ZEELAND BOARD OF PUBLIC WORKS

2026 Integrated Resource Plan

Prepared by

nFront Consulting LLC

June 5, 2026



TABLE OF CONTENTS

1 EXECUTIVE SUMMARY

This report documents the 2026 Integrated Resource Plan ("IRP") developed for the Zeeland Board of Public Works ("BPW"). The IRP was developed to assist BPW to evaluate various resource options to meet its customer's electric needs while balancing critical objectives, including system reliability, economics, regulatory compliance, and responsibly executing sustainability initiatives. Electric utility resource planning is an ongoing practice, and BPW may want to consider formal IRP updates as frequently as every three years, or as conditions warrant, supplemented by ongoing resource planning in the interim.

1.1 IRP Approach

The IRP considers BPW's resource needs in order to reliably and economically meet the energy requirements of its customers under two different scenarios —one scenario that assumes that no state requirements pertaining to renewable or clean energy production are in effect throughout the Study Period ("Business-as-Usual" or "BAU"), and a second scenario that assumes the requirements of Michigan's Renewable Energy Standard ("RES") and Clean Energy Standard ("CES") remain in effect over the Study Period ("PA 235").[1] Within each scenario, multiple portfolio strategies were evaluated to reflect different approaches to meeting future resource need and reliability requirements. These portfolio strategies include: an economically optimized portfolio in which large-frame thermal resources are available beginning in 2030; a delayed large-frame portfolio in which large-frame resources are first available in 2035; and a local generation portfolio that limits resource additions to local generation and renewable PPA resources.

The resulting portfolios were simulated though a series of alternative assumptions for key variables to assess the sensitivity of portfolio power supply costs across the portfolio strategies. The scenarios, portfolio strategies, and sensitivities evaluated in this IRP are summarized as shown in Table 1-1. While the overall cost to serve BPW's projected system energy requirements will vary based on the underlying assumptions reflected in each scenario, the focus of this IRP is not on the comparative economics of each resource plan within each scenario, but rather is on how resource decisions vary between scenarios.

[1] https://www.legislature.mi.gov/documents/2023-2024/publicact/pdf/2023-PA-0235.pdf

Table 1-1: IRP Scenarios, Portfolios, and Sensitivities

Category	Case	Description
Scenario	Business As Usual (”BAU”)	No State Requirements for PA 235
	Public Act 235 (”PA 235”)	Compliance with PA 235
Porfolio Strategy	Economically Optimized	Large-frame thermal resource available as early as 2030
	Large Units Available 2035	Large-frame thermal resource available starting 2035
	Local Generation	Only local generation and renewable PPA resources available
Sensitivity	Low Load Growth	Assumes lower load growth
	High Load Growth	Assumes higher load growth
	Low Fuel Price	Assumes lower fuel prices
	High Fuel Price	Assumes higher fuel prices

1.2 Conclusions

The following presents a high-level summary of the conclusions based on the analysis and evaluations performed for and discussed throughout this IRP. Additional conclusions and supporting details related to the conclusions are included in Sections 11 and 13.

- BPW’s current open capacity position provides flexibility to adapt to future resource strategies; however, optimum capacity builds under the resulting portfolio strategies show limited alignment in near-term resource additions across these scenarios, indicating that early investment decisions may differ significantly depending on the assumed regulatory future. Importantly, these near-term resource decisions may introduce path dependencies that impact long-term cost and resource outcomes if future regulatory conditions differ from expectations.
- Participation in larger, shared thermal generating resources is a key driver of economic value. Near-term planning decisions should prioritize preserving the ability to participate in future large generating units, even if full commitment occurs at a later date. Results of the IRP that support this conclusion include the following.
- Reliance exclusively on local generation is consistently identified as the higher-cost portfolio strategy. While local resources can provide operational and siting advantages,

limiting the portfolio to these options reduces economic efficiency and increases overall system costs over the study period.

- Power supply portfolios designed to fully meet the requirements of PA 235 result in higher costs relative to the BAU portfolios.
- Delaying an aggressive near-term buildout of renewable resources to meet PA 235 requirements results in the lowest incremental cost exposure. Given the uncertainty surrounding the regulatory compliance and the considerations related to the phase-out of the Inflation Reduction Act tax credits, BPW should plan to remain compliant while avoiding higher costs associated with early commitments that may prove misaligned with future regulatory outcomes.

1.3 Near-Term Actions

Table 1-2 provides a summary of the near-term actions that BPW may want to consider based on the analysis and evaluations performed for and discussed throughout this IRP.

Table 1-2: Summary of Near-Term Actions

Action	Description
Advance Local Generation Site Due Diligence	Continue environmental, permitting, interconnection, fuel supply, and constructability evaluations of potential BPW-owned generation sites and identify additional strategic locations.
Reduce Near-Term Capacity Market Exposure	Pursue interim capacity procurement strategies to mitigate BPW's open capacity position while long-term solutions are evaluated.
Evaluate New Generation Alternatives	Evaluate both locally owned and jointly owned generation resources using lifecycle cost, performance, financing, risk, and portfolio optimization criteria.
Coordinate with Michigan Public Power Agency ("MPPA") Resource Development Initiatives	Maintain active participation in MPPA planning efforts and evaluate opportunities for economies of scale and shared development risk.

2 STUDY OVERVIEW

This report documents the 2026 Integrated Resource Plan ("IRP") developed for the Zeeland Board of Public Works ("BPW"). The IRP was developed to assist BPW to evaluate various resource options to meet its customer's electric needs while balancing critical objectives, including system reliability, economics, regulatory compliance, and responsibly executing sustainability initiatives. Electric utility resource planning is an ongoing practice, and BPW may want to consider formal IRP updates as frequently as every three years, or as conditions warrant, supplemented by ongoing resource planning in the interim.

The IRP considers BPW's resource needs in order to reliably and economically meet the energy requirements of its customers under two different scenarios.

- **Business-as-Usual ("BAU") Case.** Scenario assuming that no state requirements pertaining to renewable or clean energy production are in effect throughout the study period
- **Public Act 235 ("PA 235") Case.** Scenario in which the requirements of the State of Michigan's Renewable Energy Standard ("RES") and Clean Energy Standard ("CES"), or "PA 235"[2] remain in effect over the study period

While the overall cost to serve BPW's projected system energy requirements will vary based on the underlying assumptions reflected in each scenario, the focus of this IRP is not on the comparative economics of each resource plan within each scenario, but rather on how resource decisions may vary between scenarios.

2.1 State of Michigan Renewable and Clean Energy Standard

Michigan Public Act No. 235 of 2023 ("PA 235"), effective February 27, 2024, amended Michigan's Clean and Renewable Energy and Energy Waste Reduction Act (Public Act 295 of 2008). The act sets forth requirements related to renewable and clean energy production, energy waste reduction, and development of utility-scale battery energy storage systems ("BESS") for electric utilities in the State of Michigan. Table 2-1 below summarizes the requirements of PA 235.

[2] https://www.legislature.mi.gov/documents/2023-2024/publicact/pdf/2023-PA-0235.pdf

Table 2-1: State of Michigan Public Act No. 235 Requirements

Renewable Energy Standard	Clean Energy Standard	Energy Storage Target
15% through 2029 50% by 2030 60% by 2035	80% by 2035 100% by 2040	2,500 MW by 2030[3]
Applicable Resources: o Biomass and Landfill Gas o Solar and Wind	Applicable Resources: o Biomass, Landfill Gas, and Hydro o Combined Cycle with Carbon and Capture Sequestration o Nuclear o Solar and Wind	Applicable Resources: o Battery Energy Storage

2.2 Outline of IRP

The relevant assumptions and methodologies utilized to develop the inputs considered throughout this IRP are discussed in more detail in subsequent sections of this IRP, along with the results of the economic analysis and corresponding conclusions. The remainder of this IRP is structured as follows:

- Section 3.0 provides a description of BPW's existing generating resources, including ownership entitlements and contractual purchase power resources.
- Section 4.0 discusses the economic parameters (escalation, inflation, and discount rates; interest during construction rate; and capital recovery factor) used throughout this IRP.
- Section 5.0 provides an overview of the BPW load forecast, including peak demand and annual net energy requirements forecasts.
- Section 6.0 discusses BPW's projected seasonal capacity requirements, which take into account BPW's existing capacity resources, seasonal peak demand forecasts, and the Midcontinent Independent System Operator ("MISO") planning reserve margin requirements.
- Section 7.0 discusses the supply-side resource options considered in this IRP, which include conventional generating units, utility-scale renewable and energy storage technologies, and emerging technologies (i.e. small modular reactor, or "SMR", and carbon capture and sequestration, or "CCS").
- Section 8.0 discusses the process and methodology used to develop the natural gas price projections reflected in this IRP.

[3] This is a requirement for Michigan rate-regulated utilities in aggregate, and is not applicable to BPW.

- Section 9.0 discusses the levelized cost of energy ("LCOE") analysis, that was performed to assess the economics of the supply-side options.
- Section 10.0 discusses the process and methodology used to develop the power market price projections reflected in this IRP.
- Section 11.0 discusses the resource portfolio optimization analysis performed for this IRP.
- Section 12.0 discusses the stakeholder engagement process performed for this IRP.
- Section 13.0 presents conclusions and near-term actions that BPW may want to consider based on the results of the analysis presented throughout the IRP.

3 DESCRIPTION OF THE BPW SYSTEM

BPW is a municipally owned and operated electric and water utility serving the City of Zeeland, Michigan, and neighboring communities. As of 2025, the BPW serves more than 7,000 electric meters and has an annual energy requirement of 464,587 MWh and a summer peak load of nearly 91.6 MW. The utility's energy and capacity requirements have consistently increased over the past few decades due to an increasing commercial and industrial customer base, a trend that is forecasted to continue. Although BPW's commercial and industrial customers represent a small percent of BPW's total electric customer accounts, they represent an overwhelming majority of demand on the system, accounting for over 85% of our annual energy requirements. The BPW participates in the wholesale market through the Michigan Public Power Agency ("MPPA"), operating in Local Resource Zone 7 of the Midcontinent Independent System Operator ("MISO").

3.1 BPW Existing Generating Resources

The BPW existing power supply portfolio consists of a combination of local generation, owned generation entitlements through MPPA, and Power Purchase Agreements through MPPA. The remaining balance of the BPW's power supply portfolio is filled through a series of bilateral contracts executed with counterparties through MPPA.

BPW Internal Generation Facilities

The BPW presently owns and operates a combined total of approximately 34.5 MW of behind-the-meter generating capacity located at three facilities within the BPW service territory. The Washington Ave units are dual fuel reciprocating internal combustion engines ("RICE") operating on natural gas ("NG") and distillate fuel oil ("DFO"), while the West Washington and Riley RICE units operate solely on NG. All units are typically dispatched only during peak demand periods.

A summary of these units is provided in Table 3-1 below.

Table 3-1: BPW Local Generating Facilities

Unit	Technology	Fuel	Commercial Operation Date	Nameplate Capacity (MW)
Washington Ave Generation Facility				
1	RICE	NG/DFO	1967	1.3
2	RICE	NG/DFO	1967	1.1
7	RICE	NG/DFO	1945/1985	2.0
8	RICE	NG/DFO	1963	1.6
9	RICE	NG/DFO	1971	4.5
10	RICE	NG/DFO	1974	5.6
11	RICE	NG/DFO	1980	6.0
West Washington Generating Facility				
1	RICE	NG	2002	1.0
2	RICE	NG	2002	1.0

Unit	Technology	Fuel	Commercial Operation Date	Nameplate Capacity (MW)
Riley Generating Facility				
1	RICE	NG	2005	2.0
2	RICE	NG	2005	2.0
3	RICE	NG	2005	2.0
4	RICE	NG	2005	2.0
5	RICE	NG	2005	2.0

BPW Ownership Entitlements

In addition to the local resources shown in Table 3-1, BPW receives ownership entitlements to two generation resources through MPPA.

- DTE Energy Company's ("DTE") coal-fired Belle River (Units 1 & 2)
- American Municipal Power's natural gas-fired combined cycle Fremont Energy Center

BPW's ownership entitlements in these resources are summarized in Table 3-2. Specific considerations related to BPW's ownership entitlements are outlined below.

- Belle River Units 1 and 2 are assumed to be converted from operating on coal to operating on natural gas by December 31, 2025 (Belle River Unit 1) and December 31, 2026 (Belle River Unit 2). For purposes of this IRP, these units will be modeled as operating on natural gas with no changes to the capacity shown in Table 3-2 and are assumed to be removed from service in May 2039.
- Fremont Energy Center is located in the PJM Regional Transmission Organization (outside of MISO) and is considered as a resource to contribute to BPW's energy needs, but not a capacity resource for BPW's MISO planning reserve margin purposes.

Table 3-2: BPW Ownership Entitlements

Resource	Technology Type	COD	Balancing Authority	Nameplate Capacity (MW)
Belle River	NG Steam	1984	MISO	11.6
Freemont Energy Center	NG Combined Cycle	2012	PJM*	7.1
*Fremont Energy Center is located in the PJM (outside of MISO) and is considered as a resource to contribute to BPW's energy needs, but not a capacity resource for BPW's MISO planning reserve margin purposes.				

Renewable Energy Purchases

In addition to the local resources and ownership entitlements shown in Tables 3-1 and 3-2, BPW has numerous renewable resources in its portfolio. These resources are made available through

Power Purchase Agreements ("PPA") managed through participation in MPPA projects. BPW's share of nameplate capacity and expiration dates for these resources are summarized in Table 3-3.

Table 3-3: BPW Renewable PPAs

Resource	Technology Type	PPA Expiration Date	Balancing Authority	Nameplate Capacity (MW)
Beebe	Wind	12/2034	MISO	2.3
Pegasus	Wind	12/2039	MISO	12.2
Assembly Ph1	Solar PV	12/2045	MISO	6.4
Assembly Ph2	Solar PV	12/2046	MISO	7.8
Invenergy Calhoun	Solar PV	4/2048	MISO	8.0
Brandt Woods	Solar PV	3/2045	MISO	2.9
White Tail	Solar PV	11/2045	MISO	2.8
Hart	Solar PV	12/2046	MISO	5.6

4 ECONOMIC AND FINANCIAL PARAMETERS

This section summarizes the economic and financial parameters used throughout this IRP. The economic and financial parameters were developed based on discussions between BPW and nFront Consulting LLC ("nFront" or "nFront Consulting") and are considered reasonable and appropriate for use in long-term planning activities such as this IRP. It should be noted that BPW may ultimately make financing decisions that differ from the parameters outlined below.

4.1 General Inflation and Escalation Rates

General Inflation Rate

The general inflation rate is used to convert from real dollars to nominal dollars and is assumed to be 2.5 percent.

Capital Cost Escalation Rate

The capital cost escalation rate used to escalate the capital cost estimates of new resource options from 2025 basis dollars to installed year dollars is assumed to be 2.5 percent.

Non-Fuel Variable Operations and Maintenance ("O&M") Escalation Rate

Non-fuel variable O&M costs represent costs of operating and maintaining generating units that vary based on how often the generating units are operating. Examples of non-fuel O&M costs include chemicals and lubricants, and other maintenance costs that vary based on the number of hours a unit is operated. The non-fuel variable O&M escalation rate is used for escalating non-fuel variable O&M costs for BPW's existing generating units as well as non-fuel variable O&M costs for new resource options from 2025 basis dollars to nominal dollars and is assumed to be 2.5 percent.

Fixed O&M Escalation Rate

Fixed O&M costs represent costs associated with generating units that do not vary based on how often the generating units are operated. Examples of fixed O&M costs include staffing and labor and other general and administrative costs. The fixed O&M escalation rate is used for escalating fixed O&M costs for BPW's existing generating units as well as fixed O&M costs for new resource options from 2025 basis dollars to nominal dollars and is assumed to be 2.5 percent.

4.2 Tax-Exempt Municipal Bond Interest Rate

The IRP assumes that BPW would issue tax-exempt municipal bonds to finance the capital cost associated with new resource options. The tax-exempt municipal bond interest rate is assumed to be 5.0 percent.

4.3 Present Worth Discount Rate

The present worth discount rate is assumed to be 5.0 percent and is used to discount future cash flows to current dollars (discounted to the year 2025 for purposes of this IRP). Assuming a present worth discount rate equal to or similar to a utility's expected cost of financing is a standard practice for long-term resource planning studies such as IRPs.

4.4 Interest During Construction Rate

The interest during construction rate refers to the interest rate during the construction phase for new resources. For this IRP, the capital cost estimates developed for the new resource options reflect consideration of interest costs during construction. Since capital cost estimates were not developed using a "bottoms up" approach but instead based on review of relevant information (as discussed in Section 7 of this IRP), a specific interest during construction rate has not been utilized.

4.5 Capital Recovery Factor

The capital recovery factor ("CRF") is applied to the capital cost of the new resource options considered in this IRP to calculate a levelized amortization rate. When the CRF is applied to capital cost, the product equals the annual capital cost recovery, including interest costs, for new resources.

Although different generating technologies may have different economic lives, for purposes of this IRP, it has been assumed that if BPW were to finance new generating resources, the financing terms would be 20 years. Final financing decisions would be determined by BPW subsequent to the development of this IRP. The CRF utilized for the IRP reflects the 5.0 percent tax-exempt municipal bond interest rate, as discussed above, and is approximately 8.2 percent (i.e., the annual cost of new resources would then be 8.2 percent of the assumed capital cost at COD over the 20-year assumed cost recovery period).

5 LOAD FORECAST

The forecasts of annual energy and seasonal peak demands evaluated in this IRP were provided by BPW. This section presents the methodology used by BPW and the resulting load forecast and scenario forecasts used in this IRP.

5.1 Base Forecast

The Base Case Forecast incorporates both an Econometric Forecast and a projection of New Load Additions. The Econometric Forecast reflects organic growth within the BPW service territory, while the New Load Additions capture anticipated large commercial load expansions. Together, these projections are integrated and translated into a forecast of net system energy requirements and seasonal peak demands.

Econometric Forecast

The Econometric Forecast, which was developed by MPPA, relies primarily upon an econometric approach to produce projections of system peak demand and energy requirements over calendar year 2025 through 2054. Econometric forecasting makes use of regression analysis to establish historical relationships between energy and various explanatory factors, which are generally assumed to continue into the future. The selected forecast equation is then populated with projections of explanatory variables, resulting in projections of energy requirements.

The results of the Econometric Forecast reflect the following, before considering expected large load additions.

- BPW system energy requirements are expected to grow at a compound average growth rate ("CAGR") of 1.7 percent per year over 2025-2036 and 0.9 percent per year over 2035-2044. This compares to historical average growth over the last decade of approximately 2.0 percent per year.
- The BPW winter peak demand is expected to grow at a CAGR of 1.9 percent per year over 2025-2036 and 0.8 percent per year over 2035-2044. This compares to historical average growth over the last decade of approximately 1.6 percent per year.
- The BPW summer peak demand is expected to grow at a CAGR of 1.3 percent per year over 2025-2036 and 0.9 percent per year over 2035-2044. This compares to historical average growth over the last decade of approximately 2.2 percent per year.

New Load Additions

A separate forecast of new load additions was developed by BPW to reflect the expansion activities of several large commercial customers that would not otherwise be captured in the Econometric Forecast. This forecast of new load additions is primarily based on information provided by the respective customers regarding planned facility upgrades, new construction, and operational changes.

By 2031, the forecast of new load additions reflects an additional 18 percent increase in system energy requirements, and an additional 15 percent to peak demand requirements. Importantly, while the New Load Additions reflect the best estimate based on current information, the timing and magnitude of these new load additions remain inherently uncertain as operational needs and development plans for these customers continue to evolve.

Base Case Forecast Results

The resulting forecasts of energy requirements and seasonal peak demands, combining the Econometric and New Load Addition Forecasts, are depicted in Figures 5-1 through 5-3, respectively.

- BPW system net energy requirements are expected to grow at a CAGR of 3.3 percent per year over 2025-2036 and 0.8 percent per year over 2035-2044. This compares to historical average growth over the last decade of approximately 2.0 percent per year.
- The BPW winter peak demand is expected to grow at a CAGR of 3.1 percent per year over 2025-2036 and 0.7 percent per year over 2035-2044. This compares to historical average growth over the last decade of approximately 1.6 percent per year.
- The BPW summer peak demand is expected to grow at CAGR of 2.5 percent per year over 2025-2036 and 0.8 percent per year over 2035-2044. This compares to historical average growth over the last decade of approximately 2.2 percent per year.

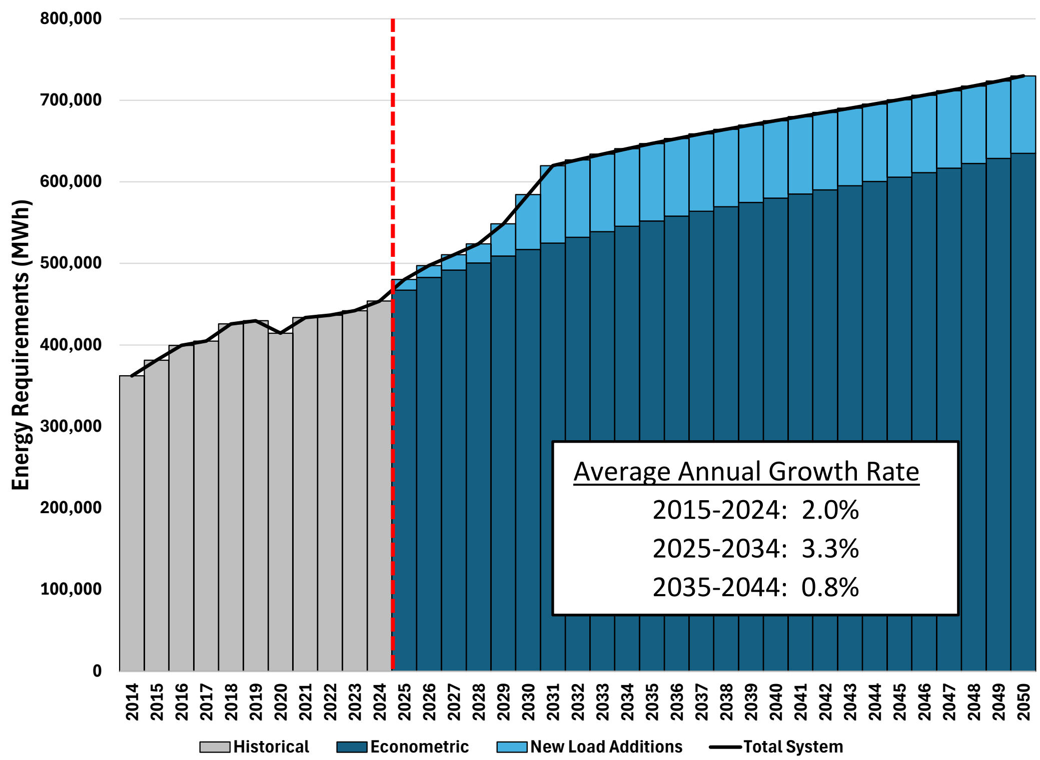

Figure 5-1: System Net Energy Requirements (MWh)

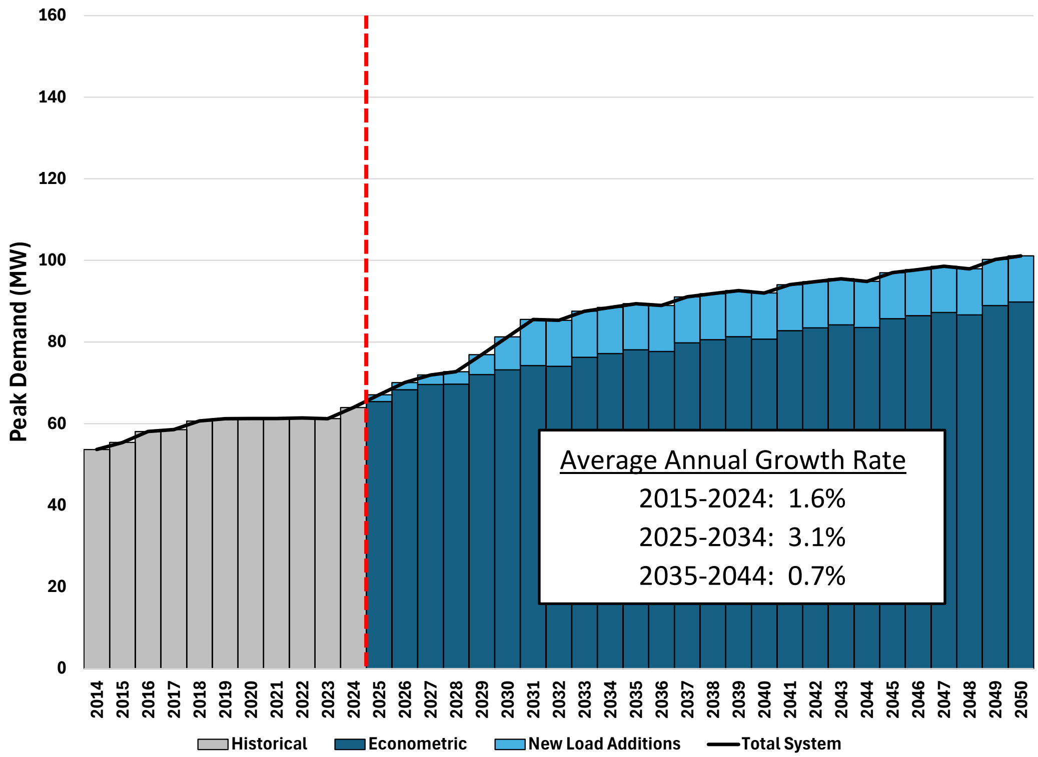

Figure 5-2: Winter Peak Demand (MW)

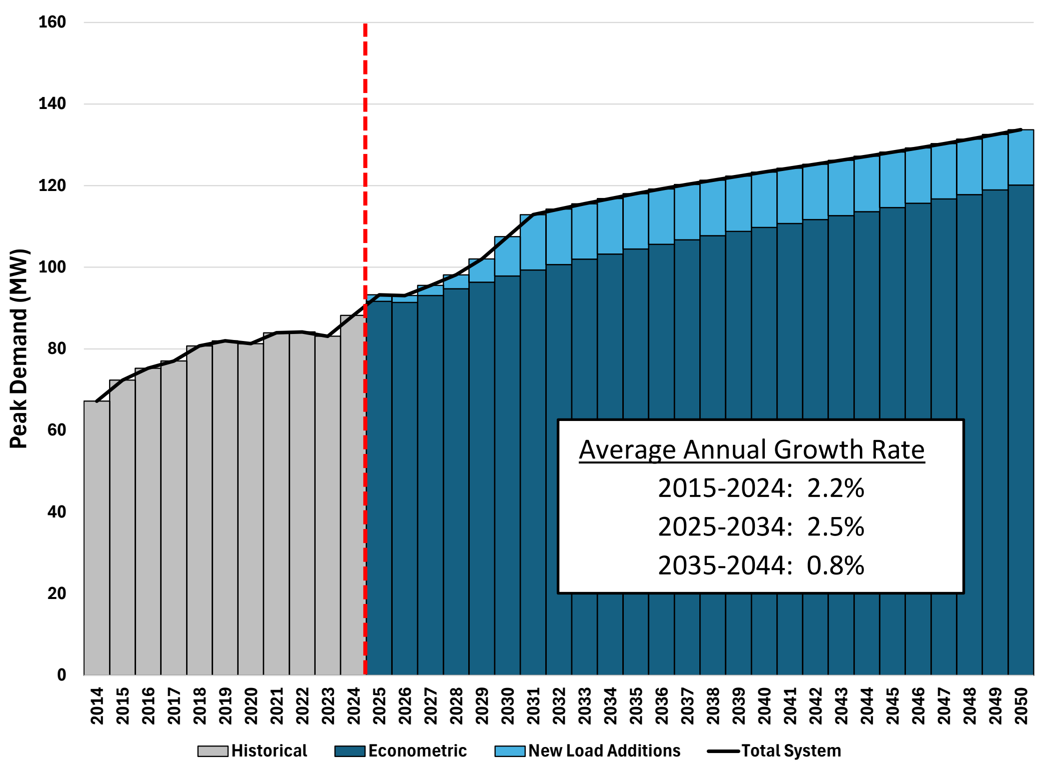

Figure 5-3: Summer Peak Demand (MW)

5.2 Scenario Forecasts

The High and Low Forecast scenarios were prepared to capture the uncertainty in the trend of economic activity in BPW's service area. In these scenarios, the projections of explanatory variables underpinning Econometric Forecast are varied from the base case assumptions based on statistics published by Woods & Poole regarding historical errors in their state-level forecasts across the United States, intended to encompass 90 percent of the uncertainty in the driving variables. The New Load Additions are assumed to be consistent with the Base Case. The resulting ranges of net energy requirements and seasonal peak demands are presented in Figures 5-4 and 5-5, respectively.

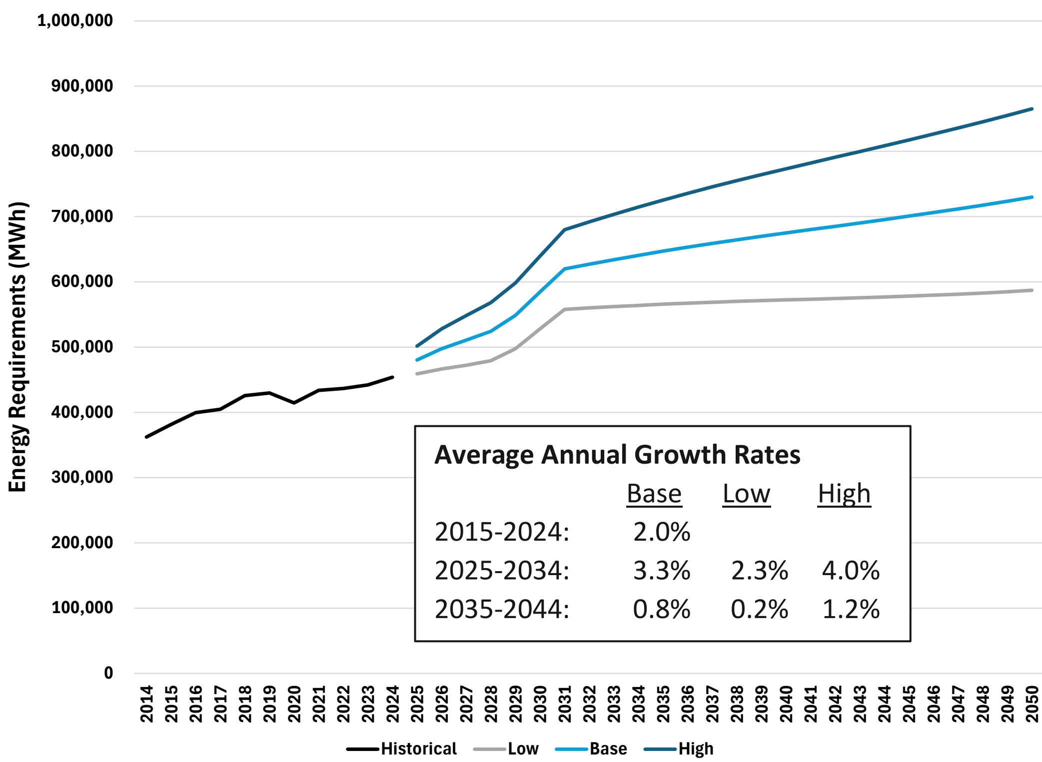

Figure 5-4: Scenario Forecasts – Net Energy Requirements

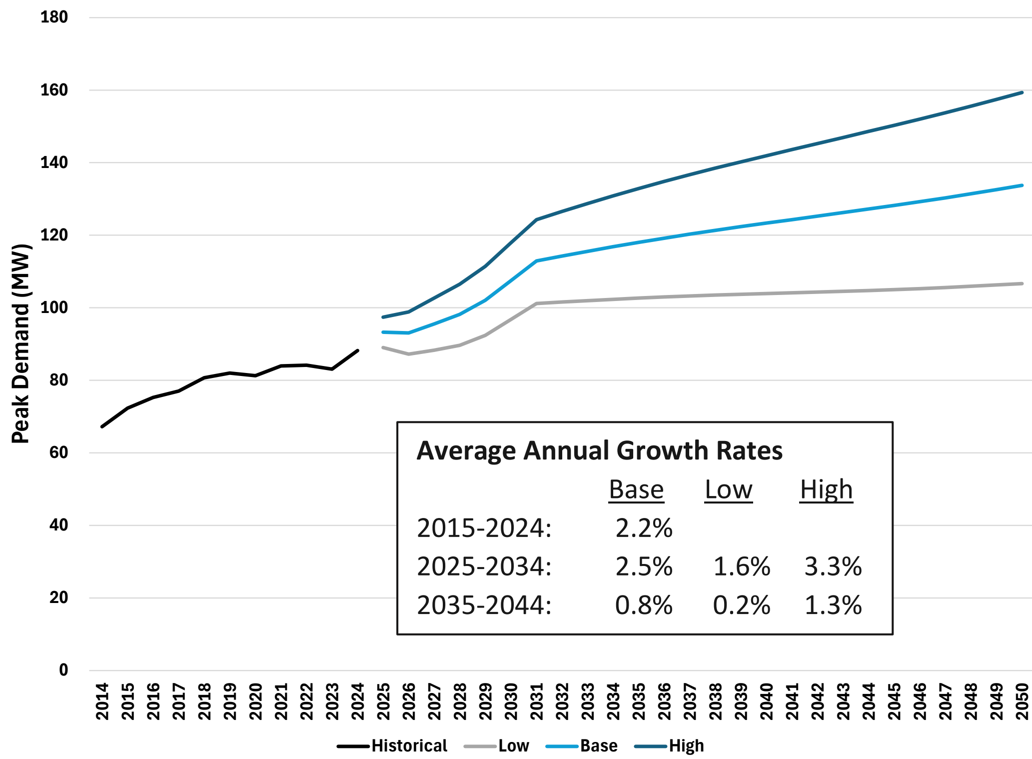

Figure 5-5: Scenario Forecasts – Summer Peak Demand (MW)

5.3 Demand-Side Management and Energy Efficiency

Michigan Public Act No. 229 of 2023 ("PA 229"), effective February 13, 2024, amended the energy waste reduction targets that were set forth under Michigan's Clean and Renewable Energy and Energy Waste Reduction Act (Public Act 295 of 2008). Under PA 229, beginning in 2026 the energy waste reduction programs of an electric provider in the State of Michigan "…shall collectively achieve incremental energy savings equivalent to 1.5% of total retail electric sales in megawatt hours in the preceding year…". The energy waste reduction requirements of PA 229 are applicable to BPW, as BPW is a municipal electric utility and qualifies as an "electric provider" under PA 229.

The load forecast discussed previously in this section and utilized for purposes of this IRP reflects the assumption that BPW will achieve the energy waste reduction requirements of PA 229 through customers participating in the *Energy Smart Programs* offered by BPW to its customers. The *Energy Smart Programs* and BPW's demand response program are summarized below; more information on these programs can be found at Zeeland - Energy Smart Programs[4].

[4] https://mienergysmart.com/zeeland

Rebates for Income-Qualified Residential Customers

This program assists income-qualified customers in making energy-efficient choices for their homes. Eligible customers can earn enhanced rebates (as compared to the rebates offered to non-income-qualified customers) for the purchase of ENERGY STAR® certified appliances and electronics, which help reduce participating customers' energy use and utility bills.

Eligible customers can receive rebates for the following:

- Whole home heating, ventilation, and air conditioning ("HVAC") equipment, including central air conditioning, heat pumps, mini-split heat pumps, and dehumidifiers.
- Heat pump water heaters.
- ENERGY STAR® certified refrigerators, freezers, smart thermostats, clothes washers and dryers, room air conditioning, portable dehumidifiers and air purifiers, personal computers, monitors, and TVs.
- Intelligent surge protectors.
- Building envelope measures including ceiling insulation, wall insulation, attic insulation, rim joist insulation, ENERGY STAR® certified windows and doors, and air sealing, weatherstripping, and duct repairs.

Rebates for Residential Customers

This program is similar to the program offered to income-qualified customers, but offers lower rebate amounts than offered to income-qualified customers. Participating customers can receive rebates for the following:

- Whole home HVAC, including central air conditioning, heat pumps, mini-split heat pumps, and dehumidifiers.
- Heat pump water heaters.
- ENERGY STAR® certified refrigerators, freezers, smart thermostats, clothes washers and dryers, room air conditioning, portable dehumidifiers and air purifiers, personal computers, monitors, and TVs.
- Intelligent surge protectors.
- Building envelope measures including ceiling insulation, wall insulation, attic insulation, rim joist insulation, ENERGY STAR® certified windows and doors, and air sealing, weatherstripping, and duct repairs.

Rebates for Business Customers

This program provides rebates to businesses to reduce their energy usage and lower their costs. Participating customers can receive rebates for the following:

- Lighting and lighting controls, including occupancy sensors.
- Indoor agricultural lighting.
- HVAC equipment and related controls equipment.
- Compressed air and industrial equipment.
- Refrigeration equipment.
- Food service and computer equipment.
- Demand response.

Appliance Recycling

Zeeland offers free pick-up as well as rebates to customers who have unwanted refrigerators, freezers, room air conditioners, and dehumidifiers. Participating customers receive a $50 rebate for refrigerators and freezers, and a $15 rebate for room air conditioners and humidifiers. This program is intended to incentive customers to dispose of older, often inefficient appliances that they may otherwise be using but do not necessarily need, thereby reducing electric consumption.

Demand Response

In late 2025, the BPW began offering a Commercial & Industrial ("C&I") demand response program, developed in partnership with a third-party demand response implementer. This program enables BPW's C&I customers to voluntarily reduce electric demand during grid capacity emergency events in exchange for compensation. Participation in the program provides BPW with a low-risk opportunity without direct cost to enhance system reliability, support sustainability goals, and strengthen the local economy by keeping performance payments within the community while positioning BPW competitively among other utilities.

5.4 BPW Historical Conservation and Energy Efficiency Reductions

As noted above, the conservation programs offered by BPW to its customers have focused primarily on rebates for upgrades for lighting, HVAC, appliances, and other equipment. Participation in BPW's conservation programs have resulted in the following:

- Cumulative reduction in energy usage over the 2012 through 2024 period of 8.5% (38,582 MWh) of BPW's 2024 total energy requirements (as illustrated in Figure 5-6).
    - Considering the energy reductions noted above, total energy requirements increased by 30.6% (2.25% annually) over the 2012 through 2024 period (as illustrated in Figure 5-6).

- Increase in peak demand from 2012 through 2025 averaged 2.3% annually, with an overall increase of 27% during that period, after accounting for demand reductions associated with BPW's conservation programs (as illustrated in Figure 5-7).

While BPW's historical energy efficiency initiatives have been effective in reducing both energy consumption and peak demand, these conservation efforts alone are not sufficient to mitigate BPW's incremental energy and capacity needs. The Base Case Load Forecast (discussed above in Section 5.1) incorporates the impacts of energy efficiency, moderating the level of future load growth and reducing the magnitude of new resource additions needed. However, even after accounting for the impacts of energy efficiency, the load forecast demonstrates that BPW will continue to experience additional energy and capacity needs over the planning horizon.

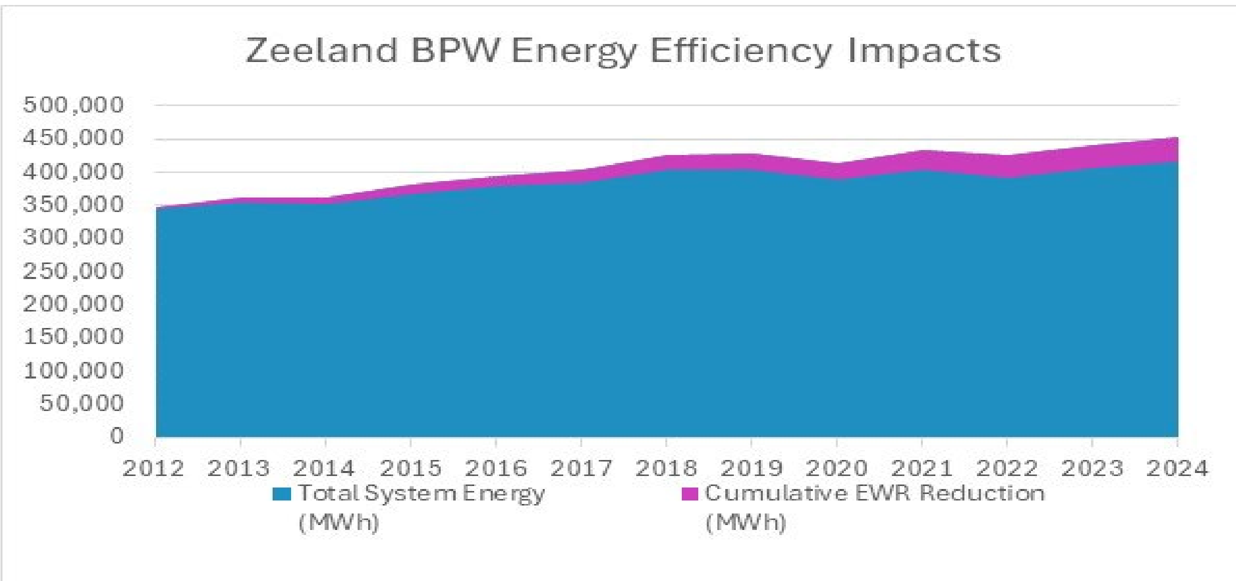

Figure 5-6: BPW Energy Efficiency Program Impacts

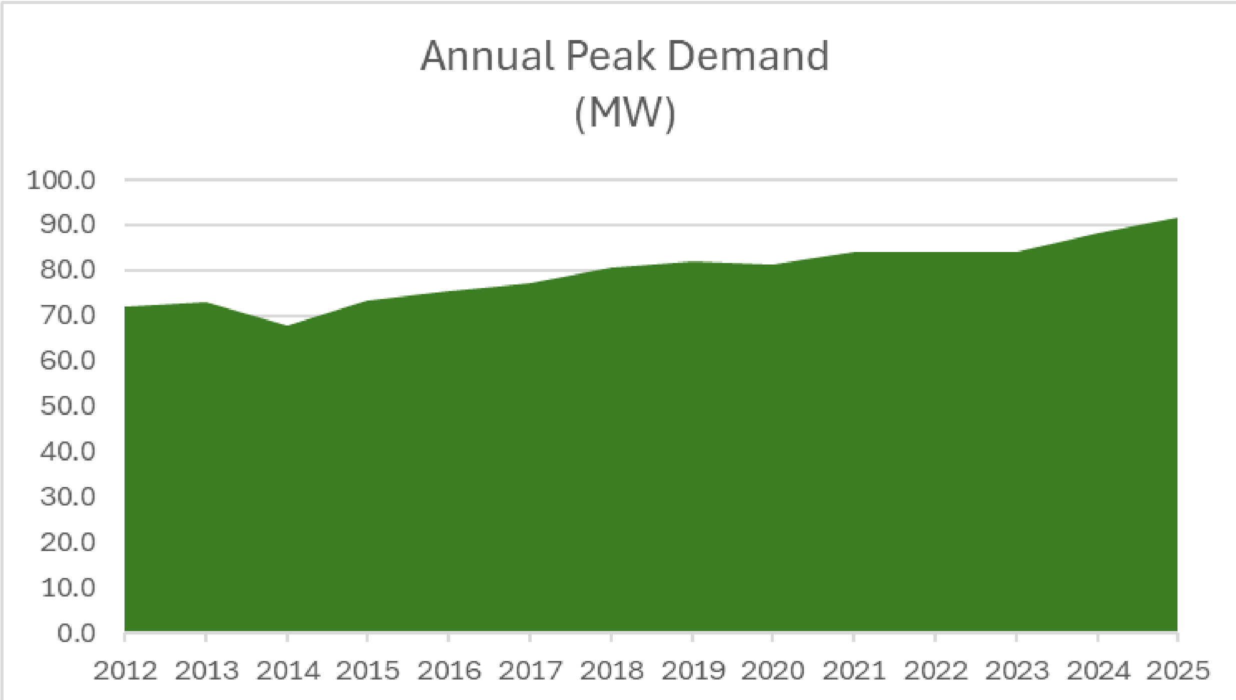

Figure 5-7: BPW Historical Peak Demand

6 PROJECTED CAPACITY REQUIREMENTS

Electric generating resource planning utilizing a reserve margin approach allows for determination of the amount of capacity required to meet projected annual peak demand while maintaining additional capacity (the reserve margin). The reserve margin is intended to allow the utility to meet the peak demand even during unexpected events, such as when actual peak demand exceeds the projected peak demand and in situations where generating resources are unexpectedly not available.

The MISO Planning Reserve Margin ("PRM") requirements are applied to BPW's seasonal peak demand projections (as discussed in Section 5 of this IRP) and the resulting total seasonal capacity requirements are compared to BPW's existing capacity resources (as summarized in Section 3 of this IRP) to determine the seasonal capacity requirements that must be satisfied through the addition of new resources.

6.1 Reserve Margin Considerations

BPW's resource planning includes consideration of planning reserve margins to comply with MISO's guidelines for unforced capacity. Importantly, beginning with Planning Year 2025/26, MISO has implemented the Reliability-Based Demand Curve ("RBDC") mechanism which will adjust the seasonal PRM based on auction results. The seasonal MISO PRM requirements assuming Unforced Capacity ("UCAP") and the assumed seasonal RBDC are presented in Table 6-1 below. It is important to note that in Planning Year 2028/29, the MISO PRM will be based on a Direct Loss of Load ("DLOL") methodology, resulting in a new set of seasonal PRM values.

Table 6-1: Seasonal MISO PRM

	PY 26/27			PY 28/29		
Season	Base	RBDC	Total	Base	RBDC	Total
Summer	7.9%	3.1%	11.0%	2.3%	3.1%	5.4%
Fall	11.6%	2.0%	13.6%	6.0%	2.0%	8.0%
Winter	18.9%	5.1%	24.0%	5.6%	5.1%	10.7%
Spring	23.4%	1.4%	24.8%	1.0%	1.4%	2.4%

6.2 MISO Zone 7 Coincidence Factors

BPW's resource planning includes consideration of the BPW peak coincidence with the MISO Zone 7 system wide peak hour within each season. The seasonal MISO Zone 7 peak coincidence factors that are applied to BPW's seasonal peak demand projections are shown below in Table 6-2.

Table 6-2: MISO Zone 7 Seasonal Coincidence Factors

Season	Coincidence Factor
Summer	92.4%
Fall	91.4%
Winter	88.2%
Spring	92.5%

6.3 Transmission Losses

BPW's resource planning includes consideration for the transmission losses incurred on the transmission system. The seasonal transmission loss factors that are applied to the BPW seasonal peak demand projections are shown below in Table 6-3.

Table 6-3: Transmission Loss Factors

Season	Transmission Losses
Winter	3.0%
Spring	2.6%
Summer	3.4%
Fall	3.3%

6.4 MISO Seasonal Capacity Accreditation

BPW currently relies on the historical performance as the basis of seasonal accreditation for its local generation facilities. In addition, BPW relies on the standard MISO Schedule 53 methodology for Belle River and renewable resources managed through MPPA. BPW will be able to continue this approach of seasonal accreditation through MISO Planning Year 2027/2028.

As mentioned previously, beginning in MISO Planning Year 2028/29, the MISO resource accreditation methodology will be based on a DLOL methodology. The DLOL seasonal accreditation values currently estimated by MISO are shown below in Table 6-4.

Table 6-4: DLOL Seasonal Capacity Accreditation Beginning Planning Year 2028/2029

Resource Class	Summer	Fall	Winter	Spring
Coal	89%	85%	76%	72%
Oil/Gas	87%	84%	79%	77%
Gas	88%	85%	64%	68%
Combined Cycle	95%	92%	77%	78%
Oil	77%	75%	74%	73%
Solar	45%	28%	19%	28%
Wind	8%	15%	23%	15%

6.5 Capacity Balance

Consideration of BPW's existing seasonal accredited capacity and applying MISO's seasonal PRM requirements to BPW's projected demand requirements indicates that projected capacity requirements will be highest during the summer season. Figure 6-1 below illustrates BPW's projected capacity needed to satisfy projected summer peak demand and associated PRM requirements.

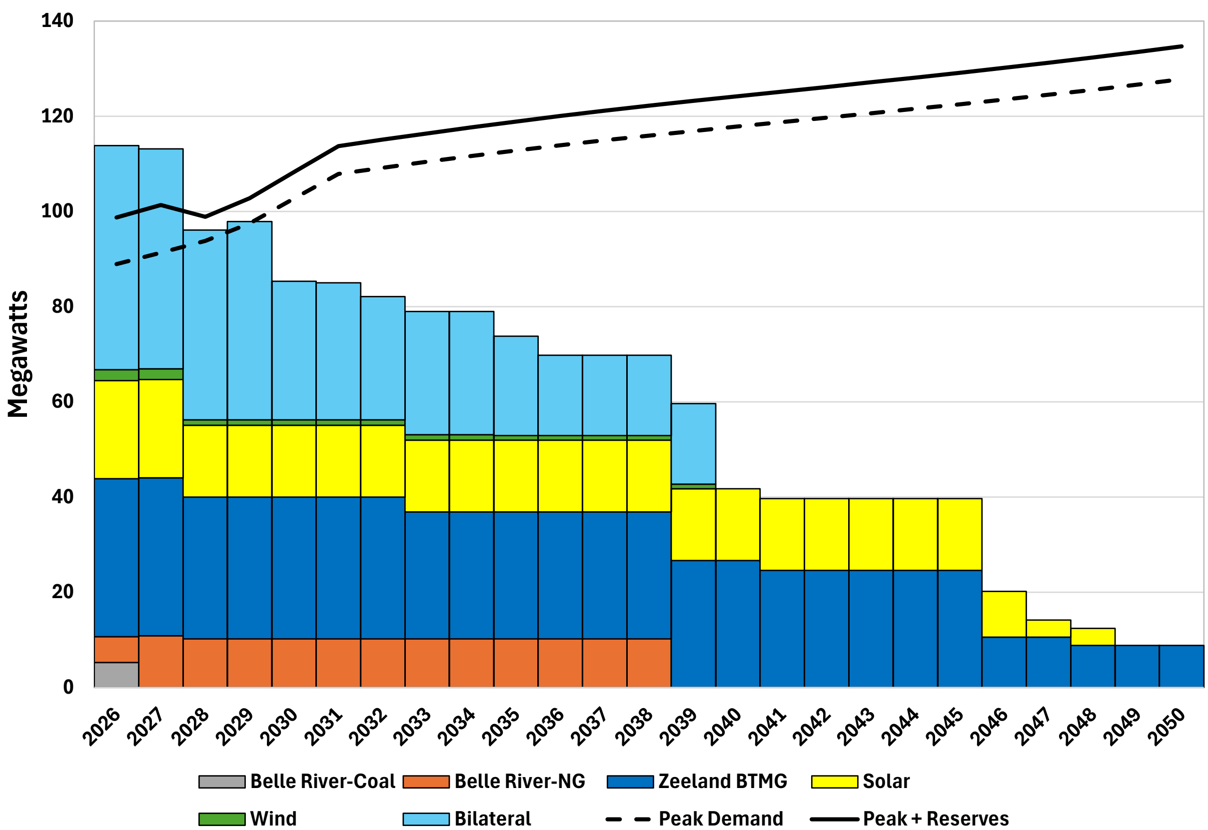

Figure 6-1: BPW Summer Capacity Balance

BPW currently relies on the bilateral transactions executed through MPPA to satisfy its planning reserve margin requirements above its existing resource portfolio. As shown in Figure 6-1, and described in more detail below, BPW is projected to need capacity beginning with the summer of 2028.

- Prior to 2030, the need for additional capacity is less than 5 MW and is assumed to be satisfied through the purchase of MISO Zonal Resource Credits ("ZRCs").
- By 2030, the need for additional capacity grows to 30 MW with the step-down of capacity from bilateral contracts.
- By 2040, the need for additional capacity is projected to increase to approximately 85 MW as a result of the anticipated retirement of Belle River, the expiration of the existing capacity contracts, and projected load growth.
- By 2050, the need for additional capacity is projected to increase to approximately 125 MW as a result of the anticipated retirements of the Washington Ave. Generation Facility and West Washington Generation Facility, expiration of existing renewable PPA's, and projected load growth.
  - It should be noted that, due to their condition, maintenance practices, and limited operation, the existing generating units have been kept in service beyond their expected operating life. While BPW has an anticipated retirement timeline for these units and has continued to maintain them in a manner that promotes reliable operation when needed, their increasing age may make long-term support a growing concern.

It should be noted that the addition of new resources reflected in this IRP is not solely driven by reserve margin considerations and may also be influenced by BPW's generation needs to comply with the requirements of PA 235.

7 RESOURCE OPTIONS

The analysis performed for this IRP includes consideration of various supply-side options, including conventional generating units, utility-scale renewable and energy storage technologies, and emerging technologies (i.e. small modular reactor, or "SMR", and carbon capture and sequestration, or "CCS") to meet projected system capacity and energy requirements. The following subsections discuss the approach and methodology used to develop the planning-level estimated capital and operating costs and performance characteristics for use in this IRP and present the corresponding estimates.

7.1 General Considerations

As a relatively small electric utility, BPW's supply-side options are limited to relatively smaller generating units, or purchases of shares of larger units (with the implicit assumption being that another entity develops the larger unit, and BPW is able to participate on a pro rata type basis for a smaller share). The resource options evaluated in this IRP were selected to provide an informative analysis of various supply-side options that may be suitable for BPW to consider and to provide insight into the relative economics of smaller units as compared to larger units. The resource options considered in this IRP included the following.

- BPW sole ownership of reciprocating internal combustion engines ("RICE")
- Entitlements to capacity (5 MW shares) from utility scale thermal generation resources, including natural gas-fired General Electric ("GE") LM6000 simple cycle aeroderivative turbines, GE advanced-class simple cycle combustion turbine ("NGCT"), and GE advanced-class combined cycle combustion turbine ("NGCC"), with and without 90% CCS
- Entitlements to capacity (5 MW shares) from small modular reactors ("SMR") resources
- Entitlements to capacity (5 MW shares) from renewable resources, including utility-scale solar photovoltaic ("PV") and utility-scale wind resources
- Entitlements to capacity (5 MW shares) from utility-scale 4- and 8-hour battery energy storage systems ("BESS")

It should be noted that the decision to characterize and evaluate General Electric ("GE"), Caterpillar, and Solar Turbines as the basis for the natural gas resource options evaluated in this IRP is not intended to imply that these are the only types of generating units available to BPW, but these manufacturers were viewed as representative. Several other manufacturers may offer competing technologies that BPW may ultimately consider (e.g., Mitsubishi-Hitachi Power Systems, Siemens, Wartsila, MAN Energy, Jenbacher). Regardless of the unit type or manufacturer, prior to making any final decisions on new generating units, BPW should consider working with an owner's engineer to develop more detailed, site-specific capital cost estimates, and going to the market by issuing a bid/specifications package to solicit formal pricing estimates from manufacturers.

General Basis for Estimated Capital and Operating Costs and Performance

Estimated capital and operating costs and estimated performance (i.e., net heat rate) for the natural gas and SMR options evaluated in this IRP were developed based on nFront Consulting's proprietary collection of resource capital costs, O&M costs, and operating characteristics for supply-side options for use in resource planning studies. The characteristics are based on nFront Consulting's research on recent projects, regulatory filings for IRPs and other resource planning proceedings, participation in various power supply RFPs, discussions and data from equipment vendors, vendor performance models and reporting, and publicly available information. The estimates are considered inclusive of engineering, procurement, and construction costs as well as additional owner's costs.

Estimated costs for renewable (solar PV and onshore wind) and energy storage technologies were developed based on nFront's experience related to renewable power supply RFPs, independent research, and publicly available information (such as the National Renewable Energy Laboratory[5] ("NREL") Annual Technology Baseline ("ATB"). For purposes of this IRP, the all-in costs for these resources are represented as PPAs and include consideration of tax credits available under the Inflation Reduction Act, with consideration of the impact of more recent federal legislation, and likely cost trends capturing the potential for declining capital costs as these technologies mature, as discussed further below. However, BPW may consider other approaches for implementing these resources.

Electric Transmission Costs

Transmission related costs have become an increasingly significant driver of overall power supply costs. In recent years, transmission charges have grown at a faster rate than other components of power supply costs, making transmission-related costs a material contributor to upward cost pressure and an important consideration in long-term resource planning.

The electric transmission costs that were considered as a part of the IRP evaluation include transmission upgrade costs, congestion and marginal losses, and MISO Schedule 26A charges. A summary of how these transmission charges were applied within the IRP evaluation is illustrated below in Table 7-1, and described in more detail in the following paragraphs. Importantly, charges associated with Network Integrated Transmission Services ("NITS") have not been included as such costs can be considered "sunk costs" that would not change nor influence the resource and dispatch decisions reflected in this IRP.

[5] Recently renamed the National Laboratory of the Rockies.

Table 7-1: Projected Costs of Transmission Upgrades, Congestion, and Schedule 26A

New Resource Option	Location	Transmission Upgrade	Congestion & Losses	Schedule 26A Charges
SMR	Off-System	Yes	Yes	Yes
RICE	Local	No	No	No
RICEx2	Local	No	No	No
Small CT	Off-System	Yes	Yes	Yes
Large CT	Off-System	Yes	Yes	Yes
1x1 CC	Off-System	Yes	Yes	Yes
1x1 CC-CCS	Off-System	Yes	Yes	Yes
Solar PV	Off-System	Yes	Yes	Yes
Wind	Off-System	Yes	Yes	Yes
BESS (4-Hr)	Off-System	Yes	Yes	Yes
BESS (8-Hr)	Off-System	Yes	Yes	Yes
Legend: Small modular reactor ("SMR"); Reciprocating internal combustion engines ("RICE"); Simple cycle combustion turbine ("CT"); Combined cycle combustion turbine ("CC"); Combined cycle combustion turbine with carbon capture and sequestration ("CC-CCS"); Solar photovoltaic ("Solar PV"); Battery energy storage systems ("BESS")				

For purposes of evaluating new resource options that would be located outside of BPW's electric distribution system, it has been assumed that these resources would incur additional transmission costs related to transmission upgrades. The incremental transmission upgrade costs are included to account for the additional infrastructure required to reliably integrate those resources into the transmission system. The assumed transmission upgrade costs applied in this evaluation are based on a review of historical MISO generator interconnection cluster study results and escalated at 2.5 percent.

Additional costs associated with delivering energy from resources located outside of Zeeland include costs for locational marginal price ("LMP") congestion and marginal losses from the Michigan hub to Zeeland and transmission charges under Schedule 26A[6]. The projected cost of congestion and marginal losses are based on a historical average of the last 3 years and escalated at 2.5 percent. The projected charges associated with Schedule 26A are based on indicative forecasts produced by MISO.

The assumed costs of transmission upgrades, costs of congestion and marginal losses, and Schedule 26A charges applied in this evaluation are summarized in Table 7-2.

[6] MISO Schedule 26A charges recover costs for certain large regional transmission projects within MISO referred to as Multi-Value Projects.

Table 7-2: Projected Costs of Transmission Upgrades, Congestion, and Schedule 26A (Nominal$)

Year	Transmission Upgrade ($/kW)	Congestion & Losses ($/MWh)	Schedule 26A Charges ($/MWh)
2026	300.0	0.63	1.58
2027	307.5	0.65	1.56
2028	315.2	0.67	1.53
2029	323.1	0.68	1.50
2030	331.1	0.70	1.47
2031	339.4	0.72	1.44
2032	347.9	0.74	1.41
2033	356.6	0.75	1.39
2034	365.5	0.77	1.36
2035	374.7	0.79	1.33
2036	384.0	0.81	1.31
2037	393.6	0.83	1.28
2038	403.5	0.85	1.26
2039	413.6	0.87	1.23
2040	423.9	0.90	1.21
2041	434.5	0.92	1.18
2042	445.4	0.94	1.16
2043	456.5	0.96	1.13
2044	467.9	0.99	1.11
2045	479.6	1.01	1.09
2046	491.6	1.04	1.07
2047	503.9	1.06	1.04
2048	516.5	1.09	1.02
2049	529.4	1.12	1.00
2050	542.6	1.15	0.98

Natural Gas Transportation Costs

For purposes of the evaluations performed in this IRP, it was assumed that BPW would incur both transmission-level and local delivery charges for natural gas, and those costs are reflected in the natural gas price forecasts presented in Section 8 of this IRP. The natural gas delivery charges were modeled as variable costs per MMBtu of natural gas consumed.

7.2 PA 235 Clean Energy Standards and Renewable Energy Standard Considerations

As discussed previously, the IRP considers a scenario in which BPW meets the RES and CES requirements of PA 235, which are generally outlined as follows:

- Minimum of 15 percent renewable energy through 2029
- Minimum of 50 percent renewable energy in 2030 through 2034
- Minimum of 60 percent renewable energy in 2035 and thereafter

- Minimum of 80 percent clean energy in 2035 through 2039
- 100 percent clean energy in 2040 and thereafter

Of the new resource options evaluated in this IRP, SMR, NGCC with CCS, solar PV, and wind resources all contribute to satisfying the PA 235 CES requirements, while solar PV and wind contribute to satisfying both the PA 235 CES and RES requirements. All energy from BPW's existing renewable PPAs is assumed to contribute towards satisfying both the PA 235 CES and RES requirements.

7.3 Cost and Performance Estimates

The estimated capital cost, operating cost, and performance for the natural gas-fired and SMR resource options evaluated in this IRP are shown in Table 7-3, along with additional information related to the consideration of these resource options in the IRP analysis. Please see Section 9 for analysis of the all-in, lifecycle costs of the resource options shown in Table 7-3. As shown in Table 7-2, the various natural gas and SMR resource options reflect a range of sizes and initial construction costs (capital costs), operating and maintenance (fixed and non-fuel variable O&M) costs, and efficiency (heat rate), which are all considered in the detailed economic evaluations presented in Section 11 herein.

Table 7-3: New Natural Gas and SMR Resource Cost and Performance Estimates[1]

Description	Nameplate Capacity (MW)	BPW Share (MW)	Earliest On-Line Date	Capital Cost ($/kW)[2]	Fixed O&M ($/kW-Yr)[2,3]	Non-Fuel Variable O&M ($/MWh)[1]	Full Load Net Plant Heat Rate (Btu/kWh)
SMR	300	5	2035	11,893	180	3.00	10,300
RICE	5	5	2028	2,000	30	7.12	9,800
RICEx2	10	10	2028	2,000	22.50	7.12	9,800
Small CT	16	16	2028	2,500	28.13	1.50	9,700
Large CT	426	5	2030	1,623	7.00	1.20	9,200
1x1 CC	664	5	2030	2,093	18.00	2.60	6,200
1x1 CC-CCS	598	5	2035	3,526	45.60	5.50	6,820

Notes:
1. All estimates reflect output and performance and average ambient conditions.
2. All costs are in 2025 base year dollars.
3. Fixed O&M for new combined cycle with CCS includes estimated costs for carbon dioxide ("CO_2") sequestration.

Legend: SMR: small modular reactor (nuclear) | RICE: reciprocating internal combustion engine | CT: simple cycle combustion turbine | CC: combined cycle combustion turbine | CC-CCS: combined cycle combustion turbine with carbon capture and sequestration

The assumed base year capital and fixed operating cost for solar PV, onshore wind, and BESS options, as well as the first-year capacity factors for solar and wind, are shown in Table 7-4, along with information related to the consideration of these resource options in the IRP analysis. It should be noted that capital and fixed operating costs for future install years for the solar PV, wind, and BESS options are assumed to decline as these technologies mature, based on projections adapted from the NREL ATB. Similarly, first-year capacity factors for solar and wind resources are assumed to increase somewhat over the study horizon. Solar capacity factors are assumed to decline over the operating lives of these resources due to degradation of the panels and other equipment. Please see Section 9 for analysis of the all-in, lifecycle costs of the resource options shown in Table 7-4. As shown in Table 7-4, the various solar, wind, and BESS resource options reflect a range of sizes and initial construction costs (capital costs), operating and maintenance (fixed and non-fuel variable O&M) costs, and operating profiles (capacity factor), which are all considered in the detailed economic evaluations presented in Section 11 herein.

Table 7-4: New Solar, Wind, and BESS Resource Cost and Performance Estimates

Description	Nameplate Capacity (MW)	BPW Share (MW)	Capital Cost ($/kW)[1]	Fixed O&M Cost ($/kW-Yr)[1]	Capacity Factor (%)[2]	Operating Life (Years)
Solar PV	100	5	1,776	23.41	23.8	30
Wind	100	5	1,916	43.84	33.8	30
BESS (4-Hr)	100	5	2,453	61.32	N/A	20
BESS (8-Hr)	100	5	4,314	107.84	N/A	20

Notes:
1. All costs are in 2025 dollars and reflect a 2025 installation. Future years will vary due to the assumed technology cost curve (i.e., the trend of future costs on a constant dollars basis).
2. Capacity factor estimates reflect the first year of a 2025 installation. Future install years will tend to be slightly higher due to technology improvements. Capacity factors for solar resources are assumed to decline over their operating lives as a result of degradation.

Legend: Solar PV: Solar photovoltaic | BESS: Battery energy storage systems

The Inflation Reduction Act of 2022 ("IRA") includes various incentives associated with the development of solar PV, wind, BESS, SMR, and CCS energy resources. These include both investment tax credits ("ITC"), which reflect a tax credit amount based on a percentage of the installed cost of the resource, and production tax credits ("PTC"), which reflect a tax credit amount based on the amount of "production"—of energy, for generation technologies, and carbon dioxide sequestered, for CCS.

Table 7-5 presents a summary of how these incentives were assumed to apply for purposes of developing the cost estimates for these technologies considered in the IRP. It should be noted that the information in Table 7-5 is not being provided by nFront Consulting as an interpretation of the IRA or tax advice to BPW but instead reflects an estimate of how the tax incentive provisions of the IRA may apply to the various resources.

Table 7-5: Assumed Tax Credits[1]

Technology	Type	Value	Term	Eligibility Requirements[2]
Solar PV	PTC	$27.50/MWh (2022 $)	First 10 Years of Operation	Must begin construction by June 2026
Wind	PTC	$27.50/MWh (2022 $)	First 10 Years of Operation	Must begin construction by June 2026
BESS	ITC	30% of Capital Cost	N/A	Tax credits phase out for units with construction starts in 2034-36
SMR	ITC	30% of Capital Cost	N/A	Tax credits phase out for units with construction starts in 2034-36
CCS	PTC	$85/metric ton sequestered (2026 $)	First 12 Years of Operation	Must begin construction before 2033. Minimum capture rate of 18,750 metric tons of carbon dioxide ("CO_2") per year or 75% CO_2 capture rate.

Notes:
1. Information presented in this table is not being provided by nFront Consulting as an interpretation of the IRA or tax advice to BPW, but instead reflects an estimate of how the tax incentive provisions of the IRA may apply to these resource types.
2. Eligibility for tax credits is assumed to allow for reasonable construction timeframes—4 years for solar/wind, 2 years for BESS, and 10 years for SMR and CCS resources.

Utility-scale solar, wind, and BESS resources have been reflected in the IRP as 20-year PPA options based on estimates of the LCOE, or in the case of BESS resources, levelized cost of capacity ("LCOC"), from these resources over their useful lives.[7] Financing costs reflect the cost structure of a taxable developer and interest rates based on NREL's ATB, adjusted for interest rate trends. For solar and wind resources, it is assumed that some facilities brought online over 2026-2030 will be eligible for tax credits but that the proportion of facilities that are eligible will decrease over that timeframe. Hence, for purposes of the IRP, the rate for PPAs beginning in a year within that timeframe reflects a gradual transition from achieving the full benefit of tax credits in 2026 to no benefit of tax credits in 2031. This transition is intended to capture the competitive dynamics that may be experienced during this period in which some facilities that start construction by July 2026 are able to "safe harbor" tax credit eligibility, while others may not be able to do so.

The future cost curves reflected in the evaluation of PPAs for solar PV, wind, and BESS resources in this IRP are illustrated in Figures 7-1 through 7-3. Note that Figures 7-1 and 7-2 reflect that transition in the impact of tax credits over 2026-2031.

[7] The solar, wind, and BESS resources have been evaluated in this IRP as PPAs; subsequent evaluations would be necessary to determine whether BPW would pursue such options as PPAs or as resources owned by BPW.

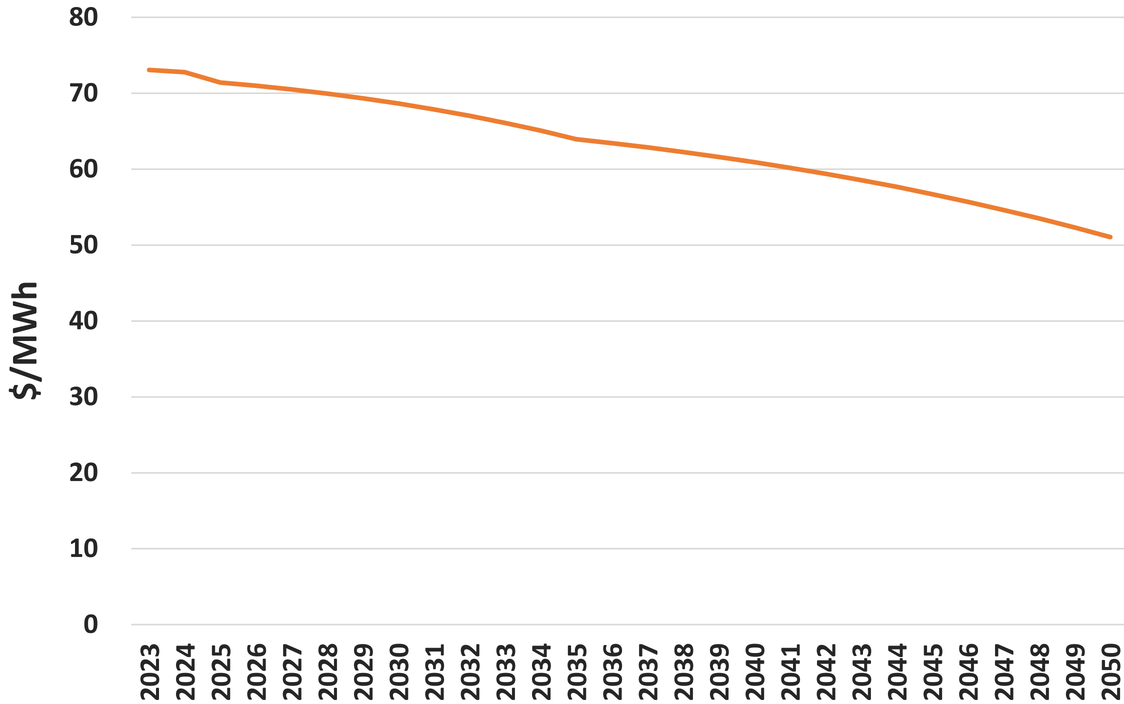

Figure 7-1. Future Solar PV PPA Cost Curve

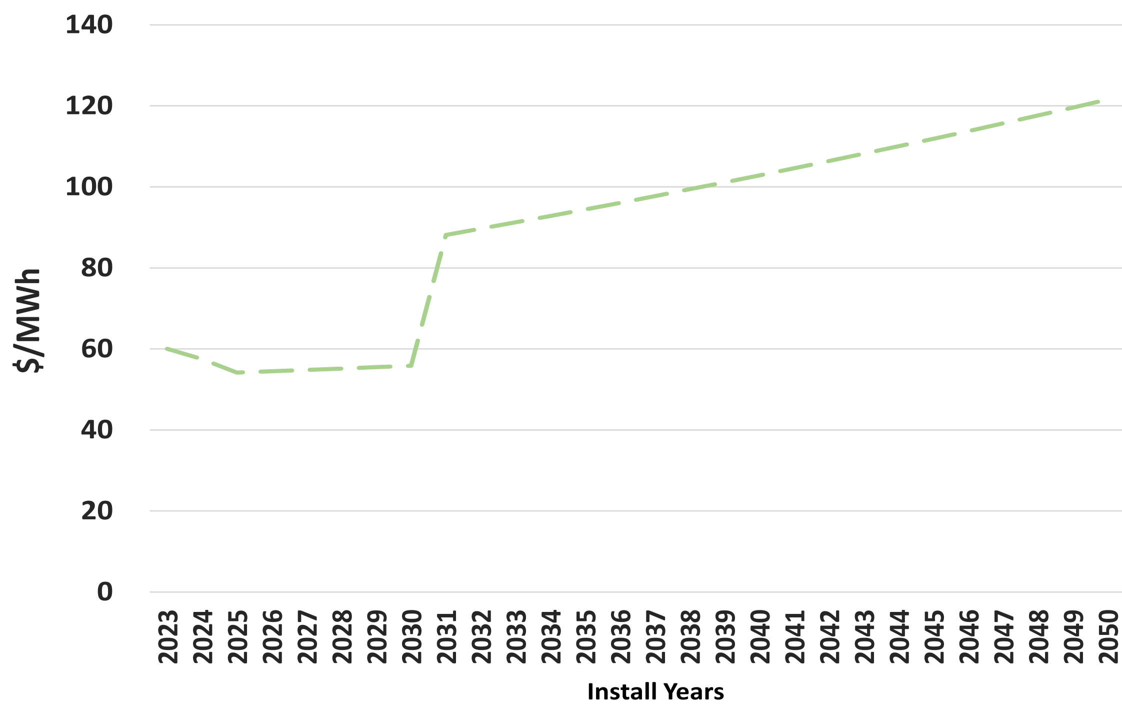

Figure 7-2. Future On-Shore Wind PPA Cost Curve

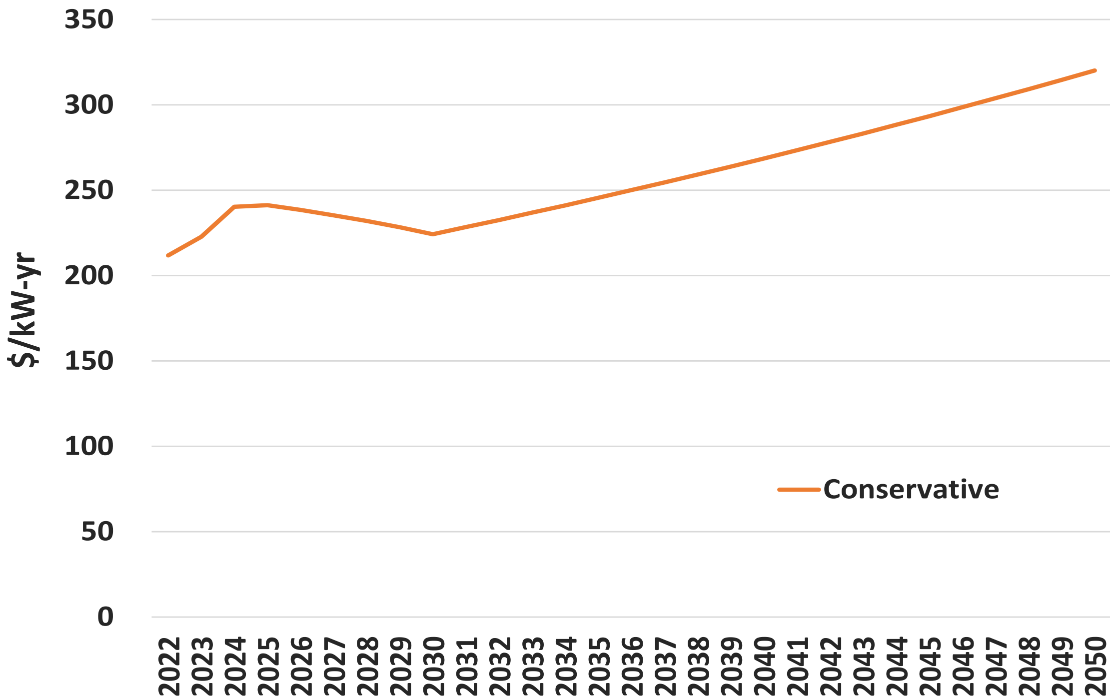

Figure 7-3. Future BESS PPA Cost Curve

8 FUEL PRICE FORECASTS

Forecasted fuel prices utilized in this IRP generally reflect an average of forecasts taken from the Energy Information Administration's 2025 Annual Energy Outlook ("AEO") Reference Case and obtained from S&P Global's August 2025 Forecast (which reflect consideration of NYMEX forward prices). The remainder of this section provides additional information related to the process used to develop the fuel price projections and presents the resulting fuel price projections. Importantly, to maintain consistency, the fuel price projections developed will be used in both the Power Market Price Forecast (Section 10) and the Resource Portfolio Optimization Analysis (Section 11) herein for purposes of evaluating the fuel cost of existing resources as well as new resource options.

8.1 Natural Gas Price Forecast

Henry Hub Price Forecast

A forecast of Henry Hub natural gas prices was developed utilizing NYMEX forward natural gas prices and the AEO forecast (published in April 2025) thereafter. Settled monthly NYMEX prices for Henry Hub for all trade days occurring during August 2025 were averaged to provide forecast monthly prices for the 2026-2029 period. Beginning with 2030, the AEO forecast of annual Henry Hub prices was assigned a monthly pattern based on relative monthly NYMEX forward prices through 2034, with the monthly pattern for 2034 applied to the AEO forecast annual price through the remainder of the study period. High and Low fuel price projections were developed based on the relative differences in the AEO Low and High Oil and Gas Supply Cases, respectively. Figure 8-1 depicts the forecasted Henry Hub prices developed for the IRP.

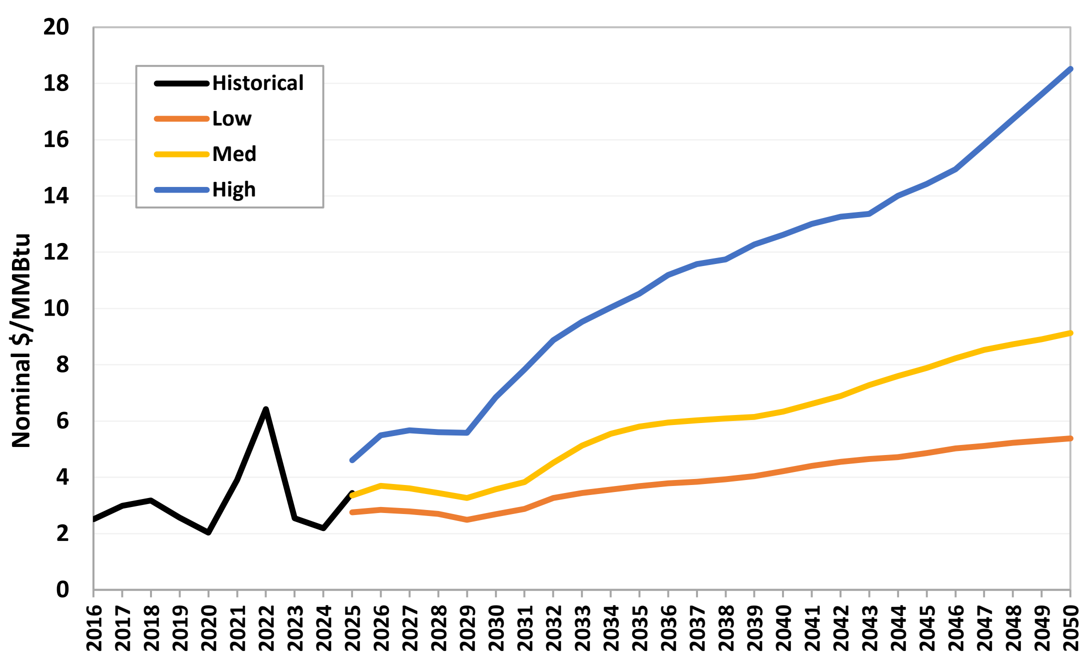

Figure 8-1: Annual Average Henry Hub Price Forecast (Nominal $/MMBtu)

Natural Gas Hub Price Forecast

For purposes of this IRP, long-term forecasts of natural gas prices were developed for major natural gas hubs throughout the MISO and PJM Balancing Authorities. Each MISO and PJM market area and a modeled BPW area were assigned natural gas prices based on the predominant natural gas hub within or near each area, as shown in Table 8-1 below.

Table 8-1: Natural Gas Hub Assignments

Market Area	Natural Gas Hub
Zeeland	Chicago Citygate
MISO IL (Zone 4)	Chicago Citygate
MISO IN (Zone 6)	Chicago Citygate
MISO MI (Zone 7)	Michcon Citygate
PJM AEP	TETCO M2
PJM ATSI	TETCO M2
PJM ComEd	Chicago Citygate

Natural gas prices modeled for each of the market areas were derived from forward prices utilizing NYMEX forward gas prices for each of the assigned natural gas hubs. For each natural gas hub, forward natural gas basis to Henry Hub based on the NYMEX forwards were utilized over the 2026-2034 period. After 2034, annual basis prices for each hub were held constant while maintaining the monthly shape. Figure 8-2 depicts the monthly forward price basis differential to Henry Hub, for each regional Hub over the forward price period for 2026-2050, and Figure 8-3 depicts the average annual basis for each calendar year for the same period. Figure 8-4 provides a summary of the average annual Henry Hub price forecasts and each modeled hub price.

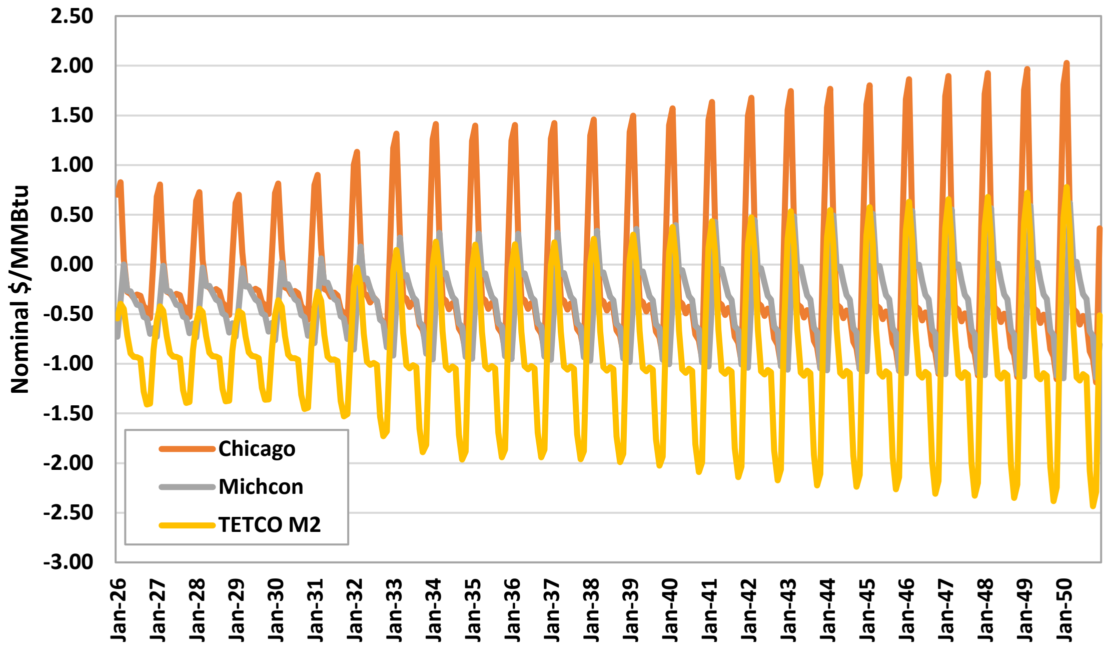

Figure 8-2: Monthly Forward Price Basis to Henry Hub (Nominal $/MMBtu)

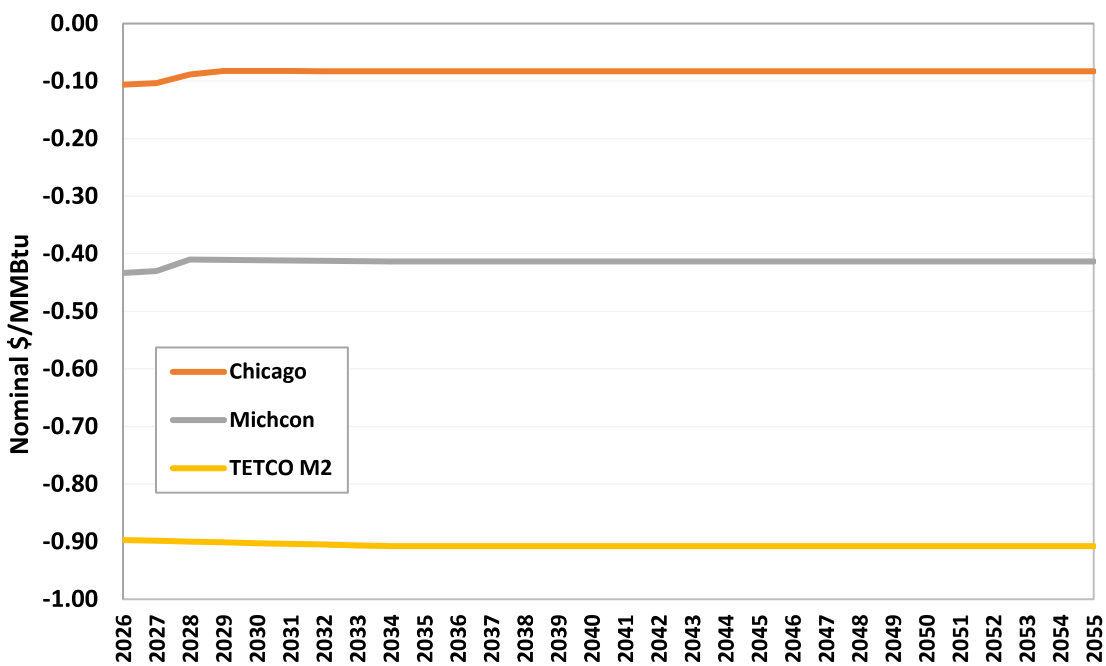

Figure 8-3: Annual Forward Price Basis to Henry Hub (Nominal $/MMBtu)

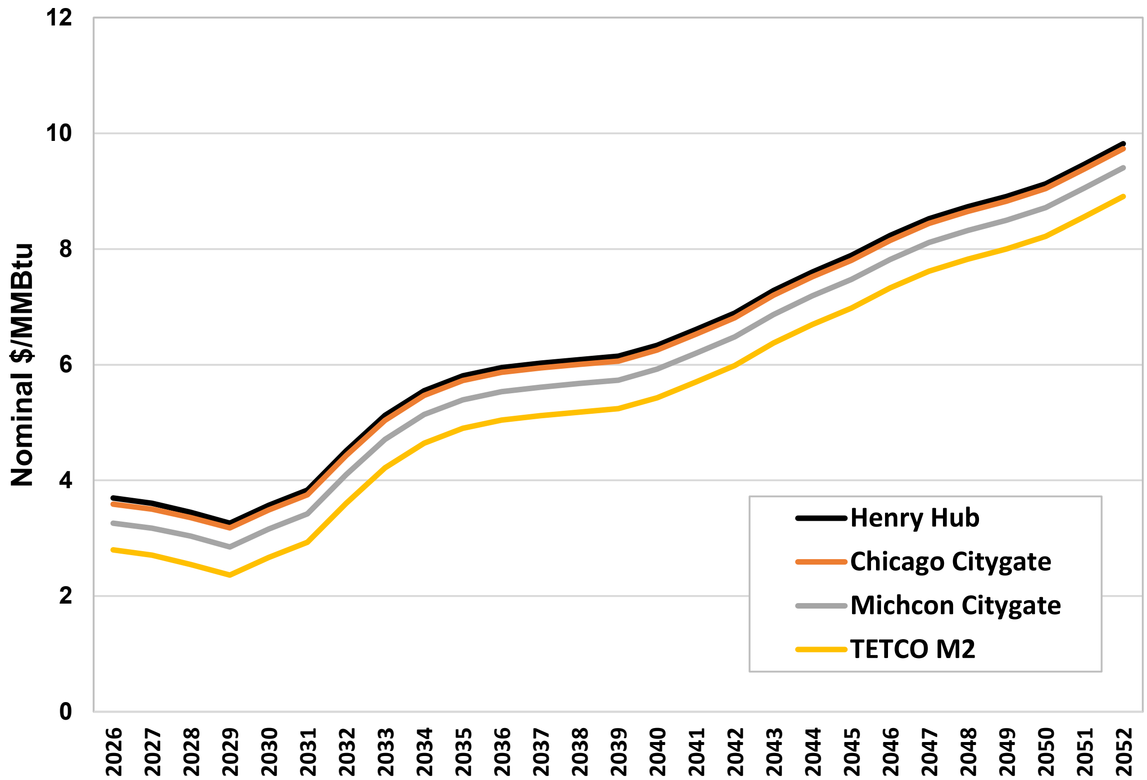

Figure 8-4: Annual Average Natural Gas Price Forecasts (Nominal $/MMBtu)

8.2 Coal Price Forecast

Forecasted coal prices are based on the average of basin price forecasts from the 2025 AEO for Central Appalachian, Northern Appalachian, Illinois, and Powder River basins. The forecasted prices for the Powder River basin, which is assumed to supply the Belle River coal plant, are shown in Figure 8-5 below.

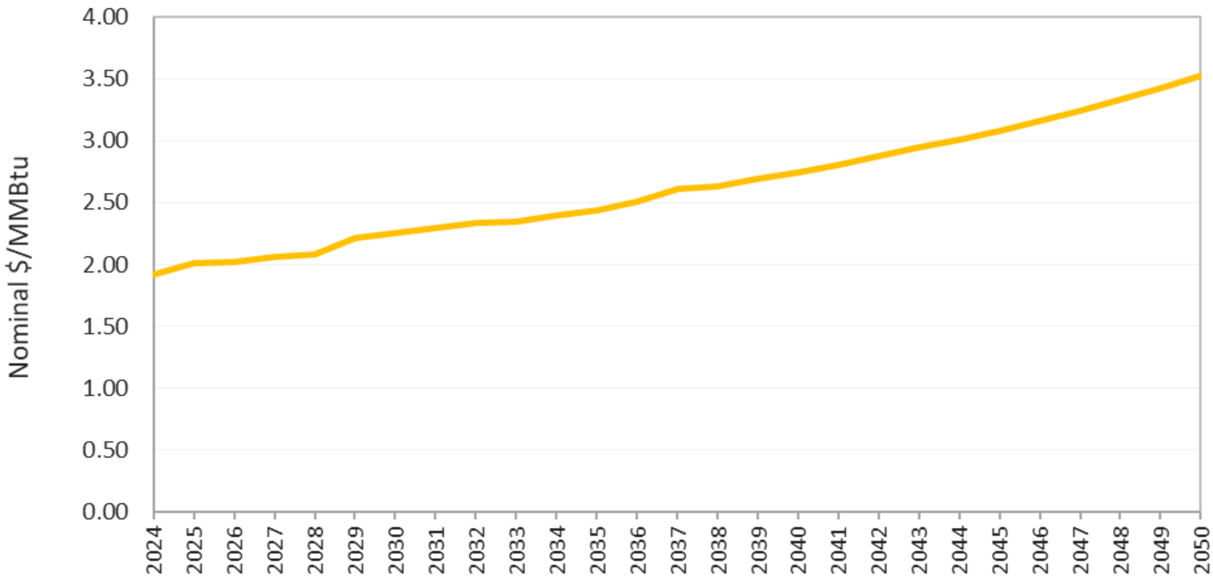

Figure 8-5: Forecast Powder River Basin Coal Prices (Nominal $/MMBtu)

8.3 Distillate Fuel Oil Price Forecast

Forecasted distillate fuel oil prices, shown in Figure 8-6 below, were based on an average of forecasts from the 2025 AEO.

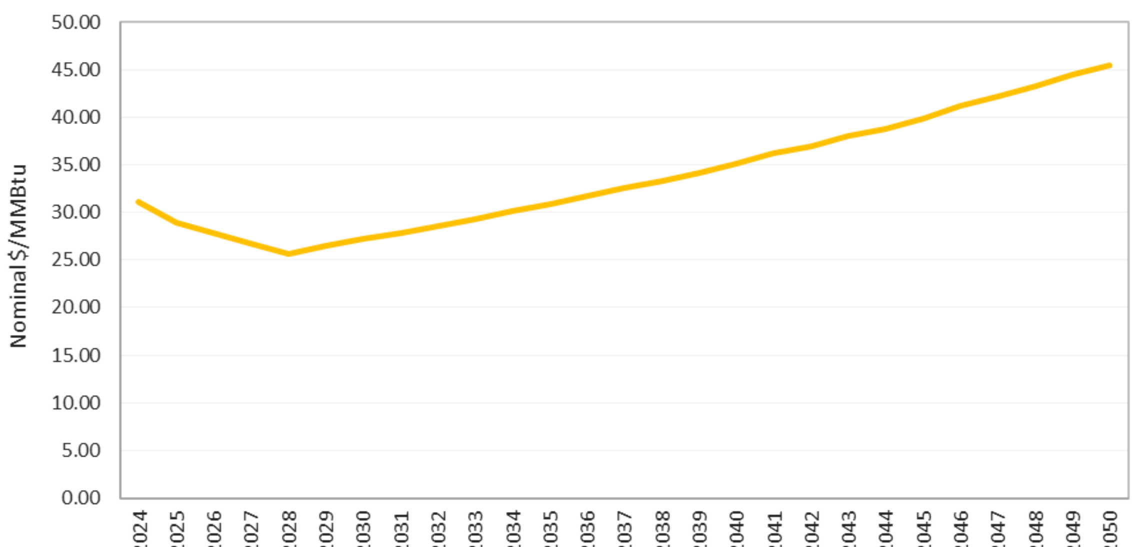

Figure 8-6: Forecast Distillate Fuel Oil Prices (Nominal $/MMBtu)

9 LEVELIZED COST OF ENERGY ANALYSIS

The levelized cost of energy ("LCOE") considers projected capital costs, operating costs, and fuel costs of resource alternatives on a present value basis to develop an average levelized cost across a range of potential resource operations (i.e., capacity factor, or amount of energy generated each year). Such an approach is widely used in the electric utility industry to compare the relative economics of resource options and to identify those resources that are consistently lower cost than other comparable resources within a likely range of operation for a class of resources (e.g., baseload, intermediate, and peaking). This process facilitates understanding of the relative economics between the different types of resource options. However, the LCOE analysis does not take into account how each resource may fit into BPW's overall portfolio to serve system load requirements, nor does it account for resource decisions that are made for the purposes of compliance with the RES and CES requirements of PA 235. The LCOE analysis reflects the economic parameters, natural gas price forecasts, and new resource cost and performance estimates presented in respective sections of this IRP.

9.1 LCOE Summary

Figure 9-1 illustrates the average levelized cost by resource type, shown for capacity factors ranging from 5 percent to 100 percent. Review of Figure 9-1 indicates the following:

- The new natural gas combined cycle ("1x1 CC") option has the lowest levelized cost at higher capacity factors.
- The large simple cycle combustion turbines ("Large CT") has the lowest levelized cost at lower capacity factors.
- Reciprocating internal combustion engines ("RICE" and "RICEx2") become economic at higher capacity factors and are seen to be more economic than new simple cycle aeroderivative turbines ("Small CT").
- Small modular reactors ("SMR") are shown to have higher levelized costs at all capacity factors.
- Comparison of the LCOE of non-dispatchable resources such as solar and wind and limited dispatch BESS to the LCOE of dispatchable resources (such as natural gas and SMR) is not a relevant comparison as such comparison does not account for the difference in firm capacity associated with each resource type.

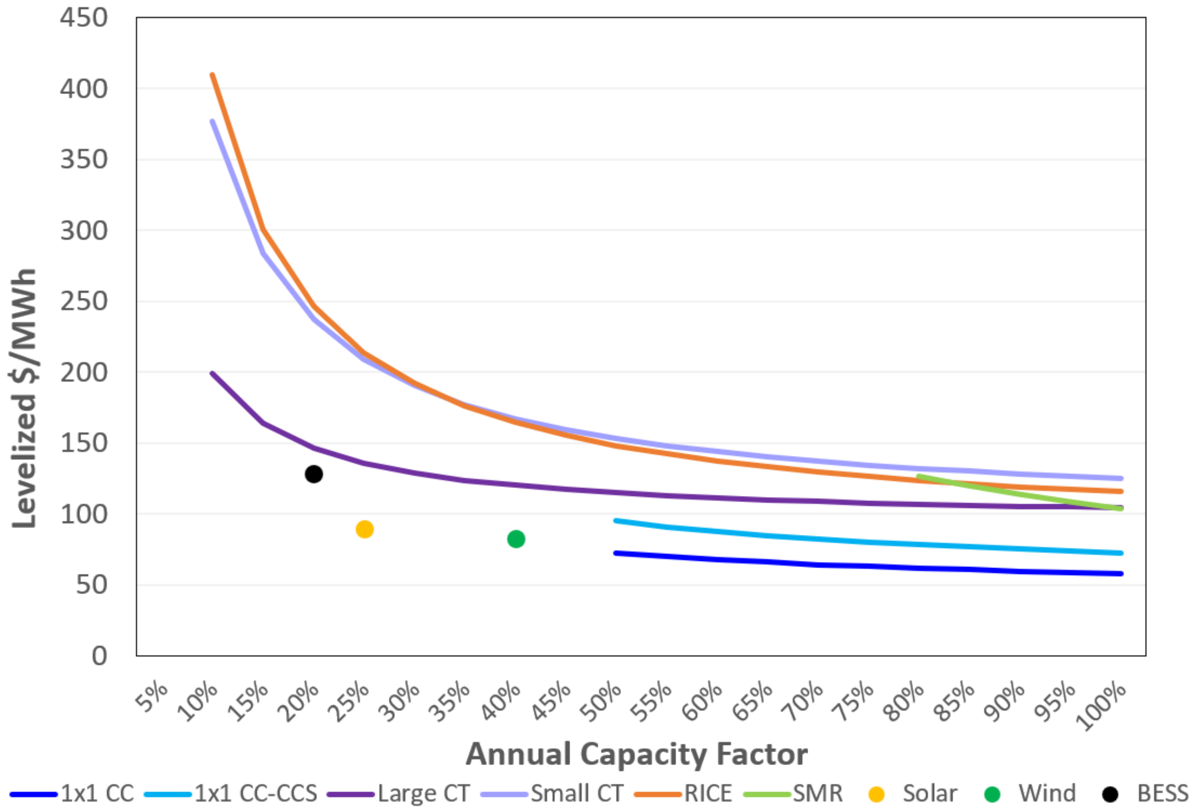

Figure 9-1: Average Levelized Cost by Capacity Factor and Resource Type

10 POWER MARKET PRICE FORECAST

MISO zonal market price forecasts were developed for use in the evaluation of BPW resource options in this IRP. Market prices forecasts were developed for the two scenarios discussed previously—one scenario that assumes no state requirements pertaining to renewable or clean energy production are in effect throughout the study period ("BAU"), and a second scenario that assumes the requirements of Michigan's Renewable Energy Standard ("RES") and Clean Energy Standard ("CES") remain in effect over the study period ("PA 235"). The two different forecasts of power market prices were developed in recognition that the market conditions between the two scenarios would be materially different.

The power market price forecasts were developed using the EnCompass™ simulation model and the vendor endorsed Horizon Energy regional database for MISO. Assumptions for fuel prices and new market resource options used for the market modeling were consistent with the fuel price forecasts and characterization of new resource options discussed previously in this IRP.

10.1 Market Model Regions

The power market model used to develop the market prices was simulated for the MISO and PJM Balancing Authorities. While the simulation was performed for all of MISO and PJM, the market forecasts were focused on relevant load zones within those Balancing Authorities for BPW. Figure 10-1 identifies the MISO and PJM load zones most relevant to the IRP considering the location of BPW's electric system within MIZO Zone 7 and BPW's power assets.

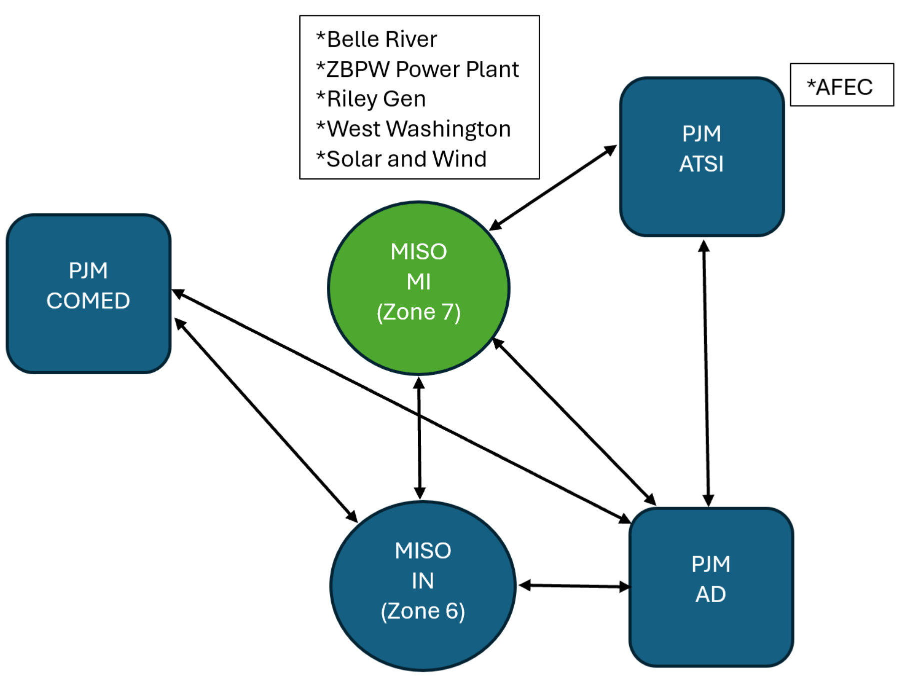

Figure 10-1: Market Model Load Zones

10.2 Fuel Prices and New Resource Options

The underlying assumptions, such as fuel prices and resource options, that form the basis of the power market model and IRP model are internally consistent. However, for purposes of the market price forecast, new resource additions were simulated utilizing assumptions for large utility-scale resources, utilizing the market planning capabilities of the EnCompass^{TM} model to identify optimum resource decisions. Please refer to Section 7 (new resource options) and Section 8 (fuel price forecasts) of this IRP for more details regarding these assumptions.

10.3 Michigan Public Act 235

As discussed previously, the IRP considers a scenario in which BPW meets the RES and CES requirements of PA 235, which are generally outlined as follows. Importantly, the RES and CES requirements listed below are enforced in the power market scenario that reflects compliance with PA 235.

- Minimum of 15 percent renewable energy through 2029
- Minimum of 50 percent renewable energy in 2030 through 2034
- Minimum of 60 percent renewable energy in 2035 and thereafter
- Minimum of 80 percent clean energy in 2035 through 2039
- 100 percent clean energy in 2040 and thereafter
- Energy Storage target of 2,500 MW by 2030 and thereafter[8]

Per PA 235, the technologies that meet the RES requirements include biomass, landfill gas, solar, and wind while the technologies that qualify towards meeting the CES requirements include all renewable energy resources as well as hydro, nuclear, and natural gas combined cycle with CCS.

10.4 Market Power Price Forecasts

Capacity expansion portfolio optimizations were performed for BAU and PA 235 to determine the optimal resource portfolio for each load zone within the MISO and PJM Balancing Authorities. The resulting MISO Zone 7 resource portfolio for Scenario A and for Scenario B are shown in Figure 10-2 and Figure 10-3, respectively. Additionally, the resulting MSIO Zone 7 total power supply costs for Scenario A and Scenario B are shown in Figure 10-4 and 10-5, respectively.

[8] The PA 235 energy storage target was only considered for the market power evaluations and not for BPW's new resource evaluations.

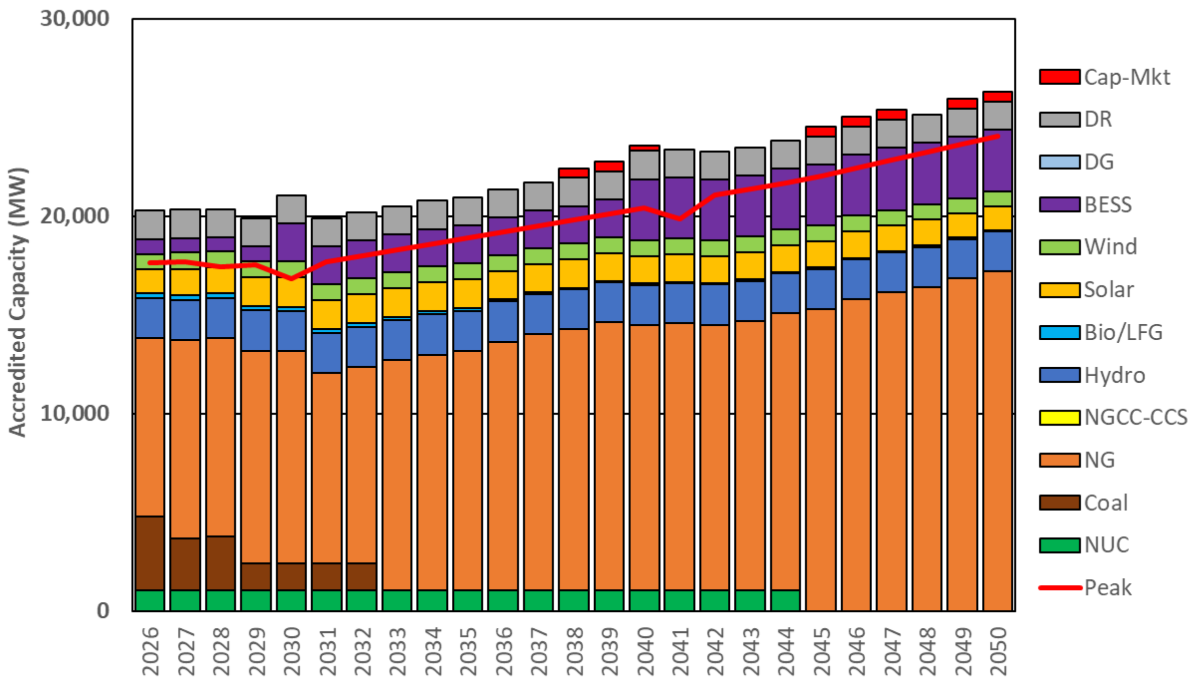

Figure 10-2: BAU – MISO Zone 7 Resource Portfolio

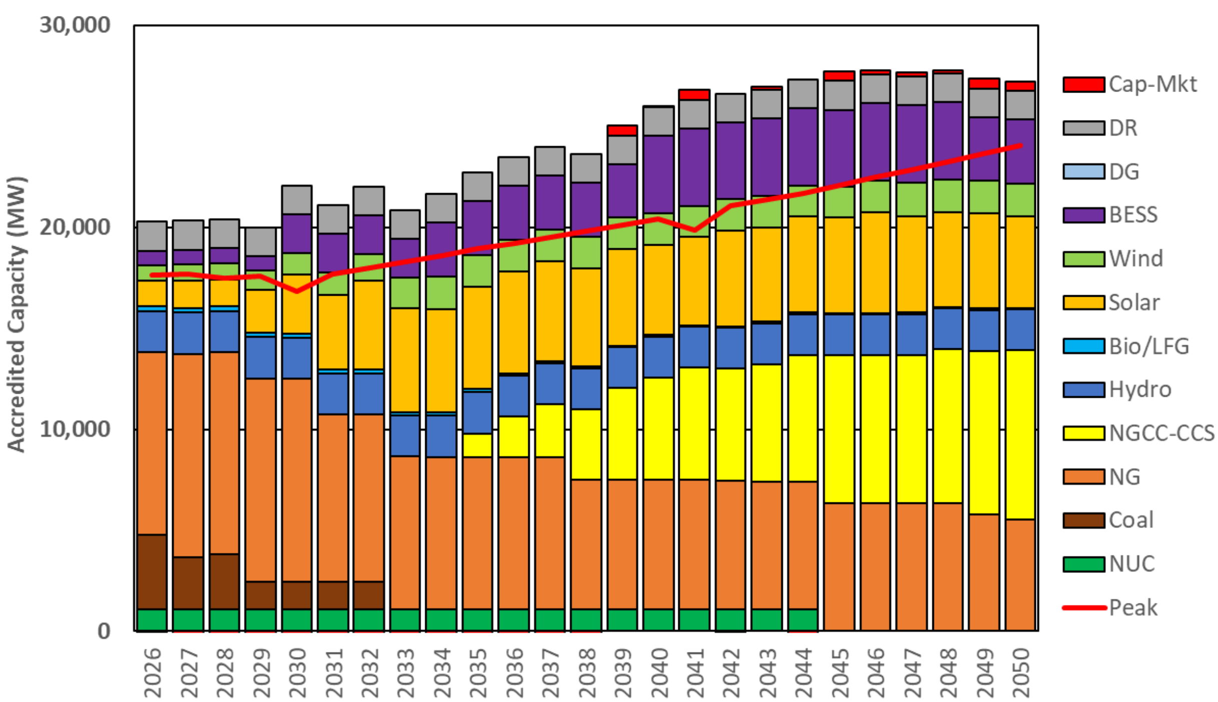

Figure 10-3: PA 235 – MISO Zone 7 Resource Portfolio

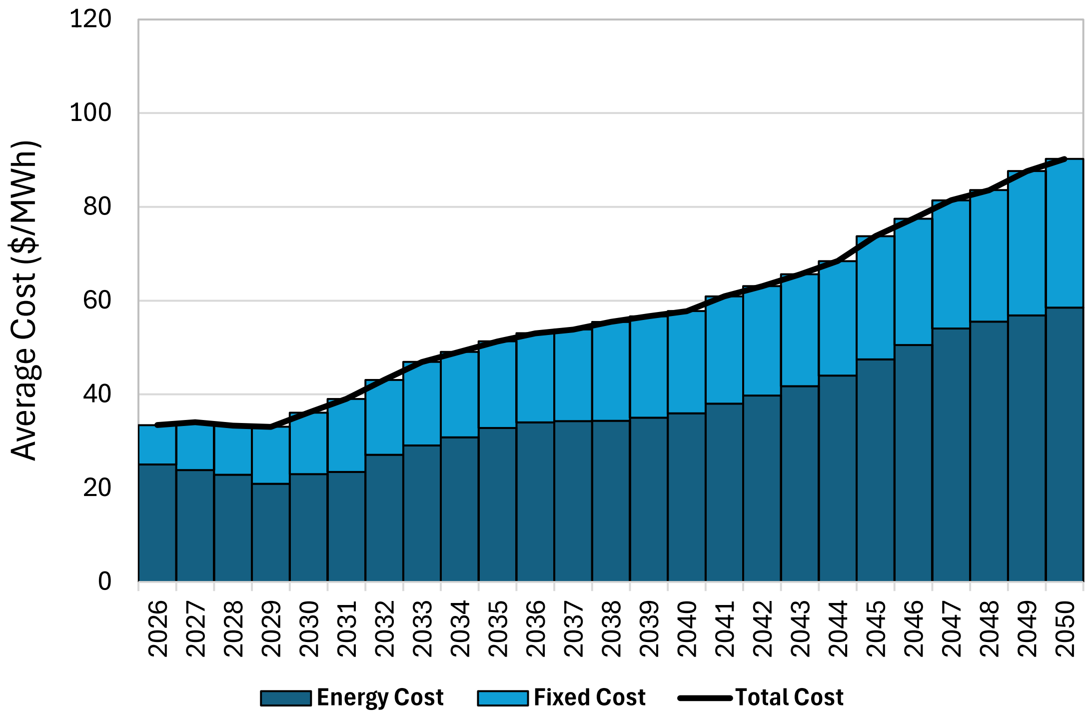

Figure 10-4: MISO Zone 7 Power Supply Costs – BAU

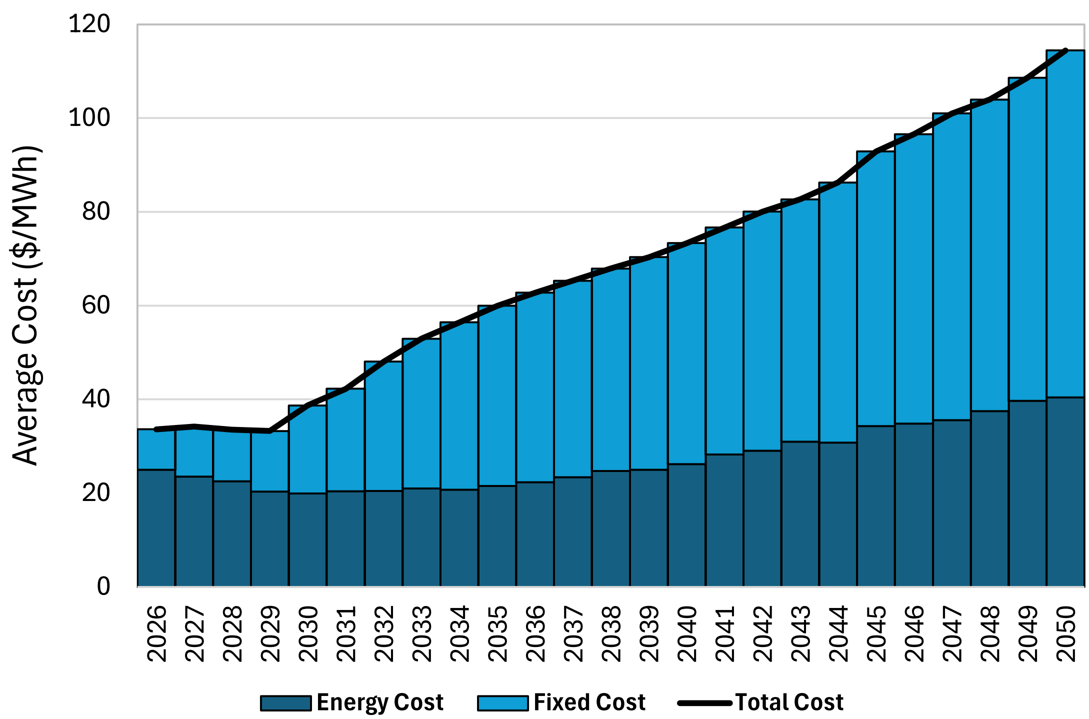

Figure 10-5: MISO Zone Power Supply Costs – PA 235

As evidenced by comparison of Figure 10-4 and 10-5 above, the long-term all-in cost of power supply in MISO Zone 7 is higher for a resource portfolio that complies with the requirements of PA 235. The divergence in costs begins in the early 2030s, coinciding with the need to construct higher-cost renewable and clean energy resources to satisfy PA 235 requirements. In addition, Figure 10-3 demonstrates that new resources are installed above the capacity requirements indicating that additional conventional dispatchable resources are necessary to ensure sufficient energy availability across all hours of the year. This combination of higher-cost clean energy additions and the continued need for firm, dispatchable capacity contributes to the elevated long-term cost trajectory observed under the PA 235-compliant portfolio.

Hourly production modeling simulations were then performed for the resulting BAU and PA 235 resource portfolios to develop the hourly market price forecasts. The forecasted on-peak and off-peak energy market prices are illustrated in Figures 10-6 and 10-7, respectively. It is important to note that while the market price for energy is lower in the PA 235 scenario due to the oversaturation of renewable generation in MISO Zone 7, any market energy that is purchased would not contribute toward a utility's compliance obligations under PA 235. As a result, reliance on lower-priced market energy does not offset the need to procure or build qualifying clean energy resources, effectively making such purchases an additional cost to the overall power supply portfolio.

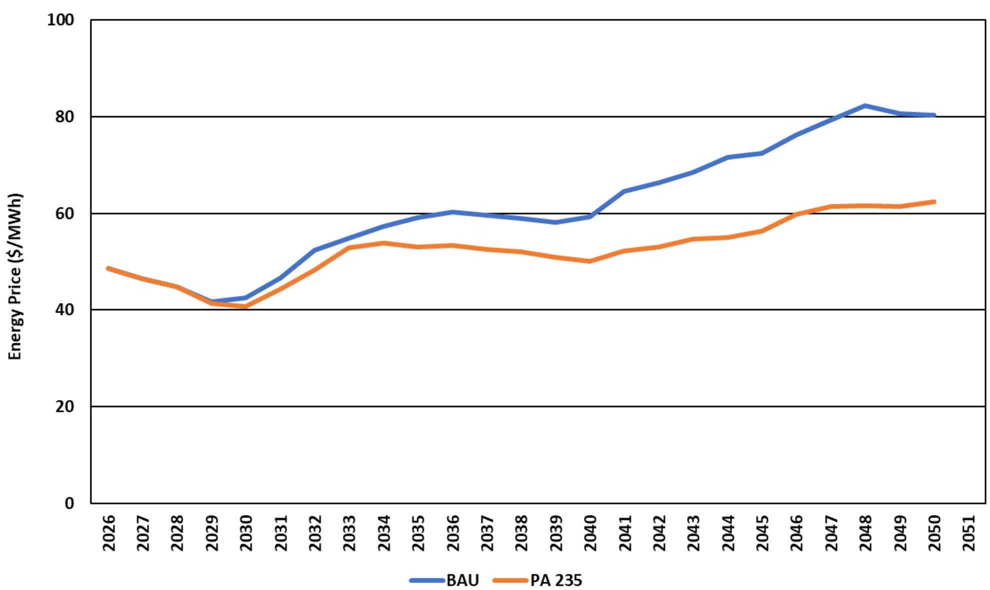

Figure 10-6: MISO Zone 7 On-Peak Pricing (Nominal $/MWh)

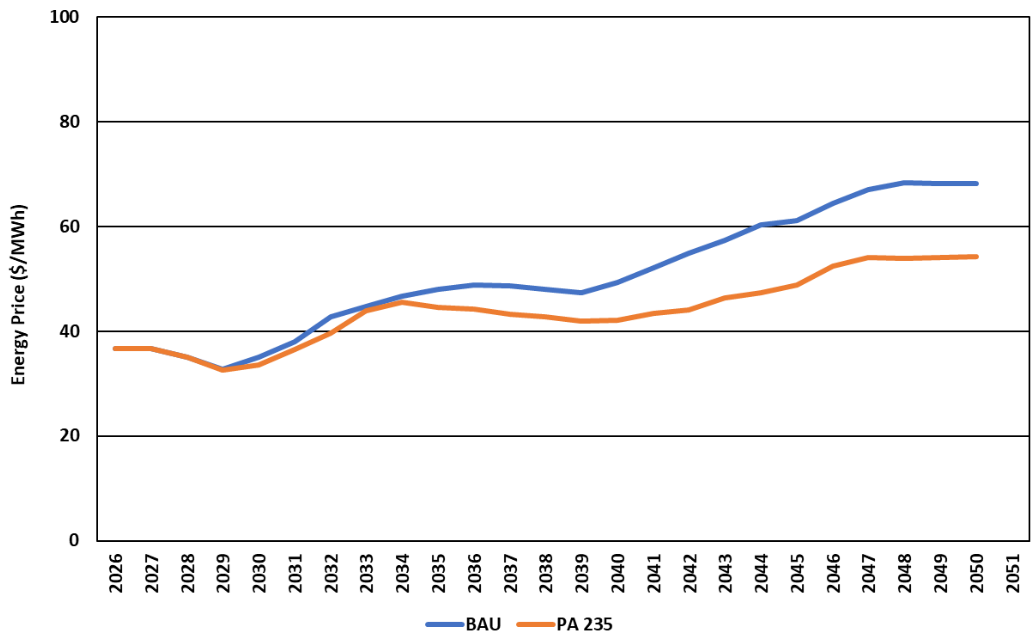

Figure 10-7: MISO Zone 7 Off-Peak Pricing (Nominal $/MWh)

Figure 10-8 compares average hourly price curves for the BAU and PA 235 scenarios for 2050. The figure shows hourly prices for four representative months (January, May, August, and September) selected to reflect the four seasons. Prices represent average hourly values within each selected month, rather than a seasonal average across all months. An important distinction for the future resource portfolio under the PA 235 scenario is the amount of solar PV and wind generation that is needed to meet the RES and CES standards. Due to the non-dispatchable nature of these renewable resources and the fact that solar PV is available only during the day, as renewable resource implementation increases, projected hourly market prices will exhibit greater price variability throughout the day, reduced pricing during daytime periods, and increased divergence across the seasons.

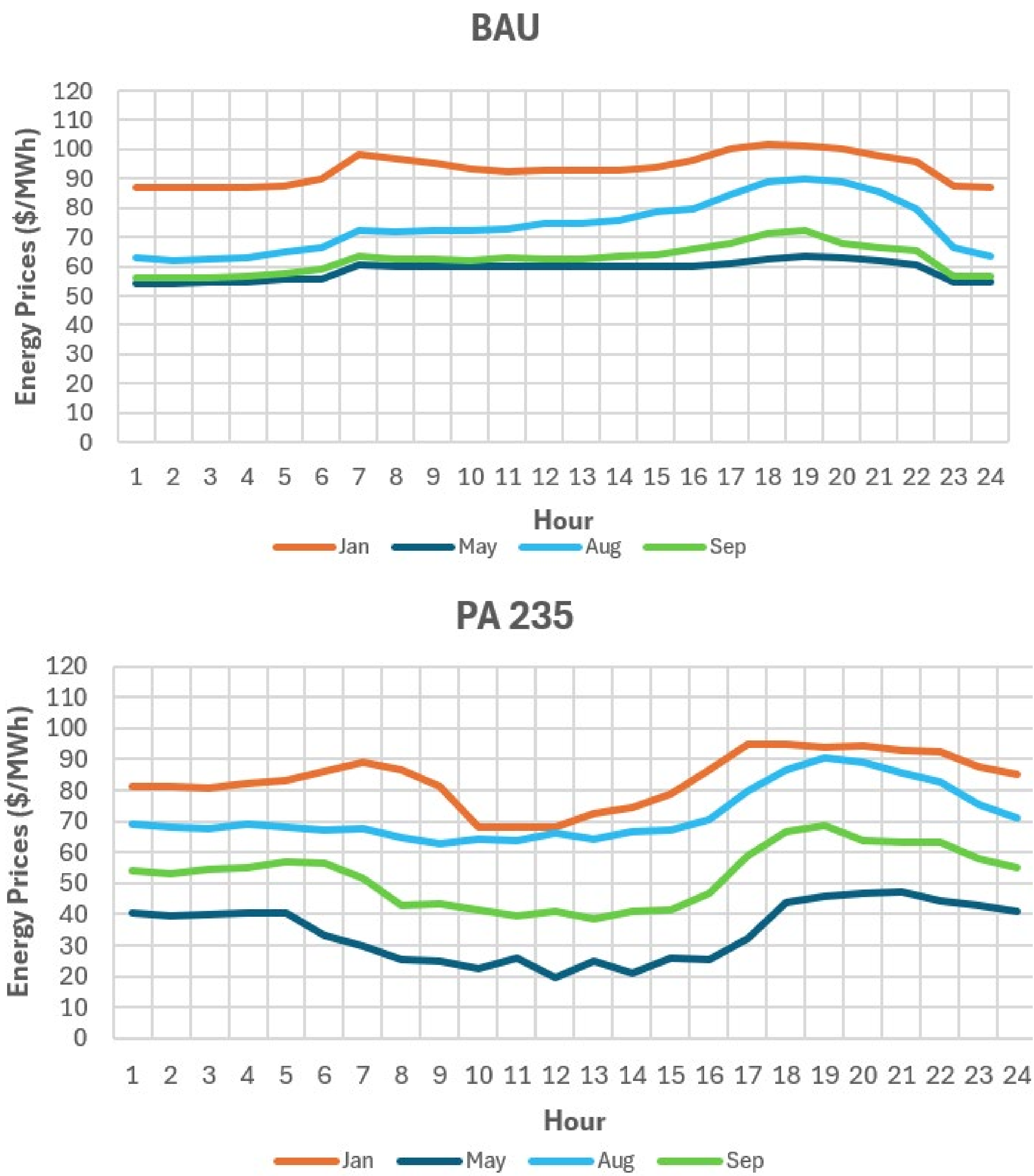

Figure 10-8: MISO Zone 7 Hourly Market Prices – 2050 (Nominal$)

11 RESOURCE PORTFOLIO OPTIMIZATION ANALYSIS

The IRP modeling approach utilized for this IRP relied upon the EnCompass™ power systems simulation model to optimize BPW's power supply portfolio using a common set of assumptions about the future. The EnCompass™ model provides significant flexibility with respect to the modeled study period and chronology used to simulate commitment and dispatch. The methodology and resulting portfolio optimization analysis are discussed in the remainder of this section.

11.1 Description of EnCompass

The EnCompass™ power market and portfolio simulation model, marketed by Anchor Power Solutions/Yes Energy, is an industry standard, generation simulation model that has been adopted by electric utilities and consultants throughout the U.S. for use in IRP studies and regulatory filings. The EnCompass™ model is a mixed integer linear programming ("MILP") model capable of optimizing generation expansion decisions; simulating generating resource commitment, dispatch, and ancillary service operations; simulation of renewable resources and energy storage; wholesale transactions and market clearing prices; and scenario and probabilistic analyses. A unique advantage of the EnCompass™ model is the ability to model wholesale markets (as described in Section 10 of this IRP report) and generation expansion decisions for BPW using assumptions and resource simulations that are internally consistent, allowing for evaluation of resource portfolios for BPW that include both self-build generating resources and wholesale power transactions across a range of assumptions, while being assured that prices and costs for fuel, market transactions, and all resources options are being modeled in a manner that is fully consistent.

11.2 Portfolio Analysis

nFront Consulting utilized EnCompass™ in order to determine the optimum selection of new resource options, in combination with BPW's existing resources, to reliably and economically meet forecast energy requirements for the various scenarios and sensitivities discussed previously in this IRP report (this process is referred to herein as "resource development"). The resource development process reflected consideration of BPW's forecasted peak demand and energy requirements, existing generating resources (internal resources, generation entitlements, and renewable PPAs), projected capacity needs to satisfy MISO seasonal PRM requirements, fuel price forecasts, power market prices, economic and financial parameters, and new resource options, all as discussed previously in this IRP. For each scenario, portfolio strategy and sensitivity evaluated as part of the resource development process, EnCompass™ used a present value revenue requirements approach to identify the least-cost resource plan over the IRP study period that meets the RES, and CES requirements (as applicable) while generating sufficient energy to meet forecast energy requirements and ensuring there is sufficient firm seasonal capacity to meet MISO's seasonal PRM requirements.

The present value of revenue requirements ("PVRR") approach is typical for use in electric utility resource planning and provides a means to compare portfolios on a total system costs basis over the full IRP study period, while appropriately reflecting variations in resource timing. The PVRR analysis is also used to illustrate how portfolios differ by cost category, such as the extent of capital investments, fixed or indexed costs and pricing, and exposure to potentially volatile fuel and market prices.

The PVRR evaluations reflected in this IRP consider the following types of costs.

- Fixed and non-fuel variable O&M costs for existing resources and new resource options
- Capital costs for new unit additions
- Fuel costs for existing resources and new resource options
- Costs for sequestration of carbon dioxide ("CO_2") (for resources with carbon capture and sequestration)
- Transmission service costs for new resources located outside of BPW's service territory
- Costs associated with new PPAs
- Costs associated with new energy market purchases

It should be noted that the PVRR evaluations do not consider fixed costs associated with BPW's existing bilateral market contracts, existing PPAs, general and administrative type costs, or any other fixed costs associated with the BPW electric system other than estimated fixed O&M costs for existing units, as such costs are considered "sunk costs" that would not change nor influence the resource and dispatch decisions reflected in this IRP.

11.3 Results of the Portfolio Analysis

The IRP considers BPW's resource needs in order to reliably and economically meet the energy requirements of its customers under two different scenarios —one scenario that assumes that no state requirements pertaining to renewable or clean energy production are in effect throughout the study period ("BAU"), and a second scenario that assumes the requirements of Michigan's Renewable Energy Standard ("RES") and Clean Energy Standard ("CES") remain in effect over the study period ("PA 235"). Within each scenario, multiple portfolio strategies were evaluated to reflect different approaches to meeting future resource need and reliability requirements. These portfolio strategies include: an economically optimized portfolio in which large-frame thermal resources are available beginning in 2030; a delayed large-frame portfolio in which large-frame resources are first available in 2035; and a local generation portfolio that limits resource additions to local generation and renewable PPA resources.

Finally, the resulting portfolios were simulated though a series of alternative assumptions for key variables to assess the sensitivity of portfolio power supply costs across the portfolio strategies. The scenarios, portfolio strategies, and sensitivities evaluated in this IRP are summarized as follows:

Category	Case	Description
Scenario	Business As Usual (”BAU”)	No State Requirements for PA 235
	Public Act 235 (”PA 235”)	Compliance with PA 235
Porfolio Strategy	Economically Optimized	Large-frame thermal resource available as early as 2030
	Large Units Available 2035	Large-frame thermal resource available starting 2035
	Local Generation	Only local generation and renewable PPA resources available
Sensitivity	Low Load Growth	Assumes lower load growth
	High Load Growth	Assumes higher load growth
	Low Fuel Price	Assumes lower fuel prices
	High Fuel Price	Assumes higher fuel prices

The remainder of this section summarizes the results of the EnCompass™ resource development process for each of the scenarios, portfolio strategies, and sensitivities discussed above and includes key takeaways based on review of the results of the analysis. The summary-level information includes the following:

- Figures that illustrate the utilization (generation) of each existing BPW resource as well as the new resources added through the expansion planning evaluation for BAU and PA 235 (Sensitivity results included in Appendix A).
- Figures that illustrate categories of capacity, including existing resources, new renewable resources, new natural gas combined cycle resources, new BESS, new natural gas combined cycle with CCS, and new peaking resources for BAU and PA 235 (Sensitivity results included in Appendix A).
- Tabular summary of the types of the changes in capacity (retirements and new unit additions), categorized by types of capacity, over specific time periods for BAU and PA 235 (Sensitivity results included in Appendix A).
- Tabular summary of the PVRR for BAU and PA 235 (Sensitivity results included in Appendix A).

Generation by Resource

Figures 11-1 through Figure 11-6 illustrate the annual generation by resource type for the BAU and PA 235 scenarios and the respective portfolio strategies as described above. It should be noted that all scenarios and portfolio strategies reflect the same assumptions related to assumed retirement dates for existing BPW generating resources, expiration dates for existing PPAs, and expiration dates for bilateral purchases. Retirement of any of BPW’s other existing generating units was not considered in this IRP.

Review of the BAU Portfolios (Figure 11-1 through Figure 11-3) indicates the following:

- The Economically Optimized portfolio relies on NGCC to provide the majority of energy, primarily displacing market purchases, Belle River, and local peaking generation.
- The Large Units Available 2035 portfolio strategy utilizes market energy and local peaking resources supply a greater share of energy in the near term, with NGCC generation increasing later in the study period once large-frame units become available.
- The Local Generation portfolio strategy increases reliance on market purchases due to the available local resources having higher variable energy costs, making market energy more economic for energy supply.

Review of the PA 235 Portfolios (Figures 11-4 through Figure 11-6) indicates the following:

- The Economically Optimized portfolio strategy replace much of the NGCC generation observed in BAU with wind, solar, and BESS in the early years, with NGCC-CCS providing a significant share of energy beginning around 2035.
- The Large Frame Units Available 2035 portfolio strategy relies more on market purchases in the near term, while renewable and NGCC-CCS generation levels in the later years are broadly consistent with the other portfolio strategies under this scenario.
- The Local Generation portfolio strategy shifts generation toward wind, solar, and BESS, displacing NGCC-CCS generation observed in the Economically Optimized and Large Frame Units Available 2035 portfolio strategies.
- The Local Generation portfolio strategy shows greater market purchases as well as more excess generation above load requirements.
- Across all portfolio strategies, the PA 235 portfolios result in lower reliance on market energy overall, as market purchases do not contribute to meeting RPS and CES requirements under PA 235.
- The analysis does not include the addition of any small modular reactor (”SMR”) resources under the BAU or PA 235 scenarios.

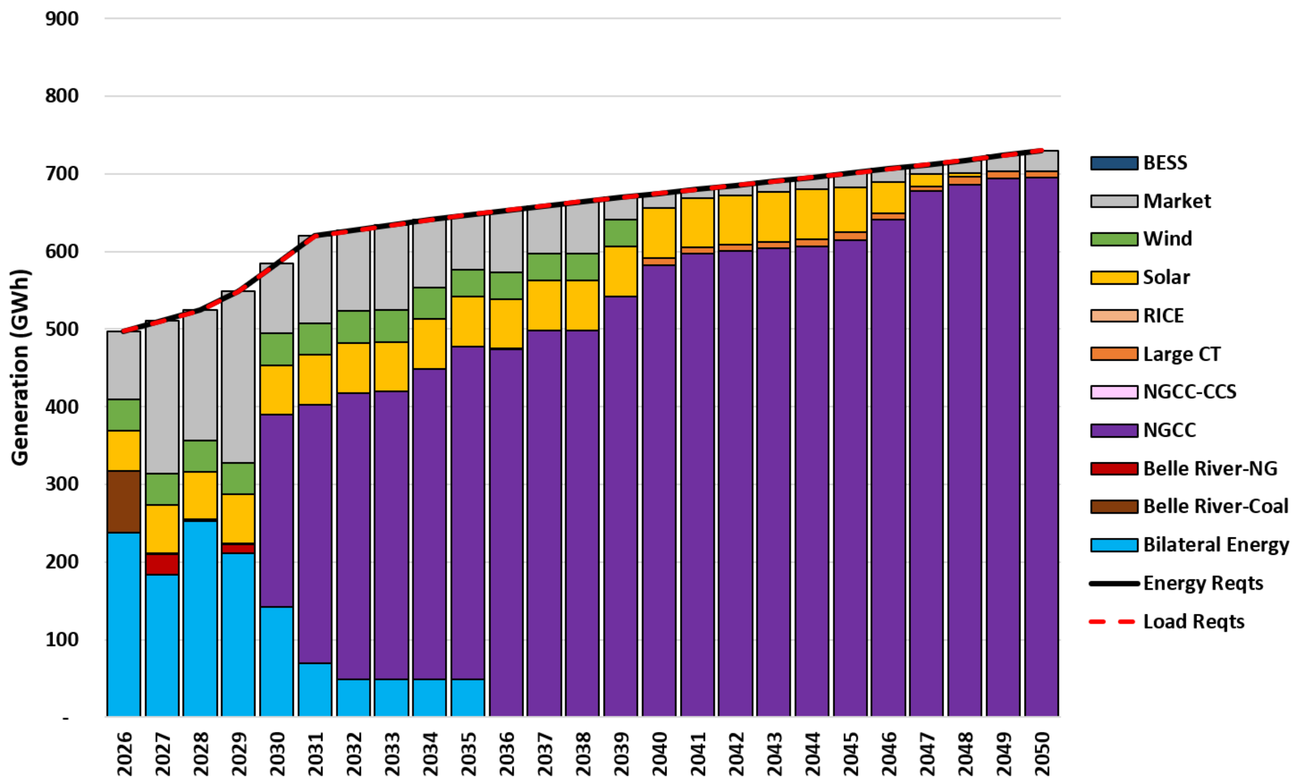

Figure 11-1: Energy Generated by Resource Type – BAU Economically Optimized

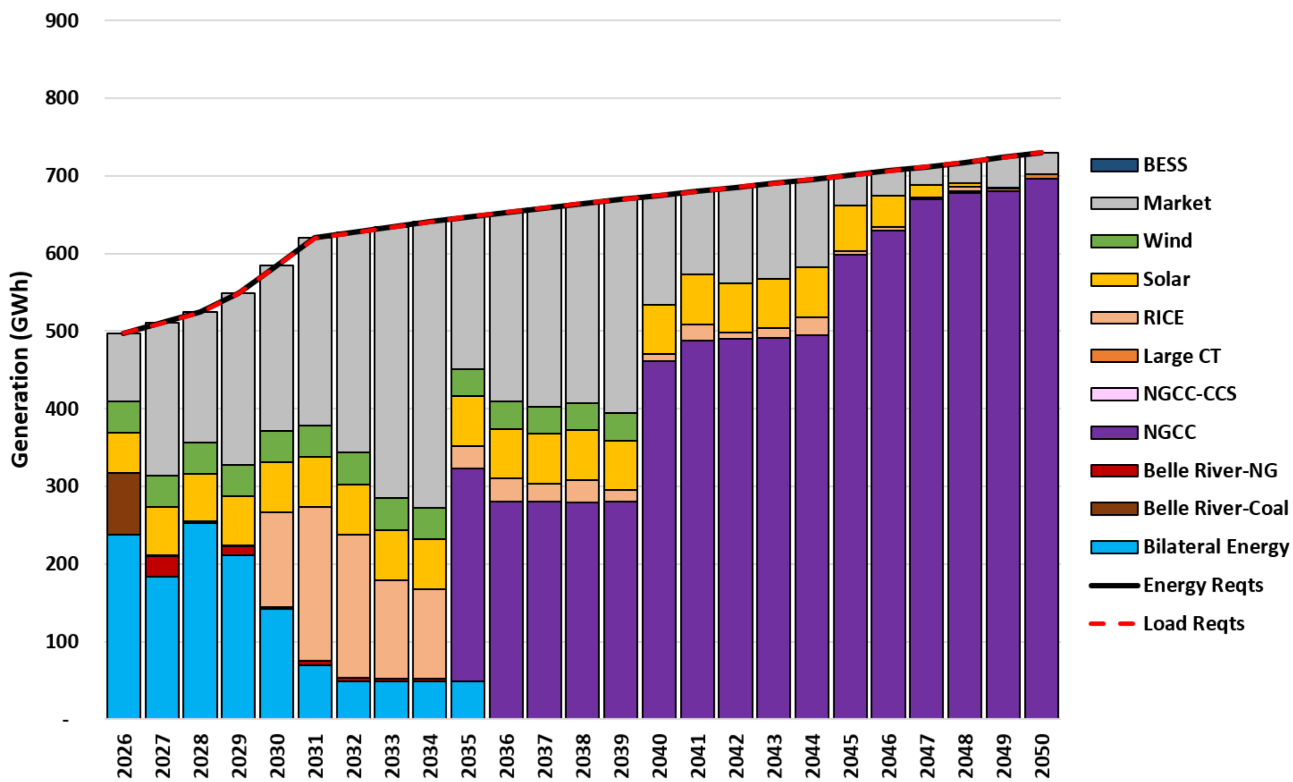

Figure 11-2: Energy Generated by Resource Type – BAU Large Units Available 2035

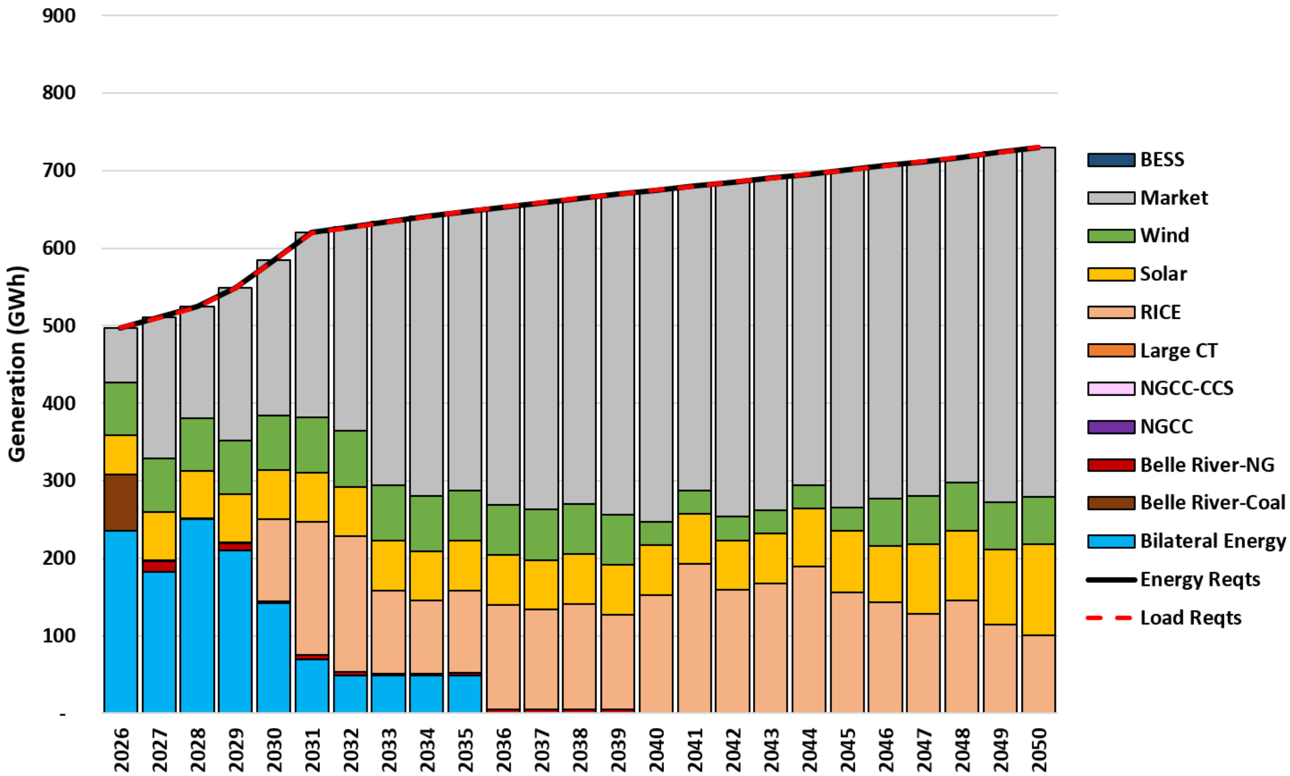

Figure 11-3: Energy Generated by Resource Type – BAU Local Generation

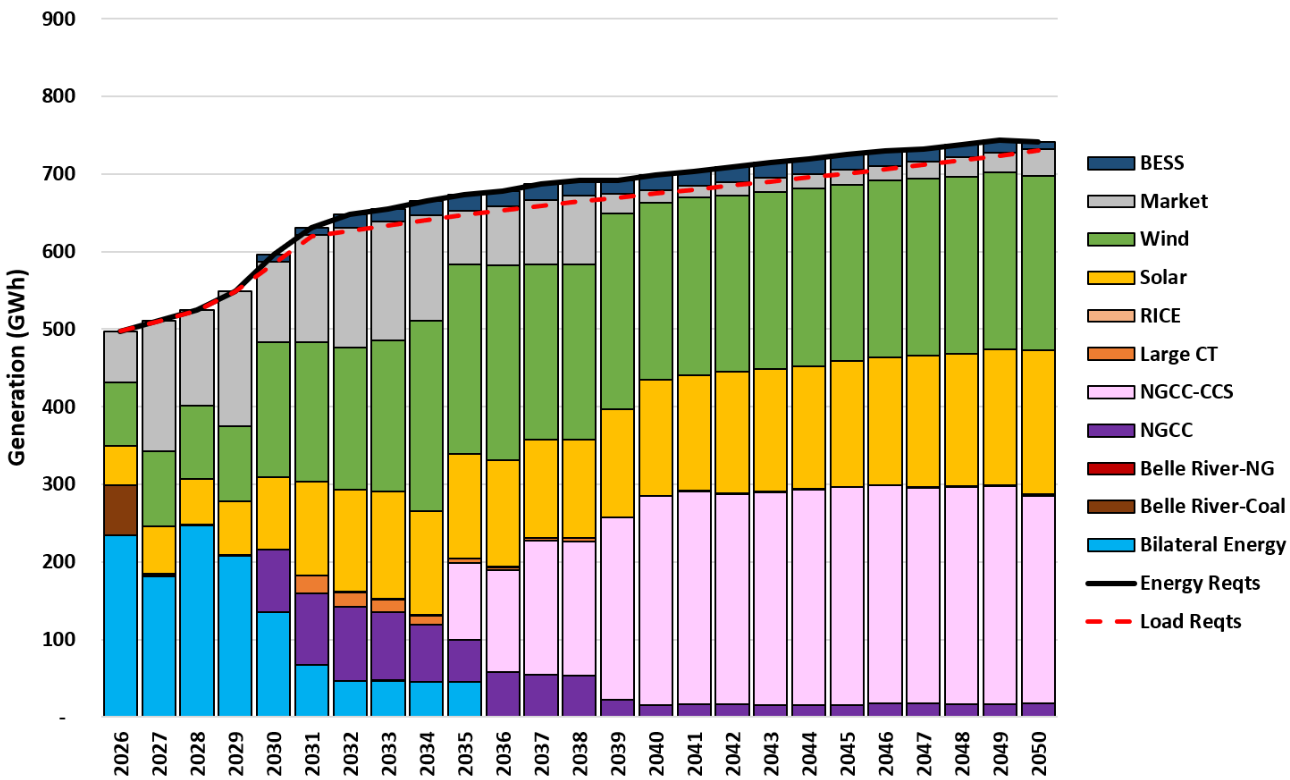

Figure 11-4: Energy Generated by Resource Type – PA 235 Economically Optimized

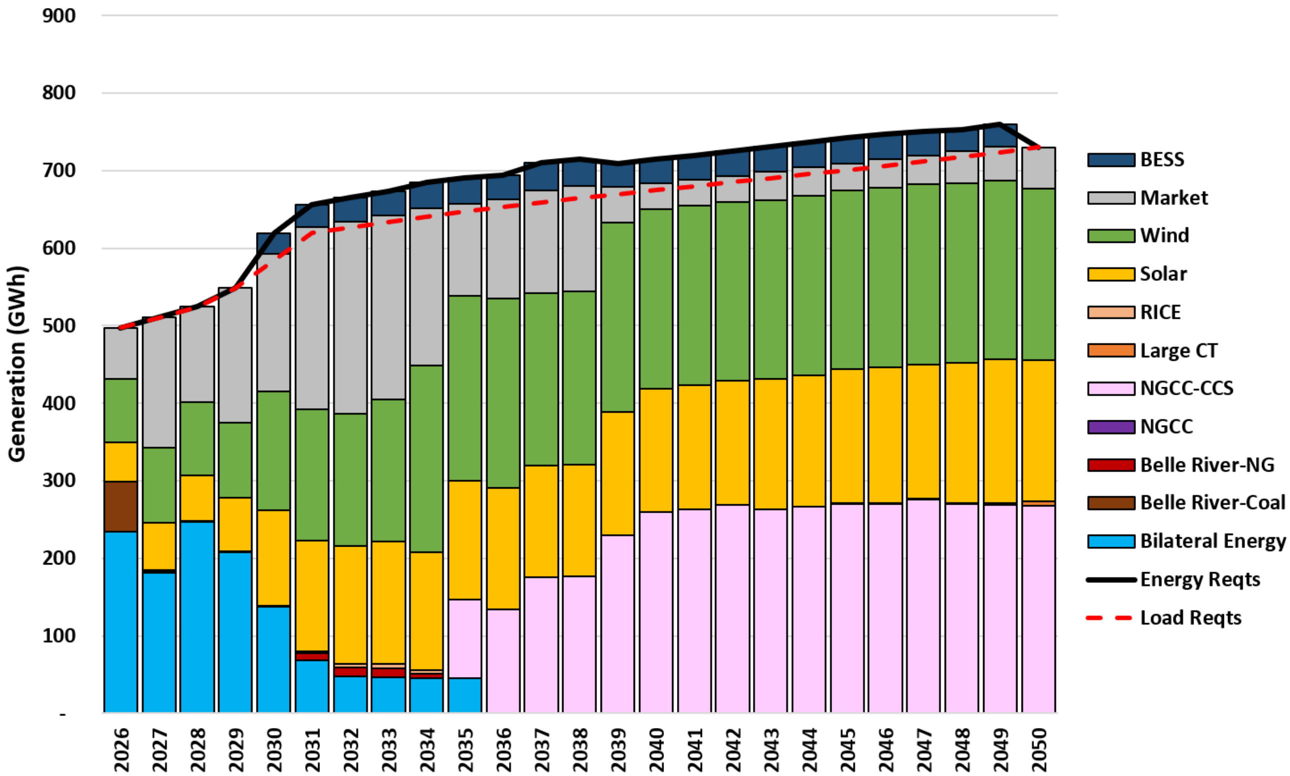

Figure 11-5: Energy Generated by Resource Type – PA 235 Large Units Available 2035

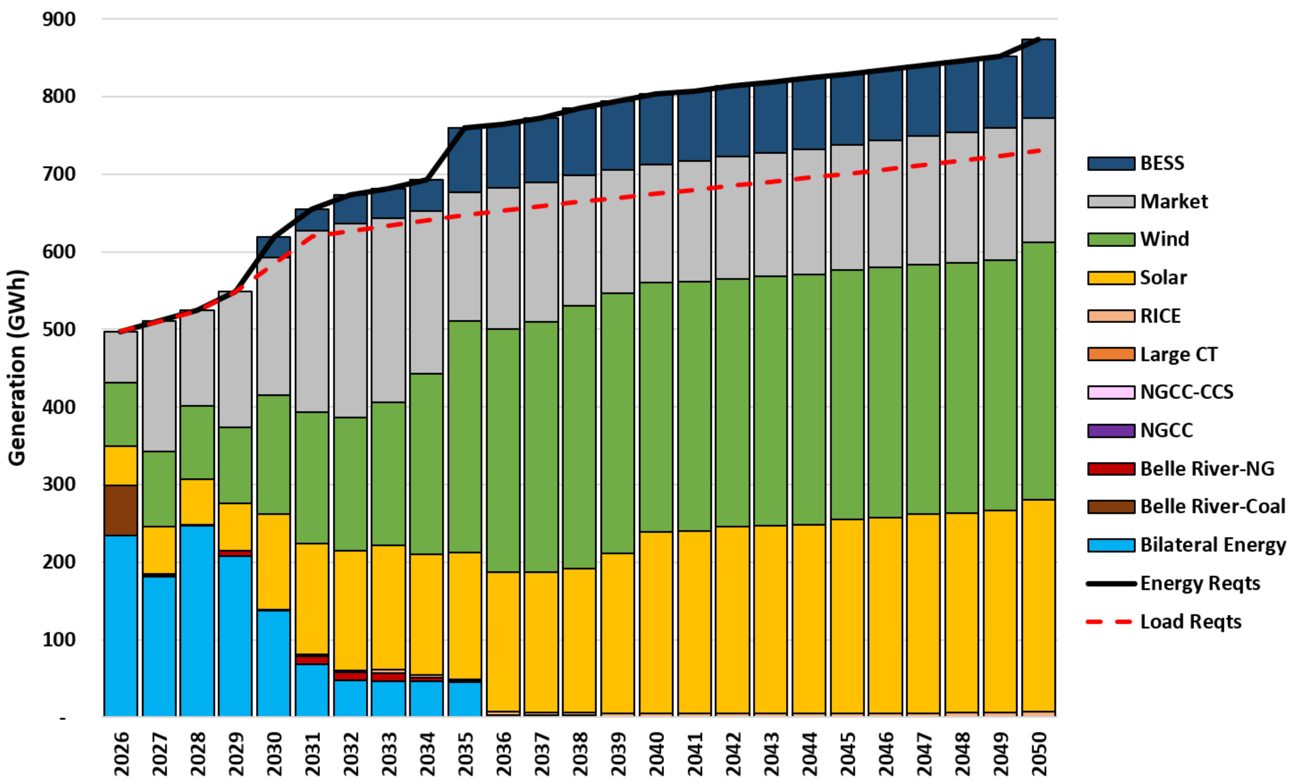

Figure 11-6: Energy Generated by Resource Type – PA 235 Local Generation

To meet CES requirements, utilities in Michigan may need to over-generate above load requirements during periods of high renewable output, which can depress market prices, increase exports to neighboring regions, and/or require additional energy storage. In other words, there will be hours in which generation continues to be produced and incur costs, but that generation is not used to serve load requirements. This dynamic is illustrated in Figure 11-7, which highlights the excess clean energy generation (i.e., "CES Dump Energy") on an annual basis.

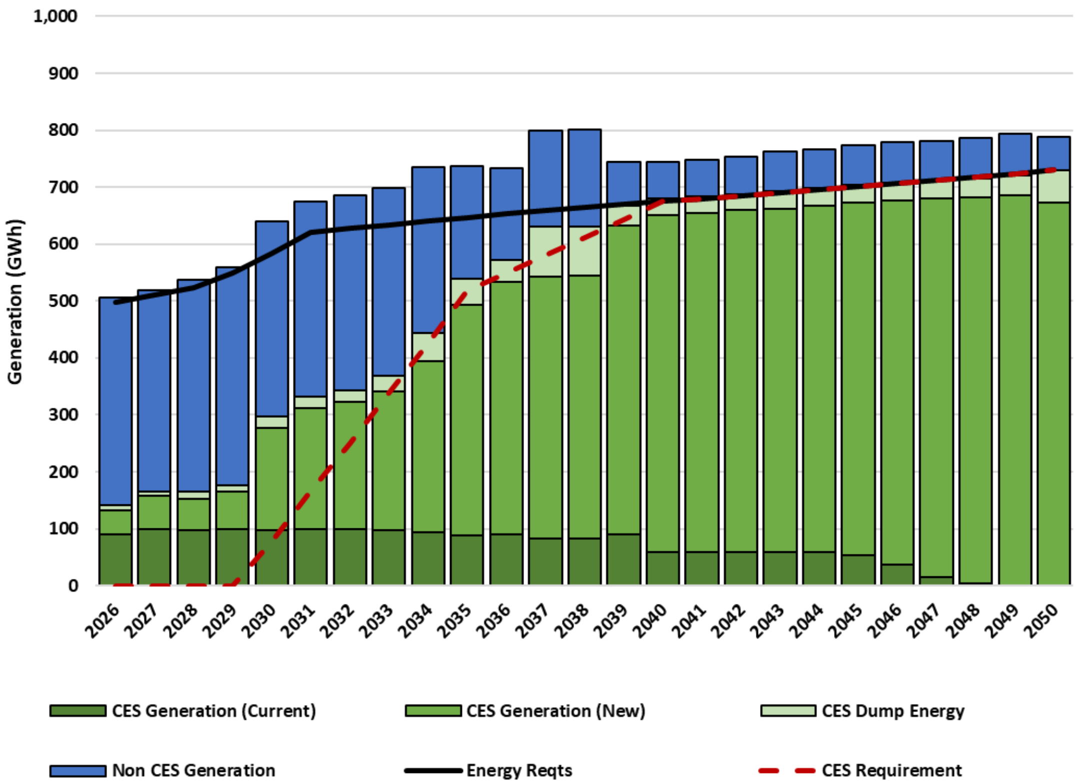

Figure 11-7: PA 235 CES Generation Contribution

System Capacity

Figures 11-8 through Figure 11-12 illustrate the total MW of summer firm capacity, by general type of capacity, that comprise BPW's system, including existing resources (including internal generating facilities, ownership entitlements, bilateral purchases, and renewable PPAs), new renewable resources, new natural gas combined cycle capacity, new BESS capacity, new natural gas combined cycle with CCS capacity, and new peaking capacity. It should be noted that all scenarios and portfolio strategies reflect the same assumptions including the retirement dates of BPW resources, expiration dates for existing PPAs and bilateral purchases. Retirement of any of BPW's other existing generating units was not considered in this IRP.

Review of the BAU Portfolios (Figures 11-8 through 11-10) indicates the following:

- NGCC capacity is installed as early as feasible across most portfolio strategies to meet capacity requirements.
- NGCT resources are added later in the study period to address incremental capacity needs.
- When large-frame resources are not made available until 2035, local RICE resources are installed in the near term to meet capacity requirements.
- The Local Generation portfolio strategy relies primarily on RICE resources to meet capacity needs, with limited renewable additions occurring late in the study period.
- No near-term renewable capacity is selected, reflecting the relative economics of available resources.

Review of the PA 235 Portfolios (Figures 11-11 through 11-13) indicates the following:

- BPW's needs for additional capacity are driven not only by the need to meet its system demand plus MISO Planning Reserve Margin requirements, but also the need for the addition of new resources that support compliance with the requirements of the RES and CES requirements under the PA 235 scenario.
- This is shown by comparing the total MW of capacity to the "Peak + Reserves" line in each of the Figures 11-11 through Figure 11-13. The excess generation generally occurs earlier in the IRP study period and is more significant in the PA 235 and the low growth scenarios. This excess generation in the PA 235 scenario is due to increased RES and CES requirements of PA 235, causing more intermittent capacity to be built to meet renewable and clean energy requirements.
- Capacity additions are primarily comprised of NGCC-CCS, wind, solar, and BESS, due to their ability to meet the RPS and CES standards under PA 235.
- The Economically Optimized portfolio strategy includes some near-term NGCC capacity alongside renewable additions to meet capacity requirements.
- Beginning in 2035, NGCC-CCS is installed to meet both capacity needs and CES requirements under PA 235.
- In portfolios where large-frame resources are not available until 2035, NGCC is not selected, with NGCC-CCS serving as the primary thermal resource once available.
- NGCC-CCS capacity additions increase in 2039, reflecting the final year in which the full value of available tax credits can be captured.
- The Local Generation portfolio strategy results in higher levels of renewable and BESS installations relative to other portfolio strategies.

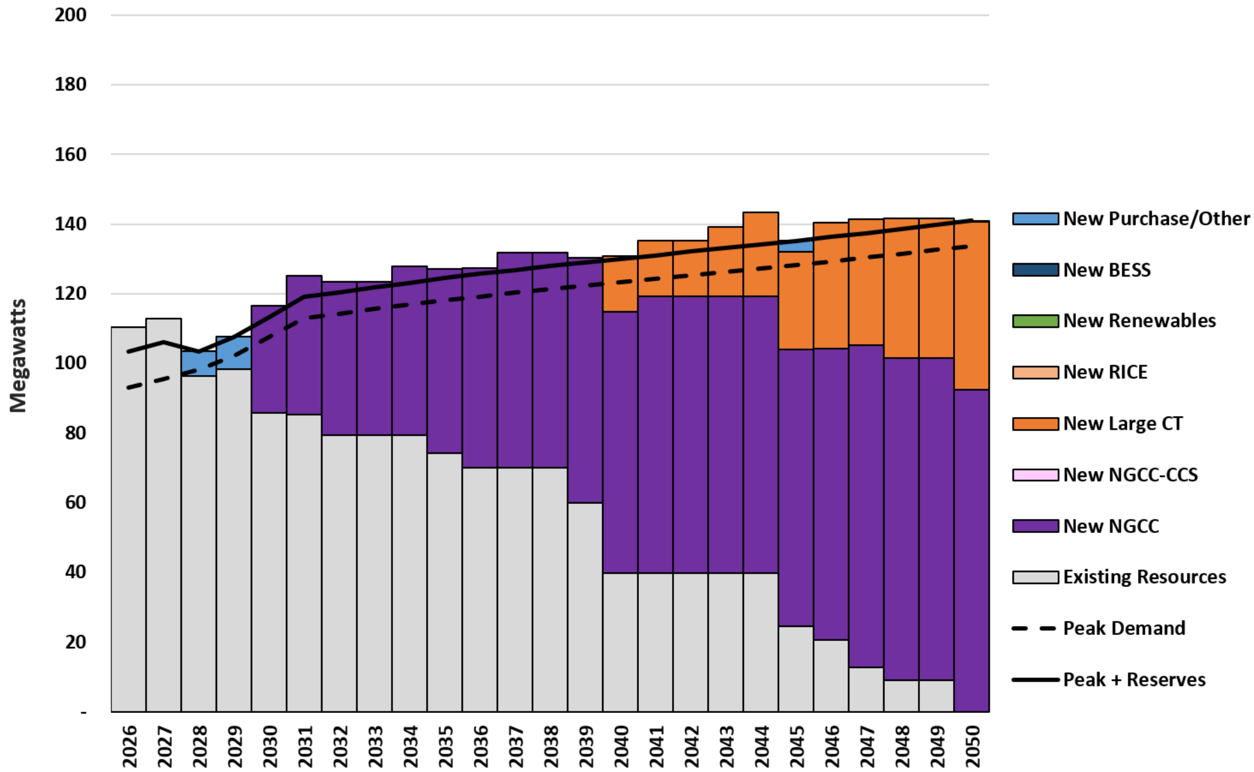

Figure 11-8: Summer Firm Capacity (MW) by Type – BAU Economically Optimized

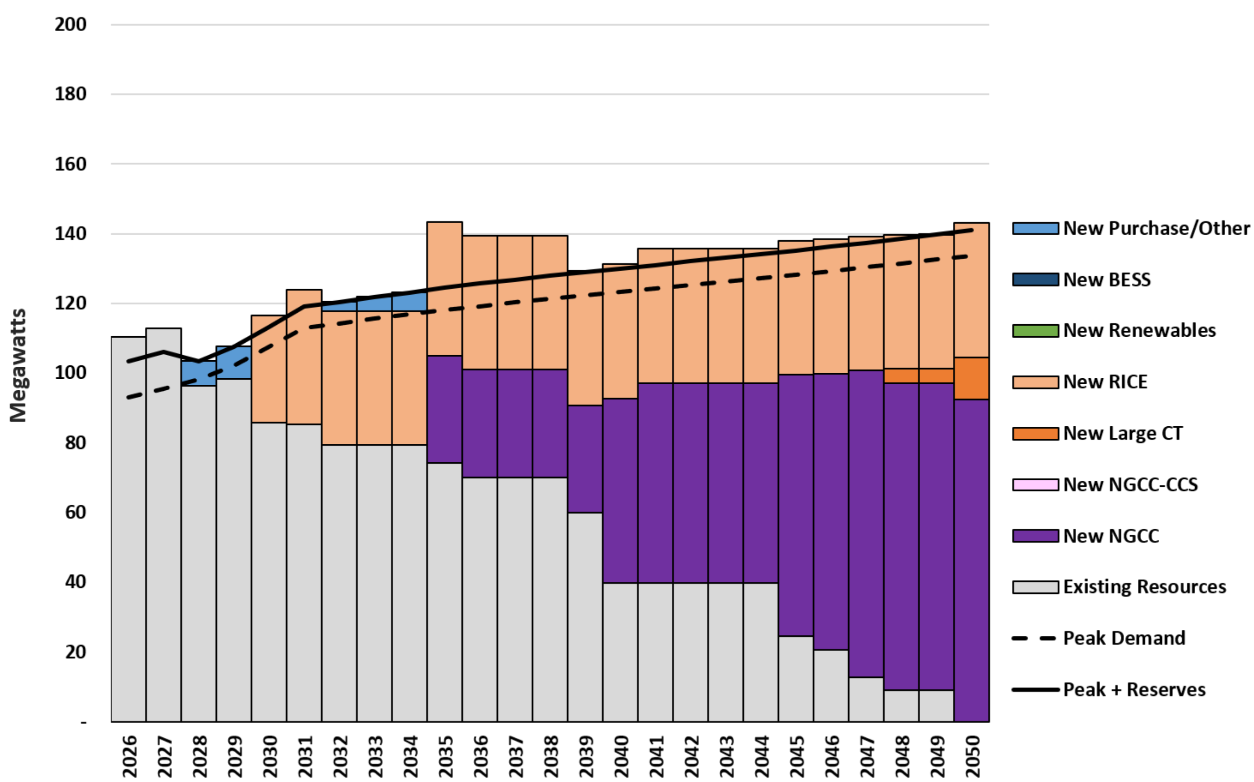

Figure 11-9: Summer Firm Capacity (MW) by Type – BAU Large Units Available 2035

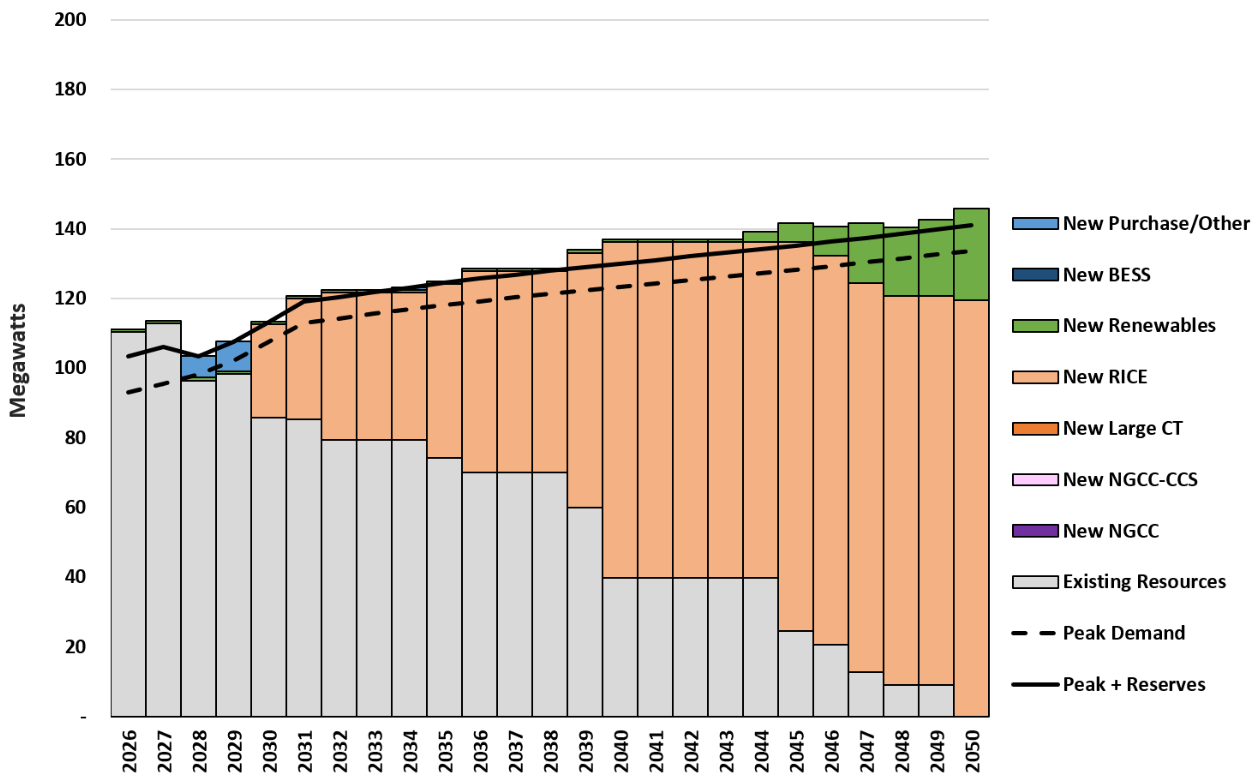

Figure 11-10: Summer Firm Capacity (MW) by Type – BAU Local Generation

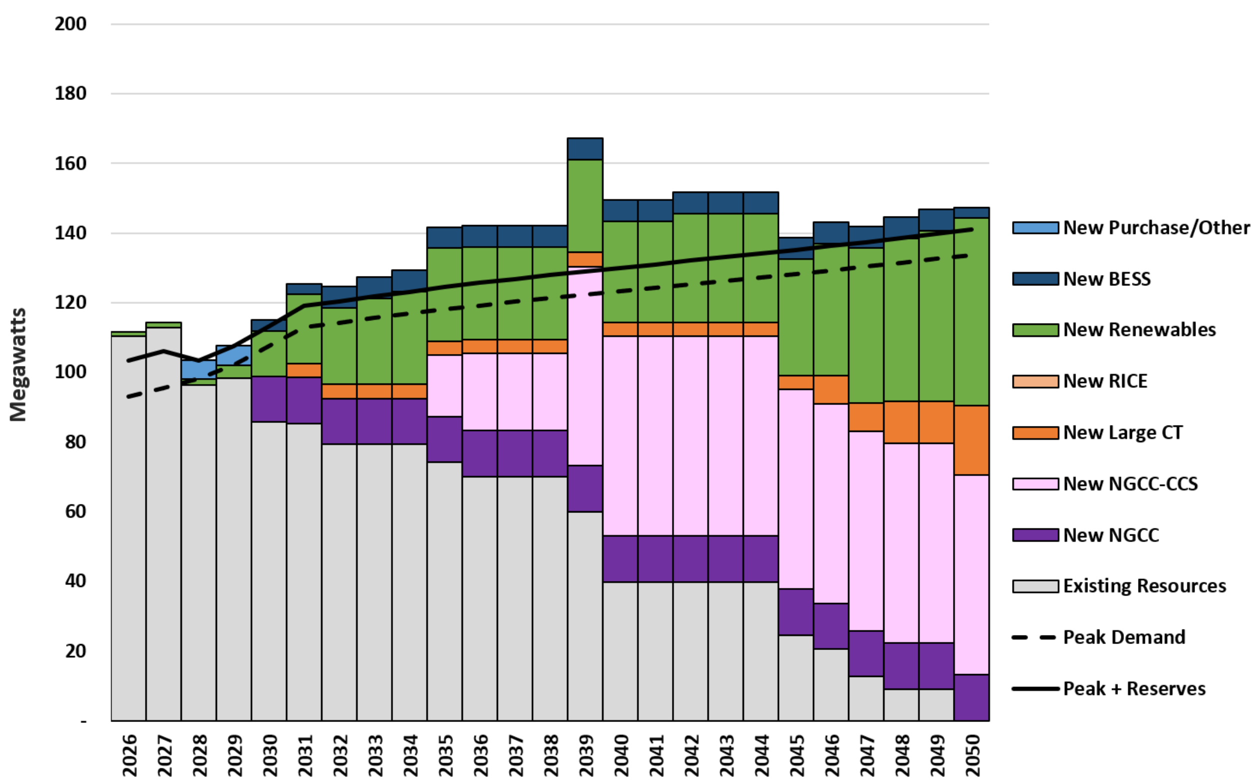

Figure 11-11: Summer Firm Capacity (MW) by Type – PA 235 Economically Optimized

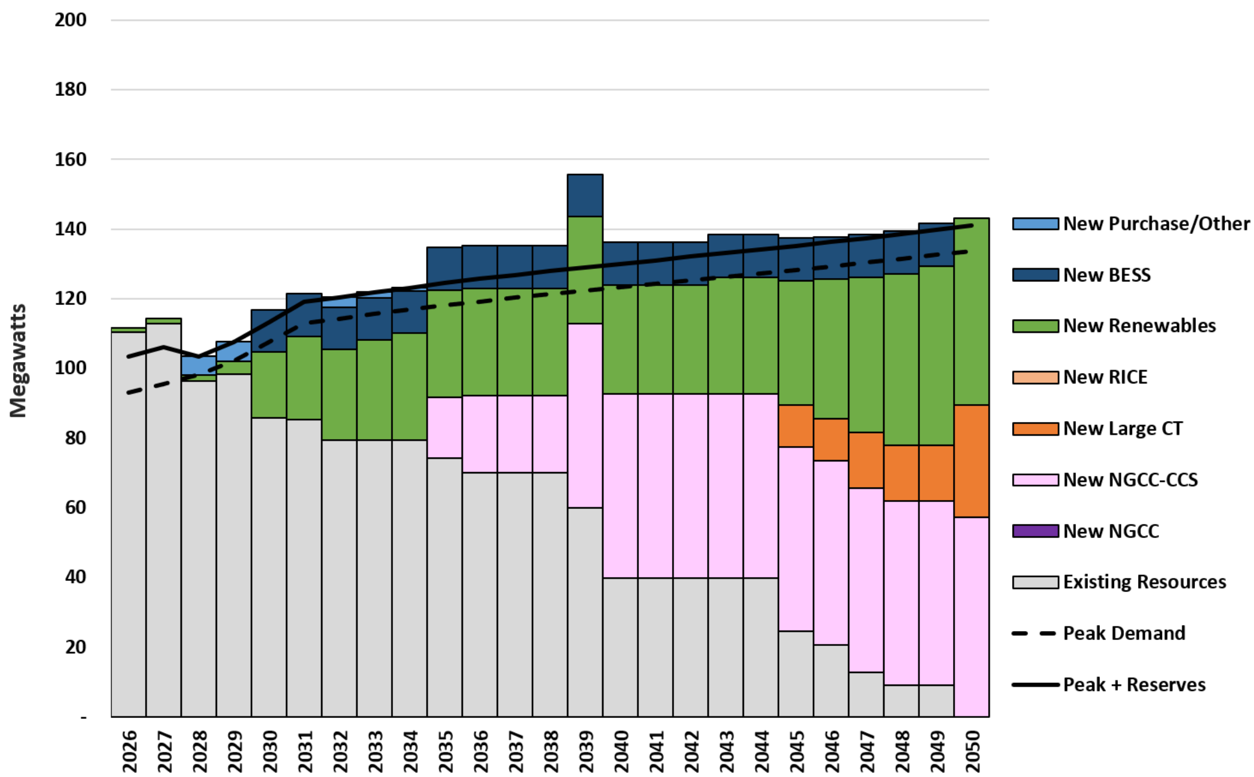

Figure 11-12: Summer Firm Capacity (MW) by Type – PA 235 Large Units Available 2035

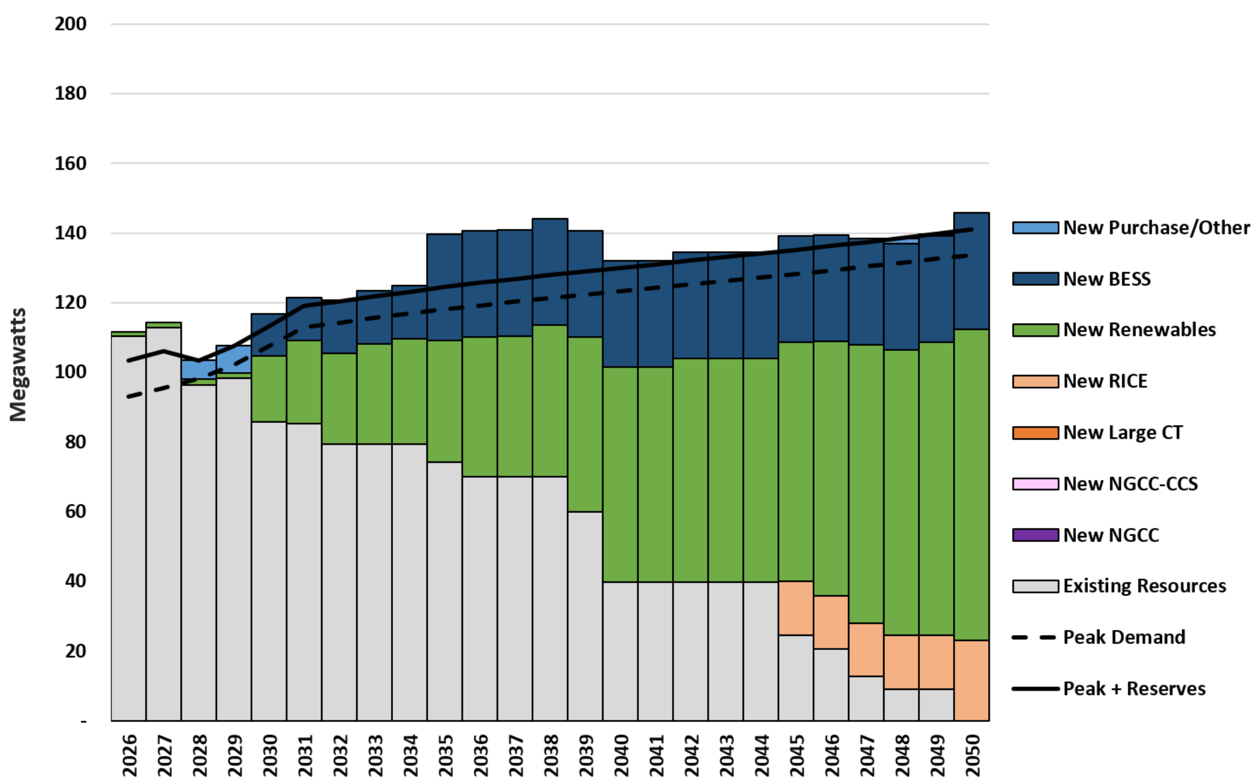

Figure 11-13: Summer Firm Capacity (MW) by Type – PA 235 Local Generation

Changes in Capacity

Table 11-1 presents a summary of the changes in capacity (retirements and new additions), categorized by types of capacity, over specific time periods, for the various scenarios and portfolio strategies.

Table 11-1: Summary of Capacity Additions (MW)

	Economically Optimized		Large Units Available		Local Generation	
Year	**BAU**	**PA 235**	**BAU**	**PA 235**	**BAU**	**PA 235**
New NGCC						
2030-2034	55	15	0	0	0	0
2035-2040	30	0	60	0	0	0
2041-2050	20	0	45	0	0	0
New NGCT						
2030-2034	0	5	0	0	0	0
2035-2040	20	0	0	0	0	0
2041-2050	40	20	15	40	0	0
New NGCC-CCS						
2035-2040	0	65	0	60	0	0
2041-2050	0	0	0	5	0	0
New Peaking						
2026-2029	0	0	0	0	0	0
2030-2040	0	0	25	0	65	0
2039-2050	0	0	0	0	15	15
New SMR						
2035-2050	0	0	0	0	0	0
New Solar						
2026-2029	0	5	0	5	0	0
2030-2040	0	45	0	50	0	115
2041-2050	0	55	0	50	55	60
New BESS						
2026-2029	0	0	0	0	0	0
2030-2040	0	10	0	20	0	50
2041-2050	0	(5)	0	(20)	0	5
New Wind						
2026-2029	0	20	0	20	0	20
2030-2040	0	60	0	60	0	105
2041-2050	0	0	0	0	0	5

The resource additions associated with the portfolio strategies identified in Table 11-1 are illustrated further in Figure 11-14. The figure provides a representation of how these resources are deployed across the portfolio strategies, emphasizing the commonalities and differences of new resource additions. Review of Figure 11-14 indicates the following:

- Participation in NGCC is consistently identified as a valuable addition under BAU, with capacity additions occurring as early as feasible to meet near-term capacity and energy needs, where available.

- Under PA 235, NGCC is primarily selected when paired with carbon capture, reflecting its value toward meeting the CES requirements under PA 235.
- Local-only strategies rely more heavily on peaking resources and renewables.
- New renewable capacity is limited under the BAU scenario, as thermal resources are more economical to meet capacity and energy needs.
- New peaking capacity is limited under the PA 235 scenario, as these resources do not contribute toward meeting the state requirements under PA 235.
- No new local peaking generation (i.e., RICE) is selected prior to 2030 across portfolio strategies, suggesting that near-term capacity and energy needs can be met without additional peaking resources, likely through a combination of existing resources and market purchases.
- Wind emerges as the most economic renewable resource in the near term, with earlier and more consistent selection releative to other renewable technologies.
- The analysis does not incluude the addition of any small modular reactor (”SMR”) resources.

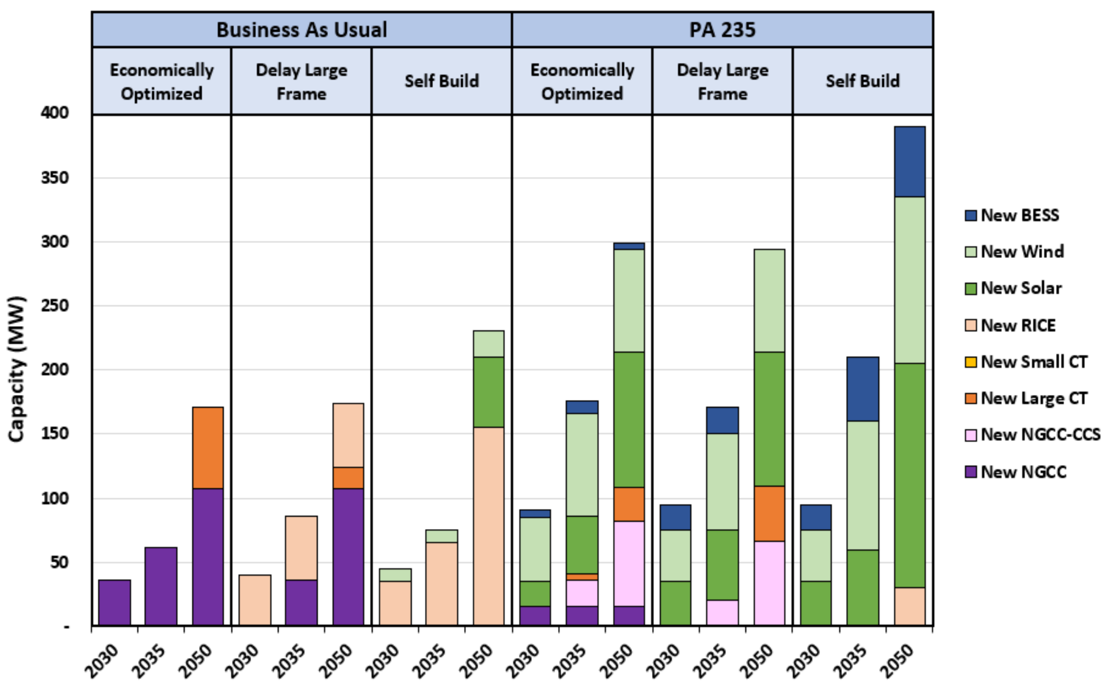

Figure 11-14: Summary of Capacity Additions (MW)

PVRR Summary

Table 11-2 presents summaries of the PVRR associated with each portfolio strategies developed for BAU and PA 235, and Figure 11-15 provides a more detailed breakout of the various cost components that makeup the PVRR. Detailed sensitivity results are provided in the Appendix. It should be noted that the PVRR analysis does not consider fixed costs associated with BPW’s existing PPAs, general and administrative type costs, or any other fixed costs associated with the BPW electric system other than estimated fixed O&M costs for existing units; such costs are considered “sunk costs” that would not change nor influence the resource and dispatch decisions reflected in this IRP. Additionally, when reviewing and comparing PVRR results, it is important to note that comparisons of PVRR results across cases may be misleading given the underlying differences in assumptions between cases; for example, the PVRR of a case reflecting higher loads would be expected to be higher than for a case reflecting lower loads, all else being equal. The conclusions presented related to PVRR are based on appropriate comparisons of cases.

Table 11-2: Present Value Revenue Requirements (PVRR; 2026-2050)

Scenario	Economically Optimized	Large Units Available 2035	Local Generation
PVRR Power Cost			
BAU ($ Million)	$648	$705	$791
PA 235 ($ Million)	$905	$906	$1,010
Levelized Cost			
BAU ($/MWh)	$70.04	$76.16	$85.41
PA 235 ($/MWh)	$97.75	$97.85	$109.06

Review of Table 11-2 and Figure 11-15 indicates the following:

- Comparisons of the BAU and PA 235 scenarios across all three portfolio strategies illustrates the impact to system costs of complying with the requirements of PA 235. Across portolio strategies, total system costs under the PA 235 scenario are approximately 30-40% higher than those under the BAU scenario.
- Under the BAU scenario, access to large-frame units beginning in 2030 reduces overall system costs by approximately 8%, while meeting capacity requirements exclusively with local generation increases costs by approximately 12%.
- Under the PA 235 scenario, access to large-frame units beginning in 2030 reduces overall system costs by less than 1%, while meeting capacity requirements exclusively with local generation increases costs by approximately 11%.

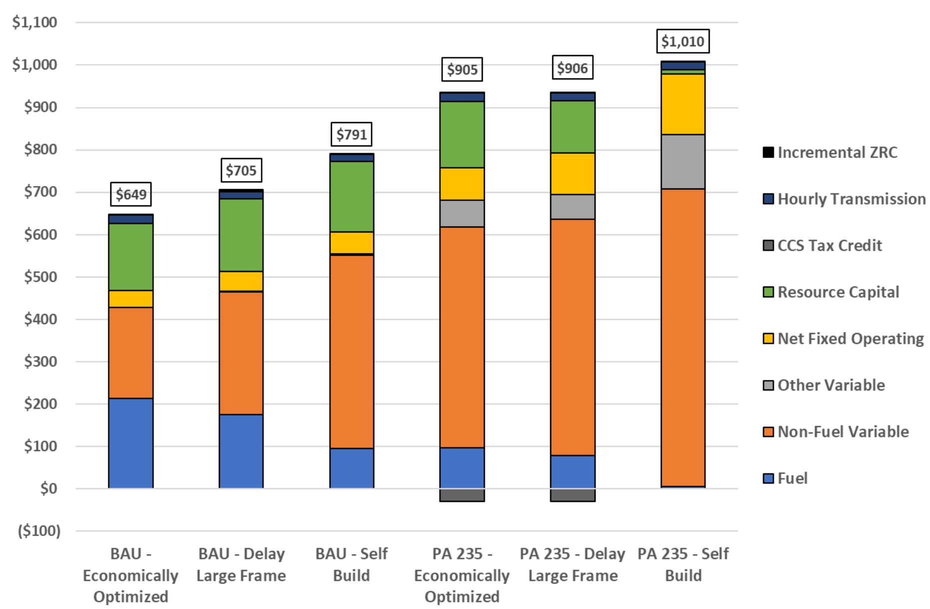

Figure 11-15: PVRR Summary – PVRR Power Costs (2026 $M, 2026-2050)

CO_2 Emissions

Figure 11-16 illustrates BPW's actual CO_2 emissions per MWh for 2019 and 2025 and the projected CO_2 emissions per MWh for each of the portfolio strategies developed for the BAU and PA 235 scenarios. As shown in Figure 11-16, all portfolio strategies would result in significantly lower CO_2 emissions per MWh as compared to historical levels.

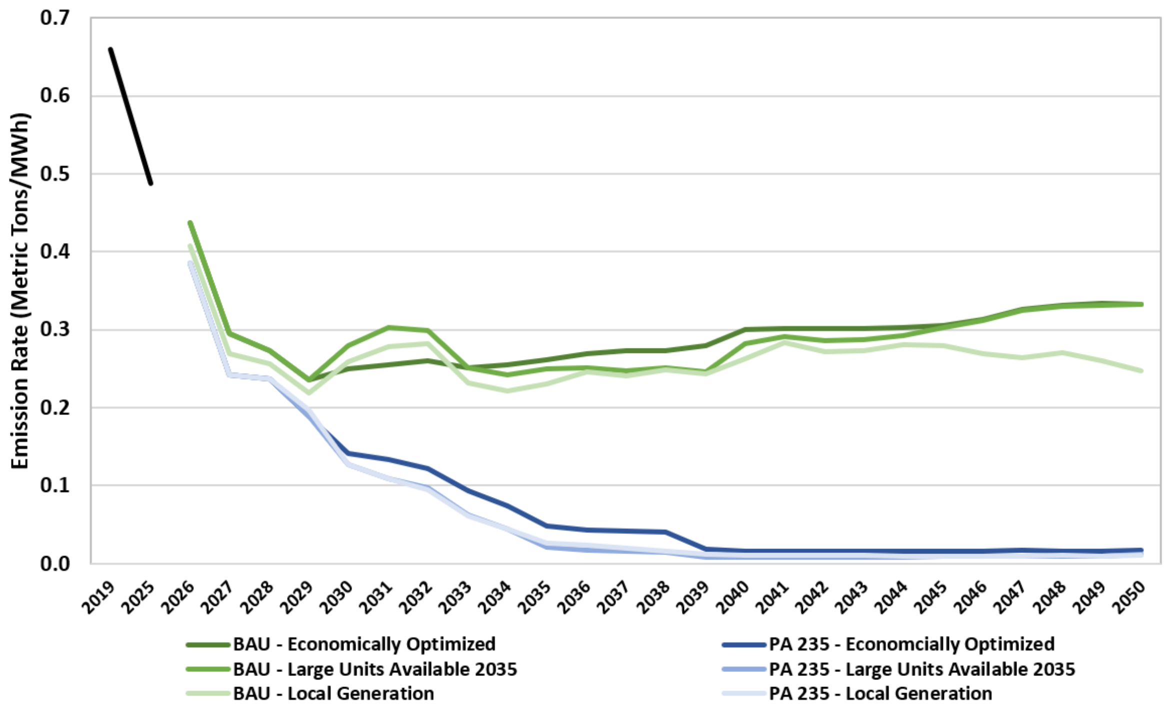

Figure 11-16: Average CO_2 Emissions by Portfolio Strategy

Table 11-3 below presents the average CO_2 emissions per MWh over the study period for each of the portfolio strategies developed for the BAU and PA 235 scenarios.

Table 11-3: CO_2 Emission Across Portfolio Strategies (2026-2050)

Portfolio Strategy	Average Emissions (Metric Tons/MWh)
BAU	
Economically Optimized	0.29
Large Units Available 2035	0.29
Local Generation	0.26
PA 235	
Economically Optimized	0.08
Large Units Available 2035	0.07
Local Generation	0.07

Review of Table 11-3 indicates the following:

- Resource portfolios under the PA 235 scenarios exhibit lower emissions than the resource portfolios under the BAU scenarios. This is a direct result of the signficant amount of renewable and clean energy generating resources that are needed to meet PA 235 requirements, thus resulting in overall lower emissions.
- The Local Generation portfolio results in lower emissions under the BAU scenario. The energy requirements under the the Local Generation portfolio are primarily meet with energy market purchases, which indicates that the emission rate of the overall energy market is slightly lower than a portfolio that is largely comprised of NGCC generation.

Sensitivity and Risk Analysis

To evaluate the robustness of the portfolio strategies under varying future conditions, a series of sensitivities were performed across both the BAU scenario and the PA 235 scenario. These sensitivities focus on key uncertainties that impact resource build decisions, dispatch, and PVRR.

Fuel Price Resiliency

For each portfolio strategy developed under both scenarios, sensitivities were applied to reflect high and low fuel prices assumptions. This approach allows for a consistent comparison of how each strategy performs under a range of plausible future conditions. Tables 11-4 and 11-5 present the average levelized power costs for each portfolio strategy across all fuel-price sensitivities for the BAU and PA 235 scenarios, respectively. Additional results and supporting figures are also provided in Appendix A.

Table 11-4: Fuel Price Resiliency for BAU Portfolios (PVRR; 2026-2050)

Portfolio Strategy	Average Levelized Power Costs ($/MWh)			
	Medium Fuel Price	Low Fuel Price	High Fuel Price	Range of Uncertainty
Economically Optimized	$70.04	$60.67	$82.62	$21.95
Large Units Available 2035	$76.16	$66.45	$85.87	$19.42
Local Generation	$85.41	$76.40	$91.24	$14.84

Table 11-5: Fuel Price Resiliency for PA 235 Portfolios (PVRR; 2026-2050)

Portfolio Strategy	Average Levelized Power Costs ($/MWh)			
	Medium Fuel Price	Low Fuel Price	High Fuel Price	Range of Uncertainty
Economically Optimized	$97.75	$93.36	$102.15	$8.78
Large Units Available 2035	$97.85	$94.22	$101.77	$7.55
Local Generation	$109.06	$108.50	$109.47	$0.97

Review of Table 11-4 and 11-5, and the supporting figures provided in the Appendix indicate the following:

- NGCC provides the majority of energy under the BAU scenario once available, dispacing market purchases and existing generation; this trend remains consistent across most sensitivities.
- Under high fuel price sensitivities, market energy becomes more economic, displacing a significant portion of NGCC generation.
- Under low fuel price sensitivities, owned resources are dispatched more heavily, with increased generation from NGCC and local peaking units, particularly in the Local Generation portfolio strategies.
- High fuel price sensitivities in the PA 235 scenario also increase reliance on market energy, though to a lesser extent than in the BAU scenario, as market purchases do not contribute toward meeting PA 235 requirements.
- While the Economically Optimized portfolio strategy is the most sensitive to fuel price, the portfolio strategy remains the lowest cost option under both BAU and PA 235 scenarios
- While the PA 235 scenarios are more resilient to changes in fuel prices, the resource porfolios needed to meet PA 235 requirements remain higher in cost.

Load Growth Responsiveness

For each portfolio strategy developed under both scenarios, sensitivities were applied to reflect high and low load growth projections. This approach allows for a consistent comparison of how each strategy performs under a range of plausible future conditions. Figures 11-16 and 11-17 present the average levelized power costs for each portfolio strategy across all load growth sensitivities for the BAU and PA 235 scenarios, respectively. Additional results and supporting figures are also provided in Appendix A.

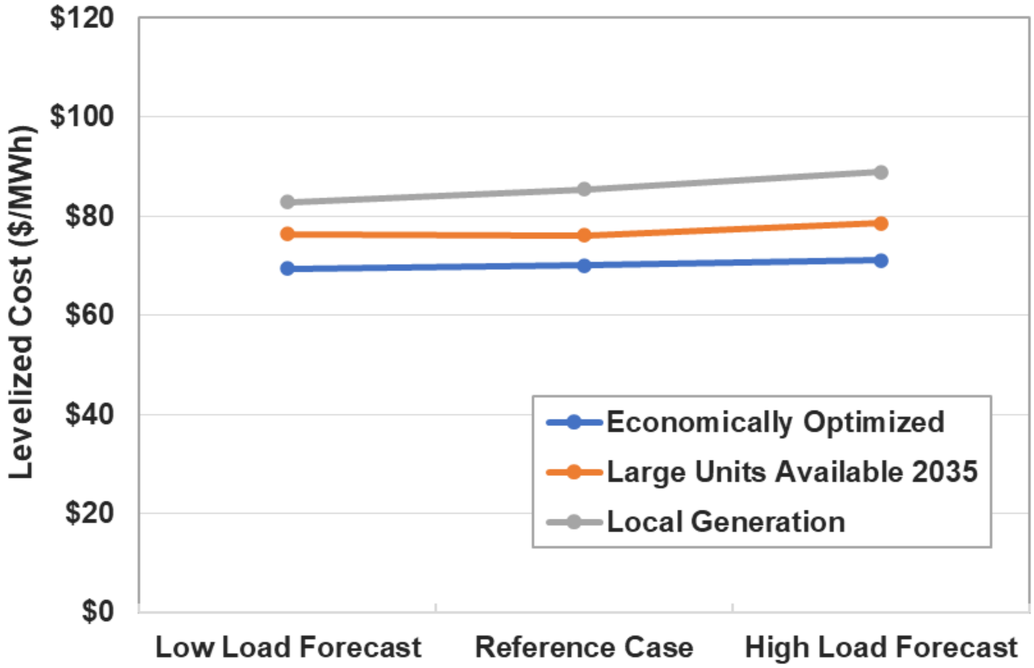

Figure 11-16: Levelized Costs for Portfolio Strategies – BAU Scenario

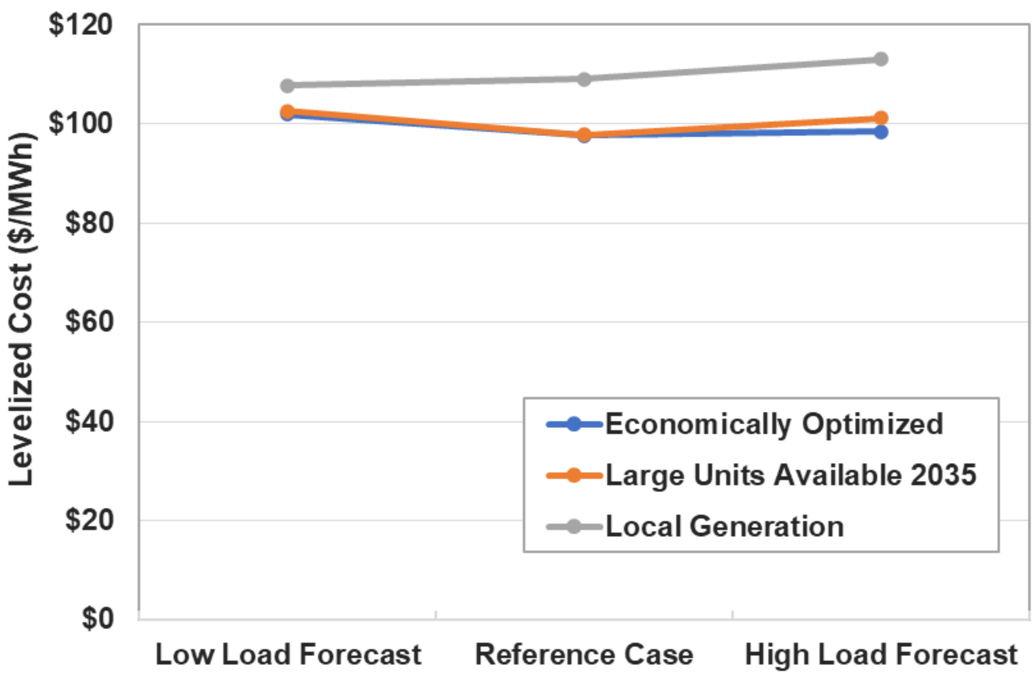

Figure 11-17: Levelized Costs for Portfolio Strategies – PA 235 Scenario

Review of Figures 11-16 and 11-17, and the supporting figures provided in Appendix A indicate the following:

- The overall mix of resource types remains generally consistent across sensitivities, regardless of scenario or portfolio strategy, with higher load growth resulting in greater levels of capacity additions, but with resource types remaining proportional to the Reference Case, and lower load growth resulting in lower levels of capacity additions, but with resource types remaining proportional to the Reference Case.
- The timing of resource additions remains largely consistent with the reference case across sensitivities, with differences primarily reflected in the magnitude of capacity additions rather than shifts in installation timing.
- Low load growth sensitivities result in excess capacity, reflecting near-term additions made to meet projected load growth that ultimately does not materialize.
- Portfolio strategies with large frame units show lower overall costs compared to those with only local generation and are less sensitive to load variations.
- Portfolio strategies under the PA 235 scenario are less senstive to load variations than the portfolio strategies under the BAU scenario.

Ranking Analysis

A comparative ranking analysis was performed to evaluate the relative performance of each portfolio strategy across both the BAU scenario and the PA 235 scenario. Each portfolio strategy was assessed against six evaluation metrics designed to capture key dimensions of performance, including reliability, affordability, local control, fuel cost resiliency, load growth response, and CO2 emissions.

For each metric, portfolio strategies were ranked relative to one another, and weights were applied to reflect the relative importance of each evaluation criterion. These weights are summarized at the bottom of Table 11-6. A weighted score was then calculated for each portfolio strategy, as shown in the rightmost column, to provide an overall comparison across scenarios and portfolio strategies.

Table 11-6: Ranking of Potential Portfolio for Evaluation Metrics

Portfolios	Reliability	Affordability	Control of Resource Particpation	Fuel Cost Resiliency	Load Growth Response	CO2 Emissions	Weighted Average
Business-As-Usual							
Economically Optimized	1	1	3	3	1	3	1.8
Large Units Available 2035	1	2	2	2	2	2	2.0
Local Generation	1	3	1	1	3	1	2.2
MI Public Act 235							
Economically Optimized	1	1	3	3	1	3	1.8
Large Units Available 2035	1	2	2	2	2	1	1.9
Local Generation	1	3	1	1	3	2	2.3
Weights	0%	50%	20%	10%	10%	10%	100%

The following discussion summarizes key findings from the ranking analysis:

- The Economically Optimized portfolio strategy ranks as the most robust strategy across both scenarios. This results suggests that early participation in large-frame resources – particularly NGCC resources – provides meaningful benefits in terms of cost and overal portfolio performance.
- The Large Units Available 2035 portfolio strategy highlights the value of maintaining optionality in the near term, indicating that preserving the ability to participate in future large-frame resource can support strong perfomance across a range of potential future conditions.
- The Local Generation provides the greatest level of local control, but results in the highest overall system costs and has worse responsiveness to changes in load growth, indicating reduced flexibility under varying future conditions.

Evaluation of Regulatory Uncertainty for PA 235

BPW faces a degree of uncertainty related to evolving state regulatory requirements in the form of PA 235, including mandates for a specified share of energy to be sourced from renewable or clean resources. While this legislation took effect in 2024, key elements of compliance remain unclear, and the anticipated phase-out of federal tax incentives under the IRA introduces additional considerations.

BPW's current open capacity position provides flexibility to adapt to future resource strategies; however, optimum capacity builds under the resulting portfolio strategies show limited alignment in near-term resource additions across these scenarios, indicating that early investment decisions may differ significantly depending on the assumed regulatory future. Importantly, these near-term resource decisions may introduce path dependencies that impact long-term cost and resource outcomes if future regulatory conditions differ from expectations. To evaluate the potential risk associated with this uncertainty, a "What-If" analysis was conducted to investigate how specific portfolio strategies are able to respond to changes in the assumed future regulatory environment.

The "What-If" analysis is intended to assess how different near-term strategies perform when evaluated against an alternative regulatory future, thereby providing insight into the risks and trade-offs associated with early action versus deferral. The two "What-If" cases evaluated are described below and the results of the analysis are presented in Table 11-7.

- **Early Renewable Additions but PA 235 is Altered**: This case assumes an aggressive near-term buildout of renewable resources to align with anticipated PA 235 requirements. The portfolio strategy is then evaluated under a regulatory future in which such requirements do not materialize, assessing the cost and operational implactions of early renewable invesment.
- **Early Local RICE Resource Build but PA 235 is Fully Enforced:** This case assumes that near-term capacity needs are met through local RICE resources, with renewable investment deferred. The portfolio strategy is then evaluated under a future in which PA 235 requirements are enforced, assessing the implications of delayed renewable deployment and the resulting need for accelerated compliance.

Table 11-7: What-If Analysis (PVRR; 2026-2050)

Portfolio Strategy	Average Levelized Power Costs ($/MWh)	
	$/MWh	Incremental
BAU		
Large Units Available 2035	$76.16	N/A
Early Renewables without PA 235	$90.84	$14.68
PA 235		
Large Units Available 2035	$97.85	N/A
Early RICE with PA 235	$104.57	$6.71

As shown in Table 11-7, pursuing an aggressive near-term renewable buildout under a future in which PA 235 requirements are relaxed results in an incremental average levelized power cost of $14.68/MWh. In contrast, meeting near-term capacity needs with local RICE resources while deferring large-scale renewable procurement until the regulatory framework under PA 235 is clarified results in a lower incremental cost of $6.71/MWh. This comparison highlights the trade-off between early commitment and regulatory flexibility and indicates that delaying the decision to aggressively pursue renewables reduces may reduce cost exposure for BPW given the current uncertainty of PA 235 implementation.

More detailed results that support the evaluation of the "What-If" scenarios are provided in Appendix A.

12 STAKEHOLDER ENGAGMENT

12.1 Stakeholder Overview

Throughout development of the IRP, BPW provided opportunities for members of the community ("Stakeholders") to participate in the IRP Stakeholder Working Group ("SWG"), which consisted of three meetings with the Stakeholders and was preceded by a public meeting for any members of the community to attend and participate in. BPW provided a dedicated IRP website (Power Supply Strategic Planning - Zeeland BPW)[9] to inform customers of the IRP process, including frequently asked questions, and invited the public to submit any questions or feedback related to the IRP process. BPW posted presentation material and recordings of the public meetings and the SWG meetings on the IRP website.

The SWG was formed by BPW and was intended to lead to improvements to the IRP and planning processes through feedback received from Stakeholders. The SWG was developed to represent a wide range of concerns and perspectives to help inform the development of an IRP that is in the best interest of the BPW's customers while meeting the requirements of the State Michigan.

BPW identified several key sectors to ensure the SWG reflected a broad and representative cross-section of the community. These sectors included governmental agencies, commercial and industrial key accounts, educational and health-care institutions, economic development organizations, community groups, and residential representatives. To engage participants from each sector, BPW conducted targeted outreach to specific contacts and supplemented these efforts with broader public promotion. Mailers, social media, and updates on the project website were used to reach the wider residential population and encourage broad community involvement.

Objectives and guidelines for the SWG process consisted of the following:

- Create an open dialogue around BPW's IRP.
- Provide education and transparency into BPW's resource planning process and obligation to provide reliable and economic power in an environmentally responsible manner.
- Provide the opportunity to share wide-ranging and diverse opinions on the planning process, analysis, and the contents of the IRP.
- Provide a forum for deep and technical discussion of the analysis, and the tradeoffs inherent to integrated resource planning.
- Collaborate and discuss how diverse perspectives and approaches could advise and benefit BPW's IRP.
- Participate in an active and focused manner and commit to the success of the IRP process.
- Build trust and strong relationships among the Stakeholders.
- Consider the interests and concerns of all BPW customers and Stakeholders, and interact respectfully with all Stakeholders.
- Evaluate fairly and thoroughly the feedback and input from all Stakeholders, and keep the needs, concerns, and questions of Stakeholders alive and present in the planning of the IRP.

---

[9] https:://zeelandbpw.com/power-plan

12.2 Summary of Meetings

Table 12-1 provides a summary of the dates and associated topics for the public meeting and each of the three SWG meetings.

Table 12-1: Summary of Meetings

Meeting Name	Meeting Date	Meeting Topics

Public Meeting	October 16, 2025	• Overview of BPW
		  ○ History
		  ○ Operations and Resources
		  ○ Interaction with MPPA and MISO
		  ○ Priorities
		  ○ Customer Demographics,
		  ○ Power Supply Basics
		  ○ Future Challenges
		• Overview of an IRP
		  ○ Key Components
		  ○ IRP Process and Goals
		• BPW's IRP Process
		• Schedule of SWG Meetings and SWG Expectations

SWG Meeting #1	November 18, 2025	• BPW Customer Survey Results
		• Refresh on BPW and Industry Challenges
		• IRP Assumptions
		  ○ Planning Criteria
		  ○ PA 235
		  ○ Load Forecast
		  ○ Fuel Price Projections
		  ○ Market Price Projections
		  ○ Options
		• Schedule of SWG Meetings and SWG Expectations

SWG Meeting #2	January 8, 2026	• Address Questions from SWG Meeting #1
		  ○ Demand-Side Management and Energy Efficiency
		  ○ Planning and Implementation
		• Structure of BPW's IRP
		  ○ Portfolios and Scenarios
		  ○ MISO
		  ○ Options
		  ○ Market Price Projections
		  ○ Sensitivities
		• Schedule of SWG Meetings and SWG Expectations

SWG Meeting #3	March 19, 2026	• Preliminary Results • Portfolio Evaluation Criteria • Near-Term Action Plan • Coordination and Collaboration with MPPA

13 CONCLUSIONS AND NEAR-TERM ACTIONS

This IRP provides a comprehensive analysis of various resource options to meet BPW's customer's electric needs while balancing critical objectives, including system reliability, economics, and regulatory compliance.

13.1 Conclusions

BPW's current open capacity position provides flexibility to adapt to future resource strategies; however, optimum capacity builds under the resulting portfolio strategies show limited alignment in near-term resource additions across these scenarios, indicating that early investment decisions may differ significantly depending on the assumed regulatory future. Importantly, these near-term resource decisions may introduce path dependencies that impact long-term cost and resource outcomes if future regulatory conditions differ from expectations.

With this context in mind, the following presents the conclusions based on the analysis and evaluations performed for and discussed throughout this IRP:

- Participation in larger, shared thermal generating resources is a key driver of economic value. Near-term planning decisions should prioritize preserving the ability to participate in future large generating units, even if full commitment occurs at a later date. Results of the IRP that support this conclusion include the following.
  - NGCC capacity is installed as early as feasible across most portfolio strategies to meet capacity requirements.
  - Participation in NGCC is consistently identified as a valuable addition under BAU, with capacity additions occurring as early as feasible to meet near-term capacity and energy needs, where available.
  - The BAU Economically Optimized portfolio relies on NGCC to provide the majority of energy, primarily displacing market purchases, Belle River, and local peaking generation.
  - The BAU Large Units Available 2035 portfolio strategy depicts the use of market energy and local peaking resources supply in the near term, with NGCC generation increasing later in the study period once large-frame units become available.
  - Under PA 235, NGCC is primarily selected when paired with carbon capture, reflecting its value toward meeting the CES requirements under PA 235.
  - Beginning in 2035, NGCC-CCS is installed to meet both capacity needs and CES requirements under PA 235.
  - In portfolios evaluated under PA-235 where large-frame resources are not available until 2035, NGCC is not selected, with NGCC-CCS serving as the primary thermal resource once available.
  - The Economically Optimized portfolio strategy ranks as the most robust strategy across both scenarios. This result suggests that early participation in large-frame

resources – particularly NGCC – provides meaningful benefits in terms of cost and overall portfolio performance.
    - The Large Units Available 2035 portfolio strategy highlights the value of maintaining optionality in the near term, indicating that preserving the ability to participate in future large-frame resources can support strong performance across a range of potential future conditions.
- Reliance exclusively on local generation is consistently identified as the higher-cost portfolio strategy. While local resources can provide operational and siting advantages, limiting the portfolio to these options reduces economic efficiency and increases overall system costs over the study period.
    - Local-only strategies rely more heavily on peaking resources and renewables.
    - Under the BAU scenario, meeting capacity requirements exclusively with local generation increases costs by approximately 12%.
    - Under the PA 235 scenario, meeting capacity requirements exclusively with local generation increases costs by approximately 11%.
    - The Local Generation provides the greatest level of local control, but results in the highest overall system costs and has worse responsiveness to changes in load growth, indicating reduced flexibility under varying future conditions.
- Power supply portfolios designed to fully meet the requirements of PA 235 result in higher costs relative to the BAU portfolios.
    - Across portfolio strategies, compliance with PA 235 is estimated to increase total power supply costs by approximately 30 to 40 percent over the study period.
    - The PA 235 portfolios result in lower reliance on market energy overall, as market purchases do not contribute to meeting RPS and CES requirements under PA 235.
    - To meet CES requirements, utilities in Michigan may need to over-generate during periods of high renewable output, which can depress market prices, increase exports to neighboring regions, and/or require additional energy storage (as illustrated in Figure 11-7, which highlights excess generation on an annual basis).
- Delaying an aggressive near-term buildout of renewable resources to meet PA 235 requirements results in the lowest incremental cost exposure. Given the uncertainty surrounding the regulatory compliance and the considerations related to the phase-out of the IRA tax credits, BPW should plan to remain compliant while avoiding higher costs associated with early commitments that may prove misaligned with future regulatory outcomes.
    - Pursuing an aggressive near-term renewable buildout under a future in which PA 235 requirements are altered results in an incremental average levelized power cost of $14.68/MWh.

- o Meeting near-term capacity needs with local RICE resources while deferring large-scale renewable procurement until the regulatory framework under PA 235 is clarified results in an incremental average levelized power cost of $6.71/MWh.

13.2 Near-Term Actions

BPW intends to continue its proactive resource planning to maintain resource adequacy beyond 2030 due to projected load growth and evolving capacity market conditions. Concurrently, MPPA forecasts capacity shortfalls among member utilities beginning in 2030. Staff have evaluated a range of resource options and recommend continued advancement of both local and regional generation opportunities while maintaining flexibility as additional technical, financial, and regulatory information becomes available.

The IRP evaluated future load obligations, resource adequacy requirements, market conditions, and resource alternatives available to BPW. Results indicate that additional capacity resources will likely be required to satisfy future reliability obligations. In parallel, MPPA has been evaluating a strategic generation initiative involving interested member communities, with BPW participating as both a potential project participant and host community.

Maintaining resource adequacy beyond 2030 will likely require a combination of local resource development, regional collaboration, and strategic capacity procurement. Based on the results of this IRP, BPW intends to pursue a series of near-term actions to refine BPW's path forward, which will position BPW to make informed investment decisions that support long-term reliability, affordability, and sustainability objectives. These near-term action items are summarized below in Table 13-1.

Table 13-1: Summary of Near-Term Actions

Action	Description
Advance Local Generation Site Due Diligence	Continue environmental, permitting, interconnection, fuel supply, and constructability evaluations of potential BPW-owned generation sites and identify additional strategic locations.
Reduce Near-Term Capacity Market Exposure	Pursue interim capacity procurement strategies to mitigate BPW's open capacity position while long-term solutions are evaluated.
Evaluate New Generation Alternatives	Evaluate both locally owned and jointly owned generation resources using lifecycle cost, performance, financing, risk, and portfolio optimization criteria.
Coordinate with MPPA Resource Development Initiatives	Maintain active participation in MPPA planning efforts and evaluate opportunities for economies of scale and shared development risk.

Appendix A

Supplemental Information to the Zeeland Board of Public Works 2026 Integrated Resource Plan

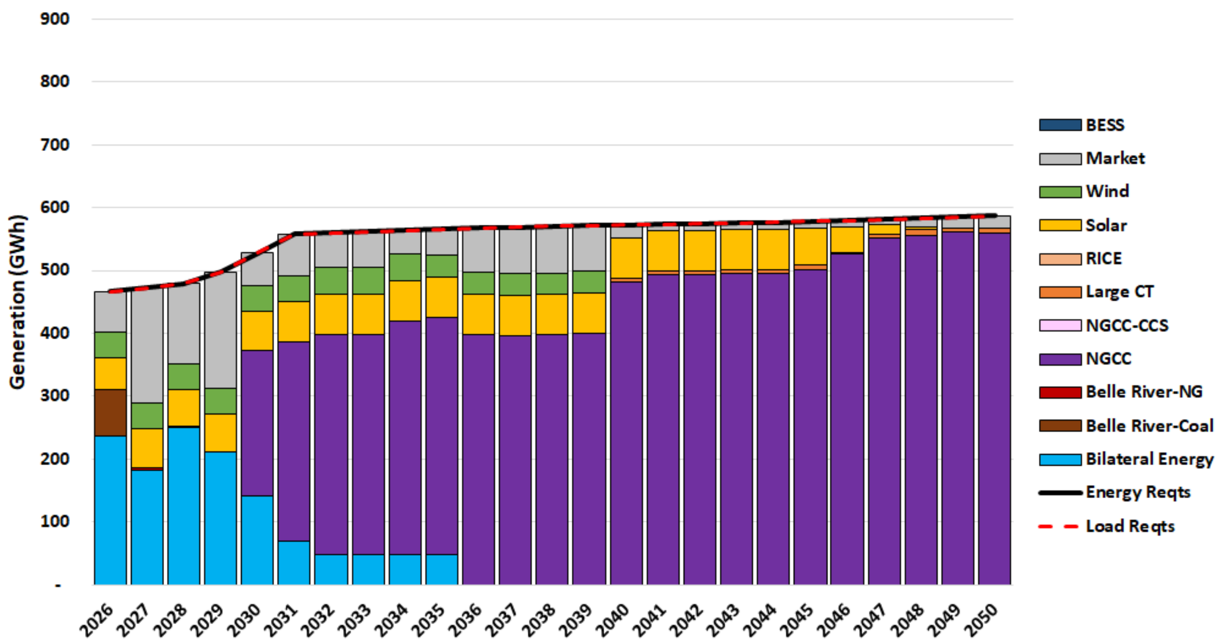

Figure A-1: Energy Generated by Resource Type – BAU Economically Optimized (Low Load Growth)

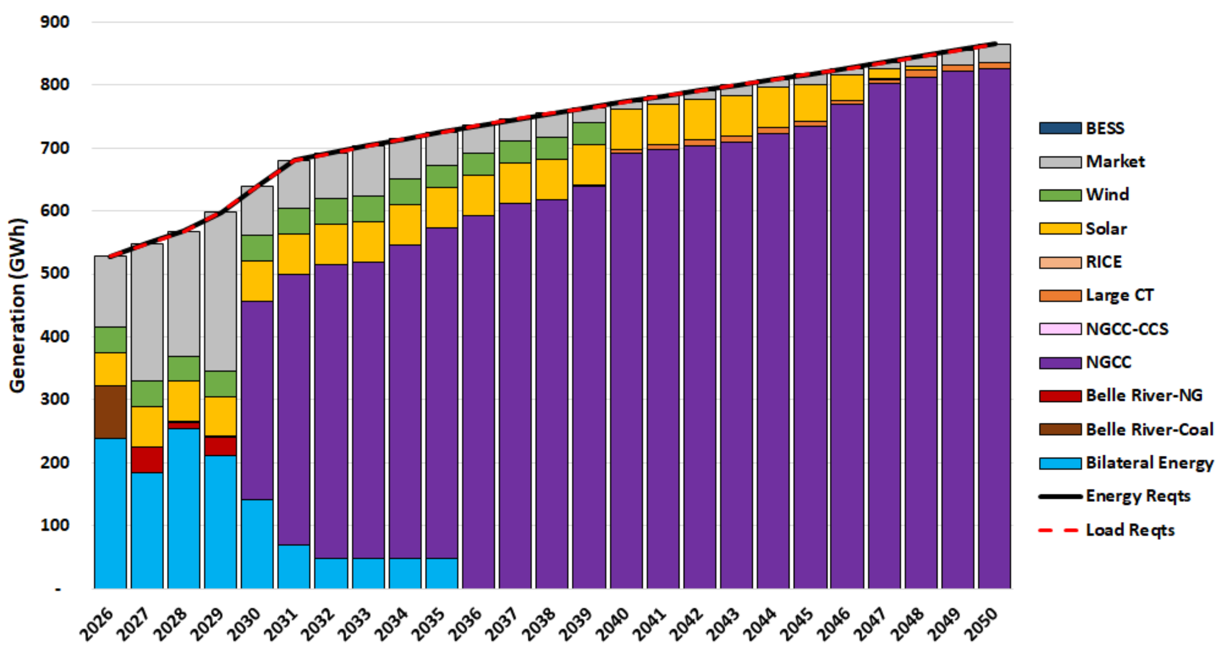

Figure A-2: Energy Generated by Resource Type – BAU Economically Optimized (High Load Growth)

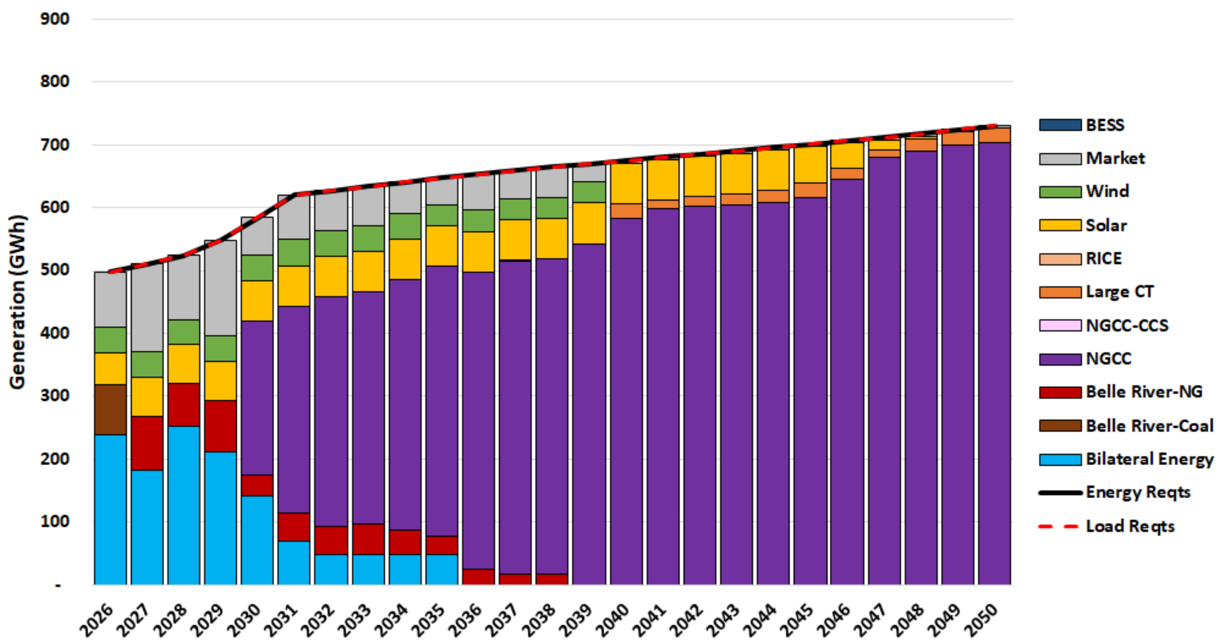

Figure A-3: Energy Generated by Resource Type – BAU Economically Optimized (Low Fuel Price)

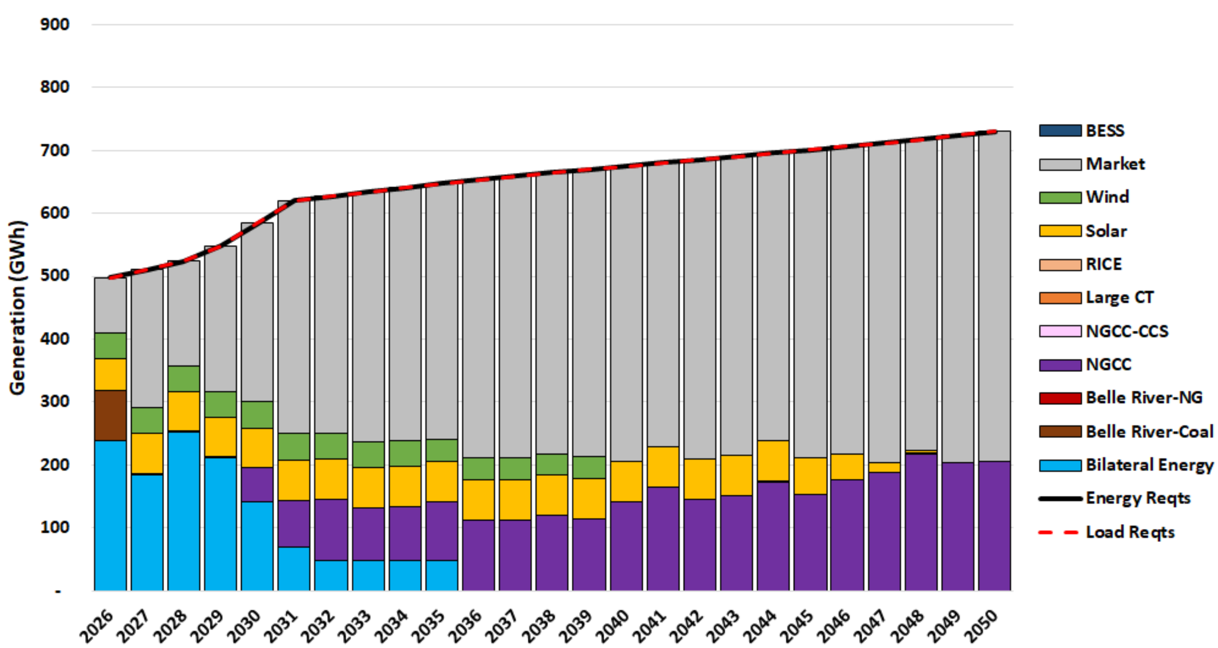

Figure A-4: Energy Generated by Resource Type – BAU Economically Optimized (High Fuel Price)

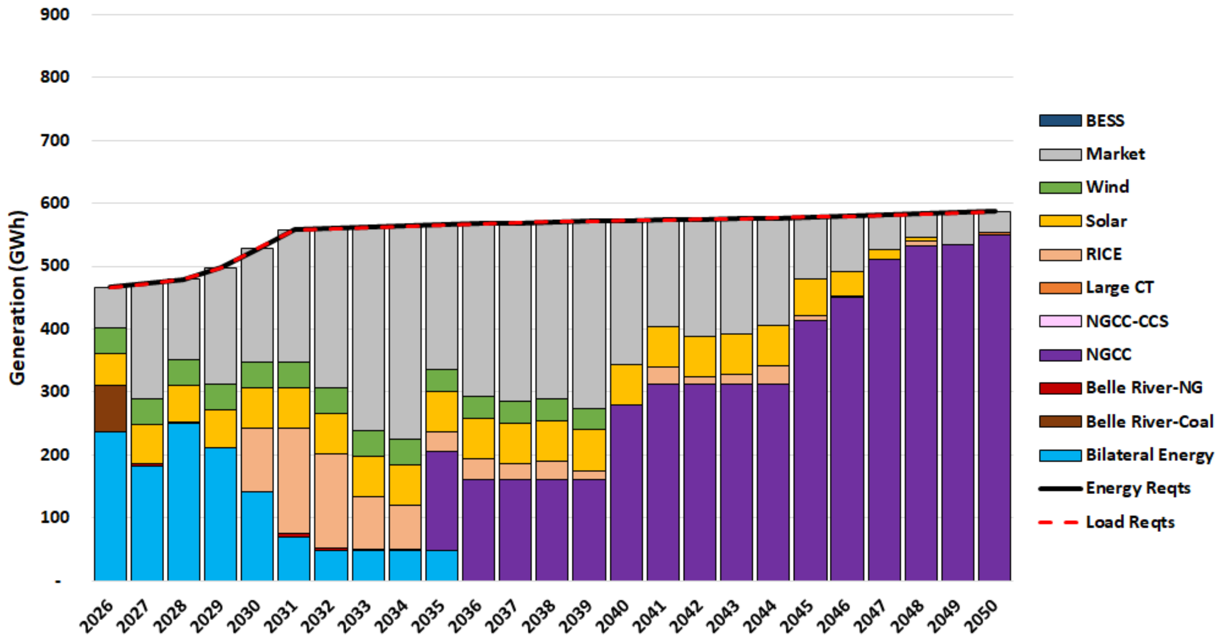

Figure A-5: Energy Generated by Resource Type – BAU Large Units Available 2035 (Low Load Growth)

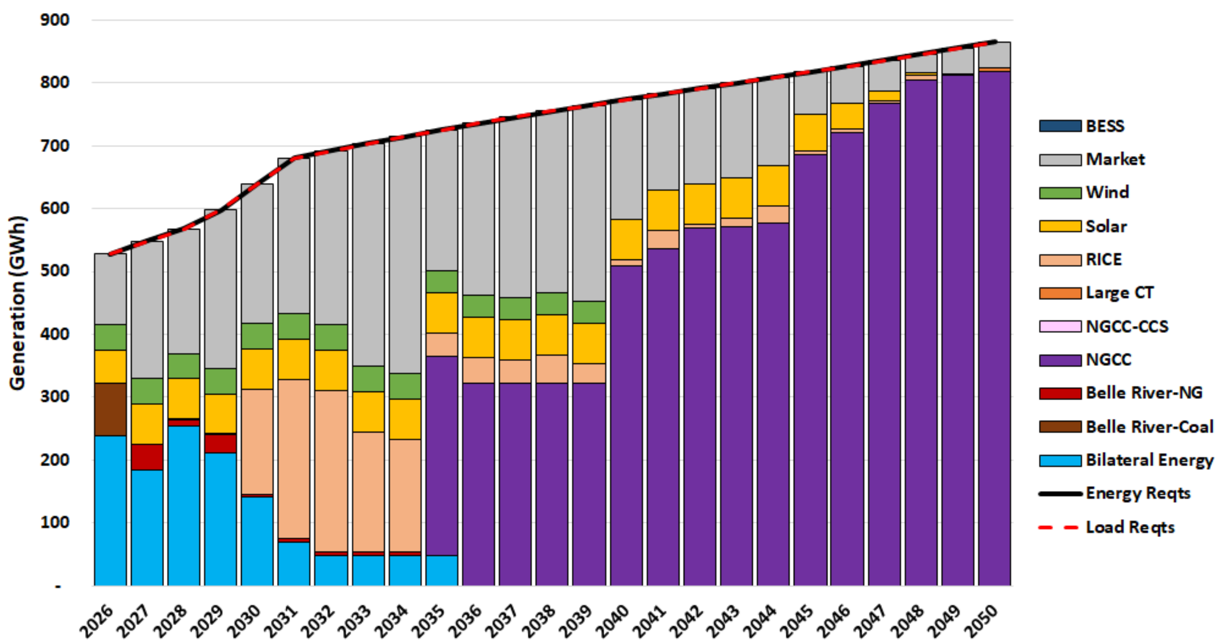

Figure A-6: Energy Generated by Resource Type – BAU Large Units Available 2035 (High Load Growth)

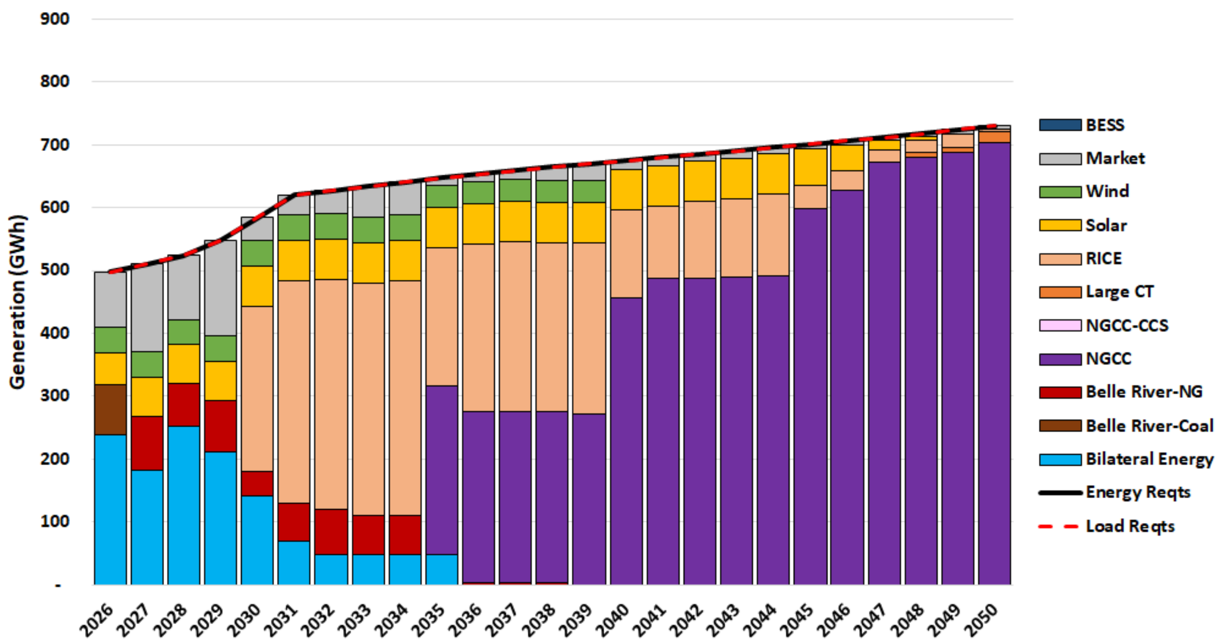

Figure A-7: Energy Generated by Resource Type – BAU Large Units Available 2035 (Low Fuel Price)

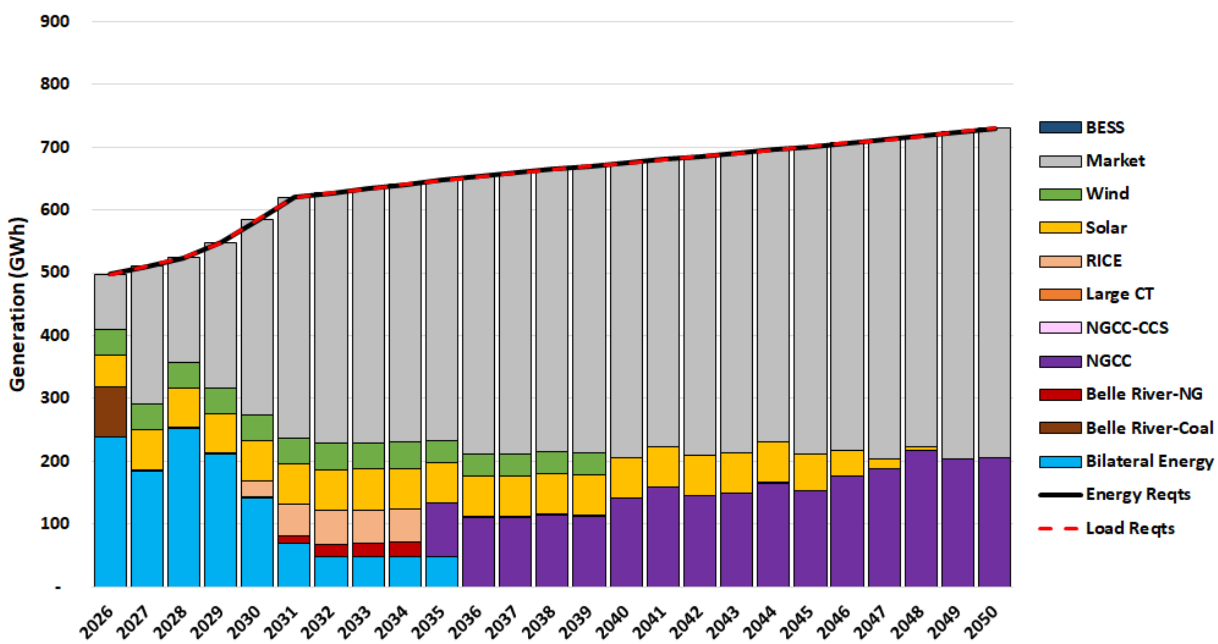

Figure A-8: Energy Generated by Resource Type – BAU Large Units Available 2035 (High Fuel Price)

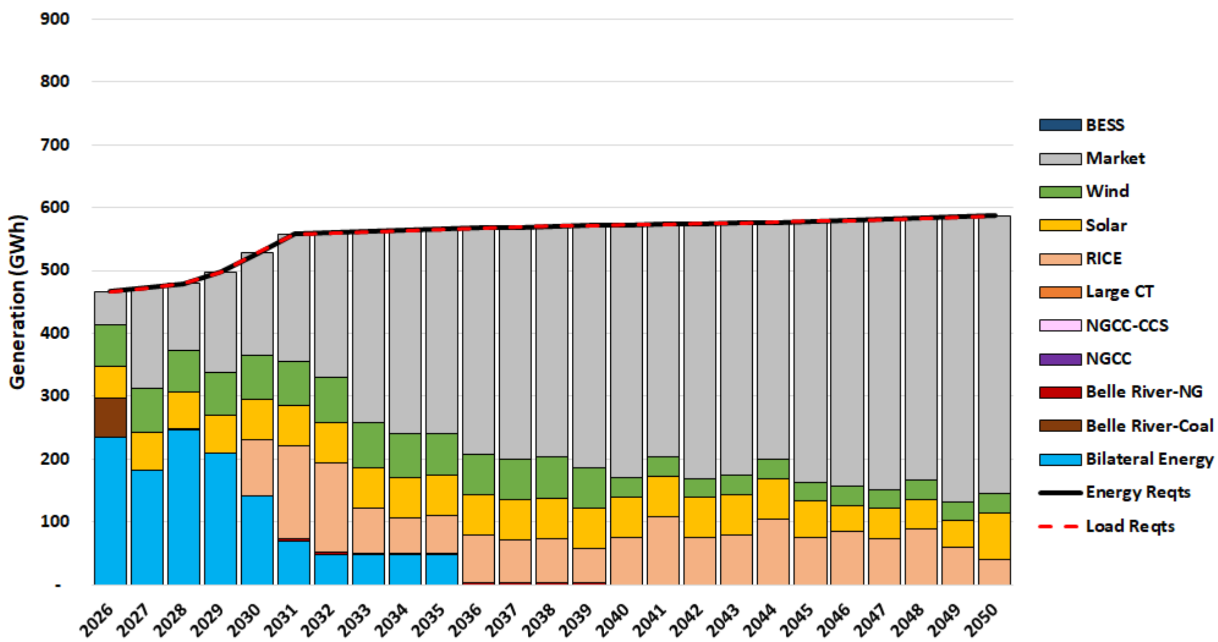

Figure A-9: Energy Generated by Resource Type – BAU Local Generation (Low Load Growth)

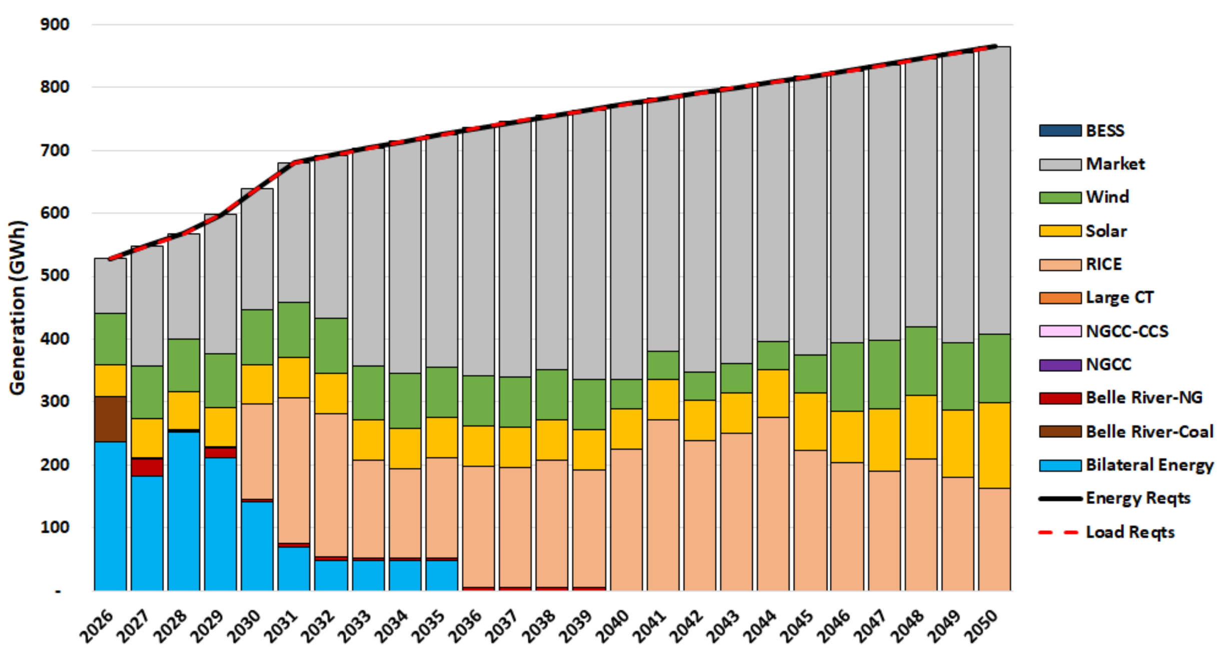

Figure A10: Energy Generated by Resource Type – BAU Local Generation (High Load Growth)

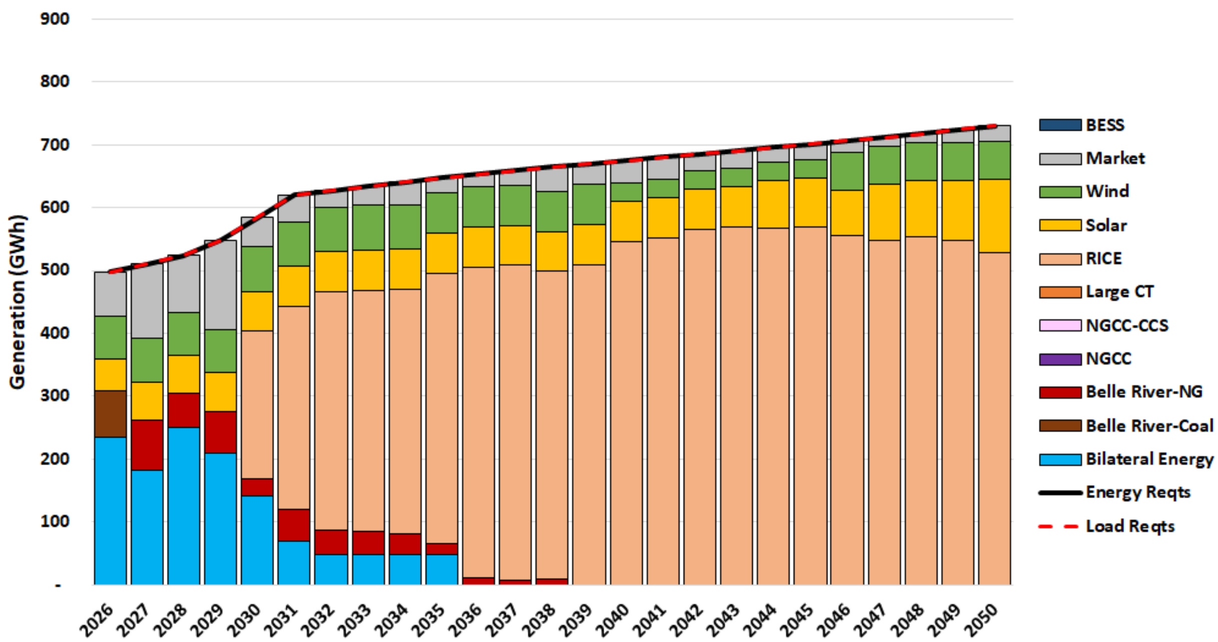

Figure A-11: Energy Generated by Resource Type – BAU Local Generation (Low Fuel Price)

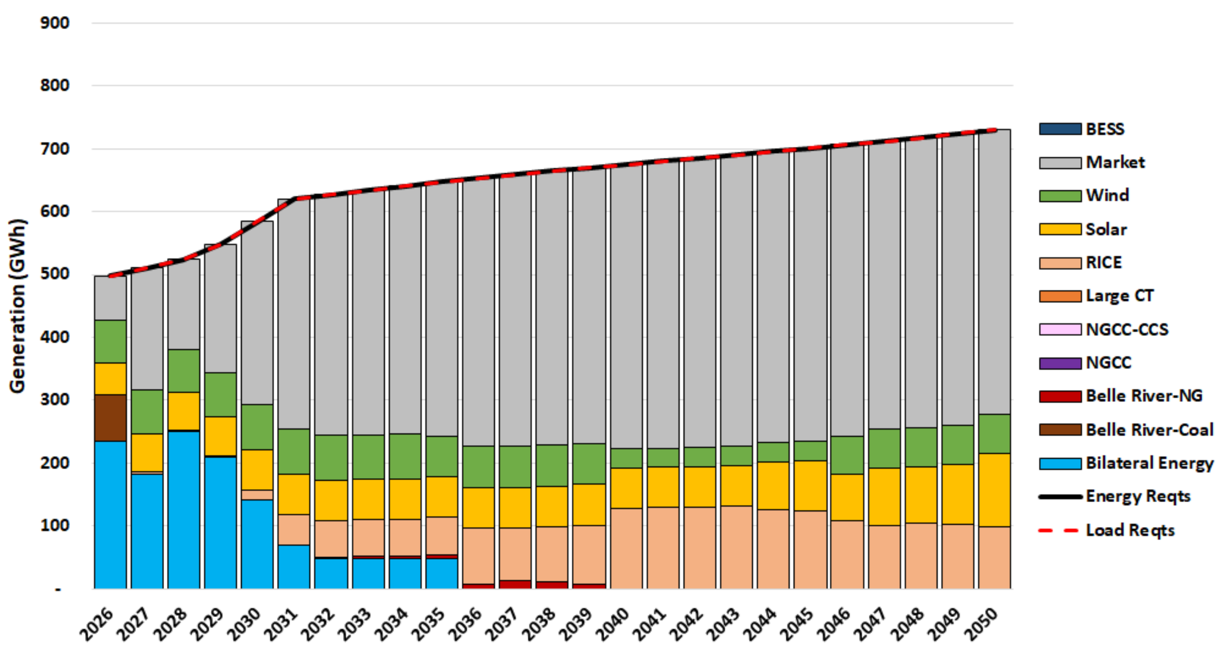

Figure A-12: Energy Generated by Resource Type – BAU Local Generation (High Fuel Price)

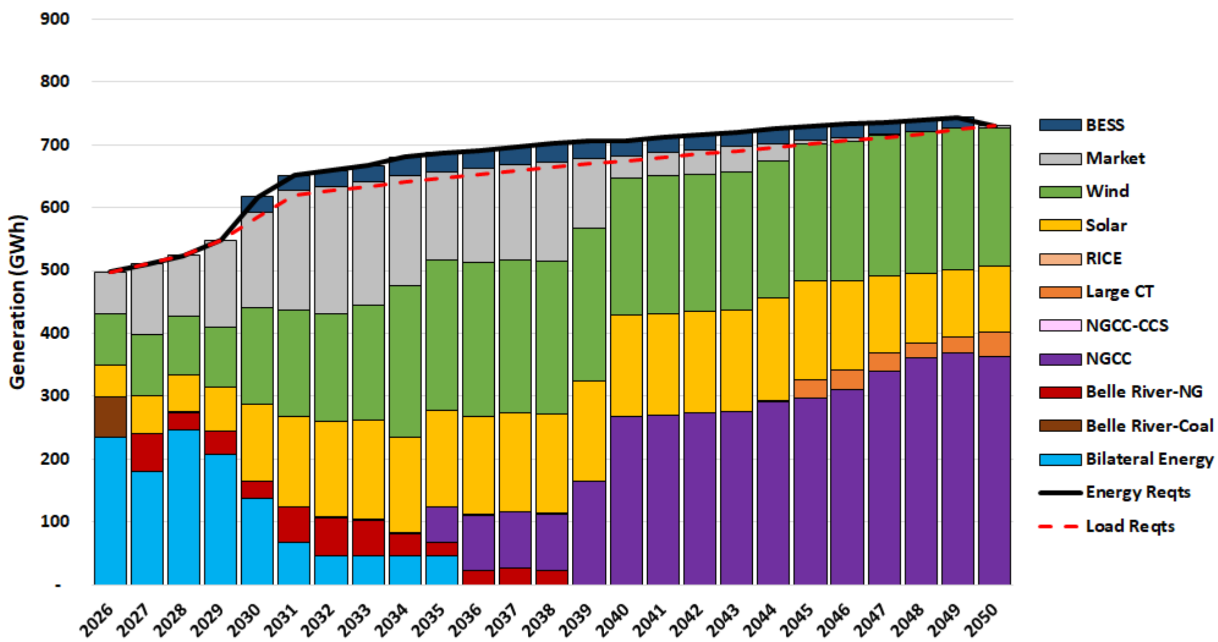

Figure A-13: Energy Generated by Resource Type – Early Renewables with no PA 235 (Low Fuel Price)

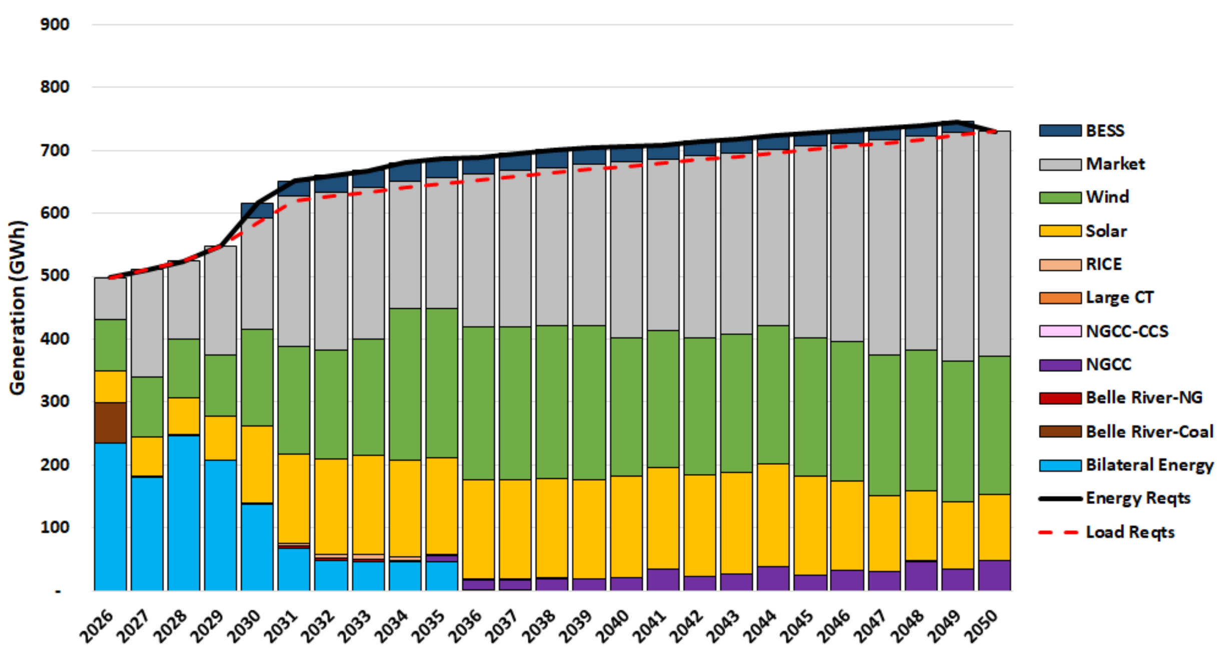

Figure A-14: Energy Generated by Resource Type – Early Renewables with no PA 235 (High Fuel Price)

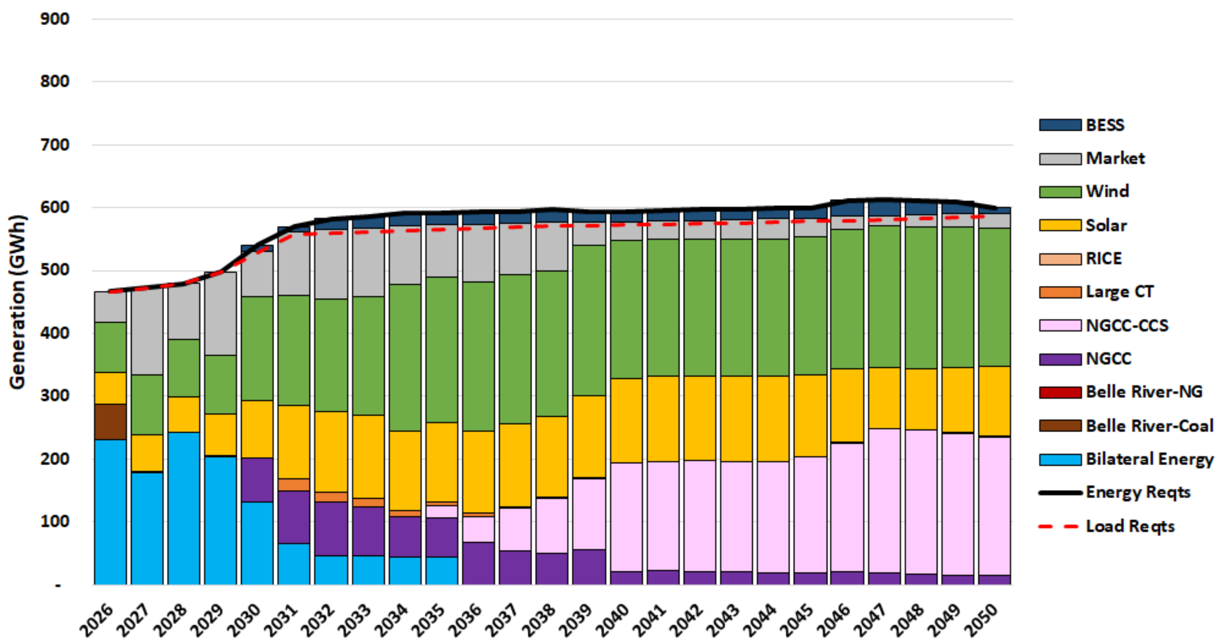

Figure A-15: Energy Generated by Resource Type – PA 235 Economically Optimized (Low Load Growth)

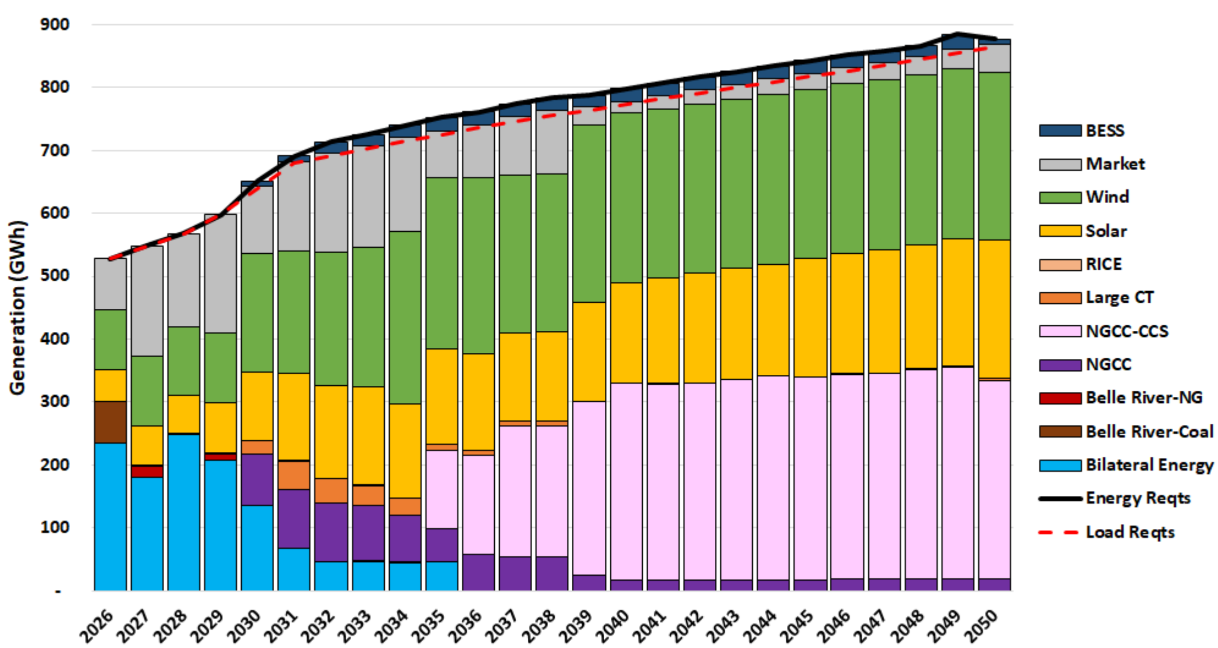

Figure A-16: Energy Generated by Resource Type – PA 235 Economically Optimized (High Load Growth)

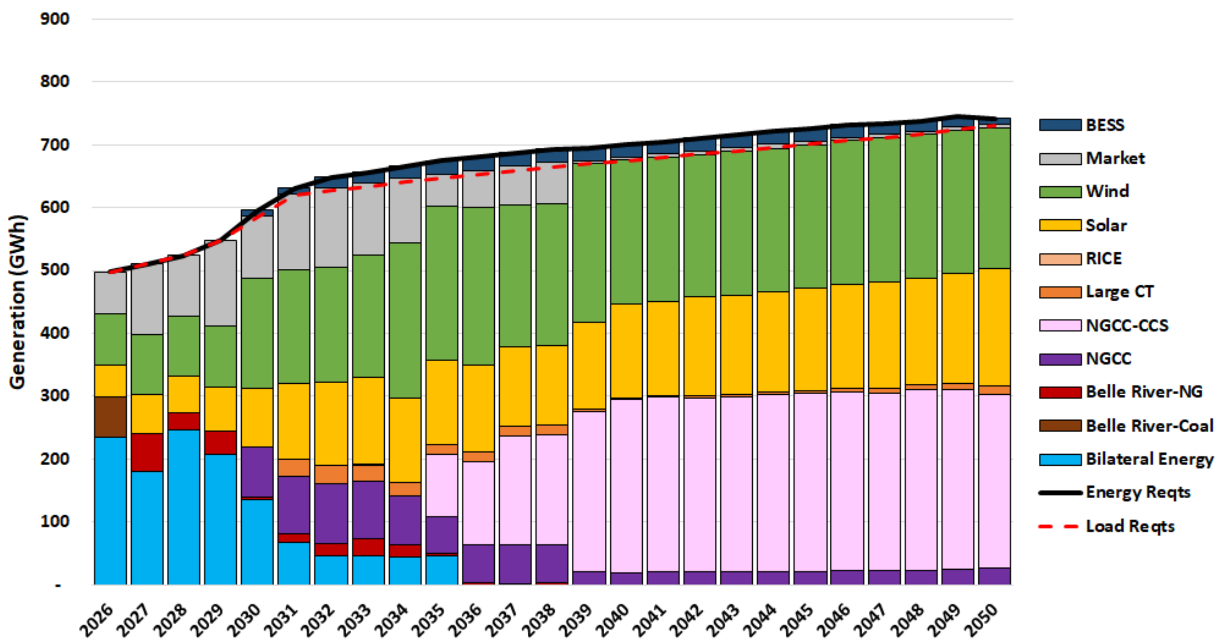

Figure A-17: Energy Generated by Resource Type – PA 235 Economically Optimized (Low Fuel Price)

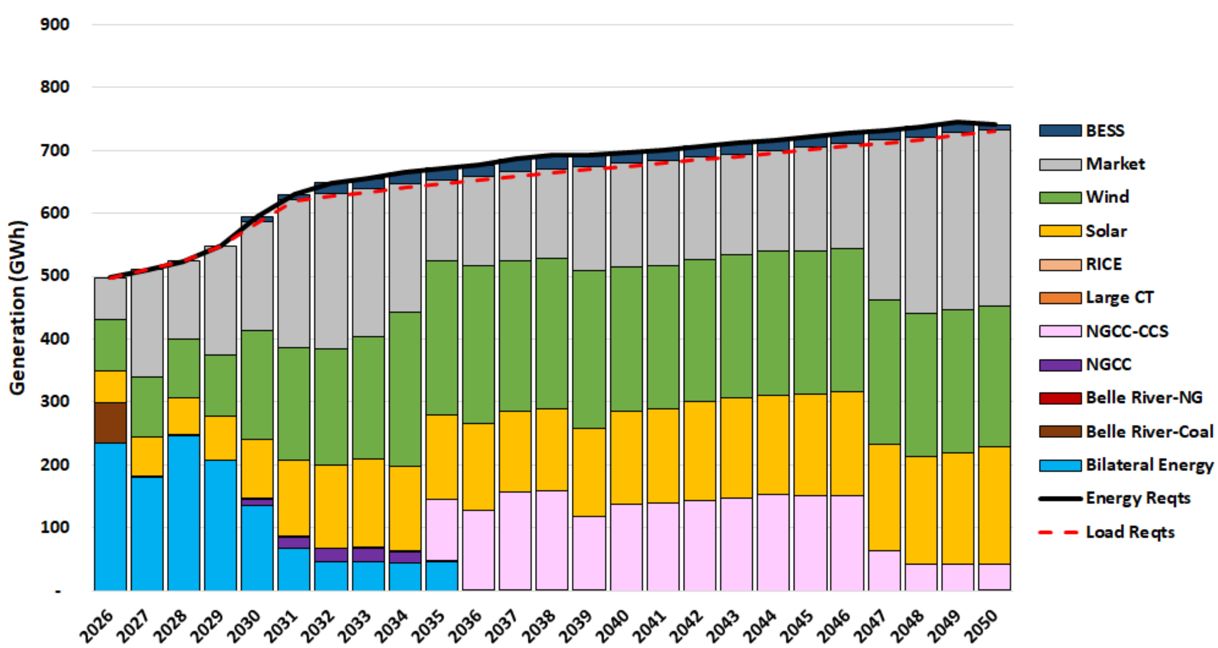

Figure A-18: Energy Generated by Resource Type – PA 235 Economically Optimized (High Fuel Price)

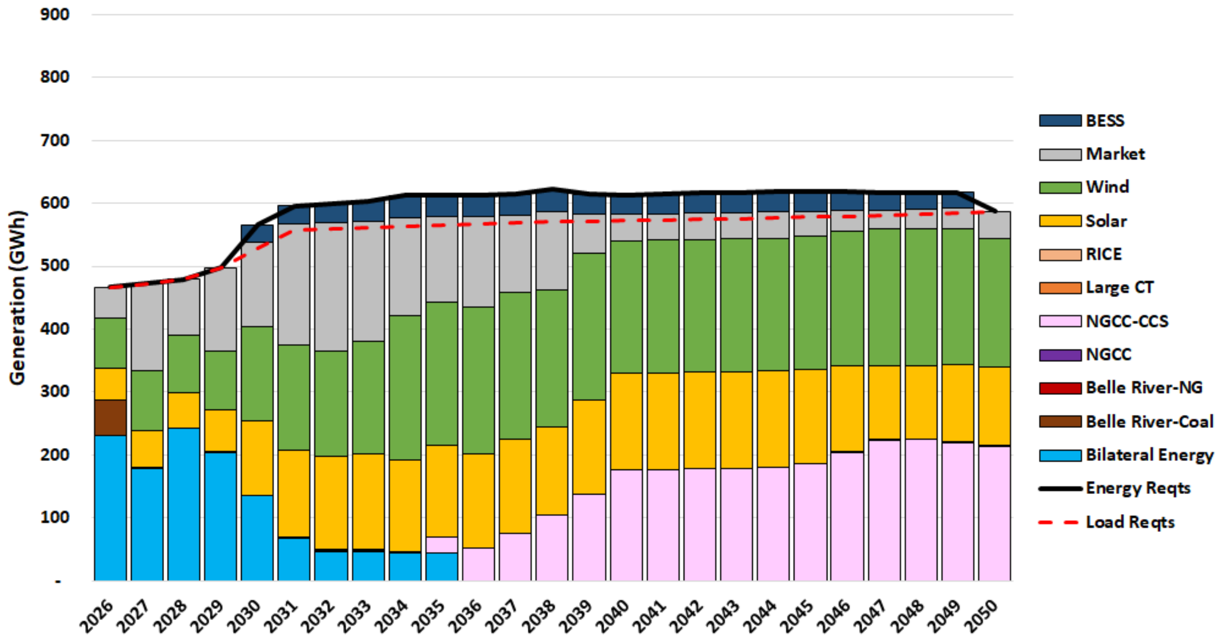

Figure A-19: Energy Generated by Resource Type – PA 235 Large Units Available 2035 (Low Load Growth)

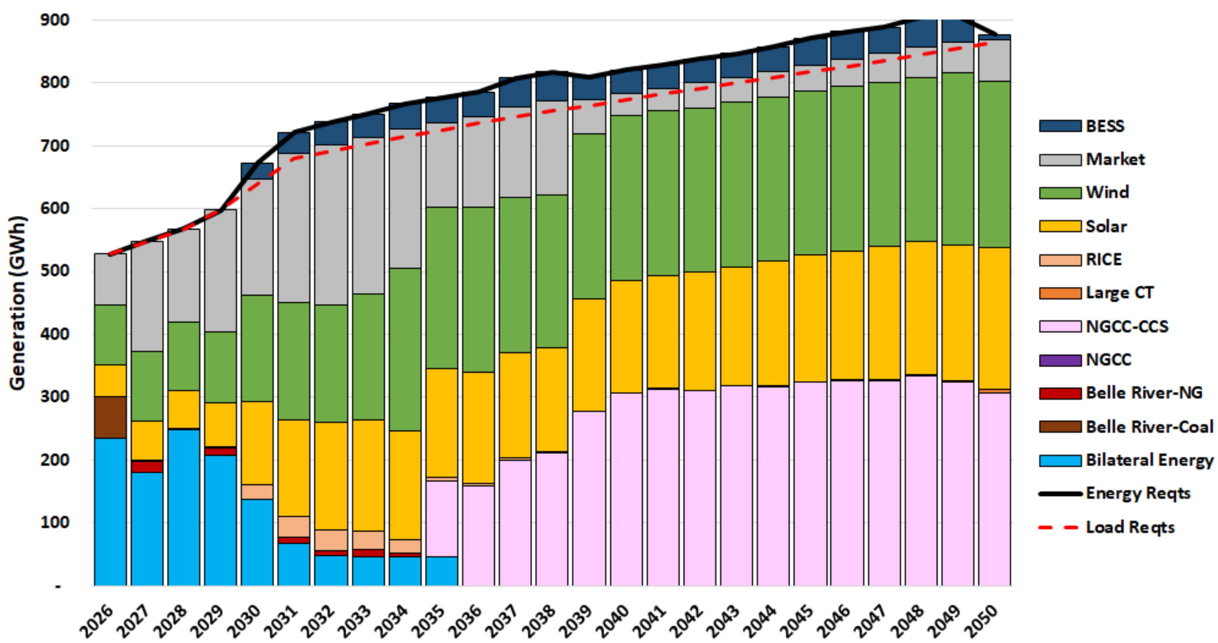

Figure A-20: Energy Generated by Resource Type – PA 235 Large Units Available 2035 (High Load Growth)

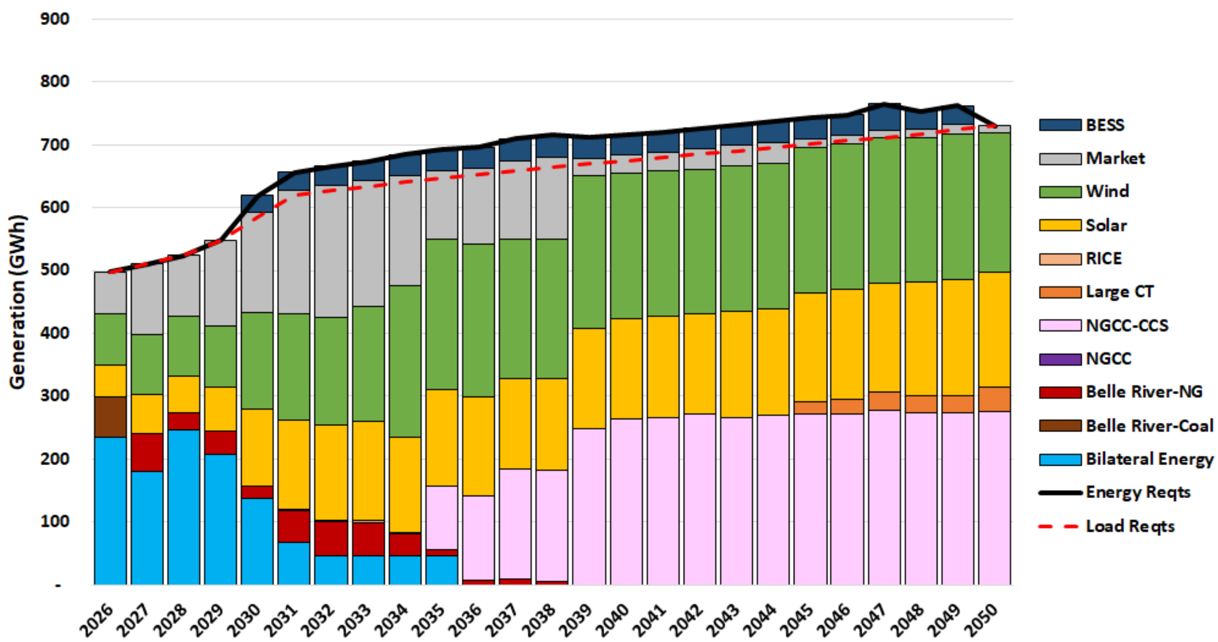

Figure A-21: Energy Generated by Resource Type – PA 235 Large Units Available 2035 (Low Fuel Price)

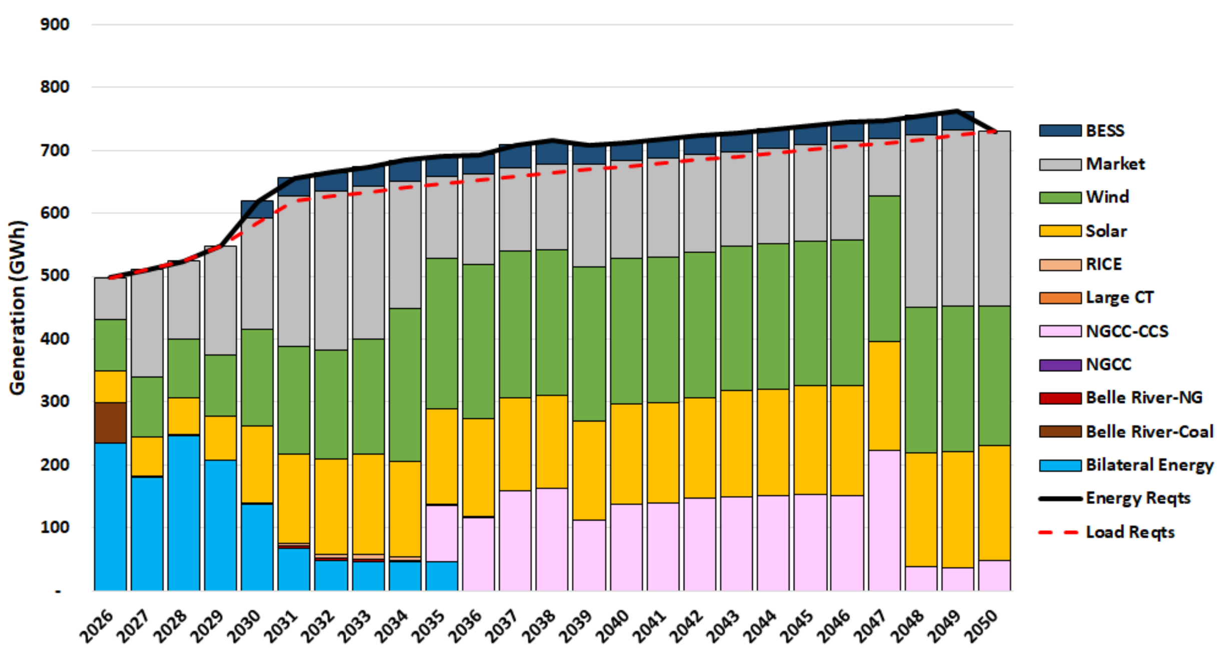

Figure A-22: Energy Generated by Resource Type – PA 235 Large Units Available 2035 (High Fuel Price)

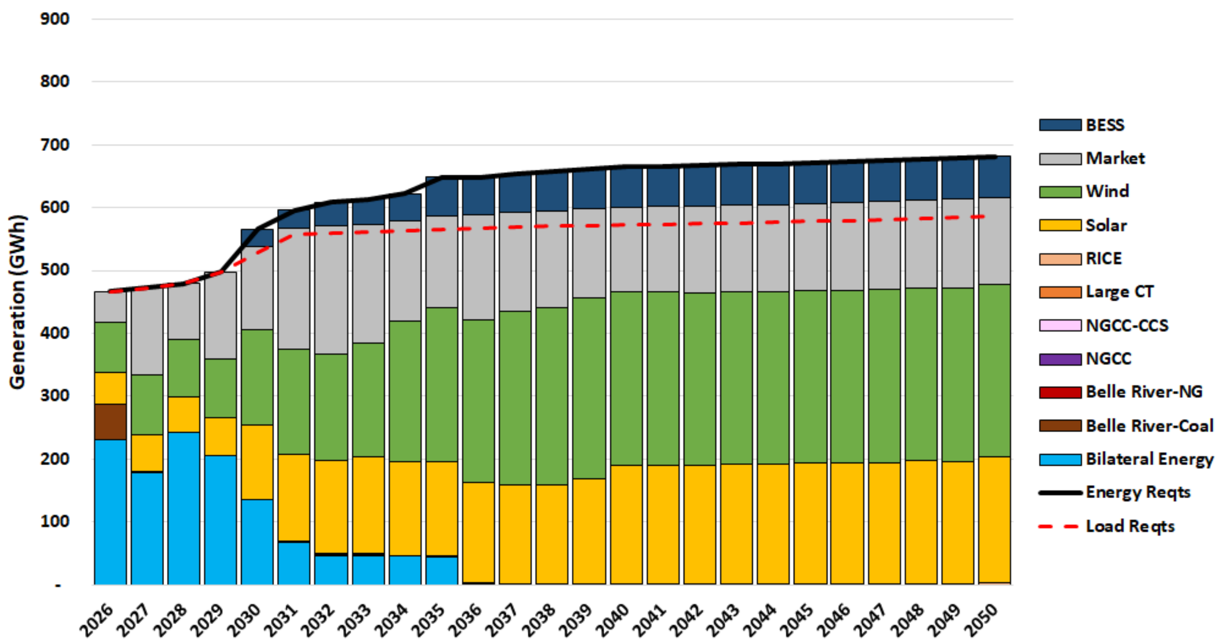

Figure A-23: Energy Generated by Resource Type – PA 235 Local Generation (Low Load Growth)

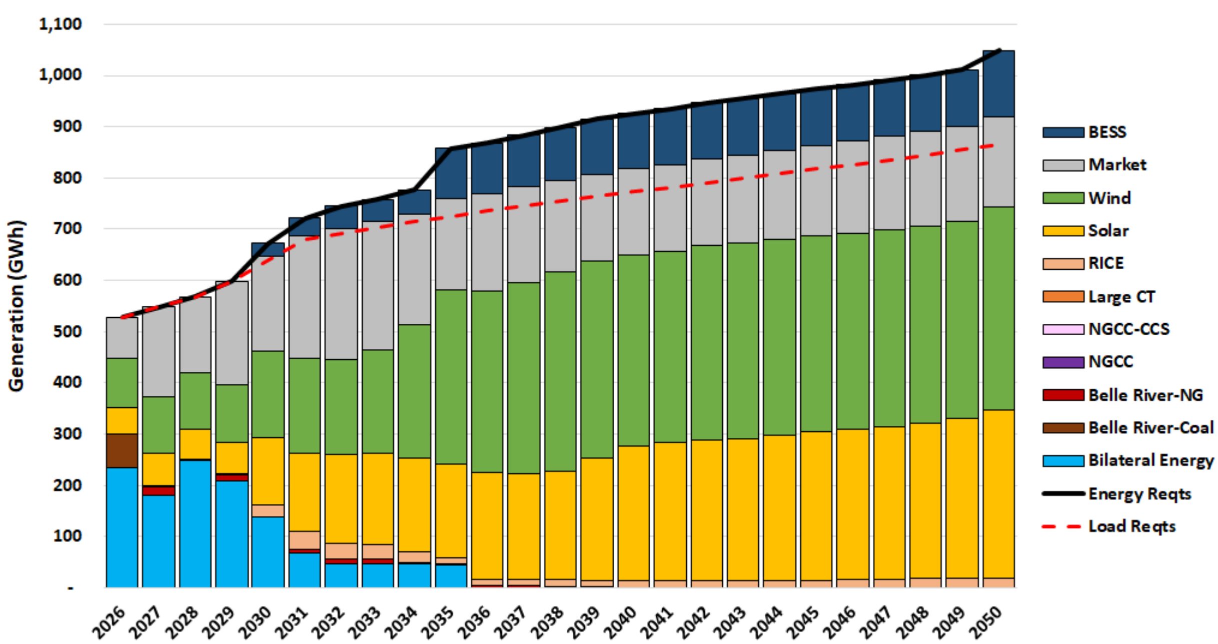

Figure A-24: Energy Generated by Resource Type – PA 235 Local Generation (High Load Growth)

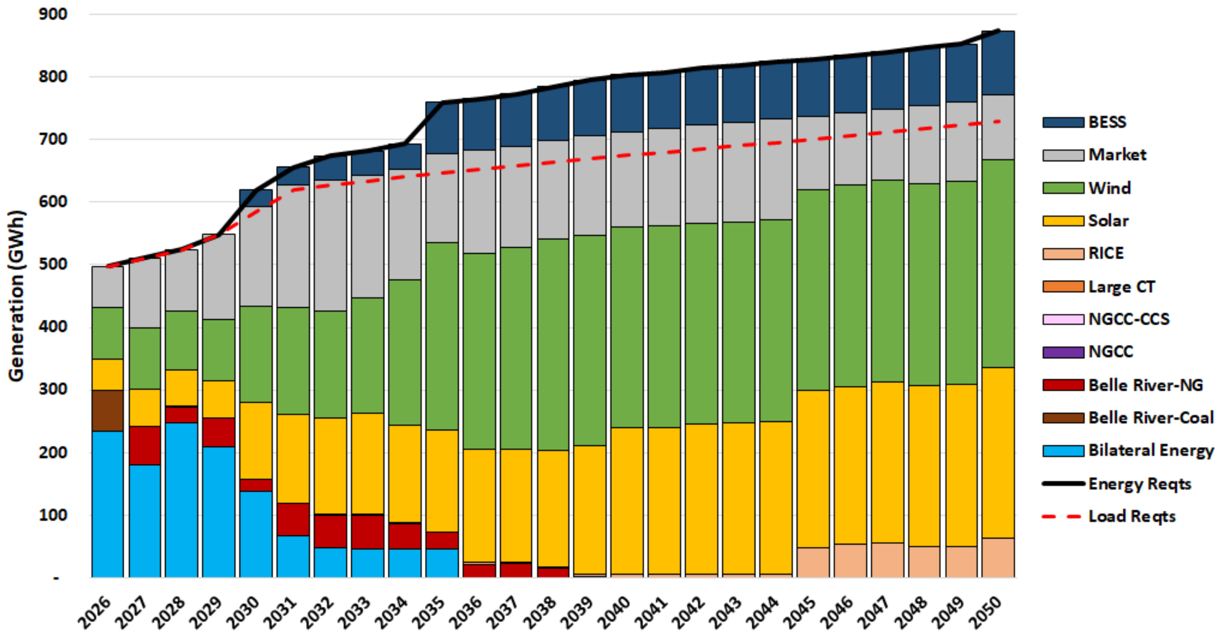

Figure A-25: Energy Generated by Resource Type – PA 235 Local Generation (Low Fuel Price)

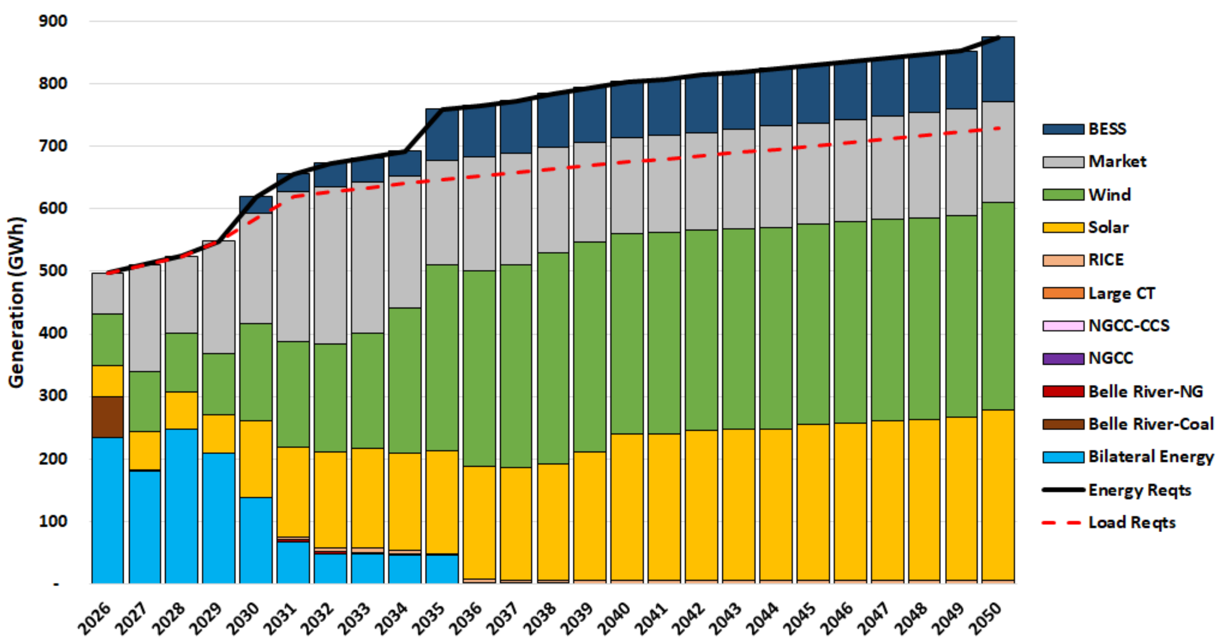

Figure A-26: Energy Generated by Resource Type – PA 235 Local Generation (High Fuel Price)

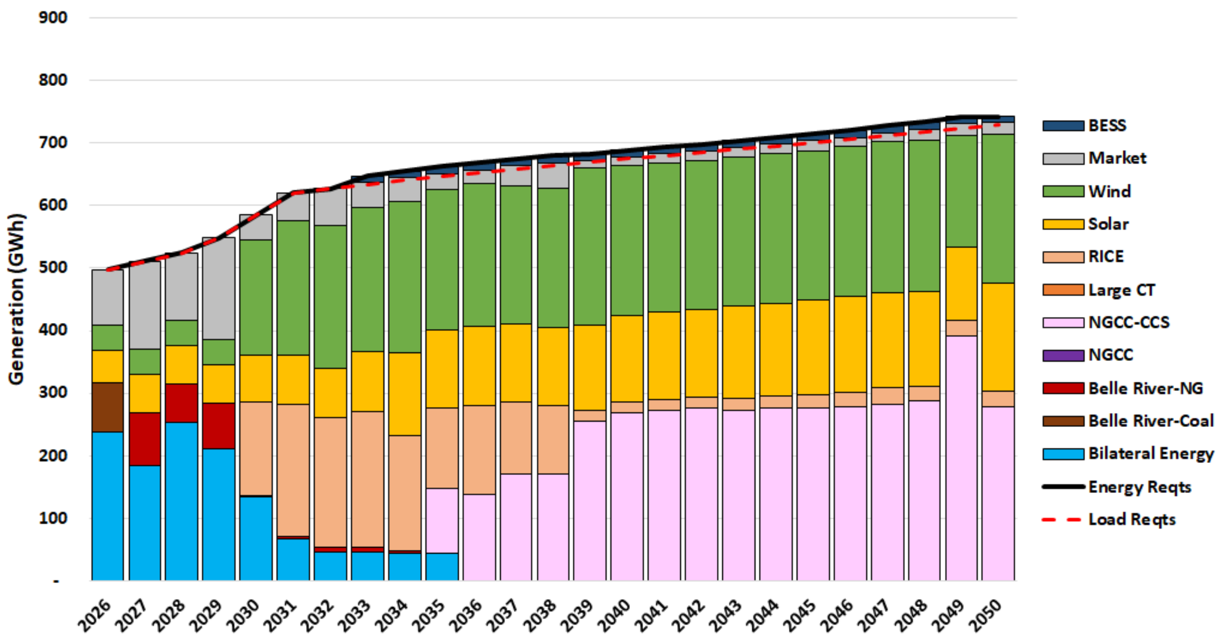

Figure A-27: Energy Generated by Resource Type – Early Local RICE with PA 235 (Low Fuel Price)

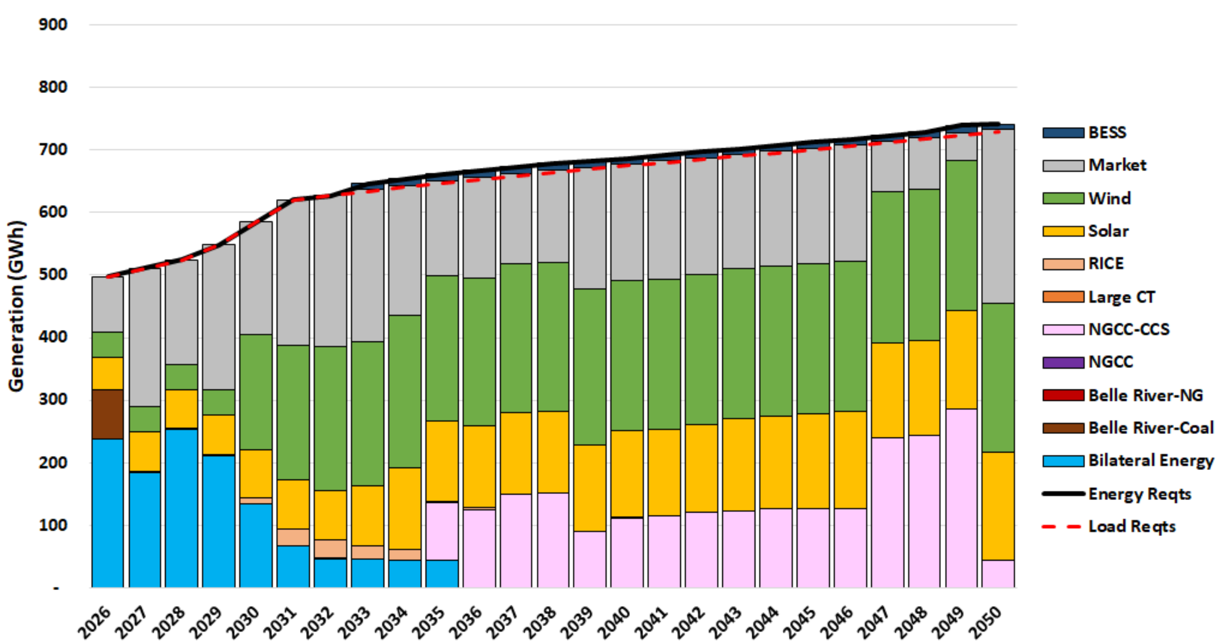

Figure A-28: Energy Generated by Resource Type – Early Local RICE with PA 235 (High Fuel Price)

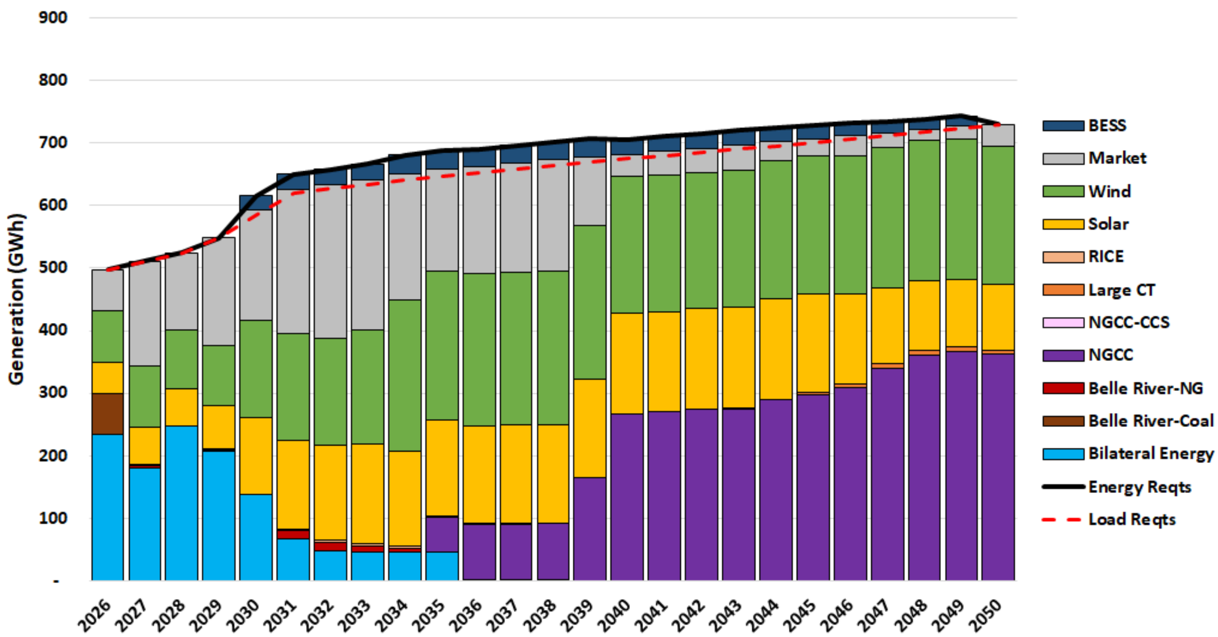

Figure A-29: Energy Generated by Resource Type – Early Renewables without PA 235

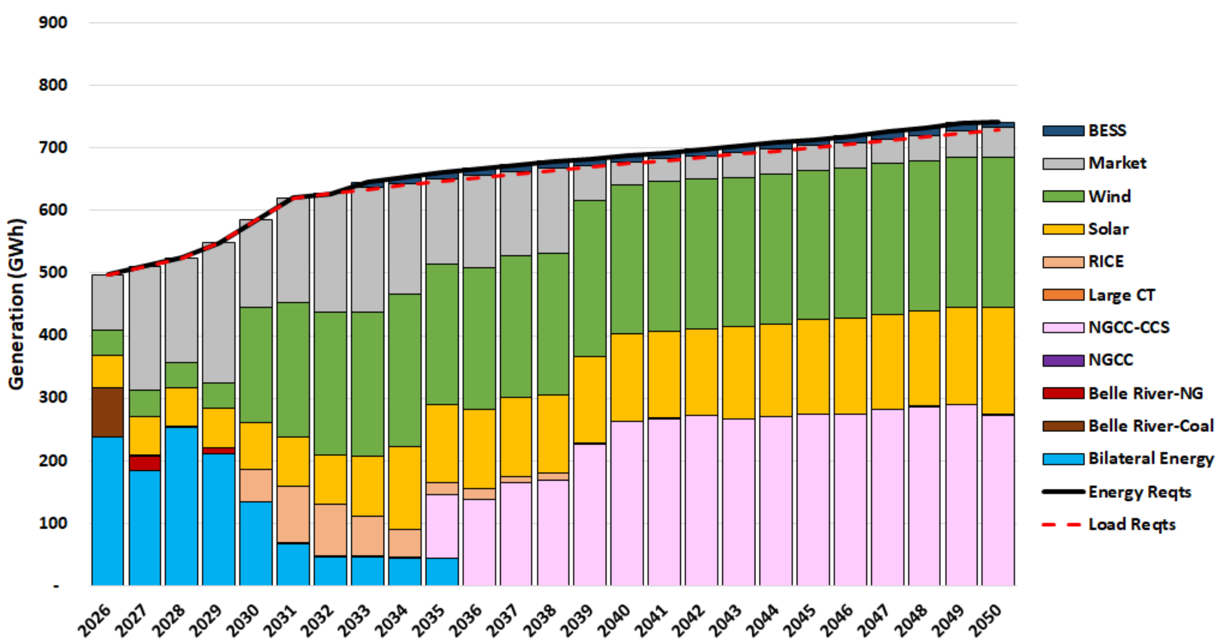

Figure A-30: Energy Generated by Resource Type – Local RICE with PA 235

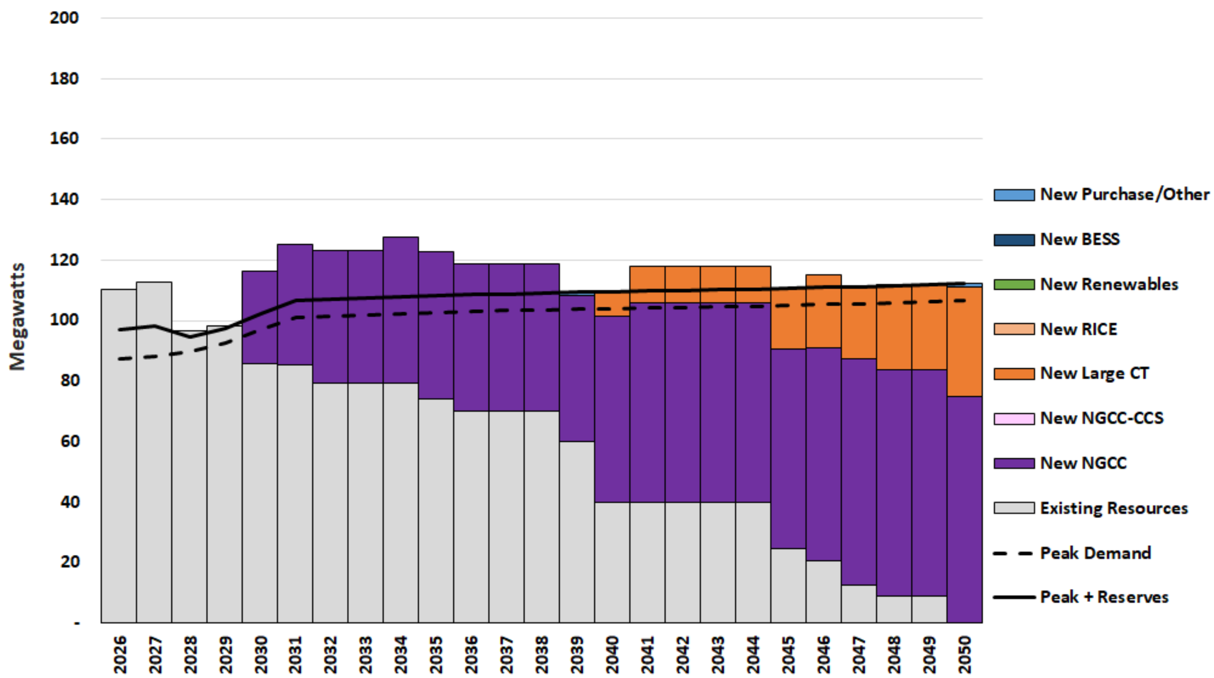

Figure A-31: Total Summer Firm Capacity (MW) by Type – BAU Economically Optimized (Low Load Growth)

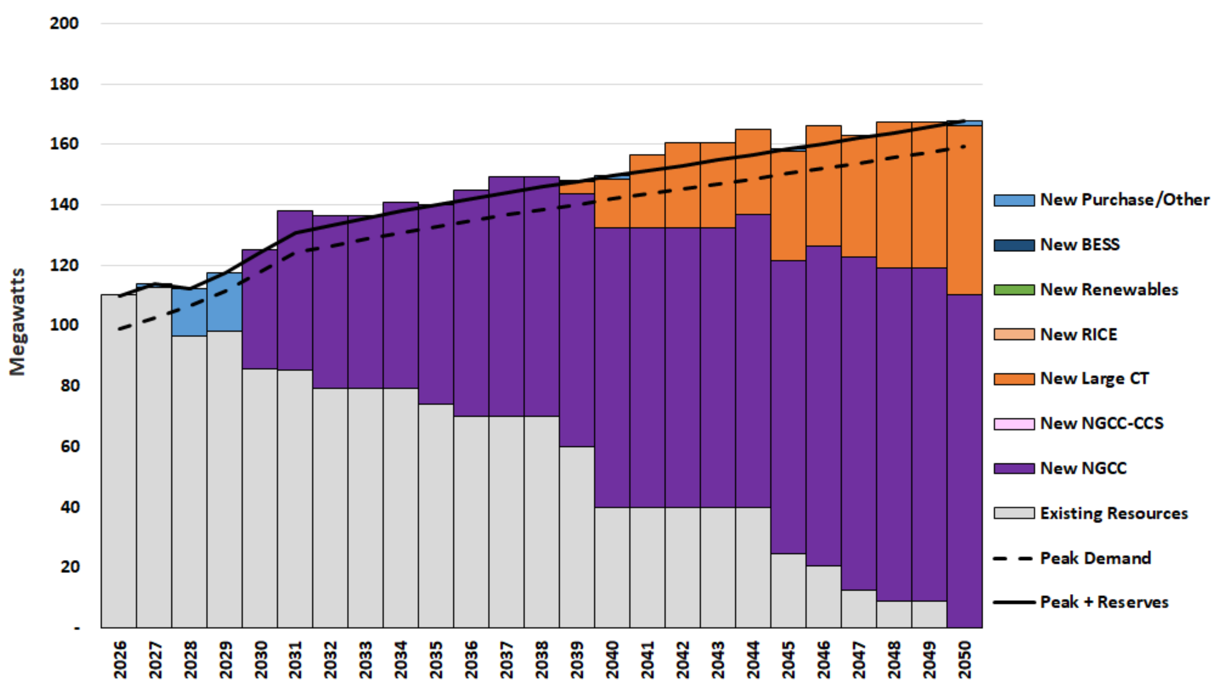

Figure A-32: Total Summer Firm Capacity (MW) by Type – BAU Economically Optimized (High Load Growth)

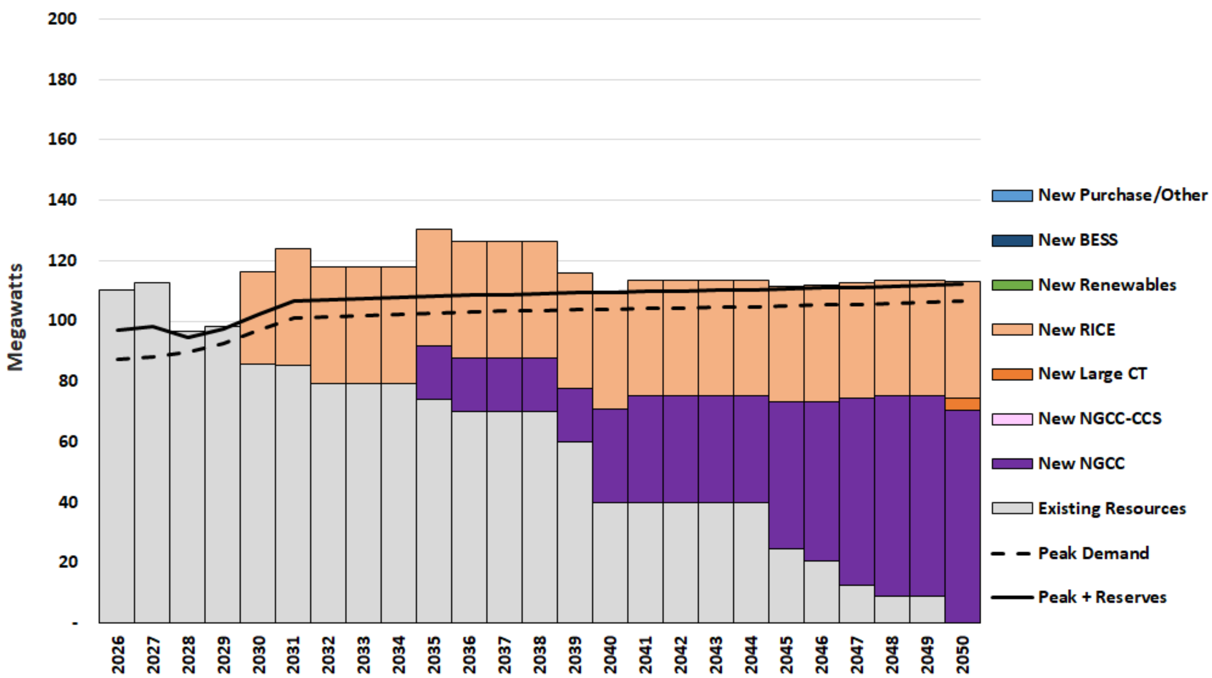

Figure A-33: Total Summer Firm Capacity (MW) by Type – BAU Large Units Available 2035 (Low Load Growth)

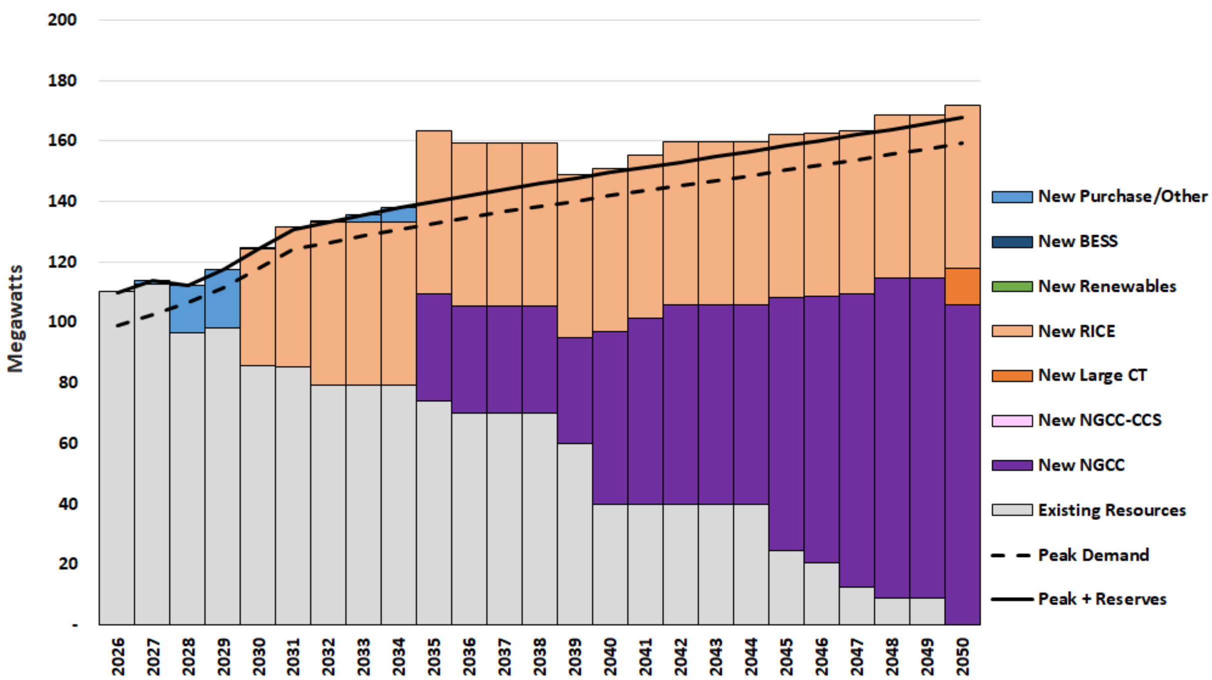

Figure A-34: Total Summer Firm Capacity (MW) by Type – BAU Large Units Available 2035 (High Load Growth)

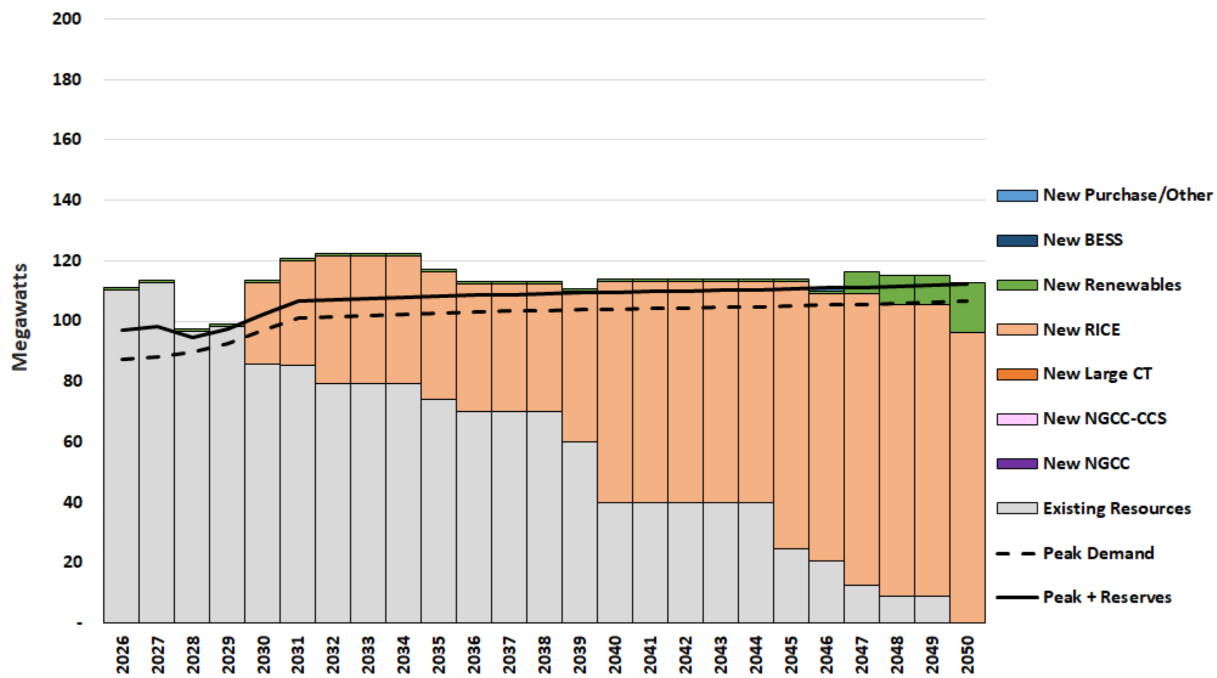

Figure A-35: Total Summer Firm Capacity (MW) by Type – BAU Local Generation (Low Load Growth)

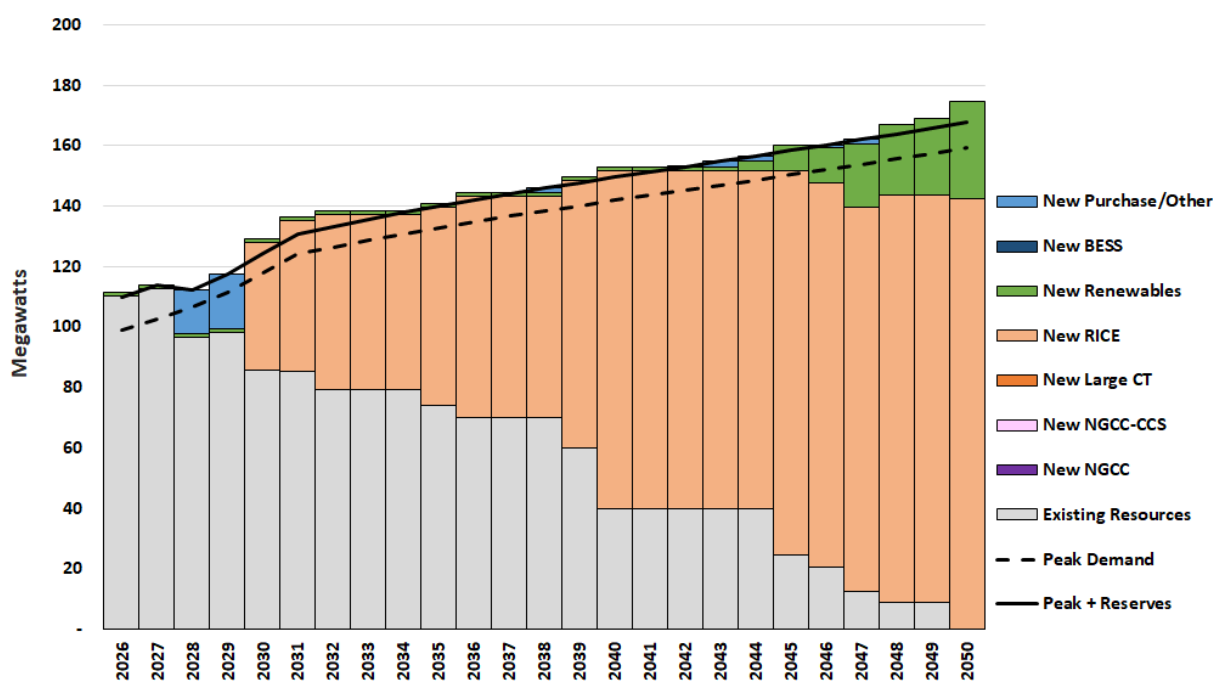

Figure A-36: Total Summer Firm Capacity (MW) by Type – BAU Local Generation (High Load Growth)

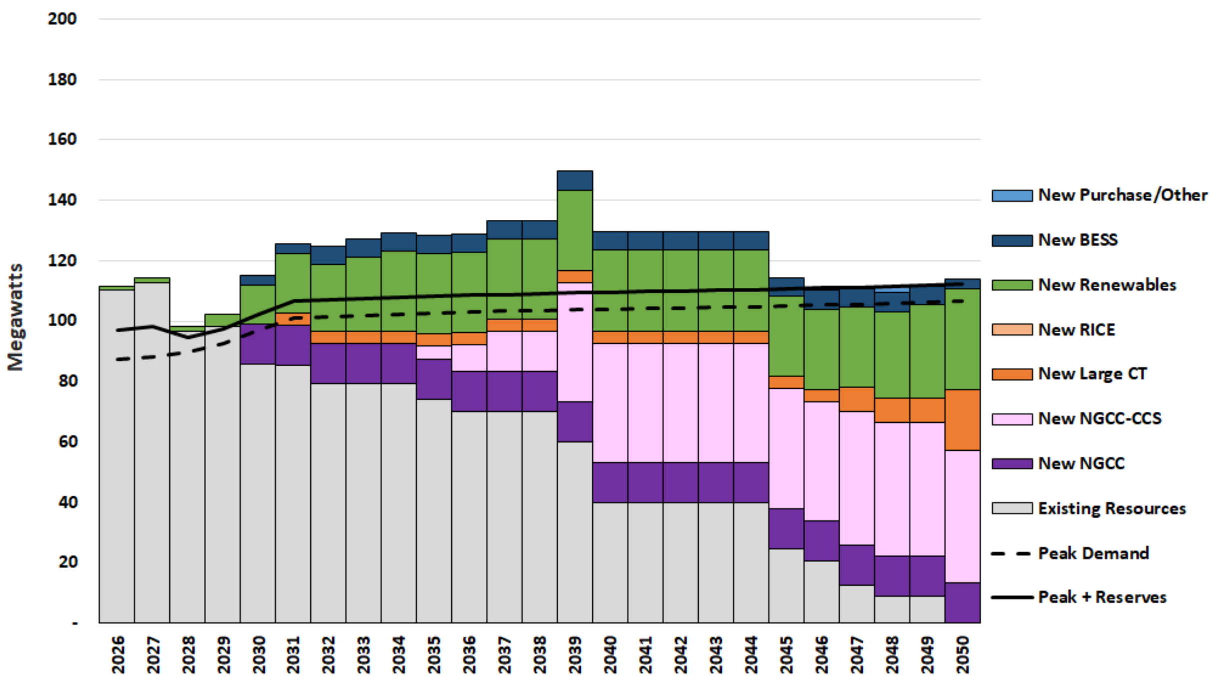

Figure A-37: Total Summer Firm Capacity (MW) by Type – PA 235 Economically Optimized (Low Load Growth)

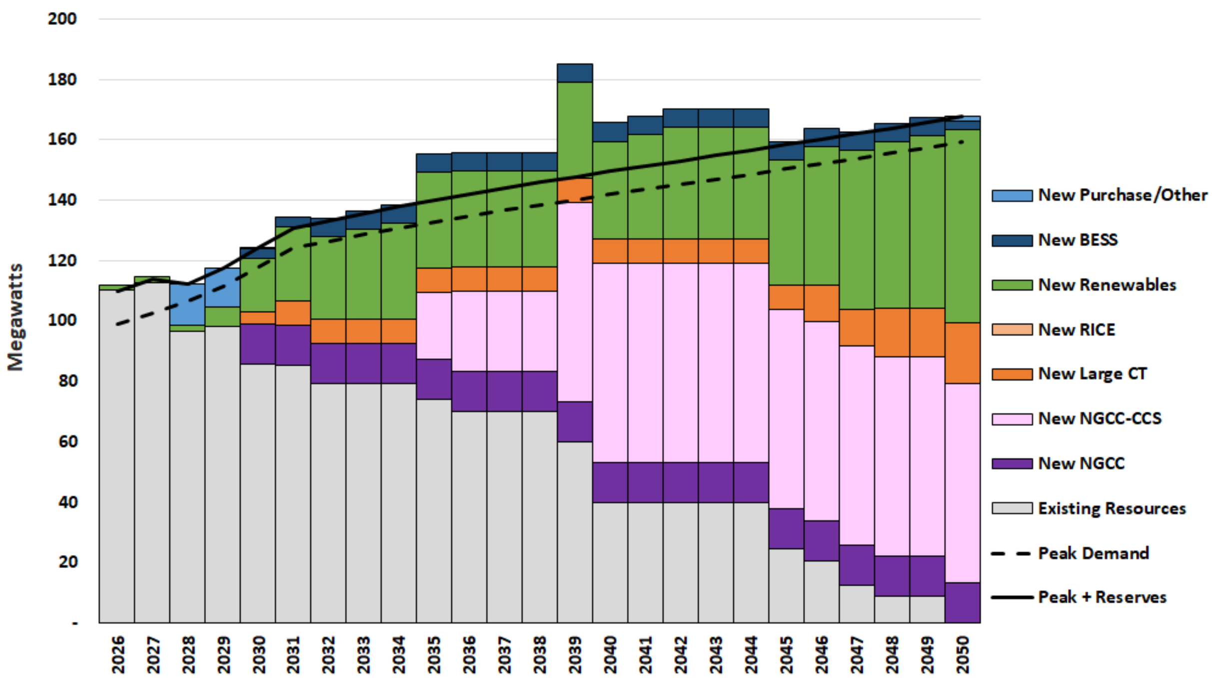

Figure A-38: Total Summer Firm Capacity (MW) by Type – PA 235 Economically Optimized (High Load Growth)

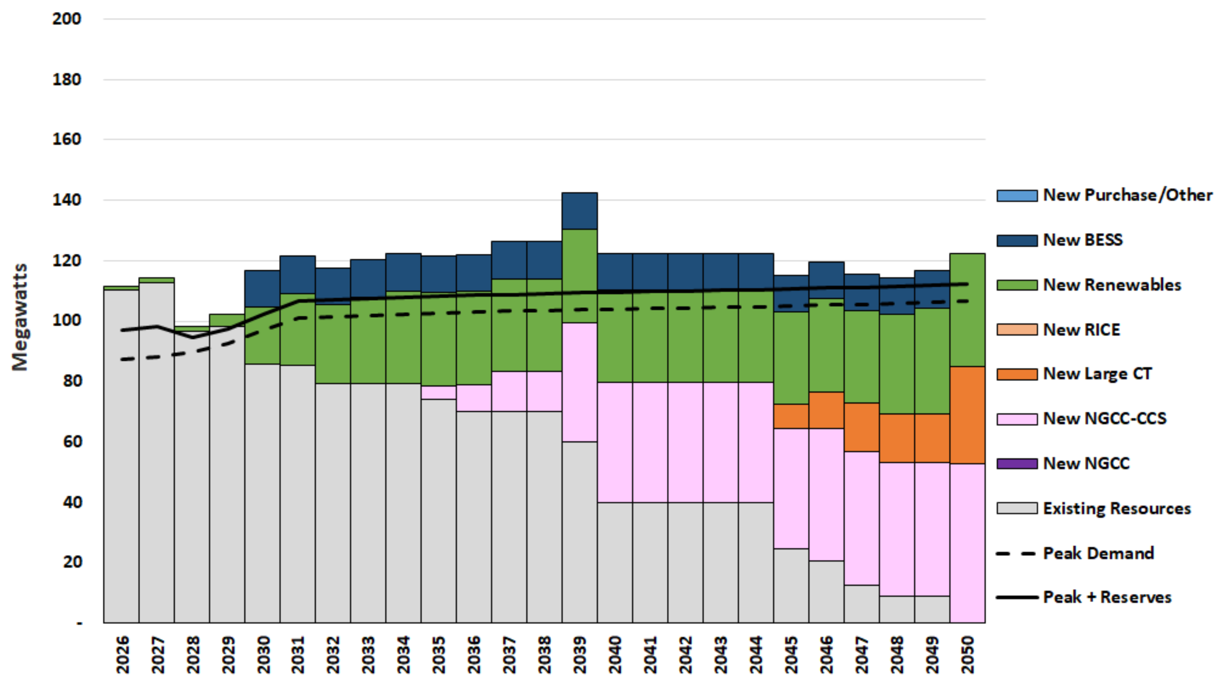

Figure A-39: Total Summer Firm Capacity (MW) by Type – PA 235 Large Units Available 2035 (Low Load Growth)

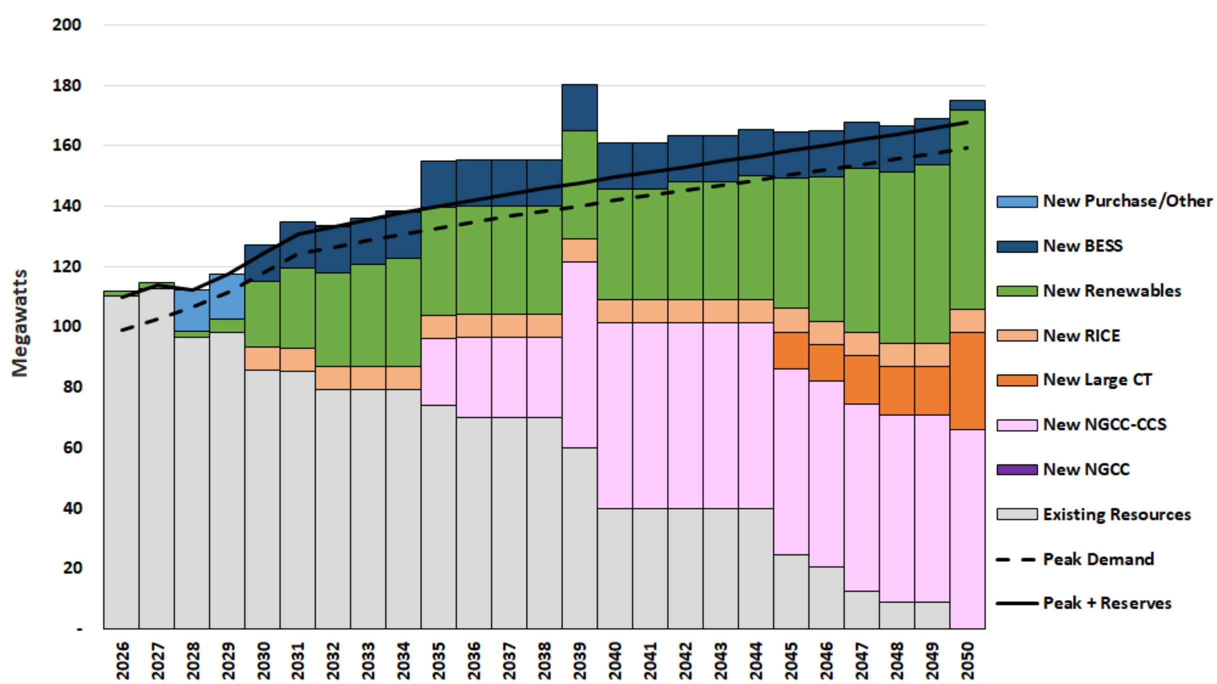

Figure A-40: Total Summer Firm Capacity (MW) by Type – PA 235 Large Units Available 2035 (High Load Growth)

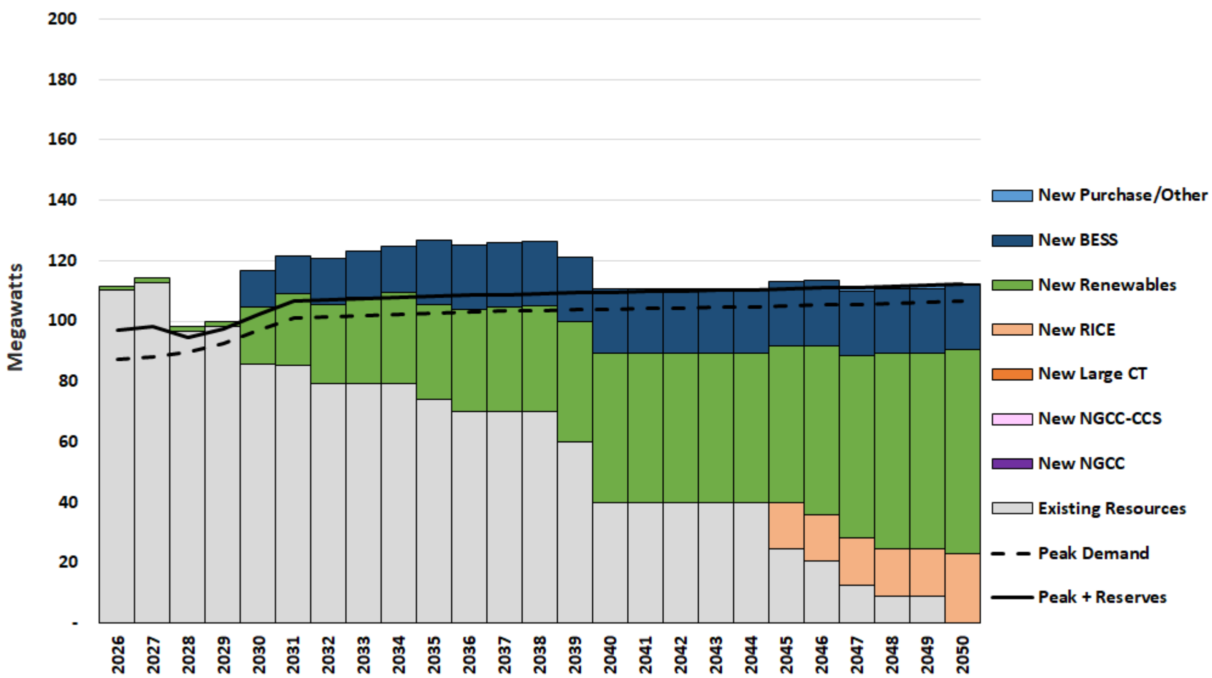

Figure A-41: Total Summer Firm Capacity (MW) by Type – PA 235 Local Generation (Low Load Growth)

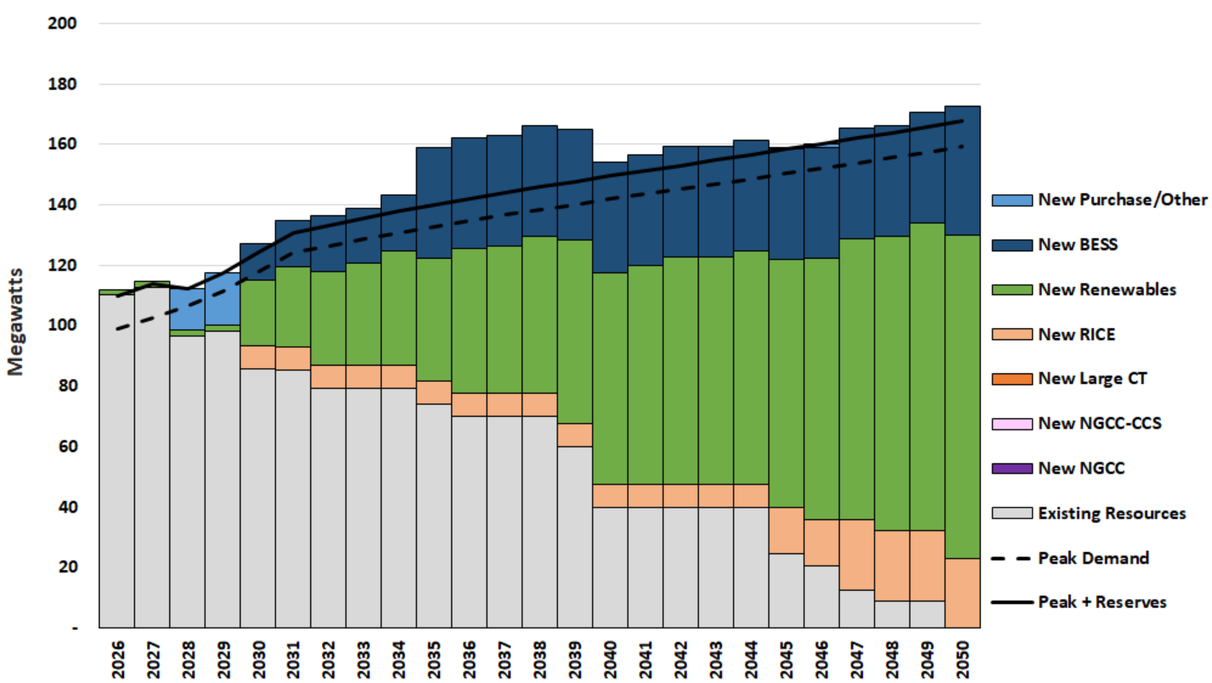

Figure A-42: Total Summer Firm Capacity (MW) by Type – PA 235 Local Generation (High Load Growth)

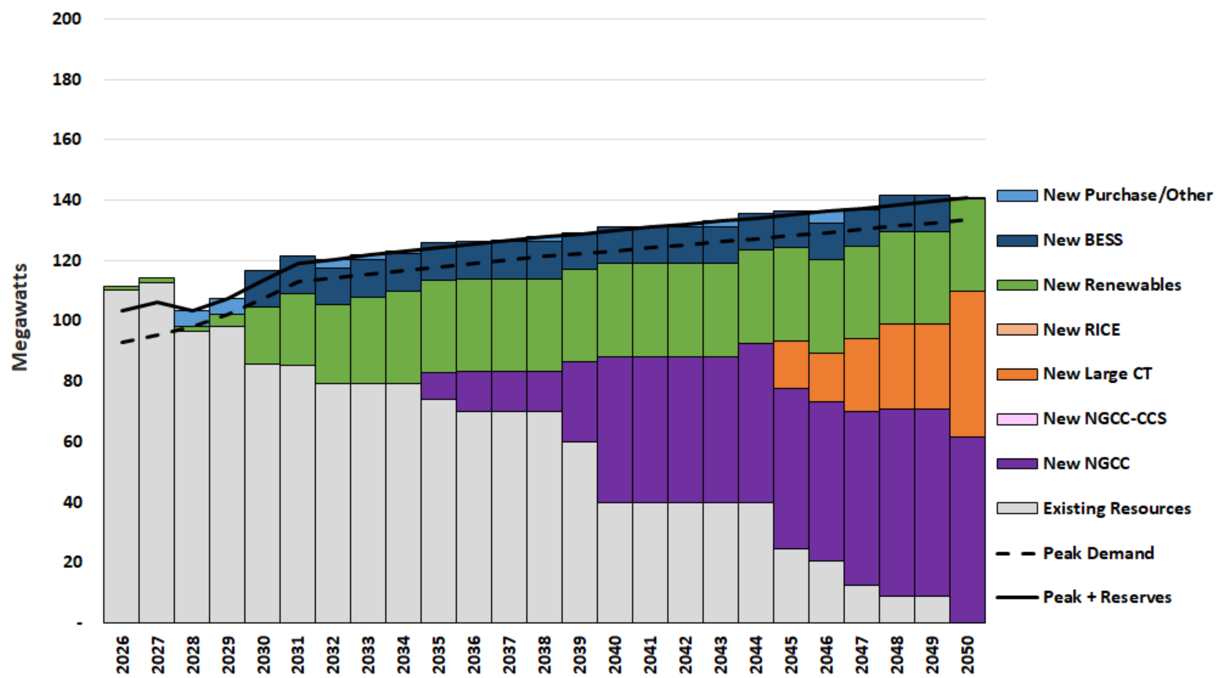

Figure A-43: Total Summer Firm Capacity (MW) by Type – Early Renewables without PA 235

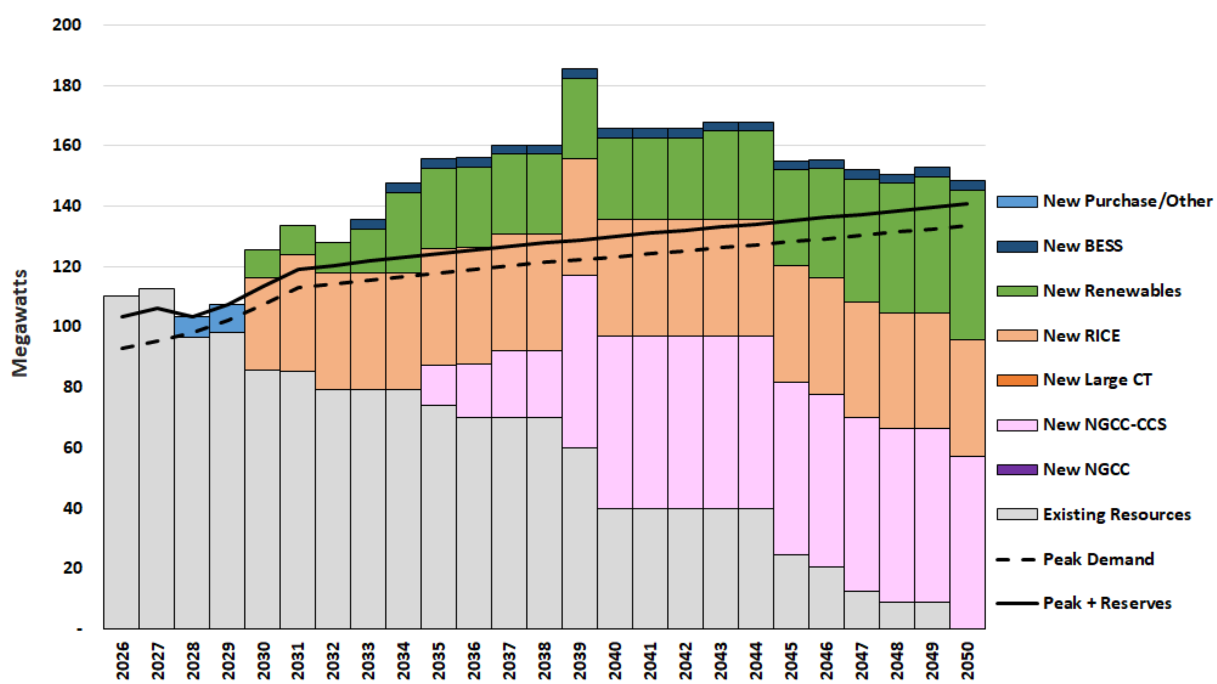

Figure A-44: Total Summer Firm Capacity (MW) by Type – Early RICE with PA 235

BAU Portfolios	PVRR Power Costs ($M)		
	Reference	Low Fuel Price	High Fuel Price
Economically Optimized	$648	$562	$765
Large Units Available 2035	$705	$615	$795
Local Generation	$791	$707	$845

Range of Fuel Cost Uncertainty (NPV $M)	
Economically Optimized	$203
Large Units Available 2035	$180
Local Generation	$137

PA 235 Portfolios	PVRR Power Costs ($M)		
	Medium Fuel Price	Low Fuel Price	High Fuel Price
Economically Optimized	$905	$864	$946
Large Units Available 2035	$906	$872	$942
Local Generation	$1,010	$1,005	$1,013

Range of Fuel Cost Uncertainty (NPV $M)	
Economically Optimized	$81
Large Units Available 2035	$70
Local Generation	$9

BAU Portfolios	Average Levelized Power Costs ($/MWh)		
	Medium Fuel Price	Low Fuel Price	High Fuel Price
Economically Optimized	$70.04	$60.67	$82.62
Large Units Available 2035	$76.16	$66.45	$85.87
Local Generation	$85.41	$76.40	$91.24

Range of Fuel Cost Uncertainty ($/MWh)	
Economically Optimized	$21.95
Large Units Available 2035	$19.42
Local Generation	$14.84

PA 235 Portfolios	Average Levelized Power Costs ($/MWh)		
	Medium Fuel Price	Low Fuel Price	High Fuel Price
Economically Optimized	$97.75	$93.36	$102.15
Large Units Available 2035	$97.85	$94.22	$101.77
Local Generation	$109.06	$108.50	$109.47

Range of Fuel Cost Uncertainty ($/MWh)	
Economically Optimized	$8.78
Large Units Available 2035	$7.55
Local Generation	$0.97

Figure A-45: PVRR for Fuel Price Sensitivities

BAU Portfolios	PVRR Power Costs ($M)			
	Low Load Forecast	Reference Case	High Load Forecast	Variation
Economically Optimized	$560	$648	$740	$180
Large Units Available 2035	$616	$705	$818	$202
Local Generation	$668	$791	$925	$257
Diff to Economically Optimized				
Large Units Available 2035	$55.8	$56.6	$78.0	
Local Generation	$107.9	$142.3	$185.1	

PA 235 Portfolios	PVRR Power Costs ($M)			
	Low Load Forecast	Reference Case	High Load Forecast	Variation
Economically Optimized	$822	$905	$1,025	$203
Large Units Available 2035	$827	$906	$1,053	$226
Local Generation	$869	$1,010	$1,176	$307
Diff to Economically Optimized				
Large Units Available 2035	$266.9	$257.5	$312.9	
Local Generation	$309.1	$361.3	$436.3	

BAU Portfolios	Average Levelized Power Costs ($/MWh)			
	Low Load Forecast	Reference Case	High Load Forecast	Variation
Economically Optimized	$69.44	$70.04	$71.07	$1.63
Large Units Available 2035	$76.36	$76.16	$78.57	$2.41
Local Generation	$82.83	$85.41	$88.86	$6.04
Diff to Economically Optimized				
Large Units Available 2035	$6.9	$6.1	$7.5	
Local Generation	$13.4	$15.4	$17.8	

Avg Levelized Portfolio Cost ($/MWh)

PA 235 Portfolios	Average Levelized Power Costs ($/MWh)			
	Low Load Forecast	Reference Case	High Load Forecast	Variation
Economically Optimized	$101.88	$97.75	$98.45	$4.14
Large Units Available 2035	$102.54	$97.85	$101.15	$4.69
Local Generation	$107.77	$109.06	$113.00	$5.22
Diff to Economically Optimized				
Large Units Available 2035	$33.1	$27.8	$30.1	
Local Generation	$38.3	$39.0	$41.9	

Figure A-46: PVRR for Load Sensitivities

Table A-1 Summary of Capacity Retirements and Additions for BAU									
	Economically Optimized			**Large Units Available 2035**			**Local Generation**		
Year	**Base**	**High**	**Low**	**Base**	**High**	**Low**	**Base**	**High**	**Low**
Retirements									
Belle River (2039)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
ZBPW (2030-2045)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)
West Wash (2047)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Riley (2050)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
New NGCC									
2030-2034	55	70	55	0	0	0	0	0	0
2035-2040	30	35	15	60	65	35	0	0	0
2041-2050	20	20	15	45	55	45	0	0	0
New NGCT									
2030-2034	0	0	0	0	0	0	0	0	0
2035-2040	20	20	10	0	0	0	0	0	0
2041-2050	40	50	35	15	15	5	0	0	0
New NGCC-CCS									
2035-2040	0	0	0	0	0	0	0	0	0
2041-2050	0	0	0	0	0	0	0	0	0
New Peaking									
2026-2029	0	0	0	0	0	0	0	0	0
2030-2040	0	0	0	25	35	25	65	75	50
2041-2050	0	0	0	0	0	0	15	20	15
New SMR									
2035-2050	0	0	0	0	0	0	0	0	0
New Solar									
2026-2029	0	0	0	0	0	0	0	0	0
2030-2040	0	0	0	0	0	0	0	0	0
2041-2050	0	0	0	0	0	0	55	65	35
New BESS									
2026-2029	0	0	0	0	0	0	0	0	0
2030-2040	0	0	0	0	0	0	0	0	0
2041-2050	0	0	0	0	0	0	0	0	0
New Wind									
2026-2029	0	0	0	0	0	0	10	15	10
2030-2040	0	0	0	0	0	0	0	0	0
2041-2050	0	0	0	0	0	0	10	20	0

Table A-2
Summary of Capacity Retirements and Additions for PA 235

	Economically Optimized			Large Units Available 2035			Local Generation		
Year	**Base**	**High**	**Low**	**Base**	**High**	**Low**	**Base**	**High**	**Low**
Retirements									
Belle River (2039)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)	(10)
ZBPW (2030-2045)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)	(19)
West Wash (2047)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Riley (2050)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)	(9)
New NGCC									
2030-2034	15	15	15	0	0	0	0	0	0
2035-2040	0	0	0	0	0	0	0	0	0
2041-2050	0	0	0	0	0	0	0	0	0
New NGCT									
2030-2034	5	10	5	0	0	0	0	0	0
2035-2040	0	0	0	0	0	0	0	0	0
2041-2050	20	15	20	40	40	40	0	0	0
New NGCC-CCS									
2035-2040	65	75	45	60	70	45	0	0	0
2041-2050	0	0	5	5	5	15	0	0	0
New Peaking									
2026-2029	0	0	0	0	0	0	0	0	0
2030-2040	0	0	0	0	5	0	0	5	0
2041-2050	0	0	0	0	0	0	15	10	15
New SMR									
2035-2050	0	0	0	0	0	0	0	0	0
New Solar									
2026-2029	5	10	5	5	5	5	0	0	0
2030-2040	45	45	40	50	60	50	115	130	90
2041-2050	55	70	15	50	65	15	60	80	40
New BESS									
2026-2029	0	0	0	0	0	0	0	0	0
2030-2040	10	10	10	20	25	20	50	60	35
2041-2050	(5)	(5)	(5)	(20)	(20)	(20)	5	10	0
New Wind									
2026-2029	20	25	20	20	25	20	20	25	20
2030-2040	60	70	60	60	65	55	105	120	90
2041-2050	0	0	0	0	5	0	5	10	0