the fall 2013 outage, NAES mechanics installed new hand wheel throttle valve mechanical parts. Thereafter, the IC&E installed a portable vacuum pump to the Unit 1 turbine to simulate 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.

3.2.1.10 Boilers and Auxiliaries

Boiler inspections are conducted every year on each of the boilers. The annual inspections typically include the inspection and cleaning of the major boiler components, including the mud and steam drums, the forced draft and induced draft fans, the windbox, condenser water box, condenser tubes, hotwell, air preheater components, and safety valves.

In FY 2011, the outlet duct expansion joint was replaced on Unit 3. Operations removed the appropriate insulation and lagging to prepare the duct. The Electric Division contracted Apex to complete the installation the equipment. A complete seam weld was utilized to seal the joint and the job site was cleaned. No additional problems with this joint developed in FY 2012.

In FY 2012, several principle changes were made on the generating system's boiler and auxiliary units at McKee Run. New beck drives were installed on Unit 3 induced draft and forced draft fans. Also, sector plates and seals were replaced in the Unit 3 air heater.

Following its FY 2010 annual inspection of the production facilities, XL Insurance recommended the City implement a program that tracks annual hot and cold settings of hangers in the steam, reheat, feedwater and boiler systems. In FY 2011 and FY 2012, the City met the recommendation by implementing a program that will examine the high energy piping systems on a five-year basis, beginning in 2014.

During FY 2013 inspections, no major issues were found within the Unit 1 or Unit 2 boiler. Unit 3 had an issue during the startup of the boiler while attempting to obtain a boiler purge. The issue was fixed by replacing a Gas Fuel Trip Relay. Waterwall tubing sections were replaced within Unit 3's A-2 burner.

3.2.1.11 Station Cooling Water Systems

The Station has split cooling water systems with one system serving Unit 1 and Unit 2 and a separate system serving Unit 3. Projectile tube cleaning was completed on the Unit 1 and Unit 2 condensers during the spring FY 2011 outage. All the tubes in each unit were cleaned utilizing the scraper blade plug method. Samples were taken from the tube cleanings and retained for inspection. No leaks were detected in the expansion joint or condenser tubes. Each condenser box was cleaned. Projectile tube cleaning was last completed in the 1980's. The cooling water systems are reported to be sufficiently sized and in satisfactory condition, with no major issues reported at the time of this Report.

3.2.1.12 Fuel Handling Systems

Natural gas is delivered to the Station via a 4-inch pipeline for Unit 1 and Unit 2 and in a 10-inch diameter pipeline for Unit 3. No. 2 fuel oil is delivered to the Station by truck and unloaded into tanks.

Forwarding pumps deliver the fuel oil to each of the units. No major fuel projects were reported to be completed in FY 2012.

3.2.1.13 Water Treatment/Steam Purity

Quality control parameters for boiler feed-water, internal boiler water, cooling tower water, and steam purity are checked at a minimum of twice per day when systems are operating. Results are recorded and graphically compared to control limits. Adjustments are then made as required. Boiler feed water is treated city water (well water from the City) using a regenerative ion resin demineralizer system, along with deaeration for oxygen control. Boilers 1 and 2 use a coordinated phosphate control for boiler internal purity control and Boiler 3 uses a balanced trisodium phosphate and disodium phosphate within a narrow pH range. A deep-bored water well was installed to provide water in addition to the City supplied water. City water has a high chlorine level which may exceed the Station permitted limits. By combining City water with the well water, the chlorine levels can be maintained at the permitted limits. Water for cooling tower makeup is also obtained from City water. The primary control parameter is silica concentration. Blow down is adjusted as required to maintain control. The City is currently undergoing the approval process with Kent County to obtain an integrated waste water permit to be able to discharge cooling water to the sewer system. No major water treatment issues were reported at the time of this Report.

Steam purity is not continuously monitored. Samples are taken twice daily and tested for pH, conductivity, and silica. There have not been any problems with steam purity. Annual inspections of the boiler drums and separation internals have verified that these systems are intact and operating properly.

Following its FY 2010 annual inspection of the production facilities, XL Insurance recommended the City implement lay-up procedures to protect water systems from corrosion. In FY 2011 and FY 2012, NAES worked to update plant procedures to conform to best practices/OSHA standards.

In FY 2012, the station did not experience any internal corrosion related failures, steam path deposits, or excessive condenser fouling. NALCO provides water treatment consulting services and chemicals. A representative visits the Station periodically to review test data and check chemical usage rates. No major issues were reported at the time of this Report.

3.2.1.14 Station Electrical Systems

Overall, Station electrical systems and transformers are considered to be in satisfactory condition. A condition assessment of the generation facilities' transformers was conducted in February 2011. Oil inspections and analyses were conducted. The inspector recommended that normal operation continue for

all the transformers at the plant. Oil sampling is now completed twice per year on the generator step-up transformers (GSUs). All plant transformers are examined annually.

Following its FY 2008 annual inspection of the production facilities, XL Insurance recommended the City build blast walls around transformers at the plant. In FY 2011, the City continued to research blast wall protection. Fire barrier walls were installed between the Unit 1 and 2 auxiliary transformers and the Unit 3 start-up transformer. Based on the 2012 XL Insurance annual inspection, there is still no sprinkler protection for GSU's 1-3.

3.2.1.15 Station Control Systems

Unit 1 and Unit 2 controls are electro-pneumatic and Unit 3 controls are a distributed control system (DCS). During the March FY 2011 spring outage, a controls upgrade was completed at McKee Run Units 1 and 2. The new devices control igniters, pilots and shut down main fuel to protect the boiler. The project included the installation of new limit switches on main gas, pilot gas, and oil supply/return valves. The controls upgrades help the system meet national fire protection codes.

Following its 2007 annual inspection of the production facilities, XL Insurance recommended the City seal openings in fire barriers through which cables pass. The City has worked each year since to make progress on sealing openings in fire barriers. The City completed sealing the rest of the openings as part of its boiler controls and control room upgrades in 2013.

In general, the station control systems are considered to be in satisfactory condition. The Unit 1 and Unit 2 control systems are outdated but perform satisfactorily. All relays have recently been inspected at both McKee Run and VanSant for North American Electric Reliability Corporation, PJM Interconnection and Mid-Atlantic Area Council compliance. The electro hydraulic control system was modified to become a primary/primary system in 2013. In 2013 additional control wiring was installed to upgrade the Unit 1 and Unit 2 gas control system. No major controls issues were reported at the time of this Report.

3.2.1.16 General Facilities

No major projects or improvements were completed to the General Facilities in FY 2013 other than routine maintenance and repairs. In general, the station facilities appeared clean and well maintained during the site visit.

3.2.1.17 VanSant Generating Station

In general, the unit is operated infrequently, but is well maintained. Although the station is only manned when operating, an operator performs a twice daily walk through with a checklist of items to review and

the results are logged. The annual overhaul and inspections were conducted at VanSant during FY 2013. No major problems were found.

The VanSant unit has the capability of black starts. The unit has the capability of remote control; however, the unit is not permitted for remote control.

XL Insurance completes inspections of the Electric Division production facilities on an annual basis. After each inspection the insurance provider issues a report detailing its risk reduction recommendations. The lone recommendation for VanSant following the FY 2012 inspection addressed safety. XL Insurance recommended the installation of gas detection equipment at the plant. A gas detection system has been installed. The gas detectors will activate the fire suppression system and alarm to the central control system. No other major repairs or upgrades were made at VanSant in FY 2013.

3.3 Transmission and Distribution Systems

On April 17, 2014, Mr. Ted Kelly visited the City to collect information and to observe the City transmission and distribution system, as operated and maintained by the Electric Division. Mr. Bill Hewlett provided information related to the transmission and distribution system. Mr. Hewlett also led a tour of the electric transmission and distribution system.

The Electric Division distributes power to its customers by a network of transmission lines, distribution substations, and distribution lines. The transmission lines are rated at 69 kV and are connected to fifteen distribution substations located throughout the service area. The distribution substations reduce the power from transmission voltages to the primary distribution voltages of 12 kV to facilitate distribution of electric power to customers.

3.3.1 Safety

Mr. Hewlett reported to Burns & McDonnell that there were no reportable injuries or lost workdays in FY 2013.

3.3.2 System Reliability

The Electric Division provides for reliability of its distribution system by configuring a majority of its distribution circuits in primary open loop arrangements, improving existing circuits, and installing adequate substation transformer capacity. Normal transformer and line loading are limited to provide sufficient margin to convey firm power requirements during an emergency or a switching operation, or for maintenance.

3.3.3 Power Quality

The Electric Division does not have any significant power quality problems. The overall power factor for the Electric System decreased from 99.86 percent in FY 2012 to 98.43 percent in FY 2013. Power transformers are equipped with load tap changers that regulate bus voltages at the distribution substations. Distribution transformers are equipped with no-load taps to make voltage adjustments. There are capacitors and voltage regulators on the Electric System that control voltage and vars on the portion of the system furthest away from the current source and generation. The system operators monitor the power factor closely and turn on capacitors or adjust the generation to compensate for low power factors.

3.3.4 Operations and Maintenance

The Electric Division has a SCADA system that is monitored continuously for any problems that may arise in the Electric System. The main control room has two system operator desks and a large screen where system operating information is displayed. System operators can monitor the Electric System operation, such as voltage levels, current flows, etc. and make necessary adjustments as problems arise. The systems operators have received some PJM training, but are not required to be certified as Delmarva Power is the controlling agency.

Loading on substation transformers used for an emergency, a switching operation, or maintenance is limited to 120 percent of the rated capacity, followed by a twelve-hour cool-down period. The Electric Division has eight line crews to work on the system. Four crews are responsible for overhead lines, four crews are responsible for underground lines, and one crew is responsible for maintenance. The primary responsibilities of the eight line crews are installation of new service connections and construction of new lines. The trouble crew maintains the street lights, repairs underground services and is the first responder to outages. Tree trimming is contracted out and is no longer performed by the Electrical Division; however, performance of the contractor is monitored by the Line Crew Superintendent.

The Substation/Relay Maintenance Division is responsible for operation and maintenance of the substations and associated equipment. Visual inspections of substations, associated equipment, trip counter checks and battery systems checks are performed regularly. The Substation/Relay Maintenance Division is also responsible for contractor oversight during annual transformer condition assessments.

TJ/H2b Analytical Services completed the annual transformer condition assessments in February 2011. No abnormal gas was indicated and since the oil condition was within acceptable parameters, TJ/H2b recommended the continuation of normal operation. The City has a contract with an environmental

consultant to check each substation for oil leaks and to provide instruction on cleaning up in the event of an oil spill.

The City contracts with an outside firm to inspect and chemically treat each wood pole in the Electric System every ten years. This is accomplished by awarding a five-year contract to spread out the expenses. Pole treatments were completed in May of 2013. Dover treated and inspected over 760 poles during 2013, of which, only one pole was rejected providing a 99.9% pass rate.

3.3.5 Design Standards and Specifications

The Electric Division designs the transmission and distribution circuits and some substation upgrades in conformance with national safety standards. Other substation and transmission design is contracted to Pike Electric, Inc.

The underground distribution design utilizes road or alley front access construction. This design means the electrical equipment, such as transformers and underground cable, are installed beside the road instead of behind houses or buildings. The advantage of front access construction is the accessibility for maintenance and repairs to cable and electric equipment. The underground cables are installed in polymerized vinyl chloride pipe for added protection and for easy cable replacement. The Electric Division installs jacketed, concentric cable that is rated at 15 kV, with 133 percent ethylene propylene rubber insulation.

The standard overhead distribution design utilizes a flat construction with a single cross-arm and insulators on 45-foot class 2 poles. Typically all electrical equipment locations have ground rods installed with measured readings of 25 ohms or less.

The substation design is generally a low-profile rigid bus design. The circuit breakers are SF6 gas-filled and the relays are microprocessor based with SCADA control and monitoring.

3.3.6 Transmission and Distribution Capital Improvements

The following describes completed, on-going, and planned improvements to the City's transmission and distribution assets:

Recently Completed:

- 69-kV Feeders 3 and 4
- Replacement of 69-kV Breakers & Design
- Governors Avenue Rebuild

- Mid-City Substation Upgrades
- Substation PT and CT Replacement
- Transmission Relaying, Replacement and Calibrations
- Outage Management System
- Wyoming Avenue – Underground
- Pleasanton Acres – Underground
- Royal Grant – New Underground Service
- Dover Downs Switchgear
- Substation Equipment & Fencing
- 69kV Switch Replacement
- Frazier Substation Reliability Upgrade

On-Going:

- Capitol Park – Underground
- Morris Estates – Underground
- Bayside Drive (Persimmon to White Oak Road)
- Lighting Project and Rehabilitation
- Horsepond Road Substation Reliability Upgrade
- Transmission Line Maintenance Program
- Distribution Capacitors – Overhead
- Distribution Capacitors – Underground
- New Developments – UG Transformers
- New Developments – UG Conductors/Devices
- Meter Replacements
- Vehicles, Trucks, & Equipment

Planned:

- Substation Battery Replacement
- Richardson Circle
- Lebanon 400 Feeder
- Townpoint Distribution Upgrades
- Distribution System Upgrades – Unidentified
- Horsepond Road URD – Distribution Feeders

- McKee Run Yard Rebuild (Transmission)
- Distribution Feeder Replacement Program
- McKee Run & State College Road Feeder Replacements
- GOTP Transmission Line Relocation
- McKee Run Transformer/Substation Repairs
- Horsepond SS to Cartanza 69kV Rebuild
- 69kV Substation Cable Replacement North Street
- General Scott Switchgear
- Dover Air Force Base Substation Rebuild
- System Automation
- DNREC R&R Metering
- West Dover Connector
- Meadows at Jefferson Terrace
- Chestnut Grove Development
- Garrison Oak Technical Park
- Uzin Utz Manufacturing

3.3.7 Condition Assessment

The transmission and distribution system assessment included drive-by observations of a sample of the transmission circuits, distribution circuits, and substations. Many of the fifteen substations were physically observed during the tour. The following substations were observed during the tour:

- McKee Substation
- College Park Substation
- Dover Downs Substation
- Frazier Substation
- VanSant Substation
- General Scott Substation
- Division Street Substation
- Mid-City Substation
- Mayfair Substation
- St. Joan's Substation
- Cartanza Substation

- Horsepond Substation
- Danner Farm Substation
- Lebanon Substation

In general, the substations were in acceptable operating conditions. Bill Hewlett provided a tour of the substations with Ted Kelly on April 17, 2014. The Frazier Substation was rebuilt last year; an additional 3 breaker system was added for a 69 kV bus. The General Scott Substation has relatively new breakers, and the controls are scheduled to be upgraded in FY 2014 or 2015. Horsepond Substation is currently being rebuilt. Work started in late February and scheduled to be back in service by June, 2014. Conductor line was replaced at the Savannah and White Oak Substation areas. The City's in the process of replacing conductor throughout the entire 69 kV system. Moving forward, a greater portion of the system will be converted from overhead to underground distribution.

3.4 Conclusions

Based on statements and information provided, as well as the observations and reviews performed, it is the opinion of Burns & McDonnell that the City's power generation facilities are being operated and maintained consistent with accepted electric utility practice in the United States. In general, the performance, operation, maintenance, staff, planning, and training aspects for the McKee Run and VanSant stations were found to be above average. Specifically, the generation facilities have demonstrated a high level of availability despite the dispatching of the units primarily for peak demand.

It is the opinion of Burns & McDonnell that the design, construction, operation and maintenance of the City's electric transmission and distribution system and the associated facilities are consistent with current generally accepted electric utility standards. In completing Annual Engineering Consultant's Reports over the past several years, Burns & McDonnell has observed that the City has made appropriate system upgrades and improvements. The City and the Electric Division are proactive in preventative maintenance and expansion of the Electric System before problems arise.

4.0 – FINANCIAL ASSESSMENT

4.0 FINANCIAL ASSESSMENT

A review of the financial results of the Electric System for the fiscal year ended June 30, 2013, is provided below.

4.1 Financial Results

The total revenue of the Electric Division during FY 2013 included revenue from charges for electric service, as well as miscellaneous revenues from items such as rents, penalties, reconnection fees, and development fees. On Table 4-4, revenues were compared to the Electric Division's costs of providing services to its customers to determine whether the financial requirements of the Electric Division were met.

4.1.1 Required Revenue Level

The level of revenues required from the retail electric rates for the Electric Division was determined through the analysis of the financial results and net income or net margins for the most recent fiscal year. The City of Dover, Delaware Resolution Authorizing and Securing Electric Revenue Bonds, adopted December 23, 1985 requires that the Electric Division maintain a debt service coverage ratio of 1.25. The following is an excerpt from Section 502(c) of the resolution.

> *"(c) The total amount of the Revenues of the Electric System during the preceding fiscal year shall have been not less than the total of the following:*
>
> *(3) The Current Expenses of the Electric System during the current fiscal years shown by the Annual Budget . . . for such fiscal year, and*
>
> *(4) One hundred twenty-five percent (125%) of the maximum amount of the Principal and Interest Requirements for any fiscal year thereafter on account of all bonds then Outstanding under the provisions of this Resolution.*
>
> *The City further covenants that, from time to time and as often as it shall appear necessary, it will adjust the electric rates as may be necessary or proper so that the revenues of the Electric System in each fiscal year will not be less than the total of the amounts set forth in subdivision (c) of this section."*

4.1.2 Electric Rates

Customers of the Electric Division are charged for the electric service based on rate schedules, tariffs, or contracts that reflect the costs to the Electric Division of providing that service. For purposes of setting

electric rates, customers with similar load and service characteristics should be placed in the same rate classification.

A comprehensive cost-of-service and rate design study was completed in 2006 and subsequent rate analyses were completed in 2007 and 2008 to examine revenue requirements and revenue generation. Specifically, the 2006 rate study was conducted to address increased costs associated with a new power supply contract that became effective on July 1, 2006. The rate study recommended combining a number of rate classes and implementing rate increases on July 1, 2006. The 2006 rate study also recommended an additional increase be implemented on January 1, 2007 to cover increased costs associated with operating the generating station. The 2007 and 2008 rate analyses re-examined Electric Division revenues and expenses and recognized additional revisions to power supply costs. As a result of these analyses, additional rate increases were implemented on July 1, 2007 and July 1, 2008. The City retained Burns & McDonnell to conduct cost-of-service and rate design study in 2012 followed by an update in 2013. The 2012 study examined revenue adequacy, revenue responsibility, and revenue recovery for the Electric Division. It scrutinized customer classes and proposed adjustments for demand rate components and corresponding changes to energy charges. In May 2013, the City retained Burns & McDonnell to incorporate updated power supply cost projections, and other updates, into the model it developed as part of the 2012 Study. The current rate classes are listed below.

- Residential
- Small Commercial (1 Phase, 3 Phase, 1 Phase Heating, Church, and Municipal)
- Medium Commercial (1 Phase & 3 Phase)
- Large Commercial (3 Phase with Reactive Metering)
- Primary
- Transmission
- Outdoor Development Lighting
- Private Outdoor Lighting

4.1.3 Operating Results

Table 4-1 presents a summary of the annual energy sales, the average monthly number of customer accounts, and the annual average kilowatt-hour (kWh) energy per customer of the Electric Division for FY 2011 through FY 2013. Annual energy sales decreased in FY 2012 to 710.3 GWh, a decrease of 3.2 percent from 734.1 GWh in FY 2011. Energy sales increased to 723.1 GWh in FY 2013, a 1.8 percent increase from FY 2012.

Table 4-1: Annual Sales and Customer Accounts

	FY 2011	FY 2012	FY 2013
Energy Sales (kWh)			
Residential	208,092,047	196,388,942	204,759,680
Commercial	243,985,517	230,814,311	232,220,877
Primary	153,879,249	160,560,686	167,144,717
Transmission	128,146,159	122,563,783	119,003,804
Total Energy Sales	734,102,972	710,327,722	723,129,078
Average Number of Monthly Customers (bills)			
Residential	19,730	19,910	19,990
Commercial	3,140	3,355	3,412
Primary	42	39	37
Transmission	3	4	4
Total Customers Accounts	22,915	23,308	23,443
Energy Usage Per Customer (kWh/cust./yr.)			
Residential	10,547	9,864	10,243
Commercial	77,702	68,797	68,060
Primary	3,663,792	4,116,941	4,517,425
Transmission	42,715,386	30,640,946	29,750,951
Average Usage Per Customer	32,036	30,476	30,846

Table 4-2 presents revenues from sales, revenue per kWh ratios, and average revenue per customer ratios for each revenue classification. Total revenue from sales to electric customers in FY 2013 was $88.3 million, representing a decrease of $3.6 million, or 3.9 percent from FY 2012. Total revenue from sales to electric customers includes utility tax revenue and power cost adjustment revenue.

In FY 2013, the average rate revenue per kWh for residential customers was 14.00 cents and the total average rate revenue was 12.22 cents per kWh. The July 2012, through June 2013 national average monthly utility-level retail sales of electricity and associated revenue per kWh, as published by the US Energy Information Administration (EIA), were 11.88 and 9.84 cents per kWh, respectively. For a state-wide comparison, the EIA summarized the Delaware July 2012 through June 2013 average monthly utility-level retail sales of electricity and associated revenue per kWh to be 13.58 cents per kWh for residential customers and 11.06 cents per kWh across all sectors.[1]

[1] US Energy Information Administration, Form EIA-826 Data Monthly Electric Utility Sales and Revenue Data, http://www.eia.gov/electricity/data/state/avgprice_annual.xls (May 22, 2014)

Table 4-2: Annual Revenues and Sales Ratios

	FY 2011	FY 2012	FY 2013
Revenue			
Residential	$ 30,774,462	$ 28,072,775	$ 28,668,248
Commercial	36,572,134	33,381,554	30,520,784
Primary	18,450,238	17,986,987	17,699,865
Transmission	13,716,322	12,506,664	11,442,299
Total Revenue	$ 99,513,156	$ 91,947,980	$ 88,331,196
Revenue/kWh			
Residential	$ 0.1479	$ 0.1429	$ 0.1400
Commercial	0.1499	0.1446	0.1314
Primary	0.1199	0.1120	0.1059
Transmission	0.1070	0.1020	0.0962
Total Revenue/kWh	$ 0.1356	$ 0.1294	$ 0.1222
Revenue Per Customer			
Residential	$ 1,560	$ 1,410	$ 1,434
Commercial	11,647	9,950	8,945
Primary	439,291	461,205	478,375
Transmission	4,572,107	3,126,666	2,860,575
Average Revenue Per Customer	$ 4,343	$ 3,945	$ 3,768

The Electric Division's largest cost in providing electric service to its customers in FY 2013 was the wholesale cost of power. The Electric Division purchased power from the PJM Interconnection marketplace through its Energy Manager, TEA. The cost of non-generated power includes energy and demand costs, power supply management expense, PJM charges and credits, generation fuels cost, and capacity charges and credits.

The significance of power supply cost to the Electric Division is illustrated in Table 4-3. The top portion of the Table shows net operating revenue as the difference between total revenues generated by the rates and the cost of power supply.[2] The ratios of power supply cost to sales revenues were calculated for FY 2011 through FY 2013. As illustrated, the Electric Division's power supply cost as a percentage of rate revenue increased from 64.1 percent in FY 2012 to 63.0 percent in FY 2013.

[2] For the purposes of this Report, the phrase "Power Supply" refers to the sum of the costs of power purchased and power generated. This includes plant costs and the cost of fuel. Power Supply also includes any expenses in the CIP Fund that are not capital expenses. The phrase "Purchased Power" refers only to the cost of power purchased from the market and other directly associated costs.

Table 4-3: Revenue Margins and Unaccounted for Energy

	FY 2011	FY 2012	FY 2013
Net Revenue Margins ($)			
Sales Revenues	$ 99,513,156	$ 91,947,980	$ 88,331,196
Power Supply	69,616,076	58,929,133	55,681,251
Net Revenue Margin	$ 29,897,080	$ 33,018,847	$ 32,649,945
Net Revenue Ratio	70.0%	64.1%	63.0%
Unaccounted for Energy (kWh)			
Power Supply	768,254,000	738,190,000	752,869,000
Energy Sales	734,102,972	710,327,722	723,129,078
Unaccounted for Energy (Losses) [1]	34,151,028	27,862,278	29,739,922
Percentage	4.4%	3.8%	4.0%

[1] Unaccounted for Energy (Losses) includes street lighting energy

Table 4-3 also illustrates the ratio of the amount of energy purchased and delivered to the electric system to total energy sales. This relationship identifies the level of unaccounted for energy in the Electric System. This unaccounted for energy may include energy that was unmetered, metered inaccurately, stolen, lost, PJM transmission line losses, local system line/transformer losses, etc. The bottom portion of Table 4-3 presents these comparisons for the Electric Division for FY 2011 through FY 2013. As shown, the percentage ratio of the unaccounted for energy to the total energy purchased for FY 2013 was 4.0 percent. This is up from 3.8 percent in FY 2012.

Table 4-4 presents a re-creation of the Electric Division's Statement of Revenues, Expenses, and Changes in Unreserved Retained Earnings for the Electric Revenue Fund for FY 2011 through FY 2013. Net income decreased from FY 2012, totaling $6.2 million in FY 2013. An increase in Operating – Transfers Out resulted in a $2.3 million decrease in net income for the year. The General Fund Transfer was increased by $2.0 million to help finance the Calpine Project which the City is currently negotiating with for a Purchase Power Agreement and Capacity Agreement in light of the decommissioning Units 1 and 2.

Table 4-4: Comparative Statement of Revenues, Expense, and Changes in Unreserved Retained Earnings

	FY 2011	FY 2012	FY 2013
Operating Revenues:			
Charges for Electric Service	$ 99,513,157	$ 91,947,980	$ 88,331,196
Miscellaneous Services/Incomes	2,389,462	1,581,421	2,354,497
Total Operating Revenues	$ 101,902,619	$ 93,529,401	$ 90,685,693
Operating Expenses:			
General Administration	$ 5,298,869	$ 5,223,149	$ 4,470,795
Power Supply	69,616,076	58,929,133	55,681,251
Transmission/Distribution	3,083,714	3,023,566	3,267,698
Engineering	1,722,244	1,163,379	1,107,231
Metering	204,352	205,791	219,010
System Operations	486,894	498,063	544,405
Utility Tax	1,944,543	1,548,208	1,443,853
Depreciation	4,710,658	4,783,444	4,621,501
Retirees Pension			1,115,765
Retiree Health Care	1,839,110	1,015,731	696,500
Total Operating Expenses	$ 88,906,460	$ 76,390,464	$ 73,168,009
Net Operating Income	$ 12,996,159	$ 17,138,937	$ 17,517,684
Non-operating Revenues (Expenses)			
Interest Earned			
Operating Fund	$ 832,145	$ 120,876	$ 190,469
Reserved Funds	511,922	348,640	506,771
Net Increase in Fair Value of Investments	(861,216)	45,200	(614,989)
Interest and Fiscal Charges	(1,385,035)	(1,283,174)	(1,432,779)
Bond Discount Amortized	(21,579)	-	
Gain/(Loss) on Sale of Assets	16,830	47,966	5,203
Total Non-operating Revenues(Expenses)	$ (906,933)	$ (720,492)	$ (1,345,325)
Net Income Before Operating Transfers	$ 12,089,226	$ 16,418,445	$ 16,172,359
Operating Transfers - In	-	-	8,282
Operating Transfers - Out	(8,856,000)	(7,876,288)	(10,000,000)
Total Net Operating Transfers	$ (8,856,000)	$ (7,876,288)	$ (9,991,718)
Net Income	$ 3,233,226	$ 8,542,157	$ 6,180,641

4.1.4 Adequacy of Electric Rates

The City's Bond Resolution requires annual revenues of the Electric Division be no less than the total current expenses plus 125 percent of the greatest remaining annual debt service. "Current expenses", as defined in the Resolution, includes all expenses necessary to maintain and repair the Electric System, all administrative expenses, and engineering, legal or other consultant fees. Transfers to reserve accounts and special purpose funds, and allowances for depreciation are specifically excluded from "current expenses."

In order to determine if the City and the Electric Division have met this requirement, the net income shown in Table 4-4 was adjusted to include the interest on bonds, depreciation expense, and other non-cash income and expenses. Table 4-5 summarizes net income adjustments and the calculation of the revenues available for debt service for FY 2011 though FY 2013.

Table 4-5: Debt Service Coverage

	FY 2011	FY 2012	FY 2013
Net Income	$ 3,233,226	$ 8,542,157	$ 6,180,641
Plus Excluded Expenses:			
Operating Transfers - Out	$ 8,856,000	$ 7,876,288	$ 10,000,000
Depreciation	4,710,658	4,783,444	4,621,501
Interest and Fiscal Charges	1,385,035	1,283,174	1,432,779
Bond Discount Amortized	21,579	-	-
Gain/(Loss) on Sale of Assets	(16,830)	(47,966)	(5,203)
Less Excluded Income:			
Net Increase in Fair Value of Investments	861,216	(45,200)	614,989
Interest Earned - Reserve Funds	(511,922)	(348,640)	(506,771)
Revenues Available for Debt Service	$ 18,538,962	$ 22,043,257	$ 22,329,654
Maximum Principal and Interest in Any Year	$ 3,401,954	$ 3,401,954	$ 3,401,954
Debt Service Coverage	5.45	6.48	6.56
Minimum Required Debt Service Ratio	1.25	1.25	1.25

As Table 4-5 illustrates, the City and the Electric Division maintained a debt service coverage ratio each year that exceeded the required 125 percent plus current expenses. Therefore, the revenues generated by the current electric rates have been sufficient to meet the applicable covenants of the Resolution.

Section 502 of the Resolution requires that the annual debt service used in evaluating the revenues is to be the maximum amount for any fiscal year thereafter. Table 4-6 presents the annual totals of principal and interest amounts due on bonds currently outstanding. The calculation of the debt service coverage ratio in Table 4-5 is based on the total maximum debt service expense in any fiscal year. The FY 2013 calculation was based on the total FY 2016 debt service expense of $3,401,954.

4.2 Status of Revenue Bonds

At the end of FY 2013, the City had two series of outstanding electric revenue bonds that were issued pursuant to the Resolution. On July 1, 2008, the City issued $22,200,000 in Electric Revenue Bonds (2008 Bonds). The proceeds from the sale of the 2008 Bonds were used (i) to finance or reimburse the

City for improvements to the City's electric system; (ii) to fund a Debt Service Reserve Fund; and (4) to pay the costs of issuance of the 2008 Bonds.

On November 17, 2010, the City issued $8,810,000 of Electric Revenue Refunding Bonds (Series 2010). The proceeds from the sale of the Series 2010 Bonds were used (i) to refund the Series 2004 Bonds, and (ii) to pay the costs of issuance of the Series 2010 Bonds. The non-taxable Series 2010 Bonds received an underlying rating of Aa2 by Moody's Investors Services and an underlying rating of A+ by Fitch Ratings.

Table 4-6 illustrates the debt service schedule for the Series 2008 and 2010 Bonds. The principal and interest and the annual total are shown for each series of bonds. At the time of issuance of the Series 2010 Bonds, the combined outstanding principal balance for both series of bonds was $30,280,000.

Table 4-6: Debt Service Schedule of Electric Revenue Bonds

	2008 Electric Revenue Bonds			2010 Electric Revenue Refunding Bonds			Total Annual
Period	Principal	Interest	Debt Service	Principal	Interest	Debt Service	Debt Service
FY 2014	430,000	986,454	1,416,454	1,740,000	219,100	1,959,100	3,375,554
FY 2015	450,000	964,954	1,414,954	1,810,000	166,900	1,976,900	3,391,854
FY 2016	475,000	942,454	1,417,454	1,890,000	94,500	1,984,500	3,401,954
FY 2017	695,000	918,704	1,613,704	-	-	-	1,613,704
FY 2018	730,000	883,954	1,613,954	-	-	-	1,613,954
FY 2019	765,000	847,454	1,612,454	-	-	-	1,612,454
FY 2020	800,000	815,706	1,615,706	-	-	-	1,615,706
FY21-34	16,325,000	6,618,185	22,943,185	-	-	-	22,943,185
Total	$21,470,000	$15,013,223	$36,483,223	$8,810,000	$ 911,867	$ 9,721,867	$46,205,090

4.3 Insurance

The City maintains a comprehensive insurance program to insure against varying types of liabilities and significant losses related to various Electric Division properties. Section 706 of the Resolution reads:

> *"The City covenants that it will maintain a practical insurance program, with reasonable terms, conditions, provisions and costs, which the City Manager determines, with the approval of the Engineering Consultants, will afford adequate protection against loss, including loss of Revenues, caused by damage to or destruction of the Electric System or any part thereof and also comprehensive public liability insurance on the Electric System for bodily injury and property damage in such amounts as may be approved by the Engineering Consultants."*

Table 4-7 summarizes itemized insurance coverage procured by the City for the period July 1, 2013, through June 30, 2014. Burns & McDonnell has reviewed this list of insurance, and in the opinion of

Burns & McDonnell, as Engineering Consultant and not as insurance counselor, the insurance in full force and affect appears to satisfy the requirements of Section 706 of the Resolution.

Table 4-7: Schedule of Insurance Coverage in Effect

Starr Technical Risks Agency	July 1, 2013 - June 30, 2014 Coverage
Property	
Earth Movement -Per Occurrence and in the Annual Aggregate, except	$20,000,000
Earth Movement in High Hazard Earth Movement Zones;	EXCLUDED
Earth Movement in California;	EXCLUDED
Flood -Per Occurrence and in the Annual Aggregate;	10,000,000
Accounts Receivable;	100,000
Business Interruption;	EXCLUDED
Contingent Time Element Coverage;	EXCLUDED
Debris Removal (or 25% of Direct Property Loss, whichever the greater);	2,500,000
Demolition and Increased Cost of Construction;	10,000,000
EDP Media;	1,000,000
Errors and Omissions;	2,000,000
Expediting Expense;	1,000,000
Extra Expense, excluding replacement power or increased cost of generation, transmission and/or distribution of electricity, water or natural gas;	2,000,000
Fire Department Service Charges and Extinguishing Expenses;	500,000
Hazardous Substances -Per Occurrence and in the Annual Aggregate;	500,000
Inland Transit;	2,500,000
Newly Acquired Locations -90 Days reporting;	1,000,000
Personal Property Temporarily Off Premises;	100,000
Professional Fees;	250,000
Incidental Course of Construction;	5,000,000
Miscellaneous Unnamed Locations (except perils of Flood, Earth Movement and	500,000
Valuable Papers and Records;	100,000

Deductibles

For each Occurrence giving rise to a claim under this policy, the Insured agrees to retain for its own account an initial amount of:

In respect of Damage to Insured Property:

$350,000 per Occurrence, except;

$100,000 per Occurrence as respects Transit.

In respect of Time Element loss (Extra Expense):

45 days per Occurrence, except;

72 hours per Occurrence in respect of Service Interruption.

XL Insurance	July 1, 2013 - June 30, 2014 Coverage
Property	
per Occurrence and in the Annual Aggregate in respect of Flood;	$ 10,000,000
per Occurrence and in the Annual Aggregate in respect of Earth Movement, Excluded. per Occurrence and in the Annual Aggregate applicable in High Hazard Movement zones;	20,000,000
per Occurrence and in the Aggregate in respect Hazardous Substance;	500,000
per Occurrence in respect of Business Interruption;	EXCLUDED
per Occurrence in respect of Accounts Receivable;	100,000
per Occurrence in respect of scheduled, direct Contingent Time Element;	EXCLUDED
per Occurrence in respect of Incidental Course of Construction;	5,000,000
(or 25.00% of the direct physical loss, whichever greater) per Occurrence in respect of Debris Removal;	2,500,000
per Occurrence in respect of Demolition and Increased Cost of Construction;	10,000,000
per Occurrence in respect of Electronic Data Processing Media;	1,000,000
per Occurrence in respect of Errors and Omissions;	2,000,000
per Occurrence in respect of Expediting Expense;	1,000,000
per Occurrence in respect of Extra Expense excluding replacement power of increased cost of generation, transmission and/or distribution of electricity, water or natural gas;	2,000,000
per Occurrence in respect of Fire Department Service Charges and Extinguishing Expenses;	500,000
per Occurrence in respect of Newly Acquired Locations (ninety (90) days reporting);	1,000,000
per Occurrence in respect of property in Course of Inland Transit;	2,500,000
per Occurrence in respect of Miscellaneous Unnamed Locations, except:	500,000
Excluded. per Occurrence in respect of Flood;	
Excluded. per Occurrence in respect of Earth Movement;	
Excluded. per Occurrence in respect of Named Storm;	
per Occurrence in respect of Valuable Papers and Records;	100,000
per Occurrence in respect of Personal Property Temporarily Off Premise.	100,000

Deductibles / Retentions

For each Occurrence giving rise to a claim under this policy, the Insured agrees to retain for its own account an initial amount of:

In respect of Damage to Insured Property:

$350,000, Per Occurrence, except;

$100,000, per Occurrence as respect Transit;

In respect of Time Element loss (Extra Expense):

45 days per Occurrence except;

72 hours Per Occurrence in respect of Service Interruption

4.4 Operating and Reserve Accounts

The Electric Revenue Fund and the Electric Improvement & Extension (I&E) Fund are the City's two funds devoted to the Electric Division. The funds are used to manage cash and transactions related to utility operations and capital expenditures, respectively. Each fund includes certain cash accounts established to make moneys available for specific purposes when they are needed. The accounts maintained within the Revenue and I&E Funds are listed herein.

Electric Revenue Fund

- Insurance Reserve Account
- Contingency Reserve Account
- Electric Rate Stabilization Reserve Account
- Interest and Sinking Account

Electric Improvement & Extension Fund

- Depreciation Reserve Account
- Future Capacity Reserve Account

The following are descriptions of each Fund, their respective accounts and their purposes.

4.4.1 Electric Revenue Fund

The Electric Revenue Fund was established in Section 503 of the Resolution. All revenues are to be deposited into the Electric Revenue Fund when received. Current expenses are to be paid and other accounts are to be maintained from the Electric Revenue Fund. Moneys are transferred from the Electric Revenue Fund to the Electric Rate Stabilization Reserve Account, the Interest and Sinking Account, the I&E Fund, the Depreciation Reserve Account, and the Future Capacity Reserve Account.

4.4.1.1 Insurance Reserve Account

The Insurance Reserve Account was established by the City to fund insurance deductibles in the event of loss(es) covered by the City's insurance policies then in effect. The target minimum balance in the Insurance Reserve is $350,000. The reserve balance at the end of FY 2013 was $733,043. Dover will be proposing raising the minimum balance from $350,000 to $750,000 per insurance carrier recommendation in order to reduce premiums. This proposal will be taken to City Council in 2014.

4.4.1.2 Contingency Reserve Account

The Contingency Reserve Account was established by the City in FY 2003 to provide for unplanned expenditures that may not be avoidable. The City's Financial Policies require that a minimum balance be maintained in the Contingency Reserve Account equal to 1.0 percent of the current year revenues for the Electric Revenue Fund. The FY 2013 year-end balance was $814,236, which is equal to 0.92 percent of the FY 2013 revenues for the Electric Revenue Fund.

4.4.1.3 Electric Rate Stabilization Account

The Electric Rate Stabilization Reserve Account was established in FY 2005 to offset the costs of the power cost adjustment to the customers of Dover. The account's target balance is a minimum of 3.0 percent, not to exceed 10.0 percent, of purchase power cost in any given year. Any excess of this amount will be refunded to customers in future years by reducing the rate of the power cost adjustment. The account's FY 2013 end-of-year balance was $17,382,124, which was 31.2 percent of the FY 2013 purchased power cost.

4.4.1.4 Interest and Sinking Account

The Interest and Sinking Account was established in Section 507 of the Resolution. This account consists of two restricted accounts: the Bond Service account and the Reserve Account. The Bond Service Account is funded with equal monthly transfers from the Electric Revenue Fund such that the balance, as of each payment date for interest or for principal and interest, will be equal to the amount of the payment due. The payments of principal and interest due on bonds are made from the Bond Service Account. The Reserve Account is funded by transfers from the Electric Revenue Fund, as necessary, to maintain a balance equal to the maximum combined principal and interest for any future fiscal year through the life of all bonds then outstanding. Moneys in the Reserve Account are used for paying interest on and principal of bonds when the balance in the Bond Service Account is insufficient for making those payments. Excess moneys in the Reserve Account are also used towards paying current interest payments. The total amount in the Restricted Accounts for the 2008 and 2010 bonds as of June 30, 2013, was $3,522,833.

4.4.2 Electric Improvement and Extension Fund

The I&E Fund was established in Section 507 of the Resolution. Funds are added to the I&E Fund from the Electric Revenue Fund to the extent that the amount of funds available from the Electric Revenue Fund exceeds the total of the amounts required to be added to the Interest and Sinking Account. The I&E Fund also receives additional funding from the Depreciation Reserve Account, the Future Capacity Reserve Account, and from development receipts. Section 510 of the Resolution indicates that, except for certain situations, moneys held in the I&E Fund are to be used only for payment of costs of unusual maintenance or repairs, renewals or replacements, obtaining or replacing equipment, constructing extensions, additions, or improvements, and engineering expenses related to the foregoing activities.

4.4.2.1 Depreciation Reserve Account

The Depreciation Reserve Account represents moneys that have been set aside for the sole purpose of funding renewals and replacements of the Electric System as components or equipment wear out,

deteriorate, or otherwise become unsuitable for the intended purpose. Transfers from the Electric Revenue Fund and investment earnings are the only sources of additional moneys for the Depreciation Reserve Account. Transfers to the I&E Fund are made as necessary to fund capital projects. The target appropriation for the Depreciation Reserve Account each year is the excess of depreciation expense for the year over the amount of principal included in debt service payments made during the year. The reserve balance at the end of FY 2013 was $9,855,704.

4.4.2.2 Future Capacity Reserve Account

The Future Capacity Reserve Account was established to set aside and accumulate funds from the Electric Revenue Fund for use in evaluating and pursuing activities related to the Electric Division's alternatives for power supply resources for future demand for electricity. The original target balance for this reserve was $5,000,000. The reserve balance at the end of FY 2013 was $10,004,190.

Table 4-8 presents FY 2011 through FY 2013 year-end summaries of the activity within the cash accounts described above. The Insurance Reserve Account, the Contingency Reserve Account, the Electric Rate Stabilization Reserve Account, and the Interest and Sinking Account are accounts within the Electric Revenue Fund. The Depreciation Reserve Account and the Future Capacity Reserve Account are accounts within the I&E Fund.

Table 4-8: Reserve Account Activity and Balances

	Insurance Reserve Account	Contingency Reserve Account	Electric Rate Stabilization Account	Bond Reserve Account	Depreciation Reserve Account	Future Capacity Account
Year Ended June 30, 2011						
Balance in Account on July 1	$ 396,530	$1,039,766	$ 4,776,519	$3,337,822	$ 8,021,155	$ 9,023,928
Receipts						
Interest Earned	6,804	17,022	83,648	108,706	141,066	154,843
Appropriations	-	-	1,300,000	3,588,881	2,250,000	-
Total Funds Available	$ 403,334	$1,056,788	$ 6,160,167	$7,035,409	$10,412,221	$ 9,178,771
Disbursements						
Debt Service Payments	-	-	-	(3,516,027)	-	-
Transfer to Capital Projects	-	-		-	-	-
Balance in Account on June 30	$ 403,334	$1,056,788	$ 6,160,167	$3,519,382	$10,412,221	$ 9,178,771
Year Ended June 30, 2012						
Balance in Account on July 1	$ 403,334	$1,056,788	$ 6,160,167	$3,519,382	$10,412,221	$ 9,178,771
Receipts						
Interest Earned	4,661	14,026	69,966	3,451	129,837	126,711
Appropriations	-	-	5,000,000	-	-	-
Total Funds Available	$ 407,995	$1,070,814	$11,230,133	$3,522,833	$10,542,058	$ 9,305,482
Disbursements						
Debt Service Payments	-	-	-		(500,000)	-
Transfer to Capital Projects	(70,730)	-	(1,000,000)	-	(300,000)	500,000
Balance in Account on June 30	$ 337,265	$1,070,814	$10,230,133	$3,522,833	$ 9,742,058	$ 9,805,482
Year Ended June 30, 2013						
Balance in Account on July 1	$ 337,265	$1,070,814	$10,230,133	$3,522,833	$ 9,742,058	$ 9,805,482
Receipts						
Interest Earned	10,178	16,022	151,991	3,224	172,146	153,208
Appropriations	385,600	-	12,400,000	3,375,534	-	2,100,000
Total Funds Available	$ 733,043	$1,086,836	$22,782,124	$6,901,591	$ 9,914,204	$12,058,690
Disbursements						
Debt Service Payments	-	(272,600)	-	(3,375,534)	(58,500)	(54,500)
Transfer to Capital Projects	-	-	(5,400,000)	-	-	(2,000,000)
Balance in Account on June 30	$ 733,043	$ 814,236	$17,382,124	$3,526,057	$ 9,855,704	$10,004,190

5.0 – CONCLUSIONS

5.0 CONCLUSIONS

In the preparation of this Engineering Consultant's Report, Burns & McDonnell completed assessments of the electric generating stations and the transmission and distribution system of the City Electric Division. The investigations included interviews, observations, and reviews of FY 2013 expenditures and FY 2014 budgets. In addition, an analysis of the balances of the Improvement and Extension Fund and other funds benefiting the Electric Division was performed. Burns & McDonnell also reviewed the adequacy of the revenues provided by the current retail rates in relation to the requirements of the City of Dover, Delaware Resolution Authorizing and Securing Electric Revenue Bonds, adopted December 23, 1985. A high level assessment of the City's insurance coverage related to the Electric Division was also completed. Based on these reviews and assessments, it is Burns & McDonnell's opinion that:

1. The City's power generation facilities are being operated and maintained consistent with accepted electric utility practice in the United States.
2. The design, construction, operation, and maintenance of the City's electric transmission and distribution system and the associated facilities are consistent with current generally accepted electric utility standards and over the past few years. The system has been upgraded in order to improve operation and service to customers.
3. The Electric Division capital projects included in the City's Capital Investment Plan and the FY 2014 Operating Budget are necessary and should provide improved reliability and power quality for the Electric System.
4. The balances as of June 30, 2013 for the various reserve funds maintained by the City for the Electric Division appear to be sufficient for their defined purposes.
5. The insurance coverage in full force and affect as maintained by the City related to the various assets of the Electric Division appears to satisfy the requirements of Section 706 of the Resolution.
6. The electric revenues generated by the City's current retail rates are more than sufficient to fulfill the debt service coverage requirement defined in Section 502(c) of the Resolution.

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The Energy Authority, Inc.

Monthly Management Committee Update – April 2014

May 22, 2014

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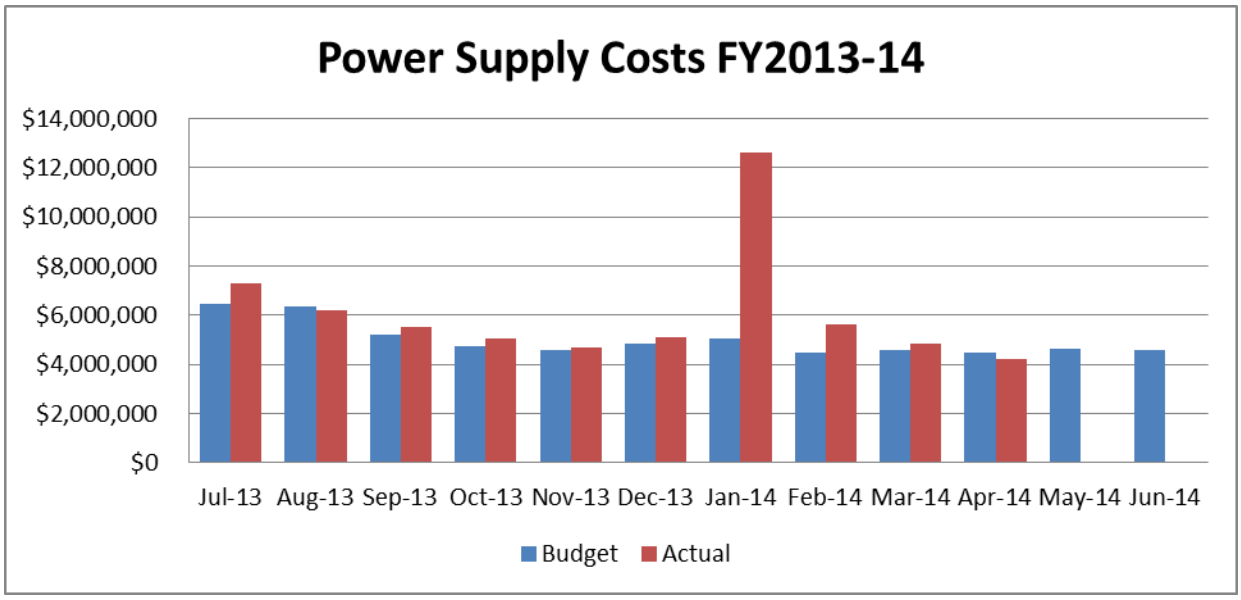
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I. Executive Summary

A. Power Supply Summary:



Overall Power Supply costs were $267,987 under budget due to lower hedge prices and a prior month adjustment which lowered energy costs.

Dover's budgeted cost for all power supply (capacity AND energy) was $83.79/MWh. The actual cost of all power supply (capacity AND energy) was $80.06/MWh.

The cost of energy alone was $42.63/MWh, versus a budgeted energy cost of $49.20.

Dover's hedge purchases totaled 41,280 MWh, which was 79% of the actual load. The budgeted hedge purchase totaled 26,720, which was 50% of the budgeted load.

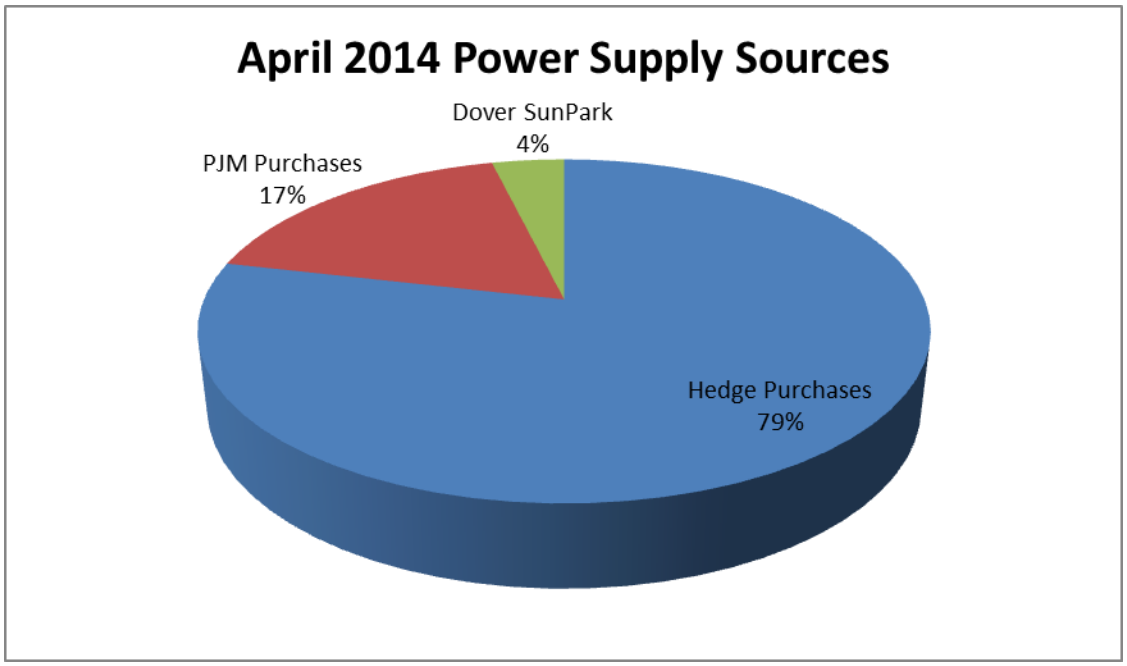
Dover's power purchases from hedge transactions totaled $1,977,556. Purchases from PJM (energy and fees) totaled $593,382 which included DA Energy purchases totaling $154,447 and Reactive Services Charges totaling $116,655.

Dover's total load was 52,517 MWh versus a forecasted load of 53,377 MWh.

Dover's planned energy purchase from the SunPark solar installation was 2,100 MWh. Dover's actual energy purchase from the SunPark installation was 1,999 MWh.

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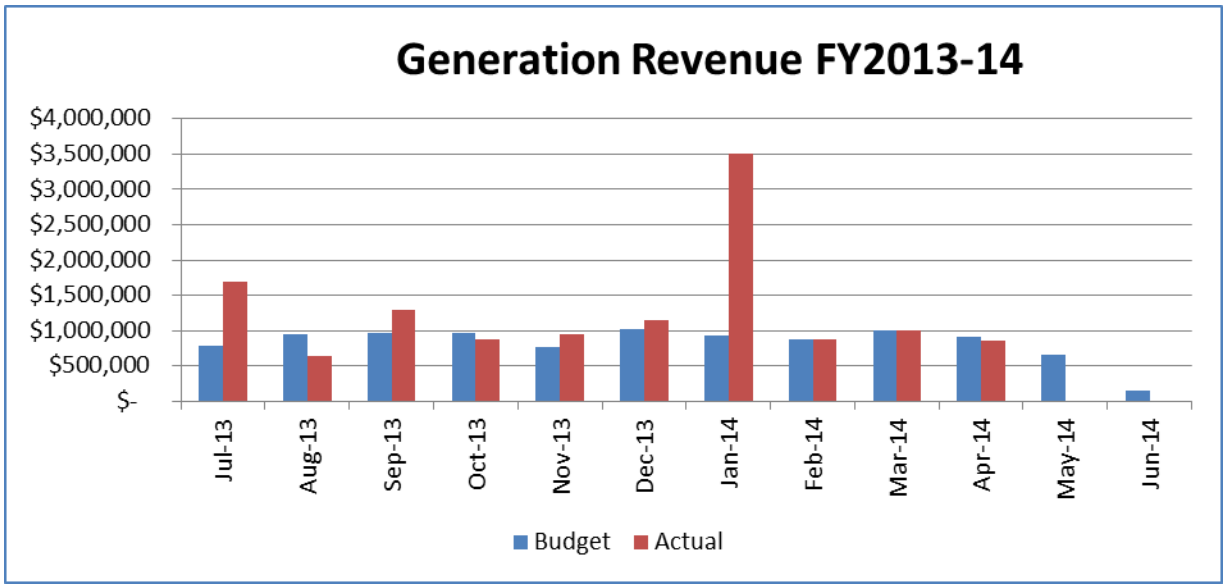
Supply Source Summary:



Supply Variance:

	Budget	Actual	Variance
Gross Load	53,377	52,517	860
Wholesale Load	51,277	50,518	759
Hedged Volume (MWh)	26,720	41,280	(14,560)
Unhedged Volume (MWh)	24,557	9,238	15,319
Dover SunPark Volume (MWh)	2,100	1,999	101
Renewable Energy Credits Volume	315	202	113
Hedged Cost ($/MWh)	$ 55.67	$ 47.91	$ 8
Unhedged Energy Cost ($/MWh)	$ 38.93	$ 6.10	$ 33
Solar Energy Cost ($/MWh)	$ 87	$ 102	$ (15)
Energy Costs ($/MWh)	**$49.20**	**$42.63**	**$6.57**
All-in Costs - Energy, Capacity and RECs ($/MWh)	**$83.79**	**$80.06**	**$3.73**

B. Generation Summary:



Dover generated 1032 MWh in the month. Net generation revenue was $865,107 vs. a budget of $909,320.

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Generation Breakdown:

City of Dover

Monthly Wholesale Generation

April 2014

Net Generation
1031.91

All In Generation

PJM - Generation			
	Economic and Reliability Dispatch	$	61,669.61
	Generation Capacity Credit	$	1,286,250.00
	Black Start and Transmission Losses	$	45,238.81
Natural Gas & Oil Consumption			
	Purchases for Generation	$	(67,156.02)
	Natural Gas Transport	$	(9,230.25)
	Eastern Shore Cashout	$	4,053.10
	Oil Consumption	$	-

Production Margin

PJM - Generation			
	Economic and Reliability Dispatch	$	61,669.61
Natural Gas & Oil Consumption			
	Purchases for Generation	$	(67,156.02)
	Natural Gas Transport	$	(9,230.25)
	Eastern Shore Cashout	$	4,053.10
	Oil Consumption	$	-
Gross Production Margin		$	(10,663.56)
$/MWh Generation Production Gross Margin		$	(10.33)

C. Emissions Summary:

Emissions Allowance Summary through April 30, 2014

McKee Run3 did operate during the month of April for testing, so there were additional emissions during this period.

CAIR EMISSION ALLOWANCE SUMMARY				
Date	**Action**	**SO_2 Allowances**	**NO_x Allowances[1]**	
			Seasonal	**Annual**
1/1/09	2008 Carryover	3,240	0	0
1/1/09	2009 Allocation	2,723	53	80
2/1/10	2010 Allocation	2,039	50	78
1/1/11	2011 Allocation	1,988	49	78
4/1/11	2011 Reallocation		2	4
1/11/12	2012 Allocation	1,988	51	80
10/4/2012	2013 Allocation	1,988	49	76
	2014 Allocation	**1,988**	**49**	**76**
9/29/09	SO_2 Sales	(1,500)		
11/12/09	NO_x Ann. Sales			(45)
11/13/09	SO_2 Sales	(1,410)		
11/20/09	NO_x Seas. Sales		(25)	
12/31/09	2009 Emissions[2]	(1)	(6)	(13)
12/31/10	2010 Emissions	0	(54)	(54)
10/31/10	EPA Linearity Testing Req.		(68)	(68)
2011	2010 Deficit NO_x Purchases		53	22
Aug 2011	Revised 2010 ECMPS data		30	30
Nov 2011	NO_x Seas. Sales (DEMEC)		(1)	
12/31/11	2011 Emissions[2]	(1)	(32)	(36)
12/31/12	2012 Emissions[2]	(1)	(37)	(37)
Nov 2012	NO_x Seas. Sales (DEMEC)		(2)	
2/13/2013	NO_x Annual. Sales (DEMEC)			(3)
11/15/13	NO_x Annual Sales (DEMEC)		(5)	
12/31/13	C.Y.T.D. 2013 Emissions	(0)	(20)	(20)
4/30/14	**2014 YTD Emissions**	**(1)**	**0**	**(8)**
REMAINING ALLOWANCES		**13,040**	**99**	**242**

On August 21, 2012, a three-judge panel of the U.S. District Court of Appeals (DCA) in Washington vacated EPA's Cross State Air Pollution Rule (CSAPR) which would have become effective on January 1, 2012. The DCA instructed EPA to continue

[1] Per CAIR, starting in 2009, NOx emissions are governed by a seasonal and annual program.
[2] Under CAIR, pre-CAIR SO2 allowances are retired at a rate of 2 allowances for each ton emitted. It is assumed that pre-CAIR allowances will be retired before CAIR allowances.

administering the Clean Air Interstate Rule (CAIR). EPA appealed the DCA ruling to the U.S. Supreme Court, which heard arguments on December 10th, 2013.

On April 29th, 2014, the U.S. Supreme Court overturned the DCA opinion; however it did not immediately reinstate CSAPR. It sent the rule back to the DCA for further action consistent with the Supreme Court's opinion. EPA will continue to administer CAIR until the DCA takes action and EPA is able to respond.

Market liquidity for CAIR allowances continues to be low, with few transactions occurring. The following table shows estimated values for Dover's banked allowances, based on settlement prices on the Intercontinental Exchange (ICE).

Mark-to-Market for CAIR Allowances (May/16/2014)			
Commodity	**$/Ton (Bid/Offer Avg.)**	**Tons**	**Extended Value**
SO_2 Allowances (2009 & earlier)	$ 1.35	5,089	$ 6,870
SO_2 Allowances (2010-13)	$ 0.85	7,951	6,758
NO_x Allowances - Seasonal	$23.00	99	2,277
NO_x Allowances - Annual	$53.00	242	12,826
TOTAL			**$28,731**

Regional Greenhouse Gas Initiative

The State of Delaware is a participant in the Regional Greenhouse Gas Initiative (RGGI). The City of Dover must comply with RGGI by surrendering carbon dioxide (CO_2) allowances pursuant to the State of Delaware's laws (Title 7, Chapter 60, Sub-Title II-A). Delaware has elected a combined emissions allowance allocation/auction mechanism for RGGI, in which 40% of CO_2 allowances were allocated to sources for 2009, declining by 8% per year so that by 2014, all CO_2 allowances are auctioned.

Dover had more than a sufficient number of RGGI allowances allocated to it to cover its requirements through the first compliance period (calendar years 2009-2011). Any unused allowances are carried over ("banked") for subsequent years. The table below shows RGGI allowance allocations, deductions and the cumulative balance by year (column 8).

CO2 Allowance Summary (2/28/2014)							
1	2	3	4	5	6	7	8
CO_2 Allowance Vintage	CO_2 Allowances Sold YTD	CO_2 Allowances (Per Facility, Prior to Sale)		Allocated CO_2 Allowances	CO_2 Tons Emitted	Annual CO_2 Allowance Balance	Cumulative Balance
		McKee Run	***VanSant***				
2009	0	60,128	2,056	62,184	(5,796)	56,388	56,388
2010	0	48,102	1,645	49,747	(32,971)	16,776	73,164
2011	0	36,077	1,234	37,311	(17,763)	19,548	92,712
2012	0	27,058	925	27,983	(15,265)	11,793	104,505
2013	0	15,032	514	24,818[3]	(10,231)	16,091	**119,091**
2014	0	-0-	-0-	-0-	(5,344)		**113,748**

Dover no longer receives allocations of RGGI allowances. The Cumulative Balance (column 8) – aka "Banked Allowances") can be utilized for generation in 2014 and future years. Once the banked allowances have been fully utilized, Dover will be required to purchase RGGI allowances through the auctions or through over-the-counter markets. Assuming that Dover does not sell any banked allowances, it will be able to maintain a positive balance through 2016–2025, depending on actual annual energy production in 2012 and beyond.

On February 7, 2013, RGGI proposed changes to its Model Rule. The Delaware Department of Natural Resources published the final rule on December 1, 2013 the Delaware Register of Regulations with an effective date of December 11, 2013[4]. The new RGGI rule includes a provision which eliminates some portion of banked allowances in future years.

Dover could elect to sell all or a portion of its banked allowances now and re-acquire allowances at a later date; however TEA is currently of the opinion that Dover will be better off retaining its banked allowances for use during future compliance years.

The most recent RGGI auction occurred on March 5th, 2014; the auction cleared at $4.00/ton. The next auction will occur on June 4th, 2014. RGGI futures settlement prices posted on Intercontinental Exchange (ICE) on May 16th, 2014 ranged from $4.45 to $4.70/ton, depending settlement month and vintage. **Based on the May 16th, 2014**

[3] Includes Q3 2013 allocations of 7,846,757 for McKee Run and 1,424,677 for VanSant.
[4] http://regulations.delaware.gov/register/december2013/final/17%20DE%20Reg%20644%2012-01-13.pdf

ICE for June, 2014, Vintage 2013 ($4.47/ton), the value of Dover's existing 114,634 ton RGGI allowance bank is $512,414.

Renewable Energy Certificates

Dover owns two photovoltaic systems totaling 15 kW, consisting of (one 5 kW unit at the Utilities Administration Building and two 5 kW units at the McKee Run generating station. Dover also receives solar energy produced by the 10 MW Dover Sun Park which is owned by White Oak Solar Energy, LLC. In addition to the all of the physical energy produced by the Sun Park, Dover receives 15% of Sun Park's SRECS. Through the end of February 2014, Dover has accumulated a total of 7,004 SRECS from these renewable energy resources.

The nearest viable market for Dover's SRECs is Pennsylvania. Pennsylvania's April 15, 2014 SREC auction cleared separately for 2012/2013 through 2013/2014 vintage allowances. Clearing prices and Dover's SREC market value estimate are shown in the table below.

SREC Vintage (June 1 – May 31)	Auction Clearing Price	SREC Quantity	Market Value
2010/2011	$ 4.01 (Aug-13 Auction)	13	$ 52
2011/2012	$ 40.01 (Jan 2014 Auction)	2,375	95,024
2012/2013	$40.00 (April 2014 Auction)	2,725	109,000
2013/2014	$51.00 (April 2014 Auction)	2,095	106,845
TOTAL		**7,208**	**$310,921**

TEA continues to recommend to Dover to retain these allowances for compliance with its Renewable Portfolio Standard which DEMEC is working on. Once Dover has an approved RPS in place, it may be required to retire a portion of its current SREC balance for compliance in the 2012/13 future compliance year. Any remaining SRECs could be used for the 2013/14 compliance year.

NOTE: SRECs in both Delaware and Pennsylvania expire without value after 3 years. Dover currently has thirteen (13) 2010/2011. Based on a recent discussion with DEMEC staff, this expiration provision is not likely to be of concern within the current compliance year.

If Dover has not accumulated adequate non-solar RECs, it will need to acquire some from DEMEC for the 2013/2014 compliance year. DEMEC has told TEA that it will likely have sufficient non-solar RECs for Dover's requirements. Dover can purchase and retire a portion of these non-solar RECs during the current compliance and fiscal years,

or it can defer acquisition until the June – August, 2014 time frame, after the exact amount of non-solar REC requirements is known.

D. Operations Management Summary:

During the month of April, there were no restricted work days or lost time accidents. The facility has now gone 3 years and 196 days (1,291 days) through April, 2014 without an OSHA Recordable Accident or a Lost Time reportable accident. There were no Near Miss incidents during the month.

The plant received no Notice of Violations (NOVs) during the month. The April (March Discharge) DMR was submitted for the McKee Run site with no NPDES exceedences. There were no opacity deviations during the month.

During the month of April, there was one IWW discharge to the Kent County Sewer. Sampling occurred on 4/21/2014 and laboratory analytical data is expected the week of May 16, 2014.The March SIU Report was submitted to Kent County. The DNREC SLEIS (Air Emission Inventory Report) was submitted on April 30, 2014. Plant-wide hearing and respiratory testing was completed. Four individuals attended the annual DOT/RCRA refresher course on April 17, 2014.

E. Risk Management Summary:

Forward power prices in PJM are higher than last month, especially later in the hedging time horizon.

The current projected cost of service is below:

PY	Hedge Ratio	Blended Cost ($/MWh)	Monthly Change ($/MWh)
2013-14	79%	$ 51.17	$ (0.81)
2014-15	70%	$ 46.58	$ (0.39)
2015-16	55%	$ 43.92	$ 0.38
2016-17	18%	$ 43.56	$ 0.93
2017-18	10%	$ 45.37	$ 1.39

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II. Budget Report

Variance Report:

	Budget Apr-14	Actual Apr-14	Variance
Gross Load	**53,377**	**52,517**	**860**
Power Supply			
Hedged Energy	$1,487,372	$1,977,556	($490,184)
PJM - Energy, Congestion & Losses	$955,908	$56,383	$899,525
PJM - ARR, Transmission and Fees	$395,000	$536,999	($141,999)
Dover SUN Park Energy	$182,770	$204,781	($22,011)
Dover SUN Park RECs	$25,000	$28,882	($3,882)
Management Fees	$83,000	$83,000	$0
PJM - Capacity UCAP Obligated Purchased	$1,343,442	$ 1,316,904.00	$26,538
Subtotal - Power Supply	**$4,472,492**	**$4,204,505**	**$267,987**
Power Generation O&M			
Plant O&M	$407,510	$455,718	(48,208.00)
Subtotal Generation O&M	**$407,510**	**$455,718**	**($48,208)**
Power Generation Production Margin			
PJM - Economic and reliability dispatch	$0	($61,670)	$61,670
Fixed Fuel and Transport Charges	$0	$72,333	($72,333)
Subtotal Generation Production Margin	**$0**	**$10,664**	**($10,664)**
Power Generation Non-Production Revenue			
PJM - Generation Capacity Credit	($1,286,250)	$ (1,286,250.00)	$0
Emissions Allowance Sales	$0	$ -	$0
PJM - Black Start & Transmission Losses	($30,580)	$ (45,238.81)	$14,659
Subtotal - Non-Production Revenue	**($1,316,830)**	**($1,331,489)**	**$14,659**
SubTotal - All Generation	**($909,320)**	**($865,107)**	**($44,213)**
Total - Utilities Cost	**$3,563,172**	**$3,339,398**	**$223,774**
Unit Costs			
Total - Power Supply	$83.79	$80.06	$3.73
Total - Power Generation	($17.04)	($16.47)	($0.56)
Final Cost of Service to City of Dover Ratepayers	$66.75	$63.59	$3.17

Variance Analysis:

Power Supply

- Dover consumed 860 MWh less than forecast for the month.
- PJM energy costs were lower than expected as below budget market prices occurred during the month. Hedged costs were higher than forecasted due to an additional layering in of hedges. PJM Fees were higher than budget.
- Hedges were placed at below budget levels and lower market prices offset the higher fees. This resulted in a net power supply cost of $80.06/MWh, $3.73/MWh below budget.
- For the month, the city realized a favorable variance of $267,987 for power supply vs. the monthly budget.
- Dover Sun Park generated 101 MWh less than forecast.

Generation

- Power generation had an unfavorable budget variance of $44,213.
- Plant O&M expenses had an unfavorable budget variance of $48,208 for the month.

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YTD Variance Report:

	Budget YTD	Actual YTD	Variance
Gross Load	**616,999**	**638,850**	**(21,851)**
Power Supply			
Hedged Energy	$20,907,344	$24,506,047	($3,598,703)
PJM - Energy, Congestion & Losses	$10,083,536	$14,251,611	($4,168,075)
PJM - ARR, Transmission and Fees	$3,950,000	$6,676,599	($2,726,599)
Dover SUN Park Energy	$1,195,473	$1,380,541	($185,068)
Dover SUN Park RECs	$250,000	$295,076	($45,076)
Management Fees	$830,000	$830,000	$0
PJM - Capacity UCAP Obligated Purchased	$13,613,549	$13,361,950	$251,599
Subtotal - Power Supply	**$50,829,902**	**$61,301,825**	**($10,471,922)**
Power Generation O&M			
Plant O&M	$4,418,905	$4,451,516	($32,611)
Subtotal Generation O&M	**$4,418,905**	**$4,451,516**	**($32,611)**
Power Generation Production Margin			
PJM - Economic and reliability dispatch	($230,472)	($5,432,915)	$5,202,443
Fixed Fuel and Transport Charges	$0	$2,199,196	($2,199,196)
Subtotal Generation Production Margin	**($230,472)**	**($3,233,718)**	**$3,003,247**
Power Generation Non-Production Revenue			
PJM - Generation Capacity Credit	($13,034,000)	($13,034,000)	$0
Emissions Allowance Sales	$0	$0	$0
PJM - Black Start & Transmission Losses	($335,800)	($1,062,510)	$726,710
Subtotal - Non-Production Revenue	**($13,369,800)**	**($14,096,510)**	**$726,710**
SubTotal - All Generation	**($9,181,367)**	**($12,878,713)**	**$3,697,346**
Total - Utilities Cost	**$41,648,536**	**$48,423,112**	**($6,774,576)**
Unit Costs			
Total - Power Supply	$82.38	$95.96	($13.57)
Total - Power Generation	($14.88)	($20.16)	$5.28
Final Cost of Service to City of Dover Ratepayers	$67.50	$75.80	($8.30)

III. Operations Management

NAES Corporation
Dover, Delaware
April 2014
Monthly Report



Unit 3 Turbine Undergoing Overhaul in Spring 2014

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1.0 Environmental, Health and Safety:

During the month of April, there were no restricted work days or lost time accidents. The facility has now gone 3 years and 196 days (1,291 days) through April, 2014 without an OSHA Recordable Accident or a Lost Time reportable accident. There were no Near Miss incidents during the month.

The plant received no Notice of Violations (NOVs) during the month. The April (March Discharge) DMR was submitted for the McKee Run site with no NPDES exceedences. There were no opacity deviations during the month.

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Environmental, Health, and Safety Statistics		
	Month (April)	Fiscal Year to Date (7/1/13-6/30/14)
NOVs	0	0
Opacity Deviations	0	11
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	2
Man Hours Worked	4,926.50	43,743.00
Date last OSHA Recordable		10/14/10
Date last Lost Time Accident		10/14/10
Days since last OSHA recordable		1,291
Days since last Lost Time Accident		1,291

Emissions (NO_x, CO_2 & SO_2) All data thru 4/30/14

NOx Summary – Ozone Season (May-Sep) Tons					
Year	*Unit #1*	*Unit #2*	*Unit #3*	*Unit #11*	*TOTAL*
2011	1.8	1.5	31.4	1.4	36.1
2012	1.2	1.0	35.8	1.0	33.1
2013	1.1	1.7	19.3	1.3	23.4
2014	0.0	0.0	0.0	0.0	0.0
NOx Summary - Year (Jan-Dec) Tons					
Year	*Unit #1*	*Unit #2*	*Unit #3*	*Unit #11*	*TOTAL*
2011	1.8	1.5	32.6	2.9	38.8
2012	1.2	1.1	35.8	1.0	36.9
2013	1.1	1.7	19.4	1.3	23.5
2014	0.5	0.5	4.8	2.9	8.7
SO_2 Summary - Year (Jan-Dec) Tons					
Year	*Unit #1*	*Unit #2*	*Unit #3*	*Unit #11*	*TOTAL*
2011	0.0	0.0	0.1	0.5	0.6
2012	0.0	0.0	0.0	0.1	0.1
2013	0.0	0.0	0.0	0.2	0.2
2014	0.0	0.0	0.4	0.6	1.1

CO2 Allowances Summary					
CO2 Allowance Vintage	**CO2 Allowances Sold YTD**	**CO2 Allowances Available (Per Facility, Prior to Sale)**		**Total CO2 Tons Emitted**	**CO2 Allowance Balance**
		McKee Run	***VanSant***		
2009	0	60,128	2,056	5,796	56,388
2010	0	48,102	1,645	32,971	16,776
2011	0	36,077	1,234	17,763	19,548
2012	0	27,058	925	15,265	11,793
2013	0	22,879#	1,939#	10,231	14,587
2014	0	0	0	5,344	(5,344)
			Total CO2 Allowance Balance		**113,748**

***Note: CO2 allowance values are provided by the RGGI CO2 Allowance Tracking System.**
Note: All emissions (NOx, SO2 and CO2) totals for 2013 are unofficial.
#Note: Additional CO2 Emission Values were added to 2013 balances by RGGI COATS- 7,846.757 for McKee Run and 1,424.677 for VanSant

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CAIR NOx Allowances Summary*

CAIR NOx Allowance Vintage	CAIR NOx Allowances Sold YTD	NOx Allowances Available (Per Facility, Prior to Sale)		Total NOx Tons Emitted (Yr/ Season) McKee Run - VanSant	CAIR NOx Allowances Purchased YTD	NOx Allowance Balance	
		McKee Run (Yr/Season)	***VanSant (Yr/Season)***			***McKee Run (Yr/Season)***	***VanSant (Yr/Season)***
2010 and earlier	3***					27/0	0/2
2011	0	77/48	5/3	33/31– 3/1	0/0 - 0/0	42/10	2/2
2012	2**	75/46	5/3	36/36 – 1/1	0/0 - 0/0	39/10	2/0
2013	5**	77/48	5/3	19/19 – 1/1	0/0 - 0/0	58/24	4/2
2014	0	71/46	5/3	5/0 - 3/0	0/0 – 0/0	66/46	2/3
				Total NOx Allowance Balance		**232/90**	**10/9**

***Note – Emissions allowances are deducted according to oldest vintage first or unless otherwise directed.**
****Note – The facility transferred Ozone Season allowances to a third party.**

SO_2 Allowances Summary

SO_2 Allowance Vintage	SO_2 Allowances Sold - YTD	SO_2 Allowances Available (Per Unit, Prior to Sale & Reconciliation)		Total SO_2 Tons Emitted – U3 and U11 YTD	SO_2 Allowances Balance
		Unit #3	***Unit #11***		
2010 and earlier	0	4815	276	0	5089
2011	0	1850	138	1	1988*
2012	0	1850	138	1	1988*
2013	0	1850	138	0	1988*
2014	0	1850	138	1	1987
			Total SO2 Allowance Balance		**13,040**

***Note – Emissions allowances are deducted according to oldest vintage first, unless otherwise directed.**

2.0 Financial

Financial – Current Month

Month – April			
	Actual	Budget	Variance
Personnel	243,667	257,110	13,443
Materials & Supplies	17,351	16,610	(741)
Administrative Expenses	194,700	132,690	(62,010)
Total	**$455,718**	**$406,410**	**($49,308)**

Financial – Fiscal Year to Date

Number of Months – 10			
	Actual	Budget	Variance
Personnel	2,469,215	2,707,210	237,995
Materials & Supplies	164,841	196,275	31,434
Administrative Expenses	1,637,495	1,514,800	(122,695)
Total	**$4,271,551**	**$4,418,285**	**$146,734**

2.1 Variance analysis:

The actual expenses for the month of April are $455,718 against a budgeted amount of $406,410 for an unfavorable variance of $49,308 or 12.13%. The variance was due to the following:

PERSONNEL EXPENSES – A favorable monthly variance of $13,443 was due to having a less overtime and corresponding Labor Burdens. Overtime reduction resulted from not filling shifts to full complement where vacancies due to flex time occurred.

MATERIALS AND SUPPLIES EXPENSES- An unfavorable monthly variance of $741 was due to the timing of the water – sewer invoices. There were two (2) months invoiced during the billing period for April.

ADMINISTRATIVE EXPENSES – An unfavorable monthly variance of $62,010 due primarily to the timing of electricity monthly invoices and invoices for operator training that were originally budgeted in May. There were two (2) months of electricity costs invoiced during the billing period for April.

The forecasted expenses for this fiscal year are $5,809,593 expensed versus an approved budget of $6,015,800 thereby realizing a 96.57% expenditure rate.

3.0 Operations

Unit Operations / Outages / Trips; All units have been on spring outage since 0700 hours on March 3, 2014. Unit 3 has been run for testing four (4) times in the month of April to try to balance the turbine generator after repairs had been made to the unit during the overhaul.

Month April 2014							
		McKee Unit 1	McKee Unit 2	McKee Unit 3	MRS Facility	VanSant Unit 11	Total All Units
Capacity	MW	17	17	102	136	39	175
On Line Hours	Hrs	0.0	0.0	24.732	24.732	0.0	24.372
Starts	#	0	0	4	4	0	4
Gross Generation	MWh	0.0	0.0	1,150.878	1,150.878	0.0	1,150.878
Net Generation	MWh	0.0	0.0	1,040.065	1,040.065	0.0	1,040.065
Total Auxiliaries	MWh	0.0	0.0	395.739	395.739	0.0	395.739
Auxiliaries purchased	MWh	22.960	22.960	284.926	330.846	3.185	334.031
Fuel Gas Used	MMBTU	0.0	0.0	14,310.388	14,310.388	0.0	14,310.388
Fuel Oil Used	MMBTU	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Oil Used	Gallons	0.0	0.0	0.0	0.0	0.0	0.0
Total Fuel	MMBTU	0.0	0.0	14,310.388	14,310.388	0.0	14,310.388
Net Heat Rate	BTU/KWh	0.0	0.0	13.759	13.759	0.0	13.759
Unit Trips	#	0.0	0.0	0.0	0.0	0.0	0.0
Capacity Factor	%	0.00	0.00	0.00	0.00	0.00	0.00
Availability Factor	%	0.0	0.0	0.0	0.0	0.0	0.0
Commercial Unavailability (CU)	%	0	0	0	0	0	0
Planned Outage Hours	Hours	720.00	720.00	720.00	2,160.00	720.00	2,880.00
Maintenance Outage Hours	Hours	0.0	0.0	0.0	0.0	0.0	0.0
Forced Outage Hours	Hours	0.0	0.0	0.0	0.0	0.0	0.0
Reserve Shutdown Hours	Hours	0.0	0.0	0.0	0.0	0.0	0.0
HW Boiler Gas Usage	MMBTU				0.0		0.0
Pilot Gas Usage	MMBTU	0.0	0.0		0.0		0.0

 # Note: Does not include HWB or Pilot Gas. Fuel usage numbers are taken from fuel flow instruments.

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2013-2014 Fiscal Year-to-Date - April							
		McKee Unit 1	McKee Unit 2	McKee Unit 3	MRS Facility	VanSant Unit 11	Total All Units
Capacity	MW	17	17	102	136	39	175
On Line Hours	Hrs	135.697	214.032	287.773	637.502	75.655	713.157
Starts	#	7	7	20	34	20	54
Gross Generation	MWh	959.877	1,413.560	17,575.585	19,949.022	2,615.094	22,564.116
Net Generation	MWh	895.980	1,309.804	16,085.387	18,291.171	2,613.006	20,904.177
Total Auxiliaries	MWh	358.547	463.504	3,313.873	4,135.924	40.967	4,176.891
Auxiliaries purchased	MWh	337.273	379.803	1,824.119	2,541.195	38.150	2,579.345
Fuel Gas Used	MMBTU	8,924.901	15,004.575	160,565.972	184,495.448	19,584.819	204,080.267
Fuel Oil Used	MMBTU	5,504.840	4,463.354	36,178.243	46,146.437	15,380.547	61,526.984
Fuel Oil Used	Gallons	38,567	31,228	252,473	322,268	108,053	430,321
Total Fuel	MMBTU	14,429.741	19,467.929	196,744.215	230,641.885	34,965.366	265,607.251
Net Heat Rate	BTU/KWh	15.641	14.141	12.613	14.131	13.198	13.898
Unit Trips	#	1	1	0	2	5	7
Capacity Factor	%	0.72	1.06	2.16	1.84	0.92	1.64
Availability Factor	%	60.84	61.94	61.94	61.57	61.94	61.66
Commercial Unavailability (CU)	%	0.95	0.04	0.01	0.13	0.0	0.10
Planned Outage Hours	Hours	2,777.00	2,777.00	2,777.00	8,331.00	2,777.00	11,108.00
Maintenance Outage Hours	Hours	0.0	0.0	0.0	0.0	0.0	0.0
Forced Outage Hours	Hours	80.000	0.0	0.0	80.000	0.0	80.000
Reserve Shutdown Hours	Hours	4,303.303	4,268.968	4,258.555	12,830.826	4,443.345	17,274.171
HW Boiler Gas Usage	MMBTU				6,203.127		6,203.127
Pilot Gas Usage	MMBTU	2,375.134	4,694.627		7,069.761		7,069.761

Fuel Oil Inventory							
	Monthly Inventory (Start)	Monthly Inventory (End)	Fuel Purchases (Month)	Monthly Inventory (Change)	FY 13-14 Inventory (Start)	Fuel Purchases (YTD)	FY 13-14 Inventory (Change)
McKee Run (#2 Fuel Oil)	461,775	462,656	0	881	454,725	378,003	7,931
VanSant (#2 Fuel Oil)	72,561	72,814	0	253	146,133	35,000	(73,319)

Note: As measured by tank level instruments. Tank levels may change due to oil temperature.

VanSant Lifetime through April 2014			
	Actual Starts	Factored Starts	Fired Hours
VanSant	1350	2,311.25	4,306.00
Since HGP - Dec 2004	257	643.55	922.42

Team Report:

Operations personnel continue to support maintenance by working on Preventative Maintenance (PM) work orders and other work orders that they have the necessary skills to successfully complete the task. The Operations Department continues to utilize the Day Shift Worker in both the Operations and Maintenance areas to help in maintaining the plant. In addition, the Operations staff continues to support maintenance activities during the planned outage by serving as Confined Space Attendants for confined space areas as well as other support tasks. The Operations staff has also supported the outage

Capacity Testing – FY 2013-2014

Summer 2013 (June 1- Aug 31)			**Winter 2013-2014 (Dec 1- Feb 28)**		
Unit	Rated Net Capability (MW)	Reported Net Capability (MW)	Unit	Rated Net Capability (MW)	Reported Net Capability (MW)
1	17	17.2	1	17	17.5
2	17	17.8	2	17	18.2
3	102	103.0	3	102	104.4
11	39	40.9#	11	39	44.05#
Total	175	178.9	Total	175	184.1

Note: * Denotes Unit is qualified for the PJM Winter Demonstration Period Exemption Program and data has been submitted into the PJM eGADS
Note: # Depicts Net Corrected Capacity for Ambient Air Conditions – VanSant Unit only

by performing various LOTO tasks needed to test or place equipment in or out or service.

4.0 Maintenance

During the month of April, the Plant Maintenance staff continued addressing the backlog of work orders. There were forty-six work orders issued with eighty-three work orders being completed during the month. No zero safety work orders were entered into the plant's Computerized Maintenance Management System (MP2) during the month. The table below summarizes the monthly work order activities.

Work Order Report

April - 2014

Priority #	Outstanding From Previous Month	Issued This Month	Completed This Month	Outstanding at the end of the month
1	17	3	3	17
2	74	8	23	59
3	40	3	5	38
4	5	0	0	5
5	15	0	1	14
SW1	0	0	0	0
SW2	0	0	0	0
SW3	0	0	0	0
SW4	0	0	0	0
SW5	0	0	0	0
PM	100	32	51	81
EM	0	0	0	0
Totals	251	46	83	214

Note: PM Work Orders are included in the priority totals

Notable activities during the month include:

NAES Maintenance Staff completed the removal and replacement of the Units 1 and 2 boiler drain piping. The piping was replaced due to damage as a result of the lines freezing and cracking during a extreme cold spell this past winter.

During the month, the turbine contractor completed the reassembly of the Unit 3 turbine. With the reassembly complete, a third party vibration monitoring vendor was contracted to perform vibration testing and balancing analysis. During the operation of the unit, it was determined that a shaft sealing steam packing rub was occurring which was part of the cause of the unit experience higher than normal vibration on the number three and two bearings. The turbine contractor team and NAES Maintenance staff removed the IP and LP hood to access the packing. The necessary repairs and adjustments were made to the packing and packing boxes and the equipment reassembled in preparation for further testing.

NAES IC&E Staff removed and replaced two charts recorders on Unit 3. The chart recorders were obsolete and replacement parts were no longer available for them. New digital recorders were installed and were tested for proper operation on all points.

5.0 Capital Improvement Projects (CIP)

Project Number	Description	Update
EG1402	Unit #3 Cooling Tower Repairs	Progress: Cooling Tower decking is 100% complete. Inspection was conducted in March as a precursor for CIP work scope development next FY. Schedule: Inspection work completion and work scope is being modified to reflect deficiencies found during inspection. Bid requests and bid meeting to be set up for April-May time period.
EG1404	McKee Run Auxiliary Component Replacement	Progress: Work planned for the Fall is 100% complete. Schedule: Remaining Fall outage items were completed in December. Spring activities started in March.
EG1405	VanSant Station Component Replacement	Progress: Work planned for the Fall is 100% complete. Schedule: Project activities for this fiscal year have been completed.
EG1406	McKee Run HEP Pipe Repairs	Progress: The recently completed hanger adjustments will need to be checked with the unit in the hot (running) position. Schedule: Final report was received which indicated one area that should be addressed in the near future. Plans are underway to develop work scope to change out the section of pipe scheduled for the fall of 2014
EG1407	Metering System Upgrades	Progress: Work scope is still being developed for an RFP. Schedule: Work activities are moving forward. Working with vendor to finalize RFP documents for release in late May or early June period.
EG1408	McKee Run/VanSant Safety Compliance Items	Progress: Work scopes are being developed for RFP(s) to be put out in June period. Will need to go out for bids once complete. Schedule: Work activities are behind due to Fall Outage activities.
EG1409	McKee Run Natural Gas Block-Bleed Valves	Progress: Work scheduled for the Spring Outage. Schedule: Work activities are back on track for a Spring Outage completion date. Expect to be complete in early May.
EG1413	McKee Run/VanSant Structural Preservation	Progress: Plant staff completed development of paint specifications and bid requests were received. Schedule: Bids were received in early September. Work is on hold due to budget restraints.
EG1212	Unit 3 Turbine Repairs	Progress: Work commenced and is ongoing. Rotor was removed and sent out to shop for 9th stage installation, inspection of the rotor, and

		balancing and has been returned and reinstalled. Testing continues to determine balancing in-place. Schedule: Rotor returned and was reinstalled upon arrival. Testing of unit and balancing is underway.
EG1415	McKee Run Units #1-#2 Component Repairs	Progress: Cost to be incurred due to repairs on Unit 1 Boiler and turbine were completed in November. Schedule: Other scope activities being evaluated due to the announcement to stop operation of Units 1 and 2 in 2016.
EG1416	VanSant Capacity Increase	Progress: Submitted permit application to DNEC in March and currently discussing possible permit limitation. Constructions Bids were returned, evaluated and a recommendation provided to TEA and to the COD. Approval of contractor is expected in early May. Schedule: Construction vendor approval is on slate for early May COD Council Meeting. Continuing to work with DNRC on permit language and limits.

6.0 General Plant Information

On April 4th, 2014, Senior Operator Ricardo Barber celebrated 20 years with the power plant. The plant held a congratulatory lunch in Rick's honor on April 11, 2014.

Training:

Plant employees continue with General Physics safety training and environmental courses to enhance their overall knowledge of permit and safety requirements.

Topics discussed during the monthly safety committee meeting were reviewed by the entire staff. The monthly safety topic was on "Ten Rules to Preserve Ten Fingers".

PJM Simulation training was completed on April 8-9 by a third party vendor. A total of six operators and one Operations supervisor attended from McKee Run plant.

Calendar of Events	Date
EIA-860 Report	TBD
EIA-923 Report	TBD
NPDES Permit Expires (DNREC has Extended)	March 4, 2014 (TBD)
Units 1, 2, and 3 Spring Outage	March 3, 2014 – May 30, 2014
Unit 11 Spring Outage	March 3, 2014 – May 30, 2014
Annual VanSant Black Start Test	April, 2014
Air Emission Inventory	April, 2014
NOx Ozone Season Starts	May 1, 2014
PJM Summer Capacity Test Period	June 1, 2014 – August 31, 2014
FY 2013-2014 Budget Year Ends	June 30, 2014
Toxic Release Inventory (TRI) Annual Report	July 1, 2014
Semi-Annual Title V Certification Due	July 31, 2014
NOx Ozone Season Ends	September 30, 2014
Units 1, 2, 3 and 11 Fall Outage	October 1, 2014
Four Year Accident Free	October 14, 2014
Winter Capacity Period	December 1, 2014 to February 28, 2015
NOx Emissions Reconciliation Due	March 1, 2015
SO2 Emissions Reconciliation Due	March 1, 2015
SARA III / Tier II Report Due	March 1, 2015

7.0 Summary of NAES Performance to Date

Plant Performance FY 2013-2014						
Measure	**Month**		**Year to Date**		**YTD Incentive**	**FY Maximum Incentive**
Commercial Unavailability (CU)	0.0%		0.10%		$91,087	$94,882
Safety	0		0		$17,790	$17,790
Environmental	0		0		$17,790	$17,790
Capacity Tests Completed	Summer	Winter	Summer	Winter		
Unit 1	No	No	Yes	Yes	$3,559	$3,559
Unit 2	No	No	Yes	Yes	$3,559	$3,559
Unit 3	No	No	Yes	Yes	$21,349	$21,349
Unit 11	No	No	Yes	Yes	$7,117	$7,117
Total YTD Incentive %	97.71%		***Total YTD Incentive***		$162,249	$166,045

Note: All units successfully completed the Summer and Winter Capacity (FY 2013-2104) Testing for PJM.

IV. Appendix 1 – PJM Invoice Breakdown

		Gen	Load	Grand Total
⊟480-8102-592-95-49	Capacity Resource Deficiency		($2,826.00)	($2,826.00)
	Capacity Transfer Rights		($18,612.90)	($18,612.90)
	Incremental Capacity Transfer Rights		($1,632.90)	($1,632.90)
	Locational Reliability		$1,339,975.80	$1,339,975.80
480-8102-592-95-49 Total			**$ 1,316,904.00**	**$ 1,316,904.00**
⊟480-8102-592-95-50	RPM Auction	($1,286,250.00)		($1,286,250.00)
480-8102-592-95-50 Total		**$ (1,286,250.00)**		**$ (1,286,250.00)**
⊟480-8102-592-95-90	Auction Revenue Rights		($25,818.00)	($25,818.00)
	Balancing Operating Reserve		$17,476.26	$17,476.26
	Balancing Operating Reserve for Load Response		($19.19)	($19.19)
	Black Start Service		$1,842.44	$1,842.44
	CT Lost Opportunity Cost Allocation		($16.80)	($16.80)
	Day-Ahead Load Response Charge Allocation		$2,285.96	$2,285.96
	Day-ahead Operating Reserve		$4,805.52	$4,805.52
	Day-ahead Operating Reserve for Load Response		$348.21	$348.21
	Day-ahead Scheduling Reserve		$1.12	$1.12
	Demand Resource and ILR Compliance Penalty		($1,929.60)	($1,929.60)
	Expansion Cost Recovery		$408.30	$408.30
	FERC Annual Recovery		$3,617.97	$3,617.97
	Generation Deactivation Refund		($735.06)	($735.06)
	Load Management Test Failure		($42.90)	($42.90)
	Load Reconciliation for Transmission Losses		$4,310.92	$4,310.92
	Market Monitoring Unit (MMU) Funding		$209.03	$209.03
	Michigan - Ontario Interface Phase Angle Regulators		$176.99	$176.99
	Network Integration Transmission Service		$316,178.40	$316,178.40
	Non-Firm Point-to-Point Transmission Service		($424.66)	($424.66)
	Non-Synchronized Reserve		$592.95	$592.95
	North American Electric Reliability Corporation (NERC)		$551.47	$551.47
	Organization of PJM States, Inc. (OPSI) Funding		$36.06	$36.06
	PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center		$1,365.13	$1,365.13
	PJM Scheduling, System Control and Dispatch Service - Capacity Resource/Obligation Mgmt.		$913.50	$913.50
	PJM Scheduling, System Control and Dispatch Service - Control Area Administration		$8,720.25	$8,720.25
	PJM Scheduling, System Control and Dispatch Service - Market Support		$2,037.93	$2,037.93
	PJM Scheduling, System Control and Dispatch Service - Market Support Offset		($162.03)	($162.03)
	PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration		$81.08	$81.08
	PJM Scheduling, System Control and Dispatch Service Refund - Capacity Resource/Obligation Mgmt.		($28.50)	($28.50)
	PJM Scheduling, System Control and Dispatch Service Refund - Control Area Administration		($345.43)	($345.43)
	PJM Scheduling, System Control and Dispatch Service Refund - Market Support		($83.62)	($83.62)
	PJM Scheduling, System Control and Dispatch Service Refund - Regulation Market Administration		($3.36)	($3.36)
	PJM Settlement, Inc.		$162.03	$162.03
	Reactive Services		$116,654.91	$116,654.91
	Reactive Supply and Voltage Control from Generation and Other Sources Service		$35,523.17	$35,523.17
	Real-Time Load Response Charge Allocation		$1,616.63	$1,616.63
	Regulation and Frequency Response Service		$15,527.91	$15,527.91
	Reliability First Corporation (RFC)		$783.36	$783.36
	Synchronized Reserve		$16,579.15	$16,579.15
	Transmission Enhancement		$9,972.34	$9,972.34
	Transmission Owner Scheduling, System Control and Dispatch Service		$3,829.29	$3,829.29
480-8102-592-95-90 Total			**$ 536,999.13**	**$ 536,999.13**
⊟480-8102-592-95-91	Balancing Spot Market Energy		($132,651.22)	($132,651.22)
	Balancing Transmission Congestion		($5,916.77)	($5,916.77)
	Balancing Transmission Losses		($3,270.53)	($3,270.53)
	Day-ahead Spot Market Energy		$549,022.30	$549,022.30
	Day-ahead Transmission Congestion		$33,549.02	$33,549.02
	Day-ahead Transmission Losses		$70,867.42	$70,867.42
	Emergency Load Response		$49.58	$49.58
	Inadvertent Interchange		($101.37)	($101.37)
	Load Reconciliation for Balancing Operating Reserve		($1,163.95)	($1,163.95)
	Load Reconciliation for Day-ahead Scheduling Reserve		($53.76)	($53.76)
	Load Reconciliation for FERC Annual Recovery		($414.60)	($414.60)
	Load Reconciliation for Inadvertent Interchange		$219.57	$219.57
	Load Reconciliation for Market Monitoring Unit (MMU) Funding		($25.02)	($25.02)
	Load Reconciliation for Non-Synchronized Reserve		($65.77)	($65.77)
	Load Reconciliation for North American Electric Reliability Corporation (NERC)		($66.73)	($66.73)
	Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding		($4.50)	($4.50)
	Load Reconciliation for PJM Scheduling, System Control and Dispatch Service		($1,339.46)	($1,339.46)
	Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Refund		$98.66	$98.66
	Load Reconciliation for Reactive Services		($8,931.33)	($8,931.33)
	Load Reconciliation for Regulation and Frequency Response Service		($2,385.81)	($2,385.81)
	Load Reconciliation for Reliability First Corporation (RFC)		($95.17)	($95.17)
	Load Reconciliation for Schedule 9-6 - Advanced Second Control Center		($180.31)	($180.31)
	Load Reconciliation for Spot Market Energy		($386,460.60)	($386,460.60)
	Load Reconciliation for Synchronized Reserve		($1,580.00)	($1,580.00)
	Load Reconciliation for Synchronous Condensing		($0.03)	($0.03)
	Load Reconciliation for Transmission Congestion		($27,963.55)	($27,963.55)
	Load Reconciliation for Transmission Losses		($20,200.02)	($20,200.02)
	Load Reconciliation for Transmission Owner Scheduling, System Control and Dispatch Service		($481.95)	($481.95)
	Meter Error Correction		($4,071.28)	($4,071.28)
480-8102-592-95-91 Total			**$ 56,382.82**	**$ 56,382.82**
⊟480-8102-592-95-92	Balancing Spot Market Energy	($60,123.63)		($60,123.63)
	Balancing Transmission Congestion	($92.58)		($92.58)
	Balancing Transmission Losses	($1,453.40)		($1,453.40)
480-8102-592-95-92 Total		**-61669.61**		**-61669.61**
⊟480-8102-592-95-93	Reactive Supply and Voltage Control from Generation and Other Sources Service	($29,467.58)		($29,467.58)
	Transmission Losses	($15,771.23)		($15,771.23)
480-8102-592-95-93 Total		**$ (45,238.81)**		**$ (45,238.81)**
Grand Total		**$ (1,393,158.42)**	**$ 1,910,285.95**	**$517,127.53**

City of Dover
Electric Revenue Fund
FY14 - White Oak Solar Park Incremental Cost

	July	August	September	October	November	December	January	February	March	April	YTD	Original Budget
Power Supply & Generation												
Dover Sun Park - Energy	$ 187,421	$ 176,372	$ 204,852	$ 120,839	$ 99,447	$ 64,684	$ 82,605	$ 101,681	$ 137,856	$ 204,781	$ 1,380,539	$ 1,565,800
Dover Sun Park - REC's	43,005	38,516	42,894	25,307	20,875	13,583	17,301	21,304	28,882		251,667	300,000
Total Power Supply Cost	230,426	214,888	247,746	146,146	120,322	78,267	99,906	122,985	166,738	204,781	1,632,206	1,865,800
Non-Solar Power Supply Cost	(180,227)	(154,545)	(154,590)	(100,770)	(79,066)	(52,006)	(146,406)	(90,909)	(105,944)	(158,303)	(1,222,765)	(1,186,411)
Incremental Energy Cost	$ 50,199	$ 60,343	$ 93,156	$ 45,376	$ 41,256	$ 26,261	$ (46,500)	$ 32,077	$ 60,794	$ 46,478	$ 409,441	$ 679,389
Revenues												
Customer Sales - Electricity	(9,404)	(7,389)	(7,538)	(7,662)	(7,721)	(8,019)	(8,071)	(7,950)	(7,648)	(7,632)	(79,034)	(26,300)
Rent Receipts	(14,446)	-	-	(14,446)	-	-	(14,807)	-	(34,450)	-	(78,149)	(58,300)
Total Revenues	(23,850)	(7,389)	(7,538)	(22,108)	(7,721)	(8,019)	(22,878)	(7,950)	(42,098)	(7,632)	(157,183)	(84,600)
Incremental Sun Park Cost	$ 26,349	$ 52,954	$ 85,618	$ 23,268	$ 33,535	$ 18,242	$ (69,378)	$ 24,127	$ 18,696	$ 38,846	$ 252,258	$ 594,789
MWh Purchased/Generated - Solar	2,052.584	1,815.656	2,000.128	1,179.844	970.972	631.556	806.536	992.788	1,345.984	1,999.428	13,795.476	18,159.000
MWh $ Solar Energy	$ 91.31	$ 97.14	$ 102.42	$ 102.42	$ 102.42	$ 102.42	$ 102.42	$ 102.42	$ 102.42	$ 102.42	$ 100.07	$ 86.23
Solar REC's MWh	307.000	272.000	300.000	177.000	146.000	95.000	121.000	149.000	202.000	-	1,769.000	
MWh $ Solar REC (one month lag)*	$ 140.08	$ 141.60	142.98	142.98	142.98	142.98	142.98	142.98	142.98	$ -	$ 142.27	
MWh $ Non-Solar Energy	$ 87.81	$ 85.12	$ 77.29	$ 85.41	$ 81.43	$ 82.35	$ 181.52	$ 91.57	$ 78.71	$ 79.17		

Note: Solar REC's are one month behind due to the time the invoice is received.