TEA
THE EnergyAuthority

2023
DOVER INTEGRATED RESOURCE PLAN

PREPARED FOR

THE CITY OF DOVER

The City of Dover
Capital of the First State
Delaware

EXECUTIVE SUMMARY

Foreword Dave Hugg - City Manager

The City of Dover (Dover) is pleased to present the 2022 Integrated Resource Plan (IRP) document, the results of a detailed analysis of alternatives it may select to meet its energy and capacity requirements for 2022-2042. Dover's Electric Utility is owned and accountable to its community. In the rapidly changing electric industry, Dover remains steadfast in serving its customers by offering competitive rates, high reliability, local control, public accountability, and responsive customer service to the community. In response to those changes, Dover is updating its IRP more frequently, working with The Energy Authority (TEA), a strategic partner, to build upon our significant progress toward the goals laid out in the 2017 IRP.

Introduction

Dover, the Capital of Delaware, is centrally located in the State and is part of the Mid-Atlantic region. The city is approximately 90 miles from Philadelphia and Washington, D.C. Dover's population ranks second only to Wilmington, Delaware. Delaware and the Eastern Shore counties of Maryland and Virginia comprise the Delmarva Peninsula. Dover is also the largest city in land area on the peninsula, with a total land area of over 23 square miles.

Dover is responsible for electric power supply reliability and the engineering, construction, and maintenance of electric infrastructure. The Electric Team maintains a system that covers 75 square miles and serves approximately 25,000 customers. Dover also operates a 42 MW generation station at Van Sant by Schutte Park, which generates electricity for use in Dover and sells it into PJM, the regional organized market.

Electric power is a keystone of our nation's economic and social welfare, as nearly every aspect of daily life depends on the reliable, economical, and safe delivery of electric power. To successfully provide electric services to the community, The City of Dover, Delaware, must make effective power resource decisions in a complex and uncertain environment. Technology development, electricity and commodity pricing, economic factors, environmental regulations, and cultural and social forces are elements of risk to long-term planning. Thus, a comprehensive Integrated Resource Plan (IRP) is essential in identifying and advancing a strategy to achieve the city's mission, vision, and goals.

Understanding IRP as a Road Map

The 2022 Dover IRP is a comprehensive decision support tool and roadmap for meeting the city's objective of providing reliable, safe, low-cost electric service to all customers. As part of the planning process, Dover monitors changing market conditions, such as more stringent environmental regulations and technological advancements. This systematic market review helps guide Dover's future resource decisions, inform appropriate actions within the recommended ranges, and identify the right timing for initiating the next IRP.

The following are some of the key variables that could have a significant influence on the future generation portfolio:

IRP Methodology

Developing the 2022 IRP has been a 12-month process that began with scoping in the spring of 2022. The IRP utilizes an iterative methodology that starts with identifying assumptions that become the basis for forecasting future electric demand and the potential resources to meet that demand. The process optimizes a mix of resources and minimizes future costs while meeting Dover's overarching goals.

This executive summary looks at plan objectives, modeling, forecasting approach, existing resources, and an overview of plan recommendations.

Additional key plan concepts (bulleted below) are applied within the planning framework to form the most important considerations for Dover's decision-making process.

- Create a baseline projection for this IRP process.
- Analyze essential commodities, emissions, and price forecasts.
- Incorporate proven methodologies for energy and demand forecasting.
- Analyze existing and new resources on a cost-to-serve load basis.
- Forecast future demand and supply requirements to determine the optimal mix of resources to minimize future costs while meeting reliability, regulatory, and social expectations.
- Build a strategic long-term "buy" or "build" plan for capacity resources to meet PJM's capacity obligation requirements.
- 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 and Net Present Value calculations in asset evaluation.
- Present consumable information and assumptions with transparency.
- Provide clear recommendations.

Recommendations

The IRP results, including the base case, five defined scenarios, and one alternate case, provide a robust set of potential resource additions. Under all of the studied scenarios, solar generation has a significant expansion. The final recommendation is derived from this evaluation.

- Balance short-term capacity needs through 2026 in PJM's Reliability Pricing Model market.
- In spring 2023, issue an RFP for 125 MW in 2027 and an additional 100 MW tranche in 2028.
- Capacity options for evaluation should include:
    - Purchased power agreements.
    - Solar purchased power agreements.
    - Battery energy storage.
    - Utility-owned gas turbines or reciprocating internal combustion engines.
- Subsequent RFPs should be timed appropriately to satisfy capacity shortfalls beyond 2028
- If selecting purchased power agreements for capacity requirements, it is recommended that Dover use a diversified combination of vendors and term lengths to help mitigate energy commodity risks.
- Initiate a Demand Side Peak Reduction Study focused on 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.

PLANNING ENVIRONMENT

Industry and Economic Factors/Risks

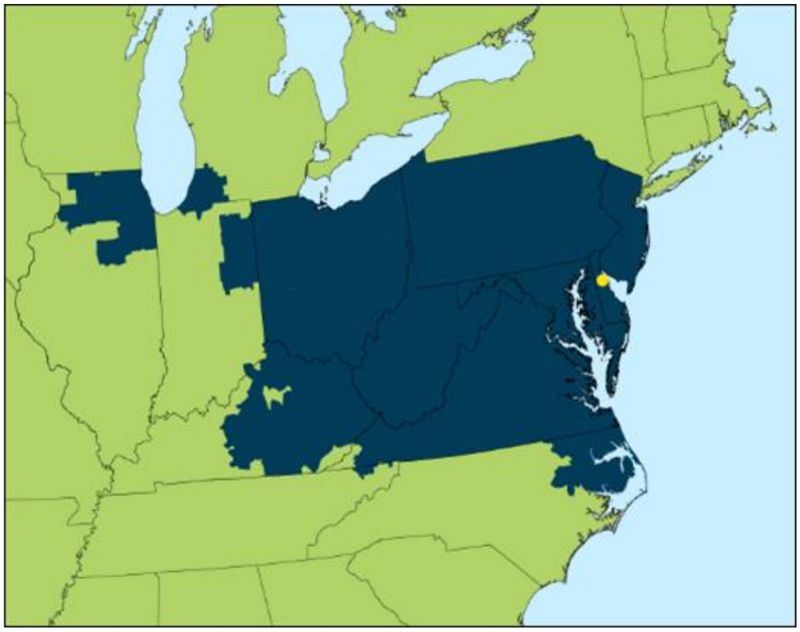
Dover faces the challenge of delivering reliable, safe, and cost-effective energy to its customers in an industry that is changing at an increasingly rapid pace. Since Dover's previous Integrated Resource Planning, completed in 2017, notable changes have included increasingly stringent environmental goals, growing penetration of renewable resources as a replacement of carbon-emitting thermal generation, battery energy storage becoming a more viable option, and the economic challenges of the pandemic and current high inflationary period.

The following are industry risks considered in the development of Dover's recommended resource plan:

- Possible changes to federal energy policy and federal, state, and local environmental regulations continue to evolve as the energy sector transitions from primarily fossil-based systems of energy production and consumption to cleaner, carbon-free sources.
- Future solar pricing remains relatively high after recent market disruptions dramatically reversed the price declines that had been occurring consistently for over a decade.
- Continued long lead times are required for new renewable and thermal resources due to ongoing supply chain issues and project backlogs.
- The PJM's Installed Reserve Margin (IRM) requirement can potentially increase.
- Decreasing Effective Load Carrying Capability (ELCC) accreditation for renewables as renewable penetration increases.
- Possible increased congestion into the Dover service territory that would result in higher locational marginal pricing.
- A change in the Unforced Capacity (UCAP) accreditation methodology for conventional resources could result in lower accreditation values.
- The potential for reduced peak demand and energy forecasting accuracy caused by using renewables, battery energy storage, electric vehicles, and distributed energy resources increases.

Market Constraints

Several key market constraints identified in the IRP process are discussed in this section. The natural geography of a peninsula is a contributing factor to various market constraints presented. Electricity transmission grid constraints impact the price of wholesale electricity. Natural gas pipeline constraints affect the owned generation and the resource plan options that Dover can choose economically. Lastly, transmission grid reliability constraints, requiring transmission upgrade projects that impact Dover's ratepayers, are presented. An overview of the available competitive electricity markets leads the discussion.



Dover is a member of the Pennsylvania-New Jersey-Maryland Interconnection (PJM), a regional transmission organization that coordinates wholesale electricity movement in portions of the Mid-Atlantic and Midwestern United States. Dover is located on the Delmarva peninsula in PJM's eastern service territory. Below is a map of the PJM service territory, with Dover's location marked in yellow on the peninsula.[1]

Acting as a neutral, independent party, PJM operates a competitive wholesale electricity market and manages the high-voltage electricity grid to ensure reliable energy transmission for more than 65 million people. PJM's long-term regional planning process provides a broad, interstate perspective that identifies the most effective and cost-efficient improvements to this transmission grid to ensure reliability and economic benefits on a PJM-system-wide basis. An independent board oversees PJM's activities, informed by a robust and collaborative stakeholder process in which stakeholders like Dover participate. Dover's membership in PJM benefits Dover's ratepayers by leveraging PJM's typically lower-cost energy resources, transmission grid expertise, and cost-control measures.

Dover purchases wholesale electrical energy directly from PJM's competitive energy markets. Dover buys bilateral energy contracts to hedge the market price uncertainty and reduces its energy costs with revenues from Dover's owned generation when it is economically dispatched into the PJM energy markets.

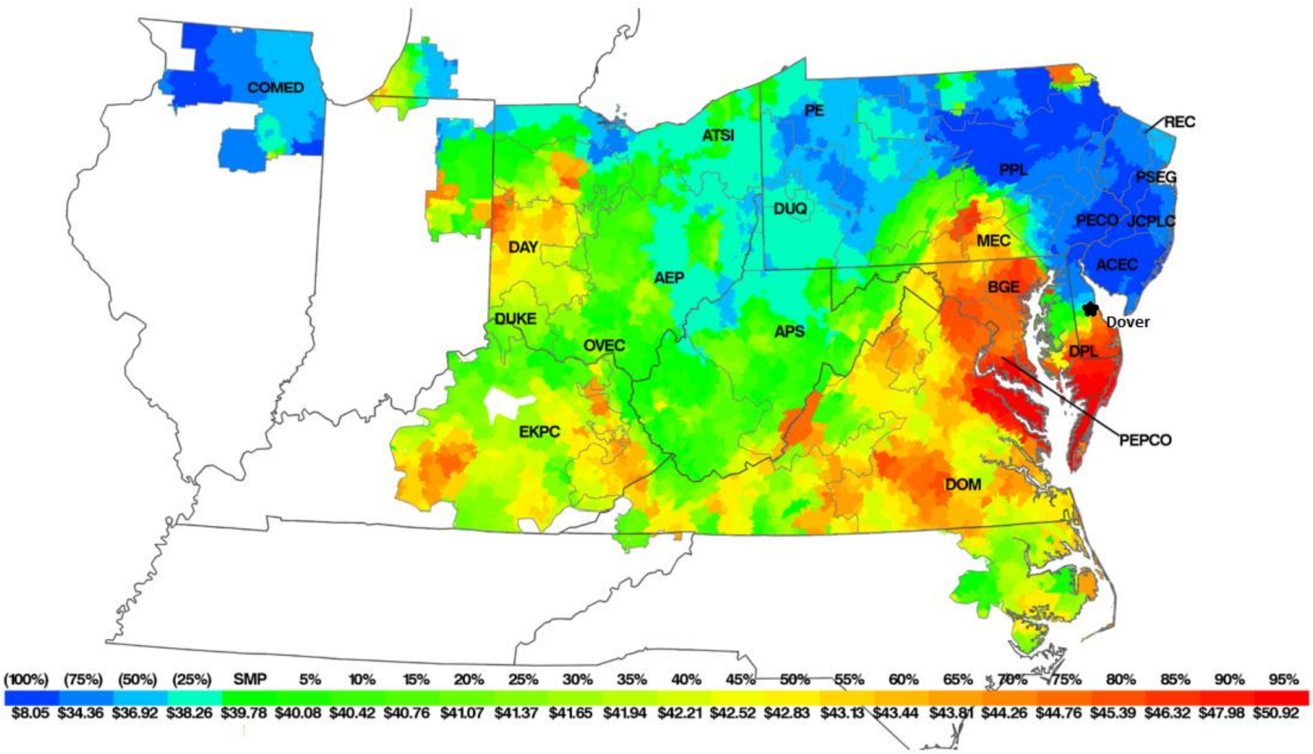
[1] Map of PJM Territory

As a competitive market, PJM is independently evaluated by a third-party market monitoring entity, which publishes its evaluation in various documents. The 2021 Independent Market Monitor's State of the Market Report table lists the historical averages for PJM market energy prices. (Monitoring Analytics, 2022) These annual averages are load-weighted prices, in dollars per megawatt-hours, of the energy purchased from PJM's energy markets by all its members. PJM has two independently priced energy markets: one allows Dover to buy energy at real-time prices as it is being produced and consumed. The second market works like a one-day-ahead firm reservation to buy the next day's energy at forecasted market prices, but only for the reserved volume of energy in that reservation. Dover participates in both energy markets, with most of its energy purchases reserved in the day-ahead market. The balance of Dover's hourly energy needs is purchased in the real-time energy market. The net bilateral hedging market revenues and any net economic owned-generation dispatch revenues are financial offsets to Dover's energy market purchases.[2]

Load-Weighted Average LMP		
	Day-Ahead	Real-Time
2001	$32.75	$32.38
2002	$28.46	$28.30
2003	$38.73	$38.28
2004	$41.43	$42.40
2005	$57.89	$58.08
2006	$48.10	$49.27
2007	$54.67	$57.58
2008	$66.12	$66.40
2009	$37.00	$37.08
2010	$44.57	$44.83
2011	$42.52	$42.84
2012	$32.79	$33.11
2013	$37.15	$36.55
2014	$49.15	$48.22
2015	$34.12	$33.39
2016	$28.10	$27.57
2017	$29.48	$29.42
2018	$35.69	$35.75
2019	$26.03	$26.02
2020	$20.33	$20.66
2021	$37.76	$38.18

2 Day-ahead and real-time load-weighted average LMP (Dollars per MWh): 2001 through 2021

The color-coded price map below is from the independent PJM market monitor's 2021 State of the Market Report, with Dover's location marked with a black star on the Delmarva peninsula. (Monitoring Analytics, 2022) The price map shows load-weighted average real-time energy prices across the full PJM region during 2021, providing a color-coded graphic comparison to the PJM system-wide average energy price for all of 2021. The figure's legend states that the baseline system-wide average price is labeled "SMP," or system marginal price. The annualized PJM-wide system marginal price used for comparison is not load-weighted.



In contrast, the localized energy prices are load-weighted to account for the energy used in those regions. The blue-green represents the system marginal price in the figure's price/color legend. In contrast, each incremental color to the right or left represents five percent of the average load-weighted real-time prices above and below that system marginal price for a particular region. [3]

PJM transmission grid constraints and projected improvements are evaluated and factored into the IRP process. This evaluation can affect the energy resources selected for the plan because forecasted fuel and market-energy prices are significant factors in assessing the cost of prospective energy resources. Because large waterways on three sides surround the Delmarva peninsula, it is geographically isolated from the rest of the PJM service territory in a way that naturally constrains useful energy imports from and exports to the surrounding PJM service territory.

[3] This price map graphically illustrates DOVER's average load-weighted price to purchase energy from PJM's real-time energy market fell into the chart's light-blue-to-light green color bars.

These transmission constraints frequently impact PJM market energy pricing in Dover and the peninsula. That market pricing is a significant part of DOVER's load cost, although the transmission constraint impacts can be financially favorable or unfavorable for Dover's customers, varying from month to month. The financial impact has generally been favorable to Dover's ratepayers in recent years. As shown in the table below, DOVER's average annual PJM market energy prices have typically been below the average PJM price, indicating that Dover's customers are typically paying lower costs for power than most PJM entities.

PJM Energy Market Prices			
Year	Dover Avg PJM Price	PJM DA Avg	PJM RT Avg
2016	$27.28	$28.10	$27.57
2017	$29.34	$29.48	$29.42
2018	$36.75	$35.69	$35.75
2019	$23.57	$26.03	$26.02
2020	$18.34	$20.33	$20.66
2021	$35.03	$37.76	$38.18 [4]

Dover receives its natural gas services as an interruptible-gas customer because Dover's owned generation is infrequently economically dispatched into the electricity market. During times of high demand for natural gas, the natural gas pipeline management company is contractually required to limit its interruptible customers to ensure that its firm-gas customers are supplied the natural gas their contracts specify. The cost to switch from interruptible-gas service to firm-gas service is high. Any expansion of firm natural gas capacity in the Dover area would require years of planning by pipeline management companies, which includes funding and building additional pipeline infrastructure. New customers must share the cost of the new infrastructure necessary and are required to enter into decades-long firm-gas contractual commitments. Dover avoids the high cost of acquiring firm-gas customer status by owning dual-fuel generation. Dover can run its generation on fuel oil whenever natural gas is unavailable to the pipeline's interruptible customers.

[4] Load-Weighted Pricing in $ per megawatt-hour

Lastly, a primary mission of PJM is to ensure its bulk electric power system's safety, reliability, and security across its entire 13-state region. Power grid operators at PJM make real-time decisions that balance electricity supply and demand to keep the lights on across PJM. To keep the power grid balanced, PJM continuously monitors its system, reacting to changes in electricity use, equipment problems, weather conditions, and other factors to keep electricity flowing to customers.

PJM's robust planning process ensures that electricity will be available when customers need it for years into the future. PJM analyzes several factors to see what changes or additions are required – such as connecting new power lines or upgrading existing equipment – to ensure ongoing reliable power supplies for all its consumers. PJM's annual Regional Transmission Expansion Plan determines the changes likely to be needed up to 15 years into the future. Generation interconnection studies determine whether the existing grid can handle power from a new generating plant and what transmission grid changes are needed to connect the new resource. Therefore, any impacts to transmission grid reliability are carefully monitored by PJM, including the removal of existing generation, so these significant resource changes do not adversely affect reliability for its PJM customers. Generation retirement planning studies and associated transmission upgrade projects ensure that the grid can accommodate various generator deactivation requests.

The Delmarva peninsula is experiencing these transmission-grid growing pains from a requested deactivation of an aging coal plant. Significant transmission upgrades to the Delmarva grid are needed before the coal plant can safely retire, even while equipment upgrades are required to keep the aging coal plant fully functional. The seven identified transmission grid upgrades are scheduled to be implemented over approximately five years. PJM's thorough planning process keeps the lights on in the Delmarva peninsula. The customers share the sizeable cost of accommodating the coal plant retirement across the limited region of transmission reliability impact. With this retirement, the cost to keep the plant operating for five years far exceeds the cost of transmission grid improvements. The cost to run the unit is spread over the five years the coal plant remains online, while the transmission upgrade costs are spread over the expected life of those improvements, typically 20-40 years. Dover's ratepayers are currently impacted by the cost of continuing to run the coal plant.

PJM Capacity Construct

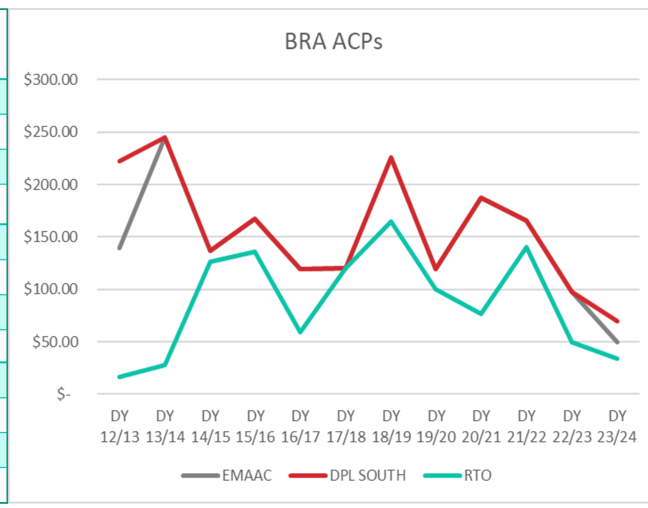
Each PJM member that is a load-serving entity provides electricity to consumers and must acquire enough power supply resources to meet the demand for today, tomorrow, and the future. Load-serving entities secure these resources for the future through the PJM capacity market. PJM's capacity market, called the Reliability Pricing Model, ensures long-term grid reliability by procuring the appropriate power supply resources needed to meet predicted energy demand for three years. Under a "pay-for-performance" model, power supply resources must deliver on demand during system emergencies or owe a significant payment for non-performance. Sufficient electricity capacity means adequate resources on the grid to ensure that the electricity demand can be reliably supplied every hour, including each year's peak system demand. Because every supply resource cannot be available during all hours of the year, PJM must plan to have additional resources available to cover planned and unexpected outages. Therefore, each load-serving entity is responsible for approximately 120% of its forecasted yearly peak demand, with the exact percentage determined yearly through the PJM capacity planning process.

The 2022 Dover IRP has incorporated the PJM capacity market construct into the modeling, analysis, and recommendation process. Dover participates in the PJM capacity market and bilateral capacity markets as a load-serving entity to purchase sufficient capacity to meet its load-serving obligation. As an owner of generation, Dover sells its generating capacity into the PJM capacity market.

PJM's capacity market was created to help efficiently deliver resource adequacy on a physical, locational basis. PJM's resource mix has been and is still undergoing a significant transition driven by consumer preference, technology, and state/federal policy changes. 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 reflected in the historical volatility of capacity market clearing prices.

Table. PJM capacity auction prices for the delivery zone applicable to Dover (DPL-South)

Delivery Year		EMAAC	DPL SOUTH	RTO
2013	BRA	$ 139.73	$ 222.30	$ 16.46
2014	BRA	$ 245.00	$ 245.00	$ 27.73
2015	BRA	$ 136.50	$ 136.50	$ 125.99
2016	BRA	$ 167.46	$ 167.46	$ 136.00
2017	BRA	$ 119.13	$ 119.13	$ 59.37
2018	BRA	$ 120.00	$ 120.00	$ 120.00
2019	BRA	$ 225.42	$ 225.42	$ 164.77
2020	BRA	$ 119.77	$ 119.77	$ 100.00
2021	BRA	$ 187.87	$ 187.87	$ 76.53
2022	BRA	$ 165.73	$ 165.73	$ 140.00
2023	BRA	$ 97.86	$ 97.86	$ 50.00
2024	BRA	$ 49.49	$ 69.95	$ 34.13



Renewable Portfolio Standard (RPS)

Delaware statute requires all investor-owned, municipal, and cooperative electric utilities to:

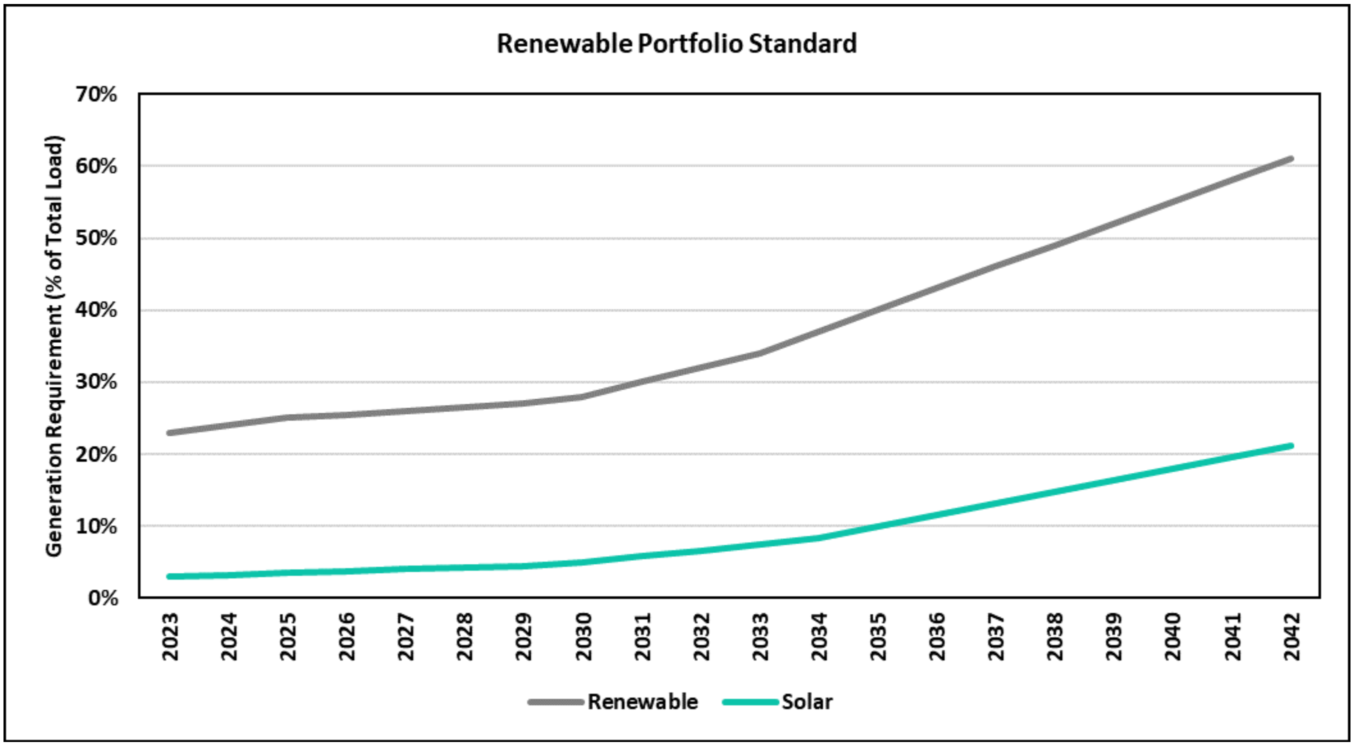
- Integrate renewable energy resources into their energy portfolios,
- Contribute annually to the Delaware Green Energy Fund,
- Submit annual compliance reporting to the Delaware Public Service Commission.

However, Delaware statute also permits municipal and cooperative electric utilities three statutory options to comply with its state RPS law: (1) letter-of-the-law compliance with full Delaware Public Service Commission oversight and stringent reporting requirements, (2) self-exemption if the utility establishes its own comparable RPS program, or (3) annual alternative compliance payments to the Delaware Green Energy Fund, instead of utilizing renewable resources. After comparing the three options, Dover has elected to self-design and administer a comparable municipal program, achieving the lowest compliance cost possible for its ratepayers.

In developing its comparable plan, Dover has and will continue to add qualifying renewable energy resources to its energy portfolio to achieve the lowest possible compliance cost to protect its ratepayers from unreasonable and burdensome impacts on their cost of electricity. Dover's goal is to comply with the spirit of the Delaware RPS without negatively impacting the community ratepayers or the Dover economy. By choosing the self-exemption option, Dover can also fund its local, comparable Green Energy Fund, providing a more direct benefit to its local ratepayers.

In 2021, the Delaware Legislature updated its RPS statute by extending and increasing its annual RPS target goals, lowering its alternative-compliance-payment cost caps, and repealing a second compliance cost-containment option. The target goals were developed from 2025 to 2035, continuing with annually increasing requirements. The prior standard required utilities to reach 25% of eligible energy consumption derived from suitable renewable energy sources by 2025, with at least 3.5% from solar photovoltaic sources. The new standard requires 40% by 2035, with at least 10% from solar photovoltaic sources.

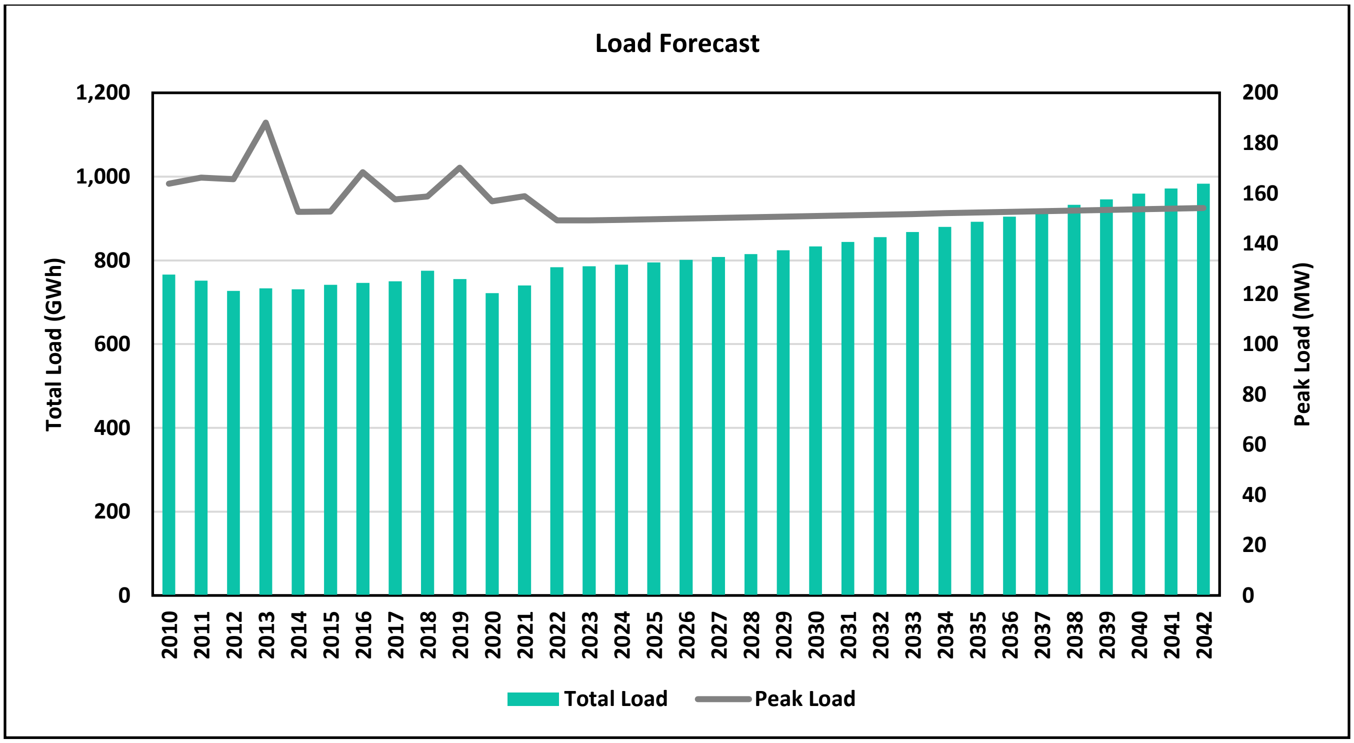
The table below contains Dover's annual compliance goals, which match Delaware's statutory-mandated goals:



Dover will review and rebalance its compliance schedule annually to ensure cost impacts to our community ratepayers are reasonable and accurately match qualifying retail electricity sales with renewable energy resource procurement. As permitted by self-exemption, Dover will annually prepare and submit an RPS compliance report to the Delaware Department of Natural Resources and Environment Control rather than the Delaware Public Service Commission.

Load Forecast

A load forecast was developed to capture changes in separate customer classes over time for the following: residential, commercial, primary, Dover Air Force base, Proctor and Gamble, Kraft, and First State Power Management. Each of these customer classes has a unique historical trend, with demand for some classes increasing in recent years and others decreasing. Ten years of historical load and weather data were gathered to determine a weather-normalized historical load, effectively removing the impact weather has on historical load data. Woods & Poole's economic forecast for Kent County's total employment was then utilized to project the change in weather-normalized load for each customer class. The output of this process is a 50/50 weather-normalized load forecast, meaning 50% of years will exceed the forecast while the remaining 50% will be below, depending on the weather. This 50/50 weather-normalized load forecast is shown below, with periods before 2022 representing historical data.



Fuel Prices

Fuel price forecasts developed by S&P Global Commodity Insights (S&P), Wood Mackenzie (WM), and the NYMEX forward curve served as the basis for the fuel price projections used in this IRP study.

NATURAL GAS

Henry Hub price forecasts from S&P and WM that were current in mid-2022 served as the basis for the Base Case natural gas price assumption. S&P and WM utilize detailed supply and demand fundamentals analyses in developing these forecasts. The high case values are the NYMEX closing prices as of July 21, 2022. A basis adjustment was applied to the Henry Hub values to arrive at the variable cost of gas delivered to Dover. The analysis assumed a combined cycle addition would require firm gas transportation to ensure reliable gas delivery. Lower-cost interruptible transportation was considered adequate for a simple cycle combustion turbine with diesel backup.

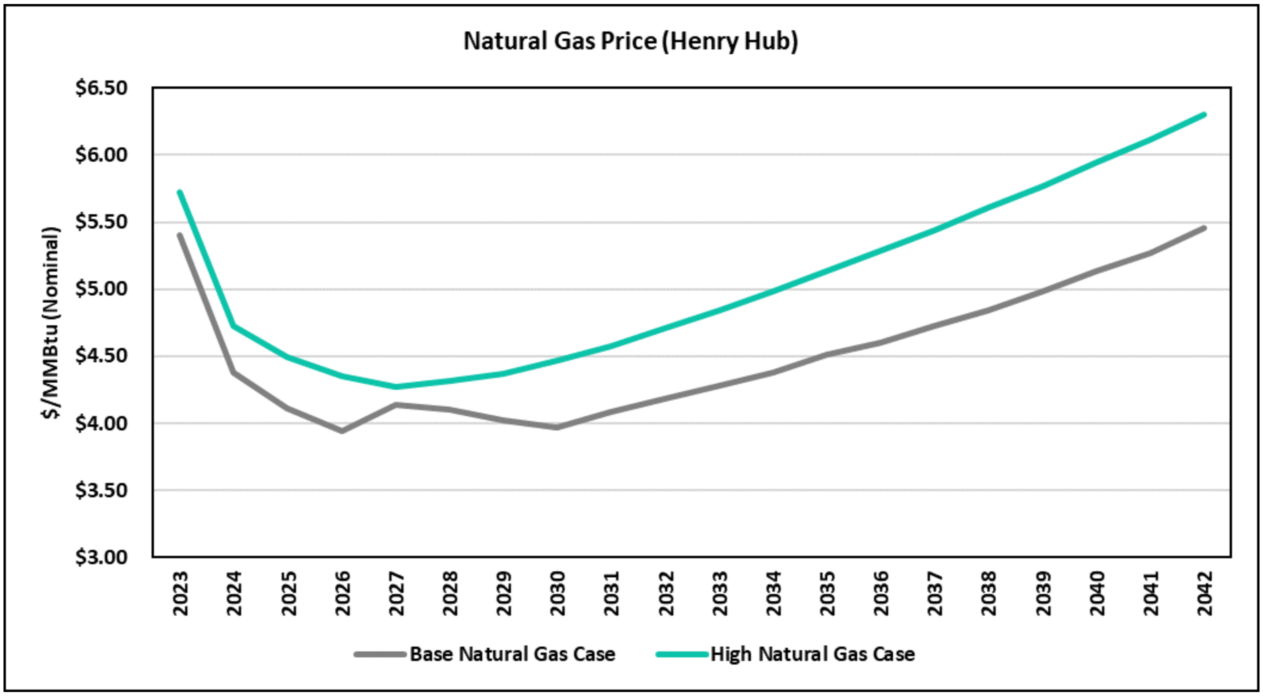
The base and high natural gas prices reflect the expectation that demand for natural gas is limited over the long term. The global energy transition and the energy industry's shift from fossil-based systems to carbon-free energy sources, including solar, wind, and battery storage, will eventually reduce gas demand. There is also the potential for federal carbon legislation to establish a Clean Energy Standard (CES). Such legislation would also place downward pressure on long-term natural gas demand in the US power sector.

Contrary to the long-term domestic demand reduction expectations, global demand for US LNG has recently been increasing. Europe's goal to diversify its supply with imports from the US is driving this growth. LNG exports will likely remain strong for the remainder of the decade due to export capacity additions, relatively high global gas prices, and increased global demand. Furthermore, although renewable resources will dominate incremental generating resources, coal retirements will provide additional opportunities for natural gas demand growth before decarbonization becomes the predominant driver.

In the short term, the continuation of the Russia/Ukraine conflict and the curtailment of Russian gas supplies into Europe have driven up the spot price of natural gas and widened global gas price risk premiums. US storage deficits have persisted due to strong power and LNG feedgas demand and limited production gains brought about by supply chain issues and labor shortages. Domestic LNG facilities are operating at high levels resulting in the US becoming the world's largest LNG exporter during the first half of 2022, averaging 11.2 Bcf per day.

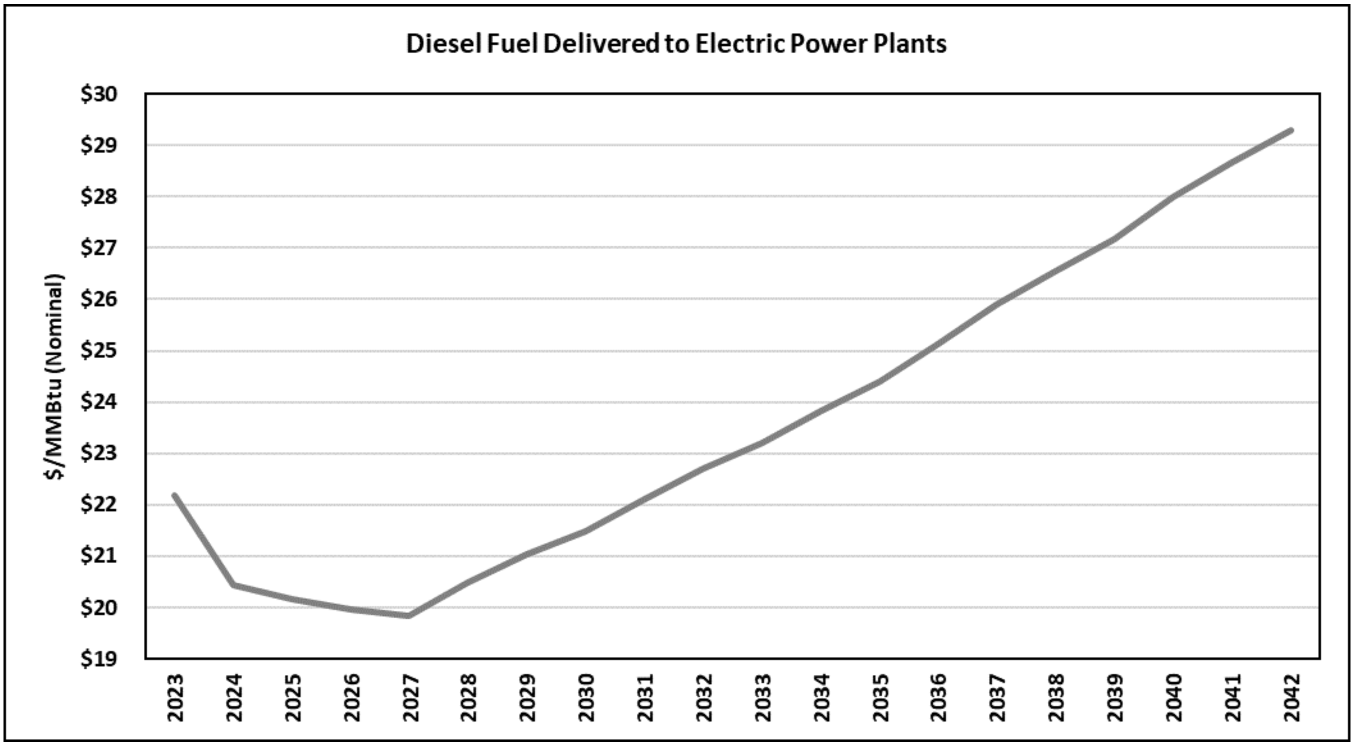
The domestic supply/demand imbalance resulted in Henry Hub pricing exceeding the High Natural Gas values for 2022. Despite the near-term bullish factors, the current high oil and gas prices have begun to cause more supply to come back to the market and reduce the deficit. Consistent with the current NYMEX forward curve, the natural gas pricing used in this study assumes that Henry Hub prices will decline after the winter of 2022-23.

Despite recent high prices exacerbated by global turmoil, the base and high natural gas prices used in this study are reasonable for planning purposes. The Base Case resource plan focuses on adding solar and battery resources while avoiding natural gas-fired combustion turbines and reciprocating internal combustion engines. Higher gas prices drive high power prices, making renewable solar additions even more cost-effective.



DIESEL FUEL

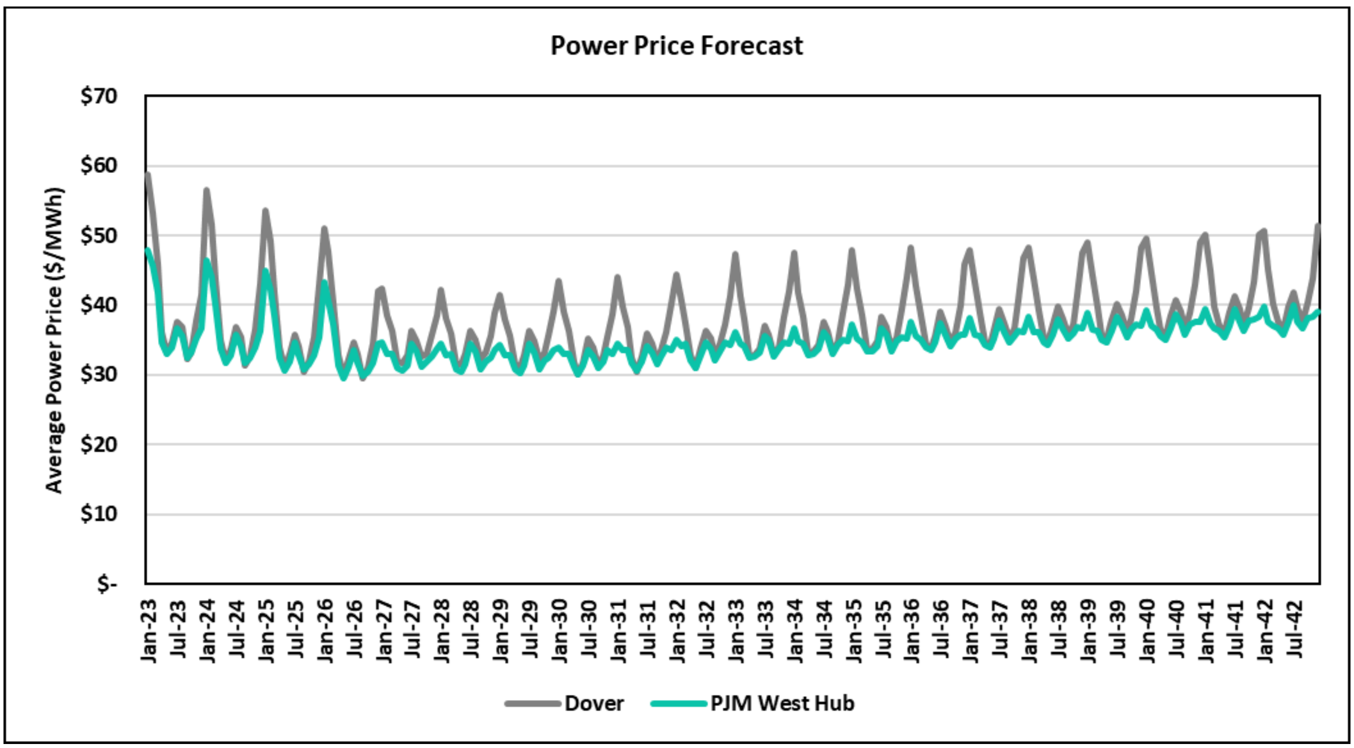
Diesel was modeled as a backup fuel for the combustion turbine and reciprocating internal combustion engine options. The projected diesel price was based on actual New York Harbor heating oil values reported by the Energy Information Administration (EIA) through June 2022 and a representative transportation cost. The cost was escalated based on NYMEX heating oil futures through 2024 (July 22, 2022) and EIA's forecast of the cost of diesel fuel delivered to power plants from its 2022 Annual Energy Outlook.



Market Power Price

The power price forecast was developed using the model from PJM's 2021 Regional Transmission Expansion Plan. PJM performs this study every year to determine future transmission upgrade projects on their system. The model for this study forecasts the entire PJM transmission system for several future years, calculating the hourly price of power across the region. Input into this model was the forecasted base natural gas price, as described in the fuels section. After doing so, the model was run, outputting a power price forecast for each zone in PJM. These zonal prices aggregate each location in a particular area of PJM. The hourly zonal price forecasts were obtained for Dover's zone.

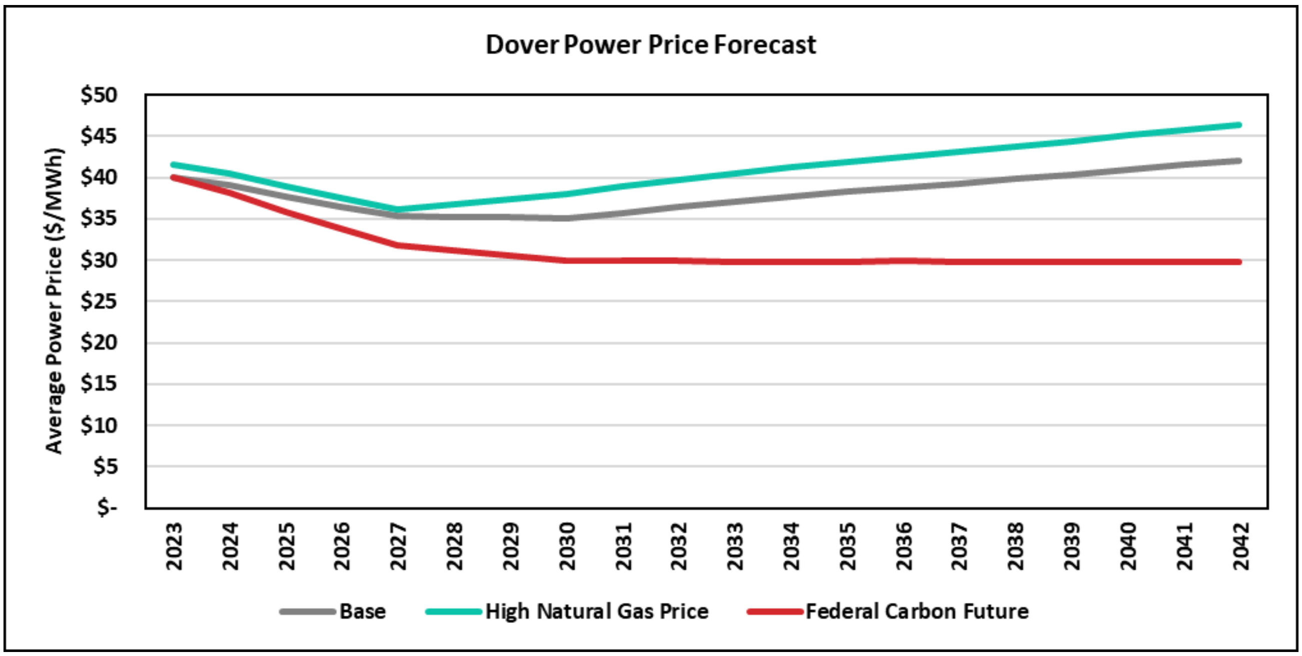
Additionally, several zonal price forecasts were grouped to create a projection for PJM Western Hub's power price. Western Hub is an aggregate power price for the western region of PJM, which was used for evaluating nonlocal solar projects. Below is the monthly average price forecast for Dover and PJM West Hub.



Two alternate power price forecasts were evaluated as well:

1. The first involves an assumed increase in natural gas prices relative to the base assumptions. This increase is outlined in the fuel price assumptions and increased projected power prices.
2. The second alternate power price forecast included assumptions for federal carbon reduction requirements. [5]

The overall impact of the federal carbon reduction requirements is an assumed increase in the amount of renewable generation throughout PJM. Furthermore, the increased power generation from renewable resources results in a decrease in the power price forecast. The annual average power price at Dover is shown below for the base and two alternate price forecasts.



Existing Capacity Resources

Dover's existing generation resources are listed in the table below. The McKee Run Unit 3 is not included in this study because Dover has retired the resource. SunPark is behind the PJM billing meter; it offsets Dover's peak demand and energy purchases from PJM.

Plant	Type	Year of Commercial Operation	Year of Retirement	Net (MW)	PJM Capacity (MW)
VanSant	CT	1992	2041	42	42
SunPark	Renewable	2010	2031	10	BtMG
Total				52	42

[5] These assumptions can be found in the 'Scenario Analysis – High Natural Gas & Federal Carbon Future' section.

RESOURCES

New resources will be needed during the study period to accommodate the increased load. Due to the significant lead times required for construction and interconnecting a resource to PJM's regional transmission system, timely planning for each new resource is critical to ensure capacity requirements are met. Eight different resource options were analyzed in the IRP based on the following criteria:

- Cost and economic returns
- Accredited capacity provided
- Reliability benefits
- Environmental compliance

The study included an evaluation of solar obtained through purchased power agreements (PPAs), several thermal natural gas-fired generation options, and bilateral capacity PPAs. In addition, battery energy storage was included in the analysis.

Utility-scale and community solar projects, which have provided most of the recent generating capacity additions in PJM, are the renewable resource options for Dover that were evaluated in this study. Solar generation currently makes up about 5% of the installed capacity in PJM. Despite recent disruptions, including ongoing supply chain interruptions, high inflation rates, and regulatory uncertainties, utilities, and their communities prioritize renewable resources to satisfy future energy requirements while achieving carbon-reduction goals. S&P Global Commodity Insights projects that PJM's nameplate solar capacity will increase by over 50,000 MW by the mid-2030s when it is likely to make up about a quarter of installed generation capacity in PJM.

This study also considered dispatchable thermal resources sited in Dover's service territory. At least until storage reaches technical maturity, the ability of dispatchable generating resources to follow load is essential for reliable and uninterrupted electric service. Natural gas-fired small-scale industrial frame combustion turbines and reciprocating internal combustion engines with diesel backup were evaluated as candidates for inclusion in Dover's resource portfolio. Manufacturers of combustion turbines and reciprocating internal combustion engines are attempting to decarbonize the operation of these units by improving their capability to operate on increasing percentages of hydrogen gas.

Nuclear generation utilizing the emerging small modular reactor technology was also included as a supply-side option for Dover. Nuclear power has the potential to play a pivotal role in helping the US meet its carbon reduction goals, and the industry is currently focusing on the development of small modular reactors that offer numerous advantages over traditional large-scale reactors. These advantages include reduced costs, modular production, smaller land requirements, inherent safety features, and longer refueling cycles. Although SMR holds great promise, power output from an initial domestic project is unlikely before 2029.

A bilateral capacity purchase is another option for Dover that was included in this study. Reflecting an increasing value of capacity in the PJM market as the penetration of renewables grows, pricing for capacity PPAs having a 5-year term is assumed to increase at an average annual rate exceeding 5% over the study period.

Battery storage is a viable resource option for Dover, and 4-hour duration batteries were evaluated in this study. Battery storage is proving effective in integrating wind and solar into the electric grid. This technology can collect or store electricity when demand or prices are low and discharge or supply energy when demand or market prices are higher. Until recently, battery storage costs had been experiencing a continual decline, allowing this technology to become cost-effective for utility-scale use and dominate the energy storage market. As with solar and wind projects, high inflation and supply chain constraints have adversely impacted the cost and project lead times. Utilities continue to monitor this technology and are beginning to include battery storage as an integral part of an effective resource plan.

The following table provides some of the key operating characteristics of the resources evaluated:

RESOURCE OPTION	FUEL TYPE	Overnight Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Full Load Heat Rate (mmBtu/MWh)	CAPACITY (MW)
Combustion Turbine (Industrial Frame)	Natural Gas	800	5	8	9500	56.43
1x1 Combined Cycle	Natural Gas	1250	3	16	6500	80.685
Reciprocating Engine	Natural Gas	1250	7.5	23.5	8450	9 / 19
Solar PPA	Solar	N/A	53	0	N/A	50
Community Solar	Solar	N/A	69	0	N/A	10
Nuclear: Small Modular Reactors	Uranium	7300	3.5	106	10450	50 per reactor
Battery Storage PPA (4-Hour Li-ion)	N/A	N/A	0	128	N/A	25
Bilateral Capacity PPA (5-year duration)	N/A	N/A	0	Market	N/A	50 [6]

[6] Figures are initial 2022 values.

Offshore wind is an emerging technology expected to significantly contribute to PJM's power supply by the middle of this decade. New Jersey, Maryland, and Virginia have set offshore wind targets to be met between 2030 and 2035. In November 2021, S&P projected that offshore wind in PJM will exceed 12,000 MW and provide approximately 5% of PJM's electric generation by 2034.

US Wind and Ørsted are developing projects approved by the Maryland Public Service Commission that will be located off the Delaware and Maryland coasts. These offshore wind projects will add over 2000 MW of nameplate capacity.

In 2017, Governor Carney established the Offshore Wind Working Group. The working group studied Delaware's participation in the following:

- Developing offshore wind
- Identifying ways to leverage the related economic opportunities
- Making specific recommendations for engaging in the development of offshore wind for Delaware.

An expert analysis indicated that "offshore wind prices are likely to fall significantly as development ramps up and the industry supply chain develops" (Carney, 2017) and did not recommend participation in one of the initial projects. Dover continues to monitor the offshore wind market for opportunities but did not include it as a supply option for this IRP study.

In addition to supply-side resource options, demand-side management (DSM) programs may provide cost-effective options for future evaluation. Energy-focused DSM programs intended to improve energy efficiency include using programmable "smart" thermostats, efficient HVAC, water heating, lighting, appliances, smart thermostats, and low-income insulation.

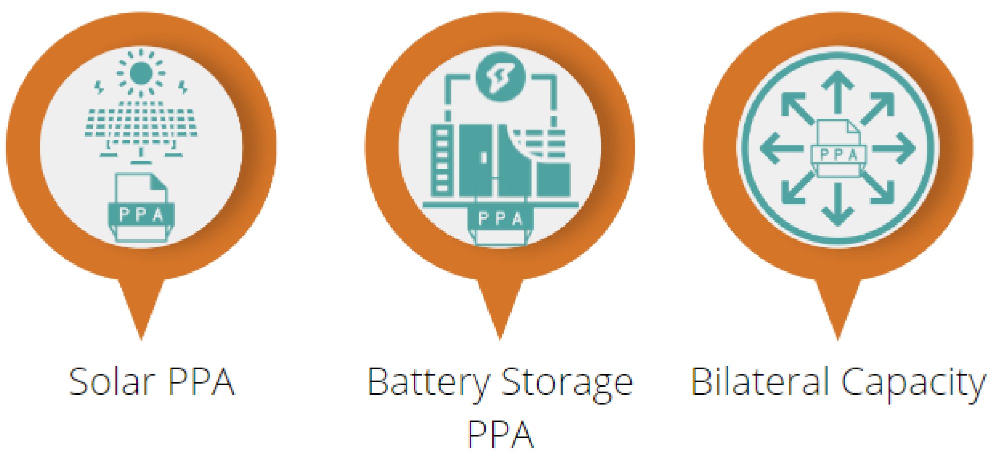
BASE CASE SOLUTION

The base case solution represents the resource selection with the Lowest Levelized Cost of Energy and Net Present Value that meets the constraints specified by Dover. Net Present value is the sum of all costs and revenues throughout the study. Levelized Cost of Energy takes the Net Present Value and divides it by the total energy consumed by Dover throughout the study. The 20-year IRP is broken up into five-year actionable periods for decision-making purposes. Every five years, a graphic shows the resources built or PPAs expired. The MegaWatt (MW) value shown next to each resource represents the nameplate capacity, or maximum possible output, of that resource being built or retired.

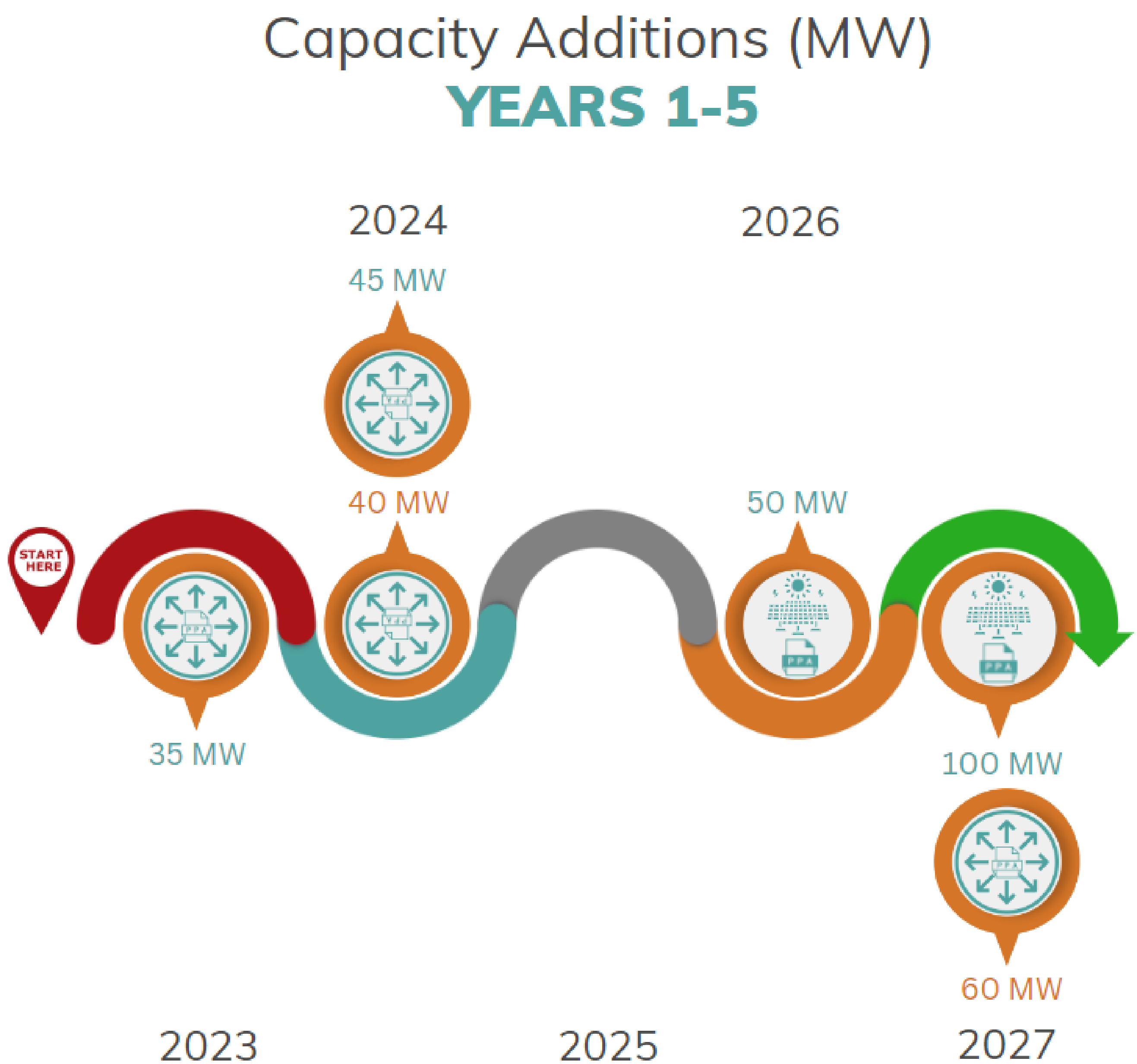
For reference, the legend below depicts the resource types being represented in each graphic.

Legend

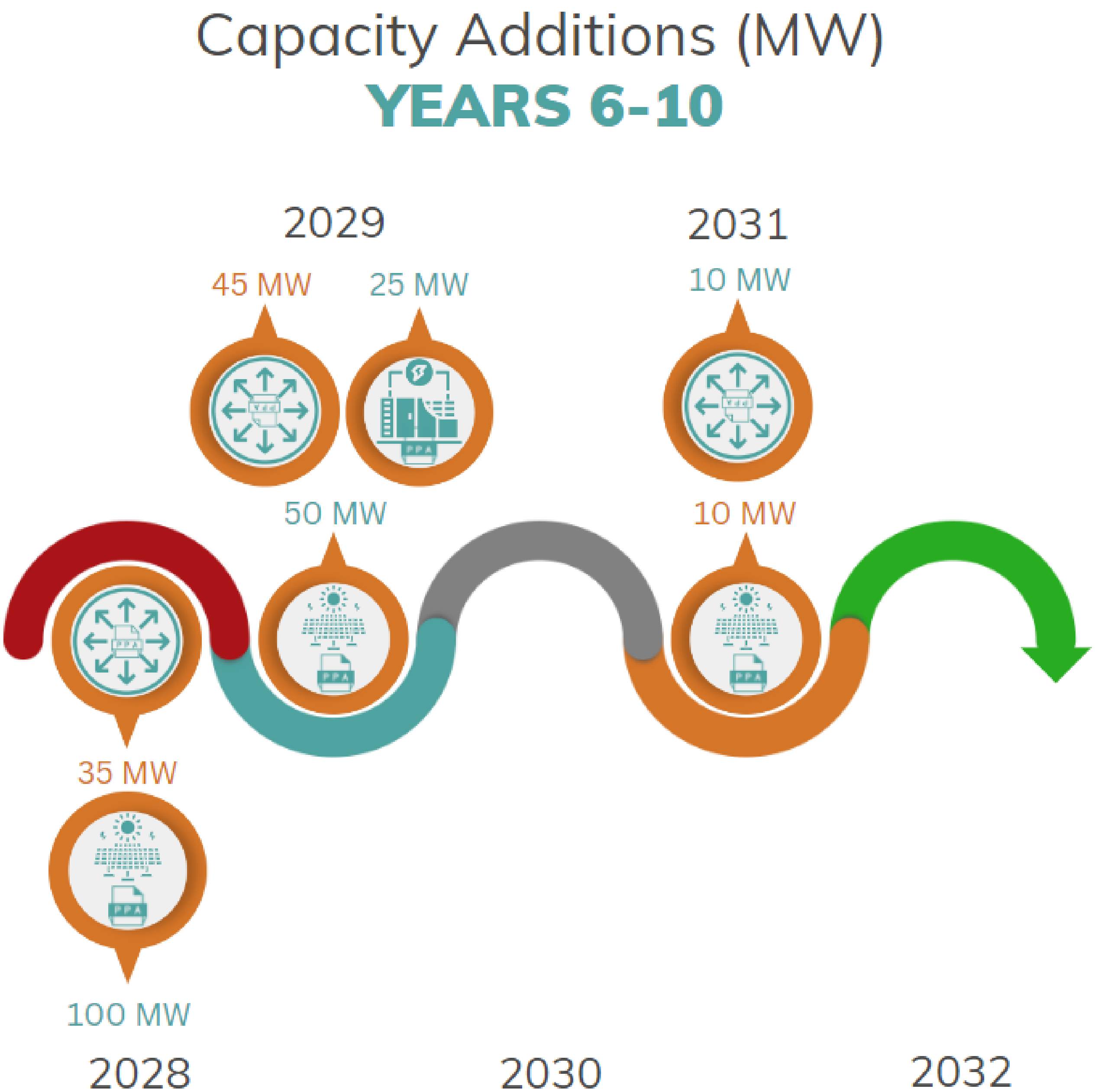
***Capacity Additions* and *PPA Expirations* (MW):**



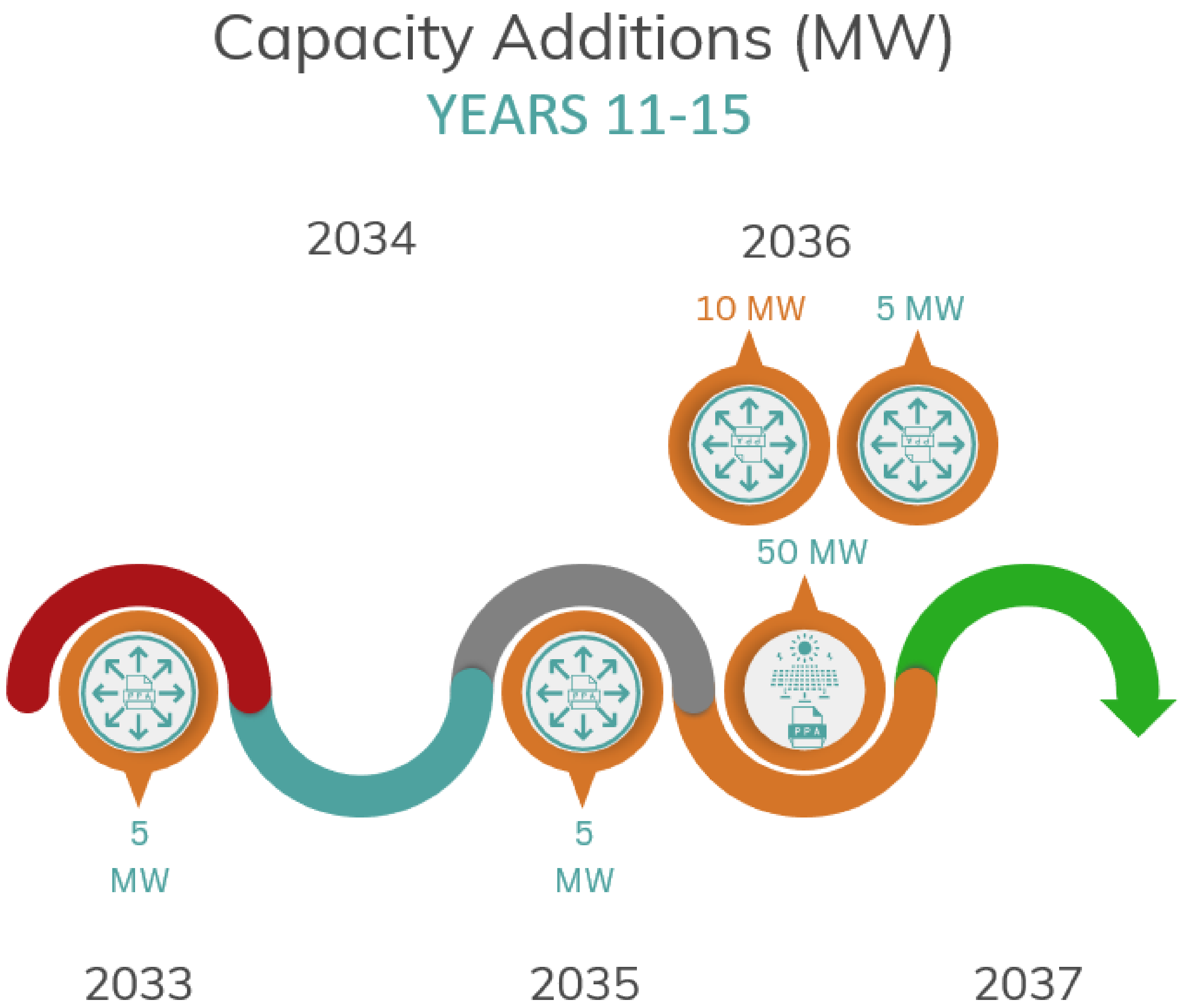
Through the first five years of the IRP study, a combination of utility-scale solar PPAs and bilateral capacity is being built or retired. In 2023, 35 MW of bilateral capacity will be purchased to ensure Dover meets the capacity requirements set by PJM. During the following year, an additional 45 MW of bilateral capacity is purchased to offset 40 MW of existing bilateral capacity, which is expiring. 50 MW of utility-scale solar PPA will be built in 2026. This PPA helps Dover meet their PJM capacity requirements and assists in meeting state requirements for renewable and solar generation. In the last year of this period, an additional 100 MW of utility-scale solar PPAs is built. This second PPA provides additional generation to meet state renewable generation requirements and offsets the expiration of 60 MW of existing bilateral capacity during the same year.



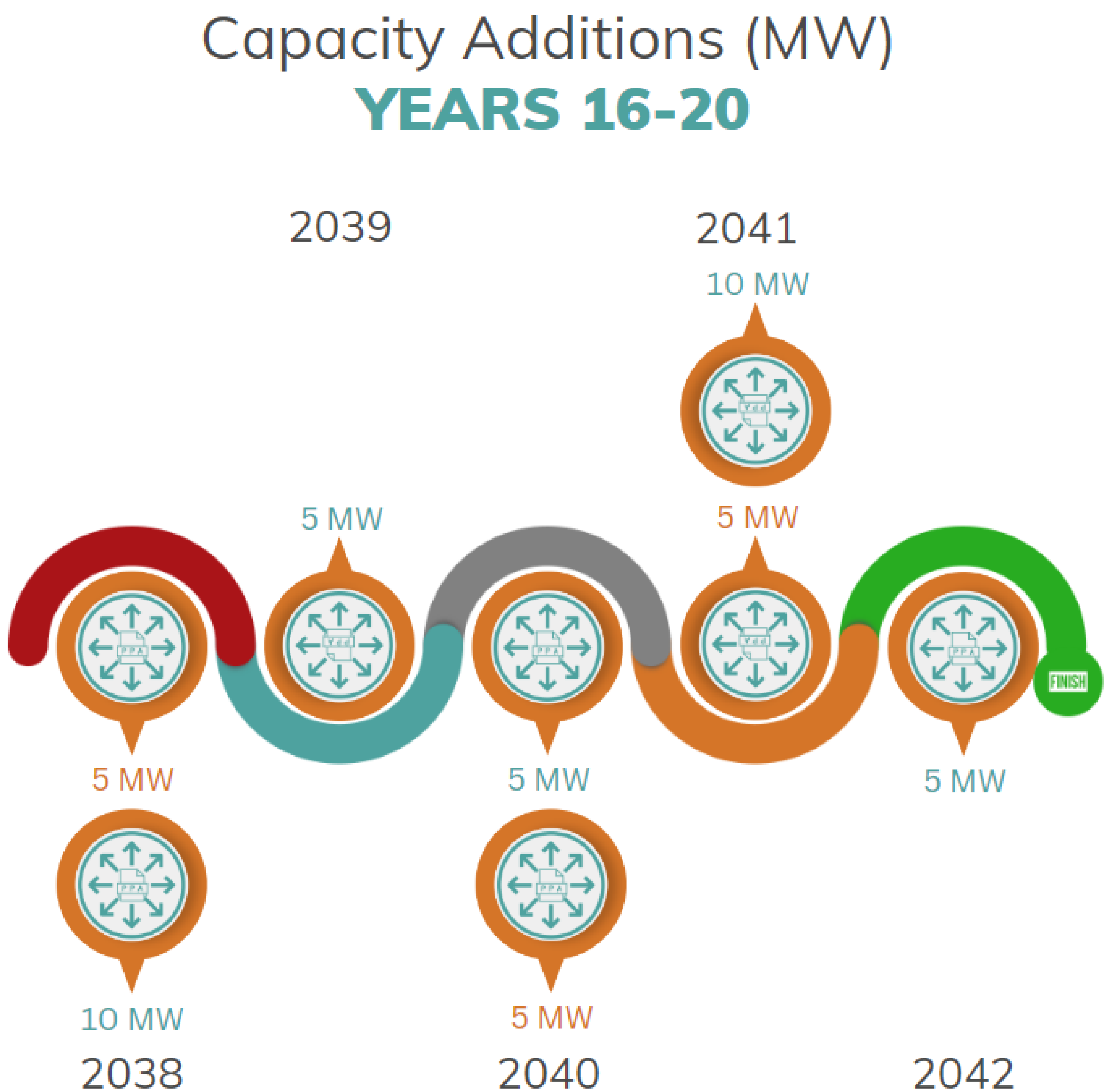
Following the end of the previous period, in 2028, an additional 100 MW of utility-scale solar PPAs are built in the base case results. This procurement assists in offsetting the loss of 35 MW bilateral capacity, which expired in the same year. In 2029, a 45 MW block of bilateral capacity expires, with the loss in capacity replaced by a 75 MW utility-scale solar/storage PPA. This project is broken into 50 MW solar and 25 MW battery storage in the above graphic. During the remainder of this second period, the Sun Park solar PPA expires in 2031. A 10 MW block of bilateral capacity is purchased to offset the lost capacity due to Sun Park's expiration.



In 2033 and 2035, 5 MW blocks of bilateral capacity are purchased. These are added to ensure Dover is meeting PJM capacity requirements. During 2036, a 10 MW block of bilateral capacity expires and is replaced with a new 5 MW block of bilateral capacity and a 50 MW utility-scale solar PPA.



Through the last 5-year period in the study, previously purchased bilateral capacity is expiring in 2039, 2040, and 2041. New bilateral capacity purchases offset these expirations and ensure that Dover continues to meet their PJM capacity requirements.

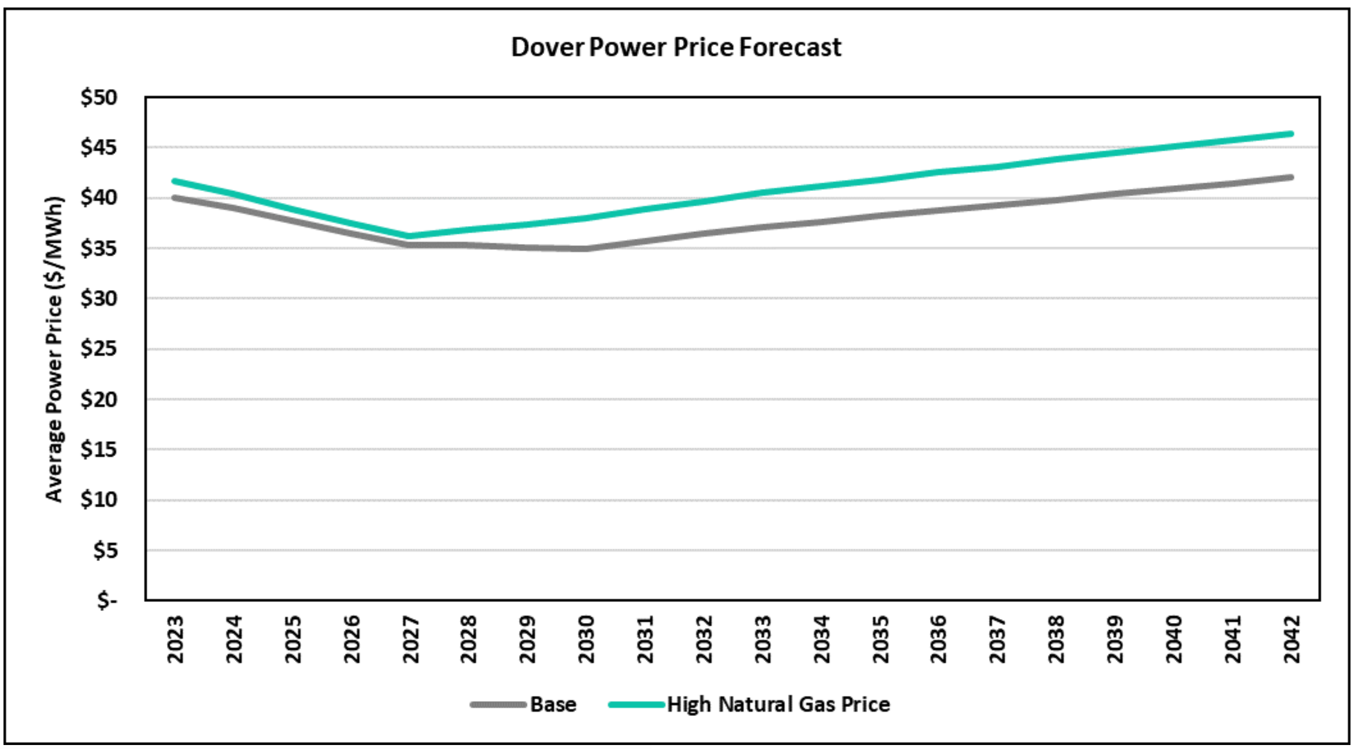


SCENARIOS AND ALTERNATE BASE CASE PORTFOLIOS

Scenario Analysis – High Natural Gas Price

The base case natural gas price projection is based on expected natural gas supply and demand fundamentals; however, throughout much of 2022, we have seen a significant increase in the domestic price of natural gas due primarily to unexpected geopolitical unrest. With the continued military conflict between Russia and Ukraine, Europe's demand for US-liquefied natural gas is elevated as it attempts to replace the lost Russian supply. In addition, the ongoing decarbonization of the power market allows additional natural gas utilization as coal units are retired. In the future, unexpected geopolitical, environmental, and other bullish factors may drive the price of natural gas above the base case projection. Thus, a high natural gas price scenario is important in identifying Dover's best path forward.

This increase in natural gas prices drives a rise in projected power prices. Below is a comparison of Dover's average annual power price in the base case and the high natural gas price scenario. While there are power price increases in the near term, the largest growth in expected power prices is observed from 2030 onward.

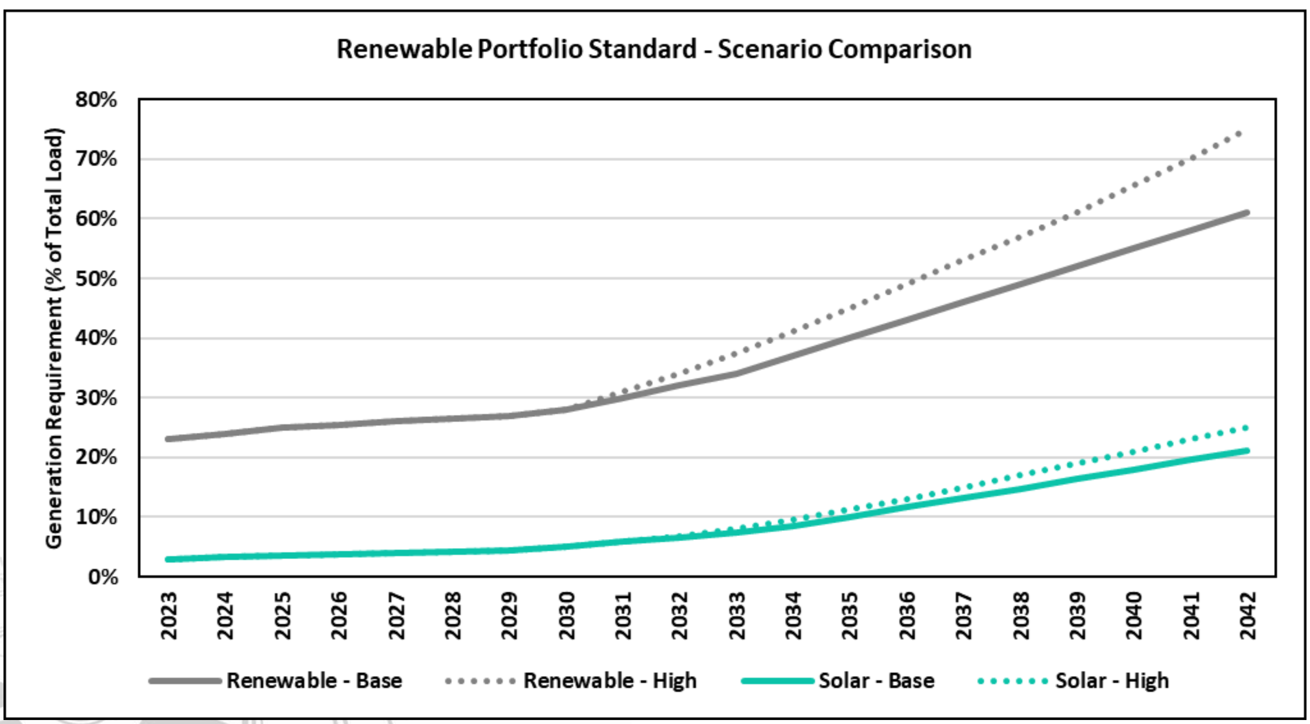


Solution Comparison																							
Scenario	Nameplate Capacity (MW)	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	LCoE ($/MWh)	NPV ($M)
Base	VanSant																					$31.21	$331.9
	Existing Capacity		-40			-60																	
	Local Solar PPA				50	100	100			-10					50					0	0		
	Local Solar/Battery PPA							75															
	Bilateral Capacity	35	45				-35	-45		10		5		5	-5		5	5	0	5	5		
High Natural Gas Price	VanSant																					$31.69	$337.0
	Existing Capacity		-40			-60																	
	Local Solar PPA				50	100	100			-10					50					0	0		
	Local Solar/Battery PPA							75															
	Bilateral Capacity	35	45				-35	-45		10		5		5	-5		5	5	0	5	5		

While higher natural gas prices result in a higher Levelized Cost of Energy and Net Present Value, there is no difference in build and retirement decisions from the base case. The higher financial outputs in this scenario are driven largely by elevated average power prices, increasing the cost to purchase power at Dover's load.

Scenario Analysis – Base Natural Gas High Renewable Portfolio Standard

Another possible risk from a planning perspective is a Delaware statutory increase to Dover's renewable portfolio standard requirements. As mentioned in previous sections, the renewable portfolio standard is a policy from the State of Delaware that requires each utility to achieve a level of generation from renewable resources and a level of generation specifically from solar resources. These levels are based on a percentage of the total load volume for each utility during a defined planning year period. This scenario evaluates the impact of an increase in Delaware's renewable and solar generation requirements. Below is a comparison of the base case and high renewable portfolio standard assumptions by planning year.



These assumed renewable portfolio standard requirements remain the same between the base and high case through 2029, then increase through the remainder of the study. The high case increases the renewable generation requirement from 61% to 75% and the solar generation requirement from 21% to 25% by the last planning year of the study.

Solution Comparison

Scenario	Nameplate Capacity (MW)	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	LCoE ($/MWh)	NPV ($M)
Base	VanSant																					$31.21	$331.9
	Existing Capacity		-40			-60																	
	Local Solar PPA				50	100	100			-10					50					0	0		
	Local Solar/Battery PPA							75															
	Bilateral Capacity	35	45				-35	-45		10		5		5	-5		5	5	0	5	5		
High Renewable Portfolio Standard	VanSant																					$31.63	$336.4
	Existing Capacity		-40			-60																	
	Local Solar PPA				50	100	100			-10					50					0	0		
	Local Solar/Battery PPA							75															
	Bilateral Capacity	35	45				-35	-45		10		5		5	-5		5	5	0	5	5		

Overall, increasing the renewable portfolio standard requirements for Dover does not impact this study's build and retirement decisions. The solar and solar/battery PPAs selected in the base case forecast are already reaching a renewable/solar generation level that puts Dover comfortably above this scenario's assumed higher renewable and solar generation requirements. There is an increase in both financial metrics compared to the base case, which is solely due to a reduction in the sale of excess renewable and solar renewable energy credits.

Scenario Analysis – Base Natural Gas & Seasonal Capacity Planning

Current PJM capacity requirements are determined based on a utility's summer peak load. As discussed in previous sections, a utility must acquire a firm capacity equal to 20.5% above its summer peak load volume. In recent years, however, adopting a seasonal capacity requirement has become prominent amongst regional transmission organizations, requiring utilities to acquire capacity separately for summer, winter, or all four seasons. A significant driver of this change is extreme weather events observed in recent years. A prime example is February 2021's Winter Storm Uri, which caused rolling blackouts throughout the central United States.

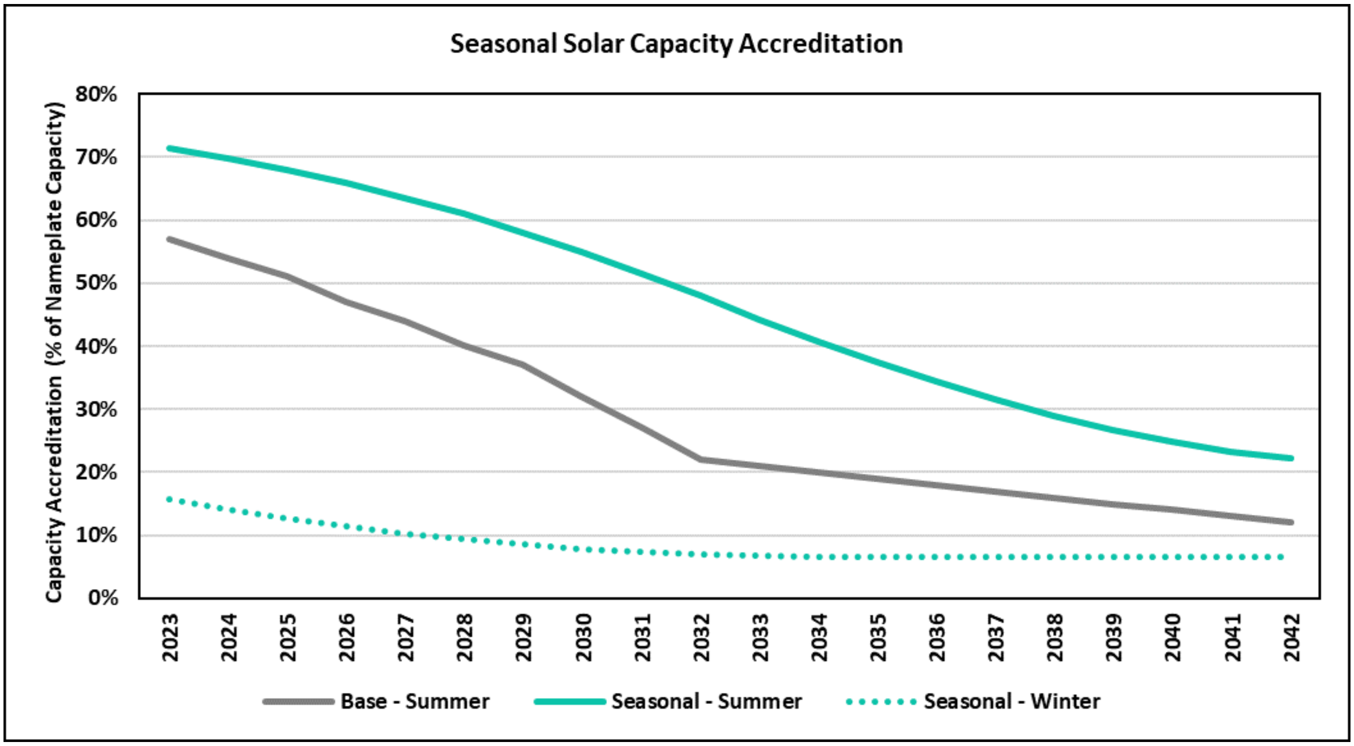
While PJM currently does not have a seasonal capacity requirement, this may be adopted in the future. This scenario evaluates the impact of such a policy on Dover. A comparison of the assumed summer and winter capacity requirements is shown below. The winter requirement was obtained from a neighboring organized market to PJM, the Midcontinent Independent System Operator's winter capacity requirement. They adopted a seasonal capacity construct beginning in June 2023.

Capacity Requirement (% Above Peak Load)

	Summer	Winter
Base	20.5%	
Seasonal Capacity Planning	20.5%	25.5%

Another consideration in this scenario is evaluating seasonal capacity accreditation for renewable resources. As mentioned in the 'PJM Capacity Construct' section, renewable resource capacity was assumed to be assessed based on Effective Load Carrying Capacity, a measure of a resource's ability to generate power when needed most by the grid. This is of particular concern for solar resources because there is a large discrepancy between solar generation during the peak load periods in summer (afternoon hours) and the peak load periods in winter (morning and evening hours).

Below is a comparison of the assumed solar capacity accreditation for the base and Seasonal Capacity Planning scenarios. Overall, if a seasonal capacity construct were adopted, solar resources would receive greater accreditation during summer and much lower accreditation during winter.



Solution Comparison

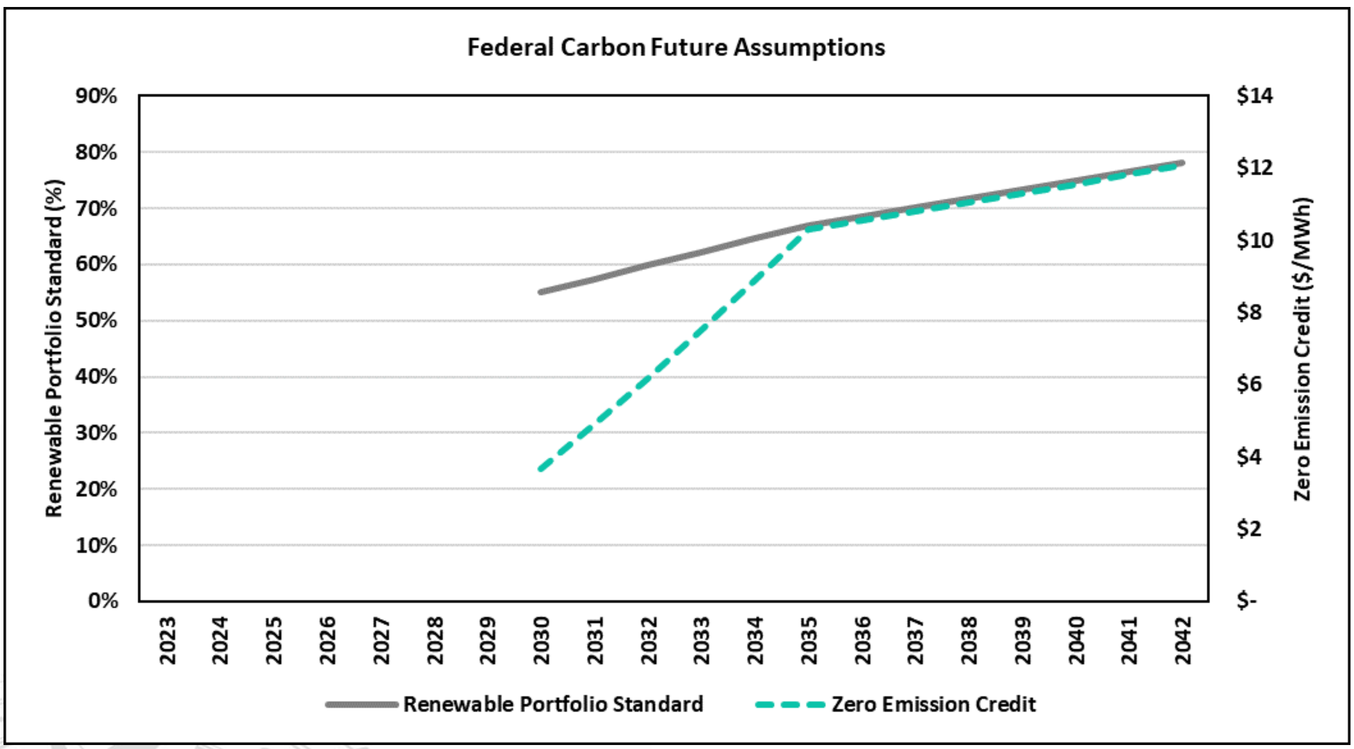
Scenario	Nameplate Capacity (MW)	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	LCoE ($/MWh)	NPV ($M)
Base	VanSant																					$31.21	$331.9
	Existing Capacity		-40			-60																	
	Local Solar PPA				50	100	100			-10					50					0	0		
	Local Solar/Battery PPA							75															
	Bilateral Capacity	35	45				-35	-45		10		5		5	-5		5	5	0	5	5		
Seasonal Capacity Planning	VanSant																					$32.86	$349.5
	Existing Capacity		-40			-60																	
	Local Solar PPA				50	50		50	100	-10					50					0	0		
	Local Solar/Battery PPA						75																
	Bilateral Capacity	45	40	10	5		-45	-25	-10	0			0	5	-5			0	0				

The forecast suggests a seasonal capacity construct would not impact which resources Dover should invest in but will affect when they are selected. Solar and solar/battery hybrid are still chosen during the late 2020s, with additional near-term investment into bilateral capacity compared to the base case. In this scenario, the impact on net present value is an increase of $17.6 million, largely driven by increased bilateral capacity purchase costs and an earlier investment into solar/battery hybrid to meet winter capacity requirements.

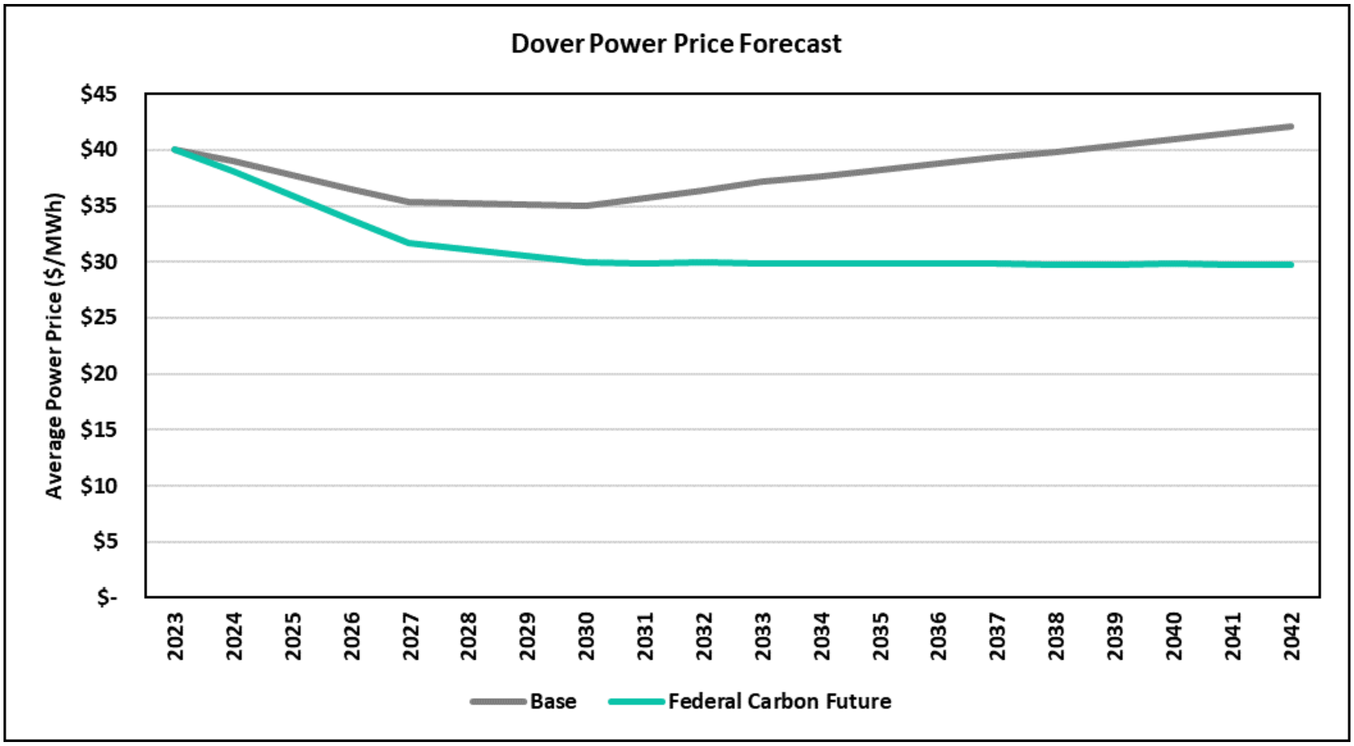
Scenario Analysis – High Natural Gas & Federal Carbon Future

With the Inflation Reduction Act signed into law in August 2022, the United States government has set a goal to reduce carbon emissions by at least 40% by 2030. The Federal Carbon Future scenario aims at determining the impact of a more aggressive carbon emissions reduction goal by the US government. In previous analyses, the assumed financial incentive to drive carbon reduction was a carbon tax levied on utilities for the carbon they produce when generating power using fossil fuels. In recent years, however, the utilization of a zero-emission credit has gained traction as the financial incentive for carbon reduction. A zero-emission credit is a rebate for each megawatt power generated from non-carbon-emitting resources, including solar, wind, hydroelectric, and nuclear resources, along with coal or natural gas resources with carbon capture technology.

The study's assumed carbon reduction incentive combines a zero-emission credit and an aggressive renewable portfolio standard. These assumptions, shown below, are based on information from S&P Global Platts and Wood Mackenzie. Both incentives are assumed to begin in 2030 and escalate yearly.



With this heavy subsidy for non-carbon emitting generation, the total power generated will increase, adversely affecting power prices. The power supply is rising in this scenario but not the power demand. Below is a comparison of Dover's annual average power price forecast for the base case and the Federal Carbon Future scenario. In the near-term, power prices between these two scenarios are comparable. However, the price forecast in the Federal Carbon Future through the mid-2020s decreases and continues throughout the study.

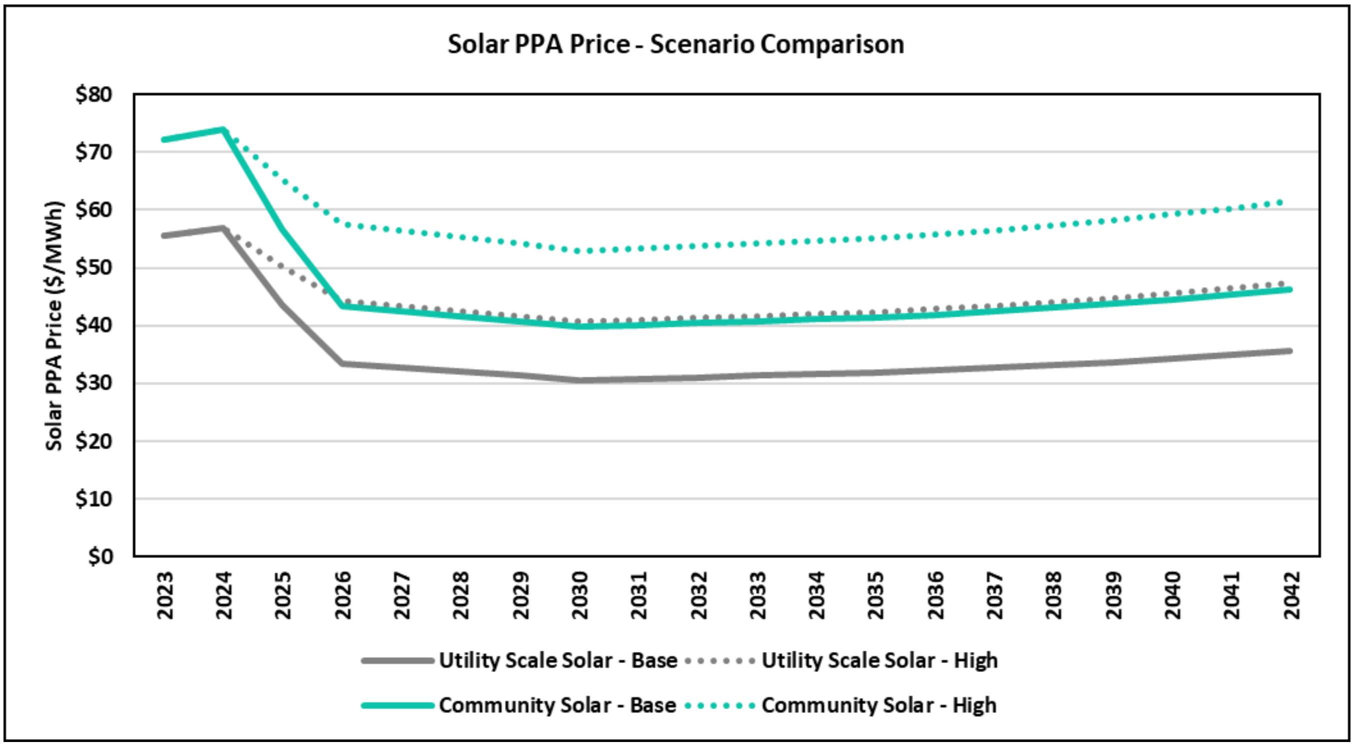


Solution Comparison																							
Scenario	**Nameplate Capacity (MW)**	**23**	**24**	**25**	**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**	**41**	**42**	**LCoE ($/MWh)**	**NPV ($M)**
Base	VanSant																					**$31.21**	**$331.9**
	Existing Capacity		-40			-60																	
	Local Solar PPA				50	100	100			-10					50					0	0		
	Local Solar/Battery PPA							75															
	Bilateral Capacity	35	45				-35	-45		10		5		5	-5		5	5	0	5	5		
Federal Carbon Future	VanSant																					**$28.83**	**$306.6**
	Existing Capacity		-40			-60																	
	Local Solar PPA				50	50	100		50	-10					50					0	0		
	Local Solar/Battery PPA							75															
	Bilateral Capacity	35	60				-35	-60		10		5		5	-5		5	5	0	5	5		

The impact of this emissions reduction incentive is minimal on build/retirement decisions. The main difference is the forecast delays the selection of a 50 MW solar project from 2027 to 2030. The Net Present Value is lower in this scenario than the base case, largely due to lower power prices. Dover can purchase power at a lower price while receiving revenues from zero-emission credit rebates.

Scenario Analysis – Base Natural Gas & High Renewable PPA Prices

In this study, purchase power agreement (PPA) rates for solar resources were assumed to change over time. Initially, the rates reflect the near-term premium due to increased raw material costs, supply chain issues, and tariff concerns. In the chart below, the prices reflect a utility-scale and community scale solar PPA rate available during the year the PPA is signed. The steep decline observed from 2024-2026 reflects a return of solar PPA rates to pre-pandemic levels. In the high renewable PPA price scenario, the near-term issues affecting PPA rates were assumed to remain throughout the study, resulting in an approximately $10-12/MWh increase in solar PPA rates from 2026 onward.



Solution Comparison																							
Scenario	Nameplate Capacity (MW)	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	LCoE ($/MWh)	NPV ($M)
Base	VanSant																					$31.21	$331.9
	Existing Capacity		-40			-60																	
	Local Solar PPA				50	100	100			-10					50					0	0		
	Local Solar/Battery PPA							75															
	Bilateral Capacity	35	45				-35	-45		10		5		5	-5		5	5	0	5	5		
High Renewable PPA Price	VanSant																					$39.70	$422.2
	Existing Capacity		-40			-60																	
	Local Solar PPA				50			150	50	-10					50					-50			
	Local Solar/Battery PPA										75												
	Bilateral Capacity	35	55	5		60	-35	-55	-5	10	-60	5		5	-5		5	5	0	10	5		

The main impact on building and retirement decisions due to higher renewable PPA prices is a reduced investment into solar and delayed investment into solar/battery hybrid resources. While PPA prices are sizably higher, it is still a better long-term financial option when compared to purchasing bilateral capacity and renewable energy credits. The increase in Net Present Value ($90.3 million) is sizable compared to the base case projection due to increased generation costs from solar resources.

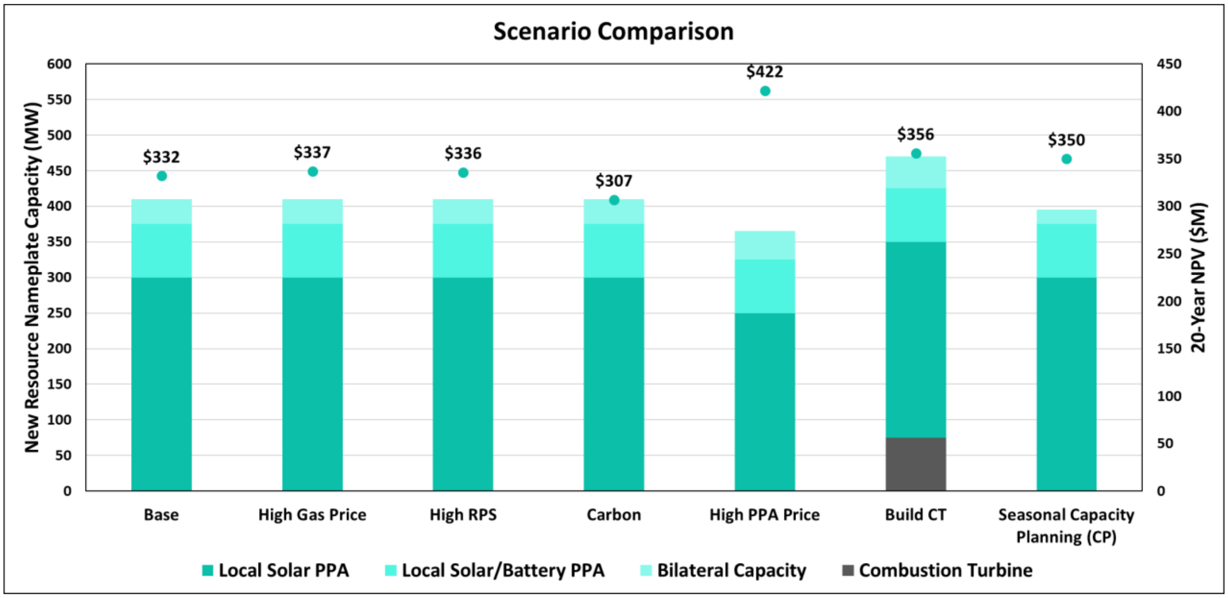
Alternate Base Case Portfolio – Build Combustion Turbine

In scenario analysis, a fundamental assumption (such as higher natural gas prices or increased renewable portfolio standards) is changed, and the forecasting model is rerun. On the other hand, an alternate base case portfolio forces a change to the base case results and determines the financial impact of that change. The alternate base case portfolio evaluated in this study forced a combustion turbine to be built in 2027 to assess the increased cost of investing in a thermal generation resource instead of strictly solar and solar/battery hybrid resources.

Solution Comparison

Scenario	Nameplate Capacity (MW)	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	LCoE ($/MWh)	NPV ($M)
Base	VanSant																					$31.21	$331.9
	Existing Capacity		-40			-60																	
	Local Solar PPA				50	100	100			-10					50					0	0		
	Local Solar/Battery PPA							75															
	Bilateral Capacity	35	45				-35	-45		10		5		5	-5		5	5	0	5	5		
Build Combustion Turbine	VanSant																					$33.51	$356.4
	Existing Capacity		-40			-60																	
	Local Solar PPA				50		50	150	50	-10					50					0			
	Combustion Turbine					56																	
	Bilateral Capacity	35	45				-35	-45		20			5	5	-10	5	5	5	0	5	5		

If a combustion turbine is built in 2027, the forecast avoids building a solar/battery hybrid resource since it is no longer needed to meet PJM capacity requirements. In addition, the model delays investment in solar resources. By 2030 though, the same amount of solar was selected between the 'Build Combustion Turbine' case and base case. The financial impact of investing in a combustion turbine is a $24.5 million increase in Net Present Value throughout the study.



CONCLUSION

Over the last 12 months, Dover developed a robust plan that meets all of Dover's objectives and reflects what we know today about the planning environment and market constraints we can reasonably expect in the coming years. The model analyzed how to achieve the lowest-cost portfolio in each scenario, giving Dover a sense of how the target power supply mix might change as the future changes and delivering an optimal solution that provides flexibility for how the future evolves.

Implementing the least-cost resource plan with Dover's goals and priorities will help ensure Dover continues to fulfill its mission to serve the community by providing affordable, reliable, and clean power in an environmentally responsible manner to all its customers.

PROJECT TEAM

Dover found immense value in undertaking the 2022 IRP and especially appreciates the input, review, and insights of all individuals on the IRP project team and Dover Risk Management Committee. Dover appreciates their involvement and the expertise they provided on behalf of stakeholders in making this a better IRP.

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THE BENEFITS OF WORKING WITH THE ENERGY AUTHORITY

The Energy Authority (TEA) provides public power utilities with access to advanced resources and technology systems so they can respond competitively in the changing energy markets. Through partnership with TEA, utilities benefit from an experienced organization that is singularly focused on deriving the maximum value of their assets from the market.

THE Energy Authority

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