UTILITY COMMITTEE
A G E N D A

APRIL 14, 2014 - 5:00 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. **Proposed Amendments to the Retail Customer Demand Response Program**
   (Staff recommends revising the second paragraph of the Retail Customer Demand Response to include energy efficiency)

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

3. **Garrison Oak Technical Park Project Updates**
   - **A. City Infrastructure**
     (Committee action not required)
   - **B. Calpine Energy Center**
     (Committee action not required)
   - **C. Dover Sun Park**
     (Committee action not required)

4. **Adjournment by 5:25 p.m.**

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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.

ACTION FORM

PROCEEDING: Utility Committee
DEPARTMENT OF ORIGIN: City Manager's Office **DATE SUBMITTED**: April 8, 2014
PREPARED BY: Scott D. Koenig, P.E., City Manager
SUBJECT: Proposed Amendment to the Demand Response Program
REFERENCE: N/A
RELATED PROJECT: N/A
REVIEWED BY: Scott D. Koenig, P.E., City Manager
EXHIBITS: Exhibit A – Page 31 of the City of Dover Electric Rates & Tariffs
EXPENDITURE REQUIRED: N/A **AMOUNT BUDGETED**: N/A **FUNDING SOURCE (Dept./Page in CIP & Budget)**: N/A
TIME TIMETABLE: Implement tariff change upon final approval of City Council.
RECOMMENDED ACTION: Revise the 2nd paragraph of the Retail Customer Demand Response to include energy efficiency.

BACKGROUND AND ANALYSIS

The City of Dover partners with DEMEC to manage our Demand Response Program (DRP). DEMEC functions as our Authorized Designee per our approved tariff. Recently, DEMEC has asked for the City to clarify whether or not Energy Efficiency is included in the Demand Response Program. This inquiry was forwarded to Kirk Betts, Betts & Holt, LLP to review since Mr. Betts functions as the City's power supply attorney. Mr. Betts has replied as follows:

"The *intent* of the provision was to include PJM's Demand (Load) Response programs subject to Dover or its authorized designee having oversight of the participant and its performance. At the time this rule was drawn, I believe Dover focused on capacity and ancillary services markets, not the more passive Energy Efficiency program. Demand reduction was important since Dover needed to plan its capacity purchases and wanted to take into account these resources in its planning.

"It would be reasonable to include Energy Efficiency under the same terms as the highlighted paragraph. I recommend a short amendment to include "Energy Efficiency" in the highlighted paragraph where the programs are listed, notwithstanding that most of those are ancillary services.

"I believe including it is consistent with the intent of the drafters at the time and presumably now, but it should be documented in the rule. Programmatically, Energy Efficiency is bid into the RPM market for up to 4 years, but there is a requirement to demonstrate the change, which Converge would do. It is good to have this information since it does affect the City's forward energy positions."

Based on Mr. Betts' opinion, staff proposes the 2nd paragraph (highlighted on the exhibit) be amended to read as follows:

"Dover or its authorized designee may allow a Customer to bid DR into PJM's ancillary services market for energy imbalance, energy efficiency, spinning reserves, supplemental reserves, reactive power and voltage control, or regulation and frequency response ancillary services, subject to the same terms and conditions."

RETAIL CUSTOMER DEMAND RESPONSE

AVAILABILITY

The Dover Electric Utility ("Dover") or its authorized designee is the sole entity permitted to bid demand response directly into the PJM Interconnection, L.L.C. ("PJM") ("DR Program") on behalf of retail customers served by Dover. No Customer may participate in a DR program of any other entity unless such program is consistent with the terms and conditions in this tariff and approved in advance by Dover.

Dover or its authorized designee may allow a Customer to bid DR into PJM's ancillary services market for energy imbalance, spinning reserves, supplemental reserves, reactive power and voltage control, or regulation and frequency response ancillary services, subject to the same terms and conditions.

DR programs may reduce electric service costs for the Customer, provide enhanced usage data, reduce emissions from electric generation, and provide demand flexibility.

CONTENTS OF APPLICATION

Customer shall submit to Dover a written request to participate that includes the following: 1) Type of DR program; and 2) Metering requirements for participation. Dover's approval of the application shall be granted within fourteen (14) days.

EFFECT OF APPLICATION AND PARTICIPATION IN DR PROGRAM

Dover's receipt and review of any documentation submitted by a Customer shall not constitute approval of such DR Provider or a guarantee of performance or payment by a DR Provider, nor shall Dover be liable for ANY damages sustained by the Customer.

RIGHT TO TERMINATE PARTICIPATION IN DR PROGRAM

Dover reserves the right to disapprove a request to participate in a DR program or to terminate participation by Customer when, in Dover's sole discretion, Dover determines that participation by Customer will be detrimental to another customer or to the City of Dover.

SPECIAL METERING REQUIREMENTS

If Customer requires special metering equipment or devices to participate in the DR program, Customer shall provide the specifications for such equipment or devices in writing to the Dover Electric Department at the time of application or promptly thereafter. Within fourteen (14) days thereafter, Dover will provide the Customer with an estimate of the cost of the special metering equipment or devices and an estimate of the cost of providing special meter reading data. The cost of any special metering equipment or device shall be the responsibility of the Customer and shall be paid prior to the scheduled installation date. All costs for data or special readings shall be billed to Customer monthly.

Effective Date: February 28, 2011

The Energy Authority, Inc.

Monthly Management Committee Update – February 2014

March 27, 2014

Prepared by:

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Client Services Manager
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rtrinnear@teainc.org

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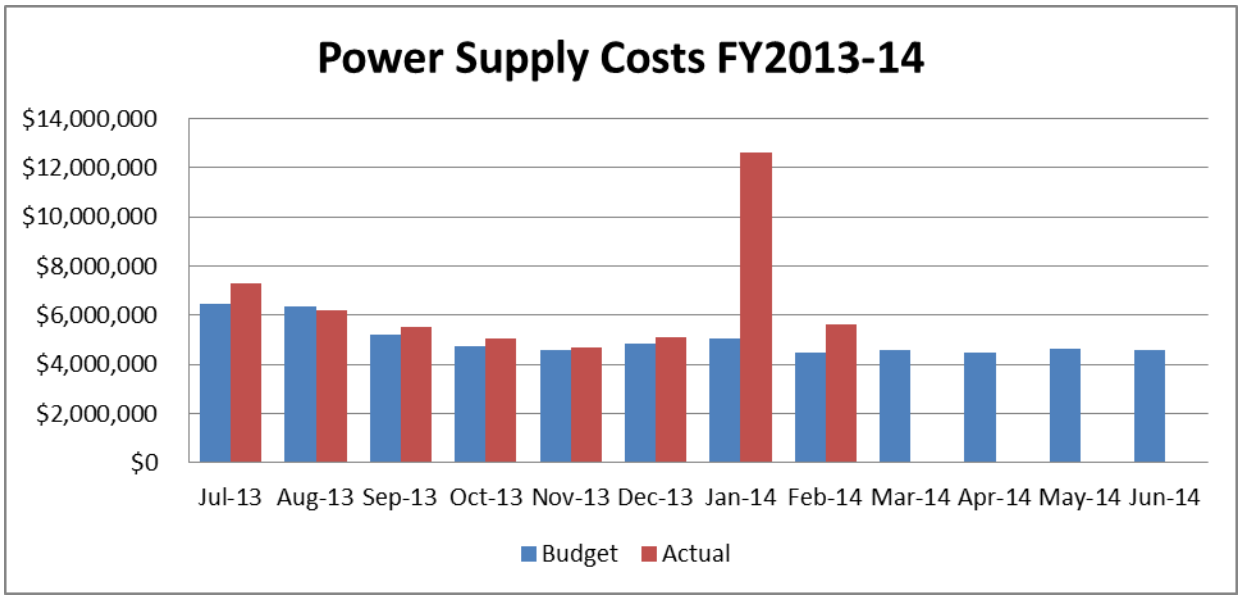
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I. Executive Summary

A. Power Supply Summary:



Overall Power Supply costs were $1,165,513 over budget due to higher load and higher market prices caused by below normal weather temperatures.

Dover's budgeted cost for all power supply (capacity AND energy) was $81.18/MWh. The actual cost of all power supply (capacity AND energy) was $92.09/MWh.

The cost of energy alone was $64.95/MWh, versus a budgeted energy cost of $49.42.

Dover's hedge purchases totaled 41,760 MWh, which was 68% of the actual load. The budgeted hedge purchase totaled 27,840, which was 50% of the budgeted load.

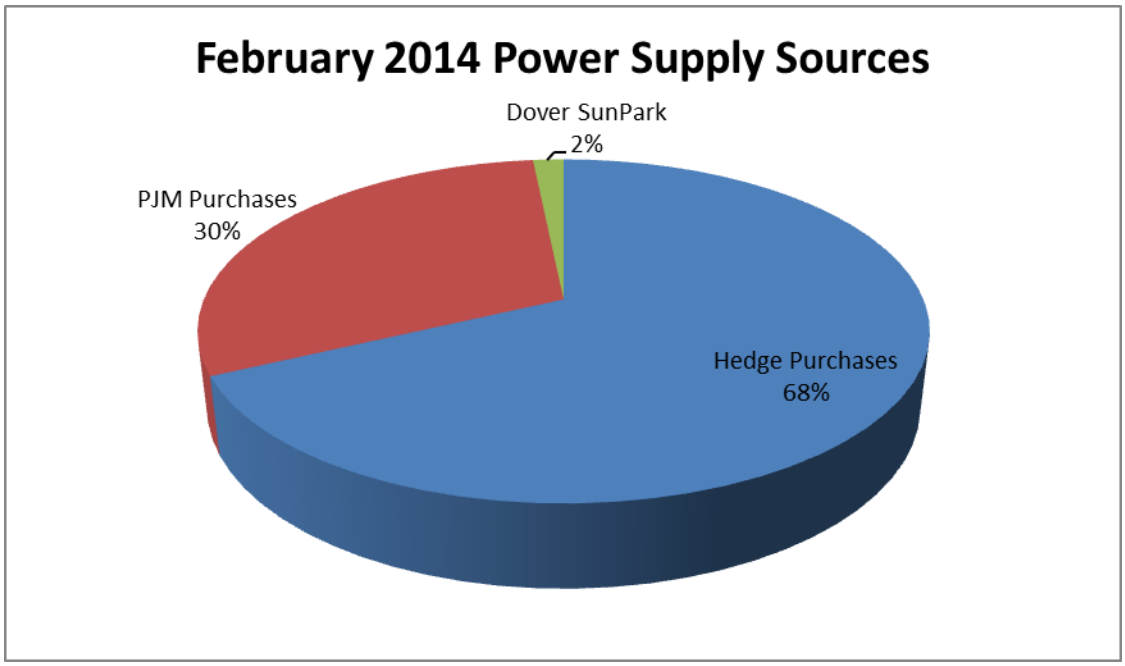
Dover's power purchases from hedge transactions totaled $1,996,784. Purchases from PJM (energy and fees) totaled $2,228,410 with DA Energy purchases totaling $992,520, DA transmission congestion totaling $300,952 and Reactive Services Charges totaling $67,525.

Dover's total load was 61,423 MWh versus a forecasted load of 55,324 MWh.

Dover's planned energy purchase from the SunPark solar installation was 1,151 MWh. Dover's actual energy purchase from the SunPark installation was 993 MWh.

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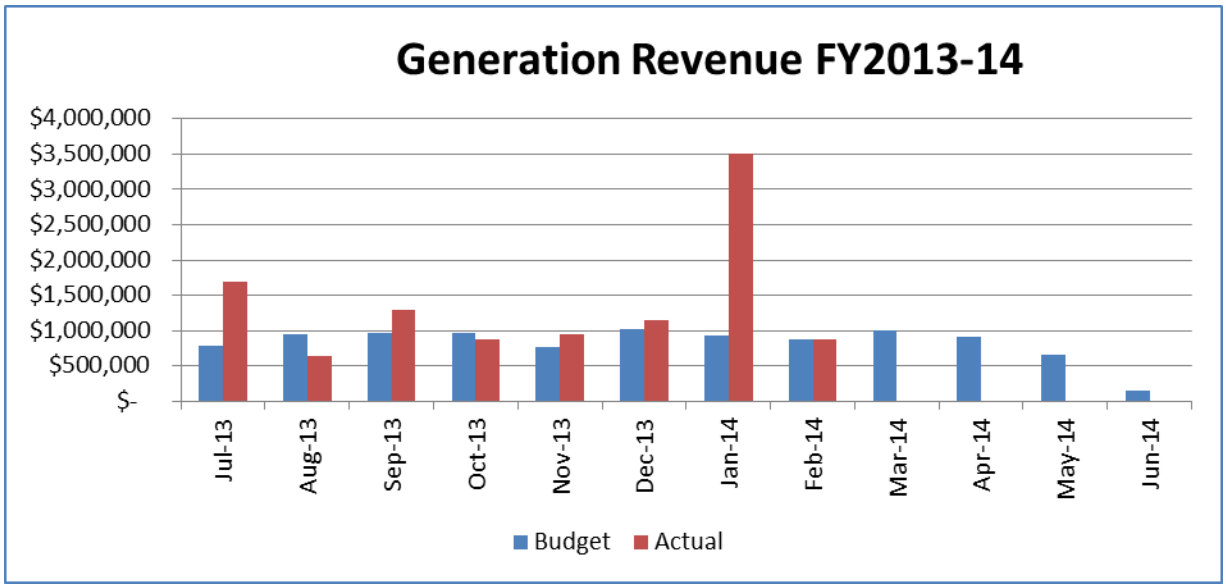
Supply Source Summary:



Supply Variance:

	Budget	Actual	Variance
Gross Load	55,324	61,423	(6,099)
Wholesale Load	54,173	60,430	(6,257)
Hedged Volume (MWh)	27,840	41,760	(13,920)
Unhedged Volume (MWh)	26,333	18,670	7,663
Dover SunPark Volume (MWh)	1,151	993	158
Renewable Energy Credits Volume	173	121	52
Hedged Cost ($/MWh)	$ 54.29	$ 47.82	$ 6
Unhedged Energy Cost ($/MWh)	$ 42.62	$ 101.27	$ (59)
Solar Energy Cost ($/MWh)	$ 87	$ 102	$ (15)
Energy Costs ($/MWh)	**$49.42**	**$64.95**	**($15.53)**
All-in Costs - Energy, Capacity and RECs ($/MWh)	**$81.18**	**$92.09**	**($10.92)**

B. Generation Summary:



Dover generated 632 MWh in the month. Net generation revenue was $875,148 vs. a budget of $875,310.

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Generation Breakdown:

City of Dover

Monthly Wholesale Generation

February, 2014

Net Generation for February
632.45

All In Generation

PJM - Generation			
	Economic and Reliability Dispatch	$	56,438.97
	Generation Capacity Credit	$	1,200,500.00
	Black Start and Transmission Losses	$	88,522.50
Natural Gas & Oil Consumption			
	Purchases for Generation	$	(80,198.60)
	Natural Gas Transport	$	(4,855.07)
	Eastern Shore Cashout	$	10,810.80
	Oil Consumption	$	3,022.97

Production Margin

PJM - Generation			
	Economic and Reliability Dispatch	$	56,438.97
Natural Gas & Oil Consumption			
	Purchases for Generation	$	(80,198.60)
	Natural Gas Transport	$	(4,855.07)
	Eastern Shore Cashout	$	10,810.80
	Oil Consumption	$	(3,022.97)
Gross Production Margin		$	(20,826.87)
$/MWh Generation Production Gross Margin		$	(32.93)

C. Emissions Summary:

Emissions Allowance Summary through February 28th, 2013

The CAIR units (McKee Run 3 & VanSant) did operate during the month of January, 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)
2/28/14	**2014 YTD Emissions**	**(1.1)**	**(0)**	**(6.4)**
REMAINING ALLOWANCES		**13,039.9**	**99**	**243.6**

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). In response to an EPA appeal to the U.S. Supreme Court, the Supreme Court heard arguments on December 10th, 2013. The Court did not indicate when it plans to release an opinion in the CSAPR case.

In a related proceeding, at the end of 2013, Governors from eight Northeastern states petitioned EPA to add nine Southern and Midwestern states to the Ozone Transport Region (OTR). If the Supreme Court rules against EPA in the CSAPR case, EPA would need to act on the OTR petition within 18 months of its filing.

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 broker bids & offers:

Mark-to-Market for CAIR Allowances (3/20/2014)			
Commodity	**$/Ton (Bid/Offer Avg.)**	**Tons**	**Extended Value**
SO_2 Allowances (2009 & earlier)	$ 1.35	5,089	$ 6,870
SO_2 Allowances (2010-13)	$ 0.65	7,950.9	5,168
NO_x Allowances - Seasonal	$18.00	99	1,782
NO_x Allowances - Annual	$40.00	243.6	9,744
TOTAL			**$23,564**

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-	(4,458)		**114,634**

After 2013, 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]. NOTE: The new RGGI rule includes a provision which will eliminate some portion of banked allowances in future years. TEA will be investigating the potential impact of this provision on Dover's RGGI allowance bank.

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 March 20th, 2014 ranged from $4.26 to $4.48/ton, depending settlement month. **Based on the March 20th, 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

Intercontinental Exchange prices for March, 2014 ($4.26/ton), the value of Dover's existing 114,634 ton RGGI allowance bank is $488,341.

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 January 2014, Dover has accumulated a total of 6,852[5] SRECS from these renewable energy resources.

The nearest viable market for Dover's SRECs is Pennsylvania. Pennsylvania's March 3, 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	$55.00 (March 2014 Auction)	2,725	149,875
2013/2014	$55.00 (March 2014 Auction)	1,739	96,645
TOTAL		**6,852**	**$341,596**

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

[5] Includes 121 RECs for Sun Park generation in January 2014 which had not been posted to Dover's PJM GATS account as of March 24th, 2014.

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 February there were no reportable or lost time accidents or injuries. The facility has now gone 1,230 days without an OSHA recordable accident and 1,230 consecutive days without a lost time reportable accident. There were zero Environmental Notices of Violations issued and there was one opacity deviation on Unit 2 on startup. There were no Near Miss incidents. In the month of February, Units 1, 2, and 3 were not dispatched By PJM. Unit 11 was dispatched once by PJM. Capacity tests for Units 1,2, and 3 were successfully completed.

Monthly Budget Variance – The actual expenses attributable to O&M of the two sites for the month of February were $390,956 against a budgeted amount of $355,495 for an unfavorable variance of $35,461 or 9.98%. The principal reasons for the unfavorable variance were due to unscheduled overtime, higher water, sewer, and electrical costs to support unscheduled generation. Also contributing to the unfavorable variance was the timing of insulation repairs which were budgeted later in the year.

E. Risk Management Summary:

Forward power prices in PJM are higher than last month though out the hedging time horizon.

The current projected cost of service is below:

PY	Hedge Ratio	Blended Cost ($/MWh)	Monthly Change ($/MWh)
2013-14	78%	$ 52.19	$ 0.16
2014-15	65%	$ 46.44	$ 0.97
2015-16	46%	$ 42.50	$ 0.55
2016-17	18%	$ 41.16	$ 0.82
2017-18	10%	$ 41.98	$ 1.41

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II. Budget Report

Variance Report:

	Budget Feb-14	Actual Feb-14	Variance
Gross Load	**55,324**	**61,423**	**(6,099)**
Power Supply			
Hedged Energy	$1,511,560	$1,996,784	($485,224)
PJM - Energy, Congestion & Losses	$1,122,370	$1,890,712	($768,342)
PJM - ARR, Transmission and Fees	$395,000	$337,698	$57,302
Dover SUN Park Energy	$100,175	$101,681	($1,506)
Dover SUN Park RECs	$25,000	$17,301	$7,699
Management Fees	$83,000	$83,000	$0
PJM - Capacity UCAP Obligated Purchased	$1,253,880	$1,229,322	$24,558
Subtotal - Power Supply	**$4,490,985**	**$5,656,498**	**($1,165,513)**
Power Generation O&M			
Plant O&M	$355,770	$390,956	($35,186)
Subtotal Generation O&M	**$355,770**	**$390,956**	**($35,186)**
Power Generation Production Margin			
PJM - Economic and reliability dispatch	$0	($56,439)	$56,439
Fixed Fuel and Transport Charges	$0	$79,357	($79,357)
Subtotal Generation Production Margin	**$0**	**$ 22,918.05**	**($22,918)**
Power Generation Non-Production Revenue			
PJM - Generation Capacity Credit	($1,200,500)	($1,200,500)	$0
Emissions Allowance Sales	$0	$0	$0
PJM - Black Start & Transmission Losses	($30,580)	($88,523)	$57,943
Subtotal - Non-Production Revenue	**($1,231,080)**	**($1,289,023)**	**$57,943**
SubTotal - All Generation	**(875,310)**	**($875,148)**	**($162)**
Total - Utilities Cost	**$3,615,675**	**$4,781,349**	**($1,165,674)**
Unit Costs			
Total - Power Supply	$81.18	$92.09	($10.92)
Total - Power Generation	($15.82)	($14.25)	($1.57)
Final Cost of Service to City of Dover Ratepayers	$65.35	$77.84	($12.49)

Variance Analysis:

Power Supply

- Dover consumed 6,099 MWh more than forecast for the month.
- PJM energy costs were higher than expected as high market prices occurred during the month driven by the much below normal temperatures. Hedged costs were higher than forecasted due to an additional layering in of hedges. PJM Fees were slightly lower than budget.
- Hedges were placed at below budget levels, however higher market prices more than offset this benefit. Higher market prices resulted in a net power supply cost of $92.09/MWh, $10.92/MWh above budget.
- For the month, the city realized an unfavorable variance of $1,165,513 for power supply vs. the monthly budget.
- Dover Sun Park generated 158 MWh less than forecast.

Generation

- Power generation had an unfavorable budget variance of $162.
- Plant O&M expenses had an unfavorable budget variance of $35,186 for the month.

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YTD Variance Report:

	Budget YTD	Actual YTD	Variance
Gross Load	**506,540**	**525,468**	**(18,928)**
Power Supply			
Hedged Energy	$17,796,306	$20,427,246	($2,630,940)
PJM - Energy, Congestion & Losses	$8,175,287	$13,404,768	($5,229,481)
PJM - ARR, Transmission and Fees	$3,160,000	$5,782,737	($2,622,737)
Dover SUN Park Energy	$873,015	$1,037,904	($164,889)
Dover SUN Park RECs	$200,000	$244,890	($44,890)
Management Fees	$664,000	$664,000	$0
PJM - Capacity UCAP Obligated Purchased	$10,881,883	$10,684,245	$197,638
Subtotal - Power Supply	**$41,750,491**	**$52,245,790**	**($10,495,299)**
Power Generation O&M			
Plant O&M	$3,650,984	$3,598,525	$52,459
Subtotal Generation O&M	**$3,650,984**	**$3,598,525**	**$52,459**
Power Generation Production Margin			
PJM - Economic and reliability dispatch	($230,472)	($5,371,245)	$5,140,774
Fixed Fuel and Transport Charges	$0	$2,126,863	($2,126,863)
Subtotal Generation Production Margin	**($230,472)**	**($3,244,382)**	**$3,013,910**
Power Generation Non-Production Revenue			
PJM - Generation Capacity Credit	($10,418,625)	($10,418,625)	$0
Emissions Allowance Sales	$0	$0	$0
PJM - Black Start & Transmission Losses	($274,640)	($940,080)	$665,440
Subtotal - Non-Production Revenue	**($10,693,265)**	**($11,358,705)**	**$665,440**
SubTotal - All Generation	**($7,272,753)**	**($11,004,561)**	**$3,731,809**
Total - Utilities Cost	**$34,477,738**	**$41,241,229**	**($6,763,490)**
Unit Costs			
Total - Power Supply	$82.42	$99.43	($17.00)
Total - Power Generation	($14.36)	($20.94)	$6.58
Final Cost of Service to City of Dover Ratepayers	$68.07	$78.48	($10.42)

III. Operations Management

NAES Corporation
Dover, Delaware

February 2014
Monthly Report



New Compliance Coordinator, Mark Gramer

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6.0 General Plant Information

7.0 Summary of NAES Performance

1.0 Environmental, Health and Safety:

During the month of February, there were no restricted work days or lost time accidents. The facility has now gone 3 years and 135 days (1,230 days) through February 28, 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 February (January Discharge) DMR was submitted for the McKee Run site with no NPDES exceedences. There was one opacity deviation on Unit 2 during unit operations in the month.

During the month of February, there were twelve (12) IWW discharges to the Kent County Sewer. Sampling was conducted on one of the discharges, as is required by the IWW Permit. Results have yet to be received. The January SIU Report was submitted to Kent County.

Environmental, Health, and Safety Statistics		
	Month (February)	Fiscal Year to Date (7/1/13-6/30/14)
NOVs	0	0
Opacity Deviations	1	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	4,234.75	34,231.00
Date last OSHA Recordable		10/14/10
Date last Lost Time Accident		10/14/10
Days since last OSHA recordable		1,230
Days since last Lost Time Accident		1,230

Emissions (NO_x, CO_2 & SO_2) All data thru 2/28/14

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	3.5	2.9	7.4
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	0.5	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	4,458	(4,458)
			Total CO2 Allowance Balance		**114,634**

***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

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	3.5/0 - 2.9/0	0/0 – 0/0	67.5/46	2.1/3
				Total NOx Allowance Balance		**233.5/90**	**10.1/9**

***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	1.1	1986.9
			Total SO2 Allowance Balance		**13,039.9**

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

2.0 Financial

Financial – Current Month

Month – February			
	Actual	Budget	Variance
Personnel	252,711	251,265	(1,446)
Materials & Supplies	13,424	11,150	(2,274)
Administrative Expenses	124,821	93,080	(31,741)
Total	**$390,956**	**$355,495**	**($35,461)**

Financial – Fiscal Year to Date

Number of Months – 8			
	Actual	Budget	Variance
Personnel	1,980,080	2,195,220	215,140
Materials & Supplies	133,521	169,340	35,819
Administrative Expenses	1,304,959	1,286,904	(18,055)
Total	**$3,418,560**	**$3,651,464**	**$232,904**

2.1 Variance analysis:

The actual expenses for the month of February are $390,956 against a budgeted amount of $355,495 for an unfavorable variance of $35,461 or 9.98%. The variance was due to the following:

PERSONNEL EXPENSES – An unfavorable monthly variance of $1,446 was due to unscheduled overtime to support generation unit operations, capacity testing, and training.

MATERIALS AND SUPPLIES EXPENSES- An unfavorable monthly variance of $2,274 was due to higher water – sewer costs than anticipated in order to support generation unit operations.

ADMINISTRATIVE EXPENSES – An unfavorable monthly variance of $31,741 was due to the timing of invoices for plant wide insulation repairs, unanticipated environmental costs, and higher than anticipated electricity costs to support generation unit operations.

The forecasted expenses for this fiscal year are $5,807,568 expensed versus an approved budget of $6,015,800 thereby realizing a 96.54% expenditure rate.

3.0 Operations

Unit Operations / Outages / Trips

In the month of February, Units 1, 2, and 3 were not dispatched; Unit 11 was dispatched once by PJM. The capacity tests for Units 1, 2, and 3 were successfully completed in the month of February.

Month February 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	4.800	6.750	7.380	18.930	1.116	20.046
Starts	#	1	1	1	3	1	4
Gross Generation	MWh	57.225	86.008	488.983	632.216	46.050	678.266
Net Generation	MWh	55.447	82.026	451.463	588.936	45.969	634.905
Total Auxiliaries	MWh	43.031	45.235	225.541	313.807	8.182	321.989
Auxiliaries purchased	MWh	41.253	41.253	188.021	270.527	7.372	277.899
Fuel Gas Used	MMBTU	837.930	1,015.002	5,765.759	7,618.691	602.888	8,221.579
Fuel Oil Used	MMBTU	0.0	0.0	146.715	146.715	0.0	146.715
Fuel Oil Used	Gallons	0.0	0.0	1,023	1,023	0.0	1,023
Total Fuel	MMBTU	837.930	1,015.002	5,912.474	7,765.406	602.888	8,368.294
Net Heat Rate	BTU/KWh	15.112	12.374	13.085	13.523	13.115	13.421
Unit Trips	#	0.0	0.0	0.0	0.0	0.0	0.0
Capacity Factor	%	0.49	0.72	0.66	0.64	0.17	0.54
Availability Factor	%	100.00	100.00	100.00	100.00	100.00	100.00
Commercial Unavailability (CU)	%	0	0	0	0	0	0
Planned Outage Hours	Hours	0.00	0.00	0.00	0.00	0.00	0.00
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	667.200	665.250	664.620	1997.070	670.884	2667.954
HW Boiler Gas Usage	MMBTU				1,239.504		1,239.504
Pilot Gas Usage	MMBTU	206.584	268.770		475.354		475.354

 # 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 - February							
		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	263.041	612.770	75.655	688.425
Starts	#	7	7	16	30	20	50
Gross Generation	MWh	959.877	1,413.560	16,424.707	18,798.144	2,615.094	21,413.238
Net Generation	MWh	895.980	1,309.804	15,045.322	17,251.106	2,613.006	19,864.112
Total Auxiliaries	MWh	301.080	406.037	2,759.126	3,466.243	30.863	3,497.106
Auxiliaries purchased	MWh	279.806	322.336	1,380.185	1,982.327	28.046	2,010.373
Fuel Gas Used	MMBTU	8,924.901	15,004.575	146,255.584	170,185.060	19,584.819	189,769.879
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	182,433.827	216,331.497	34,965.366	251,296.863
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	%	0.90	1.32	2.53	2.17	1.15	1.95
Availability Factor	%	75.16	76.53	76.53	76.07	76.53	76.19
Commercial Unavailability (CU)	%	0.95	0.04	0.01	0.13	0.0	0.10
Planned Outage Hours	Hours	1,369.000	1,369.000	1,369.000	4,107.000	1,369.000	5,476.000
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	4,248.303	4,213.968	4,203.555	12,665.826	4,388.345	17,054.171
HW Boiler Gas Usage	MMBTU				4,816.127		4,816.127
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)	267,019	460,013	194,807	192,994	454,725	378,003	5,288
VanSant (#2 Fuel Oil)	72,139	72,224	0	85	146,133	35,000	(73,909)

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

VanSant Lifetime through February 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 Workers in both Operations and Maintenance areas to help in maintaining the plant.

The operators continue to use the Plant Readiness Program for training and refreshing their plant knowledge on different systems to improve the plant's reliability. Some of the training involved promotes teamwork with other staff members to work together to find a solution and to promote further discussions on equipment operation. The operators also use the GPi Learning courses to improve their knowledge and skills. The GPI online training which supports plant safety, OSHA, and environmental training requirements are being used by the teams to complete their training for the year. Along with the GPI OSHA training, the operators review the plant's safety procedures.

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

4.0 Maintenance

During the month of February, the Plant Maintenance staff continued addressing the backlog of work orders. There were fifty-two work orders issued with ninety-two work orders being completed during the month. There were no safety work orders 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

February - 2014

Priority #	Outstanding From Previous Month	Issued This Month	Completed This Month	Outstanding at the end of the month
1	20	2	8	14
2	67	9	29	47
3	47	1	12	36
4	6	0	1	5
5	17	0	2	15
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	72	40	40	72
EM	0	0	0	0
Totals	229	52	92	189

Note: PM Work Orders are included in the priority totals

Notable activities during the month include:

NAES Maintenance Mechanics adjusted Unit 3 cooling tower water distribution flows across the north and south hot water basins during the capacity testing of Unit 3. Equalized water distribution ensures proper cooling of the water.

NAES Maintenance Mechanics completed repairs to Units 1 and 2 boiler level sight glass columns. The sight glasses were identified as having poor visibility of the proper water levels as observed from the control room during unit operation events. Each sight glass was disassembled, cleaned and new mica kits installed. Sight glasses operated properly during subsequent unit operations.

NAES Maintenance Mechanics removed and repaired various steam and water pipes damaged from extreme weather conditions during the month. The repaired piping was Unit 2 air preheater drain piping, Unit 3 soot blower steam piping and Unit 1 boiler water

sample piping to the lab. Each area was removed and replaced with new pipe. No additional work or leaks were observed during February unit operations.

NAES IC&E Staff completed repairs to one outdoor eyewash unit. During monthly testing of the eyewash unit, it was discovered that the eyewash water was extremely hot from piping heat tracing cable. IC&E staff installed a temperature controller to better control the water temperature during times of operation.

5.0 Capital Improvement Projects (CIP)

Project Number	Description	Update
EG1402	Unit #3 Cooling Tower Repairs	Progress: Cooling Tower decking is 100% complete. Schedule: Remaining inspection work to complete in april-may timeframe.
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 to start 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: FAC work inspection vendor selected. Spring work on schedule to start March 10.
EG1407	Metering System Upgrades	Progress: Proposal received from vendor. COD and plant personnel have discussed proposal and submitted a list of "to do" items to the vendor for more information and clarification. Schedule: Work activities are moving forward. Additional questions have been posed to vendor and work scope is being developed. Waiting on response from vendor.
EG1408	McKee Run/VanSant Safety Compliance Items	Progress: Work is being planned to be completed in the Spring 2014 outage period. Specifications being written for VanSant breaker installation. 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.
EG1413	McKee Run/VanSant	Progress: Plant staff completed development of paint specifications and bid requests were received.

	Structural Preservation	Schedule: Bids were received in early September. Work is on hold due to budget restraints.
EG1212	Unit 3 Turbine Repairs	Progress: Repair vendor selected. Consumables parts have been received. Schedule: Repair vendor will mobilize March 1
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: Capacity increase request is in the PJM queue. Proposals have been received and are being evaluated. Met with DNREC to review the construction permit application. Will submit application in March. Facility impact study results provided by PJM indicate no additional modifications required. Schedule: Environmental Support contractor is now preparing the Title V Application Modification that will be submitted to the DNREC for project approval.

6.0 General Plant Information

The Plant welcomed Mark Gramer as the newly hired Compliance Coordinator on February 19, 2014. Mark brings a wide variety of experience and will be concentrating on learning plant specific requirements for Environmental and Safety issues.

Training:

Plant employees continue General Physics safety training and environmental courses to enhance their overall knowledge of permit and safety requirements. As the GPI courses are being completed, the employee reviews the standard operating procedure (SMP) for the same topic they are training on to review NAES policy as well.

Topics discussed during the monthly safety committee meeting were reviewed by the entire staff. The monthly safety topic was on “Take Two For Safety”.

Simulation training for PJM operations is scheduled to occur on April 8-9 by a third party vendor. Completion of this training enables plant operators to meet Continuing Education Hours (CEHs) requirements that are part of maintaining their PJM System Ops Certification.

Calendar of Events	Date
Winter Capacity Period	December 1, 2013 to February 28, 2014
EIA-860 Report	TBD
EIA-923 Report	TBD
NOx Emissions Reconciliation Due	March 1, 2014
SO2 Emissions Reconciliation Due	March 1, 2014
SARA III / Tier II Report Due	March 1, 2014
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	March, 2014
Air Emission Inventory	March , 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
Annual Title V Certifications Due	January 30, 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)	0.16%		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	Yes	Yes	Yes	$3,559	$3,559
Unit 2	No	Yes	Yes	Yes	$3,559	$3,559
Unit 3	No	Yes	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		($2,438.98)	($2,438.98)
	Capacity Transfer Rights		($17,372.04)	($17,372.04)
	Incremental Capacity Transfer Rights		($1,511.33)	($1,511.33)
	Locational Reliability		$1,250,644.08	$1,250,644.08
⊟480-8102-592-95-50	RPM Auction	($1,200,500.00)		($1,200,500.00)
⊟480-8102-592-95-90	Auction Revenue Rights		($24,135.38)	($24,135.38)
	Balancing Operating Reserve		$12,786.92	$12,786.92
	Balancing Operating Reserve for Load Response		($2.10)	($2.10)
	Black Start Service		$1,807.59	$1,807.59
	CT Lost Opportunity Cost Allocation		($15.68)	($15.68)
	Day-Ahead Load Response Charge Allocation		$2,047.48	$2,047.48
	Day-ahead Operating Reserve		$7,185.12	$7,185.12
	Day-ahead Operating Reserve for Load Response		$120.22	$120.22
	Day-ahead Scheduling Reserve		$253.40	$253.40
	Demand Resource and ILR Compliance Penalty		($1,800.96)	($1,800.96)
	Expansion Cost Recovery		$405.14	$405.14
	FERC Annual Recovery		$4,335.35	$4,335.35
	Generation Deactivation Refund		($734.39)	($734.39)
	Load Management Test Failure		($40.04)	($40.04)
	Load Reconciliation for Transmission Losses		$926.63	$926.63
	Market Monitoring Unit (MMU) Funding		$284.38	$284.38
	Michigan - Ontario Interface Phase Angle Regulators		$178.40	$178.40
	Network Integration Transmission Service		$292,660.14	$292,660.14
	Non-Firm Point-to-Point Transmission Service		($1,256.59)	($1,256.59)
	Non-Synchronized Reserve		$1,201.68	$1,201.68
	North American Electric Reliability Corporation (NERC)		$660.83	$660.83
	Organization of PJM States, Inc. (OPSI) Funding		$43.21	$43.21
	PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center		$1,686.33	$1,686.33
	PJM Scheduling, System Control and Dispatch Service - Capacity Resource/Obligation Mgmt.		$852.60	$852.60
	PJM Scheduling, System Control and Dispatch Service - Control Area Administration		$10,449.35	$10,449.35
	PJM Scheduling, System Control and Dispatch Service - Market Support		$2,399.12	$2,399.12
	PJM Scheduling, System Control and Dispatch Service - Market Support Offset		($330.65)	($330.65)
	PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration		$75.73	$75.73
	PJM Scheduling, System Control and Dispatch Service Refund - Capacity Resource/Obligation Mgmt.		($113.40)	($113.40)
	PJM Scheduling, System Control and Dispatch Service Refund - Control Area Administration		($1,562.48)	($1,562.48)
	PJM Scheduling, System Control and Dispatch Service Refund - Market Support		($362.34)	($362.34)
	PJM Scheduling, System Control and Dispatch Service Refund - Regulation Market Administration		($14.12)	($14.12)
	PJM Settlement, Inc.		$330.65	$330.65
	Reactive Services		($67,525.52)	($67,525.52)
	Reactive Supply and Voltage Control from Generation and Other Sources Service		$34,852.13	$34,852.13
	Real-Time Load Response Charge Allocation		$1,511.75	$1,511.75
	Regulation and Frequency Response Service		$25,494.49	$25,494.49
	Reliability First Corporation (RFC)		$938.72	$938.72
	Synchronized Reserve		$17,617.76	$17,617.76
	Transmission Enhancement		$9,897.89	$9,897.89
	Transmission Owner Scheduling, System Control and Dispatch Service		$4,588.58	$4,588.58
⊟480-8102-592-95-91	Balancing Spot Market Energy		$464,196.64	$464,196.64
	Balancing Transmission Congestion		$49,283.75	$49,283.75
	Balancing Transmission Losses		$28,264.36	$28,264.36
	Day-ahead Spot Market Energy		$992,520.26	$992,520.26
	Day-ahead Transmission Congestion		$300,952.38	$300,952.38
	Day-ahead Transmission Losses		$157,776.37	$157,776.37
	Emergency Load Response		$302.79	$302.79
	Inadvertent Interchange		($2,621.22)	($2,621.22)
	Load Reconciliation for Balancing Operating Reserve		($343.42)	($343.42)
	Load Reconciliation for Day-ahead Scheduling Reserve		($1.26)	($1.26)
	Load Reconciliation for FERC Annual Recovery		($115.16)	($115.16)
	Load Reconciliation for Inadvertent Interchange		$41.30	$41.30
	Load Reconciliation for Market Monitoring Unit (MMU) Funding		($7.41)	($7.41)
	Load Reconciliation for Non-Synchronized Reserve		($2.48)	($2.48)
	Load Reconciliation for North American Electric Reliability Corporation (NERC)		($19.35)	($19.35)
	Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding		($1.34)	($1.34)
	Load Reconciliation for PJM Scheduling, System Control and Dispatch Service		($399.66)	($399.66)
	Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Refund		$110.90	$110.90
	Load Reconciliation for Reactive Services		($5,271.24)	($5,271.24)
	Load Reconciliation for Regulation and Frequency Response Service		($323.77)	($323.77)
	Load Reconciliation for Reliability First Corporation (RFC)		($27.68)	($27.68)
	Load Reconciliation for Schedule 9-6 - Advanced Second Control Center		($43.31)	($43.31)
	Load Reconciliation for Spot Market Energy		($75,632.06)	($75,632.06)
	Load Reconciliation for Synchronized Reserve		($157.72)	($157.72)
	Load Reconciliation for Transmission Congestion		($2,558.48)	($2,558.48)
	Load Reconciliation for Transmission Losses		($4,571.02)	($4,571.02)
	Load Reconciliation for Transmission Owner Scheduling, System Control and Dispatch Service		($143.80)	($143.80)
	Meter Error Correction		($10,496.15)	($10,496.15)
⊟480-8102-592-95-92	Balancing Operating Reserve	($14,781.63)		($14,781.63)
	Balancing Spot Market Energy	($39,876.85)		($39,876.85)
	Balancing Transmission Congestion	($1,549.56)		($1,549.56)
	Balancing Transmission Losses	($230.93)		($230.93)
⊟480-8102-592-95-93	Reactive Supply and Voltage Control from Generation and Other Sources Service	($29,467.58)		($29,467.58)
	Synchronized Reserve	($3,197.85)		($3,197.85)
	Transmission Losses	($55,857.07)		($55,857.07)
Grand Total		**$ (1,345,461.47)**	**$ 3,457,731.89**	**$2,112,270.42**

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

	July	August	September	October	November	December	January	February	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	$ 1,037,902	$ 1,565,800
Dover Sun Park - REC's	43,005	38,516	42,894	25,307	20,875	13,583	17,301	-	201,481	300,000
Total Power Supply Cost	230,426	214,888	247,746	146,146	120,322	78,267	99,906	101,681	1,239,383	1,865,800
Non-Solar Power Supply Cost	(180,227)	(154,545)	(154,590)	(100,770)	(79,066)	(52,006)	(146,406)	(91,259)	(958,868)	(898,706)
Incremental Energy Cost	$ 50,199	$ 60,343	$ 93,156	$ 45,376	$ 41,256	$ 26,261	$ (46,500)	$ 10,423	$ 280,515	$ 967,094
Revenues										
Customer Sales - Electricity	(9,404)	(7,389)	(7,538)	(7,662)	(7,721)	(7,662)	(7,907)	(7,950)	(63,233)	(26,300)
Rent Receipts	(14,446)	-	-	(14,446)	-	-	(14,807)	-	(43,699)	(58,300)
Total Revenues	(23,850)	(7,389)	(7,538)	(22,108)	(7,721)	(7,662)	(22,714)	(7,950)	(106,932)	(84,600)
Incremental Sun Park Cost	$ 26,349	$ 52,954	$ 85,618	$ 23,268	$ 33,535	$ 18,599	$ (69,214)	$ 2,473	$ 173,582	$ 882,494
MWh Purchased/Generated - Solar	2,052.584	1,815.656	2,000.128	1,179.844	970.972	631.556	806.536	992.788	10,450.064	18,159.000
MWh $ Solar Energy	$ 91.31	$ 97.14	$ 102.42	$ 102.42	$ 102.42	$ 102.42	$ 102.42	$ 102.42	$ 99.32	$ 86.23
Solar REC's MWh	307.000	272.000	300.000	177.000	146.000	95.000	121.000	-	1,418.000	
MWh $ Solar REC (one month lag)*	$ 140.08	$ 141.60	142.98	142.98	142.98	142.98	142.98	$ -	$ 142.09	
MWh $ Non-Solar Energy	$ 87.81	$ 85.12	$ 77.29	$ 85.41	$ 81.43	$ 82.35	$ 181.52	$ 91.92		

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