TEA
THE EnergyAuthority

City of Dover

2017

Integrated Resource Plan

May 2017

Contents

EXECUTIVE SUMMARY

INTRODUCTION

Electric power is a keystone of our nation's economic and social welfare. Nearly every aspect of daily lives depends in some way upon electricity and the infrastructure that supplies it. The Federal Energy Regulatory Commission (FERC) has referred to the importance of electricity as "staggering" to the North American way of life.

Given the importance of electricity to modern society, long-term supply planning impacts everyone. How customers consume and ultimately pay for this critical commodity will be driven by the decisions The City of Dover, Delaware makes today. Power supply decisions have economic lives measured in decades, and long term planning is fraught with uncertainty, making it a difficult undertaking. Technology development, electricity and commodity pricing, economic factors and cultural and social forces all present elements of risk to the long-term planning model.

Starting last summer, the City of Dover, Delaware (Dover) utility staff teamed with The Energy Authority (TEA) to begin studying the resource future for the community. The results of this study are published in this document, titled the 2017 Integrated Resource Plan (2017 Dover IRP).

This City of Dover, DE (Dover) Integrated Resource Plan (IRP) presents the results of a detailed analysis of alternatives it may select to meet the electrical energy and demand requirements of its retail electric consumers for the period 2018-2037. It includes an assessment of Dover's existing supply resources, alternatives for new and replacement power supply options, and demand side management alternatives such as load management and end-user energy conservation measures which could be installed on the electrical distribution system or at the end-use customers' facilities.

This executive summary provides a look at plan objectives, modeling, forecasting approach, existing resources, and in conclusion, an overview of plan recommendations. The complete document package includes a detailed description of the study.

IRP OBJECTIVES

The 2017 Dover IRP provides forward looking projections of likely resource scenarios that Dover's community may experience over the next 20 years. Additional key plan concepts (bulleted below) are applied within plan framework to form the most important considerations for Dover's decision-making process.

- Create a baseline projection for this IRP processes.
- Analyze key commodity, emissions, and price forecasts.
- Incorporate proven methodologies for energy and demand forecasting.
- Analyze existing and new resources on a cost to serve load basis.
- Forecasts future demand and supply requirements to determine the optimal mix of resources to minimize future costs while meeting reliability, regulatory, and social expectations.
- Builds a strategic long-term "buy" or "build" plan for capacity resources needed to meet PJM's capacity obligation requirements.

    - Dover will continue to rely on PJM for short-term tactical energy and capacity to serve Dover's load throughout the study period.
- Utilize Levelized Cost of Energy (LCOE) in asset evaluation.
- Present assumptions clearly and with transparency.
- Provide clear recommendations.

Modeling

Economic models are utilized for analyzing future scenarios and providing relevant outcomes. These models are good at economic analysis using various assumptions. The items below are a synopsis of appropriate model expectations.

- Long-Term Models Do:
    - Forecast future market conditions from specified input assumptions
    - Estimate the magnitude of future power supply costs
    - Allow comparison of sensitivities of results to key assumptions

- Long-Term Models Don't:
    - Predict human behavior
    - Predict significant changes in market design, rules, or technological advances
    - Forecast non-economic unit operation
    - Evaluate short-term operational reliability constraints
    - Explicitly evaluate the need for and cost of ancillary services (Operating Reserves, Regulation, Voltage Control)
    - Estimate transmission and distribution cost, customer services, administrative and general costs, existing debt service, etc.

The selected modeling approach utilizes a commercial generation expansion planning application for analysis purposes. This energy market simulation and optimization software suite simulates economic dispatch to minimize variable costs for both Dover and the PJM (PJM) market, while selecting future resources with the objective of minimizing incremental Net Present Value (NPV) of future power supply cost for both the market and Dover.

Sensitivities & Scenarios

The 2017 Dover IRP includes the analysis of many different scenarios and sensitivities. The project team selected these sensitivities as demonstration of likely realities that may be present over the next 20 years. Table 1 is an overview of the analyzed sensitivities.

TABLE 1
LIST OF SENSITIVITIES ANALYZED

<table>
<tr><th colspan="4">Sensitivities</th><th></th></tr>
<tr><th>Load</th><th>Carbon</th><th>Gas Price</th><th>RPS</th><th></th></tr>
<tr><td rowspan="5">Zero Load Growth</td><td rowspan="4">RGGI</td><td rowspan="2">Base Gas</td><td>Existing RPS</td><td>Base Case</td></tr>
<tr><td>RPS 50%</td><td>RPS 50</td></tr>
<tr><td>High Gas</td><td>Existing RPS</td><td>High Gas</td></tr>
<tr><td>Low Gas</td><td>Existing RPS</td><td>Low Gas</td></tr>
<tr><td>Carbon Constraints</td><td>Base Gas</td><td>Existing RPS</td><td>Carbon Constraint</td></tr>
</table>

In addition to these five sensitivities, three retirement schedules, and nine (9) generation expansion alternative scenarios for each retirement schedule have been included in this report. Detailed results of these scenarios are included in the Appendix to this report.

FORECASTING

While precarious in nature, forecasting is necessary for forward looking studies. Forecasting demand and commodity futures are the primary tenets of any resource planning process. Careful deliberation was given to each forecast.

Since all forecasts are best predictions, not guarantees, sensitivity analyses must be performed to portray future uncertainties. Graphs portraying these sensitivities are included in this section for information.

Demand Forecast

TEA prepared a long-term demand forecast in 2015. Since local economic conditions have not changed significantly from the time when that forecast was prepared, the 2015 forecast has been used for this IRP.

Figures 1 and 2 present the demand forecasting baseline that was used in this analysis.

FIGURE 1
PEAK DEMAND HISTORY AND FORECAST

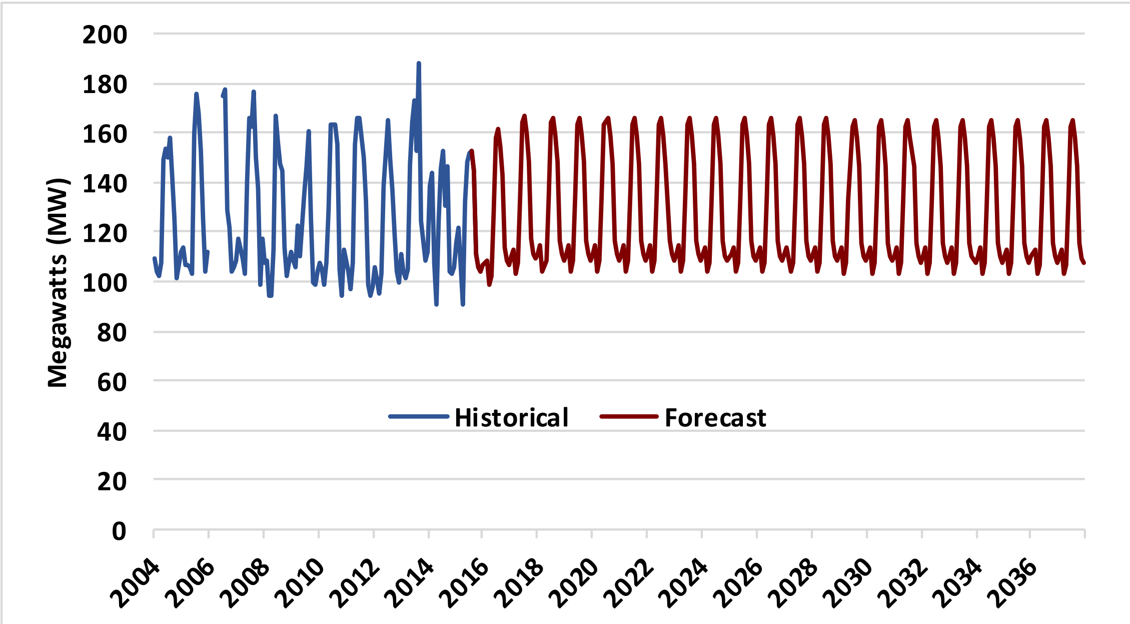
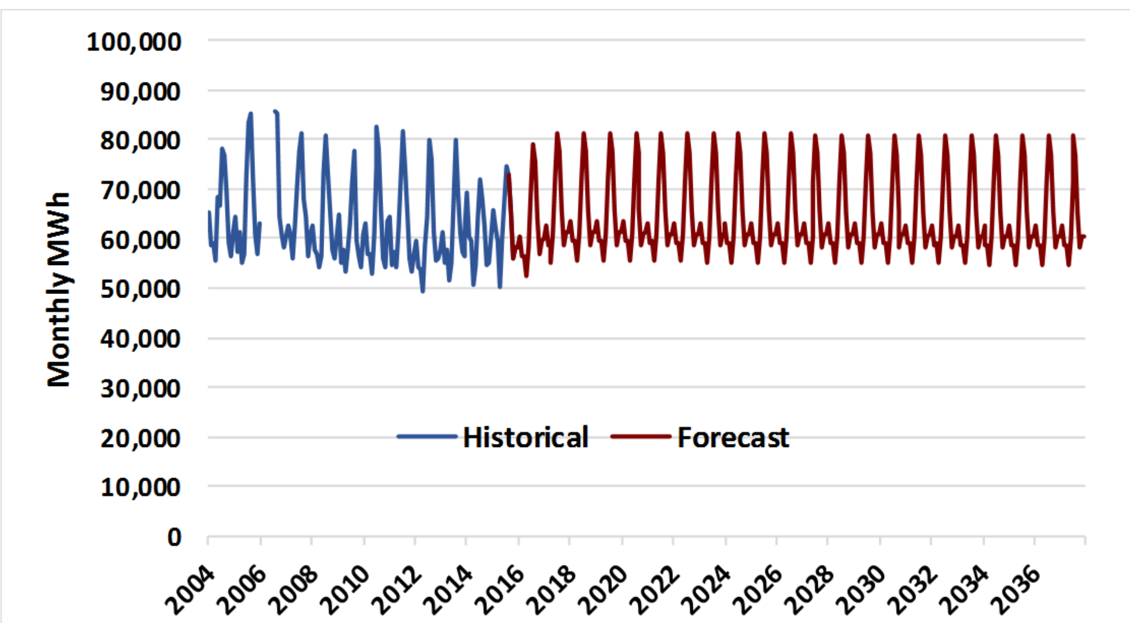


FIGURE 2
MONTHLY ENERGY DEMAND HISTORY AND FORECAST



Demand Forecast Methodology

DOVER'S CURRENT GENERATION RESOURCES

Dover's existing generation resources are listed in Table 2 below. McKee Run Units 1 and 2 are not included in this study because Dover has retired the resources effective May 31, 2017.

TABLE 2
GENERATION RESOURCES

Plant	Type	Year of Commercial Operation	Year of Retirement	Net (MW)	PJM Capacity (MW)
McKee Run 3	Steam	1975	2027	102	102
VanSant	CT	1992	2041	43	43
SunPark	Renewable	2011	2031	10	BtMG[1]
TOTAL				**155**	**145**

Demand Forecast Methodology

- Years 2018 - 2037
- 10-year historical energy data by customer grouping
- Uses Woods & Poole county by county econometric database
- Historical locational weather used as input into weather normalization model

Dover's existing fleet resource diversity is limited in number of resources and their age and fuel types.

CAPACITY REQUIREMENTS

The 2017 Dover IRP has incorporated the PJM Reliability Pricing Model (RPM) requirement into the modeling, analysis, and recommendation process. PJM Load Serving Entities (LSE) must have capacity to serve 116.5% of peak demand forecast which represents PJM's 16.5% reserve requirement.

Dover participates in the PJM Capacity Market. As an LSE, it purchases all capacity required to meet its load serving obligation. As an owner of generation, it sells its generating capacity into the PJM Capacity Market. The PJM Capacity Market is for three years into the future, and only clears one year's requirement at a time. For the purpose of this IRP, it is considered a short-term market.

PJM's capacity market construct is evolving and has been subject to a number of design changes over the last ten years. Market fundamentals (supply-demand balance) have also been shifting, with load forecasts declining, existing generation such as inefficient coal units retiring, and new renewable and efficient natural gas resources added. The net result of these ever changing market dynamics is

[1] SunPark is behind the PJM billing meter; it off-sets Dover's peak demand and energy purchases from PJM.

volatility in market clearing prices. The PJM capacity auction prices for the delivery zone applicable to Dover (DPL-South) ranged from a low of $40/MW-Day in Delivery Year (DY) 2007/08 to a high of $245/MW-Day for DY2013/14, with the latest at $120/MW-day for DY 2019/20.

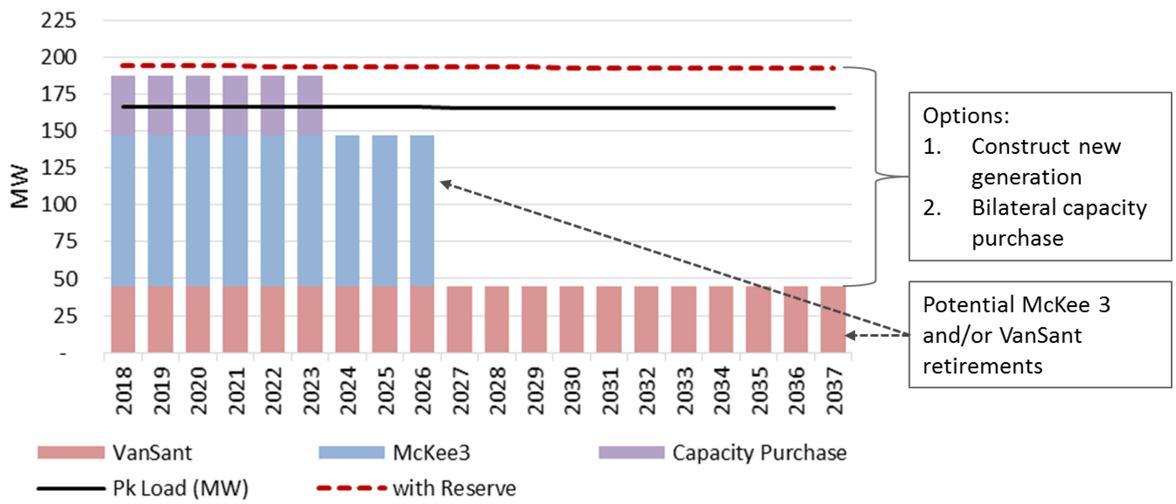
Dover could choose to simply rely on the PJM Capacity Market to meet its load serving obligation. If it were to choose this option, it would be exposed to considerable price risks. It is prudent practice to secure capacity assets for the long-term to mitigate such price risks. Capacity can be acquired by construction of self-generation (as Dover has done with the McKee Run and VanSant generation), through joint ownership of generation with other utilities or through long-term bilateral purchases from other owners of generation.

Dover has historically relied on its existing McKee Run and VanSant generating stations to meet its load serving obligations. These facilities have historically been of considerable benefit for Dover's electric customers for a number of years, and have been maintained in good operating condition. However, as will happen with any equipment, they are approaching the end of their useful economic life. Dover therefore must make decisions about when to retire them and what to replace them with.

Due to age and economics, Dover has retired McKee Run Units 1 and 2, effective May 31, 2017. McKee Run 3 is 42 years old and is inefficient when compared to technologies currently available. The VanSant gas turbine is only 25 years old, however it is also relatively inefficient. While Dover can continue to rely on these generating units for capacity requirements, they are seldom operated and are of limited value as hedges against volatile energy prices.

Figure 3 presents a forward-looking comparison of Dover's expected capacity obligation and the existing resources available to meet the obligation. Note that Dover is currently slightly deficient and must rely on PJM's Capacity Market for the difference. After the Purchase Power Agreement (PPA) expires and Dover's existing generation is retired, it will be prudent to secure its capacity needs with new self-generation resources or bilateral purchases.

FIGURE 3
CAPACITY REQUIREMENTS



Note: Reserve capacity is calculated to be approximately 16.5%.
In the past, Dover's reserve capacity requirement was between 14-21%.

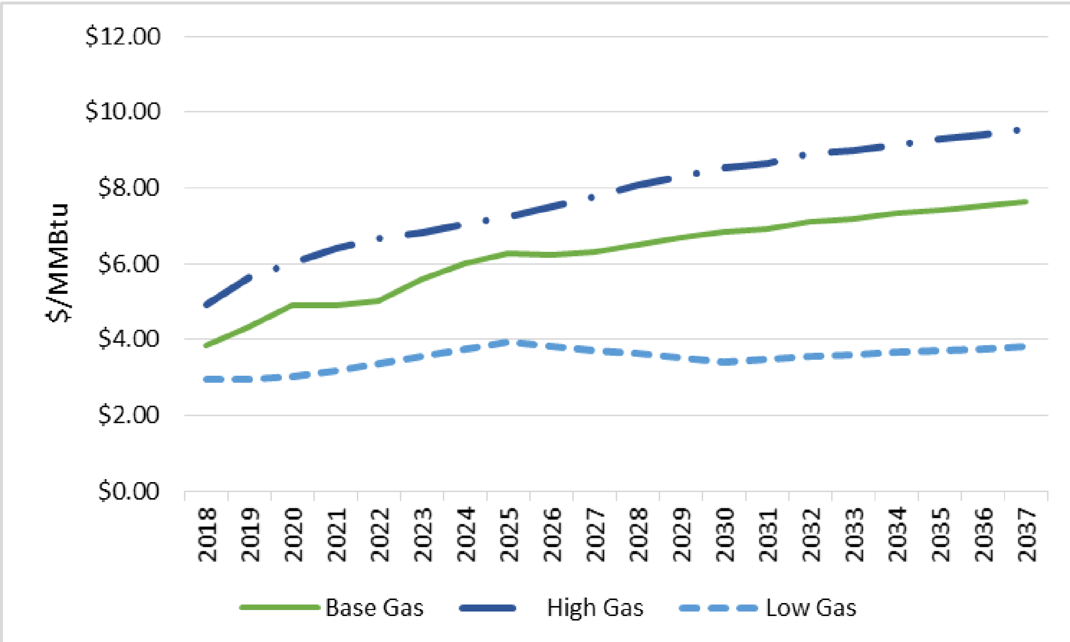
FUEL PRICE FORECAST

Natural Gas (NG) Forecast: Natural gas is the primary fuel for Dover's existing generation. Figure 4 presents the natural gas price projections used for this IRP. Three sensitivities have been analyzed for this IRP:

- **Base Case**– Base case plus Energy Information Administrations (EIA) percentage offset for Clean Power Plan (CPP) in 2016 Annual Energy Outlook (AEO)
- **High Natural Gas Price Case –** Natural Gas Prices from PJM's 2016 Regional Transmission Expansion Plan (RTEP)
- **Low Natural Gas Price Case** –NYMEX Natural Gas futures from August 16, 2016

Natural Gas Transportation: Natural gas prices used for Dover gas generation include the additional basis cost between Henry Hub and Transco Zone 6 Non New York and the gas transport cost. Natural gas transportation costs for all sensitivities and scenarios have been increased by an escalating basis from $0.72/MMBtu in 2018 to account for delivered cost of natural gas using non-firm transportation. For new natural gas fueled units, it is assumed that Dover will acquire firm transportation from the Eastern Shore Natural Gas pipeline.

FIGURE 4
HENRY HUB NATURAL GAS PRICE FORECASTS



Fuel Oil: Dover's existing generation relies on ultra-low sulfur fuel oil as a back-up fuel during periods when natural gas is not available, primarily during winter periods. The existing Clean Air Act Title V operating permit limits the number of hours Dover's units can operate on oil. It is assumed that Dover will be able to maintain its current operating permit provisions so that it can continue to utilize fuel oil.

WHOLESALE ENERGY MARKET

Dover purchases its electrical energy directly from PJM and hedges price uncertainty using bilateral contracts and self-supplied generation. These purchases are made in accordance with its "Energy Management Risk Policy". Dover programmatically purchases fixed price forward transactions up to five years in advance of the actual flow date. Decisions on which products to purchase and quantities to be purchased are made by Dover's Risk Management Committee (RMC).

For the longer-term IRP study, market area resource and load details were extracted from the PJM 2016 Regional Transmission Expansion Plan (2016 RTEP) Reference Case inputs. The 2016 RTEP is a planning study of the entire PJM market, developed jointly with all the utilities in the PJM region. It is highly vetted and incorporates local knowledge of PJM utilities. These inputs were transferred to the energy market model input format for the 2018 – 2037 study period.

CARBON CONSTRAINT PROJECTION

Carbon constraint projections were derived from the published Clean Power Plan (CPP) carbon limitations. In the 2017 Dover IRP, an implementation date of 2024 is assumed for CPP. The published CPP implementation glide path is then utilized (indexed from 2024). For the states which participate in the Regional Greenhouse Gas Initiative (RGGI), it is assumed that RGGI continues under its current market design.

MODEL RESULTS

- **Base Case** - Uses base projections for demand and commodity prices, without the addition of new regulation. RGGI is assumed to continue under current market design and with current participating states.

  High Natural Gas Price Case – High gas prices will result in significant cost increased to Dover, however, like a tide lifts all boats, other LSE's surrounding Dover will experience similar cost increases.

- **Low Natural Gas Price Case** – Extended low gas prices reduce cost to serve load. Existing Dover units have very limited generation.

- **Carbon Constraints –** Carbon constraints and higher gas prices cause market prices to increase.

- **More Stringent Renewable Portfolio Standard:** RPS requirements increased to 50% for all of PJM.

Generation Retirement Schedules and Capacity Additions

Analysis was performed for the following unit retirement alternatives: (1) McKee Run retired in 2027; VanSant life extension with $2.1 million estimated cost of major overhaul; (2) McKee Run retired in 2027**;** VanSant retired in 2021 ; and (3) Both VanSant and McKee Run retired in 2021. These retirement assumptions drive the timing and amount of replacement capacity which Dover needs to acquire. The evaluated capacity additions for each retirement schedule are listed in Table 3.

TABLE 3
APPROXIMATE CAPACITY ADDITIONS (MW)

Retirement Schedule	2021 Additions	2024 Additions	2027 Additions
1. Base Case	0	50	100
2. Retire VanSant in 2021	50	40	100
3. Retire MR3 & VanSant in 2021	150	40	0

VanSant is a newer unit than McKee Run 3 so it is assumed that it will remain in service throughout the study period in the Base Case. The last major overhaul on this unit was in 2004. The plant operator has recommended that another overhaul be performed in the near future at an estimated cost of $2.1 million. The retirement scenarios are used to evaluate the economics associated with this investment, assuming that the unit could no longer be included as reliable capacity unless the overhaul is performed.

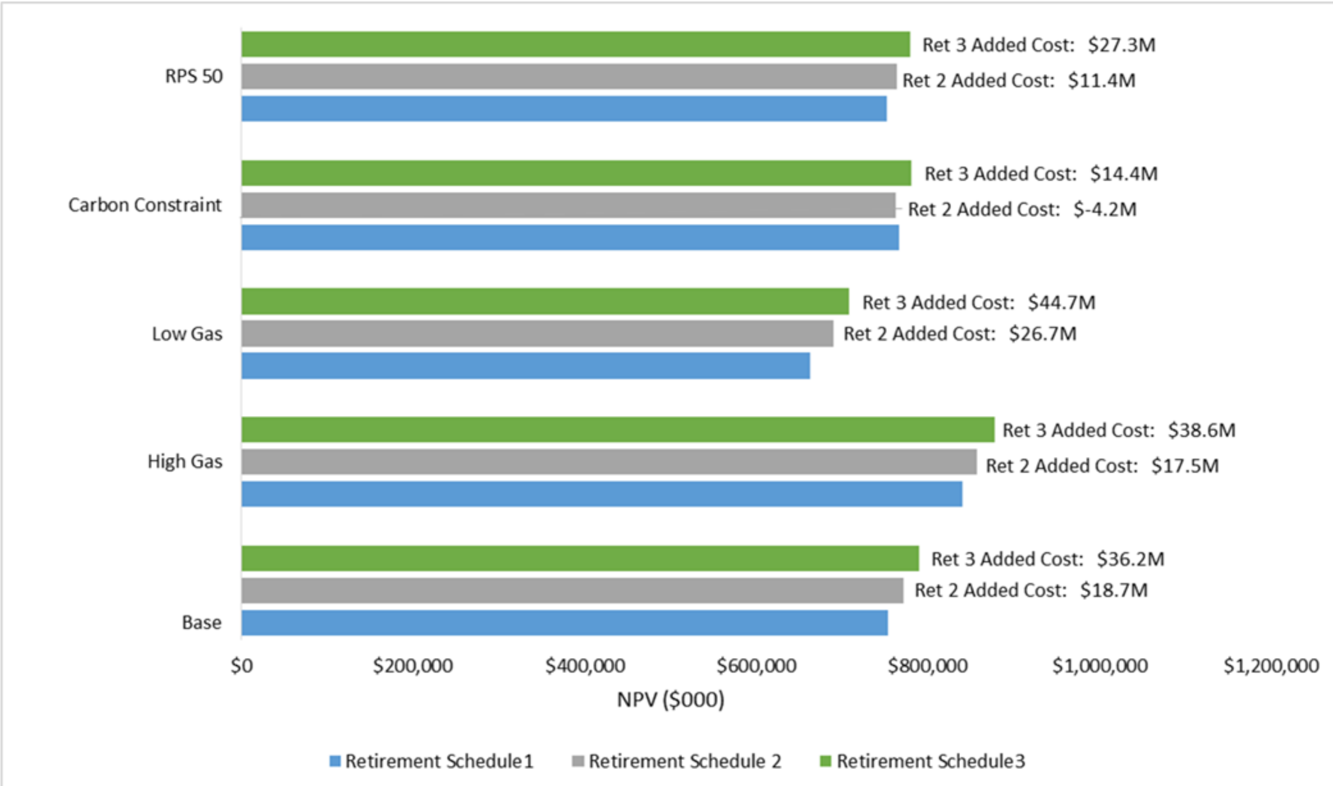
Scenarios

Individual Scenarios based on a variety of new generation alternatives were evaluated. The amount of additional generation required to meet the PJM reliability requirement is dependent on timing of the retirements of existing generation and expiration of the existing five year 40 MW capacity purchase. The nine (9) Scenarios which are presented herein represent the solutions with the lowest incremental NPV in the Base Case (expected NG prices, RGGI only, existing RPS).

For this IRP, a total of 135 separate economic analyses are presented (5 Sensitivities x 3 Retirement Schedules x 9 Scenarios). For brevity, only comparisons of the analyses which have the lowest overall Net Present Value of Revenue Requirements (NPV-RR) are shown in this Executive Summary. Results from all analyses are shown in Sections 4 and 5 and in the Appendix.

Figure 5 presents a high-level comparison of the lowest cost generation expansion scenarios for each of three retirement plans and the five (5) sensitivities which have been analyzed for this IRP. This figure presents cumulative NPV for the entire study period.

FIGURE 5
COMPARISON OF SCENARIO RESULTS



A noteworthy observation is that Retirement Schedule 1 (McKee Run 3 retired in 2027 and VanSant retired in 2041) shown in Table 3 resulted in the lowest NPV across all sensitivities. Regarding the natural gas price sensitivities, overall NPV varies from 88% of the base case for the low natural gas price sensitivities to 112% for the high natural gas price sensitivities. While this range of uncertainty is significant, it should be recognized that all LSEs will experience similar cost variations, so Dover should be able to remain competitive with its neighbors.

The NPVs for the higher carbon constraint and higher renewable portfolio sensitivities should be compared to the Base Case since they utilize the expected, or middle, natural gas price projections. Notice that the analysis shows these Sensitivities are expected to only have small impacts on Dover's overall costs. Without further analysis, explanation for the reasons for this minimal impact cannot be fully explained, however with the rapid declines in the cost of renewable energy generation and the fact that its variable cost for renewable resources is near zero likely drive these comparative results.

More detail which compares the three scenarios is shown on Table 4. This table provides the types and amount of new generation resources which were added for each of these three lowest cost scenarios. When existing generation is retired earlier, larger amounts of new capacity will be required sooner.

TABLE 4
COMPARISON OF SCENARIO RESULTS

		Retirement Schedule 1			Retirement Schedule 2			Retirement Schedule 3		
		No Vansant Retirement McKee 3 Retires 2027			Vansant Retires 2021 McKee 3 Retires 2027			Vansant Retires 2021 McKee 3 Retires 2021		
Lowest Cost Scenario		Scenario 6			Scenario 15			Scenario 25		
		Unit Name	PJM Peaking Capacity	Year of Install	Unit Name	PJM Peaking Capacity	Year of Install	Unit Name	PJM Peaking Capacity	Year of Install
		PPA NGCC	40	2024	PPA NGCC	50	2021	PPA NGCC	150	2021
		Solar	11.4	2024	Solar	11.4	2024	Solar	11.4	2024
		PPA NGCC	90	2027	PPA NGCC	30	2024	PPA NGCC	30	2024
		Solar	11.4	2027	Solar	11.4	2027			
					PPA NGCC	90	2027			
Results		**NPV ($000)**			**NPV ($000)**	**Change from Schedule 1 ($000)**		**NPV ($000)**	**Change from Schedule 1 ($000)**	
Sensitivities	Base	$753,495			$772,167	$18,672		$789,670	$36,175	
	High Gas	$839,822			$857,351	$17,529		$878,461	$38,639	
	Low Gas	$663,164			$689,818	$26,654		$707,905	$44,741	
	Carbon Constraint	$766,502			$762,285	-$4,217		$780,894	$14,392	
	RPS 50	$752,533			$763,924	$11,392		$779,863	$27,331	

In the Carbon Constraint Sensitivity, Locational Marginal Prices (LMPs) are elevated in the later years of the study. This makes new installations more valuable in this time frame. However, the later years in the study inherently introduces more risk in the LMP assessment. More detail of model analysis can be found in the sections that follow this Executive Summary. The following conclusions can be drawn from our study.

CONCLUSIONS

- The ownership/PPA fixed cost for replacements to McKee 3 and VanSant are greater than the ongoing Operating and Maintenance (O&M) cost of the existing generation.
  - Extension of VanSant's useful life economic feasibility assumes life extension costs of $2.1 million in 2018 as provided by Dover staff.
- The most economical solutions include the self-build installation of Solar PV.
  - Total land required for 30 MW of Solar PV plant is approximately 120 - 150 acres. This may require additional property purchase by City of Dover.

Non-solar resource option scenarios were evaluated separately to address the possibility of land limitations.

- Evaluation of options <u>including</u> Solar PV
  - PPAs of 40 MWs and installation of 30 MWs of Solar PV are the most economical results for the capacity shortage in 2024.
  - For the second tranche, 100 MW of capacity is needed for 2027. A combination of 30 MWs Solar PV and 90 MWs of PPAs is the most economical solution.
- Evaluation of options <u>excluding</u> Solar PV
  - PPAs totaling 50 MWs are the most economical by model results for the capacity shortage in 2024.
  - For the second tranche, a 100 MW of capacity is needed for 2027. The option of 100 MWs of PPAs is the most economical solution.
- The variation of NPV for the scenarios that include a PPA or self-build option is relatively small. Ranking of results could vary depending on proposals received in response to an RFP.

RECOMMENDATIONS

- To make up for the capacity shortfall in 2024, it is recommended an RFP be issued for 50 MWs of capacity to firm up IRP pricing and cost comparison. Options for this RFP should include:
    - Purchase Power Agreement
    - Installation of 30 MW of Solar PV (11.4 MWs PJM Capacity)
    - Self-Build (GT or RICE installation)
- Similarly, it is recommended a second RFP is issued for the 2027 tranche of 100 MW of capacity.
- If choosing to use PPA's for capacity requirements, it is recommended the City uses a diversified combination of vendors and term lengths to help mitigate energy commodity risks.
- Current long-term projections show future addition requirements are needed to serve peak demand requirements. A demand side peak reduction study focused on Demand Side Management programs is recommended.
- Dover's existing portfolio is nearing the end of its useful economic life. Dover needs to explore acceptable alternatives to replace the retiring capacity. Since Dover can balance its short-term capacity needs in the PJM RPM Capacity Market, there is available time to conduct detailed evaluations of alternatives.

LIST OF ACRONYMS

AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
BA	Balancing Authority
BTMg	Behind the Meter generation
C&I	Commercial and Industrial
CAA	Clean Air Act
CCGT	Combined Cycle Gas Turbine
CT	Simple Cycle Gas (Combustion) Turbine
CDD	Cooling Degree Days
CPP	U.S. EPA's Clean Power Plan
CO_2	Carbon Dioxide
CSAPR	Cross State Air Pollution Rule
CSP	Curtailment Service Provider
DA	Distribution Automation
DEMEC	Delaware Municipal Electric Corporation
DMRPS	Delaware Municipal Renewable Portfolio Standard
DRR or DR	Demand Response Resource
DSM	Demand Side Management
DY	PJM's Capacity Delivery Year (June 1 – May 31 of the following year)
EE	Energy Efficiency
EGUs	Electric Generating Units
EIA	United States Energy Information Agency
EM&V	Evaluation, Measurement and Verification
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
FOM	Fixed Operating and Maintenance
FT	Firm Transmission
FTR	Financial Transmission Right
GHG	Greenhouse Gases
GWh	GigaWatt-hour (energy)
GPR	Green Power Rider
GT	Gas Turbine
HDD	Heating Degree Days
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation and Air Conditioning
IA	Interconnection Agreement
ITC	Federal Investment Tax Credit
IRP	Integrated Resource Plan

ISO	Independent System Operator
kW	KiloWatt (power)
kWh	Kilo Watt-hour (energy)
LDC	Local Distribution Company for natural gas
LSE	Load Serving Entity
LMR	Load Modifying Resource
MATS	Mercury and Air Toxic Standards (EPA air emissions regulation)
MAE	Mean Absolute Error
MP	Market Participant
MPS	Market Potential Study
MW	MegaWatt (power)
MWh	MegaWatt-hour (energy)
NAAQS	National Ambient Air Quality Standards
NAES	North American Energy Services (Provides power plant O&M services)Dover)
NERC	North American Electric Reliability Corporation
NG	Natural Gas
NGCC	Natural Gas Combined Cycle generator
NOPR	Notice of Proposed Rulemaking
NOx	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NPVRR	Net Present Value of Revenue Requirements
NSPS	New Source Performance Standards
NYMEX	New York Mercantile Exchange
OATT	Open Access Transmission Tariff
O&M	Operating and Maintenance Expense
PJM	PJM Interconnection LLC
PM	Particulate Matter
PPA	Power Purchase Agreement
PTC	Federal Production Tax Credit
PV	Photovoltaics
RAA	PJM's Reliability Assurance Agreement
RECs	Renewable Energy Certificates
RFP	Request for Proposals
RGGI	Regional Greenhouse Gas Initiative
RICE	Reciprocating Internal Combustion Engine
RPM	PJM's Reliability Pricing Model for Capacity Market
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Operator
RTEP	Regional Transmission Expansion Plan
SC	Simple Cycle generating unit
SREC	Solar Renewable Energy Certificate
SO_2	Sulfur Dioxide
STG	Steam Turbine-generator

PJM RTO or PJM	PJM Regional Transmission Operator
TEA	The Energy Authority, Inc.
TOU	Time of Use
ULSFO	Ultra-low sulfur fuel oil
VOM	Variable Operating and Maintenance

SECTION 1 – DOVER'S IRP PROCESS & CURRENT RESOURCE ASSESSMENT

WHAT IS INTEGRATED RESOURCE PLANNING?

An Integrated Resource Plan (IRP) is a comprehensive plan that explains the mix of generation and demand-side resources a utility plans to use to meet its customers' electricity needs in the future. An IRP should include:

- A demand forecast over a 20-year time horizon
- An assessment of supply-side generation resources
- An economic appraisal of renewable and non-renewable resources
- An assessment of feasible conservation and efficiency resources
- A *preferred* plan for meeting the utility's requirements
- An action plan

WHY DOES DOVER NEED AN IRP?

This IRP will guide Dover in making decisions about capacity and energy resources it will use to meet future demand for electricity in the Dover service area. Having a long-range energy resource plan enables Dover to provide affordable, reliable electricity to the people it serves well into the future and will better equip Dover to meet many of the challenges facing the electric utility industry.

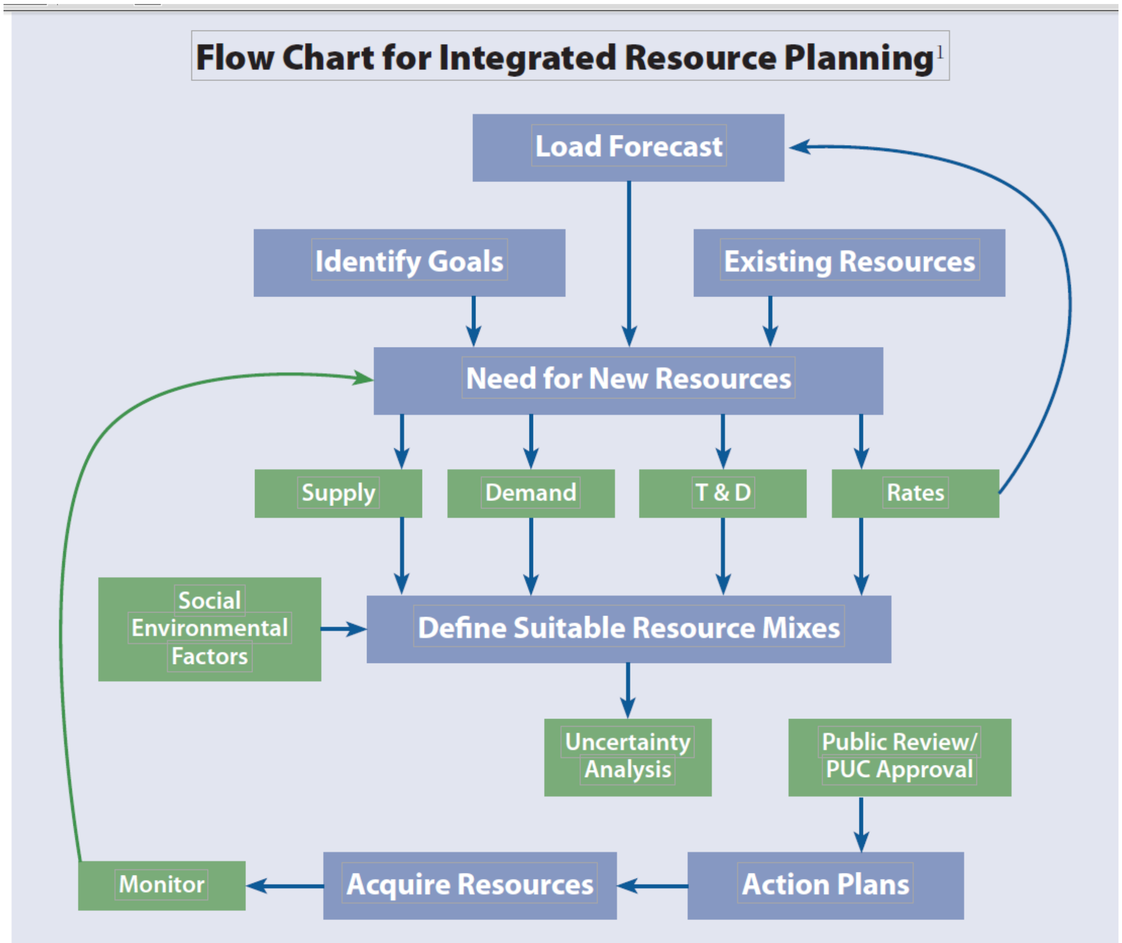
The IRP is an effort to anticipate key challenges facing Dover. Primarily, this means determining *how much* power Dover will need and *when* it will be needed. These projections are used to identify the optimum mix of energy resources to meet such demands. Evolving energy resources, technology, and regulations have implications for the best path forward for Dover, but each step will take time to implement.

Dover must allow adequate time to properly study, engineer, site and conduct environmental reviews to modify existing resources or build additional generation and transmission infrastructure. Given the long lead times required to plan, permit and build new generation, the IRP demand forecasts involve 10- to 20-year outlooks.

All of these activities entail varying levels of risk and uncertainties which this IRP accounts for in its analysis and energy resource portfolio. With this in mind, it is important that Dover maintain a mix of energy resource options, including natural gas, energy efficiency and other renewables, to reduce the risks associated with relying too much on a specific fuel type or resource type.

How is the IRP Derived?
A typical IRP process is diagramed in Figure 1-1.

FIGURE 1-1
TYPICAL IRP PROCESS



It is important that the IRP process identify supply and demand side alternatives for energy and reliable capacity that will:

- ✓ Best meet its objectives under a wide variety of possible future scenarios
- ✓ Identify financially acceptable alternatives based on cost and risk
- ✓ Identify non-financial influences that could affect decision
- ✓ Addresses sources of uncertainty (fiscal, physical, policy, regulatory)

Dover's 2017 IRP includes cost analysis of supply side resource options. Dover has already addressed demand side resource options and it's the Delaware Municipal Electric Corporation's (DEMEC) *Green Energy Program*. These programs are described in more detail in Section 2 – Dover's Needs Analysis of this report.

The 2017 Dover IRP provides projections of likely resource scenarios that it may experience over the next 20 years. Additional key directives have been applied within this IRP framework to inform Dover's decision-making process. They act as guiding principles while developing and implementing the 2017 Dover IRP.

- Analyze key commodity, emissions, and price forecasts
- Incorporate proven methodologies for energy and demand forecasting
- Analyze existing and new resources on a cost-to-serve-load basis
- Utilize Net Present Value (NPV) in asset evaluation
- Present assumptions clearly and with transparency
- Provide clear recommendations

As part of the IRP process, Dover may develop an action plan that identifies the steps that must be taken over the next three to five years to implement the IRP recommendations.

Why Does Dover Need Generating Capacity?

Generating capacity is the ability of equipment which is able to produce electrical energy. Generating capacity is able to produce electrical energy whenever it is operated. Since customer demand for electrical energy varies by season and time of day, only a portion of generating capacity may be operating at any particular time, with the remaining capacity resources shut-down and on stand-by for periods when electrical demand is high and/or other generation resources are unable to operate due to equipment malfunctions.

Electric utilities must have both generation capacity resources and the ability to provide electrical energy instantaneously to serve its retail customers. Dover is no exception to these fundamental physical requirements. Electric generating units have the ability to produce both capacity and energy, so a balanced portfolio will have a mixture of generation resources to meet its customers' requirements.

Dover's requirements for capacity and energy are determined by the market it operates in. In Dover's case, it is a part of the PJM Regional Transmission Operator (RTO). Dover, as a Load Serving Entity (LSE) is bound by the requirements of PJM's Reliability Assurance Agreement (RAA).

Section 7.2 of the RAA specifies:

> *"7.2 Responsibility to Pay Locational Reliability Charge…. each Party shall pay, as to the loads it serves …. a Locational Reliability Charge for each such Zone during such Delivery Year. The Locational Reliability Charge shall equal such Party's Daily Unforced Capacity Obligation in a Zone…., times the Final Zonal Capacity Price for such Zone…."*

The *Daily Unforced Capacity Obligation* is determined by PJM through a peak demand forecasting process. PJM procures capacity for LSEs through RPM[2] Auctions. Owners of capacity resources, including Dover, compete in the auction. The RPM Base Residual Auctions (BRA) are conducted three years in advance of the Delivery Year, with a series of incremental auctions being conducted as the Delivery Year approaches to fine-tune the capacity-demand balance. A weighted average auction clearing price is used to determine the *Final Zonal Capacity Price* which is paid by the LSE just before the Delivery Year begins. Delivery Years are for June through May, with the Final Capacity Price posted in the month of May for the upcoming Delivery Year.

The design of the capacity market, the associated uncertainties of the supply-demand balance and the frequent modifications to the RPM rules result in significant variability of the RPM capacity prices. RPM capacity prices for the DPL-South zone, which Dover is in, has ranged from a low of $2.51 per MW-Day to a high of $245/MW-Day over the last five years.

Dover's Unforced Capacity Obligation is approximately 180 MW. Using the range of zonal clearing prices above, Dover's annual Locational Reliability Charge could have ranged from $165,000 to $16.1 million. The maximum price for the auctions is 1.5 times the Net Cost of New Entry (Net CONE), or $394/MW-Day for the upcoming BRA for Delivery Year 2021, at a potential cost of $25.9 million to Dover.

While it is highly unlikely the auction will clear at such a high price, it does provide insight into the degree of price risk which is associated with the PJM Capacity Market. It is therefore imperative that Dover mitigate this price risk by securing capacity outside the PJM RPM Capacity Market framework.

Several mechanisms are available for Dover to mitigate, or "hedge" this capacity price risk:

1. Reduce the UCAP Obligation through Demand Side programs
    a. Load Management
    b. Install Demand-Side, or "Behind-the-Meter" Resources (such as Dover's SunPark)
2. Enter long-term bilateral contracts for capacity
3. Own and operate self-supply generation, such as McKee Run and VanSant

DOVER'S WHOLESALE ELECTRIC MARKET ENVIRONMENT AND RESOURCES

Dover's Market Environment for wholesale electricity is primarily defined by the PJM Regional Transmission Organization (RTO) and its Open Access Transmission Tariff (OATT), Operating Agreement and Reliability Assurance Agreement (RAA). Dover is a party to these agreements. Wholesale purchase and sale transactions are governed by these agreements.

Dover also owns and operates electric generation, transmission and distribution systems which are used to provide electrical service to its retail electric customers. This IRP addresses long-term plans for its wholesale energy and capacity market. Potential changes or improvements to Dover's transmission and distribution system are beyond the scope of this IRP.

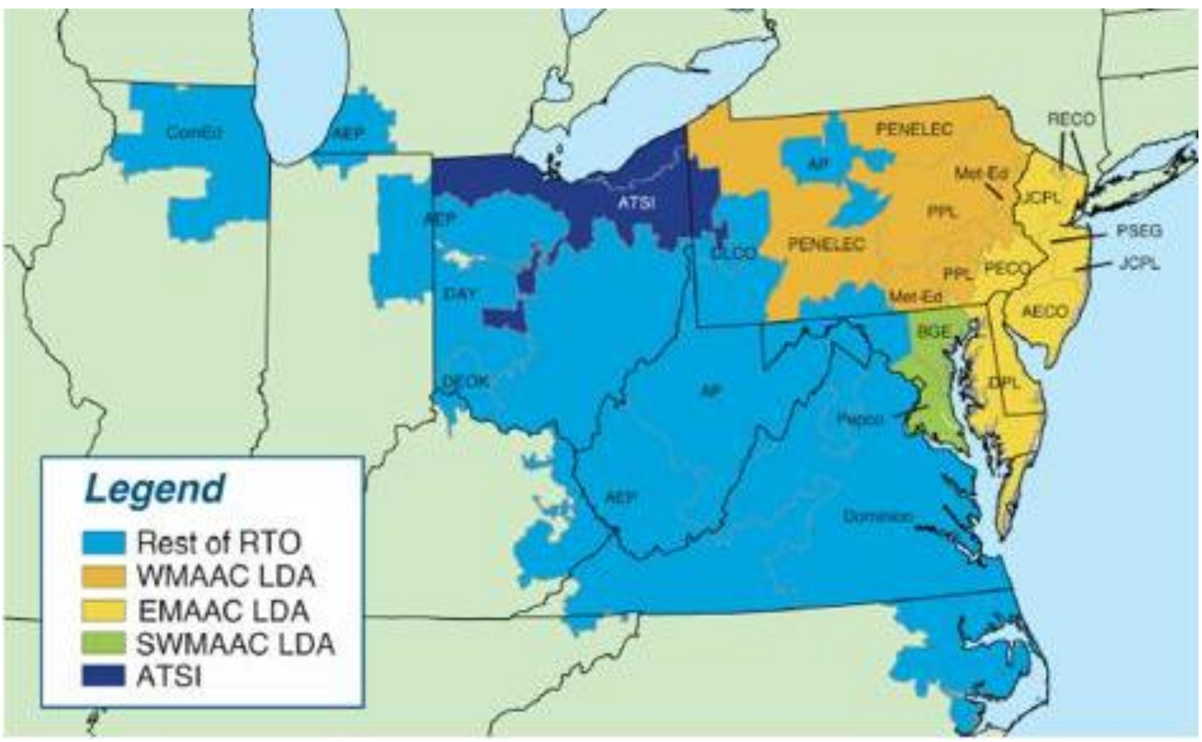
[2] Resource Pricing Model

PJM

Today, PJM oversees the bulk electric grid and wholesale power market in the northeastern United States on behalf of a diverse group of utilities and transmission companies. The PJM system covers more than 243,000 square miles in 13 states and the District of Columbia. Serving approximately 61 million people, the PJM system includes major U.S. load centers from the western border of Illinois to the Atlantic coast including the metropolitan areas of Baltimore, Chicago, Cleveland, Columbus, Dayton, Newark, Norfolk, Philadelphia, Pittsburgh, Richmond and Washington D.C.

PJM dispatches more than 183,600 megawatts of generation capacity over 81,000 miles of transmission lines, a system that serves nearly 21 percent of the U.S. economy. The PJM system is electrically continuous and consists of multiple electrical service territories. PJM's Bulk Electric System (BES) includes a robust network of 765kV, 500kV, 345kV, 230kV, 161kV, 138kV, and 115kV facilities. The map below depicts the PJM service territory footprint overlaid with Local Delivery Areas identified.

FIGURE 1-2
PJM LOCAL DELIVERY AREAS



Specifically, the PJM market includes:

- A Day-Ahead Energy Market with Financial Transmission Rights (FTRs).
- A Reliability Unit Commitment process (RUC)
- An Ancillary Services market (AS)
- A Real-Time Energy Balancing Market
- A generation Capacity Market (RPM)

- Incorporation of a price-based Operating Reserve Market.
- Combining current Balancing Authorities into a single PJM Balancing Authority.

PJM facilitates a number of important functions to coordinate operation and planning of the wholesale electric grid within its service territory. It is a stakeholder-driven organization, with decision making and conflict resolution achieved through a stakeholder committee structure.

Because PJM manages an electric transmission grid which crosses state boundaries and involves wholesale power transactions, it is subject to federal regulation under the Federal Power Act. PJM's primary governing regulatory body is the Federal Energy Regulatory Commission (FERC), with input from state regulators when appropriate. All tariffs, rates, and operating agreements associated with this wholesale market are subject to FERC approval, including any changes which are made to these important agreements.

THERMAL GENERATION

Dover owns two generating stations with one active steam turbine-generator (ST) and one combustion turbine-generators (CT, a.k.a. CTG or GT) totaling 145 megawatts (MW) of summer capacity. Dover's generating units use natural gas, with capability of burning ultra-low sulfur fuel oil as a back-up. Table 1-1 lists the individual generating units along with relevant information about each one.

TABLE 1-1

GENERATION RESOURCES

Plant	Type	Year of Commercial Operation	Year of Retirement	Net (MW)	PJM Capacity (MW)
McKee Run 3	Steam	1975	2027	102	102
VanSant	CT	1992	2041	43	43
SunPark	Renewable	2011	2031	10	BtMG[3]
TOTAL				**155**	**145**

RENEWABLE ENERGY RESOURCES

Dover has contracted with DEMEC to manage its RPS compliance. DEMEC facilitates this by transferring a portion of the Renewable Energy Credits (RECs) from Laurel Hill to Dover's account. Dover pays DEMEC for its non-Solar REC requirements under the RPS without directly receiving any capacity or energy from Laurel Hill.

Solar

Dover SunPark Solar Farm

[3] SunPark is behind the PJM billing meter; it off-sets Dover's peak demand and energy purchases from PJM.

In 2011, Dover added solar energy to its portfolio of locally-generated electricity by entering into a 25-year Power Purchase Agreement for approximately 9.3 MW White Oak Solar, LLC, (a.k.a. Sunpark) a subsidiary of LS Power. It has performed as projected with a 20% capacity factor in its first five years of operation. Dover has the option to purchase the plant when this PPA expires in 2032.

SunPark is interconnected to Dover's internal electrical network. Its electrical output goes directly to serve Dover's retail customers; meter readings are not submitted to the PJM and it is not offered into the PJM energy and capacity markets as a generation resource. Therefore, this is also considered a behind-the-meter resource and is a form of distributed resources (DR).

Wind

Even though Dover does not own or directly contract with any wind-based generating resources, it fulfills much of its non-solar Renewable Portfolio Standard (RPS) requirements indirectly from the Laurel Hill Wind Farm Located in Lycoming County, Pennsylvania. This facility is capable of generates up to 69 megawatts of electricity, enough to power about 20,000 homes. Commercial operation began in October 2012.

The Laurel Hill Wind Farm supplies electricity to Delaware Municipal Electric Corporation (DEMEC) under the terms of a 25-year PPA.

DOVER'S TRANSMISSION SYSTEM

Dover's existing transmission system consists of a 69 kilo-Volt (kV) loop with a 230 kV interconnection with Delmarva Power & Light (DPL) at the Cartanza Substation. The 69 kV grid serves several transmission-to-distribution voltage step-down substations located throughout the Dover urban area.

There are additional generation facilities located in or near the Dover urban area which are not owned by Dover. These include the 300 MW Calpine's Garrison Oak combined cycle plant which directly interconnects with the DPL-owned Cartanza 230 kV substation and NRG Dover Energy located between the Kraft Foods and Proctor and Gamble industrial plants. NRG's 22 MW steam turbine can be used to off-set industrial load or supply energy to Dover's distribution system. Its two 44 MW gas turbine-generators are interconnected with DPL's 69kV facilities in the vicinity of the plant and are not directly connected to Dover's electrical network.

FUEL SUPPLY

Dover's McKee Run and VanSant generating plants are capable of utilizing natural gas or ultra-low sulfur fuel oil (ULSFO). The Title V environmental operating permit restricts how much these units can operate on either fuel. Generally, use of ULSFO is restricted to only emergency conditions when natural gas is not available.

Natural Gas

Dover receives natural gas from the market, using interruptible transportation on the Eastern Shore Natural Gas interstate pipeline. Interruptible transportation is only available when firm shippers (such as Chesapeake local distribution company (LDC)) is not using its own firm transportation.

Since firm shipper requirements take priority over non-firm shippers, and there are intra-day limitations on ratable usage, the amount of gas which Dover can use for electric generation is significantly less during critical winter periods. During non-critical winter periods, LDC utilization of the firm transportation capability will be relatively small, leaving interruptible and released firm transportation capacity available for Dover's gas fired generation.

Dover has evaluated acquisition of year-round firm transportation (FT) service for use in its generating stations, and has concluded that the costs of acquiring adequate FT outweighs the potential benefits. Considering these factors, this IRP assumes that Dover will not acquire firm natural gas transportation contracts for its existing generation.

Ultra-Low Sulfur Fuel Oil

Dover purchases fuel oil as a backup fuel when natural gas is unavailable. During winter months, Dover's generating units are offered in based on an oil price in the winter and are rarely called on. Dover maintains fuel oil inventories on-site in storage tanks located at McKee Run and VanSant. This inventory is primarily designed to be able to operate the generating units for brief periods if and when PJM directs Dover to dispatch the units, particularly during the winter when natural gas transportation is not expected to be available.

Dover has oil storage capacity as follows:

McKee Run – 2,700,000 gallons, 257 hour run time at full load (Units 1-3)

Van Sant – 258,000 gallons, 80.5 hour run time at full load

Dover, with assistance from TEA, has established a Fuel Oil Purchase Policy which governs the amount of fuel oil kept in inventory and provides purchase guidelines when inventory levels are drawn down during periods of generation using fuel oil. The overall goal of the Dover fuel oil purchase program is to maintain enough fuel oil storage available to operate when called upon by PJM while ensuring excessive capital is not used for unnecessary fuel inventory. A secondary goal is to ensure diversification in supply. The City of Dover will have at a minimum 4 suppliers for ultra-low sulfur fuel oil (ULSFO). The fuel purchaser will periodically check to ensure the supplier is still capable of supplying the required fuel oil specifications. The fuel oil purchaser shall ensure that the fuel oil purchased meets environmental permits and regulations.

SECTION 2 – DOVER'S NEEDS ANALYSIS

PEAK DEMAND AND ENERGY FORECAST

Demand forecasts ensure sufficient resources are available to meet Dover customers' demand. The econometric load forecast in the IRP is a long-term model that estimates total energy usage by each respective customer category. Historical load data and econometric data establish the relationship between energy consumption and economic variables.

Demand Forecast Methodology

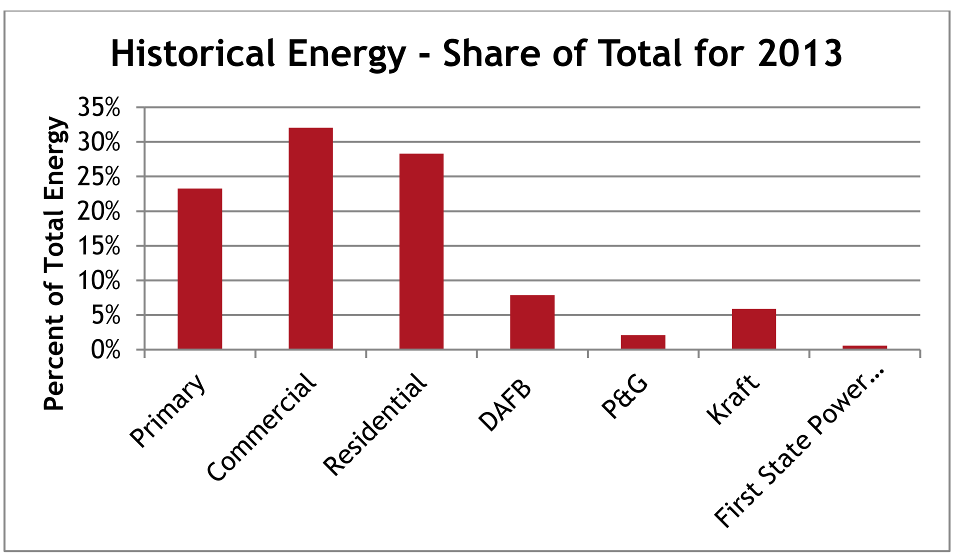
- Long-Term Forecast
    - Evaluates twenty years (2018-2037)
    - Includes 10-year historical energy data by customer category
    - Uses Woods & Poole county-by-county econometric database
    - Historical locational weather used as input into weather normalization model

Model Inputs – Historical Load

Dover provided monthly energy usage by customer grouping, including residential, commercial, primary meter service and selected large power customers. Historical data for these customer classes were provided by Dover staff.

The load data used as an input to the model is monthly consumption in kWh by customer class. Figure 2-1 presents the relative magnitude of Dover's customer demand by rate class.

FIGURE 2-1



Model Inputs – Econometric Forecast

The Energy Authority subscribes to Woods and Poole Economic Forecasts, which are updated annually, most recently in July 2015. The Woods and Poole Economics, Inc. database contains more than 900 economic and demographic variables for every county in the United States for every year from 1970 to 2050.

The comprehensive database includes:

- Detailed population data by age, sex, and race
- Employment and earnings by major industry
- Personal income by source of income
- Retail sales by kind of business
- Data on the number of households, their size, and their income

The Woods and Poole projection for each county in the United States is done simultaneously so that changes in one county will affect growth or decline in other counties. The specific economic projection technique used by Woods and Poole to generate the employment, earnings, and income estimates for each county in the United States generally follow a standard economic "export-base" approach.

According to Woods and Poole, the long-term outlook for the United States economy is one of steady and modest growth through the year 2050. Although periodic business cycles, such as the 2008-09 recession, will interrupt and change the growth trajectory, the nation's employment and income are expected to rise every year from 2015 to 2050. Although employment growth has been uneven in recent years, with particularly sharp job losses in manufacturing, the economy is expected to stabilize and produce steady job gains.

The load forecast model utilizes the data for total population, total employment, total number of households, and total retail sales, including eating and drinking places sales, for Kent County, Delaware. Figures 2-2, 2-3, 2-4 and 2-5 present historical and projected annual growth rates for key economic indications for Kent County which were used for this demand forecast.

Figure 2-2
Population Growth Rate

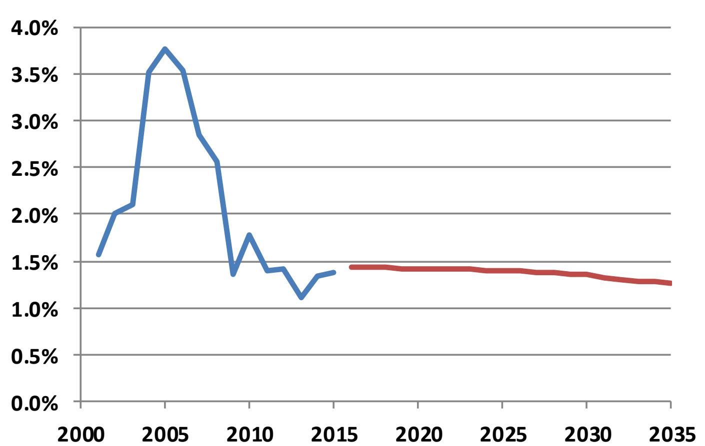


Figure 2-3
Number of Households Growth Rate

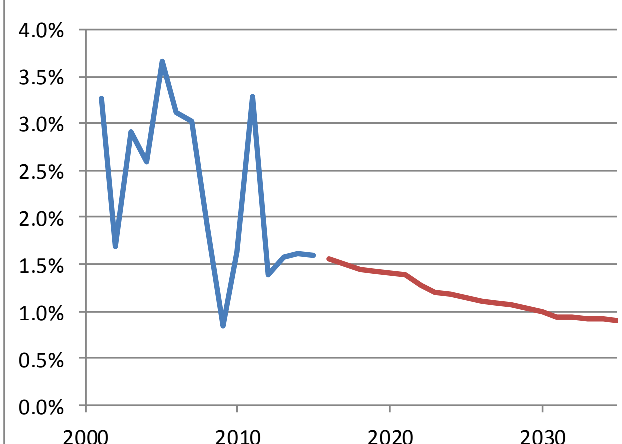


Figure 2-4
Personal Income Growth Rate

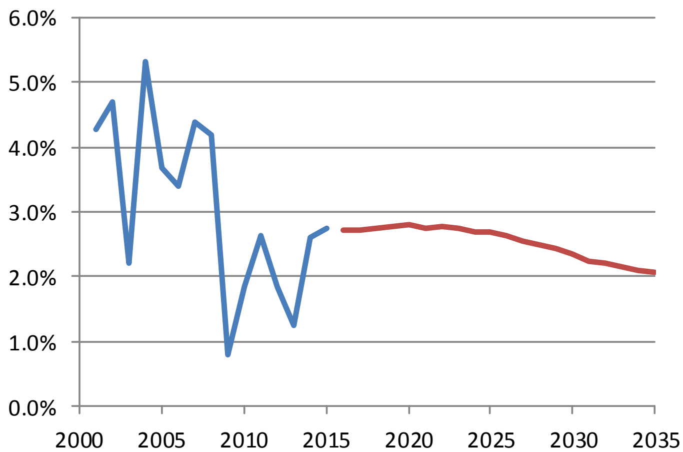
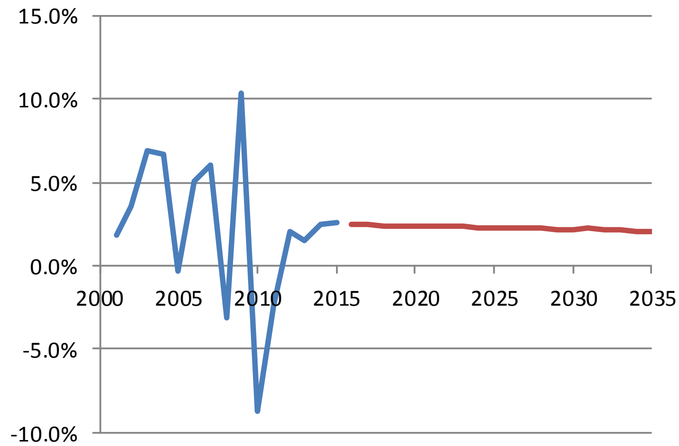


Figure 2-5
Gross Regional Product Growth Rate



Model Inputs – Weather

The load forecast incorporates weather data from the KDOV weather station located at the Dover Air Force Base. Heating degree days represent days where customers demand heating services and cooling degree days represent days where customers require air conditioning services. For the purposes of this forecast, heating and cooling degree days have been calculated using a temperature with a 65-degree base.

$$\text{CDD65} = \sum \max(\text{Temperature}_d - 65, 0)$$

$$\text{HDD65} = \sum \max(65 - \text{Temperature}_d, 0)$$

Where d is the daily observation.

The forecasted cooling and heating degree days are based off a 10-year time period average and represent "normal" weather as shown on Figures 2-6 and 2-7 below.

Figure 2-6
Heating Degree Days

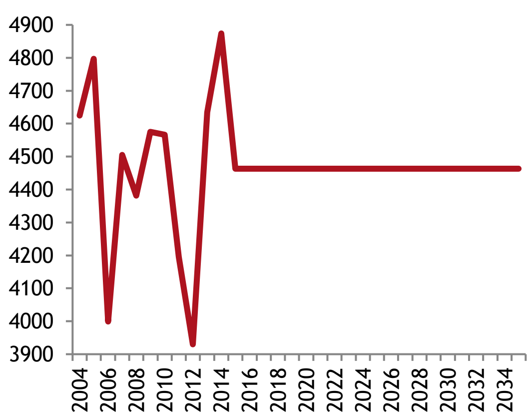


Figure 2-7
Cooling Degree Days

Other Load Forecast Input Assumptions

In addition to the growth captured in the econometric indicators, local industries communicate their expansion schedules to The City of Dover Electric Department. In the coming years, Playtex plans to add a new load of 6 MW which brings the total load to 10 MW. New load slowly came on line in 2016 and will reach full load by summer of 2017. Playtex is included in the Primary rate class.

Since 2015, the Chester Grove and Lender Lakes residential began expansion by 16 houses and 321 apartments combined. This information is not explicitly added to the forecast, as it is captured in the Number of Households economic indicator.

Load Forecast Methodology

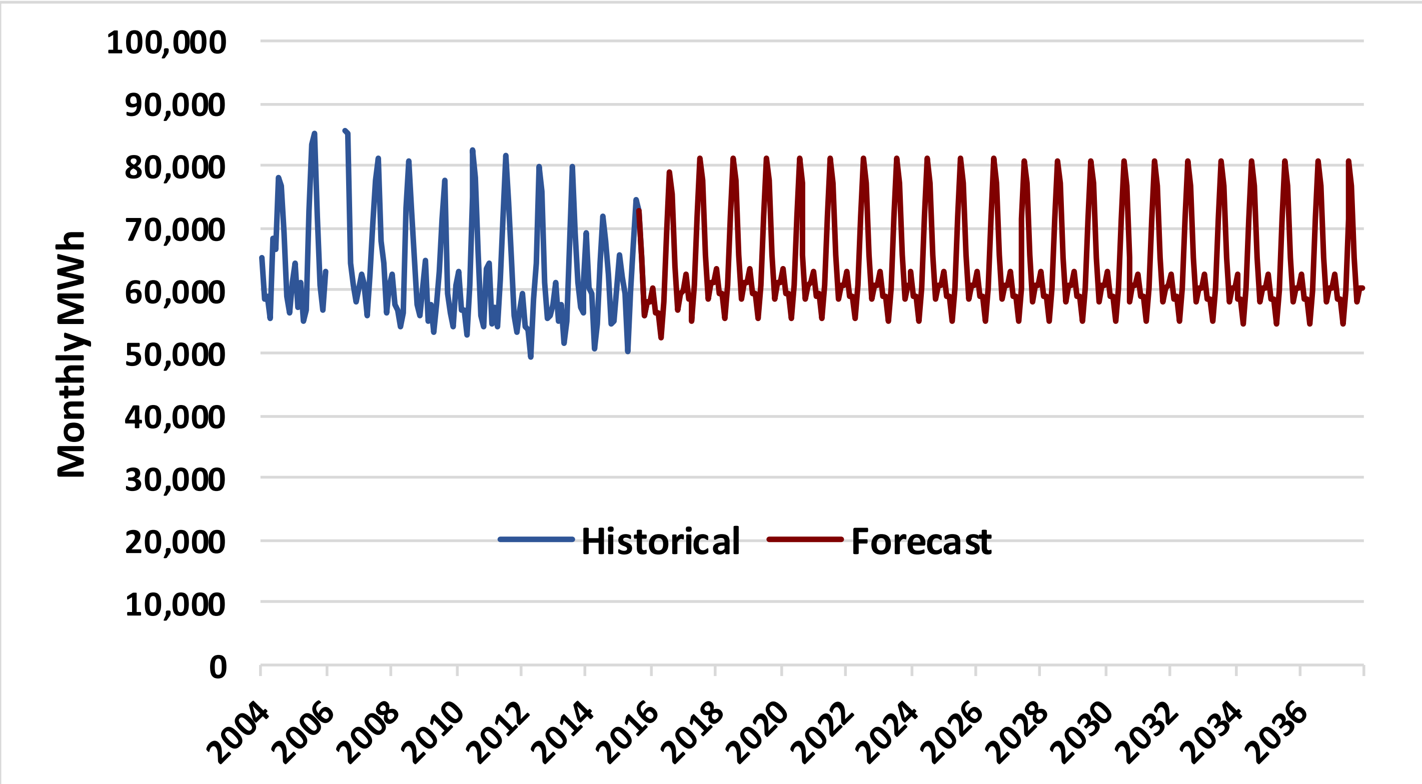
The relationship between the normalized historical load data and the econometric variables is determined by partial least squares (PLS) regression. This is a typical approach when constructing predictive models with factors that are highly correlated, as is the case when dealing with econometric factors. PLS regression is a technique that generalizes and combines features from principal component analysis and multiple regressions. PLS regression tends to outperform multiple linear regression when there are a large number of variables because it avoids over-fitting the data. The established relationship between load data and econometric variables is then used with the Woods and Poole Economic projections to create an energy consumption forecast.

Forecast Results

Figure 2-8 presents the monthly historical peak demand and peak demand forecast used in all sensitivities analyzed. Energy sales have been gradually declining since 2005. TEA is not forecasting any significant increases in energy demand during the study period. While this may be counter-intuitive to long-time energy professionals, this trend is being seen by electric utilities nation-wide.

It is notable that this forecast reflects no load growth despite the econometric forecasts indicating that the region will continue to grow in population. The load forecast is capturing the fact that in the past population and number of households have grown, but the historical load remained flat. This implies that efficiency of electrical usage is keeping pace with population growth.

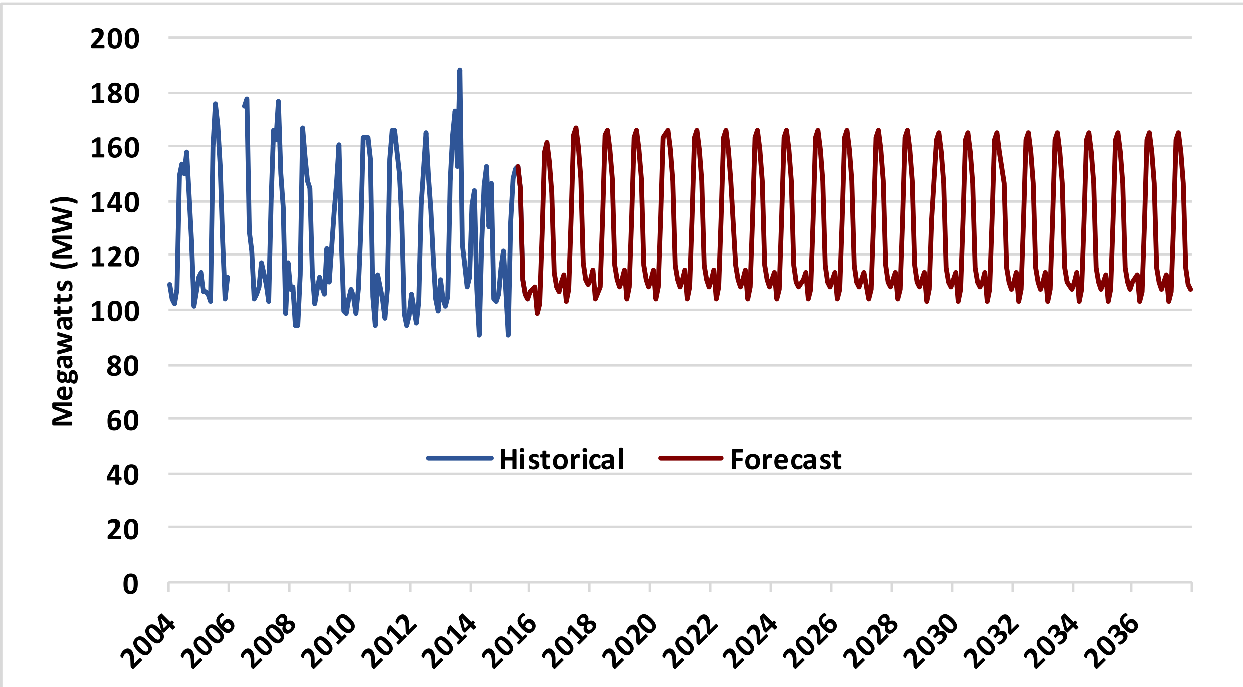
FIGURE 2-8
DOVER'S TOTAL ENERGY
(HISTORICAL AND FORECASTED)



Peak Demand Forecast

To calculate monthly peak demand, a peak load factor was calculated using the historical relationship between total monthly load and the monthly peak demand. The calculated peak load factor was applied to the monthly load forecast to generate peak demands for every month. Figure 2-9 presents the peak demand forecasts.

FIGURE 2-9
PEAK DEMAND FORECASTS



PJM Resource Adequacy Requirements

As a Load Serving Entity (LSE) in the PJM Balancing Authority, Dover is responsible for complying with PJM's Resource Adequacy Requirement (RAR). The RAR requires an LSE to maintain enough capacity to meet its summer season net peak demand plus a Planning Reserve Margin of 16.5%.

Dover participates in the PJM Capacity Market. As a Load Serving Entity (LSE), it purchases all capacity required to meet its load serving obligation. As an owner of generation, it sells its generating capacity into the PJM Capacity Market. Revenues from the sale of generation capacity off-set the LSE's Locational Reliability payments for capacity.

The PJM Capacity Market is separable from the energy market. It is possible to purchase or sell a capacity product without any obligation to purchase or sell energy products. An LSE in PJM needs to be attentive to both markets. Even though the PJM Capacity Market is for three years into the future, it only clears one year's requirement at a time. Therefore, it is a relatively short-term market.

PJM's capacity market construct is evolving and has been subject to a number of design changes over the last ten years. Market fundamentals (supply-demand balance) have also been shifting, with load forecasts declining, existing generation such as inefficient coal units retiring and new renewable and efficient natural gas resources added. The net result of these ever changing market dynamics is volatility in market clearing prices. The Base Residual Auction (BRA) prices for the delivery zone applicable to Dover (DPL-South) ranged from a low of $40/MW-Day in Delivery Year (DY) 2007/08 to a high of $245/MW-Day for DY2013/14.

Dover could choose to simply rely on the PJM Capacity Market to meet its load serving obligation. If it were to choose this option, it would be exposed to considerable price risks. It is prudent practice to secure capacity assets for the long-term to mitigate such price risks. Capacity can be acquired by construction of self-generation (as Dover has done with the McKee Run and VanSant generation), through joint ownership of generation with other utilities or through long-term bilateral purchases from other owners of generation.

PJM required LSE's to have sufficient capacity to meet its annual peak demand plus a reserve margin to insure reliability of supply. PJM's most recent reliability analysis established a reserve requirement which is 16.5% of load. Therefore, Dover must purchase sufficient capacity to meet its peak demand plus 16.5%.

DELAWARE MUNICIPAL RENEWABLE PORTFOLIO STANDARD

Dover is required by Delaware state law to implement renewable energy resources into its portfolio. The state law permits municipal and cooperative electric utilities to establish their own Renewable Portfolio Standard (RPS) requirements which are generally consistent to requirements applicable to investor owned utilities subject to the statute.

Dover's City Council approved Dover's participation in the Delaware Municipal Renewable Portfolio Standard (DMRPS) and its administration by the Delaware Municipal Electric Corporation (DEMEC) on December 10, 2012.

In developing a comparable plan, DEMEC evaluated its accomplishments and commitments regarding investments in renewable energy. DEMEC invested in the development of a portfolio of qualifying renewable energy resources to achieve the lowest possible compliance cost to protect its ratepayers from unreasonable and burdensome impacts on their cost of electricity. DEMEC's goal is to comply with the spirit of the Delaware RPS without creating a negative impact on the community ratepayers or the Delaware economy. The RPS incorporates the following features:

- Increasing the RPS target to 25% by 2025 with at least 3.5% from solar sources.
- Allowed municipal electric companies to develop and implement a comparable program to the State Renewable Energy Portfolio Standard for its ratepayers beginning in the 2013 Compliance Year (June 1, 2013 – May 31, 2014).
- Provided a method to freeze the RPS compliance obligations for utilities if costs exceed "circuit breakers" of 3% of the total cost of purchased power for Renewable Energy Credits (RECs) and 1% for Solar Renewable Energy Credits (SRECs) in any calendar year.

DEMEC has set the following objectives as goals for its Municipal RPS Plan.

- Develop and implement a compliance plan that is comparable to the State-mandated plan for Delmarva Power and that encourages development of qualifying renewable energy resources in the State of Delaware in all State-defined tiers.
- Plan in 5 year increments. The parameters of the 5 year planning cycle will have the goals of achieving a comparable plan that:

  - Achieves the lowest cost compliance solutions to mitigate high renewable energy cost impacts for our community ratepayers and the state economy
  - Encourages the development of renewable resources in our member communities
  - Maintains the high reliability of electric service in our community systems.
- DEMEC will review and rebalance its compliance schedule annually to assure cost impacts to our community ratepayers are reasonable and accurately match qualifying retail electricity sales with renewable energy resource procurement.

Table 2-1
Municipal Renewable Energy 5-Year Procurement Schedule

Compliance Year - (beginning June 1st)	Minimum Cumulative Percentage from Eligible Energy Resources*	Minimum Cumulative Percentage from Solar Photovoltaics
2013	10.00%	0.60%
2014	11.50%	0.80%
2015	13.00%	1.00%
2016	14.50%	1.25%
2017	16.00%	1.50%

* Minimum Percentage from Eligible Energy Resources Includes the Minimum Percentage from Solar Photovoltaics.

It is expected that DEMEC and Dover will update its DMRPS to conform to State goal of 25% renewables by 2025.

As of the 2015/2016 compliance year, Dover reached the solar 1% compliance cost limit also known as the "circuit breaker" and may elect to stop increasing its solar portfolio percentage per State of Delaware regulations (26 Del. C. § 363(g)). Since this provision is intended to extend the ultimate compliance requirements, if Dover's cost of compliance drops below 1%, it will be required to meet the 3.5% overall solar RPS target within the IRP study period.

Regional Greenhouse Gas Initiative

The Regional Greenhouse Gas Initiative (RGGI) is the first mandatory market-based program in the United States to reduce greenhouse gas emissions. RGGI is a cooperative effort among the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap and reduce CO2 emissions from the power sector.

The RGGI CO2 Budget Trading Programs regulate emissions from fossil fuel-fired power plants with a capacity of 25 MW or greater located within the RGGI States ("CO2 budget sources" or "sources"). The RGGI CO2 Budget Trading Program became effective as of January 1, 2009. CO2 budget sources are required to possess CO2 allowances equal to their CO2 emissions over a three-year control period.

A CO_2 allowance represents a limited authorization to emit one short ton of CO_2 from a regulated source, as issued by a participating state. CO_2 allowances are issued by each state in an amount defined in each state's applicable statute and/or regulations.

Following a comprehensive 2012 Program Review, the RGGI states implemented a new 2014 RGGI cap of 91 million short tons. The RGGI CO_2 cap then declines 2.5 percent each year from 2015 to 2020. The RGGI CO_2 cap represents a regional budget for CO_2 emissions from the power sector. RGGI is currently conducting the 2016 Program Review. While it is expected that RGGI may implement lower caps and other program design revisions, the program approved in 2012 has been used for this IRP.

Specifically, Dover's McKee Run 3 and the VanSant gas turbine are included in this program. Dover must acquire sufficient allowances in the RGGI auctions or secondary markets to cover any CO_2 emissions from these two units.

DEMAND SIDE RESOURCE ACTIVITIES

Dover's existing demand side programs are described below:

- DEMEC Renewable Energy and Energy Efficiency Program
- Demand Response and Curtailment Service Providers
- Smart Meters

DEMEC Renewable Energy and Energy Efficiency Programs

The State of Delaware, pursuant to Senate Bill 74, mandates for each municipal electric company in the state to implement a renewable energy program which promotes energy efficiency technologies, renewable energy technologies or demand side management programs by June 1, 2006.

Dover entered into an agreement with DEMEC on April 11, 2006 wherein DEMEC acts as an agent to Dover and other participating Municipal Electric Companies to administer the mandated Renewable Energy Program on their behalf.

Pursuant to this agreement, DEMEC has established the "*Municipal Green Energy Fund*" (MGEF) which is a self-administered fund separate from the State's Green Energy Fund. DEMEC invoices Dover each month for Dover's prorate share of the costs associated with the Renewable Energy Program. DEMEC periodically updates its Green Energy Fund Program, with the most recent update becoming effective on August 10, 2015.

The MGEF provides grant funding directly to Dover's electric customers to install and own various Renewable Energy Technologies:

1. Solar Photovoltaic Systems
2. Solar Water Heating
3. Small Wind Turbines
4. Geothermal Heat Pump Systems
5. Fuel Cells

Under the separate Energy Efficiency Program, individual participating Municipal Electric Companies, including Dover, assign preference to projects that provide overall system benefits to the community.

TEA has not analyzed the overall impact of these programs on Dover's future power supply requirements. For the purpose of the IRP analysis, it is assumed that the historical load data used to develop the demand forecast projections already implicitly recognizes the impact of these programs on Dover's energy sales to its retail customers.

Since Dover currently has demand side programs which facilitate demand side and energy efficiency programs, additional programs are not suggested in this IRP. Dover may wish to conduct an analysis of the overall effectiveness of these programs and to determine what additional programs, if any, should be considered in the future.

Demand Response and Curtailment Service Providers

PJM defines Demand Response (DR) as follows:

> *The ability of retail consumers to respond to wholesale electricity prices – is integrated into PJM Interconnection's wholesale electricity markets, providing equivalent treatment for generation and demand resources. Retail customers have the opportunity to participate in PJM's energy, capacity and other markets and receive payments for the demand reductions they make.*
>
> *Other demand side alternatives include selective curtailment of service to specific electrical loads during periods of high demand."*

In the PJM market, retail consumers have the opportunity to manage their electricity use in response to conditions in the wholesale market. They can reduce their electricity consumption when wholesale prices are high or the reliability of the grid is threatened, receiving payments for the reductions they make. Common examples of reductions are turning up the temperature on the thermostat to reduce air conditioning or slowing down or stopping production at an industrial facility temporarily.

In PJM, qualified market participants who act as agents, called Curtailment Service Providers (CSPs), work with retail customers who wish to participate in demand response. CSPs aggregate the demand of retail customers, register that demand with PJM, submit the verification of demand reductions for payment by PJM and receive the payment from PJM. The allocation of the PJM payment between the CSP and the retail customer is a matter of private agreement between them. A CSP can help a customer identify opportunities and determine the needed equipment and systems to benefit financially from demand response participation.

Dover accommodates participation in this PJM program through an arrangement with DEMEC and CPower Corporation, a division of Constellation Energy. While Dover's electric system does not directly benefit from this program, it provides customers who are interested in curtailment services an avenue to pursue such interest.

As of April, 2017 CPower has the following twelve (12) Load Management – DR customers subscribed to this program within Dover's service territory:

- Target
- Capital School District (6 service locations)
- Pioneer Materials (3 service locations)

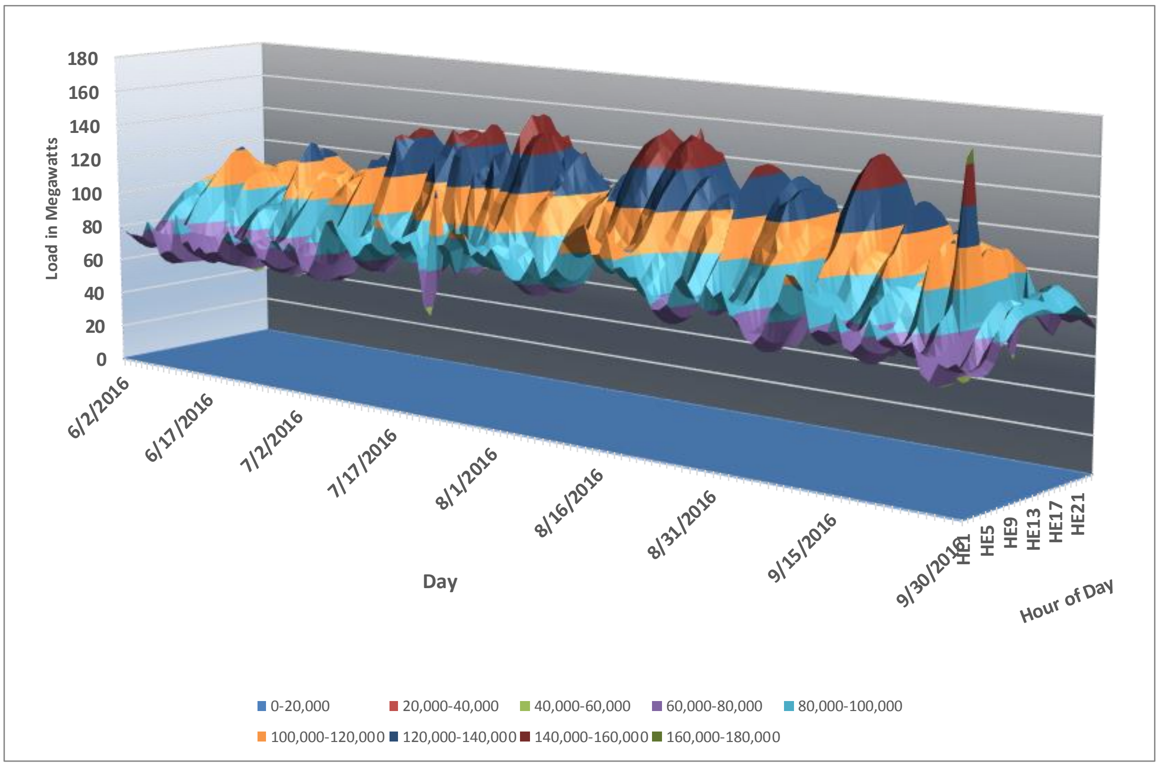
- Dover Air Force Base
- Modern Maturity

Even though Dover has facilitated DR activities through this ongoing program, it should be recognized that it is limited to providing DR services from Dover's retail customers through a third party provider. There may be additional potential for such programs through a different structure.

To illustrate, Figure 2-10 shows a 3-dimensional view of Dover's PJM hourly load profile for June 1 – September 30, 2016. The vertical axis is MW demand, the front axis is for each day during this period, and the depth axis showing "HE" on the axis is for hour of the day.

FIGURE 2-10

DOVER'S SUMMER 2016 HOURLY PJM LOAD PROFILE



Notice that there are a limited number of days in which loads exceeded 140 MW in July and August, which are normally the periods when the PJM coincident peaks occur and which are used to determine how much Dover pays for Reliability Assurance in the following year. Additionally, a "needle peak" of 168 MW occurred on September 23 around noon.

Dover may be able to implement additional DR Load Management programs which could be used to level out its daily demand profiles, shifting some portion of its peak loads to surrounding hours through a load management program and using other technologies such as storage resources. Development of such a program will require careful analysis and capital investments. A detailed analysis of the economically achievable load management is beyond the scope of this IRP.

SMART METERS

Dover may consider upgrading its retail billing meters to "Smart Meters" as many LSEs have done across the nation. Installation of smart meters is not a recommendation contained in this IRP, however Dover should evaluate costs and benefits of such investment as a part of an overall Demand Side Management program.

A smart meter is an electronic device that records consumption of electric energy in intervals of an hour or less and communicates that information at least daily back to the utility for monitoring and billing. Smart meters enable two-way communication between the meter and the central system. They require an Advanced Metering Infrastructure (AMI). An AMI is an integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers.

Smart Meters can provide capabilities which are not available from conventional electric utility meters. Dover has not yet fully explored all of the potential applications for AMI, however, they can provide a flexible platform which could be used for:

- Automated meter reading (AMR)
  - Eliminates the need for a meter reader to visit each customer's location
  - More frequent meter readings
- Active service coordination and control
  - Service connect/disconnect
  - Implement load management schemes in which Dover could curtail load at the customer's appliances for emergencies before resorting to disconnection of entire distribution feeders
  - Coordination with customer-owned demand side resources such as roof-top solar
- Diagnostic
  - Automatically detect when and where customer service interruptions ("outages") occur, thus facilitating more rapid and precise deployment of service crews
  - Data which can be used for identification of abnormal energy use at the individual customer level
- More sophisticated customer rate structures such as:
  - Three-part billing rates (customer charge, energy charge, and demand) for all customers
  - Time of use rates that provide individual customers with near real-time pricing for electricity to encourage customers to shift their consumption to lower-cost periods
  - Interruptible/curtailable load credits for customers who voluntarily agree to allow Dover to interrupt or curtail a portion of their electricity use.

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SECTION 3 - ENERGY AND CAPACITY RESOURCE OPTIONS

The demand forecast presented in Section 2 is analyzed in conjunction with resource adequacy requirements and compared with existing supply resources (including the planned retirements) to determine if, when, and how many new resource additions will be required. The primary objectives below are used to determine what types of resources, if any, should be added to Dover's portfolio:

PRIMARY OBJECTIVES OF IRP

- Maintaining an appropriate level of service reliability
- Minimizing cost to Dover's customers over the long term
- Selection of equipment sizes which are appropriate for Dover's load profile and financing capacity
- Diversifying Dover's generation portfolio so that it is flexible and robust enough to fulfill these objectives under a range of uncertainties which are outside the control of Dover, such as fuel prices and government policies

Legacy industry resource planning practices have targeted a balanced mix of baseload, intermediate, and peaking resources to minimize long-term cost to serve load, including consideration of both projected capital and operating costs for each type of resource.

In recent years, several shifts in utility industry operational paradigms have been driven by these trends:

- More stringent environmental regulations
  - Sulfur dioxide, nitrogen oxide and mercury emissions
  - Water supply and wastewater discharge
  - Carbon dioxide, or Green House Gasses (GHG)
- Expansion and evolution of Regional Transmission Operators (RTOs) and Independent System Operators (ISOs)
- Availability and low cost of natural gas, especially relative to coal
- Substantial increases in renewable energy resources which have been added to the PJM network in recent years
  - Public policies which encourage migration from a fossil fuel based economy to one based on renewable resources (i.e. Renewable Portfolio Standard or RPS)
  - Rapidly decreasing cost of renewable resources
- Energy efficiency programs and policies (i.e. Energy Efficiency Resource Standards)
- Inexpensive digital computational and communication devices (i.e. "Smart Grid", "Smart Meter" and "Smart House")

The capital investments in existing resources are a "sunk cost" and thus are not included in the forward-looking resource plan. This IRP does, however, incorporate future fixed and variable Operations and Maintenance (O&M) cost. While many of these "fixed" costs are not avoidable in the short-run, they can be avoided entirely if the existing resources can be replaced with new, more cost-effective options. Another pricing consideration is the goal to diversify resources across multiple fuels (renewable, nuclear, coal, natural gas, and oil) so that the planned system will be robust enough to adapt to unexpected changes in relative fuel costs.

Resource Options included in IRP

Future resource requirements can be satisfied through the purchase or construction of new resources, through the reduction in demand and energy consumption by end-users, or a combination of the two. New resource options available to Dover could include:

- Supply Side Alternatives
  - Constructing or purchasing a new or existing central station thermal resource such as natural gas-fueled combined cycle facility (NGCC), combustion turbine (CT) or reciprocating internal combustion engine (RICE) generators that are wholly or jointly owned by Dover.
  - New Power Purchase Agreements that provide both capacity and energy
  - Construction of, or participation in, new or existing utility scale renewable facilities such as:
    - Solar – utility scale solar project
    - Energy storage – utility scale storage project Dover could also pursue projects which modify consumer demand to eliminate or defer the need for a new supply resource.
- Demand Side Alternatives
  - Peak reduction programs such as demand response
  - Rooftop solar, possibly coupled with customer based battery storage
  - Demand shifting programs such as time-of-use rates, residential demand rates and direct load control
  - Energy efficiency programs such as high efficiency hot water heaters, high efficiency refrigerators, high efficiency HVAC systems

The following sections provide descriptions of each type of resource which may be used to meet Dover's future capacity and energy resource options.

Conventional Thermal Generation

Steam Units

Simple thermodynamic cycle ("Simple Cycle" or "SC") steam turbine-generators (STG) have been the stalwart of electric generating units for many decades, with 460 GW, or approximately 38%, of total generating capacity currently operating in North America. Until the last two decades, SC steam units have been the primary choice for base load operation due to their reliability and fuel flexibility (coal, oil, natural gas and nuclear). SC-STG's typically have relatively long start-up times (8-24 hours) and are usually restricted in the number of starts and minimum run-time to reduce thermal fatigue, wear and tear on large expensive components.

Over the last two decades, SC-STGs have become less competitive than other alternatives such as combined cycle (CC) units due to higher thermal efficiencies realized by CCs and relatively low natural gas prices.

Simple Cycle Gas Turbines ("SC-GT", "GT" or "CT")

Simple cycle gas turbines began to penetrate the electric generation fleet in the 1960s. Early vintage gas turbines were relatively inexpensive to build on a $/kW basis, but were inefficient and generally limited to smaller size units. Because of their inefficiency, they were limited to serving load only during peak load and emergency operating conditions (i.e. less than 1,000 hours per year).

Unlike SC-STGs, fuel choices for CTs are generally limited to light oil and natural gas and can generally be started with 30 minutes or less notice, thus providing significant operating flexibility. Currently there are 145 GW, or 12%, of total generating capacity currently operating in North America.

Over the last three decades, technological advances have resulted in substantial improvements in CTs, resulting in larger and significantly more efficient electric generation when compared with earlier vintage CTs. Today, there are a variety of sizes, types (aero-derivative vs. industrial or "frame" types) and manufacturers to choose from for CTs.

Combined Cycle Units

Combined cycle units combine the best features of SC-STGs and SC-GTs and are now the primary choice for new fossil-fueled generation. The very hot exhaust gas from the CTs are recovered with a heat recovery steam generator (HRSG) to produce steam which powers a conventional STG. Thermal efficiencies are approaching or exceeding 60%, as compared to the 40% efficiency of SC-STGs. Today, there are 275 GW, or 23%, of CCs operating in North America.

Reciprocating Internal Combustion Engine (RICE)

Reciprocating Internal Combustion Engines (RICE) are becoming an increasingly popular choice for utilities. They generally have higher thermal efficiencies than SC-CTs, and efficiency does not vary significantly over the operating range of a single unit. They also offer modularity (ability to add additional units to existing units in small blocks), quicker start-up and ramp times, are capable of more frequent starts and stops, and help lower operating and maintenance costs while providing dual fuel capability. This type of flexibility is becoming more valuable given the intermittent nature of wind and solar generation. As wind and solar generation rapidly ramps up or down, these type of quick start units are able to quickly respond and balance the intermittent nature of wind and solar generation.

Besides the reliability benefits of this type of flexible unit, FERC has recently released a Notice of Proposed Rulemaking (NOPR) requiring RTOs to allow fast-start resources to set power prices. This is an important development, as new regulatory requirements should more fairly value the benefits of fast-start resources, and result in an additional revenue stream that would foster investment in the resources and reduce the uplifts the artificially increase the cost to serve demand.

Renewable Generation

Electric generation using renewable energy resources is generally considered good public policy. As a result, state and federal lawmakers and regulatory authorities have placed considerable emphasis on increasing the amount of electricity which is produced by renewable energy resources through Renewable Portfolio Standards (RPS), tax breaks and other incentives.

Wind and solar are variable resources which cannot necessarily be depended on for serving load at any particular time. While PJM has not imposed specific back-up requirements for wind, there is a reasonable expectation that some form of tariff requirement will evolve.

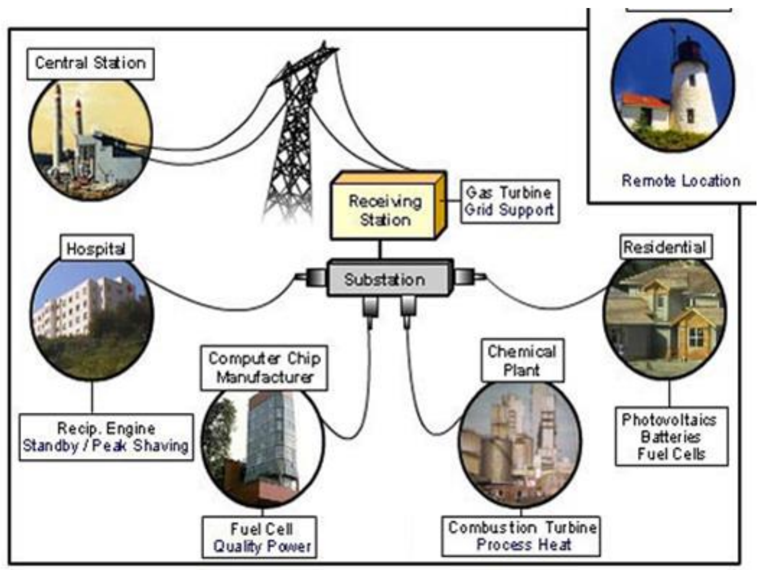
Energy Storage

Along with increasing market penetration of variable resources such as wind and solar, managing the power grid around the variability of these renewable resources has become more challenging. Distributed and grid-scale energy storage resources has gained significant interest by the industry. Energy storage devices are distinguishable from other forms of generation in that they do not directly convert primary energy (such as wind and solar) into electricity. Instead, they store electricity produced from such resources when supply exceeds demand and discharge during periods when demand increases and/or the primary energy is not available. Thus, they can level out the variable production from wind and solar generation.

On November 17, 2016, the Federal Energy Regulatory Commission (FERC) issued a Notice of Proposed Rulemaking (NOPR) in Docket No. RM16-23-000, "Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent Transmission System Operators". This NOPR is not limited to energy storage resources but also includes similar goals for demand side resources in general. The proposed rule requires RTOs/ISOs to revise their tariffs to remove barriers to the participation of these resources in the capacity, energy, and ancillary services markets.

Distributed Energy Resources (DER)

Instead of traditional, one-way delivery of electricity from large, central station power plants located far from demand, via high voltage transmission lines, to lower voltage distribution lines, and, finally, to the home, technologies are now available directly to customers that allow them to generate their own electricity, respond to prices, reduce (or increase) demand when useful to the system, or store electricity for use at a later time. Many of these technologies are affordable to many customers, with more technologies coming down in costs over the near term. Understanding how distributed energy resources (DR) impact the grid itself, including reliability, is an important factor. Understanding where, when, and how DER can benefit the grid is of equal value.



There is no single definition of a DR. Some technologies and services easily fit into any definition, such as residential rooftop wind or solar, but others have yet to be definitively placed inside or outside of this definition. DRs are being adopted at ever-increasing rates due to favorable policies from both the state and federal governments, improvements in technology, and reduction in costs, as well as becoming more widely accepted with identifiable customer benefits, both at the individual level and, possibly, for the grid.

Once DR adoption passes certain levels, DRs can begin to cause significant issues for traditional rate making, utility models, and the delivery of electricity which can result in a cost shift among classes of ratepayers. In defining DR, it is important for electric utilities to identify potential economic and grid issues and benefits from DR. Then, after empirically establishing what adoption level DR will affect the grid, utilities should explore and implement rates and compensation methodologies that will lead to greater benefits for the public, customers, developers, and utilities alike. Importantly, having a plan in advance of that determination will facilitate the ability of a jurisdiction to be proactive in planning for and responding to increased levels of DR in concert with the increasei.

Demand Side Resources

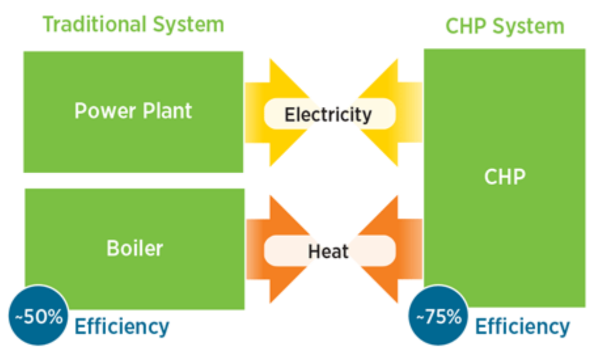
Demand Side Resources (DSR) are a category of DR which are installed or implemented on the site of residential customers, usually electrically connected "behind-the-meter" (BTM). Examples include roof-top solar photovoltaic systems, back-up or emergency generators such as are installed at hospitals and cogeneration units installed at larger industrial facilities.

Such resources are distinguished from other BTM resources because they are located behind the retail meter and, unlike SunPark Solar, are normally owned or leased by the customer rather than Dover.

An Integrated Resource Plan should consider DSR programs as a potential alternative to traditional supply-side options or as a synergistic supplement to supply-side alternatives such as construction of new utility scale generation (renewable or conventional) and/or improvements to the utility's transmission and distribution system.

The overall objective for a municipal electric utility will be to minimize total cost to its customers without consideration of ownership or cost recovery.

There is a growing trend in the industry for retail customers to implement various DSR systems. This trend is expected to continue and expand, resulting in decreases in energy consumption and peak demand. TEA's demand forecast implicitly incorporates existing DSR operated by Dover's retail customers by extrapolating from historical measured aggregate energy and demand.



Combined Heat and Power (CHP)

CHP, also known as cogeneration, is:

- **The concurrent production** of electricity or mechanical power and useful thermal energy (heating and/or cooling) from a single source of energy.
- **A type of distributed generation**, which, unlike central station generation, is located at or near the point of consumption.
- **A suite of technologies** that can use a variety of fuels to generate electricity or power at the point of use, allowing the heat that would normally be lost in the power generation process to be recovered to provide needed heating and/or cooling.

CHP technology can be deployed quickly, cost-effectively, and with few geographic limitations. CHP can use a variety of fuels, both fossil- and renewable-based. It has been employed for many years, mostly in industrial, large commercial, and institutional applications. CHP may not be widely recognized outside industrial, commercial, institutional, and utility circles, but it has quietly been providing highly efficient electricity and process heat to some of the most vital industries, largest employers, urban centers, and campuses in the United States. It is reasonable to expect CHP applications to operate at 65-75% efficiency, a large improvement over the national average of ~50% for these services when separately provided.

Federal, State and Local Tax Credits and Incentives

The most significant incentives are the federal production tax credit (PTC) applicable to wind generation and investment tax credit (ITC) applicable to solar generation.

Federal tax credits have served as one of the primary financial incentives for renewable energy (RE) deployment in the United States over the past two decades. The PTC was first enacted as part of the Energy Policy Act of 1992 and has historically played a significant role in supporting wind energy. The ITC of 30% for solar projects was initially established in the Energy Policy Act of 2005. Since their initial inceptions, federal renewable tax credits have expired, been extended, modified, and renewed numerous times. Historically, changes in federal tax policies have been highly correlated with year-to-year variations in annual RE installations, particularly for wind, where the U.S. wind industry has experienced multiple boom-and-bust cycles that coincided with PTC expirations and renewals (Wiser and Bolinger 2015).

Prior to the passage of the Consolidated Appropriations Act of 2016 in December 2015, the PTC had expired and the ITC was set to decline at the end of 2016. The Consolidated Appropriations Act of 2016 extended these ITC and PTC deadlines by five years from their prior scheduled expiration dates, but included ramp downs in tax credit value during the latter years of the five-year period. Notably, the act kept the commenced-construction provision for the wind PTC and extended the provision to the ITC for utility-scale and commercial solar.

Table 3-1 summarizes the wind and solar tax credit schedule set forth in the act as well as the tax credit schedule before the act was passed.

TABLE 3-1
WIND AND SOLAR TAX CREDITS PRIOR TO AND AFTER THE CONSOLIDATED APPROPRIATIONS ACT OF 2016

New Policy		2015	2016	2017	2018	2019	2020	2021	Future
Wind PTC		Full	Full	80%	60%	40%	0%	0%	0%
Solar ITC	Utility	30%	30%	30%	30%	30%	26%	22%	10%
	Commercial/Third-Party-Owned	30%	30%	30%	30%	30%	26%	22%	10%
	Residential Host-Owned	30%	30%	30%	30%	30%	26%	22%	0%
Prior Policy		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Wind PTC		0%	0%	0%	0%	0%	0%	0%	0%
Solar ITC	Utility	30%	30%	10%	10%	10%	10%	10%	10%
	Commercial/Third-Party-Owned	30%	30%	10%	10%	10%	10%	10%	10%
	Residential Host-Owned	30%	30%	0%	0%	0%	0%	0%	0%

The New Policy schedules reflect "commenced-construction" dates for all categories except Solar ITC Residential Host-Owned for which "placed-in-service" dates are shown. The Prior Policy schedules reflect "placed-in-service" dates for all categories except or the Wind PTC which had a "commenced-construction" deadline of December 31, 2014. The "Full" (100%) wind PTC value is 2.3¢/kWh for electricity production over the first ten years.

COST OF NEW RESOURCES

There are a variety of types and sizes of new generation which could be used to meet Dover's future requirements for new generating capacity and energy production. Generally, larger central station generation using advanced technologies will be less expensive and more efficient than smaller resources, however Dover's need for new resources will be in the 50 – 100 MW range which is significantly smaller than 500 – 1,000 MW range of new, large scale central station generation.

The choices of new resources considered for this IRP has been limited to those which are size-compatible with Dover's requirements over the next 20 years. Additionally, certain technologies, such as nuclear and coal, are not likely to be reasonable choices due to capital requirements and environmental limitations.

Supply-side resource options evaluated for this IRP include Table 3-2 below. All costs are expressed in 2017 dollars. After the most cost effective supply side alternative(s) are determined, the long-run incremental cost can be estimated and compared with the cost of demand-side alternatives.

TABLE 3-2

NEW SUPPLY RESOURCE OPTIONS

Resource	Total Unit Size MW	Dover Share Size MW	Maint. Rate %	VOM $/MWh	FOM $/kW-yr	Capital Cost $/kW	Levlized Annual Capital Costs (Dover's Share) $/yr	Full Load Heat Rate (2018) BTU/kWh	Contrib. to Peak Capacity MW
Own Build Options									
NGCC	200	50	4%	$ 1.96	$ 17.50	2,000	5,455,744	7,400	50
NGCC - LMS100	106	50	4%	$ 1.96	$ 17.50	1,500	4,091,808	8,600	50
NGCT - Frame	100	50	5%	$ 3.42	$ 17.12	1,000	2,727,872	10,000	50
NGCT - Aeroderivative	50	50	4%	$ 4.31	13.17	1,250	3,409,840	9,000	50
RICE (Reciprocating Internal Combustion Engine)	10	10		$ 6.80	$ 19.90	1,100	600,132	8,200	10
PV SOLAR	30	30	0%	$ -	$ 10.00	Varies 1,800 - 1030	2,618,757	n/a	11
DEMAND RESPONSE									
Capacity Purchase Options									
NGCC	1600	50	4%	$ 1.96	$ 19.25	1,100	4,753,765	6,300	50

Notes:

- Capacity purchase options include firm transmission costs and 10% mark-ups on capital costs and FOM.
- For capacity build options, when Dover share size is less than total unit size, joint participation will be required.
- Maintenance rates are industry standards.
- Any own build options using natural gas as fuel will require gas pipeline capacity purchase.
- Costs given are general indicative costs and are not final transactable numbers.

Operation and Maintenance Costs

Fixed and Variable Operation and Maintenance costs (FOM and VOM, respectively) are shown in 2017 dollars. An annual escalation rate of 2% per year is applies for O&M costs for both existing and new resources.

Capital Cost

Capital costs are expressed in $/kW of installed capacity. Except for Solar PV, these costs are escalated by 2% per year inflation rate up to the year of installation. Solar PV costs are expected to continue to decline as technology improves and mass production evolve.

Levelized Annual Capital Costs

TEA has assumed that Dover will issue Tax-Exempt Revenue Bonds to finance the "Own Built Options" at a 3.6% annual interest. A 30-year financing period has been used for all resource types except Solar PV, which uses a 20-year period. Annual levelized financing requirements do not include an allowance for Debt Service Coverage Ratio (DSCR). While it will be necessary to maintain a DSCR of 150% or greater to maintain adequate bond ratings, these excess revenues can be used to make other capital improvements to Dover's system or to retire debt early.

An example of the Levelized Annual Capital Costs for the 50 MW Combined Cycle is shown below:

Financing Requirement: 50 MW x $2,000/kW = $100,000,000

Capital Financing Charge = 5.46% per year (3.6% interest, 30 years).

Annual Levelized Debt Service = $100,000,000 x 5.46% / Year = $5,455,744 per year

Fixed charges used for the PPA represent a proxy estimate of the annualized ownership cost to a taxable corporation which invests in a generating station.

Contribution to Peak Capacity

Generally, the full capacity for conventional fossil fuel steam units is eligible to meet eligibility requirements in the PJM Capacity Market. While PJM's RPM typically reduces this Installed Capacity (ICAP) by a forced outage rate (eFORD) to derive the Unforced Capacity (UCAP) which the generating unit is eligible to receive, such eFORDs for new units are not utilized for the purpose of this IRP. A more refined analysis should be used when evaluating proposals which will be received by Dover in response to a Request for Proposals (RFP).

Special rules apply to variable resources such as wind and solar. These units are exempt from PJM's Capacity Performance (CP) penalties, however PJM only allows a portion of the nameplate capacity for variable resources to be eligible for capacity payments. For wind resources, PJM's current allowance is 17% of nameplate capacity, and for Solar PV, 38%.

Qualification

The assumed values for cost and performance shown in Table 3-2 are TEA's best estimates and are considered to be indicative cost, and not necessarily values which can actually be purchased within the PJM market. A number of factors will impact actual cost once a particular project is identified and procurement proceeds. TEA has used the assumed values for the purpose of identification of most economic options for power supply which are reasonable available to Dover. More certainty in actual costs of such resources will become apparent as Dover solicits proposals or offers during a procurement process.

Section 4 – Resource Plan Development

General Assumptions

The most fundamental assumption is that Dover will continue to be the sole Load Serving Entity (LSE) within its current service territory throughout the study period. Given the current regulatory environment within PJM and some surrounding states, we believe this to be a reasonable assumption. Should the regulatory framework change, this assumption and the impacts on Dover's resource base should be revisited.

Some foreign countries and fourteen individual states in the U.S. have required electric utilities to "unbundle" its services into separate wholesale generation, transmission and retail distribution companies, allowing direct competition for serving individual retail customers ("Retail Choice" or "Retail Competition").

Unbundling of wholesale services, and the evolution of RTOs/ISOs has facilitated competition for generation at the wholesale level, allowing entry of non-traditional independent power producers (IPPs) to compete with traditional vertically integrated utilities for power supply.

While unbundling and wholesale competition have provided some benefits in states that have implemented retail choice, many states and municipalities have maintained the traditional regulated vertically integrated utility paradigm. Details of utility regulatory frameworks continue to evolve. In the case of PJM, and Dover specifically, the traditional framework has been retained to the extent permissible under federal regulations.

For example, if for some reason, Dover is mandated or chooses to implement direct retail access, it may want to limit its exposure to large fixed-payment options such as construction of a large power plant in Dover or a large, long-term PPA. TEA has assumed that Dover will remain as the sole LSE and will not be exposed to load attrition through a direct retail access program.

Table 4-1 provides other major assumptions which have been utilized for this study. Details for a number of assumptions are presented in other sections of this report.

TABLE 4-1

MAJOR ASSUMPTIONS

CATEGORY	MAJOR ASSUMPTION
Study Period	January 2018 through December 2037
Demand Forecast	Base Case: No load growth (See Section 2) No demand sensitivities were analyzed
Fuel Prices	Expected (Base Case), low and high natural gas prices Coal cost does not vary between sensitivities. See Section 2 for details
Environmental Regulations	Base Case: RGGI only Carbon Constraints: A region-wide Greenhouse Gas (GHG) regulation starting in 2024
Renewable Energy	Base Case: Dover will continue to fulfill its obligation to achieve 25% renewable resources by 2025. RPS50: 50% RPS requirements region-wide
Inflation & Discount Rates	Inflation Rate: 2.0%/year; Discount Rate: 3.6%/year
Financing	Dover Owned: 3.6% / year average cost of debt with levelized payments over a 30-year period. PPA: 7.0%/year weighted average cost of capital (WACC) Financing spread over a 30 year period.
Retirements	McKee Run 3 will be retired December 2026 VanSant will be available throughout the study period ($2.1 million included in 2018 for a major overhaul)

MODELING DOVER'S DEMAND AND RESOURCES

Using the resulting resource costs, the IRP team constructed nine resource portfolio scenarios for three retirement scenarios. The scenarios are evaluated in terms of cost and risk. Based on the result, Dover will choose the best-performing resource strategy.

The primary class of models used to project energy costs into the future are known as "Production Cost" models. Models in this class can vary significantly regarding the level of detail considered in the model and the amount of detail in the results (resolution).

Economic models are utilized for analyzing future scenarios and providing relevant outcomes. These models are good at economic analysis using various assumptions. The items below are a synopsis of appropriate model expectations.

- Long-Term Models Do:
  - Forecast future market conditions from specified input assumptions
  - Estimate the magnitude of future power supply costs
  - Allow comparison of sensitivities of results to key assumptions

- Long-Term Models Don't:
  - Predict human behavior
  - Predict significant changes in market design, rules, or technological advances
  - Forecast non-economic unit operation
  - Evaluate short-term operational reliability constraints
  - Explicitly evaluate the need for and cost of ancillary services (Operating Reserves, Regulation, Voltage Control)
  - Estimate transmission and distribution cost, customer services, administrative and general costs, existing debt service, etc.

The selected modeling approach utilizes a commercial generation expansion planning application for analysis purposes. This energy market simulation and optimization software suite simulates economic dispatch to minimize variable costs for both Dover and PJM, while selecting future resources with the objective of minimizing incremental Net Present Value (NPV) of future power supply cost for both the market and Dover.

- A PJM regional model was developed using Energy Exemplar's PLEXOS software to get LMP price streams and emissions costs for Dover.
  - Market area resource and load details extracted from the PJM 2016 Regional Transmission Expansion Plan (2016 RTEP) Reference Case inputs.
- A Dover only model was developed using ABB's Planning and Risk software to evaluate the appropriate build/purchase options.

Energy Exemplar's PLEXOS market area model was used to forecast PJM (PJM) power prices over a 20-year time horizon under three demand forecast scenarios (base, high, low) and three fuel cost scenarios (base, low and high natural gas price).

PLEXOS

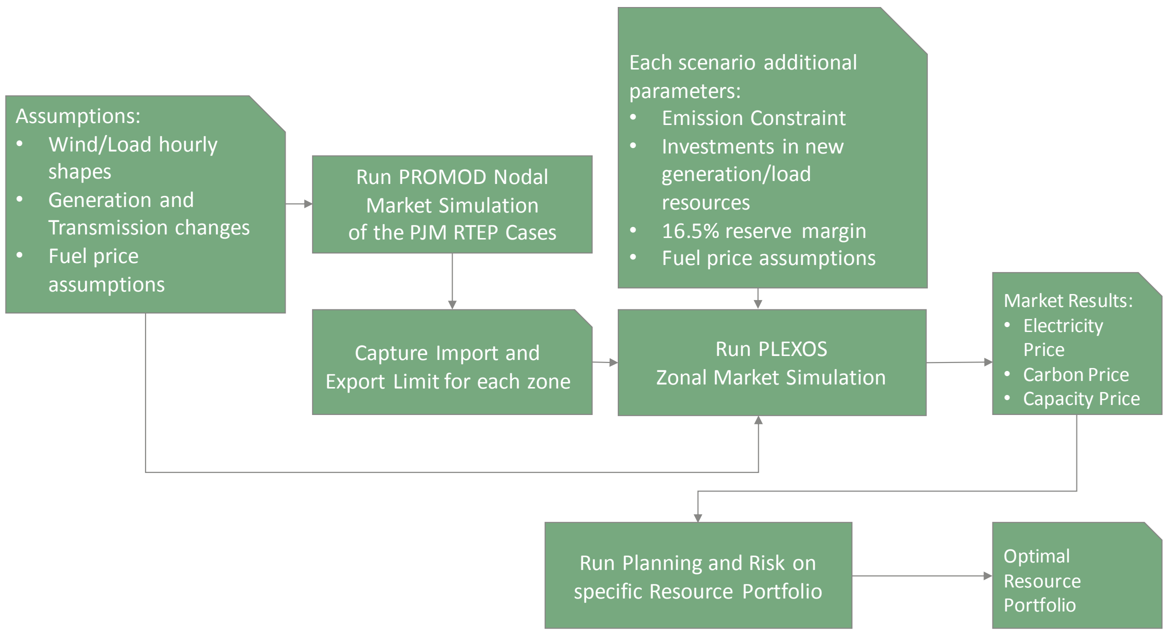
PLEXOS is a "next generation" energy market simulation and optimization software system licensed to TEA by Energy Exemplar. PLEXOS is capable of co-optimizing thermal, hydro-electric, energy, reserves, fuel, emissions markets and power purchase contracts. TEA has elected to utilize this model because it is computationally more efficient and comprehensive than other models TEA has utilized and provides easy to use graphical user interfaces and a wide range of output alternatives. It also optimizes choices of future resources with the objective of minimizing overall Net Present Value (NPV) of future power supply cost for both the market and Dover.

Rather than using a nodal form of the model, it was used as zonal mode to better accommodate the relatively long study period. We have also aggregated customer demand into 144 non-contiguous energy blocks per year. While this approach reduces available resolution and the ability to represent certain operating constraints such as voltage support, generation start-up time and minimum run time, we believe that this mode of simulation does not significantly compromise the ability to compare results from various scenarios studied.

The diagram below depicts the modeling process used for this study:

FIGURE 4-1

MODELLING PROCESS



TEA has also used the entire geographic foot-print that PJM uses for its RTEP planning process. This foot-print includes all generation and Demand within the PJM ISO/RTO footprint plus portions of MISO, PJM and TVA. Not only does this allow representation of non-Dover generation and demand within PJM but also simulates the interchange between PJM and power systems which surround it.

Planning and Risk

Planning & Risk is a comprehensive portfolio planning tool licensed to TEA by ABB. Planning & Risk allows for comprehensive description of energy assets and markets, and can be used to estimate the optimal dispatch of a generation portfolio against either a market price or a load requirement. Planning and Risk is built on a leading chronological optimization model, the PROSYM simulation engine.

The Planning & Risk model includes Dover's forecasted load, their existing generation units as well as all new generation options. This generation is dispatched against the Dover LMP's provided by the

PLEXOS model. The PLEXOS shadow prices for the impact of carbon emission constraints are used in Planning & Risk to determine emission costs for the units. Load pays the projected LMP prices.

Results of Planning & Risk give the production costs and revenues of the units as well as energy charges. The optimum resource solutions are derived from these results.

PJM 2016 RTEP Database

PJM released the [2016 Regional Transmission Expansion Plan (RTEP)] report on January 7, 2017. A copy of the PROMOD input data set for this study was converted to PLEXOS format and utilized for this study. Only existing generating units and transmission interfaces have been used, Future generation additions for the entire regional footprint have been selected based on optimized generation expansion capability of PLEXOS and vary by study scenario.

Transmission Constraints

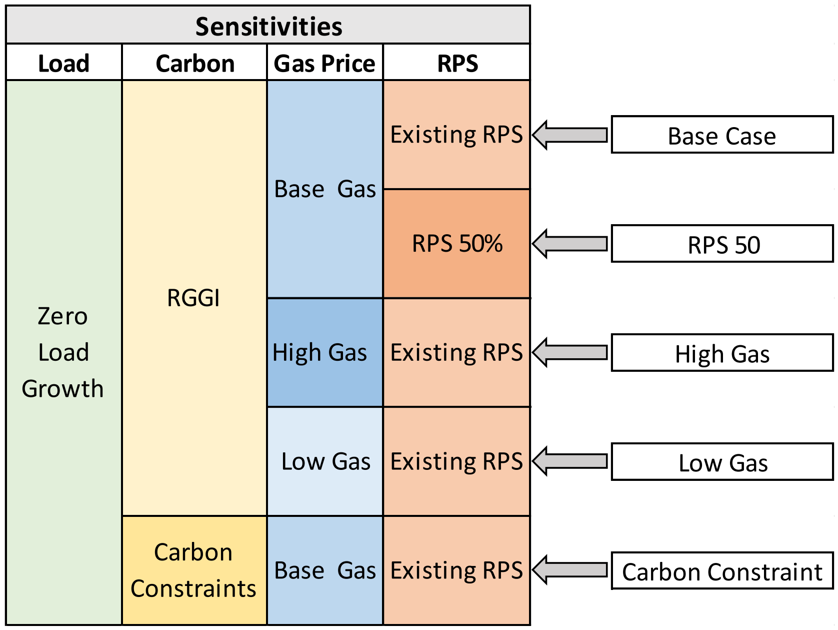
The 2016 RTEP database is structured for nodal simulations. To reduce computational time, this transmission model configuration has been converted from nodal to zonal. The IRP model is a zonal-based model, where energy flows into or out of each zone is limited by its import and export limit, and consequently the zonal pricing for electricity is elevated or reduced accordingly when the import and export limits are binding.

Description of Sensitivity Analysis

Figure 4-2 shows a pictorial representation of the hierarchy of the Sensitivities which have been analyzed for this IRP. Two different views of carbon markets, three natural gas price forecasts and two levels of Renewable Portfolio Standards have been analyzed. Various combinations of these variables result in five separate PLEXOS simulations.

FIGURE 4-2

SENSITIVITY ANALYSIS ASSUMPTIONS



- Carbon Constraint
  - Base Case: Regional Greenhouse Gas Initiative (RGGI)
  - Additional Carbon Constraint
    - Derived from the published Clean Power Plan (CPP) carbon limitations.
    - An implementation date of 2024 is selected for CPP
    - The published implementation glide path is then utilized (indexed for 2024)

Modeling of Carbon Constraints

A sensitivity case was used that assumes a national carbon market, where the price is determined by the amount of carbon emissions that are allowed for a particular year. While there currently is not a national market for carbon, the EPA proposed rule on Clean Power Plan is an approach that is representative of a national effort in limiting carbon emissions.

Table 4-2 shows the total emissions in year 2012 in metric tons, which is the baseline that EPA uses in the proposed Clean Power Plan (CPP) rule. Under CPP, the EPA reduces carbon emissions by applying the Best System Emission Reductions (BSER) that involves improving efficiency of the electric generating units, higher utilization of national gas units, and growing investments in Renewable Energy units that span from year 2022 to year 2030. The resulting total emissions for each interconnection are shown in metric tons in TABLE 4-3 and in percentage reduction from the baseline in TABLE 4-4

The U.S. Supreme Court granted a stay on Clean Power Plan in February 2016. Despite changes in the administration and uncertainties around if or when the stay would be lifted, it is likely that pressures from the public and from international communities will force the United States to eventually develop a carbon market. The Future projections used in this study applies the same amount of carbon reduction seen in the Clean Power Plan study (as shown in TABLE 4-4

was applied to achieve a 27% reduction of carbon emissions from the Baseline in year 2030, and that limit was held constant through the end of the study period in year 2037.

TABLE 4-2

ADJUSTED BASELINE CARBON EMISSIONS IN METRIC TONS FROM EXISTING ELECTRIC GENERATING UNITS

(AS SPECIFIED IN THE TECHNICAL SUPPORTING DOCUMENT)

	Coal		NGCC		OG Steam		Total	
Interconnection	Emissions (tons)	Gen (MWh)	Emissions (tons)	Gen(MWh)	Emissions (tons)	Gen(MWh)	Emissions (tons)	Gen(MWh)
Eastern	1,356,066,366	1,230,447,795	328,219,519	734,535,157	52,979,259	74,240,802	1,737,265,144	2,039,223,754
Western	229,424,716	203,976,918	89,135,327	198,374,376	9,433,180	13,326,187	327,993,223	415,677,481
ERCOT	129,404,298	115,050,132	65,236,948	137,182,895	5,835,641	8,331,348	200,476,887	260,564,376

TABLE 4-3

RESULTING EMISSION TARGETS IN METRIC TONS BY INTERCONNECTION AFTER APPLYING THE THREE BUILDING BLOCKS

Mass Goal	2022-2024	2025-2027	2028-2029	Interim	Final
Eastern	1,508,611,687	1,381,002,269	1,311,175,180	1,411,399,029	1,273,389,713
Western	286,870,944	263,574,121	251,287,843	269,238,860	244,990,155
ERCOT	174,376,282	160,489,145	153,301,315	163,899,864	149,724,189

TABLE 4-4

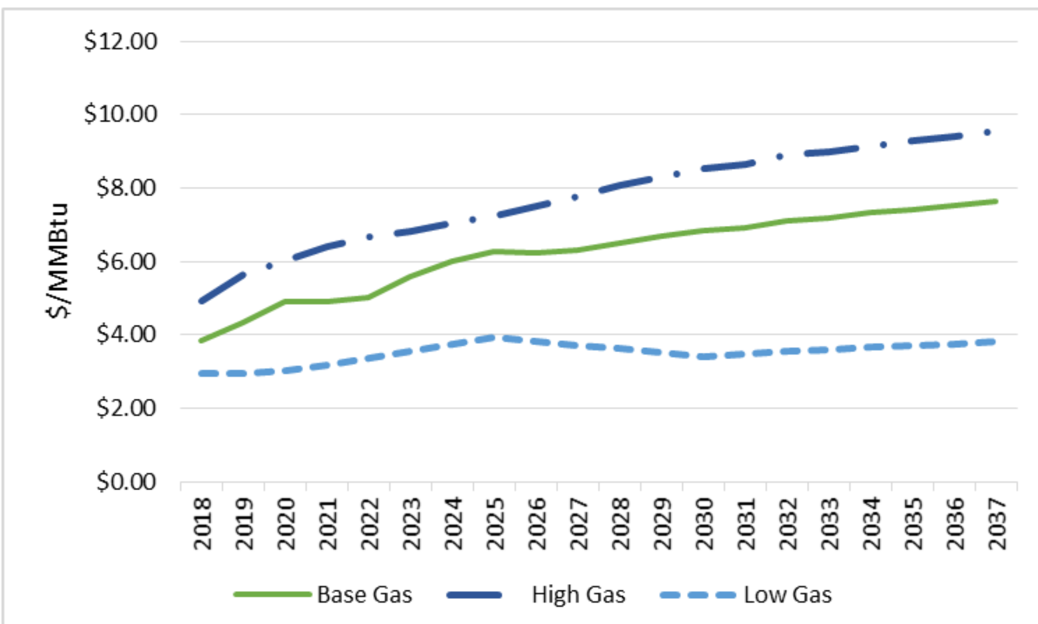
RESULTING EMISSION TARGETS BY INTERCONNECTION AS A PERCENTAGE REDUCTION FROM THE ADJUSTED BASELINE CARBON EMISSIONS

Calculated CO2 Emission Reduction from Baseline					
	2022-2024	2025-2027	2028-2029	Interim	Final
Eastern	-13%	-21%	-25%	-19%	-27%
Western	-13%	-20%	-23%	-18%	-25%
ERCOT	-13%	-20%	-24%	-18%	-25%

- Fuel Prices:
  - Base Case natural gas prices are from Energy Information Administration's (EIA) forecast for Clean Power Plan from the 2016 Annual Energy Outlook.
  - High Gas Case prices are from the PJM 2016 Regional Transmission Expansion Plan (2016 RTEP) Reference Case.
  - Low Gas prices are from the NYMEX NG price settles as of trade date August 16, 2016.

Figure 4-3 presents the assumptions for natural gas prices which were used in the production cost simulations. Natural gas prices used for Dover gas generation include the additional basis cost between Henry Hub and Transco Zone 6 Non New York and the gas transport cost.

FIGURE 4-3
HENRY HUB NATURAL GAS PRICE FORECASTS



- Renewable Portfolio Standard (RPS)
  - Base Case: Renewable Energy Portfolio Standards Act (REPSA)
    - Utilities procure an increasing percentage of their electricity from renewable resources leading up to 25% of energy derived from renewable sources by 2025
    - Includes a cost cap provision that if the cost of compliance exceeds 3% of total retail costs of electricity for the entire RPS or 1% for Solar PV

– Additional RPS Requirement

- Increases the percentage of required energy derived for renewable sources from 25% to 50%
- This requirement applies to the entire market footprint

Retirement Studies
Dover is interested in the economics for continuing to operate and maintain its existing generating units at McKee Run and VanSant. For the Base Case, it is assumed that McKee Run 2 is retired in 2027 and VanSant will continue throughout the 20-year study period.

Generation Retirement Schedules: Analysis was performed for the following unit retirement alternatives: (1) McKee Run retired in 2027; VanSant life extension with $2.1 million estimated cost of major overhaul; (2) McKee Run retired in 2027**;** VanSant retired in 2021 ; and (3) Both VanSant and McKee Run retired in 2021. These retirement assumptions drive the timing and amount of replacement capacity which Dover needs to acquire. The evaluated capacity additions for each retirement schedule are listed in Table 4-5.

TABLE 4-5

APPROXIMATE CAPACITY ADDITIONS ANALYZED (MW)

Retirement Schedule	2021 Additions	2024 Additions	2027 Additions
4. Base Case	0	50	100
5. Retire VanSant in 2021	50	40	100
6. Retire MR3 & VanSant in 2021	150	40	0

Figures 4-4, 4-5 and 4-6 show Dover's year-by-year capacity plans for the Base Case, early VanSant Retirement Case and early retirement of McKee Run and VanSant, respectively.

FIGURE 4-4

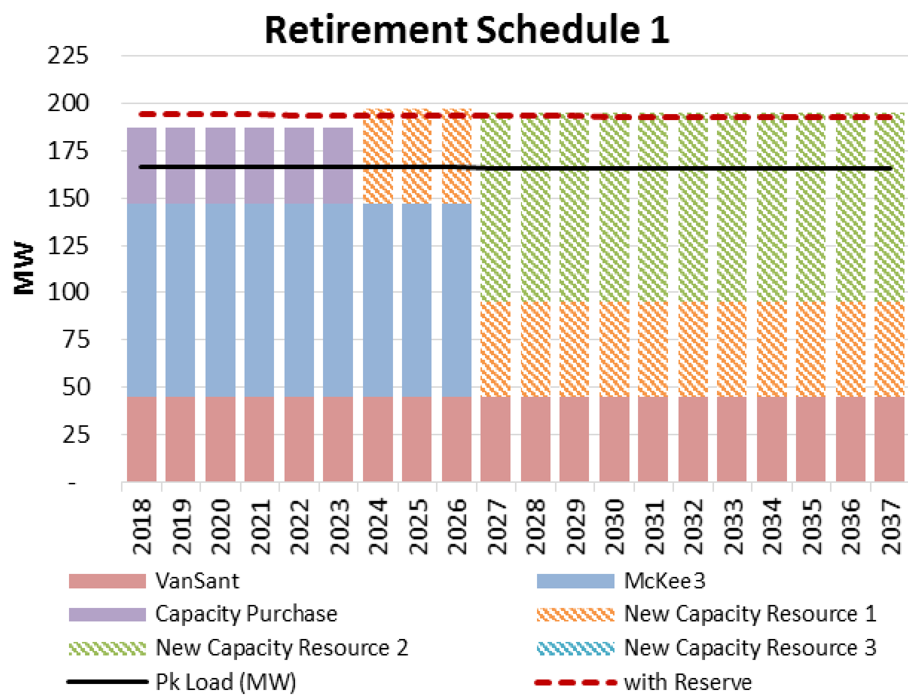


FIGURE 4-5

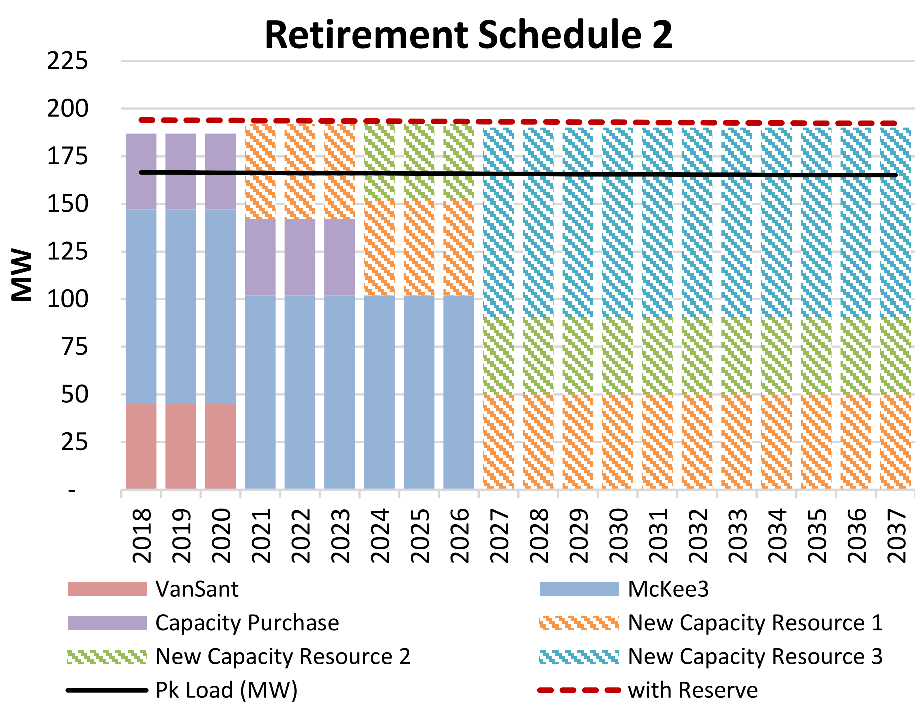
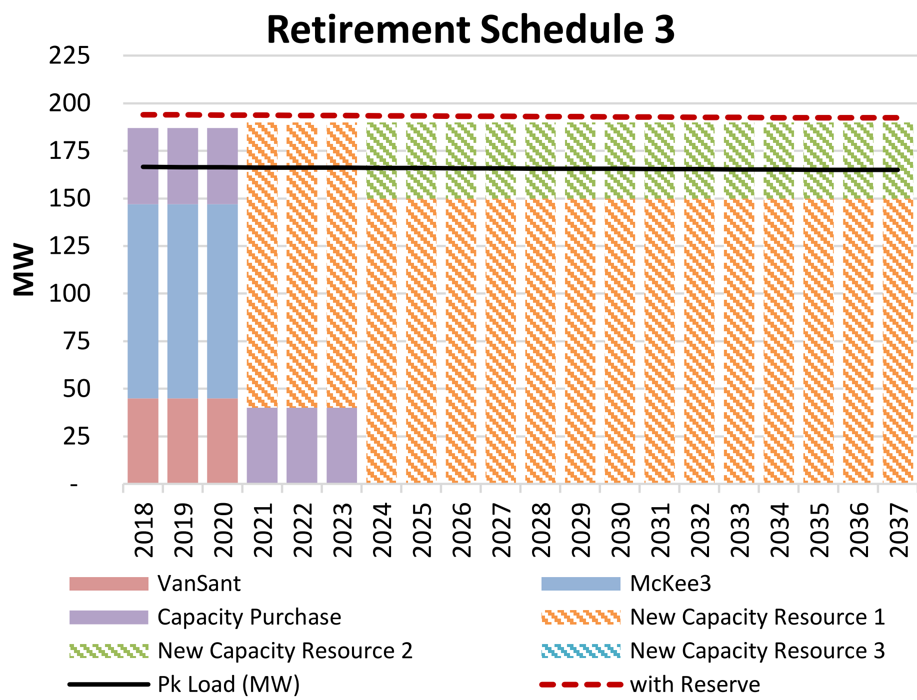


FIGURE 4-6



Retirement Schedule 3
MW
225
200
175
150
125
100
75
50
25
-
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
VanSant
McKee3
Capacity Purchase
New Capacity Resource 1
New Capacity Resource 2
New Capacity Resource 3
Pk Load (MW)
with Reserve

SECTION 5 – RESULTS OF ECONOMIC ANALYSIS

OVERVIEW

The five sensitivities described in Section 4 were modeled for the PJM footprint using PLEXOS. The resulting hourly zonal prices for the DPL zone were then used as an input to the Planning and Risk (PaR) model of Dover's specific portfolio for each Sensitivity and Scenario. Nine scenarios alternatives for alternative choices in new generation and three retirement schedules were analyzed, resulting in a total of 135 separate analyses.

Sensitivities:

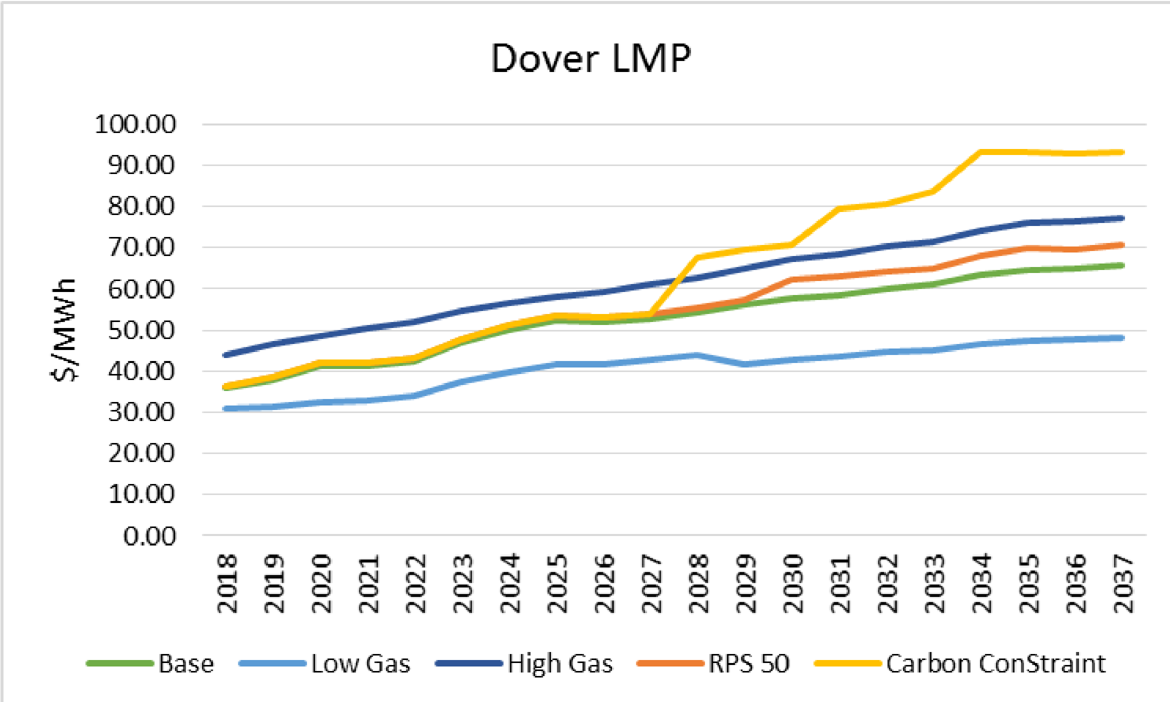
- **Base Case** - Uses base projections for demand and commodity prices, without the addition of new regulation. RGGI is assumed to continue under current market design and with current participating states.
- **High Natural Gas Price Case** – High gas prices will result in significant cost increased to Dover, however, like a tide lifts all boats, other LSE's surrounding Dover will experience similar cost increases.
- **Low Natural Gas Price Case** – Extended low gas prices reduce cost to serve load. Existing Dover units have very limited generation.
- **Carbon Constraints** – Carbon constraints and higher gas prices cause market prices to increase.
- **More Stringent Renewable Portfolio Standard:** RPS requirements increased to 50% for all of PJM

Market LMP Prices from PLEXOS

Figure 5-1 shows the annual average Locational Market Prices (LMP) in DPL-South which were produced by the PLEXOS simulations for each of the five sensitivities which have been evaluated.

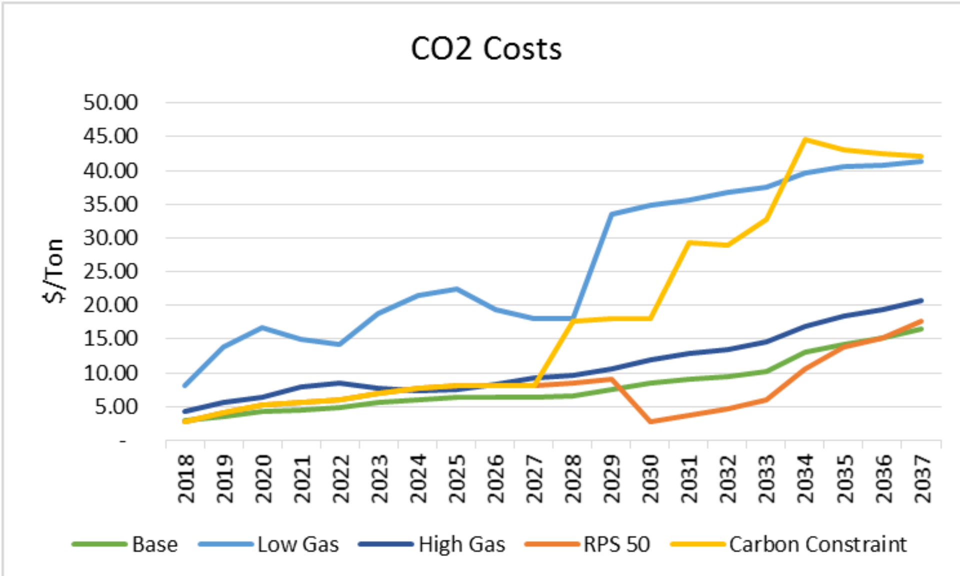
While this figure shows annual averages, the model produced hourly prices which were then used for input into the Planning and Risk model for the Dover specific portfolio analysis.

FIGURE 5-1
LOCATIONAL MARKET PRICES FOR SENSITIVITIES EVALUATED



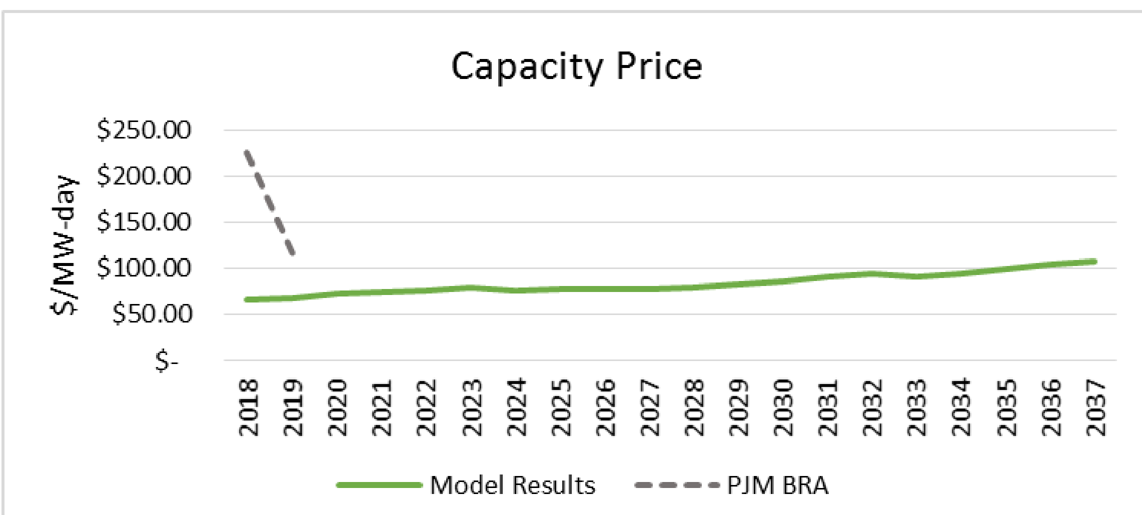
The PLEXOS simulations provide “shadow prices” for the impact of carbon emissions constraints. These vary by sensitivity analysis since they are dependent on particular resources the model selects for future PJM capacity requirements. The resulting carbon prices are sown on Figure 5-2.

FIGURE 5-2



The PLEXOS model also produced shadow prices for the PJM Capacity Market. These prices have been used in the analysis to determine the amount of capacity payment revenue generating resources receive from the PJM and for the amount load pays under PJM's Reliability Assurance Agreement (RAA). In the IRP analysis, Dover is required to own or contract for capacity to satisfy the PJM capacity requirements. Therefore, what Dover pays for its load is approximately what it receives for its capacity. By including both cash flows in the analysis, it permits slight miss-matches between RAA requirements and capacity resources available to Dover in any particular year.

FIGURE 5-3



Scenarios

Individual Scenarios based on a variety of new generation alternatives were evaluated. The amount of additional generation required to meet the PJM reliability requirement was dependent on timing of the retirements of existing generation and expiration of the five year 40 MW capacity purchase . The nine (9) Scenarios which are presented herein were among represent the solutions with the lowest NPV in the Base Case (expected NG prices, RGGI only, existing RPS).

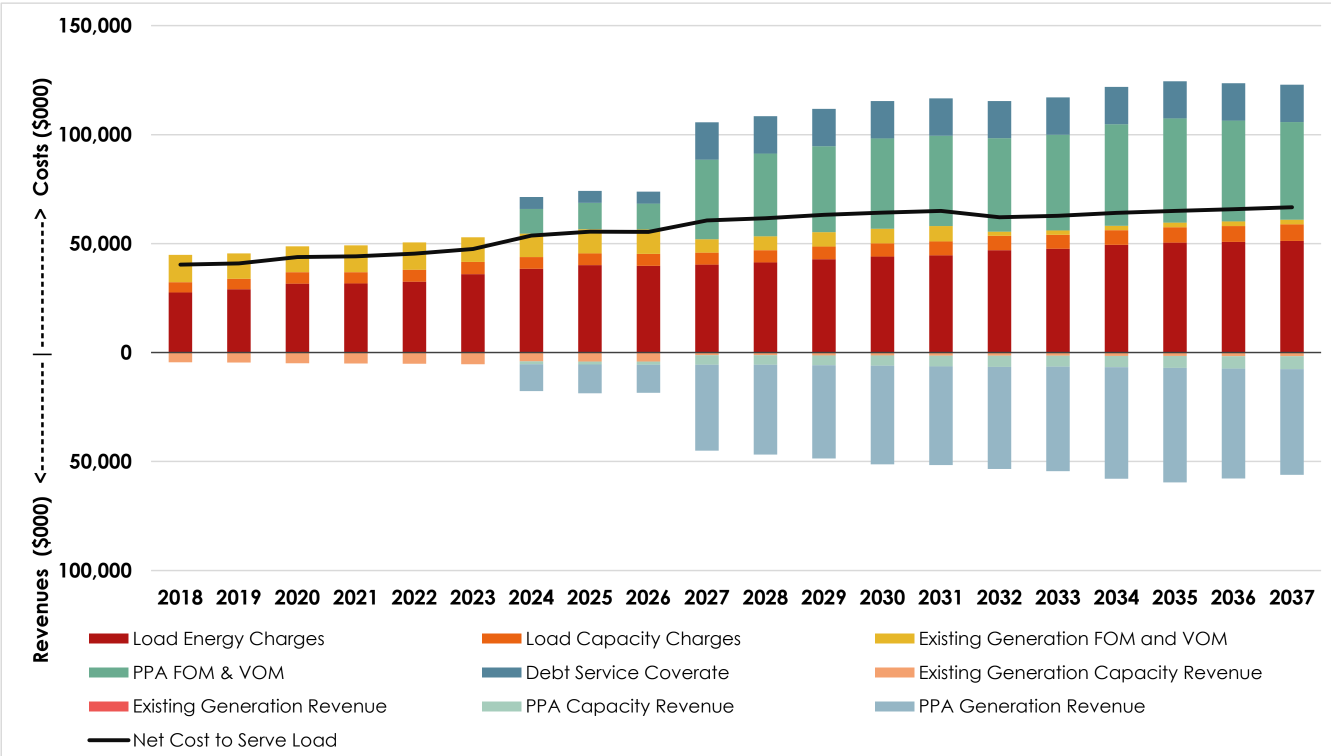
This figure presents cumulative net present value of incremental (NPV) revenue requirements (RR) for the entire study period have been computed for all Sensitivities, Retirement Alternatives and Scenarios for comparison. This NPV is representative of a portion of Dover's overall electric system revenue requirements as follows:

- Included in NPV RR
    - Payments to PJM for Reliability Assurance and Energy
    - Capacity revenues received from PJM
    - Fixed and Variable O&M for existing and new fossil generation
    - $2.1 million for major overhaul of VanSant in 2021
    - Fuel costs including the cost of firm transportation of natural gas for new resources
    - Capital carrying costs for new self-build generation
    - Capacity and energy payments for PPAs
    - Payments to White Oak Solar Energy Center (a.k.a. SunPark)
    - Payments under the current 40 MW PPA

- Not Included in NPV RR
    - PJM costs and revenues for Ancillary Services
    - PJM charges for transmission service
    - Other miscellaneous PJM charges and credits
    - Debt Service on existing debt
    - Capital improvements to existing facilities (Exception: VanSant $2.1 million overhaul)
    - O&M costs for transmission, distribution, customer service and administration
    - Payments to DEMEC for RPS compliance and the Green Energy Fund
    - Cost of energy hedges

Figure 5-4 shows year-by-year cash flows for the Base Case. Major cost components such as energy costs, capacity costs, O&M costs and debt service on new generation are shown above the zero axis. Revenues from PJM's energy and capacity markets are shown below the axis. The black line represents the net of the costs and revenues. This annual net cost is converted to a single Net Present Value (NPV) for all sensitivities and scenarios which have been analyzed. The NPVs have been used for all subsequent comparisons in this report.

FIGURE 5-4
ANNUAL CASH FLOWS FOR BASE CASE

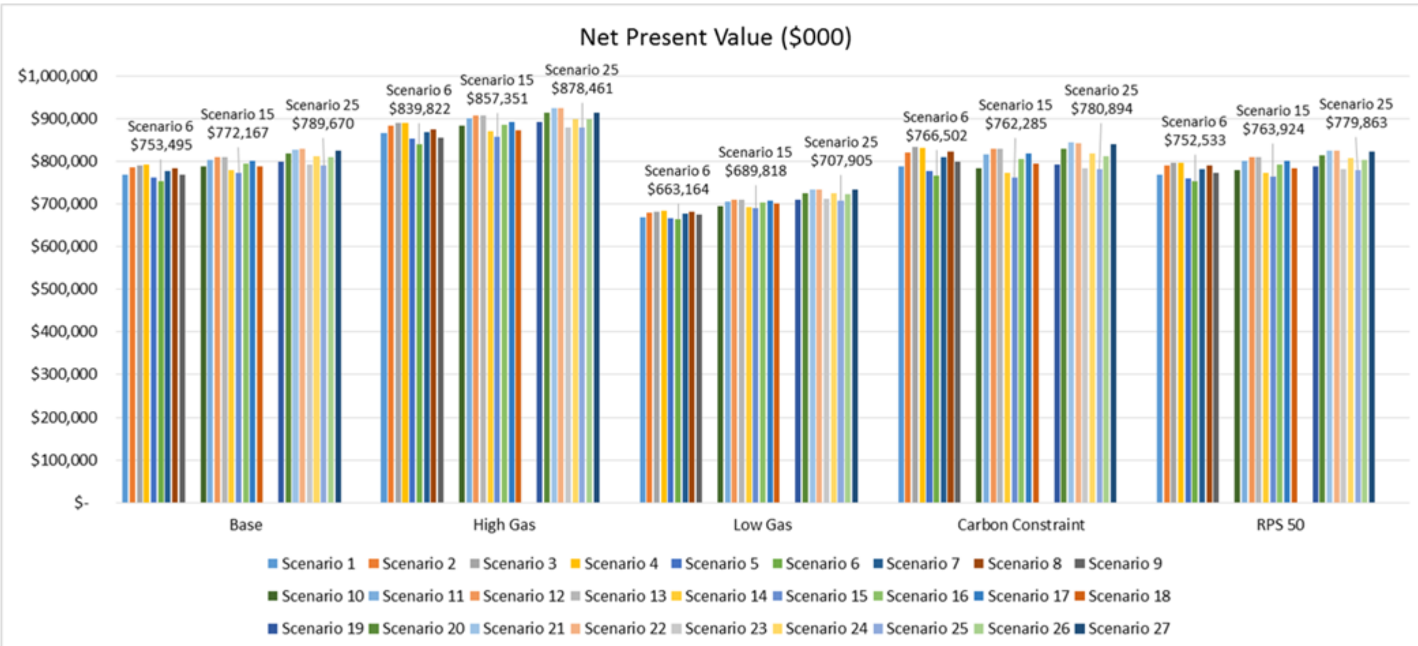


Detailed Scenario Descriptions and Results

Figure 5-5 presents a high-level comparison of the five (5) Sensitivities and twenty-seven (27) Scenarios which have been analyzed for this IRP. Detailed explanations for each Scenario are provided after the figure. This figure presents cumulative net present value of incremental (NPV) revenue requirements (RR) for the entire study period.

COMPARISON OF SCENARIO RESULTS

FIGURE 5-5

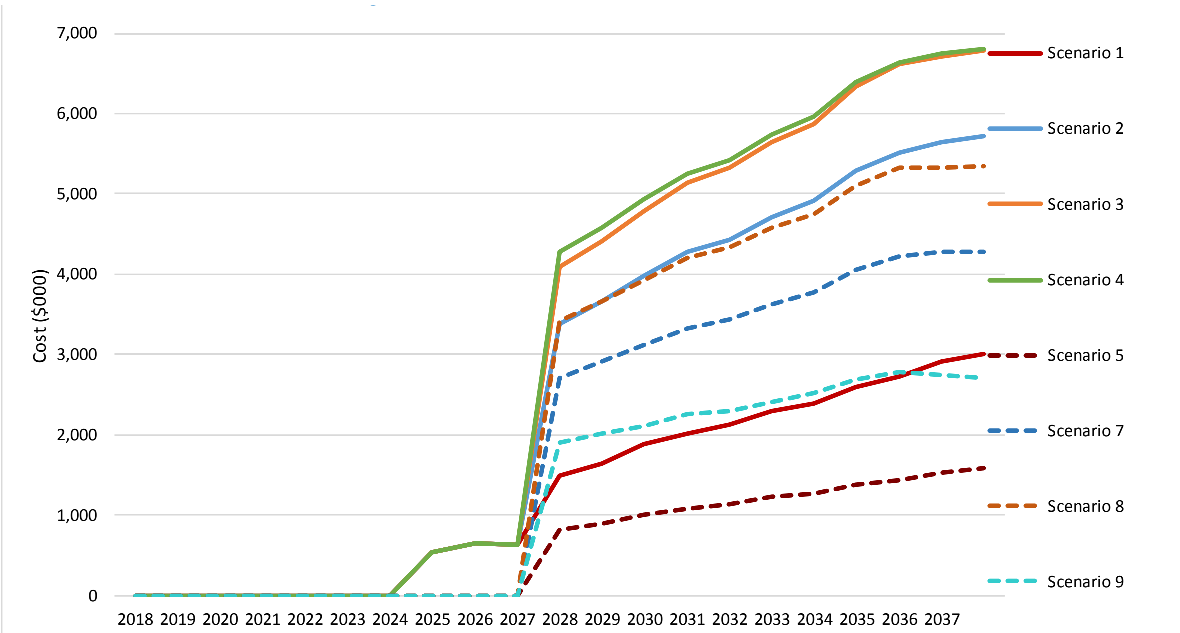


Scenario 1-9 – Retirement Schedule 1: No VanSant Retirement, McKee 3 Retires 2027
Scenario 10-18 – Retirement Schedule 2: VanSant Retires 2021 , McKee 3 Retires 2027
Scenario 19-27 – Retirement Schedule 3: VanSant and McKee 3 Retires 2021
Note: Retirement Schedule 1 includes $2.1M in 2018 costs to extend life of VanSant.

See appendix for scenario descriptions.

Cumulative NPV is a reasonable metric to easily compare many simulations, however it does not provide insight into how cash flows evolve over time. An additional comparison of the Scenarios for Retirement Schedule 1 is shown on Figure 5-6.

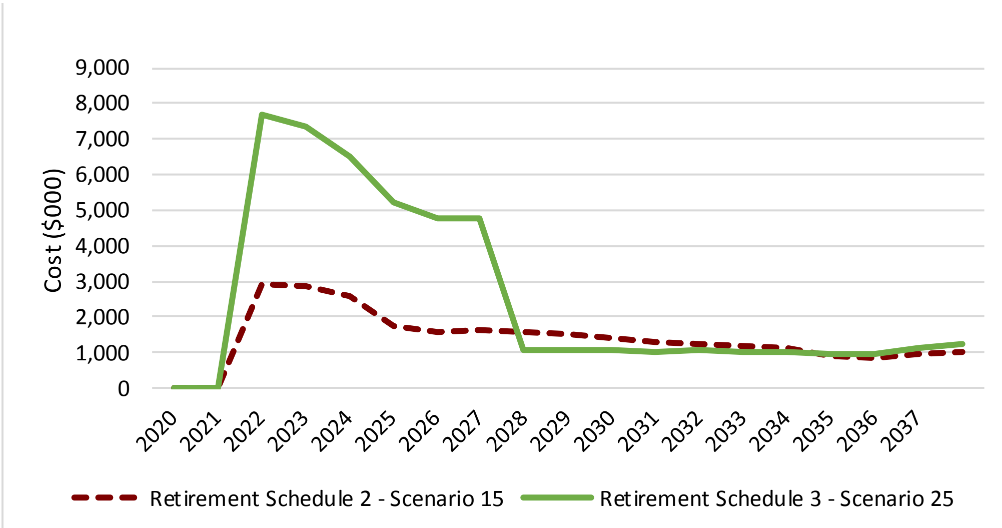
FIGURE 5-6
RETIREMENT SCHEDULE 1
CHANGE IN ANNUAL COST VS. LOWEST COST SCENARIO 6



This figure shows the difference in annual costs between the lowest cost generation addition scenario (Scenario 6) and the other Scenarios. Notice that the cost differences do not begin to appear until 2024 when the current PPA expires, and become significantly different starting in 2027 after McKee Run 3 is assumed to be retired. Also notice that the maximum annual cost differences between scenarios is around $7 million by 2037. This is somewhat less than 7% of total cash flows of $125 million previously shown in Figure 5-4.

A similar comparison of the differences in annual costs differences for the lowest cost Scenarios for each of the three Retirement Schedules. The magnitude of the cost differences peaks at $3 million in 2022 for Retirement Schedule 2 and peaks at $8 million in 2022 for Retirement Schedule 3. These cost differences are relatively close in time and will have significant adverse impacts on Dover's overall cost structure.

FIGURE 5-7
CHANGE IN ANNUAL COST VS. LOWEST COST SCENARIO 6



Base Case

For the Base Case it is assumed that all existing resources maintain their current heat rate, fixed operation and maintenance cost (FOM), variable O&M, maximum and minimum generation output levels, and retirement dates are utilized in the PLEXOS long-term model. While using the PLEXOS long-term model, ramp rates, minimum up/down times, and outage schedules are not taken into account.

High Gas Case

For the High Gas Case, all Base Case assumptions were maintained except for the natural gas curve. The Base Case natural gas curve was replaced with the High Gas Curve which is the PJM RTEP Henry Hub natural gas curve. The High Gas price curve is 117% to 132% of the Base Case Natural Gas price curve, depending on the year.

Low Gas Case

For the Low Gas Case all Base Case assumptions were maintained except for the natural gas curve. The Low Gas price curve was the NYMEX Henry Hub Natural Gas prices as of trade date August 16, 2016. The Low Gas price curve is between 50% to 76% of the Base Case Natural Gas price curve, depending on the year.

Carbon Regulation w/ CPP Natural Gas Escalation

In the Carbon Regulation with CPP Natural Gas Escalation Case the Base Case assumptions were maintained except that a Carbon Constraint was introduced across the entire model and natural gas prices were slight escalated. Carbon regulation is first introduced in 2024 and then more restrictive limits are implemented again in 2027 and 2030.

Renewable Portfolio Standard of 50%

In the RPS-50% case, the Base Case assumptions were maintained except that an assumed 50% renewable portfolio standard is implemented across the entire PJM market footprint.

CONCLUSIONS

- The ownership/PPA fixed cost for replacements to McKee 3 and VanSant are greater than the ongoing Operating and Maintenance (O&M) cost of the existing generation.
  - Extension of VanSant's useful life economic feasibility assumes life extension costs of $2.1 million in 2018 as provided by Dover staff.
- The most economical solutions include the self-build installation of Solar PV.
  - Total land required for 30 MW of Solar PV plant is approximately 120 - 150 acres. This may require additional property purchase by City of Dover.

Non-solar resource option scenarios were evaluated separately to address the possibility of land limitations.

- Evaluation of options <u>including</u> Solar PV
  - PPAs of 40 MWs and installation of 30 MWs of Solar PV are the most economical results for the capacity shortage in 2024.
  - For the second tranche, 100 MW of capacity is needed for 2027. A combination of 30 MWs Solar PV and 90 MWs of PPAs is the most economical solution
- Evaluation of options <u>excluding</u> Solar PV
  - PPAs totaling 50 MWs are the most economical by model results for the capacity shortage in 2024.
  - For the second tranche, a 100 MW of capacity is needed for 2027. The option of 100 MWs of PPAs is the most economical solution.
- The variation of NPV for the scenarios that include a PPA or self-build option is relatively small. Ranking of results could vary depending on proposals received in response to an RFP.

SECTION 6 – RECOMMENDATIONS

SUMMARY OF RECOMMENDATIONS

- **To make up for the capacity shortfall in 2024, it is recommended an RFP be issued for 50 MWs of capacity to firm up IRP pricing and cost comparison. Options for this RFP should include:**
  - **Purchase Power Agreement**
  - **Installation of 30 MW of Solar PV (11.4 MWs PJM Capacity)**
  - **Self-Build (GT or RICE installation)**
- **Similarly, it is recommended a second RFP is issued for the 2027 tranche of 100 MW of capacity.**
- **If choosing to use PPA's for capacity requirements, it is recommended the City uses a diversified combination of vendors and term lengths to help mitigate energy commodity risks.**
- **Current Long-Term projections show future addition requirements are needed to serve peak demand requirements. A Demand Side Peak Reduction Study focused on Demand Side Management programs is recommended.**
- **Dover's existing portfolio is nearing the end of its useful economic life. Dover needs to explore acceptable alternatives to replace the retiring capacity. Since Dover can balance its short-term capacity needs in the PJM RPM Capacity Market, there is available time to conduct detailed evaluations of alternatives.**

REQUEST FOR PROPOSALS

It is recommended that Dover issue Request for Proposals (RFP) to begin the process of implementing these recommendations. The RFP should be sufficiently generalized to allow for a range of proposals including an "Engineer-Procure-Construct" (EPC) option for installation of local generation to be financed and owned by Dover as well as proposals for Power Purchase Agreements.

Once proposals are received, the analyses performed for this study can be updated and refined using actual offers and a final economic ranking of proposals prepared.

Demand Side Management

Existing industry studies show that targeted DSM programs can provide more value than competing infrastructure improvements. Dover has been committed to providing demand-side management and energy efficiency resources for its customers for many years. It is recommended that a Peak

Reduction Study be performed to determine if there is additional potential for economic benefit through load management programs.

Decommissioning and/or Dismantlement of Existing Resources

Cost for decommissioning and/or dismantlement of Dover's existing generation resources is not included in this study. To get these costs Dover should retain the services of an engineering firm experienced in this area. The cost of decommissioning and dismantlement will ultimately be incurred by Dover. The decision to make such expenditures are not a matter of if they will be incurred; they are a matter of when.

RISK FACTORS TO CONSIDER

Regulatory Uncertainty

U.S. energy policies may change directions during the period of this study.

Environmental Regulations and Constraints

Electric generating plants must comply with a significant number of environmental regulations, some of which overlap with respect to a particular emission chemical. The most significant chemicals subject to such regulations include particulates (such as ash), Sulfur Dioxide (SO_2), Nitrogen Oxides (NO_x), Mercury and other air toxics. Over the years, since the enactment of the original federal Clean Air Act, more laws, rules and regulations have evolved into a complex web of federal and state mandates which, if violated, are subject to civil and possibly criminal violations. Generating plant owners and operators are familiar with this web of regulations and what is required to comply with them.

While all of these regulations impact the cost of operating generation, a few stand out sufficiently to be noteworthy in this IRP. These include emissions of green-house gas regulation (primarily carbon dioxide or CO_2) through the contested federal Clean Power Plan, air toxics being regulated by the enacted Mercury and Air Toxics Standard and Sulfur Dioxide (SO_2) and Nitrogen Oxides (NO_x) which are regulated under the enacted Cross-State Air Pollution Rule.

U.S. EPA Clean Power Plan (CPP)

The EPA published the proposed rule (CPP) to regulate CO_2 emissions from existing sources on October 23, 2015. This rule is designed to achieve a 33% reduction of CO_2 by 32% from 2005 CO_2 emissions from existing generation. The CPP applies to non-exempt existing generating units which were operating in 2012

Since this proposed rule was promulgated under previously existing law rather than a new congressional mandate, EPA has woven a relatively complex set of rules so that the CPP, in the opinion of EPA, conforms to existing law, however not all stake holders agree with EPA's opinion.

The CPP (along with the companion Section 111(b) rule applicable to new, modified and reconstructed generating units) has been and continues to be a topic of significant legal and political challenges. The CPP legal challenge currently resides in the U.S. District Court of Appeals (DCA) of the District of

Columbia. A DCA ruling on the legality of the CPP is uncertain. Analysts and advocates on either side of this proposed rule anticipate that the DCA finding will be appealed to the U.S. Supreme Court, thus extending regulatory uncertainty well into 2018.

Regardless of the ultimate outcome of the CPP, the potential for greenhouse gas regulations has gained significant momentum through state and regional programs such as the Regional Greenhouse Gas Initiative (RGGI) in the northeastern United States and California's extensive greenhouse gas regulation which have been promulgated under the California law named "AB-32".

A noteworthy issue is the nexus between CPP, renewable energy resources and energy efficiency improvements. One of the permissible ways to reduce CO2 emissions is to produce more generation from renewable resources and to make shifts from coal toward natural gas a lesser emitting thermal resource.

Market Risks

Fuel Cost and Availability

One of the largest sources of risk on a forward basis for any thermal unit is the cost and availability of fuel. Fuels markets are related to power markets, but are driven by myriad different factors including political, technology, and transportation risks. We have made attempts to explore this as a risk in this IRP through the addition of high and low gas price sensitivity analysis, although it is possible for market conditions to reach levels outside of even these bands.

Organized power markets have continued to evolve since their creation as regulatory policies change when flaws and enhancements are identified, new technologies require adjustments to existing designs, and entities enter or leave existing markets. Given the rapid continued evolution of the market structures with which utilities interact, it is possible that future regulatory policy shifts are not aligned with the resource investments and recommendations for reasons that cannot be fully foreseen at this time.

Capacity Markets

PJM has an organized capacity auction which is currently undergoing review. The intent of these auctions is to provide adequate resources to maintain reliability across a region in an economically rational fashion. In markets with a high penetration of merchant generators which lack a defined rate base of a vertically integrated utility, capacity markets allow these entities to recover some or all of their fixed costs by clearing in the auction. For all their high level benefits however, all current capacity market implementations remain wrought with flaws including a lack of price stability or forward looking duration necessary for entities necessary to justify a significant investment in a long term asset.

Ancillary Services

Historically, electric generators have provided a number of services beyond capacity and energy. While such services aren't widely recognized, they are essential to the reliable operation of the bulk power network. These are characterized by the utility industry as "Ancillary Services" and include operating reserves (spinning and supplemental or "fast-start"), voltage support, regulation, frequency response and black-start.

Detailed assessments of these requirements are beyond the scope of this IRP, but must be considered when evaluating specific projects. Many RTOs have evolving markets for these services, and FERC is showing increasing interest in promulgating regulations which will permit competition to provide such services. Dover should further evaluate the impact of the recommendations contained in this IRP to insure it will continue to be able to provide these very necessary and vital Ancillary Services. It should also actively monitor any developments within PJM and at a national level which could impact Dover's Ancillary Services requirements in the future.

Future Developments

To this point in organized markets, renewable resources have been largely relegated to providing energy, but not the reliability services. The notable exception to this has been the ability to provide regulation down in the PJM market. This has been driven by a combination of resources which historically lacked the technology to provide these services and the ability of external market subsidies to distort the normal function of markets. The majority of wind resources across the nation currently receive production tax credits making it economic for them to produce electricity and pay the market to take their electricity to prices around -$35 MWh for a period of 10 years. The result of the subsidy has been little interest in providing operating reserves which would require a resource to reduce output and forego the tax credits that often constitute much of an asset's revenue stream. On a more forward basis, it is probable there will be enhanced ability for intermittent resources to provide ancillary services driven by technological advances, lower market prices resulting from higher renewable penetration, and resources which are ineligible for production tax credits after 10 years or the current phase out of the wind Production Tax Credit for resources begun between now and the investment deadline of 2019. As intermittent resources become more capable of providing their own reliability services, further penetration becomes increasing feasible.

Efficient, cost effective energy storage has been evasive to this point in history, however it offers tremendous potential for the utility industry. Efficient Storage has the ability to provide frequency response and reliability benefits in a more flexible manner than traditional thermal assets. Significant advances in battery technology over the last few years have brought this closer to becoming a reality, which has driven FERC to publish a Notice of Proposed Rulemaking to ensure storage has a footing in the rules framework of organized markets.

Technology Risks

The technologies and their associated costs included in this IRP reflect the best information publicly available from respected sources across the industry; however, the nature of innovation is such that future technology may move at a faster or slower rate than forecasts. A change in technology development, or cost efficiency rate has the potential to impact the viability of said technologies to the recommendations contained herein. Should any one technology make substantial unforeseen improvements in output efficiency or cost relative to others, there is a considerable chance it may become more viable than the recommendations introduced in this report.

In addition to the risks associated with evolution of accepted technologies is the disruptive potential of technologies not yet known or accepted as mainstream. Should new technologies reach the forefront, it could substantially alter the recommendations by making those technologies viable for addition to Dover portfolio and may fundamentally alter the economics of the new and existing generation recommendations.

Technology risks also exist on the demand side and have potential to result in further reductions in Customer demand in the form of increased energy efficiency or distributed generation which would alter Dover customer demand.

Resource Flexibility

The immediate nature of the power grid necessitates flexible resources to maintain reliability and this onus is only greater magnified by the continued proliferation of intermittent wind and solar resources. Quick starting resources are able to run in certain transitory but vital circumstances with minimal lead time which removes the need to run around the clock in order to capture the most value from peak periods as they can remain offline and come online efficiently. As a general rule, organized markets implicitly prefer more flexible resources as they can move rapidly once online to capture the economic benefits of higher market prices while lowering output to avoid low or negative prices. To this point in organized markets, benefits have been largely implicit; however, there has been discussion at several levels in organized markets to create an explicit incentive for resources with the larger goal of rewarding these resource types and driving priority in investment decisions. As renewable penetration continues to grow, we expect to see the value of these resources continue to increase relative to other generation types as they serve to complement the inherent variability of wind and solar resources.

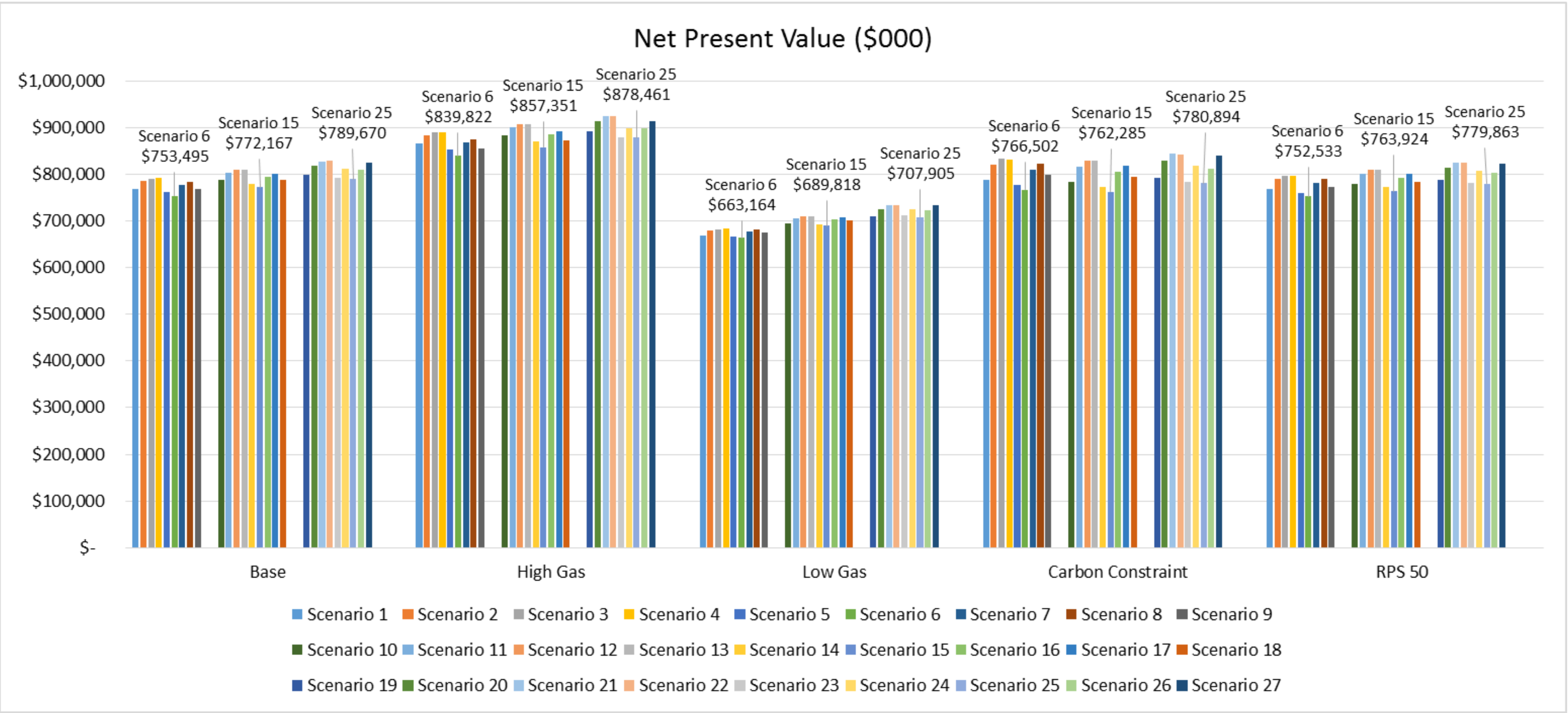
Disclaimer

- New resource parameters and costs based upon industry standards, not on actual contract numbers.
- Hypothetical performance results have many inherent limitations, some of which are described below. No representation is being made that any account will or is likely to achieve profits or losses similar to those shown. In fact, there are frequently sharp differences between hypothetical performance results and the actual results subsequently achieved by any particular trading program.
- One of the limitations of hypothetical performance results is that they are generally prepared with the benefit of hindsight. In addition, hypothetical trading does not involve financial risk, and no hypothetical trading record can completely account for the impact of financial risk in actual trading. For example, the ability to withstand losses or to adhere to a particular trading program in spite of trading losses are material points which can also adversely affect actual trading results. There are numerous other factors related to the markets in general or to the implementation of any specific trading program which cannot be fully accounted for in the preparation of hypothetical performance results and all of which can adversely affect actual trading results

IRP Appendix

Modelling Results

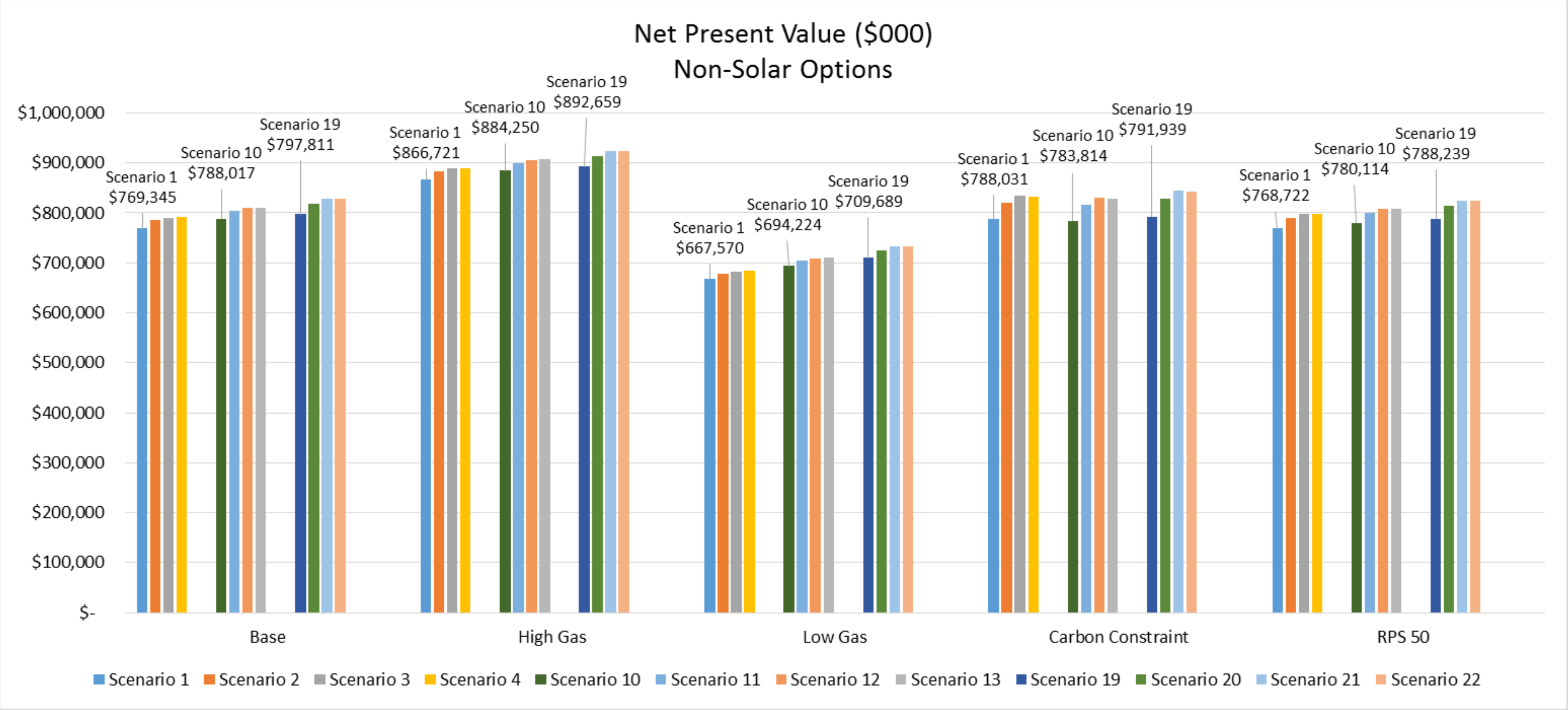
Costs by Scenario Comparison



Scenario 1-9 – Retirement Schedule 1: No VanSant Retirement, McKee 3 Retires 2027
Scenario 10-18 – Retirement Schedule 2: VanSant Retires 2021 , McKee 3 Retires 2027
Scenario 19-27 – Retirement Schedule 3: VanSant and McKee 3 Retires 2021
Note: Retirement Schedule 1 includes $2.1M in 2018 costs to extend life of VanSant.

Costs by Scenario Comparison

Non-Solar Resource Option Scenarios Only



Scenario 1-4 – Retirement Schedule 1: No VanSant Retirement, McKee 3 Retires 2027
Scenario 10-13 – Retirement Schedule 2: VanSant Retires 2021 , McKee 3 Retires 2027
Scenario 19-22 – Retirement Schedule 3: VanSant and McKee 3 Retires 2021
Note: Retirement Schedule 1 includes $2.1M in 2018 costs to extend life of VanSant.

Costs by Scenario Comparison

Retirement Schedule 1

Retirement Schedule 1: No Vansant Retirement, McKee 3 Retires 2027

					Base		High Gas		Low Gas		Carbon Constraint		RPS 50	
	Load Growth				Zero Load Growth		Zero Load Growth		Zero Load Growth		Zero Load Growth		Zero Load Growth	
	Carbon				RGGI		RGGI		RGGI		Carbon Constraint		RGGI	
	Gas Price				Base Gas		High Gas		Low Gas		Base Gas		Base Gas	
	Renewable Portfolio Standards				Existing RPS		Existing RPS		Existing RPS		Existing RPS		RPS 50%	
	Unit Name	**Capacity per Unit**	**# of Units**	**Year of Install**	**NPV ($000)**	**Avg Cost ($/MWh)**	**NPV ($000)**	**Avg Cost ($/MWh)**	**NPV ($000)**	**Avg Cost ($/MWh)**	**NPV ($000)**	**Avg Cost ($/MWh)**	**NPV ($000)**	**Avg Cost ($/MWh)**
Scenario 1	PPA NGCC	50	1	2024	$ 769,345	$49.86	$ 866,721	$56.17	$ 667,570	$43.26	$ 788,031	$51.07	$ 768,722	$49.81
	PPA NGCC	50	2	2027										
Scenario 2	Purch Cap NGCC	50	1	2024	$ 784,762	$50.85	$ 882,417	$57.18	$ 678,579	$43.97	$ 819,520	$53.11	$ 789,053	$51.13
	Purch Cap NGCC	50	1.2	2027										
	RICE	10	4	2027										
Scenario 3	Purch Cap NGCC	50	1	2024	$ 790,739	$51.24	$ 888,754	$57.59	$ 682,563	$44.23	$ 833,723	$54.03	$ 797,290	$51.67
	Purch Cap NGCC	50	1	2027										
	NGCT Frame	50	1	2027										
Scenario 4	Purch Cap NGCC	50	1	2024	$ 791,384	$51.28	$ 889,309	$57.63	$ 683,662	$44.30	$ 832,130	$53.92	$ 797,322	$51.67
	Purch Cap NGCC	50	1	2027										
	NGCT Aero	50	1	2027										
Scenario 5	PPA NGCC	50	0.8	2024	$ 761,205	$49.33	$ 852,523	$55.25	$ 665,786	$43.14	$ 776,986	$50.35	$ 760,346	$49.27
	Solar	11.4	1	2024										
	PPA NGCC	50	2	2027										
Scenario 6	PPA NGCC	50	0.8	2024	$ 753,495	$48.83	$ 839,822	$54.42	$ 663,164	$42.97	$ 766,502	$49.67	$ 752,533	$48.77
	Solar	11.4	1	2024										
	PPA NGCC	50	1.8	2027										
	Solar	11.4	1	2027										
Scenario 7	PPA NGCC	50	0.8	2024	$ 776,622	$50.33	$ 868,219	$56.26	$ 676,795	$43.86	$ 808,475	$52.39	$ 780,677	$50.59
	Solar	11.4	1	2024										
	PPA NGCC	50	1.2	2027										
	RICE	10	4	2027										
Scenario 8	PPA NGCC	50	0.8	2024	$ 782,599	$50.71	$ 874,556	$56.67	$ 680,780	$44.12	$ 822,678	$53.31	$ 788,915	$51.12
	Solar	11.4	1	2024										
	PPA NGCC	50	1	2027										
	NGCT Frame	50	1	2027										
Scenario 9	PPA NGCC	50	0.8	2024	$ 768,913	$49.83	$ 855,518	$55.44	$ 674,173	$43.69	$ 797,991	$51.71	$ 772,864	$50.08
	Solar	11.4	1	2024										
	PPA NGCC	50	1	2027										
	Solar	11.4	1	2027										
	RICE	10	4	2027										

Minimum Cost of Non Solar Resource Options

Minimum Cost of All Resource Options

Solar PV installations may require additional property purchase. The estimated change to NPV for every $1M of property investment is:

Year of Purchase	NPV Addition ($000)
2018	$989
2019	$921
2020	$856
2021	$793
2022	$732
2023	$673
2024	$616
2025	$561
2026	$508
2027	$457

Note: Retirement Schedule 1 includes $2.1M in 2018 costs to extend life of VanSant.

Costs by Scenario Comparison

Retirement Schedule 2

Retirement Schedule 1: Vansant Retires 2021, McKee 3 Retires 2027

					Base		High Gas		Low Gas		Carbon Constraint		RPS 50	
Load Growth					Zero Load Growth		Zero Load Growth		Zero Load Growth		Zero Load Growth		Zero Load Growth	
Carbon					RGGI		RGGI		RGGI		Carbon Constraint		RGGI	
Gas Price					Base Gas		High Gas		Low Gas		Base Gas		Base Gas	
Renewable Portfolio Standards					Existing RPS		Existing RPS		Existing RPS		Existing RPS		RPS 50%	
	Unit Name	**Capacity per Unit**	**# of Units**	**Year of Install**	**NPV ($000)**	**Avg Cost ($/MWh)**	**NPV ($000)**	**Avg Cost ($/MWh)**	**NPV ($000)**	**Avg Cost ($/MWh)**	**NPV ($000)**	**Avg Cost ($/MWh)**	**NPV ($000)**	**Avg Cost ($/MWh)**
Scenario 10	PPA NGCC	50	1	2021	$ 788,017	$51.07	$ 884,250	$57.30	$ 694,224	$44.99	$ 783,814	$50.79	$ 780,114	$50.55
	PPA NGCC	50	0.8	2024										
	PPA NGCC	50	2	2027										
Scenario 11	Purch Cap NGCC	50	1	2021	$ 803,434	$52.06	$ 899,946	$58.32	$ 705,233	$45.70	$ 815,303	$52.83	$ 800,445	$51.87
	Purch Cap NGCC	50	0.8	2024										
	Purch Cap NGCC	50	1.2	2027										
	RICE	10	4	2027										
Scenario 12	Purch Cap NGCC	50	1	2021	$ 809,411	$52.45	$ 906,283	$58.73	$ 709,217	$45.96	$ 829,506	$53.75	$ 808,682	$52.40
	Purch Cap NGCC	50	0.8	2024										
	Purch Cap NGCC	50	1	2027										
	NGCT Frame	50	1	2027										
Scenario 13	Purch Cap NGCC	50	1	2021	$ 810,056	$52.49	$ 906,838	$58.77	$ 710,316	$46.03	$ 827,912	$53.65	$ 808,714	$52.41
	Purch Cap NGCC	50	0.8	2024										
	Purch Cap NGCC	50	1	2027										
	NGCT Aero	50	1	2027										
Scenario 14	PPA NGCC	50	1	2021	$ 779,876	$50.54	$ 870,052	$56.38	$ 692,440	$44.87	$ 772,769	$50.08	$ 771,738	$50.01
	Solar	11.4	1	2024										
	PPA NGCC	50	0.6	2024										
	PPA NGCC	50	2	2027										
Scenario 15	PPA NGCC	50	1	2021	$ 772,167	$50.04	$ 857,351	$55.56	$ 689,818	$44.70	$ 762,285	$49.40	$ 763,924	$49.50
	Solar	11.4	1	2024										
	PPA NGCC	50	0.6	2024										
	Solar	11.4	1	2027										
	PPA NGCC	50	1.8	2027										
Scenario 16	PPA NGCC	50	1	2021	$ 795,294	$51.54	$ 885,748	$57.40	$ 703,449	$45.59	$ 804,257	$52.12	$ 792,069	$51.33
	Solar	11.4	1	2024										
	PPA NGCC	50	0.6	2024										
	PPA NGCC	50	1.2	2027										
	RICE	10	4	2027										
Scenario 17	PPA NGCC	50	1	2021	$ 801,271	$51.92	$ 892,085	$57.81	$ 707,434	$45.84	$ 818,461	$53.04	$ 800,306	$51.86
	Solar	11.4	1	2024										
	PPA NGCC	50	0.6	2024										
	PPA NGCC	50	1	2027										
	NGCT Frame	50	1	2027										
Scenario 18	PPA NGCC	50	1	2021	$ 787,584	$51.04	$ 873,047	$56.58	$ 700,827	$45.42	$ 793,774	$51.44	$ 784,255	$50.82
	Solar	11.4	1	2024										
	PPA NGCC	50	0.6	2024										
	PPA NGCC	50	1	2027										
	Solar	11.4	1	2027										
	RICE	10	4	2027										

Minimum Cost of Non Solar Resource Options

Minimum Cost of All Resource Options

Solar PV installations may require additional property purchase. See table on slide 20 for the estimated change to NPV for every $1M of property investment.

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Costs by Scenario Comparison

Retirement Schedule 3

Retirement Schedule 3: Vansant Retire 2021, McKee 3 Retires 2021

					Base		High Gas		Low Gas		Carbon Constraint		RPS 50	
Load Growth					Zero Load Growth		Zero Load Growth		Zero Load Growth		Zero Load Growth		Zero Load Growth	
Carbon					RGGI		RGGI		RGGI		Carbon Constraint		RGGI	
Gas Price					Base Gas		High Gas		Low Gas		Base Gas		Base Gas	
Renewable Portfolio Standards					Existing RPS		Existing RPS		Existing RPS		Existing RPS		RPS 50%	
	Unit Name	**Capacity per Unit**	**# of Units**	**Year of Install**	**NPV ($000)**	**Avg Cost ($/MWh)**	**NPV ($000)**	**Avg Cost ($/MWh)**	**NPV ($000)**	**Avg Cost ($/MWh)**	**NPV ($000)**	**Avg Cost ($/MWh)**	**NPV ($000)**	**Avg Cost ($/MWh)**
Scenario 19	PPA NGCC	50	3	2021	$ 797,811	$51.70	$ 892,659	$57.85	$ 709,689	$45.99	$ 791,939	$51.32	$ 788,239	$51.08
	PPA NGCC	50	0.8	2024										
Scenario 20	Purch Cap NGCC	50	3	2021	$ 818,117	$53.02	$ 913,377	$59.19	$ 724,605	$46.96	$ 828,533	$53.69	$ 813,675	$52.73
	RICE	10	4	2024										
Scenario 21	Purch Cap NGCC	50	2.9	2021	$ 827,873	$53.65	$ 923,555	$59.85	$ 732,621	$47.48	$ 843,872	$54.68	$ 825,000	$53.46
	NGCT Frame	50	1	2024										
Scenario 22	Purch Cap NGCC	50	2.9	2021	$ 828,520	$53.69	$ 924,088	$59.88	$ 733,823	$47.55	$ 842,234	$54.58	$ 824,988	$53.46
	NGCT Aero	50	1	2024										
Scenario 23	PPA NGCC	50	2.8	2021	$ 791,393	$51.28	$ 878,569	$56.93	$ 710,824	$46.06	$ 782,507	$50.71	$ 781,477	$50.64
	Solar	11.4	1	2021										
	PPA NGCC	50	0.8	2024										
Scenario 24	PPA NGCC	50	2.8	2021	$ 811,699	$52.60	$ 899,287	$58.28	$ 725,740	$47.03	$ 819,101	$53.08	$ 806,913	$52.29
	Solar	11.4	1	2021										
	RICE	10	4	2024										
Scenario 25	PPA NGCC	50	3	2021	$ 789,670	$51.17	$ 878,461	$56.93	$ 707,905	$45.87	$ 780,894	$50.60	$ 779,863	$50.54
	Solar	11.4	1	2024										
	PPA NGCC	50	0.6	2024										
Scenario 26	PPA NGCC	50	2.4	2021	$ 808,413	$52.39	$ 897,708	$58.17	$ 721,952	$46.78	$ 812,000	$52.62	$ 802,601	$52.01
	RICE	10	3	2021										
	Solar	11.4	1	2024										
	PPA NGCC	50	0.6	2024										
Scenario 27	PPA NGCC	50	2	2021	$ 824,394	$53.42	$ 914,502	$59.26	$ 733,544	$47.54	$ 840,576	$54.47	$ 822,421	$53.29
	NGCT Frame	50	1	2021										
	Solar	11.4	1	2024										
	PPA NGCC	50	0.6	2024										

Minimum Cost of Non Solar Resource Options

Minimum Cost of All Resource Options

Solar PV installations may require additional property purchase. See table on slide 20 for the estimated change to NPV for every $1M of property investment.

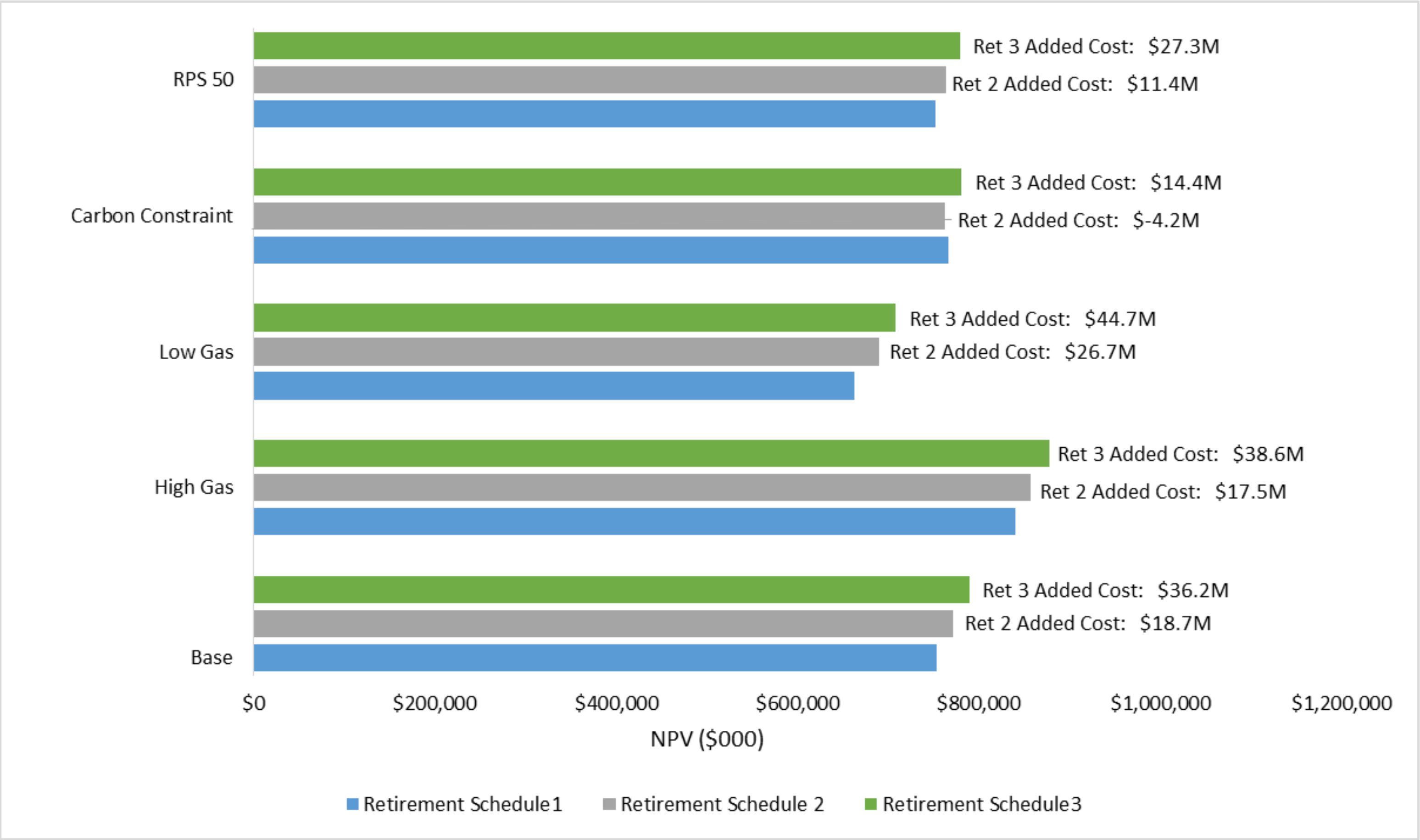
Lowest Cost Scenario vs Retirement Schedules

	Retirement Schedule 1			Retirement Schedule 2			Retirement Schedule 3		
	No Vansant Retirement McKee 3 Retires 2027			Vansant Retires 2021 McKee 3 Retires 2027			Vansant Retires 2021 McKee 3 Retires 2021		
Lowest Cost Scenario	**Scenario 6**			**Scenario 15**			**Scenario 25**		
	Unit Name	PJM Peaking Capacity	Year of Install	Unit Name	PJM Peaking Capacity	Year of Install	Unit Name	PJM Peaking Capacity	Year of Install
	PPA NGCC	40	2024	PPA NGCC	50	2021	PPA NGCC	150	2021
	Solar	11.4	2024	Solar	11.4	2024	Solar	11.4	2024
	PPA NGCC	90	2027	PPA NGCC	30	2024	PPA NGCC	30	2024
	Solar	11.4	2027	Solar	11.4	2027			
				PPA NGCC	90	2027			

Results		**NPV ($000)**	**NPV ($000)**	**Change from Schedule 1 ($000)**	**NPV ($000)**	**Change from Schedule 1 ($000)**
Sensitivities	Base	$753,495	$772,167	$18,672	$789,670	$36,175
	High Gas	$839,822	$857,351	$17,529	$878,461	$38,639
	Low Gas	$663,164	$689,818	$26,654	$707,905	$44,741
	Carbon Constraint	$766,502	$762,285	-$4,217	$780,894	$14,392
	RPS 50	$752,533	$763,924	$11,392	$779,863	$27,331

Note: In the Carbon Constraint Sensitivity, LMP prices are elevated in the later years of the study. This makes new installations more valuable in this time frame. However, the later years in the study inherently introduces more risk in the LMP assessment.

Lowest Cost Scenario vs Retirement Schedules



Lowest Cost Scenario vs Retirement Schedules

Non-Solar Resource Option Scenarios Only

		Retirement Schedule 1			Retirement Schedule 2			Retirement Schedule 3	
		No Vansant Retirement McKee 3 Retires 2027			Vansant Retires 2021 McKee 3 Retires 2027			Vansant Retires 2021 McKee 3 Retires 2021	
Lowest Cost Scenario		**Scenario 1**			**Scenario 10**			**Scenario 19**	
		Unit Name	PJM Peaking Capacity	Year of Install	Unit Name	PJM Peaking Capacity	Year of Install	Unit Name	PJM Peaking Capacity	Year of Install
		PPA NGCC	50	2024	PPA NGCC	50	2021	PPA NGCC	150	2021
		PPA NGCC	100	2027	PPA NGCC	40	2024	PPA NGCC	40	2024
					PPA NGCC	100	2027			

Results		NPV ($000)	NPV ($000)	Change from Schedule 1 ($000)	NPV ($000)	Change from Schedule 1 ($000)
Sensitivities	Base	$769,345	$788,017	$18,672	$797,811	$28,466
	High Gas	$866,721	$884,250	$17,529	$892,659	$25,938
	Low Gas	$667,570	$694,224	$26,654	$709,689	$42,119
	Carbon Constraint	$788,031	$783,814	-$4,217	$791,939	$3,908
	RPS 50	$768,722	$780,114	$11,392	$788,239	$19,517

Note: In the Carbon Constraint Sensitivity, LMP prices are elevated in the later years of the study. This makes new installations more valuable in this time frame. However, the later years in the study inherently introduces more risk in the LMP assessment.

Lowest Cost Scenario vs Retirement Schedules

Non-Solar Resource Option Scenarios Only