PART OF BURNS & McDONNELL

2026 INTEGRATED RESOURCE PLAN

HENDERSON MUNICIPAL POWER & LIGHT

MARCH 31, 2026

Disclaimer

1898 & Co.® is a part of Burns & McDonnell that performs or provides business, technology, and consulting services. 1898 & Co. does not provide legal, accounting, or tax advice. The reader is responsible for obtaining independent advice concerning these matters. That advice should be considered by reader, as it may affect the content, opinions, advice, or guidance given by 1898 & Co. Further, 1898 & Co. has no obligation and has made no undertaking to update these materials after the date hereof, notwithstanding that such information may become outdated or inaccurate. These materials serve only as the focus for consideration or discussion; they are incomplete without the accompanying oral commentary or explanation and may not be relied on as a stand-alone document.

The information, analysis, and opinions contained in this material are based on publicly available sources, secondary market research, and financial or operational information, or otherwise information provided by or through 1898 & Co. clients whom have represented to 1898 & Co. they have received appropriate permissions to provide to 1898 & Co., and as directed by such clients, that 1898 & Co. is to rely on such client-provided information as current, accurate, and complete. 1898 & Co. has not conducted complete or exhaustive research, or independently verified any such information utilized herein, and makes no representation or warranty, express or implied, that such information is current, accurate, or complete. Projected data and conclusions contained herein are based (unless sourced otherwise) on the information described above and are the opinions of 1898 & Co. which should not be construed as definitive forecasts and are not guaranteed. Current and future conditions may vary greatly from those utilized or assumed by 1898 & Co.

1898 & Co. has no control over weather; cost and availability of labor, material, and equipment; labor productivity; energy or commodity pricing; demand or usage; population demographics; market conditions; changes in technology, and other economic or political factors affecting such estimates, analyses, and recommendations. To the fullest extent permitted by law, 1898 & Co. shall have no liability whatsoever to any reader or any other third party, and any third party hereby waives and releases any rights and claims it may have at any time against 1898 & Co. and any Burns & McDonnell affiliated company, with regard to this material, including but not limited to the accuracy or completeness thereof.

Any entity in possession of, or that reads or otherwise utilizes information herein is assumed to have executed or otherwise be responsible and obligated to comply with the contents of any Confidentiality Agreement and shall hold and protect its contents, information, forecasts, and opinions contained herein in confidence and not share with others without prior written authorization.

CONTENTS

FIGURES

TABLES

LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
AEO	Annual Energy Outlook
ATC	Around-the-Clock
CONE	Cost of New Entry
CT	Combustion Turbine
CCGT	Combined Cycle Gas Turbine
DLOL	Direct Loss of Load
EIA	U.S. Energy Information Administration
ELCC	Effective Load Carrying Capability
GWh	Gigawatt-hours
HMP&L	Henderson Municipal Power & Light
IMHR	Implied Market Heat Rate
IRP	Integrated Resource Plan
LMP	Locational Marginal Price
LOLE	Loss of Load Expectation
MISO	Midcontinent Independent System Operator
MM	Million
MMBtu	Million British Thermal Units
MW	Megawatts
MWh	Megawatt-hours
NPVRR	Net Present Value Revenue Requirements
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
PPA	Power Purchase Agreement
PRA	Planning Resource Auction
PRMR	Planning Reserve Margin Requirement
RICE	Reciprocating Internal Combustion Engine
SMR	Small Modular Reactor
WACC	Weighted Average Cost of Capital
ZRC	Zonal Resource Credit

Executive Summary

Henderson Municipal Power & Light (HMP&L) engaged 1898 & Co. to develop their 2026 Integrated Resource Plan (IRP) to inform long-term resource decisions and support reliable, cost-effective electric service over the 20-year planning horizon from 2026 through 2045. As a municipally owned utility serving approximately 12,000 customers with a peak demand near 100 MW, HMP&L currently relies on market-based contracts and capacity purchases within the Midcontinent Independent System Operator (MISO) footprint to meet its energy and capacity requirements.

Using the EnCompass power system optimization model, 1898 & Co. evaluated a range of future resource strategies under market price, peak and energy demand, fuel, and policy uncertainty scenarios. The analysis incorporated capacity expansion modeling and chronological production cost simulations to identify portfolios that minimize long-term revenue requirements while maintaining operational flexibility and resource adequacy. Thirteen initial portfolios were evaluated, including market-only strategies, self-build generation options, and hybrid generation combining owned assets with contracted resources.

Across scenario analyses, the modeling results indicate that firm, dispatchable natural gas resources represent a cost-effective and operationally flexible option for addressing HMP&L's future capacity needs. The lowest-cost scenario portfolio included the addition of a Reciprocating Internal Combustion Engine (RICE) unit in model year 2030 followed by a partial ownership share in a Combustion Turbine (CT) in model year 2036. Deterministic portfolios produced similar findings, with the replacement of a CT partnership with a second RICE facility yielding comparable economic outcomes while offering a potentially more practical implementation pathway. Portfolios relying exclusively on market purchases or emerging technologies such as SMRs or hydroelectric resources were associated with higher long-term costs due to capital investment magnitude and technology maturity.

To support decision-making under uncertainty, a tradeoff assessment evaluated select portfolios across six future conditions, including high load growth, natural gas price volatility, market uncertainty, and potential carbon regulation. Results showed that portfolios with self-built natural gas resources produced lower Net Present Value Revenue Requirements (NPVRR) across future uncertainty, while reducing exposure to external market price risk and increasing the share of locally controlled generation.

Based on the modeling results and comparative analysis, this IRP identifies a phased transition toward partial self-supply through the addition of dispatchable natural gas resources as a preferred planning direction. This strategy balances affordability, reliability considerations, and risk management objectives while maintaining flexibility to adapt to evolving market conditions, regulatory developments, and customer demand trends.

1.0 Introduction

Henderson Municipal Power & Light (HMP&L) retained 1898 & Co. to develop an Integrated Resource Plan (IRP) to guide its long-term resource decisions and evaluate potential generation alternatives. An IRP is a foundational utility planning process that creates a strategic roadmap for meeting future energy and capacity obligations in a cost-effective and reliable manner. This process involves a comprehensive evaluation of resources to identify a preferred portfolio of assets and strategies. The IRP serves as a critical tool for navigating the complexities of the modern energy landscape, providing a structured framework for making prudent investment decisions that align with HMP&L's operational, financial, and service objectives over a long-term planning horizon.

The development of an IRP is a structured and iterative process that begins with establishing a comprehensive set of foundational inputs and assumptions. This includes developing long-term forecasts for the utility's peak demand and energy needs, projecting future prices for key commodities such as natural gas, and forecasting the external market prices for both wholesale energy and capacity. The process also involves a thorough review of the utility's existing resources and contractual obligations, as well as an evaluation of the cost, performance, and viability of a wide range of potential future resource alternatives, including conventional generation, renewable technologies, and energy storage.

At the core of the IRP is a sophisticated analytical phase conducted using specialized capacity expansion and production cost modeling software. In this phase, resource portfolios are optimized, constructed, and tested under varying sets of assumptions. The model simulates the construction and operation of different combinations of resources over the study period, identifying the most economic, or "least-cost," portfolio based on a comparison of the Net Present Value (NPV) of each plan's total revenue requirements. This step effectively determines the optimal timing, type, and size of new resource additions needed to maintain system reliability.

Following the initial capacity expansion analysis, a tradeoff assessment or risk analysis is performed. In this step, portfolios are subjected to a series of stress tests or "sensitivities" that represent a range of plausible but uncertain future conditions. These sensitivities often include futures with high or low load growth, volatile fuel prices, or the implementation of new environmental regulations. By evaluating how each portfolio performs across these different futures, the IRP can identify not only the least cost plan but also the plan that is resilient and presents the lowest risk across a wide spectrum of potential outcomes. The final report synthesizes these findings, presenting a clear, data-driven recommendation and a near-term action plan that provides the utility with a strategic path forward.

1898 & Co. has supported IRP efforts across the U.S., guiding investor-owned utilities, public power entities, and electric cooperatives through increasingly complex planning landscapes. The 1898 & Co. team leverages a deep understanding of power generation, transmission, and distribution systems, coupled with sophisticated analytical and modeling capabilities, to develop strategic insights. This approach allows for careful evaluation of complex variables, including evolving regulatory frameworks, volatile energy markets, technological advancements, and shifting customer expectations, to produce well-developed solutions for its clients.

1.1 Power Planning Model (EnCompass)

1898 & Co. utilized the EnCompass Power System Optimization Software, Version 8.0.7, by Yes Energy to perform analysis for HMP&L's 2026 IRP. EnCompass is a chronological unit commitment and economic dispatch platform commonly used for utility planning applications. The model employs mixed integer programming to determine optimal resource build, commitment, and dispatch decisions while reflecting real-world operational constraints such as unit operating limits, maintenance and outage assumptions, transmission and market limits, renewable energy availability, reserve requirements, and applicable environmental or policy constraints.

The overarching analytical objective is to identify resource strategies that provide reliable service at the lowest long-term cost to customers while accounting for risk and uncertainty. To meet this objective, the model minimizes total system cost over the planning horizon, including the capital and fixed costs of new resources, fixed and variable operation and maintenance costs, fuel and transportation costs, emissions and compliance costs (if applicable), and the costs and revenues associated with market purchases and sales used to balance native load.

EnCompass was applied in two complementary modes: capacity expansion and production cost modeling. In capacity expansion mode, the model evaluates candidate technologies and timing of additions to determine resource portfolios that satisfy planning reserve requirements and other constraints while minimizing long-term cost. This step identifies a least cost and feasible mix of supply side resources under each study scenario and provides a consistent set of candidate portfolios for further evaluation.

Following capacity expansion, EnCompass production cost modeling was used to simulate chronological system operations in greater detail. Production cost simulations model hourly unit commitment and dispatch to serve load while capturing key operational metrics such as start costs, minimum run times, ramp rates, renewable intermittency, forced outages, and market transactions. This step tests the operational feasibility of candidate portfolios and quantifies outcomes such as annual production costs, dispatch patterns, market dependence, renewable curtailment, emissions, and other operational performance metrics needed to compare portfolios on a consistent basis.

Together, the capacity expansion and production cost applications provide an integrated framework to develop, refine, and evaluate IRP resource portfolios under varying future conditions, supporting the selection of a preferred plan that balances cost, reliability, and risk.

1.2 Modeling Overview

HMP&L is a municipally owned electric utility providing service to approximately 12,000 customers within the city of Henderson, Kentucky. As a Transmission Owning Member of the Midcontinent Independent System Operator, Inc. (MISO), HMP&L operates within the framework of the MISO wholesale energy market and adheres to its reliability standards. The utility manages a system with a peak demand of approximately 100 megawatts (MW) and an annual energy requirement of approximately 600,000 megawatt-hours (MWh). Currently, HMP&L meets its load obligations through a portfolio of power purchase agreements (PPAs), which include contracts for long-term energy supply and the procurement of Zonal Resource Credits (ZRCs) to meet MISO's capacity planning requirements.

The IRP detailed in this report presents a comprehensive analysis conducted by 1898 & Co. to identify a prudent, cost-effective, and reliable long-term resource strategy for HMP&L over a 20-year planning horizon, from 2026 through 2045. The study incorporated a range of input variables, including load forecasts, market price projections, capital costs, and regulatory uncertainty, to model future system needs. A broad set of initial resource scenarios was evaluated, which was subsequently refined to seven distinct scenarios for more detailed examination. Each of these seven scenarios was then subjected to a trade-off analysis across five different sensitivities to assess portfolio performance and risk under a variety of potential future conditions.

2.0 Planning Assumptions

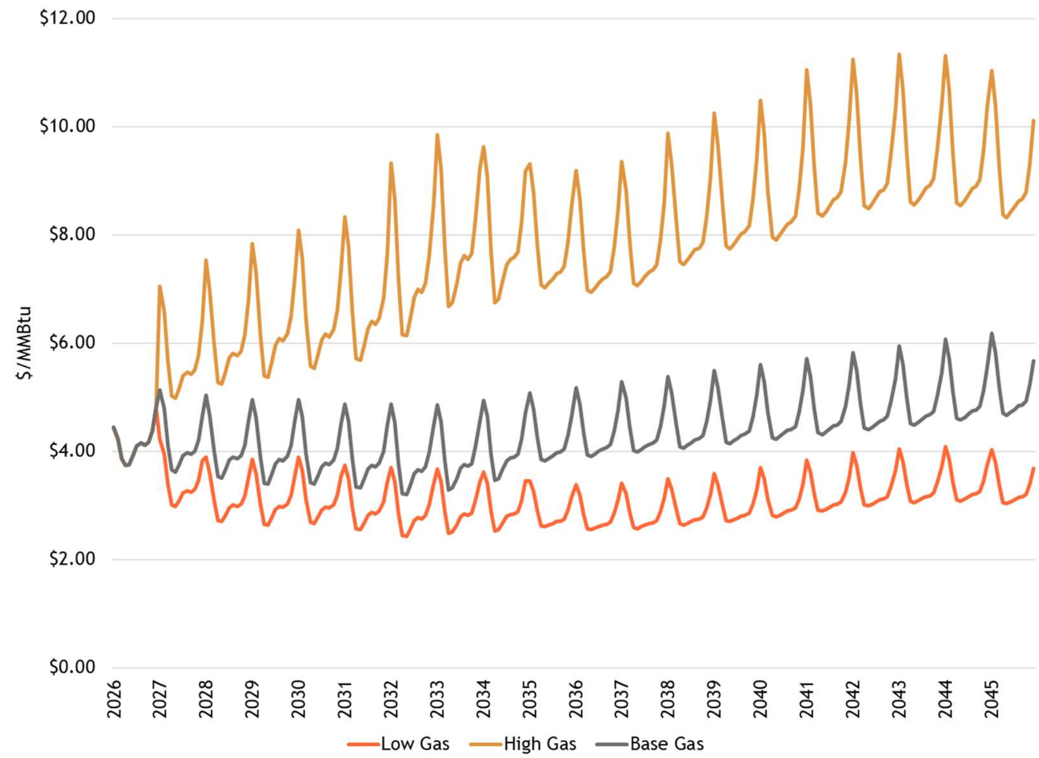
The planning assumptions described in this section establish the foundational inputs used throughout the IRP analysis, leveraging HMP&L internal forecasts, publicly available sources, and industry-standard forecasts as appropriate. These assumptions are applied consistently across all modeled scenarios. Scenario-specific adjustments are introduced where necessary to reflect the intended sensitivity. As a result, differences in outcomes can be attributed to the scenario drivers rather than changes in the underlying methodology.

2.1 Natural Gas Forecast

The natural gas price forecast used as the foundation for this analysis was developed from a forecast provided by HMP&L, which extended through 2035. To cover the full 20-year planning horizon of the IRP through 2045, this initial forecast was escalated at a fixed annual rate of 2%[1] for the remaining years. This composite forecast establishes the Base Case for natural gas prices within the study. To evaluate the impact of price volatility on resource decisions, two alternative forecasts, the High Case and the Low Case, were developed. These alternative scenarios were created by applying the price trajectories from specific U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO) cases to the HMP&L Base Case forecast. The High Gas Price forecast incorporates the shape of the EIA AEO Low Oil and Gas Supply case, while the Low Gas Price forecast incorporates the shape of the EIA AEO High Oil and Gas Supply case. These three distinct forecasts allow for a robust assessment of portfolio performance under varying market conditions for natural gas.

[1] The inflation rate was derived from the EIA 2025 AEO: https://www.eia.gov/outlooks/aeo/assumptions/pdf/MAM_Assumptions.pdf

Figure 1: Monthly Natural Gas Forecast

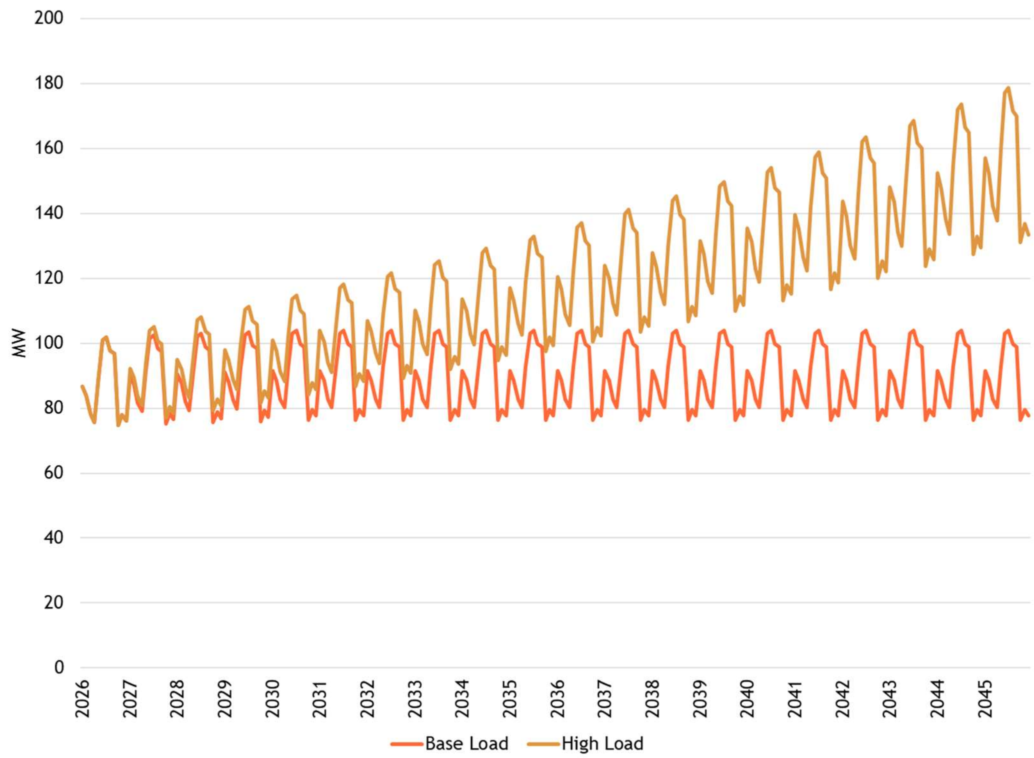


2.2 Peak and Energy Demand

The peak demand and annual energy forecasts utilized in this IRP were developed from data provided by HMP&L. This peak demand is forecasted to grow at a rate of 0.5% annually for the first four years of the study period, after which it is held constant through 2045. A separate High Load forecast was developed to analyze the system's needs under more aggressive growth assumptions. This High Load forecast begins with the same 2026 peak demand but assumes an annual growth rate of 3%[2] for the remainder of the study period.

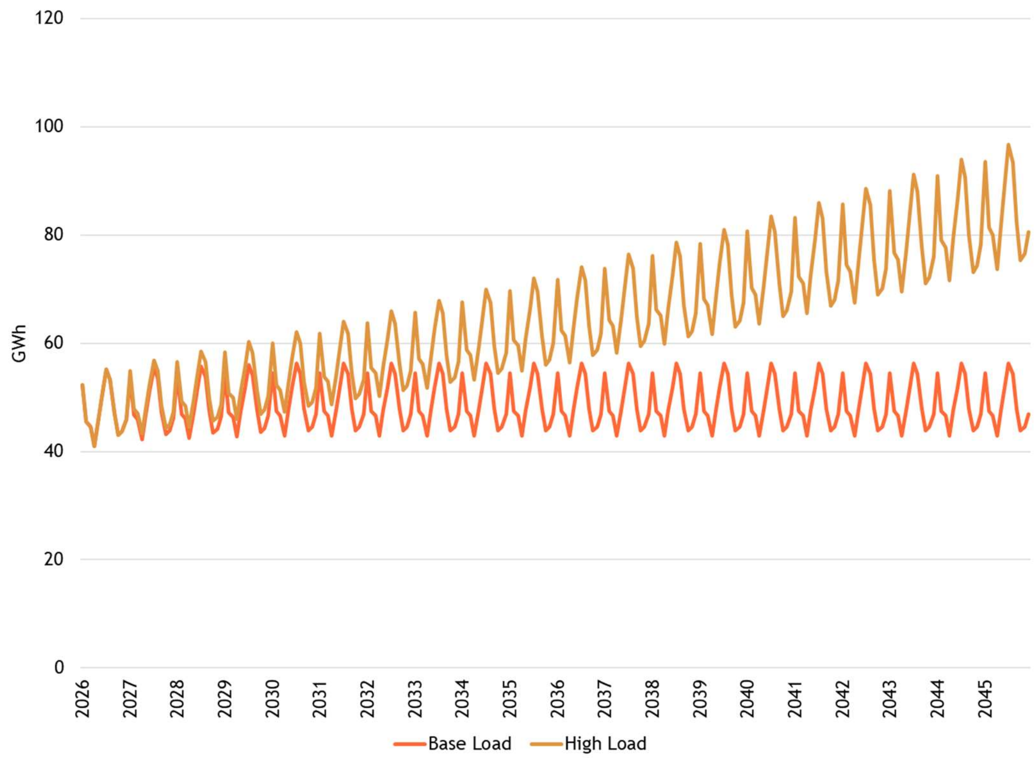
[2] A 3% growth rate was used in the 2021 HMP&L for a high load scenario and was carried forward into this IRP.

Figure 2: HMP&L Monthly Peak



The Base Case energy forecast, also provided by HMP&L, projects an annual energy requirement of approximately 568,000 MWh in 2026. This forecast incorporates an initial growth of 1% in the first year, followed by a 0.5% annual growth rate for the subsequent three years, after which the energy requirement is held constant for the rest of the 20-year planning horizon. To assess the impact of higher-than-expected energy consumption, a corresponding High Energy forecast was developed. This forecast assumes a more rapid growth trajectory, with a 3% annual increase for the study period.

Figure 3: HMP&L Monthly Energy



2.3 Market Price Forecast

To evaluate the economic performance of various resource portfolios and to model the costs and benefits of market-based transactions, a forecast of external market prices for both energy and capacity was developed. The energy price forecast was derived from an Implied Market Heat Rate (IMHR) analysis, which correlates wholesale electricity prices to natural gas prices using publicly available market data. This methodology provides a fundamental basis for projecting future energy costs. The capacity price forecast was based on historical data from the MISO Planning Resource Auction (PRA)[3], reflecting the expected costs to secure capacity within HMP&L's market footprint. Similarly, the Cost of New Entry (CONE), which represents the estimated cost to build a new reference generating unit and serves as a key input for capacity market dynamics, was determined using publicly available data from MISO.

2.3.1 MISO Energy Market Price Forecast

An external energy market price forecast was developed to model the cost of market-based energy purchases. Historical Locational Marginal Prices (LMPs) and natural gas prices were collected from the Indiana Hub[4]. From this data, monthly IMHRs were calculated and then averaged over the last five years to establish a representative monthly implied heat rate. These monthly IMHRs were then applied to the HMP&L natural gas forecast to produce a baseline Around-the-Clock (ATC) energy price forecast for the study period.

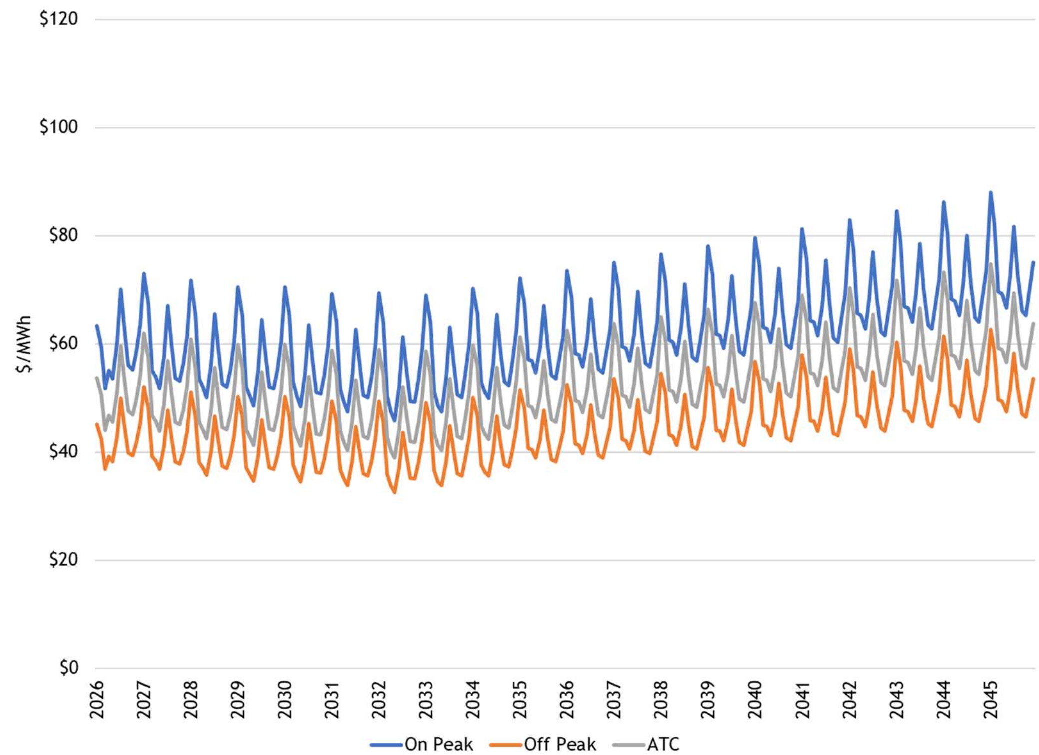
---

[3] MISO Planning Resource Auction for Planning Year 2025/26:
https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf

[4] Indiana Hub prices were pulled from S&P Global:
https://www.capitaliq.spglobal.com/web/client?auth=inherit#markets/energyMarketsNaturalGasSummary?key=982fafdb-b14f-4c18-b151-75be96d6c2c5

To incorporate daily price volatility into the forecast, the hourly price shape from the 2025 Indiana Hub LMP profile was utilized. The forecast was further refined by differentiating between on-peak and off-peak periods. Following MISO conventions, on-peak hours were defined as hours ending 7 through 22, Monday through Friday, with all other hours classified as off-peak. The annual average ATC price was weighted by the on-peak and off-peak price to forecast daily price fluctuation, resulting in a forecast that reflects typical market patterns.

Figure 4: MISO Base Energy Market Forecast



2.3.2 MISO Capacity Market Price Forecast

The forecast for capacity market prices, representing the cost to secure MISO Zonal Resource Credits (ZRCs), was developed using publicly available data from MISO. The clearing prices from the 2025 MISO PRA for each of the four seasons were used as the starting point for the forecast. These initial seasonal prices were then escalated using the inflation rate throughout the 20-year study period to project the future cost of capacity required to meet HMP&L's planning reserve margin obligations.

Table 1: MISO 2025/26 Planning Resource Auction Clearing Price

MISO Season	Price ($/MW-day)
Summer	$666.50
Fall	$91.60
Winter	$33.20
Spring	$69.88

2.3.3 Cost of New Entry Price

CONE, a key parameter in capacity expansion modeling, was established for this study to test scenarios involving self-build generation options. The starting point for this value was $130,710 MW-year[5], the most recent CONE published by MISO for Zone 6. For the purposes of this analysis, the CONE market capacity price was adjusted based on recent market trends in combustion turbine costs and is intended to discourage over-reliance on market capacity purchases in the model. This approach configures the model to optimize for alternative generation selection when a capacity need is identified, allowing for a clear evaluation of self-supply portfolios. This adjusted CONE value was then escalated throughout the 20-year study period at the modeled escalation rate.

2.4 Financial Assumptions

The financial evaluation of resource portfolios in this study is based on several key assumptions. An overall inflation rate of 2% was applied annually to escalate costs, including capital expenditures, operating expenses, and market prices, throughout the planning horizon. As a municipal utility, HMP&L is assumed to finance capital projects entirely through bond financing, and a corresponding debt rate of 3.63% was used for all self-build resource options. The Weighted Average Cost of Capital (WACC) for this analysis was determined to be 4%[6]. This WACC serves as the discount rate for calculating the net present value of the cumulative present worth of revenue requirements for each resource portfolio, allowing for a consistent, economic comparison of differing strategies over the 20-year study period.

2.5 Carbon Price

To evaluate the potential financial impact of future environmental regulations, a carbon regulation sensitivity was developed. A $75 per short ton of carbon was applied directly to all carbon-emitting generation resources within each portfolio, functioning as an additional variable operating expense. Furthermore, the external energy market price forecast was adjusted upward to incorporate this carbon price. This adjustment is based on the standard market assumption that the marginal unit setting the Locational Marginal Price (LMP) during most hours will be a carbon-emitting resource, and its offer price on the market would therefore reflect the cost of carbon. This approach allows for both self-generation and market purchases to be evaluated consistently under a potential carbon regulation scenario.

2.6 MISO Assumptions

As a member of the MISO, HMP&L must adhere to the mandatory reliability standards and market rules established by the RTO to avoid financial penalties. Key among these obligations is the Planning Reserve Margin Requirement (PRMR), which dictates the total amount of capacity HMP&L must procure, and the capacity accreditation rules, which determine the certified capacity value of each generation resource.

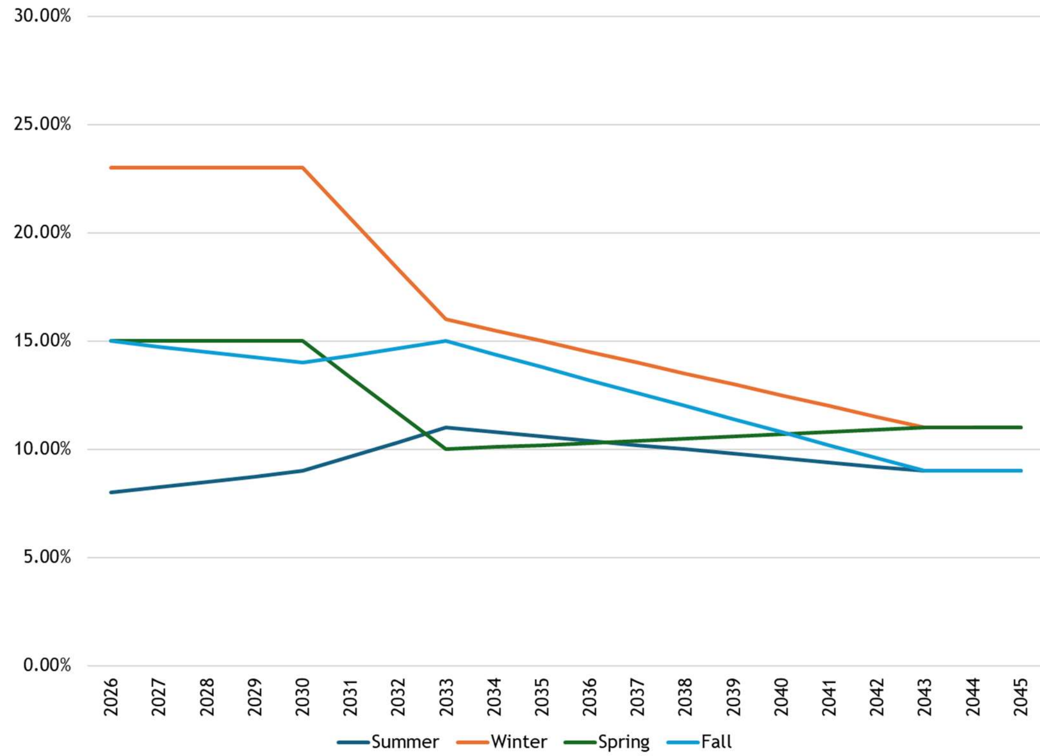
---

[5] MISO CONE Values:
https://cdn.misoenergy.org/20251001%20RASC%20Item%2006%20MISO%20Cost%20of%20New%20Entry%20(CONE)%20Presentation720296.pdf?_t_id=ztJgYGPfuR0AXpw7qmDn1g%3d%3d&_t_uuid=uiJs1SNAR0eBeSR5q11HDw&_t_q=RASC&_t_tags=language%3aen%2csiteid%3a11c11b3a-39b8-4096-a233-c7daca09d9bf%2candquerymatch&_t_hit.id=Optics_Models_Find_RemoteHostedContentItem/720296&_t_hit.pos=74

[6] The Weighted Average Cost of Capital value of 4% was the coupon rate of the bond provided by HMP&L.

The evolution in MISO's resource adequacy framework was incorporated into this analysis. MISO is transitioning its capacity accreditation methodology from the current Loss of Load Expectation (LOLE)[7] model to a performance based Direct Loss of Load (DLOL)[8] model, with this change scheduled to take effect in Planning Year 2028/2029. This new methodology is expected to have a considerable impact on the accredited capacity of renewable resources. Solar resources will experience a significant reduction in their capacity value under the DLOL framework. Concurrently with this change, MISO is also adjusting its seasonal PRMR values. To reflect the most current regulatory landscape, both the shift to the DLOL capacity accreditation and the corresponding adjustments to the PRMR were implemented within the IRP model for the relevant future years of the study.

Figure 5: MISO Wind Effective Load Carrying Capability



[7] MISO LOLE Planning Year 25/26 Values: https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401
[8] MISO DLOL Planning Year 25/26 Values: https://cdn.misoenergy.org/20250409%20RASC%20Item%2008%20LOLE%20Modeling%20Enhancements%20Storage%20Modeling689245.pdf

Figure 6: MISO Solar Effective Load Carrying Capability

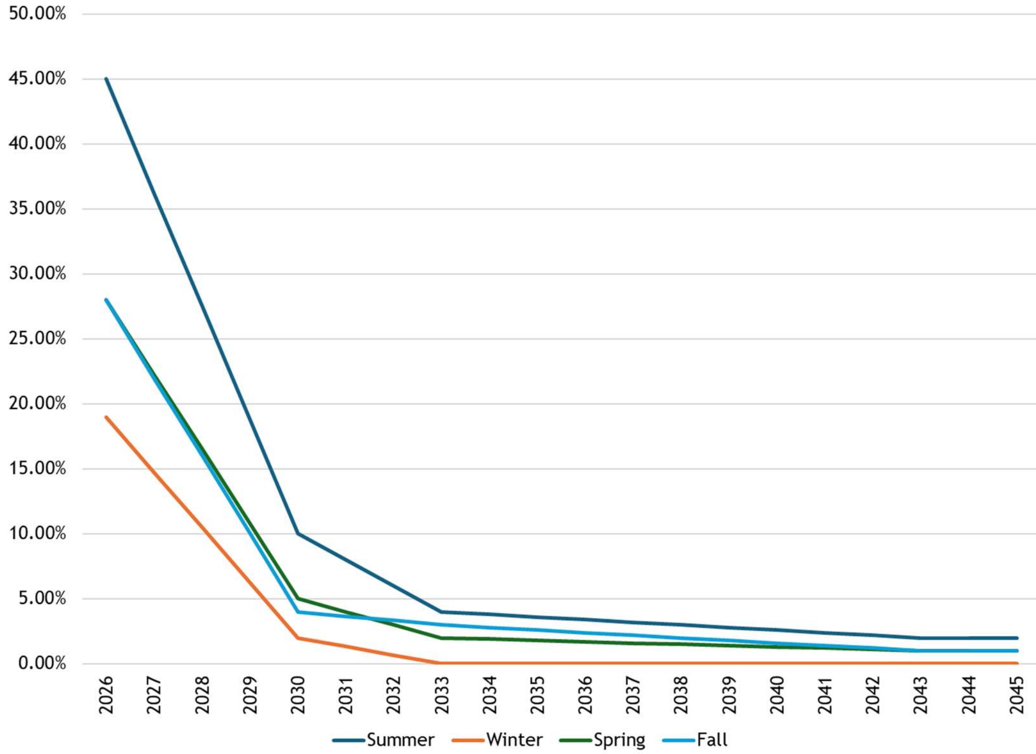


Figure 7: MISO Storage Effective Load Carrying Capability

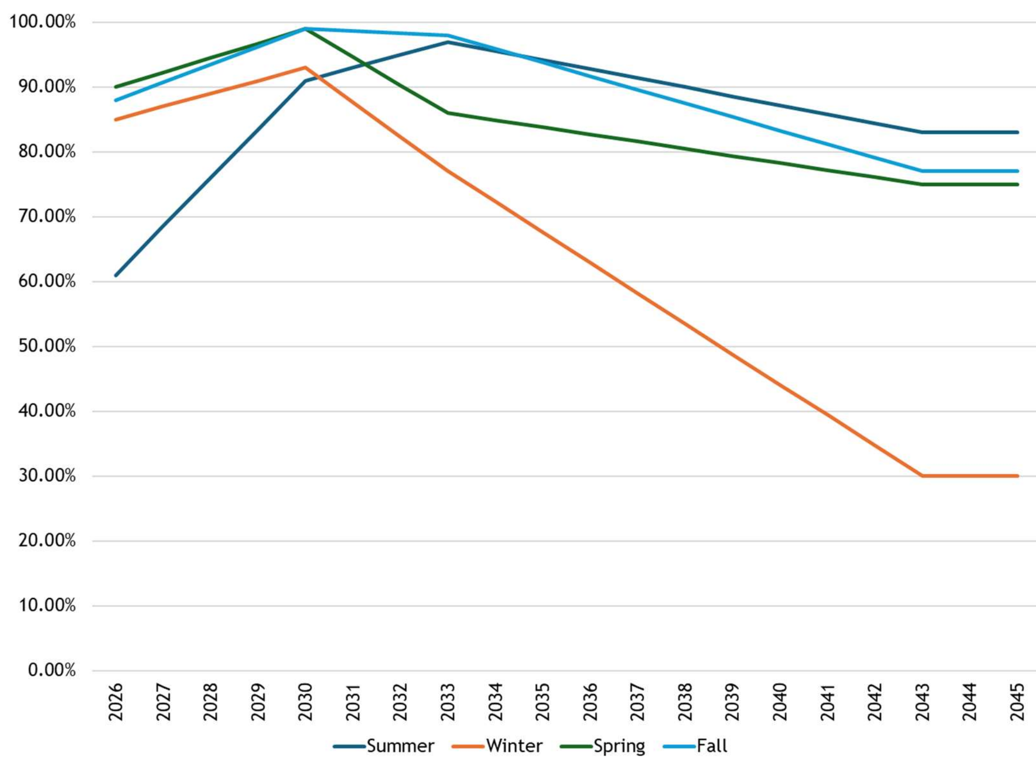


Table 2: MISO Planning Reserve Margin Requirement

MISO Season	Before PY 2028/29	PY 2028/29+
Summer (June-August)	7.9%	2.3%
Fall (September-November)	14.9%	6.0%
Winter (December-February)	18.4%	5.6%
Spring (March-May)	25.3%	1.0%

3.0 HMP&L Capacity and Energy

Henderson Municipal Power & Light currently relies on a portfolio of market-based contracts to meet its energy and capacity needs. A central objective of this IRP is to investigate the strategic alternative of HMP&L developing, owning, and operating its own generation assets. This study aims to evaluate resource portfolios that include self-build and Power Purchase Agreement (PPA) options, allowing for a direct comparison against continued reliance on power purchase agreements and other market products.

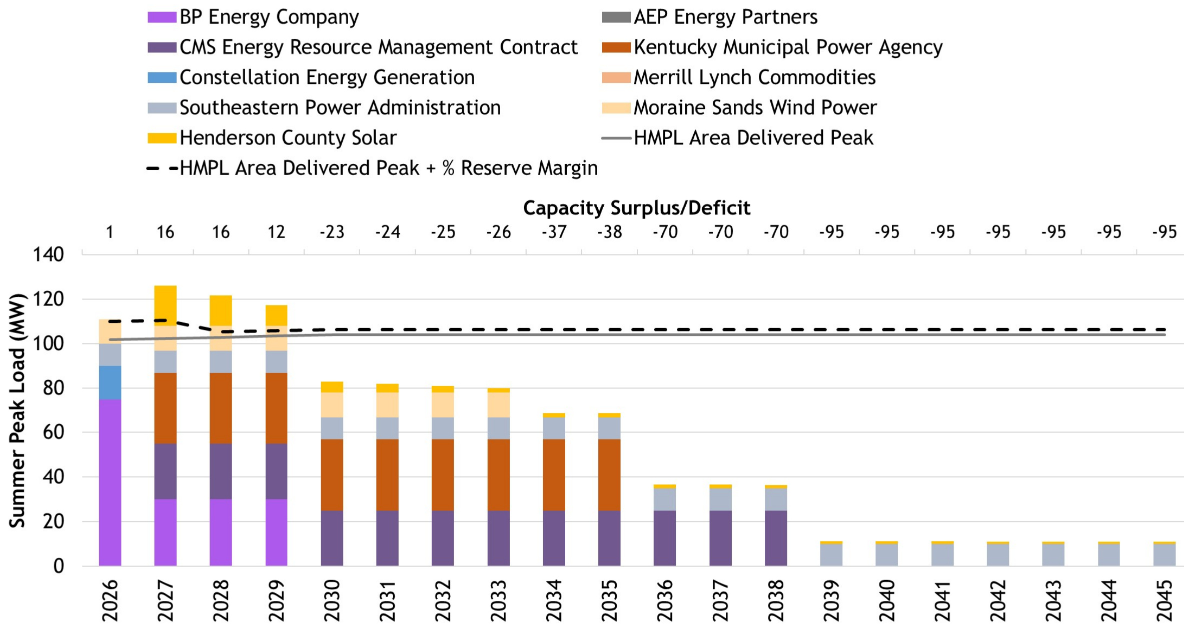
3.1 Existing Power Supply

At the outset of the study period, Henderson Municipal Power & Light meets its resource obligations entirely through contractual arrangements within the MISO market. The utility fulfills its capacity requirements exclusively through the procurement of ZRCs from the MISO market. Similarly, HMP&L's energy supply is sourced from a portfolio of bilateral energy-only Power Purchase Agreements (PPAs). This existing all-contract portfolio serves as the baseline from which all future resource planning scenarios are developed and evaluated. Table 3 details HMP&L's existing power supply resources and the resulting capacity position shown in Figure 8.

Table 3: HMP&L Existing Power Supply

Provider	Type	Commission Date	Expiration Date	Amount Contracted
CMS Energy Resource Management Contract	Capacity	6/1/2027	5/31/2039	25MW
BP Energy Company	Capacity	6/1/2027	5/31/2030	30MW
BP Energy Company	Energy	6/1/2027	5/31/2030	30MW (7x24)
AEP Energy Partners	Energy	6/1/2026	9/30/2026	15MW (5x16)
Constellation Energy Generation	Energy	Existing	5/31/2026	25MW (7x24)
BP Energy Company	Capacity	Existing	5/31/2027	75MW
BP Energy Company	Energy	Existing	5/31/2029	30MW (7x24)
Constellation Energy Generation	Capacity	Existing	5/31/2027	15MW
Kentucky Municipal Power Agency	Capacity	6/1/2027	5/31/2037	32MW
Kentucky Municipal Power Agency	Energy	6/1/2027	5/31/2037	32MW (7x24)
Merrill Lynch Commodities	Energy	Existing	2/28/2026	10MW (7x16)
Merrill Lynch Commodities	Energy	6/1/2026	5/31/2027	25MW (7x24)
Moraine Sands Wind Power	Capacity	Existing	5/31/2034	Variable
Southeastern Power Administration	Capacity	Existing	No Expiration	10MW
Southeastern Power Administration	Energy	Existing	No Expiration	18,000 MW Annually
Henderson County Solar	Capacity	5/1/2027	No Expiration	Variable
Henderson County Solar	Energy	5/1/2027	No Expiration	Variable

Figure 8: Summer Balance of Load and Resources of HMP&L's Current System



3.2 Alternative Resources

In collaboration with HMP&L, a comprehensive list of viable alternative resources was developed for consideration in the portfolio analysis. This selection of technologies was designed to provide a diverse set of options, encompassing both market-based contractual arrangements and self-build ownership opportunities.

The model was permitted to select from a variety of PPAs, including contracts for solar, wind, and battery energy storage. The model could also select generic energy-only contracts to meet energy needs and a contract for the output of a prospective Small Modular Reactor (SMR). In addition to these contractual options, the analysis included resources that HMP&L could choose to build and own. These self-built ownership options include Reciprocating Internal Combustion Engines (RICE) in two-unit blocks, a 33% ownership share in a new F-Class Combustion Turbine (CT) plant, and the development and ownership of a small hydroelectric facility.

The capital costs, operating characteristics, and performance data for all alternative resources considered in this analysis were derived from publicly available, industry-recognized sources. These foundational inputs were sourced from a variety of respected publications, including technology cost and performance reports from the U.S. National Renewable Energy Laboratory (NREL) and the U.S. Energy Information Administration (EIA), as well as other publicly available IRPs. By grounding the analysis in these established public datasets, a consistent economic comparison was maintained across the diverse set of technologies evaluated, including solar, wind, energy storage, and conventional generation. This methodology reflects a broad consensus on current and projected costs within the energy sector.

Table 4: HMP&L Alternative Resources

Generation Technology	First Year Available	Unit Size (MW)	Capital Cost ($/kW)	FOM ($/kW-yr)	VOM ($/MWh)	Heat Rate (MMBtu/kWh)
Reciprocating Engine (RICE)	2030	2x18	$1,919	$15.00	$7.00	8100
F-Class Combustion Turbine (CT)	2030	239	$1,340	$12.71	$4.42	9750[9]
Utility Scale Solar PPA	2030	10			$68.38	
Wind PPA	2030	10			$71.36	
Battery Storage PPA (4hr)	2030	50		$164.52		
Run-of-River Hydro	2038	5	$9,726	$155.00		
Small Modular Reactor PPA (SMR)	2038	25			$126.28	

The resource alternatives considered in the capacity expansion model were made available for selection beginning in the year 2030, with two specific exceptions for later-term technologies. The decision to begin resource availability in 2030 allows for planning and procurement lead time considerations for any new assets.

The first exception was the SMR contract, which was not made available for selection until 2038. This later in-service date was based on the team's assessment that SMR nuclear technology is unlikely to be commercially developed and deployed at scale before the early 2030s. It was further assumed that governmental support or incentives for new nuclear development might emerge in the late 2030s, making it a more viable option in that timeframe.

The second exception was the new hydroelectric unit, which was also restricted from being selected until 2038. This delay reflects the anticipated permitting and environmental review, and construction time for new hydro projects. The team determined that the significant regulatory and environmental actions required could push the earliest feasible in-service date for such a project to the later years of the study period.

3.3 Coal Alternatives

Coal generation remains an important part of the regional power supply mix and existing coal resources can continue to provide meaningful capacity and energy value to the market. For HMP&L, however, development of a new coal fired generating unit was not included as a resource alternative in this IRP. The primary reason is that the scale of a new coal unit is materially larger than HMP&L's projected resource need. HMP&L is a system with peak demand near 100 MW, and the practical development of a new coal facility would likely require unit size and capital commitment well beyond what is needed for the utility's load-serving requirements.

[9] Heat Rate for F-Class Combustion Turbine listed at max operating point

In addition to scale, new coal development presents significant cost, development, and implementation risk. New coal resources generally require substantial upfront capital investment, long development and construction timelines, and major commitments related to fuel supply, operations, and maintenance over the life of the asset. For a utility of HMP&L's size, those characteristics create risk around cost recovery, timing, and asset utilization. By comparison, smaller dispatchable resources, purchased power, or shared ownership structures can be more closely aligned with HMP&L's incremental need for future capacity and energy.

New coal resources also face increasing regulatory uncertainty. Environmental requirements for power plants continue to evolve, and future compliance obligations could materially increase the cost of a new coal facility over time. That risk is particularly relevant for a long-lived asset that would be expected to operate for decades. As a result, while existing coal generation may continue to serve an important role in the broader market, adding a new coal unit was not identified as a prudent alternative for HMP&L in this IRP.

4.0 Capacity Expansion Analysis

The primary objective of the Henderson Municipal Power & Light IRP is to identify the most economic and reliable long-term strategy for procuring new capacity and energy. The core of this analysis involves a capacity expansion study performed using the EnCompass modeling software, which determines the optimal resource portfolio by comparing the NPVRR for various strategies over the 20-year study period.

The EnCompass modeling process consists of two primary steps. The first step is the capacity expansion phase, where the model determines the most economic combination of resources required to meet future capacity and energy needs. During this step, constraints were placed on the model to limit reliance on external market purchases, thereby encouraging the selection of new physical assets. To prevent overreliance on market interaction capacity purchases were limited to 10% of the monthly peak demand, and market energy purchases were limited to 25% of the monthly peak demand. Conversely, market export capabilities were removed to prevent overproduction for market revenue and restrict the model to procure resource alternatives to serve HMPL's energy and capacity obligations. The second step is the production cost simulation. In this phase, the specific resource portfolio developed in capacity expansion is simulated for every hour of the study period to determine its operational performance and calculate the final portfolio NPVRR. For this production cost run, the market purchase constraints were relaxed to 50% for both capacity and energy to reflect market availability and allow for dynamic comparison of portfolio performance.

4.1 Scenario Based Portfolios

Of the 13 initial portfolios evaluated, five were designed as scenario-based portfolios to assess the impact of key uncertainties on optimal resource selection and overall system cost. These scenarios alter specific input assumptions to understand how the economic buildout and the total NPVRR changes based on different future conditions.

A foundational case, discussed in section 3.1, establishes the existing and planned power supply options available to HMP&L. In this case, no new resources were permitted, and the model had to meet all future energy and capacity needs through purchases from the external market. The first portfolio, the Base Case, was developed using a standard set of assumptions for load growth, fuel prices, and wholesale market prices discussed in section 2. This serves as the central reference point for all other scenarios.

The remaining four scenarios serve to evaluate sensitivity to major markets and regulatory drivers discussed in Section 2. A High Load Case was using the more aggressive load and energy growth forecasts. The potential for fuel price volatility was examined through two separate scenarios: a High Gas Price Case and a Low Gas Price Case. In both scenarios, the wholesale energy market price was adjusted to reflect its correlation with natural gas commodity prices. Finally, a carbon regulation case was used to understand the potential impacts of future carbon regulations. This scenario incorporated a carbon regulation penalty applied to all carbon-emitting generation resources, and the external market energy prices were adjusted upward to reflect the assumption that carbon emission in this scenario would impact wholesale market prices. Table 4 details the scenario-based approach to the capacity expansion analysis.

Table 4: HMP&L Capacity Expansion Scenario Summary

Scenario	Load	Natural Gas	Market Prices	Carbon Regulation
Base Scenario	Base	Base	Base	NA
High Load	High	Base	Base	NA
High Natural Gas	Base	High	High	NA
Low Natural Gas	Base	Low	Low	NA
Carbon Regulation	Base	Base	Base + Regulation	Included

4.2 Deterministic Based Portfolios

The remaining 8 of the 13 initial portfolios were developed as deterministic cases. In contrast to the scenario-based portfolios, these deterministic cases maintain the Base Case input assumptions for load, fuel, and market prices. Their purpose is to evaluate specific, pre-defined resource strategies by forcing the model to select alternative resources at specified in-service dates. The model then performs economic capacity expansion around these additions to fulfill any remaining needs. This approach was developed in collaboration with HMP&L based on the strategic premise that a reasonable path forward could involve HMP&L building and owning generating assets while supplementing its portfolio with contracted resources.

The eight deterministic portfolios were structured as follows:

1. A single RICE unit in 2030.
2. A 33% ownership of a new CT in 2030.
3. Construction delay on the RICE from scenario 1 to 2036.
4. To assess uncertainty around a CT partnership agreement, a RICE unit was added in 2030 and a second RICE unit in 2036.
5. A combination of self-build options with a RICE unit in 2030 and 33% CT ownership in 2036
6. Prohibiting any self-build options the model must meet energy and capacity obligation through PPAs and market imports.
7. A new hydroelectric generating unit in 2038.
8. A Long-term emerging technology strategy assuming an SMR PPA is executed in 2038.

For all deterministic portfolios incremental PPA and economic market energy and capacity was available to fill remaining shortalls.

4.3 Capacity Expansion Results

4.3.1 Scenario Based Portfolio Results

The results from the scenario-based capacity expansion analysis consistently demonstrated a preference for natural gas resources to meet HMP&L's future capacity and energy requirements. When allowed to make economic additions, the model favored NG generation due to its cost-effectiveness, dispatchability, and operational flexibility, including the ability to ramp quickly in response to changing market energy prices. The most common economic buildout across the scenarios involved the addition of a RICE unit in 2030, followed by the addition of a 33% ownership share in a CT in 2036. This staged approach aligns with the system's needs, addressing the more limited requirement for new capacity and energy in the earlier years of the study.

Variations in the natural gas price forecast did not significantly change the alternative selection. This outcome can be attributed to the system's primary need for firm, dispatchable capacity. The external capacity market prices have been elevated, especially in the summer season, and owning gas-fired generation provides a potential hedge against capacity market volatility. The model's preference for gas-fired resources is seen given the decline in ELCC projections of renewable and storage resources under the MISO DLOL framework.

To facilitate a direct economic comparison, the resultant optimized portfolio from each scenario was redispatches through the Base conditions within the production cost model. This analysis confirmed that the portfolio consisting of a RICE unit in 2030 and the CT ownership in 2036 yielded the lowest NPV. However, it is recognized that securing a partial ownership share in a new CT plant may present logistical and contractual challenges.

Table 5: Scenario Based Capacity Expansion Results

Year	Base Scenario	High Load Scenario	High Natural Gas Scenario	Low Natural Gas Scenario	Carbon Regulation Scenario
2030	RICE (36MW)	F-Class SCGT (79MW)	RICE (36MW)	RICE (36MW)	RICE (36MW)
2036	F-Class SCGT (79MW)	RICE (36MW)	F-Class SCGT (79MW)	F-Class SCGT (79MW)	F-Class SCGT (79MW)
2037		RICE (36MW)			Energy Contract (10MW)
2040		RICE (36MW)			
2045		RICE (36MW)			Energy Contract (10MW)
Portfolio NPV ($000)	$684,436	$858,570	$804,878	$640,191	$818,255
Delta to Base NPV	$0	$174,134	$120,442	-$44,245	$133,819
% Delta to Base NPV	0.0%	27.2%	18.8%	-6.9%	20.9%
Ave. Market Purchase% 2030-2045	26.02%	28.15%	22.95%	28.77%	33.18%

Table 6: Scenario Based Capacity Expansion Results Run Through Base Conditions

Year	Base Scenario	High Load Scenario	High Natural Gas Scenario	Low Natural Gas Scenario	Carbon Regulation Scenario
2030	RICE (36MW)	F-Class SCGT (79MW)	RICE (36MW)	RICE (36MW)	RICE (36MW)
2036	F-Class SCGT (79MW)	RICE (36MW)	F-Class SCGT (79MW)	F-Class SCGT (79MW)	F-Class SCGT (79MW)
2037		RICE (36MW)			Energy Contract (10MW)
2040		RICE (36MW)			
2045		RICE (36MW)			Energy Contract (10MW)
Portfolio NPV ($000)	$684,436	$752,091	$684,436	$684,436	$687,505
Delta to Base NPV	$0	$67,655	$0	$0	$3,069
% Delta to Base NPV	0.0%	10.6%	0.0%	0.0%	0.5%
Ave. Market Purchase% 2030-2045	26.02%	24.57%	26.02%	26.02%	23.37%

4.3.2 Deterministic Based Portfolio Results

The deterministic portfolios, which forced in specific resources, generally resulted in higher NPVs compared to the unconstrained scenario-based portfolios. This was anticipated, as these cases often required the selection of contracts that were more costly than the economic optimum of self-build NG generation. Among the contract-based options, storage and wind contracts were the most frequently selected by the model to meet remaining capacity needs. This is a direct result of their higher capacity accreditation relative to solar contracts, which, due to the DLOL impact, function primarily as energy-only resources.

The analysis revealed that the portfolios relying solely on contracts (the "All Contracts" case), as well as those forcing in the Hydro facility or the SMR contract, were linked to significantly higher costs than portfolios that included self-built natural gas units. A key finding from this analysis was that the deterministic portfolio forcing in a RICE unit in 2030 and a second RICE unit in 2036 produced competitive plan to the least cost plan. This result highlights a potentially more feasible self-build strategy that achieves similar economic performance without the complexities of a partial asset acquisition.

Table 7: Deterministic Portfolio Results[10]

Year	D1	D2	D3	D4	D5	D6	D7	D8
2030	RICE (36MW)	F-Class SCGT (79MW)	Energy Contract (10MW) Storage Contract (50MW)	RICE (36MW)	RICE (36MW)	Energy Contract (10MW) Storage Contract (50MW)	Energy Contract (10MW) Storage Contract (50MW)	Energy Contract (10MW) Storage Contract (50MW)
2031			Wind Contract (10MW)			Wind Contract (10MW)	Wind Contract (10MW)	
2032								Wind Contract (10MW)
2036	Energy Contract (10MW) Storage Contract (50MW)		RICE (36MW)	RICE (36MW)	F-Class SCGT (79MW)	Energy Contract (20MW) Storage Contract (50MW)	Energy Contract (20MW) Storage Contract (50MW)	Energy Contract (20MW) Storage Contract (50MW)
2037	Wind Contract (10MW)					Wind Contract (20MW)	Wind Contract (20MW)	
2038							Hydro (10MW)	SMR Contract (25MW)
2039	Storage Contract (50MW)	Storage Contract (50MW)	Storage Contract (50MW)	Storage Contract (50MW)				
2040						Storage Contract (100MW)	Storage Contract (50MW)	Storage Contract (50MW)
2041	Storage Contract (50MW)		Storage Contract (50MW)	Wind Contract (10MW)				
2042		Storage Contract (50MW)		Wind Contract (20MW)			Storage Contract (50MW)	
2043	Wind Contract (20MW)		Wind Contract (20MW)	Wind Contract (20MW)		Storage Contract (50MW)		Storage Contract (50MW)
Portfolio NPV ($000)	$774,811	$752,443	$809,555	$710,197	$684,436	$879,897	$889,589	$946,775
Delta to Low NPV	$90,375	$68,007	$125,120	$25,761	$0	$195,461	$205,154	$262,339
% Delta to Low NPV	14.1%	10.6%	19.5%	4.0%	0.0%	30.5%	32.0%	41.0%
Ave. Market Purchase% 2030-2045	22.92%	25.74%	21.54%	22.35%	26.02%	15.43%	13.95%	7.98%

5.0 Tradeoff Assessment

Following the capacity expansion analysis, a tradeoff assessment was conducted to evaluate the risk, resiliency, and economic performance of selected resource portfolios under a variety of potential future conditions. This assessment provides a more in-depth understanding of how different strategies might perform when faced with key uncertainties. For this phase of the analysis, the physical resource buildouts identified in the capacity expansion step for each selected portfolio were locked in. Each of these fixed portfolios was then run through a series of production cost simulations, with each simulation representing a different "future" or sensitivity. This process generates a range of operational and financial metrics, which were compiled into a scorecard to facilitate a direct comparison of the portfolios' relative strengths and weaknesses across the different futures.

In collaboration with Henderson Municipal Power & Light, six distinct futures were developed to test the portfolios against critical variables:

- Base Future: This simulation used the standard set of base input assumptions and allowed for 50% availability from both the external capacity and energy markets, serving as the central reference point.
- High Market Availability Future: This future utilized the base input but increased the availability of external capacity and energy markets to 80%, testing the value of portfolios in a more liquid market.

[10] Portfolio NPVRR represented as cost through Base Scenario conditions.

- High Load Future: This future subjected portfolios to the high load and energy forecast to assess their flexibility and cost to serve a high level of demand.
- High Gas Price Future: This simulation tested the portfolios' resilience to a sustained increase in natural gas prices, including the corresponding impact on market energy prices.
- Low Gas Price Future: Conversely, this future evaluated portfolio performance under a low natural gas price environment.
- Carbon Regulation Future: This future assessed the financial risk associated with potential carbon regulation by applying a carbon penalty to emitting resources and adjusting market prices accordingly.

5.1 Tradeoff Assessment Portfolios

To conduct the tradeoff assessment, the initial 13 portfolios were narrowed down to a final selection of seven. This process was performed in collaboration with Henderson Municipal Power & Light (HMP&L) and was guided by several key factors. First, some of the initial scenarios resulted in similar or identical physical resource buildouts, which allowed for logical consolidation. Second, discussions with HMP&L helped to identify the portfolios that represented strategically relevant paths forward for the utility. Finally, the Net Present Value (NPV) of each portfolio from the initial capacity expansion analysis was a primary consideration, with a focus on the most economically viable options.

This process resulted in the selection of two portfolios from the scenario-based group and five portfolios from the deterministic group. The specific resource buildouts for each of these seven selected portfolios, which were used in the subsequent tradeoff assessment, are detailed in the table below.

- Portfolio 1 represents the Base Scenario run and included a RICE built in 2030 and a partial ownership of a CT built in 2036. This portfolio repeatedly showed up as the lowest cost option when running through base case.
- Portfolio 2 represents the High Load Scenario run and includes a CT ownership share in 2030 and RICE units in 2036, 2037, 2040, and 2045. This portfolio was meant to represent how over building natural gas would be affected by different sensitivities.
- Portfolio 3 represents the deterministic scenario that has a 2030 RICE with Contracts. This was meant to represent limited CT turbine availability as well as limited NG pressure availability.
- Portfolio 4 represents the deterministic scenario that has a 2030 CT ownership share with Contracts. This portfolio represents finding a quick partnership to build a CT or larger thermal unit.
- Portfolio 5 represents the deterministic scenario that has a 2036 RICE and Contracts. This portfolio was designed to show the effects of delayed thermal buildout.
- Portfolio 6 represents the deterministic scenario that has a 2030 and 2036 RICE units and Contracts. This was designed to show a realistic scenario of building a RICE unit then adding onto the same facility a few years later when more generation was needed.
- Portfolio 7 represent the deterministic scenario where only Contracts were allowed. This portfolio shows the future of continuing how HMP&L is currently operating.

Table 8: Tradeoff Assessment Portfolios

EnCompass Optimization	Scenario Based	Scenario Based	Deterministic	Deterministic	Deterministic	Deterministic	Deterministic
Year	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5	Portfolio 6	Portfolio 7
2030	RICE (36MW)	F-Class SCGT (79MW)	RICE (36MW)	F-Class SCGT (79MW)	Energy Contract (10MW) Storage Contract (50MW)	RICE (36MW)	Energy Contract (10MW) Storage Contract (50MW)
2031					Wind Contract (10MW)		Wind Contract (10MW)
2036	F-Class SCGT (79MW)	RICE (36MW)	Energy Contract (10MW) Storage Contract (50MW)		RICE (36MW)	RICE (36MW)	Energy Contract (20MW) Storage Contract (50MW)
2037		RICE (36MW)	Wind Contract (10MW)				Wind Contract (20MW)
2039			Storage Contract (50MW)	Storage Contract (50MW)	Storage Contract (50MW)	Storage Contract (50MW)	
2040		RICE (36MW)					Storage Contract (100MW)
2041			Storage Contract (50MW)		Storage Contract (50MW)	Wind Contract (10MW)	
2042				Storage Contract (50MW)		Wind Contract (20MW)	
2043			Wind Contract (20MW)		Wind Contract (20MW)	Wind Contract (20MW)	Storage Contract (50MW)
2045		RICE (36MW)					

The analysis resulted in a limited selection of new renewable resources in the portfolios that were carried forward into the tradeoffs assessment. The value of these resources for meeting capacity obligations is diminishing. The ELCC for intermittent resources is projected to decline in future years under evolving MISO market rules. This reduction in accredited capacity presents a greater nameplate capacity requirement of renewables to meet the same planning reserve requirements, increasing their effective cost per megawatt of accreditation. Additionally, practical considerations such as local regulations and land-use limitations are beginning to present tangible constraints on the large-scale buildout of new renewable projects in many regions.

5.2 Tradeoff Assessment Analysis

To analyze the results of the tradeoff assessment, two primary analytical tools were created. The first is a NPV matrix, which provides a detailed economic comparison by showing the specific NPV calculated for each of the seven selected portfolios as simulated under each of the six different futures. This matrix allows for a direct evaluation of a portfolio's cost performance under any single, specific set of future conditions.

The second tool is a comprehensive scorecard designed to facilitate a more holistic, multi-metric comparison of the portfolios. The scorecard presents a range of key performance metrics, allowing for an evaluation beyond pure economics. For each portfolio, the values shown in the scorecard represent the average performance for each metric, calculated across all six of the simulated futures. This approach provides a measure of a portfolio's expected performance and resiliency across a wide spectrum of potential operating environments, rather than its performance in just a single outcome.

5.2.1 Net Present Value Matrix

The NPV matrix was developed to provide a direct economic comparison of all 42 simulations conducted during the tradeoff assessment, representing the 20-year cumulative present worth of revenue requirements for each portfolio under each future. The results clearly indicate that the portfolio combining a RICE unit and a 33% ownership share of a CT consistently produced the lowest NPVs across all six futures. The portfolio featuring two RICE units was a close second in terms of economic performance across each sensitivity. The "Contract Only" portfolio, which relied entirely on market purchases, was consistently the most expensive option. Many of the portfolios evaluated had NPVs that fell within a range of approximately $670 million to $900 million, providing a scale for the economic differences between the various strategies.

Table 9: 20-Year Net Present Value of Revenue Requirement ($MM)

Portfolio	Base w/ 50% Market	Base w/ 80% Market	Carbon Tax	High Gas	Low Gas	High Load
Portfolio 1	$684	$677	$839	$805	$640	$824
Portfolio 2	$753	$744	$905	$867	$711	$855
Portfolio 3	$774	$766	$889	$884	$728	$1,087
Portfolio 4	$752	$740	$953	$900	$701	$874
Portfolio 5	$810	$801	$916	$920	$762	$1,120
Portfolio 6	$710	$703	$838	$809	$672	$854
Portfolio 7	$874	$871	$944	$992	$815	$1,674

5.2.2 Scorecard Matrix

To facilitate a comprehensive, multi-faceted comparison of the seven selected portfolios, a scorecard was developed. This tool evaluates the portfolios based on a series of key performance metrics, with the value for each metric representing the average performance calculated across the six simulated futures. This approach provides a balanced view of how each strategy is expected to perform over a wide range of potential conditions.

The scorecard is organized into four distinct sections:

- NPV and Costs: This section provides an economic comparison, detailing both the 10-year and 20-year NPVs for each portfolio. The inclusion of the 10-year NPV allows for an analysis of how near-term capital expenditure may inform the resulting preferred portfolio. This section also breaks down the total revenue requirement by separately presenting the projected capital spend and the expected power costs.

Table 10: 10-Year Net Present Value of Revenue Requirement Scorecard

Portfolio	10 Year NPV ($MM)	10 Year NPV Low ($MM)	10 Year NPV High ($MM)	10 Year Standard Deviation ($MM)	10 Year Coefficient of Variation	10 Year Capital NPV ($MM)	10 Year Expected Power Cost ($/MWh)
Portfolio 1	$411	$391	$429	$17	4.1%	$23	$82
Portfolio 2	$438	$415	$465	$20	4.6%	$45	$88
Portfolio 3	$411	$391	$429	$17	4.1%	$23	$82
Portfolio 4	$438	$415	$465	$20	4.6%	$45	$88
Portfolio 5	$437	$416	$454	$16	3.6%	$0	$83
Portfolio 6	$411	$391	$429	$17	4.1%	$23	$82
Portfolio 7	$437	$416	$454	$16	3.6%	$0	$83

Table 11: 20-Year Net Present Value of Revenue Requirement Scorecard

Portfolio	20 Year NPV ($MM)	20 Year NPV Low ($MM)	20 Year NPV High ($MM)	20 Year Standard Deviation ($MM)	20 Year Coefficient of Variation	20 Year Capital NPV ($MM)	20 Year Expected Power Cost ($/MWh)
Portfolio 1	$745	$640	$839	$87	11.7%	$107	$87
Portfolio 2	$806	$711	$905	$80	9.9%	$172	$94
Portfolio 3	$855	$728	$1,087	$131	15.4%	$48	$95
Portfolio 4	$820	$701	$953	$102	12.4%	$90	$93
Portfolio 5	$888	$762	$1,120	$130	14.7%	$31	$95
Portfolio 6	$764	$672	$854	$78	10.3%	$79	$88
Portfolio 7	$1,029	$815	$1,674	$322	31.3%	$0	$107

- External Market Exposure: This section quantifies the degree to which each portfolio relies on the external wholesale market. It includes metrics for both average and maximum energy market risk, as well as the maximum capacity risk and an indication of which season presents the highest capacity procurement risk (the binding season).
- Fuel Dependence: This section analyzes the portfolio's exposure to fuel price volatility and supply risk. It specifically measures the percentage of annual energy that is generated by natural gas, providing a clear indicator of the portfolio's risk profile in the event of a natural gas supply interruption or significant price increase.
- Local Reliability: The final section of the scorecard assesses the portfolio's contribution to local system reliability. This is measured by quantifying the amount of energy generated from sources located within the HMP&L system, indicating the degree of self-sufficiency for each portfolio.

Table 12: Market Dependency, Fuel Risk, and Reliability Scorecard

Portfolio	Average Energy Market Risk	Max Energy Market Risk	Max Capacity Market Risk	Binding Season of Max Capacity Market Risk	Average Fuel Risk	Max Fuel Risk	Average Local Reliability	Max Local Reliability
Portfolio 1	29.4%	38.1%	14.4%	Winter	30.3%	41.0%	49.5%	60.0%
Portfolio 2	28.0%	33.2%	0.8%	Winter	31.7%	47.1%	50.9%	65.7%
Portfolio 3	26.9%	35.1%	19.0%	Winter	17.4%	21.4%	35.4%	38.8%
Portfolio 4	29.8%	38.5%	21.8%	Winter	26.8%	50.0%	45.0%	69.2%
Portfolio 5	25.4%	35.1%	19.0%	Winter	11.8%	21.4%	29.0%	38.8%
Portfolio 6	26.4%	35.5%	15.9%	Summer	27.1%	43.5%	45.8%	62.7%
Portfolio 7	18.8%	23.7%	25.2%	Summer	0.0%	0.0%	16.9%	18.4%

6.0 Recommendations and Conclusions

The analysis performed in this IRP indicates that HMP&L should continue to rely on market purchases and bilateral contracts as an important component of its supply portfolio, while taking prudent steps to add a measured amount of dispatchable generation to serve a portion of customer needs over time. HMP&L's existing market-based strategy has provided flexibility and remains a practical foundation for a utility of its size. At the same time, the modeling indicates that supplementing this approach with dispatchable generation can improve portfolio balance by reducing exposure to future volatility in both the energy and capacity markets, while increasing control over a portion of HMP&L's resource needs.

The IRP results support a near term action plan focused on advancing a dispatchable thermal resource for the 2030 timeframe. Across the scenario analysis, natural gas fired dispatchable generation consistently emerged as a cost competitive and operationally flexible option for meeting HMP&L's future needs. For a utility of HMP&L's size, the value of these resources is not limited to their capacity contribution alone. They also provide a practical hedge against future volatility in the energy and capacity markets by giving HMP&L greater control over a portion of its supply portfolio.

Accordingly, the recommended near-term action plan is for HMP&L to begin development work now on dispatchable thermal resource options targeted for the 2030 timeframe. This work should include continued evaluation of a self-build RICE option, while in parallel monitoring and pursuing partnership opportunities for a larger and more efficient thermal resource, including a CT or CCGT facility, that could meet the same near term need if a suitable arrangement becomes available. This dual track approach preserves flexibility and recognizes that modeling does not point to a single required solution for the early 2030 need. Rather, it supports maintaining multiple viable pathways so HMP&L can respond to changing market conditions, partner availability, and project economics while continuing to advance a resource strategy supported by the modeling.

Beyond the first action window, the IRP indicates that additional contracts and or resources are likely to be needed in the mid to late 2030s as existing supply arrangements expire and system conditions evolve. The exact timing and form of that next decision should remain flexible. It will be influenced by the resources selected for the initial 2030 need, actual load growth relative to forecast, future market conditions, changes in MISO capacity accreditation and reserve margin requirements, and the cost and commercial readiness of alternative technologies. If the initial thermal addition is a RICE based resource, HMP&L may also have the option to meet a portion of its longer-term needs through incremental expansion at the same site, allowing the utility to build on existing infrastructure, operational familiarity, and prior development work. For that reason, HMP&L should continue updating its resource plan on a regular basis so that future decisions can reflect the most current information available.

The analysis does not support a near-term recommendation for emerging technologies in place of dispatchable thermal additions. However, HMP&L should continue to monitor developing resource options, with particular attention to SMR technology, as part of its ongoing planning process. While SMRs are not currently positioned as the preferred solution for HMP&L's near-term needs, future changes in cost, commercial readiness, market design, policy support, or partnership opportunities could improve their relevance in a later planning period. HMP&L should also maintain awareness of other developing technologies, such as long duration energy storage, as part of this broader monitoring effort.

In an environment characterized by increased thermal dispatch costs, such as one with sustained high natural gas prices or the implementation of carbon regulation, the economic viability of energy storage increases. With increasing renewables to offset fuel and regulation costs market volatility increases. Energy arbitrage capability drives economic value by the price differential between charging and discharging periods. Higher thermal dispatch costs widen this differential.

During periods of high demand, thermal generators are often the marginal units setting the market clearing price for energy. If the cost of running these units increases, the on-peak market price increases. Conversely, during off-peak hours with low demand and high renewable generation (e.g., overnight wind or midday solar), energy prices can be driven lower. Storage is uniquely positioned to capitalize on this widened daily price spread. It can charge with low-cost energy over an extended period and then discharge that energy for many hours during the high-priced on-peak block, capturing a greater revenue stream than would be possible in a lower-cost thermal environment.

In a system with higher thermal costs, the value of storage extends beyond simple arbitrage. By providing dispatchability storage can displace the run-time of expensive, carbon emitting thermal units. This not only reduces overall system production costs but also lowers the portfolio's carbon footprint, creating additional value in a carbon-constrained future. While this IRP did not find storage capability to be the preferred near-term option under baseline assumptions, a sustained increase in thermal generation costs would be a critical signpost, signaling the need to reevaluate its potential as a cost-effective and operationally valuable resource in a future planning cycle.

In summary, this IRP supports a practical and measured course of action for HMP&L. The preferred planning direction is not a departure from market participation, but an incremental move toward a more balanced portfolio in which market purchases continue to play a meaningful role and dispatchable generation is added to provide a hedge against future market uncertainty for a portion of customer requirements. The most prudent near-term action is to advance development of dispatchable thermal options for the 2030 timeframe, including both a RICE based solution and potential participation in a larger, more efficient thermal partnership if available on acceptable terms. HMP&L should then use future IRP updates to monitor signposts, refine the next stage of resource additions, and preserve flexibility as the market and regulatory environment continue to evolve.

PART OF BURNS & McDONNELL

1898andco.com