Nova Scotia Power Inc.
2020 Integrated Resource Plan
DRAFT REPORT

October 30, 2020

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1 IRP Summary

1.1 Introduction

In the 2020 Integrated Resource Plan (IRP), Nova Scotia Power puts forward a long-term strategy for delivering safe, reliable, affordable and clean electricity to customers across Nova Scotia. At its core, the plan illustrates Nova Scotia Power's commitment to supporting provincial decarbonization as outlined in the Nova Scotia *Sustainable Development Goals Act* (SDGA), both by transitioning to a cleaner electricity grid and by enabling electrification of other sectors, such as transportation and heating. Given the unprecedented nature of these initiatives, as well as the increasingly dynamic and complex resource planning environment, Nova Scotia Power incorporated extensive stakeholder engagement, including input from nine public workshops, six rounds of formal submissions from stakeholders, independent expert analyses, and ongoing consultation with participants. This engagement generated critical insights at each stage of the IRP process. Supported by this collaborative effort, Nova Scotia Power produced a set of resource plans to explore a broad range of potential futures and provide insights on trade-offs between these approaches. As detailed in the Action Plan, Nova Scotia Power has identified common themes and no-regrets actions that can be employed in the near term to benefit customers and the province. These actions will rely on the continued support and involvement of the participants in this IRP process as Nova Scotia Power works together to implement this electricity strategy and transition to a deeply decarbonized electricity system.

1.2 Nova Scotia Power's System Transformation

This IRP represents a blueprint for a significant transformation in the way Nova Scotia Power generates and purchases electricity to serve its customers across the province. The scenarios considered in this report dramatically accelerate reductions in greenhouse gas emissions to align with customers' expectations and with the global scientific consensus that achieving deep decarbonization economy-wide is critical to mitigating the impacts of climate change.

This IRP also reflects Nova Scotia Power's long history of embracing technological innovation to meet customer needs reliably while providing customer rate stability. The Nova Scotia Power system today includes a diverse set of generation assets, and reflects the transformation that Nova Scotia Power has been making together with customers and the Province to its generating mix to respond to the needs of the province, including its economic and environmental goals. Nova Scotia Power operates hydro facilities, some commissioned almost 100 years ago, which have provided clean, renewable electricity since that time. The development of these assets culminated in the commissioning of the Wreck Cove facility in 1978. This facility is the largest hydroelectric resource in Nova Scotia, providing 200 MW of capacity, as well as significant volumes of clean energy and ancillary grid services. Originally designed as a peaking power plant to serve the morning and evening peak energy demand periods, this flexible plant is now vital to the integration of variable renewable generation.

Nova Scotia is directly connected to the rest of the North America electricity system via an interconnection with New Brunswick through one 345 kV tie and two 138 kV tie lines. For decades, Nova Scotia Power has relied on coal-fired power plants to provide firm dispatchable generation that delivered a reliable electricity supply as electrical demand grew. Throughout the twentieth century, this coal was largely mined within the province, supporting the domestic economy. The current coal fleet was largely built in the 1970s-1980s. The addition of coal-fired power plants also helped transition Nova Scotia Power's generation mix away from imported oil, which by the 1970s had become prohibitively expensive and volatile in pricing. Nova Scotia Power's dedicated team of employees has operated and maintained these facilities so that they continue to perform reliably today, and the company has added environmental controls to reduce their environmental impacts, including investments in mercury abatement, low-NO_x control technologies, and advanced coal blending practices. As one significant example, Point Aconi Generating Station was constructed with a circulating fluidized bed (CFB) boiler, which significantly reduces sulphur dioxide emissions and, at the time of the plant's commissioning, was the world's largest boiler of this type.

Following the global acknowledgement of the risks of climate change and the need to achieve deep decarbonization, Nova Scotia Power has re-examined how it provides power to customers, shifting investments toward lower carbon sources of generation and capacity, while ensuring reliability and rate stability. This is not new thinking for the utility. When natural gas first became available in Nova Scotia in 1999, Nova Scotia Power converted the three units at the Tufts Cove Generating Station to utilize this newly available fuel rather than more expensive and carbon-intensive heavy fuel oil. Nova Scotia Power also constructed an efficient combined cycle generating facility at the Tufts Cove site, which reduced emissions relative to coal or oil. As wind generation technology has developed, Nova Scotia Power has also added this resource to its portfolio. Nova Scotia Power added its first wind turbine at Wreck Cove in 1981, which was one of the first commercially operating wind turbines in Canada. Nova Scotia is now a wind energy leader with approximately 600 MW of wind generation installed across the province, providing 18 percent of the utility's annual energy requirement. These wind resources have contributed to meaningful reductions in greenhouse gas emissions. In addition, the recent completion of the Maritime Link, a 500 MW high-voltage direct current subsea cable and 230 kV high-voltage alternating current transmission line between the provinces of Nova Scotia and Newfoundland and Labrador, now enables access to zero-carbon electricity and dispatchable firm capacity while supporting longer term rate stability, marking another transformation of the Nova Scotia system with the first HVDC converter station and interconnection with a second neighbouring province.

The innovative spirit that is driving Nova Scotia Power's efforts to decarbonize its generation mix will also enable the utility to meet greater heating and transportation energy demand driven by electrification. The SDGA is designed to attain sustainable provincial prosperity through decarbonization of at least 53 percent (relative to 2005) by 2030 and attainment of "net zero" carbon emissions by 2050. The analysis in this IRP shows that economy-wide deep decarbonization, in line with the SDGA, can be supported by Nova Scotia Power through investment in a diverse, low-carbon resource portfolio. This transformation will also require the utility to optimize the utilization of its existing assets to manage costs and ensure reliability. Nova Scotia Power has shown repeatedly over time that it is able to harness the energy of the company and the province to transform its generation mix, and the utility is ready to do it again. The results of this IRP will guide Nova Scotia Power in completing this important work.

1.3 Evolving Planning Landscape

Electric utilities today must navigate a rapidly changing and uncertain resource planning environment, driven by decarbonization goals, regulatory and policy developments, new technologies with uncertain future price trajectories, and changing customer expectations. Nova Scotia Power has considered these factors across a wide range of planning assumptions and scenarios to ensure that this IRP considers the many ways that the future could unfold.

Decarbonization: The need for deep greenhouse gas emission reductions is recognized across the globe. On October 30, 2019 the Lieutenant Governor of the Province of Nova Scotia granted Royal Assent for the SDGA,[1] which established provincial greenhouse gas emission reduction goals of at least 10 percent below 1990 levels by 2020; at least 53 percent below 2005 levels by 2030; and "net zero" by 2050 by balancing greenhouse gas emissions with greenhouse gas removals and other offsetting measures. Similar decarbonization targets are being discussed at the Federal level. Nova Scotia Power has already reduced its own greenhouse gas emissions meaningfully below 2005 levels, achieving a 38 percent reduction by 2019. Nova Scotia Power will continue this trend through its commitments to coal unit retirements and increasingly stringent decarbonization targets. In this IRP, Nova Scotia Power has evaluated resource plans that integrate more renewable energy and achieve deep decarbonization targets by mid-century, and in some cases much earlier. The scenario plans under evaluation in this IRP achieve between 87 and 95 percent reductions in greenhouse gas emissions from the Nova Scotia Power electricity system, by 2045.

Electrification: Nova Scotia Power's Pathways Report,[2] consistent with similar studies across North America, points to electrification of vehicles and buildings as key levers in achieving economy-wide decarbonization. As the greenhouse gas content of electricity continues to decrease, the greenhouse gas

[1] *Sustainable Development Goals Act*, 2019, c. 26 – not proclaimed in force. (The SDGA will be proclaimed in force by order of the Governor in Council following public consultations and the making of regulations establishing goals to achieve sustainable prosperity consistent with the principles and focus areas set out in the act. (ss. 14 and 16).

[2] Energy + Environmental Economics (E3), Deep Decarbonization in Nova Scotia: Phase 1 Report, February 2020. https://irp.nspower.ca/documents/assumptions-and-analysis-plan/

savings from electrifying end uses such as transportation and heating increase. Thus, the utility is proactively planning the system so that it can accommodate electrified loads as they materialize.

Technology: The cost and characteristics of generation technologies are changing rapidly. The array of new and evolving technologies available to Nova Scotia Power – including wind turbines, efficient natural gas plants, battery or other energy storage, solar panels, potential new low emitting fuels and others – has advanced significantly in the last decade, and continued cost declines are expected. Moreover, new transmission projects can provide access to low- or zero-carbon energy and firm capacity[3] from other regions and help integrate Nova Scotian renewable energy. This changing landscape makes deep decarbonization more achievable than at any time before. Nova Scotia Power has evaluated a wide range of technologies that can contribute to Nova Scotia's needs, and Nova Scotia Power remains committed to evaluating new resource options as they become available. While specific resource selection in the IRP is indicative of the preferential resource category, detailed study will be required to confirm and optimize specific unit retirements and resource additions. The IRP Action Plan recommends appropriate steps to continue this work.

Customer Choice: Customers are increasingly investing in onsite energy solutions that can help manage energy usage, including energy efficiency and distributed generation technologies. In this IRP, Nova Scotia Power has forecast continued adoption of customer-sited solutions and has considered a range of resource strategies that expand energy efficiency and/or distributed generation. These technologies have the potential to provide benefits to the electricity system but can also have impacts that must be carefully understood and incorporated into system planning to ensure that value is received by all customers.

1.4 Planning Objectives

Through the IRP process, Nova Scotia Power undertakes long-term system planning to understand how the electricity system will continue to meet the needs of customers and respond to changes in the

[3] Firm capacity refers to owned or contracted generation capacity that can turn on and dispatch up to maximum output on command, barring any forced outages.

electricity planning landscape. This process informs ongoing investment, retirement, and operating decisions that are in the best interests of customers over a 25-year planning horizon. Nova Scotia Power plans the system to be safe, reliable, affordable, clean, and robust under many potential future outcomes. In the near-term, Nova Scotia Power plans to undertake "no-regrets" actions that further these planning objectives and that are shown to be robust, or common, under many potential futures. Figure 1 further describes these objectives.

Figure 1. System Planning Objectives

1.5 The IRP Planning Process

Nova Scotia Power's 2020 IRP reflects a detailed effort over more than a year to create an electricity strategy for the future. In consultation with stakeholders, Nova Scotia Power has produced several interim documents: Pre-IRP Deliverables, IRP Terms of Reference, Assumptions and Analysis Plan, Scenarios and Modeling Plan, Initial Modeling Results, Final Modeling Results, and the Draft Findings, Action Plan and

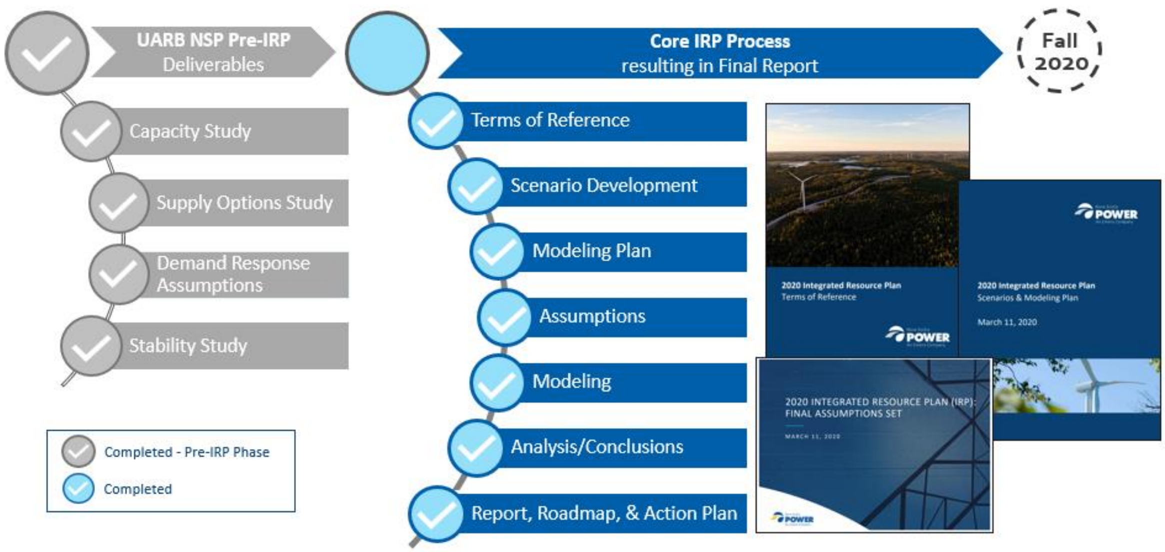
Roadmap. Throughout the process, Nova Scotia Power has incorporated input from a large group of stakeholders to utilize the best available information and include alternate views for how the system could evolve. This process ensures the IRP is transparent, inclusive of stakeholder comments, and effective at meeting Nova Scotia Power's long-term planning objectives.

To build on the findings of the IRP, Nova Scotia Power has developed an Action Plan and Roadmap to advance next steps. The Action Plan serves as a near-term guide for changes to the system and informs the planning initiatives that Nova Scotia Power will undertake. The Roadmap details a strategy for monitoring signposts that confirm or indicate a need to alter the near-term strategy.

The publication of the IRP report does not mark the end of planning efforts. As highlighted in the Action Plan, Nova Scotia Power will continue to perform planning analyses on a regular basis to ensure that it continues to identify resource options and strategies that are beneficial to customers. As is the case for utilities across North America, the IRP serves as a directional roadmap to guide future decision making but does not prescriptively predetermine actions over the coming years and decades. The IRP identifies several resource plans that could meet long-term goals and requirements, and they vary in the type, quantity, and timing of resource changes. As Nova Scotia Power continues to study resource options and obtain new information, including costs for specific project options, it will use these resource plans as a guide but will adapt as necessary to best serve customers. The IRP Findings, Action Plan and Road Map are based on common insights across the scenarios studied, to ensure a "no regrets" approach is taken in the follow-up next steps.

Figure 2 shows the key milestones within the pre-IRP study process and the core IRP process that have been undertaken in consultation with stakeholders to lead up to the delivery of this Final Report.

Figure 2. IRP Process



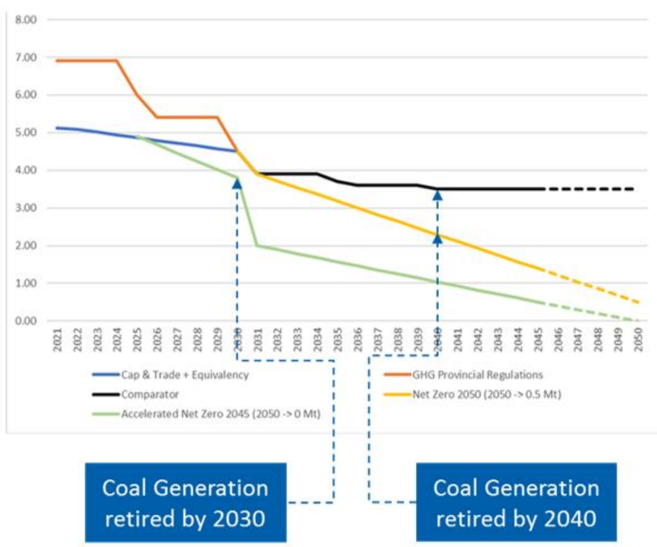
1.6 Exploring a Diverse Set of Scenarios

Nova Scotia Power undertook a half-day whiteboard exercise with stakeholders to solicit input on an appropriate range of scenarios to be considered through the IRP exercise. From there, using this stakeholder input, Nova Scotia Power constructed a diverse set of scenarios to explore policy options, resource strategies, and potential future worlds. By exploring a range of approaches under different conditions and circumstances, Nova Scotia Power has assessed the trade-offs in following different pathways to attain its long-term objectives. In addition, with a scenarios-based approach, Nova Scotia Power has ensured that its planning strategy is robust under a range of possible future conditions.

Figure 3 depicts Environmental Policy Scenarios (Greenhouse Gas Scenarios and Coal Retirement Scenarios) that were identified for evaluation through the IRP exercise. The Environmental Policy Scenarios utilize one of three trajectories for greenhouse gas emissions, which govern the maximum amount of greenhouse gas emissions from generated or imported energy during a given year. The trajectories for GHG emissions include one based on the equivalency agreement between the Province of

Nova Scotia and the Government of Canada,[4] one that is consistent with a path to reaching provincial net-zero carbon emissions by 2050, and one that reaches provincial absolute zero electricity sector carbon emissions by 2050. These last two trajectories broadly align with the targets set in the SDGA, which does not set an electricity sector-specific target. Scenarios following the accelerated net-zero by 2045 trajectory retire all coal power plants no later than 2030, while the other scenarios retire all coal plants by 2040. Coal units can be retired earlier if determined to be economic by the optimization model.

Figure 3. Greenhouse Gas Emissions Trajectories and Coal Retirements



The load trajectories developed for the IRP, shown in Figure 4, reflect three possible levels of electrification and varying levels of energy efficiency in the province. Depending on the pace of adoption for end use electrification, there could be a wide range of impacts on system load over the coming decades. The electrification trajectories impact the amount of energy that must be supplied both throughout the year and during periods of peak energy demand. The High-Electrification level envisions near-complete electrification of heating demands by 2050 and 100 percent sales of electric vehicles for

[4] The Province of Nova Scotia has an agreement-in-principle with the Government of Canada to develop a new equivalency agreement providing Nova Scotia with the ability to continue to achieve meaningful GHG reductions through moving directly from fossil fuel generation to clean energy sources while enabling Nova Scotia's coal-fired plants to operate at some capacity from 2030 to 2040.

light duty vehicles by 2040. The Mid-Electrification level envisions half of this deployment level. The Low-Electrification Level envisions continuation of the current pace of growth in building and transportation electrification. These electrification assumptions are coupled with assumptions regarding energy efficiency deployment developed by E1 for modeling. These assumptions were informed by a detailed analysis of deep decarbonization in Nova Scotia (the Pathways report), completed as an input to the IRP process.

Figure 4. Firm Peak Load and Annual Energy Forecasts

Nova Scotia Power also tested three alternative resource strategies for the planning of its system: Current Landscape, Distributed Resources, and Regional Integration. These strategies represent different approaches to planning the system. The Distributed Resources strategy contemplates a high uptake of small-scale resources (e.g. rooftop solar), while the Regional Integration strategy allows for new interconnections to other regions and corresponding access to out-of-province resources for firm energy and capacity, in addition to in-province resources. The Current Landscape strategy reflects a smaller deployment of distributed resources and does not allow for new transmission solutions to access new markets.

The various options developed for GHG emissions trajectory, load/electrification forecast, and resource strategy are summarized in Figure 5 below; this summary aligns with the naming convention Nova Scotia Power developed for various scenarios.

Figure 5. Key Drivers for Scenarios

Decarbonization	Electrification	Resource Strategy
1) **Equivalency**: Coal plants retired no later than 2040. GHG reduction trajectory consistent with the Province of Nova Scotia agreement-in-principle with the Government of Canada to develop a new equivalency agreement	0) **Low Electrification** – Current pace of growth in building and transportation electrification, which may be inconsistent with the targets outlined in the SDGA.	A) **Current Landscape** –Current pace of deployment of distributed resources and no new interconnections to other regions
2) **Net Zero**: Coal plants retired no later than 2040. GHG reduction trajectory consistent with reaching net-zero carbon emissions by 2050	1) **Mid Electrification** – Half of the building and transportation electrification achieved in the High Electrification scenario.	B) **Distributed Resources** – Adds distributed resources such as solar PV in larger quantities relative to the current trajectory
3) **Accelerated Net Zero**: Coal plants retired no later than 2030. GHG reduction trajectory consistent with reaching net-zero carbon emissions by 2045	2) **High Electrification** – Near-complete electrification of space and water heating demands by 2050 and 100% sales of electric vehicles for light duty vehicles by 2040	C) **Regional Integration** – Allows for new interconnections to other regions and corresponding access to out-of-province resources for energy and capacity

In addition to the core set of scenarios, Nova Scotia Power evaluated numerous sensitivities, many of which were requested through or informed by stakeholder feedback, to ensure the findings are robust.

1.7 Developing Optimal Resource Plans

Nova Scotia Power assessed each scenario by optimizing its resource portfolio and operations using a suite of analytical planning models. Through consultation with stakeholders, and input from the Energy and Environmental Economics (E3) Supply Options Study, prepared as part of the Pre-IRP deliverables and through the Assumptions stage of the IRP, Nova Scotia Power worked with stakeholders to characterize the capabilities and costs of various technologies that can contribute to the long-term objectives. Detailed inputs include capital costs, operating costs, operating characteristics, and contributions to system reliability. These details, along with the characteristics of Nova Scotia Power's existing system and the details of a particular scenario, are inputs to the optimization models. The models then identify the lowest-cost solution – including investment, retirement, and operating decisions – while maintaining reliability and satisfying the environmental targets for the scenario.

The optimal resource plan for each scenario includes a different long-term mix of resource technologies, based on the given system conditions and constraints modeled. The long-term capacity expansion model used by Nova Scotia Power, PLEXOS LT, is able to choose among available resource technologies that offer a range of capabilities, as seen in Figure 6. The model allows each resource technology to be assessed on a level playing field when choosing a solution that meets reliability and greenhouse gas reductions requirements at the lowest cost. The result is a unique resource portfolio for each scenario.

Figure 6. Resource Options

Resource Technology	Low-Carbon Energy	On-Demand Capacity and Grid Services
Wind Turbines	●	◉
Solar PV Projects	●	○
Hydro Plants	●	●
Imports (Firm)	●	●
Imports (Non-Firm)	●	○
Battery Storage	○	◉
Demand Response	○	◉
Energy Efficiency	●	○
Distributed Generation	●	○
Thermal Plants	○	●

● ***Provides service(s)***
◉ *Provides service(s) on a limited basis*
○ *Mostly not applicable*

Nova Scotia Power considered a wide range of technologies, including renewable resources, imports via new transmission lines, battery storage, compressed air energy storage, customer-sited solutions such as demand response and distributed resources, and natural gas power plants. Nova Scotia Power is planning its system to increase the share of generation from low- and zero-carbon resources and decrease the share of generation from greenhouse gas-emitting resources.

Hydroelectric resources in Nova Scotia have the benefit of providing zero-carbon energy, ancillary grid services,[5] and on-demand capacity, helping to reduce greenhouse gas emissions and maintain reliability. Incremental firm imports are another resource option that can provide zero-carbon energy and ancillary grid services. Firm imports are considered firm because Nova Scotia Power can rely on them to be available at any point during the year, barring any forced outages. Incremental firm imports are available in the "Regional Integration" and "Distributed Resources" scenarios.

Wind and solar PV resources provide zero-carbon energy but provide only limited ancillary grid services and do not provide on-demand capacity in the same way that hydroelectric resources, thermal plants, and firm imports do. Nevertheless, these resources do contribute to ensuring reliability, as demonstrated in the effective load carrying capability (ELCC) study completed by E3 as part of the pre-IRP deliverables. However, this same study showed that the contribution to reliability for these resources – especially solar PV – is relatively low and declines with increased penetration. Battery storage and demand response can provide on-demand capacity for limited durations, while "fossil" based generators – generators that make power by burning fossil fuels including coal, oil or natural gas – can provide on-demand capacity for unlimited durations, barring any forced outages.

Nova Scotia Power has significantly reduced greenhouse gas emissions at fossil power plants as other energy resources have become available and plans to continue that trend. Fossil fuel-based power plants will increasingly play a "back-up" role for clean energy resources. Even in deep decarbonization scenarios, these resources may continue to play a valuable role in providing ancillary grid services and on-demand capacity, even if they generate very rarely. The resource plan optimization model considers the cost of low utilization at fossil power plants and compares it to the cost of other solutions; the model considers all potential resource combinations and ultimately identifies a lowest-cost resource portfolio that maintains reliability and reduces greenhouse gas emissions according to the modeled emissions levels.

[5] "Ancillary Grid Services" is used in this IRP to encompass a variety of services that are essential for maintaining reliability of the power system, including provision of operating reserves, inertia, frequency response, reactive power / voltage control, and black start capabilities.

1.8 Overview of Key Findings

Nova Scotia Power evaluated a broad range of potential future scenarios that reflect key uncertainties over the coming decades. While each scenario has a unique optimal resource plan, Nova Scotia Power has identified common themes from across the modeling results and developed these into the Key Findings presented here. These Key Findings are the basis of the IRP Action Plan and Roadmap.

1. **Steeply reducing carbon emissions in line with Nova Scotia's Sustainable Development Goals Act will require significant efforts from each sector of the economy, with the electricity sector playing a major role.**

Nova Scotia Power has analyzed provincial economy-wide decarbonization efforts in line with the targets of the SDGA. The Pathways report confirmed that electrification of energy end uses in other sectors is an important tool to achieve deep decarbonization affordably. As more end uses electrify, Nova Scotia Power will incorporate these new loads into its planning efforts to continue providing electricity service that remains reliable and affordable. Electrifying heating and transportation already reduces greenhouse gas emissions today. For example, switching to a heat pump today reduces greenhouse gas emissions by 35 percent when compared to oil heat on today's system. As Nova Scotia Power decarbonizes its electricity mix with the addition of the Maritime Link energy blocks and other low- and zero-carbon energy resources identified in this IRP, incremental greenhouse gas savings will grow. Across the scenarios, the greenhouse gas reduction achieved by switching to a heat pump increases to 87-95 percent by 2045.

The trend for electric vehicles is similar. Today, switching to an electric vehicle can reduce greenhouse gas emissions by approximately 60 percent when compared to driving an internal combustion engine vehicle. Across the scenarios, the greenhouse gas reduction from switching to an electric vehicle increases to 91-96 percent by 2045. The electric sector will serve as a key enabler in the pursuit of economy-wide decarbonization.

Nova Scotia Power considered two primary greenhouse gas reduction trajectories.[6] Under both trajectories, Nova Scotia Power significantly reduces greenhouse gas emissions by 2045, achieving reductions of 87-95 percent relative to 2005 emissions levels.

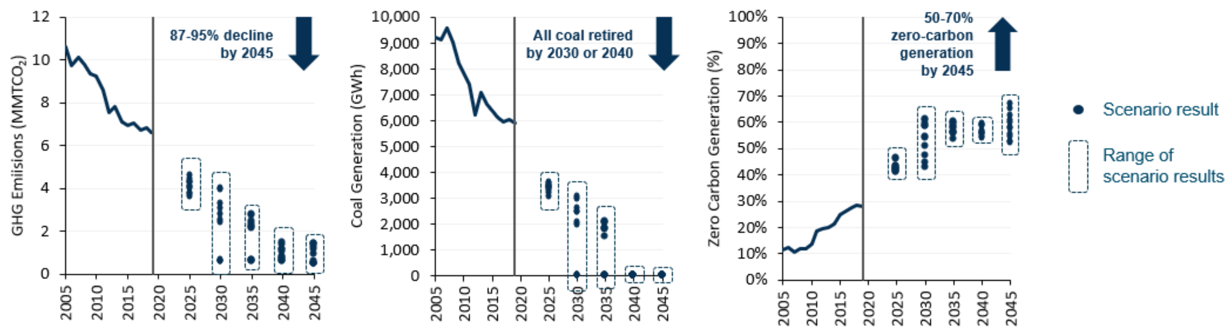
As part of this IRP, Nova Scotia Power has also considered the relative customer rate impact of various scenarios over time. The directional level analysis work has shown that increased electricity sales due to electrification can help reduce upward pressure on electricity rates while facilitating carbon reductions in other sectors; this is a consequential finding which supports the electricity sector's role in cost-effective decarbonization of the economy.

2. **Decarbonizing Nova Scotia Power's electricity supply will require investment in a diverse portfolio of non- and low-emitting resources.**

Nova Scotia Power will implement two strategies to transform its generation portfolio over the planning horizon. First, Nova Scotia Power will eliminate coal generation, which is a significant source of greenhouse gas emissions, from its generation portfolio. Nova Scotia Power has modeled the retirement of coal generation by 2030 in some scenarios, and by no later than 2040 in any scenario. Second, Nova Scotia Power will increase the share of low- and zero-carbon generation by increasing domestic renewable energy production in Nova Scotia and importing low- and zero-carbon power via new transmission. Increasing zero-carbon energy from close to 30 percent today to as much as 70 percent by 2045 is a significant undertaking and will enable critical emissions reductions. This transition must be affordable for customers and will also require that sufficient firm capacity resources be available to maintain reliability with the system's transformation and growing capacity needs. Figure 7 shows the change in greenhouse gas emissions, coal generation, and zero-carbon generation over time across scenarios.

[6] Nova Scotia Power also evaluated Comparator scenarios that follow the Equivalency trajectory for greenhouse gas reductions. However, these scenarios are not aligned with the SDGA goals and thus are not considered to be compliant plans.

Figure 7. Transformation of Generation Mix Across Scenarios



The IRP analysis demonstrates that wind is the lowest-cost domestic source of renewable energy and is selected preferentially over solar in all resource plans. Additional wind capacity of at least 500 MW by 2045 is selected by the optimization model. The timing of new wind generation often correlates with the retirement of coal units to provide replacement emissions-free energy; firm capacity to pair with the wind energy replacing reduced fossil fuel-based generation is key.

Regional Integration (i.e. investment in stronger interconnections to other jurisdictions) is an economic component of the lowest-cost plans under each load scenario. Both the Reliability Tie, which strengthens Nova Scotia's connection to the North American electrical grid, and a Regional Interconnection, which enables access to firm capacity and energy imports, are shown to have value. This finding is robust across a wide range of assumptions and sensitivities. Replacement of reliable, firm capacity, as can be provided via Regional Integration, is critical to the next phase of system transformation under evaluation in this IRP.

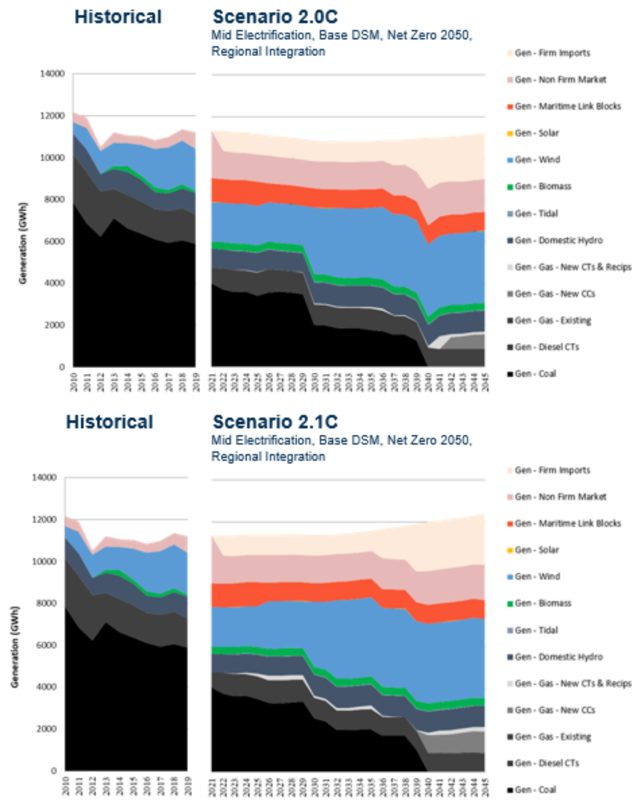
Other key elements of the plan include Nova Scotia Power's existing domestic hydro resources; these are shown to provide economic benefit to customers and are economically sustained through the planning horizon with appropriate reinvestment requirements. In addition, energy efficiency and Demand Side Management (DSM) programs in the range of the "Low" to "Base" profiles, consistent with the E1

Potential Study,[7] are shown to be most economic relative to other options evaluated when both cumulative long term cost economics and relative rate impacts are considered.

Figure 8 shows how the generation mix evolves in two low-cost key scenarios, 2.0C and 2.1C. These scenarios are representative of many of the resource plans considered. In both scenarios, greenhouse gas emissions are on the Net Zero 2050 trajectory, electrification is on the Mid Electrification pathway, and Nova Scotia Power has the option of accessing firm capacity and energy through transmission expansion to other jurisdictions. With the delivery of Nova Scotia Power's contracted hydro blocks and energy imports via the Maritime Link, clean imports increase and displace coal generation, resulting in a significant decline in coal generation early in the planning horizon. The decline in coal generation continues through 2040, by which time all coal-fired power plants are retired. Wind generation and low carbon imports grow to replace retiring coal, making up a larger share of the generation mix.

[7] https://nsuarb.novascotia.ca/ M08929, Exhibit N-1, EfficiencyOne (E1), 2019 DSM Potential Study Report (August 14, 2019).

Figure 8. Historical and Future Generation Mix Under Scenarios 2.0C and 2.1C



3. Firm capacity resources will be a key requirement of the developing Nova Scotia Power system in both the near and long term.

Today, Nova Scotia Power's coal plants provide firm capacity, energy, and essential grid services to the system, all of which are components of reliable system operation. The scenarios examined in this IRP have shown that Nova Scotia Power can retire these units and still operate the system reliably, but new resources are needed to provide these services. Nova Scotia Power will need additional firm generating capacity to ensure that the system is reliable with sufficient supply available to meet expected demand, especially during periods of low renewable generation and peak loads. The need for additional firm generating capacity may also grow with increasing energy demand. Depending on the pace of electrification, energy demand will increase over the next few decades as more vehicles and heating systems plug into the grid. This will further increase the need for additional firm generating capacity that can ensure reliability.

Figure 9 shows retirement of existing capacity and the change in energy demand for a 2040 coal phase-out schedule and the Mid-Electrification trajectory. Nova Scotia Power has been managing a small capacity deficit in the near-term, but this shortfall will grow significantly over the next ten years. Coal plant retirements, as well as economic retirements of other existing thermal power plants, reduce the amount of available firm capacity.

Figure 9. Existing Effective Capacity and Capacity Needs Under Scenario 2.0C (Left) and Scenario 2.1C (Right)

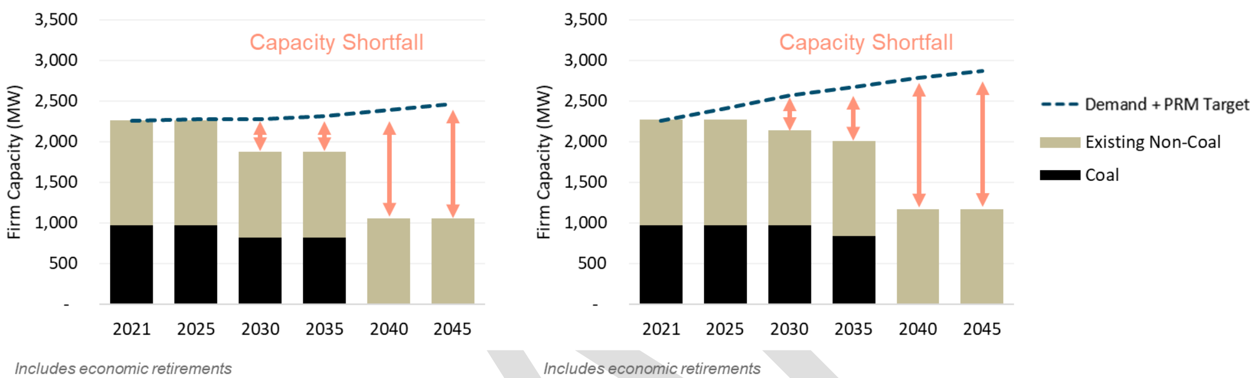
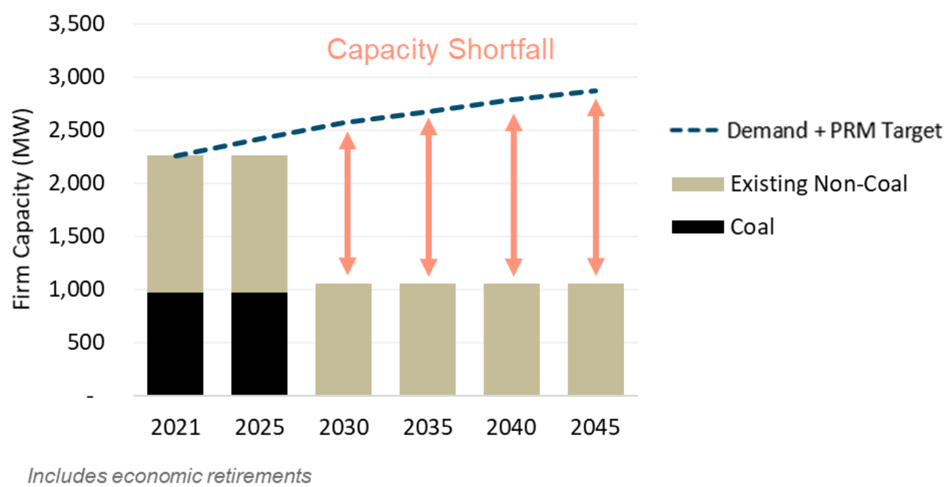


Figure 10 shows the same information, but for a scenario with a 2030 coal phase-out schedule. Because the coal retirements are accelerated and load growth is the same, the large capacity shortfall occurs earlier.

Figure 10. Existing Effective Capacity and Capacity Needs Under Scenario 3.1C



There are several resource technologies that can help fill this firm capacity shortfall, and each has a particular set of capabilities which help to contribute to this reliability need. Nova Scotia Power has drawn from the set of IRP optimized resource plans from low-cost scenarios to identify common elements; these common elements are understood to be robust to a wide range of potential futures and can be incorporated into a no regrets Action Plan and Roadmap.

The IRP analysis has shown that combustion turbines are the lowest-cost domestic source of new firm capacity; they replace retiring thermal capacity in all resource plans. These units are also fast-acting, meaning they can quickly respond to changes in wind and non-firm imported energy. They operate at low capacity factors, meaning that they facilitate integration of non-emitting resources and do not significantly contribute to GHG emissions. In addition, Nova Scotia Power's existing combustion turbine resources provide similar services and economic benefit to customers and are sustained through the planning horizon with appropriate reinvestment requirements. Low-cost, low emitting generating capacity may also be provided economically through redevelopment of existing natural gas-powered steam turbines or coal unit conversions. Fuel flexibility, including low/zero carbon alternative fuels, may also be an option for new and redeveloped resources and will be considered in the IRP Action Plan and Roadmap.

The aggregated Demand Response (DR) programs modeled in the IRP have also been shown to have economic value, offsetting firm generation capacity requirements. A DR program with a target program capacity of approximately 75 MW is shown to have value and is incorporated into the IRP Action Plan. Battery storage also provides firm capacity and can support the integration of variable renewable generation, however its ability to substitute for firm capacity resources is limited by its relatively short duration. Up to 120 MW of storage by 2045 is selected in the portfolios with deployments of 30-60 MW by 2025 in many plans.

For each scenario modeled, the IRP identifies the lowest-cost solution that addresses the firm capacity and energy requirements, meets the greenhouse gas trajectory, and satisfies all other operating requirements. Figure 11 shows the near-term change in capacity for a subset of the scenarios modeled. In all scenarios, fossil capacity is retired within the modeling horizon, and a diverse set of resources is added. Gas capacity is added across all scenarios to ensure reliability, but this gas capacity is operated relatively infrequently.

Figure 11. Cumulative Capacity Additions and Retirements in the Near Term (2026)

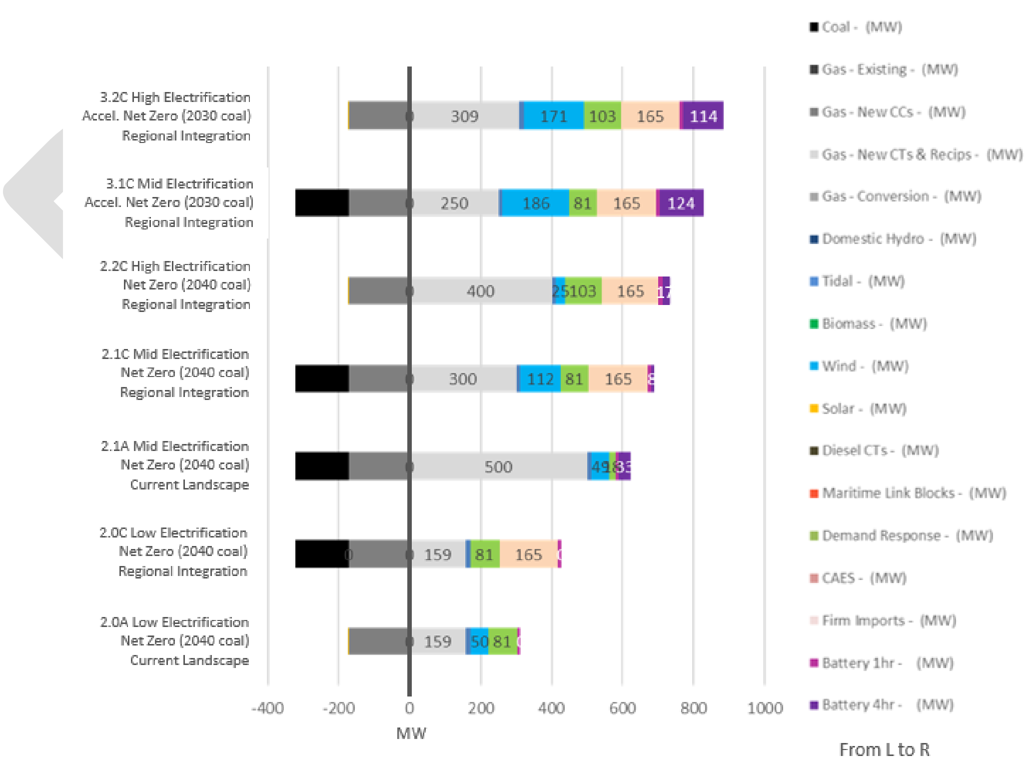
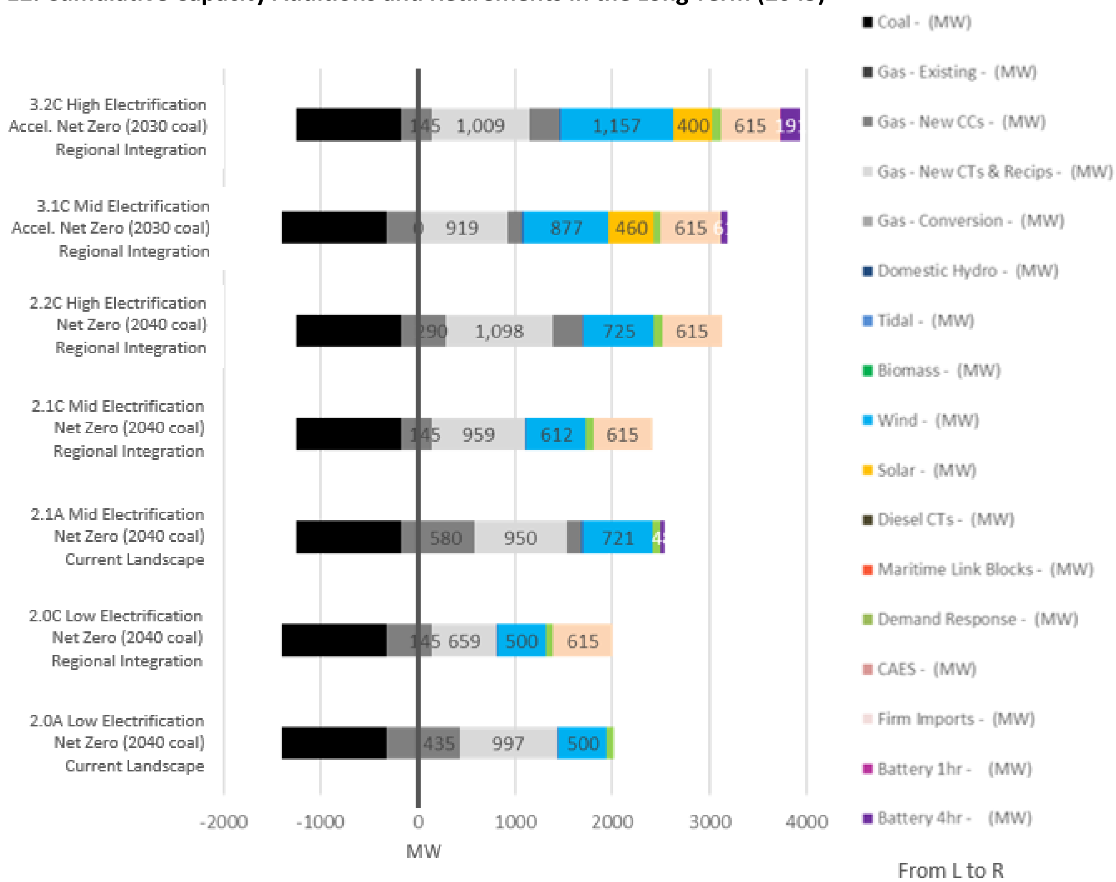


Figure 12. Cumulative Capacity Additions and Retirements in the Long Term (2045) Figure 12 shows the change in nameplate capacity in the long term for the same subset of key scenarios. By this time, all of the coal units are retired. A diverse set of resources is added to reduce greenhouse gas emissions and ensure reliability.

Figure 12. Cumulative Capacity Additions and Retirements in the Long Term (2045)



4. **The SDGA-compliant key scenario which minimizes the cumulative present value of the annual revenue requirement of the 25-year planning horizon (adjusted for end effects) is 2.0C (Low Electrification / Base DSM / Net Zero 2050 / Regional Integration).**

The model considered coal retirements in 2030 and in 2040. When coal retirements are required by 2030 in combination with accelerated GHG reduction targets, the replacement firm capacity and energy resource requirements create higher costs leading up to that year as generating resources are replaced. This contributes to a higher net present value (NPV) over the entire IRP planning horizon. Shifting the coal retirements to 2040 lowers costs on an NPV basis, however, the replacement resource mix is similar and so is the cumulative relative rate impact by 2045. This finding indicates that Nova Scotia Power should continue to monitor the planning environment for opportunities to advance the coal transition economically and affordably.

1.9 Overview of Action Plan and Roadmap

The Action Plan is a key output of the 2020 IRP. As described in the 2020 IRP Terms of Reference, the Action Plan identifies the critical undertakings required over the near term to implement the long-term electricity strategy. Nova Scotia Power has identified near-term investment and operational strategies that ensure it will satisfy its planning objectives while not closing off opportunities that may later prove to be advantageous.

The Action Plan includes insights and ranges informed by the model outputs and findings, as analyzed across the scenarios. These continue to be reviewed and interpreted and should be understood in terms of their orders of magnitude or directional time frames.

1) Develop a **Regional Integration Strategy** to provide access to firm capacity and low carbon energy while increasing the reliability of Nova Scotia's interconnection with North America. This Strategy will include:
    a. Identifying opportunities for near-term firm imports over existing transmission infrastructure
    b. Immediately commencing the development of a Reliability Tie and Regional Interconnection via an appropriate regulatory process with target in-service dates as follows:
        i. Reliability Tie: 2025-2029 (or earlier if practical and feasible)
        ii. Regional Interconnection: 2027-2035

   c. In parallel with Regional Interconnection development, and working with neighbouring jurisdictions, conducting detailed engineering and economic studies for firm import options requiring new transmission investment and strengthened regional interconnections, including evaluations of availability and security of supply, emissions intensity, and dispatch flexibility

2) **Electrification** is a key variable in this IRP and results indicate that under economic resource plans it can support provincial decarbonization while reducing upward pressure on electricity rates for customers. NS Power proposes several Action Plan items from this IRP related to electrification:
   a. Initiate an Electrification Strategy to understand options for encouraging beneficial electrification with the goals of maintaining rate stability while decarbonizing the Nova Scotia economy consistent with the Sustainable Development Goals Act.
   b. Initiate a program to collect detailed data, including data on the quantity, flexibility and hourly load shape of incremental electrification demand, to assist with further system planning work.
   c. Address electrification impacts on the Transmission & Distribution system as additional experience and data become available.

3) Initiate a **Thermal Plant Retirement, Redevelopment, and Replacement Plan**, including:
   a. Develop a plan for the retirement and replacement of Trenton 5, targeting 2023, while identifying required replacement capacity and energy in parallel. Begin decommissioning studies for NS Power's other coal assets and develop and execute a coal retirement plan including associated regulatory approval process; this coal retirement plan will include significant engagement with affected employees and communities.
   b. Complete a thermal plant Depreciation Study to update depreciation rates and a recovery strategy to better align depreciation with updated useful lives for generation assets. Invest sustaining capital into individual thermal units appropriate to their retirement categorization.

   c. Develop a plan for the redevelopment or replacement of existing natural gas-powered steam turbines to provide low-cost, fast-acting generating capacity to the Nova Scotia system. Fuel flexibility is a component of this work, including consideration for low/zero carbon alternative fuels.
   d. Initiate a wind procurement strategy, targeting 50-100 MW new installed capacity by 2025 and up to 350 MW by 2030. This strategy will solicit Nova Scotia-based market pricing information which will inform the selected wind capacity profile and timing, informed by the IRP wind sensitivities.

4) Create a **Demand Response Strategy** targeting 75 MW of capacity, for deployment by 2025. Available resource cost, flexibility, and reliability may inform pursuit of additional Demand Response capability.
   a. The strategy will be closely linked to the Electrification Strategy being developed in parallel. The strategy will build on learnings from NS Power's Smart Grid Project, NS Power's Time Varying Pricing application, the DR Joint Working Group between NS Power and Efficiency One, the ELIADC tariff, and the Large Industrial Interruptible Rider.
5) NS Power will calculate Avoided Costs of DSM (capacity and energy) for scenarios 2.0C and 2.1C. 2.0C will be used as the Reference Plan and 2.1C will be available for additional reference.

As conditions change – either through changes to policy, technology, or economics – Nova Scotia Power will adapt its resources plan to best serve customers. The Roadmap sets out a series of signposts that, if observed, may indicate a need to alter the system planning strategy.

1. Advance engineering study work on coal to gas conversions at Trenton and Point Tupper Generating Stations. Monitor cost outputs of this work relative to IRP assumptions and update the balance of new and converted capacity resources accordingly.
2. Complete detailed system stability studies under various current and future system conditions, reflective of both stressed system states and normal operating conditions, while considering higher quantities of installed wind capacity as seen in the IRP modeling results. This work will also consider

the impacts of grid service provision from inverter-based generators (such as wind turbines) and how the introduction of new ancillary services like Fast Frequency Response might affect existing services such as Synchronized Inertia. Monitor results for significant divergence from wind integration assumptions modeled in the IRP and trigger an update as needed.

3. Pursue economic reinvestment in existing hydro and combustion turbines with individual capital applications as applicable; economic justification as part of a capital application will be required to confirm decision to pursue Mersey hydro redevelopment. Continue sustaining capital investment in thermal units, aligned with their projected retirement classification. Monitor required levels of sustaining capital investment for significant changes from IRP assumptions and, if observed, trigger a unit-specific analysis of alternatives. Monitor unit reliability for significant changes from IRP assumptions and, if observed, trigger an ELCC calculation and/or PRM study as required.
4. Monitor the development of low/zero carbon fuels that could replace natural gas in powering generating units to provide firm, in-province capacity.
5. Continue to track the installed costs of wind, solar, and energy storage to look for variations from the trajectories established in the IRP (in particular, monitoring for divergence from the "Base" to the "Low" pricing scenarios). Nova Scotia Power will solicit Nova Scotia-based market information which will inform this as needed.
6. Track the ongoing development of the Nova Scotia Cap-and-Trade Program, including auction results and developing regulations. In particular, monitor GHG market size for indications that value from incremental allowance sales (beyond the projected economic emissions reductions shown in the IRP results) can be incorporated into long-term resource planning decisions with greater certainty. Significant changes in the value of incremental GHG reductions could influence resource plan components including non-emitting generation procurement, DSM levels, and coal retirement trajectories.
7. Monitor electrification growth in Nova Scotia to understand at what point the provincial load profile starts to move from Low, to Mid, to High levels of electrification. An observed transition will, among

other impacts, inform the use of DSM avoided costs in related proceedings and trigger a PRM study using actual peak, energy, and load shape data.

8. Continuously refine the Action Plan and Roadmap items via an evergreen IRP process. This process should facilitate annual updates as conditions change and technology or market options develop, and as Action Plan items are completed. Nova Scotia Power will include a summary of updates as part of IRP Action Plan reporting.

1.10 Going Forward

Nova Scotia Power's 2020 IRP reflects global themes of transformation, economy-wide decarbonization, adoption of green technologies, and collaboration with a broad range of stakeholders. Interest in these themes has been intensified as a result of the ongoing COVID-19 pandemic, and the associated focus on economic recovery. Nova Scotia Power is pleased to present this IRP Report as a result of the collective efforts of interested parties to understand and plan for the potential long term energy clean energy future of Nova Scotia and to identify on a roadmap for system planning based on scenarios that will ensure the utility continues to deliver affordable, safe, and reliable electricity while accelerating its transition to clean energy in this context.

Nova Scotia Power is appreciative of the input of stakeholders throughout this IRP process, which is among the most significant stakeholder engagements Nova Scotia Power has undertaken. The 2020 IRP expanded the focus of the traditional utility planning exercise to understand the role of the electric utility within Nova Scotia's broader transition to a clean energy future. Continuing to build on this foundation of collaboration will be a necessary element to enable Nova Scotia to meet its sustainability goals, while creating opportunities for building a thriving green economy.

2 IRP Introduction and Process

2.1 Nova Scotia Power's Mission

Delivering safe, reliable, affordable, and clean energy is central to Nova Scotia Power's mission. This Integrated Resource Plan (IRP) represents Nova Scotia Power's first long-term plan that commits to the retirement of all coal units within the IRP planning horizon. This decision reflects the preferences of customers, the goals of the province, and the scientific consensus that deep decarbonization is essential to avoid the worst impacts of climate change. The planning process and assumptions utilized for this study reflect Nova Scotia Power's mission to ensure a sustainable electricity supply - environmentally and economically - for customers across Nova Scotia.

2.2 Objectives of the IRP

As a regulated utility with an obligation to serve customers, planning for the future is a responsibility and requirement for Nova Scotia Power. The IRP is a long-term planning exercise that establishes the direction for Nova Scotia Power to meet customer demand and energy requirements, as well as environmental obligations, in a safe, reliable, affordable and clean manner across a reasonable range of foreseeable futures. The IRP provides a structured way for Nova Scotia Power and stakeholders to assess the potential impacts of uncertain policy, technological, and market factors that may have significant implications on the utility and its customers. Nova Scotia Power is required to file a 10-Year System Outlook annually; IRPs are carried out when material changes in the key external influences underlying Nova Scotia Power's long-term planning environment, such as environmental policy or market landscape, trigger a need to revisit the long-term planning strategy.

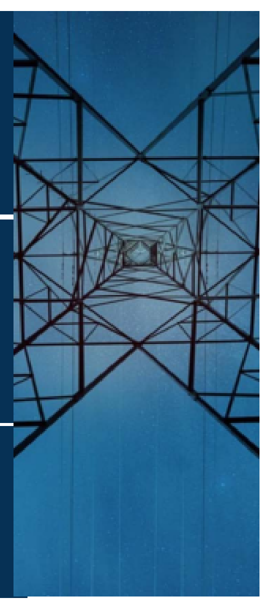
At the start of the core IRP process, Nova Scotia Power's approved 2020 IRP Terms of Reference laid out three primary objectives for the 2020 IRP, reflected below in Figure 13. The first objective of the plan was to develop a robust, risk-weighted, least-cost long-term electricity strategy that delivers energy in a safe and reliable manner, continues provincial decarbonization via non-emitting resources, and maintains affordability for customers across a range of foreseeable future scenarios. This objective reflects the Company's commitment to developing a plan that achieves significant decarbonization while ensuring rate stability to customers over the IRP's 25-year planning horizon.

The second objective of Nova Scotia Power's 2020 IRP was to construct an Action Plan and Roadmap outlining the key tasks to be undertaken in the next five years to implement the strategy, and to identify signposts to monitor and decision gates to be addressed in order to enable carefully considered changes in strategy as the external policy, technology, and market landscape evolves. This Action Plan and Roadmap are directly informed by the modeling performed by Nova Scotia Power, which reflected a range of potential external influences, as well as by other known potential future uncertainties.

The third key objective of the 2020 IRP was to develop a collaborative, transparent, and evergreen utility resource planning process in Nova Scotia that reflects industry best practices and promotes understanding and consensus. Toward that aim, this IRP process has involved extensive stakeholder engagement, including input from nine public workshops, six rounds of formal submissions from stakeholders, independent expert analyses, and ongoing consultation with participants.

Figure 13. Nova Scotia Power's Approved Terms of Reference IRP Objectives

1. Develop a robust,[2] risk-weighted least-cost long-term electricity strategy ("the Strategy") that delivers energy in a safe and reliable manner, continues provincial decarbonization via non-emitting resources, where appropriate, and maintains affordability for customers across a range of foreseeable future scenarios.
2. Develop an Action Plan and Roadmap describing the key tasks to be undertaken in the next five years to implement the Strategy and identify signposts to monitor and decision gates to be addressed in order to enable the appropriate triggering of changes to the Strategy, based on future changes in the planning environment.
3. Develop a collaborative, transparent and evergreen electric utility resource planning process in Nova Scotia that reflects industry best practices in the area of resource planning and promotes understanding and consensus among interested parties.



Please refer to Exhibit N-4 (M08929) which is the approved NSUARB-approved Terms of Reference for this matter.

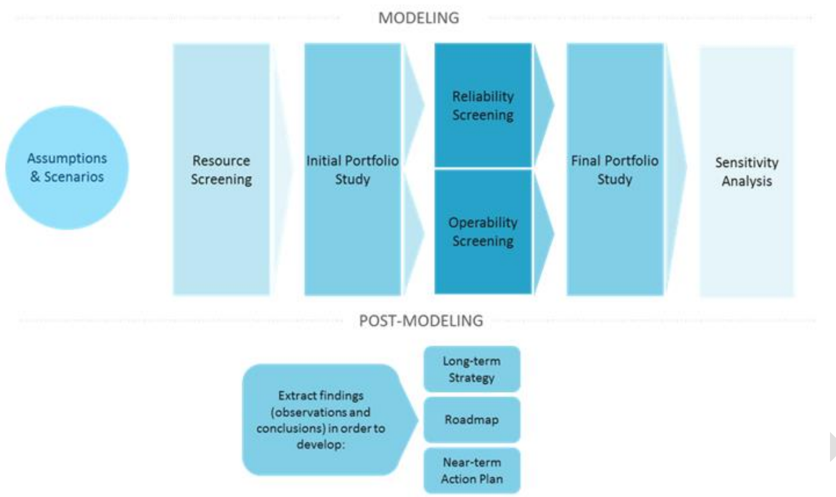
2.3 Process for the IRP

Prior to initiating the core IRP process, Nova Scotia Power undertook a number of pre-IRP studies per the recommendations of the Generation Utilization and Optimization Report[8] (completed by the Nova Scotia Utility and Review Board's (NSUARB) consultant Synapse Energy Economics, Inc.) and Bates White Economic Consulting's 2016-2017 Fuel Adjustment Mechanism Audit Report[9]. These included a Capacity Study, a Supply Options Study, a Renewables Stability Study, and a Demand Response Options Study. Nova Scotia Power engaged with interested parties over the summer of 2019 on this work through a series of workshops to present its draft studies and to solicit and reflect stakeholder feedback. Nova Scotia Power issued its Final Pre-IRP Report following this process to stakeholders on October 17, 2019 (updated November 1, 2019).[10] Following completion of the pre-IRP analysis stakeholder engagement, Nova Scotia Power commenced engagement with stakeholders on the core IRP process.

The IRP modeling process, as laid out in the Terms of Reference, comprised several modeling stages as shown in Figure 14, with stakeholder workshops and engagement between stages to facilitate input from interested parties.

[8] Matter M08059, Generation Utilization and Optimization, Exhibit N-1, May 1, 2018.
[9] Matter M08195, NSPI Fuel Adjustment Mechanism (FAM) Audit conducted by Bates White, Exhibit N-1, July 24, 2018.
[10] Matter M08929, Exhibit N-8, Final Pre-IRP Report, October 17, 2019 (updated November 1, 2019), filed May 22, 2020).

Figure 14. 2020 IRP Modeling Process



Prior to beginning work on the modeling, Nova Scotia Power then engaged in a collaborative Analysis Plan development process. The Analysis Plan described in detail the modeling and evaluation process, the portfolio evaluation criteria, scenarios and sensitivity analyses, and descriptions of the modeling approach and phases.

Using the Analysis Plan as a guide, Nova Scotia Power proceeded with establishing a defensible set of analysis assumptions, reflecting publicly available, documented and/or independently vetted sources where possible. Nova Scotia Power invited stakeholder comment on these sources and assumptions and used the resulting range of available information and sources to inform the base case and sensitivity modeling performed. The final set of analysis Assumptions and the Scenarios & Modeling Plan were published on March 11, 2020.[11]

As a next step, the Resource Screening phase was undertaken to select a reasonable set of new candidate resource options and retirement decisions, balancing the desire to test a broad range of portfolio of expansion options with the need to maintain a manageable set of model options to reduce computational

11 https://irp.nspower.ca/documents/assumptions-and-analysis-plan/

challenges within PLEXOS. This ensures reasonable model execution time and focuses computational resources on more critical decisions.

The above steps provided the required inputs for Nova Scotia Power to undertake its Initial Portfolio Study, with modeling results[12] released on June 26, 2020 and presented at a workshop on July 9, 2020[13], and in finalized form on September 9, 2020.[14] This portfolio analysis relied predominantly on capacity expansion optimization modeling using PLEXOS LT, with supporting analysis utilizing PLEXOS MT/ST and E3's RESOLVE model. The key scenarios defined in the Modeling Plan were modeled to assess the economically optimized capacity expansion plan, i.e., the portfolio of resource additions and retirements over the 25-year planning horizon and the associated NPV revenue requirement for each plan. This step then explicitly compared model results across the range of scenarios and ranked them using established evaluation criteria. These results are discussed below.

Given that all of the IRP scenarios being modeled will result in dramatic changes to the power system, Nova Scotia Power undertook two additional modeling phases to better understand both the reliability and operability of each plan. For the reliability assessment, Nova Scotia utilized E3's loss of load probability model, RECAP, to perform a robust assessment of the reliability of key scenarios in 2050, including estimating the achieved loss-of-load over thousands of simulated years of weather and resource output. Similarly, to better understand the operability of each scenario, Nova Scotia Power ran key scenarios through PLEXOS MT/ST to evaluate the production costs (e.g., fuel and purchased power) and dispatch at a more granular level.

Nova Scotia Power used the outputs from the Reliability and Operability Screening phases and associated stakeholder comments to conduct revised capacity expansion optimization modeling with PLEXOS LT. For this Final Portfolio Study, production cost simulations were completed using PLEXOS MT/ST and the resulting generation and production costs outputs were incorporated into the IRP analysis to increase the

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[12] **https://irp.nspower.ca/documents/modeling-results/,**

[13] **https://irp.nspower.ca/documents/modeling-results/**, provided as Appendix 1010

[14] **https://irp.nspower.ca/documents/draft-findings-roadmap-action-plan/**, provided as Appendix 1026

granularity of the final runs. The final Modeling Results, Draft Findings, Action Plan and Roadmap were circulated to stakeholders for comment on September 2, 2020.[15]

2.4 Advancements in the IRP Approach

The evolving planning landscape described above, coupled with advancements in modeling and utility planning best practices, has allowed Nova Scotia Power to update and improve upon its long-term resource planning process. The number and range of uncertainties in the electricity industry have increased exponentially in the past decade. These uncertainties and changes have necessitated a different approach to the IRP than the traditional approach in which the most cost-effective resource mix was selected as the preferred plan. In addition to the lowest cost resource mix, factors such as environmental and government policy requirements, reliability and grid stability, and customer rate impacts also inform the IRP. The following summarizes several of these important evolutions:

Multiple NPVRR and Rate Metrics - Traditionally, the objective for resource planners was to identify an optimal portfolio of resources that minimize cost NPVRR as the sole metric. This was done while focusing on a single central scenario for key assumptions and forecasts (e.g. load, emissions, etc.). This IRP has considered the current dynamic planning environment by incorporating additional planning objectives include quantifying resources with the best combination of costs, risks, and uncertainty with a lens toward customer affordability and decarbonization. A combination of scenario and sensitivity analyses have enabled quantification of the range of uncertainty across scenarios and along different outcome metrics.

Target Planning Reserve Margin – As explained in more detail in Section 5.3, Nova Scotia Power's PLEXOS LT expansion model considers the Planning Reserve Margin (PRM) constraint in the optimization. Traditionally, Nova Scotia Power has used an Installed Capacity (ICAP) method which

[15] https://irp.nspower.ca/documents/draft-findings-roadmap-action-plan/ provided as Appendix 1024 and 1026.

targets a 20 percent PRM, as opposed to an Unforced Capacity method (UCAP) (which targets approximately a 9 percent PRM), with thermal generators contributing at their nameplate capacity. This ICAP methodology is the most common approach used in the industry and as such, Nova Scotia Power will continue to use the PRM calculated in the Pre-IRP Planning Reserve Margin and Capacity Value Study (e.g. 20 percent) for future reference. Both methods result the in same reliability and the same quantity of effective capacity. For resources already in the portfolio, it does not matter whether an ICAP or UCAP approach is used. However, based on stakeholder feedback and working with Nova Scotia Power's IRP consultant, E3, the utility agreed to use the UCAP method for its capacity expansion modeling, as the ICAP method over-counts thermal resources relative to other resources by not considering forced outage rate. The UCAP method addresses this deficiency by counting thermal generators at their effective capacity, incorporating forced outages. The UCAP method is also better at considering reliability implications with resource sizing. In Nova Scotia Power's relatively small system, lumpy outages associated with larger resources can result in differences in effective capacity contribution (e.g. three 50 MW generators are more reliable than one 150 MW generator because it is very unlikely all three will experience a forced outage at the same time).

System Strength and Stability – The next 25 years will see a dramatic transformation in the Nova Scotia generation mix as it moves further towards decarbonization. Theories and physics of power systems were developed around synchronous machines that were historically the backbone of the power system. This IRP analysis has modeled the retirement of major large synchronous generators with replacement, in part, by inverter-based non-synchronous generation or other lower emitting generators. The retirement of coal-fired generators will not only impact system adequacy (capacity and energy) but will also require a major shift in the provision of ancillary grid services which have historically been provided by large synchronous machines.

Historically, system adequacy constraints have been imposed via the specification of a certain number of "must run" units. In Nova Scotia, these units have been the larger thermal units, reflecting the quantity of ancillary services required. For this IRP, Nova Scotia Power developed assumptions about cost and operational constraints to address these services in the absence of the thermal/coal resources. These assumptions, generally focused on aggregating sufficient synchronous inertia to survive a system contingency, have been developed by Nova Scotia Power and its consultants using the PSC Stability Study[16] from the Pre-IRP work as the basis for assumptions. Further detailed study to establish firm opportunities and constraints for inverter-based energy sources will continue to be required as the system changes.

Long-Term Capacity Expansion Modeling Software – In recent previous IRPs, Nova Scotia Power has relied on Strategist, a resource planning tool supported by ABB Enterprise Software. This tool worked well when the system was predominantly dispatchable, combustion-based generation. However, as Nova Scotia Power seeks to integrate greater quantities of variable renewable resources, Strategist's limitations make it less suitable for modeling our evolving system. To address these limitations, NS Power has instead chosen to rely on the commercially available PLEXOS LT capacity expansion model, in conjunction with E3's RESOLVE model to help screen resources and test a broader range of scenarios. PLEXOS LT is a mixed integer programming model developed by Energy Exemplar that can be used to perform detailed, robust capacity expansion modeling that models the chronological behaviour of loads and variable generation. Generation dispatch, transmission power flow and ancillary services are co-optimised and integrated with emissions modelling. PLEXOS MT/ST (mid-term/short-term) includes hourly chronological production simulation that reflects unit commitment constraints and real-time dispatch to match supply and demand. Dispatch is co-optimized to meet load and ancillary service requirements at minimum cost subject to a number of operating constraints. The detailed 8760hr/yr unit commitment and economic dispatch module was also used as an operability screening tool to help inform final modeling updates in the PLEXOS LT runs (see Section 5.3). NS Power utilized both of these

[16] **https://nsuarb.novascotia.ca/** Matter M08929, NS Power IRP, Exhibit N-8, Appendix A, pdf pages 367-433.

models for all IRP scenarios. The PLEXOS LT Model was used for capacity expansion optimization while the PLEXOS MT/ST module was used for production cost modeling (as a component of NPV) and energy balance reporting for each PLEXOS LT produced scenario.

While PLEXOS can provide valuable insights on system operations, its complexity prohibits exhaustive analysis of a large number of scenarios. As such, RESOLVE complemented PLEXOS as a faster-solving capacity expansion model designed specifically for systems seeking to integrate higher penetrations of renewable resources. RESOLVE relies on a linear optimization framework that allows it to minimize computer run time, enabling it to evaluate many scenarios and sensitivities over long time horizons. At the same time, the model has rigorous modeling of system operations to consider how resources like wind, solar, and storage will impact hourly operations as part of the investment decision, utilizing "smart" day sampling to capture a wide variety of days and a more statistically significant representation of the full spectrum of load and renewable conditions. E3 and NS Power calibrated the RESOLVE and PLEXOS LT inputs to ensure consistent modeling of the NS Power system in both tools. The RESOLVE model then enabled NS Power to quickly "screen" resources up front to reduce the amount of candidate resources within PLEXOS LT, and also allowed NS Power to explore additional scenarios and sensitivities throughout the IRP process.

2.5 Role of the IRP Working Group

The approved Terms of Reference state that Nova Scotia Power is to complete the IRP process in collaboration with the Nova Scotia Utility Review Board's staff and its consultants. Nova Scotia Power and its consultant, E3, have worked throughout the IRP process with NSUARB staff, and staff's consultants Synapse Energy Economics, Inc. (Synapse) and Bates White Economic Consulting (Bates White) (Working Group). The Working Group has met regularly since the commencement of the core IRP process to discuss and collaborate on the overall approach to the analysis review and receive feedback on detailed modeling results in live time as Nova Scotia Power and E3 have completed their work. Nova Scotia Power provided the IRP PLEXOS LT and MT/ST models to Synapse as part of this process to enable Synapse and Bates

White to complete their reviews. Nova Scotia Power has striven throughout this engagement to develop support from the members of the Working Group for its approach to the overall analysis and technical validity of its modeling work, and its responses to their requests and feedback.

2.6 Stakeholder Consultation and Public Process

Nova Scotia Power's IRP establishes the strategic direction for the electricity future of Nova Scotia; stakeholder input is integral to this process. Commencing with the pre-IRP deliverables phase, and continuing throughout the core IRP process, Nova Scotia Power has been committed to the promotion of transparency with stakeholders through continued regular engagement sessions, the distribution of draft materials for stakeholder review and input throughout the IRP phases, and individual meetings to discuss feedback and address questions.

Nova Scotia Power created a public IRP website for publication of all materials exchanged through the IRP process. In addition to background reference materials, all materials provided to stakeholders as part of the process were published on the website.

In accordance with the Terms of Reference, Nova Scotia Power hosted stakeholder workshops at each key milestone stage in the process – Scenario Development, Assumptions and Analysis Plan, Interim Modeling Results, Modeling Results, draft Findings, Action Plan and Roadmap. These workshops have been strongly attended (with several having in excess of 100 individual attendees). Each of these milestone stages involved circulation of materials to stakeholders and the opportunity for stakeholders to submit comments on the materials circulated. Nova Scotia Power appreciates the input of stakeholders, which in many cases resulted in adjustments to the analysis and additional modeling work or analysis being performed, contributing to the overall robustness of the analysis.

The members of the IRP team also had frequent direct one-on-one meetings with interested parties and their consultants, where applicable, to discuss areas of interest and questions. These meetings allowed for the sharing of information, expertise and perspectives and discussion of issues at a level of detail that could not be accommodated within the broader workshops. The approach to stakeholder engagement on this project was unprecedented for a Nova Scotia Power IRP process. The participation and depth of collaboration with interested parties surpasses that experienced in any other regulatory process. The expertise and input that stakeholders offered throughout the exercise has substantially contributed to the overall quality of the work and the outcomes reported upon in this Final Report.

Attached as Appendix [1039] is a list of all parties who registered their interest and/or participated in the IRP process.

3 Meeting Future Objectives

Through the IRP process, Nova Scotia Power undertakes long-term system planning to understand how the electricity system will continue to meet the needs of customers and respond to changes in the electricity planning landscape. This process informs ongoing investment, retirement, and operating decisions that comply with legislation and are in the best interest of customers over a 25-year planning horizon. Nova Scotia Power plans the system to be safe, reliable, affordable, clean, and robust under many potential future outcomes.

3.1 Ensuring Reliability

A reliable electric system is essential to Nova Scotians. Nova Scotia Power plans its electricity system to ensure that loss-of-load events, caused by an electricity supply shortfall, are rare. System reliability must be taken into consideration when making long-term investment, retirement, and contracting decisions. The construction time for new resources can range from several months to several years, depending on the type and quantity of a resource, among other factors. Therefore, Nova Scotia Power plans years in advance to anticipate any long-term changes in loads or resources and procures additional capacity as necessary to maintain an adequate supply of resources.

Resource adequacy is the ability of a bulk electric power system to serve load across a broad range of weather and system operating conditions, subject to a long-run reliability standard. No electricity system is perfectly reliable; there is always some chance that generator failures and/or extreme weather conditions impacting supply and demand could compound on one another to result in loss of load. In practice, Nova Scotia Power maintains a level of resource adequacy to ensure that such loss-of-load reliability events are rare. The resource adequacy of a system depends on the characteristics of load (magnitude, seasonal patterns, weather sensitivity, hourly patterns) as well as resources (size, dispatchability, outage rates) and other limitations on availability, such as the variable production of intermittent renewable resources. If the availability of resources is adequate to meet load across a wide range of conditions and limit loss-of-load events to a reasonable level – where "reasonable" is defined by a reliability target – then a system is considered to have an adequate supply of resources.

Traditionally, the majority of Nova Scotia Power's supply portfolio has consisted of thermal resources, which are dispatchable (can be turned on, turned up or turned down on command). As Nova Scotia Power continues to decarbonize the power supply, it will add increasing amounts of resources that are variable, intermittent, or limited in how they dispatch. Dispatch-limited resources, such as wind and solar generation and energy storage, add complexity to reliability planning because they have constraints that limit them from operating continuously at full capacity to meet demand. In addition, due to interactive effects among these component factors, the most challenging period for reliability may not be in the peak hour. This new complexity requires Nova Scotia Power to use a more comprehensive method for calculating the contribution of these resources toward resource adequacy.

Planning for a future decarbonized grid with fewer synchronous generators and more variable and non-synchronous resources also requires a re-evaluation of system operational requirements. For example, additional regulation reserves might be required due to the increased variability and uncertainty from wind generation. In addition, with the increased penetration of non-synchronous generation, it is important to ensure that ancillary grid services, including various types of reserve, frequency response, and synchronous inertia, can still be provided.

3.1.1 PLANNING RESERVE MARGIN (PRM)

The first step in planning for a reliable grid is load forecasting. Understanding how customer demand may change under different future scenarios is crucial to Nova Scotia Power's planning process. The load forecast relies on demographic and economic indicators (e.g. population and economic growth), historical sales data, and weather variables (e.g. cooling degree day and heating degree days). The load forecasting process used for this IRP is described in more detail in Section 4.1.

The second step in ensuring reliability is to set a reliability criterion and a corresponding planning reserve margin requirement for the system. In the pre-IRP planning reserve margin study[17], Nova Scotia Power confirmed that its reliability criterion of 1-day-in-10-years Loss-of-Load Expectation ("LOLE") was consistent with industry best practices, based on a jurisdictional review. LOLE represents the expected number of days over a given period of time that will experience a loss-of-load event. Under this standard[18], a system is considered reliable (and to have an adequate supply of resources) if the expected frequency of loss-of-load events is limited at most to one day every 10 years. This criterion is equivalent to an LOLE of 0.1 days per year. [19]

After identifying the reliability criterion, Nova Scotia Power translated the 1-day-in-10-years LOLE criterion to a PRM which specifies the need for total capacity as a percentage requirement above expected peak demand. The PRM is defined as the quantity of capacity needed, divided by the expected – or 1-in-2 year – peak demand, minus one. Utilities commonly report resource adequacy in terms of PRM because it provides a more simplified accounting framework for expressing resource adequacy.

There are two alternative PRM accounting methods commonly used in the industry, based on using a unit's unforced capacity (UCAP) or installed capacity (ICAP) values. While either method will result in the same reliability standard and the same total quantity of *effective* capacity, the methods differ in how they measure qualifying capacity. ICAP accounting credits traditional dispatchable resources (e.g., coal, natural

[17] M08929, Exhibit N-8, E3, Planning Reserve Margin and Capacity Value Study, July 2019, pages 198- 282.

[18] Planning Reserve is the reserve margin calculated to satisfy the Northeast Power Coordinating Council (NPCC) resource adequacy design criterion stated in NPCC Regional Reliability Reference Directory # 1: Design and Operation of the Bulk Power System. The planning reserve margin requirement in any year is the amount of supply resources in excess of the annual peak demand needed to meet the NPCC reliability criterion of an annual loss of load expectation of 0.1 days/year.

[19] Planning Reserve is the reserve margin calculated to satisfy the Northeast Power Coordinating Council (NPCC) resource adequacy design criterion stated in NPCC Regional Reliability Reference Directory # 1: Design and Operation of the Bulk Power System. The planning reserve margin requirement in any year is the amount of supply resources in excess of the annual peak demand needed to meet the NPCC reliability criterion of an annual loss of load expectation of 0.1 days/year.

gas) at their nameplate capacity, without considering forced outage de-rates, and credits energy-limited resources, including solar, wind, hydro, and battery storage, at their effective load carrying capacity (discussed in further detail below). As an alternative, utilities and capacity markets are beginning to transition to an unforced capacity (UCAP) rather than installed capacity (ICAP) approach to determine the PRM for purposes specifically associated with capacity expansion modeling. This UCAP value adjusts the peak contribution of thermal resources to account for their forced outage or deratings, instead accounting for these resources based on their UCAP or unforced capacity value. This approach puts existing and candidate thermal and renewable resources on "equal footing" by accounting for the resources' contributions to peak in a consistent way.

For the 2020 IRP, Nova Scotia Power used its existing 20 percent ICAP PRM, which the E3 planning and reserve margin study verified was within the range of PRMs consistent with the reliability criterion, and converted this to an equivalent 9 percent UCAP PRM. This UCAP translated value was adopted for the capacity expansion modeling only, based on feedback and discussion with IRP participants, to ensure that renewable resources (primarily wind) would face an equivalent crediting formula to new and existing thermal alternatives. This choice does not change the reliability criterion or use of ICAP PRM calculations in other reporting and analysis. The PRM target will remain appropriate for as long as the given load characteristics and reserve requirements remain consistent. As Nova Scotia Power begins to serve new electrification load, or as significant changes start to occur to the overall generation mix, the appropriate PRM may require re-evaluation and adjustment.

3.1.2 EFFECTIVE LOAD CARRYING CAPABILITY

When system reliability is maintained through a PRM requirement in the planning process, one of the most important steps is quantifying the amount of firm capacity provided by each existing and candidate resources. Electricity resources can be placed into three categories to evaluate the ways they can contribute to ensuring resource adequacy:

+ Firm resources (e.g. coal and diesel), which are generally capable of supplying power to the electricity system when needed, absent unexpected plant outages.

- Dispatch-limited resources (e.g. wind, hydro, energy storage, and solar photovoltaic (PV)), whose capability varies based on time of day and season based on a variety of factors; and
- Market purchases, which relate to procurement of capacity through various market processes from other entities to satisfy capacity needs (e.g. Maritime Link firm capacity purchases)

Firm resources and market purchases with firm contract and transmission rights are usually capable of providing firm capacities that are close to the rated nameplate capacity. Unlike traditional firm resources, dispatch-limited resources have constraints that limit them from being operated continuously at full capacity to meet demand. These constraints may take multiple forms: for intermittent renewable resources like wind and solar, the availability of generation is a function of underlying meteorological conditions and will vary by time of day and from season to season; for energy storage, the resource's duration – the number of hours of stored energy – limits the amount of time it can be operated at full capacity.

Due to these various limitations, the contributions of dispatch-limited resources to reliability are often lower than the resources' rated maximum or nameplate capacity. Another consequence of these limitations is that dispatch-limited resources tend to exhibit diminishing returns as installed capacity on the system increases due to saturation effects. That is, each increment of a specific dispatch-limited resource will tend to have a lower contribution to resource adequacy than the prior increment.

Industry practices remain varied, but the effective load carrying capability ("ELCC") method has quickly emerged as the industry best practice for estimating the contribution of dispatch-limited resources toward resource adequacy. Given its advantages, the ELCC method for quantifying the capacity contribution of dispatch-limited resources has been adopted by several independent system operators (e.g., CAISO, MISO) and by utilities in recent planning processes (e.g., Georgia Power, NV Energy, Portland General Electric, Public Service Company of Colorado, Public Service Company of New Mexico, Sacramento Municipal Utility District, Georgia Power, Public Service Company of New Mexico).

In this IRP, Nova Scotia Power utilized ELCC values for all resources based on the pre-IRP planning reserve margin and capacity study. The ELCC values are calculated using E3's loss of load probability model, RECAP, by removing the resources from the system first then adding the "perfect" dispatchable resource until system returns to its original level of reliability. The quantity of perfective dispatchable resources required to return the system to the original level of reliability is the ELCC of the resources. ELCC curves for new dispatch limited resources can be found in the IRP Assumptions. Additional details on the ELCC analysis completed can be found in the pre-IRP Planning Reserve Margin and Capacity Value Study[20].

3.1.3 ANCILLARY GRID SERVICES AND VARIABLE RENEWABLE ENERGY INTEGRATION

The Nova Scotia Power system, like all electric power systems, requires various ancillary grid services including ramping and load following reserves, reactive power support, voltage control, and inertial response in order to reliably deliver electricity to customers. In the past, these services were generally provided inherently by thermal and hydro generators along with firm capacity and energy supply. Since this IRP models the retirement of many baseload thermal generators in Nova Scotia, including all coal-fired units, alternate sources of these essential services are now required. This leads to a need to model some of these requirements more explicitly than has been done in previous IRPs.

Ancillary grid service requirements can limit the ability to integrate high levels of non-synchronous, or inverter-based, generation on the power system. These are generation sources which connect to the electrical grid via power electronics rather than the traditional large, synchronous generators installed in hydro and thermal plants. These non-synchronous generators have not historically provided significant quantities of ancillary grid services; this is changing as new technology develops and as non-synchronous generation penetration increases globally. Factors such as power system size and level of demand as well as presence of interconnections with neighboring systems influence the requirements for ancillary grid services and ability to integrate inverter-based generation. Limiting constraints include the ability of a power system to export excess power to neighboring systems and the ability of the system to maintain stability in an islanded mode in the event of the loss of AC interconnections at various levels of energy imports.

[20] Matter M08929, Exhibit N-8, Final Pre-IRP Report, October 17, 2019 (updated November 1, 2019), filed May 22, 2020), pages 198-282.

The ancillary grid services listed below have been identified as those that can be directly addressed in the IRP model to facilitate modeling additional non-synchronous generation while maintaining stable and secure operation of the power system. The provision of ancillary grid services (including operating reserves) is co-optimized with generation dispatch in the capacity expansion and production cost models to minimize total cost to customers.

1. Regulation reserve and net load-following capabilities
2. Synchronous Inertia

Other ancillary grid services, such as system strength and voltage support, are not as well suited to modeling directly in a capacity expansion / production cost simulation. These requirements have been modeled via integration requirements for various penetrations of variable renewable generation; at lower penetrations, multiple options are available to satisfy these requirements allowing the model to optimize resource selection based on cost and performance. The sections that follow describe how each of these requirements has been modeled in this IRP.

3.1.3.1 Regulation Reserve and Net Load Following Capabilities

Regulation reserve is defined in this IRP as operating reserves which are available to responds quickly to changes in system net load, including wind ramping. Incremental quantities of reserve will be required as variable generation increases in order to manage the increased variability and uncertainty in net load. As part of the Stability Study for Renewable Integration,[21] four years of historical wind data was analyzed to determine variability. The 5-minute net load data was compiled and the 3-sigma approach was used determine the additional ramping reserve requirements beyond the capabilities provided by the current generation fleet.

[21] Matter M08929, Exhibit N-8, PSC Nova Scotia Power Stability Study for Renewable Integration, July 24, 2019, page 365-434.

For the purpose of IRP modeling, new inverter-based generation will be linked to a requirement for sufficient fast-acting generation to satisfy the ramping reserve constraint. In addition, based on participant feedback through the IRP process, Nova Scotia Power added the ability for new wind generation to provide ramp down reserve service to the PLEXOS model prior to completion of the Final Portfolio Study.

3.1.3.2 Synchronous Inertia

Inertial Response is a key property of a power system which helps to ensure reliability. It is the ability of synchronous generators to release kinetic energy stored in their rotating generators in response to a drop in grid frequency, triggered by a system contingency such as a generator or line outage. This kinetic energy slows the rate of change of frequency and allows other response actions, such as primary frequency response on generator controls, to respond and stabilize the frequency before under-frequency load shedding schemes are triggered.

Replacing the current fleet of large coal-fired synchronous generators with inverter-based and smaller gas turbine generators will cause a significant reduction in the available synchronous inertia of the system, depending on current dispatch. To offset this, the Nova Scotia Power system must be reliably synchronized with neighboring utilities through AC interties and/or must adopt local mitigation options to maintain inertia required to resist sharp declining of system frequency following potential system contingencies.

In previous IRPs and system studies, Nova Scotia Power modeled this requirement as a constraint on system dispatch, enforcing a minimum number of thermal generating units that must be online at all times to maintain system reliability. The pre-IRP Stability Study for Renewable Integration emphasized the need for a more general approach of quantifying synchronized inertia requirements by using the total aggregate online kinetic energy as a measure instead of minimum unit criteria. In response, Nova Scotia Power developed new customer constraints within its PLEXOS model to enforce a minimum inertia requirement, which could be met from a variety of sources including synchronized generators, synchronous condensers, and transmission interconnections to neighbouring jurisdictions.

The same pre-IRP study established a system inertia constraint via transient stability analysis which recommended the equivalent of three thermal units as the limit for online inertia, of 2766 MW.sec. Steady-state operation will require an additional machine to provide for the probability that one machine could trip at any time, leaving a minimum of three units. This was modeled as an additional 500 MW.sec of inertia requirement, resulting in a steady state constraint of a minimum of 3266 MW.sec of synchronous inertia will be required for steady-state operation.

Some participants felt that this study was more restrictive than necessary, and so Nova Scotia Power completed several sensitivity cases examining alternate inertia constraints, as well as reduced inertia provision from the Reliability Tie transmission interconnection. Please see Section 6.8 for further details on these sensitivity analyses.

3.1.3.3 Variable Renewable Integration Requirements

In addition to detailing the specific synchronous inertia and reserve requirements described above, the Stability Study for Renewable Integration looked at available options to enable wind integration beyond the current approximately 600 MW nameplate capacity.

First, the study confirmed that the system remains stable without additional mitigation / integration requirements with an incremental 100 MW of wind. The study then identified two options, both of which were individually shown to integrate an additional 400 MW of inverter-based generation (modeled as wind):

- Reliability Tie Option: A second 345 KV AC tie between Onslow NS and Salisbury NB
- Domestic Mitigation Option: A 200 MVA Synchronous Condenser and 200 MW Battery. For IRP modeling purposes, this requirement was linearized so that it could be added in parallel with smaller wind additions.

In addition to these key recommendations from the Stability Study, which were studied at a Low Electrification level, Nova Scotia Power recognizes that load growth is an effective tool for wind integration and so developed assumptions that allowed for additional wind integration at the Mid and High electrification levels.

Throughout the IRP process, participants have shown significant interest in offering more wind resources to the model than the quantities recommended in the stability report. Nova Scotia Power has responded to these requests by allowing the Reliability and Domestic Integration options to be selected in parallel, although this was not tested in the stability study. The incremental wind quantities offered to the model via different integration options and at different levels of electrification are compiled in Figure 15.

Figure 15 IRP Wind Integration Options

Available Wind (Nameplate MW)	No Integration Requirements*	Reliability Tie*	Domestic Integration* (Batteries + Sync. Condenser)	Total Incremental Wind Available
Low Electrification	100	400	400	900
Mid Electrification	100	500	500	1,100
High Electrification	100	600	600	1,300

**Local Integration requirements would be determined via specific System Impact Studies*

Nova Scotia Power notes that any resource plans which go beyond the findings of the pre-IRP stability study will require further analysis to confirm they can be operated reliably. Fortunately, these penetrations generally occur late in the IRP planning horizon and so there is time for technology to continue to develop and for additional studies to be completed. Nova Scotia Power has addressed these requirements in its Action Plan and Roadmap.

3.2 Maintaining Affordability

As reflected in the Terms of Reference for this IRP, in addition to the traditional metric of minimization of cumulative present value of annual long term revenue requirements over the 25-year planning horizon, it was agreed that for the 2020 IRP, a number of other metrics were of increasing importance to evaluate the outcomes of the IRP modeling results, including the magnitude and timing of electricity rate effects. As discussed further in the Rate Impact Assessment section, the magnitude and timing of electricity rate effects became a particularly important metric for the 2020 IRP analysis because this IRP is evaluating disparate load levels through the Electrification, DSM and DER scenarios being considered. As a result, the lowest cumulative present value of annual revenue requirements cannot be understood to be an absolute measure of lowest cost to customers as larger cost systems are needed to serve a larger number of customers, but those costs are spread out among that larger number of customers, and similarly smaller cost systems can be used to serve smaller numbers of customers as a result of DER, but those costs are shared among a smaller amount of customers. As a result, understanding affordability in this way has been critical to understanding the costs to customers of higher and lower load systems.

IRP assumptions are inherently uncertain, and the degree of uncertainty grows as one moves further out into the planning horizon. As a result, it is important to appreciate the degree to which the net present value analysis may include biases, associated with higher or lower degrees of value projected to occur in the outer years of the planning horizon. To assist with understanding these risks, Nova Scotia Power has provided analysis for all plans to show the relative rate impacts over a 10-year horizon in addition to those calculated over the 25-year planning horizon.

3.3 Supplying Clean Energy

Nova Scotia Power is working to increase the share of clean and renewable energy on the Nova Scotia Power system and has incorporated significant emissions reductions targets into this IRP that demonstrate that commitment. In addition, Nova Scotia Power is required to meet a wide variety of standards and regulations related to air emissions and renewable energy. Key factors in the IRP modeling process are discussed in this section, and additional information is available in the IRP Final Assumptions[22]

[22] **https://irp.nspower.ca/documents/assumptions-and-analysis-plan/**, March 11, 2020.

3.3.1 AIR EMISSION LEGISLATION AND REGULATION

There are several different sources of air emission regulations which apply to Nova Scotia Power's operations. The Nova Scotia *Greenhouse Gas Emissions Regulations*[23] specify GHG emission caps for 2010-2030, as outlined in Figure 16. The net result is a hard cap reduction from 10.0 to 4.5 million tonnes over that 20-year period, which represents a 55 percent reduction in CO_2 release over 20 years.

Figure 16. Multi-Year Greenhouse Gas Emission Limits

Period	Greenhouse Gas Allowances (Million Tonnes)
2021-2024	27.5 (Total)
2025	6
2026-2029	21.5 (Total)
2030	4.5

The Sustainable Development Goals Act[24] sets out Nova Scotia's goals to achieve province-wide greenhouse gas emission reductions of at least 10 percent below 1990 levels by 2020, at least 53 percent below 2005 levels by 2030, and "net zero" by 2050 via balancing greenhouse gas emissions with greenhouse gas removals and other offsetting measures. The SDGA has received Royal Asset, though has not yet been proclaimed in force as this will follow the making of regulations which will further detail how the SDGA principles will be met. While the specific application of the SDGA to Nova Scotia Power has yet to be determined, these targets were integrated into the development of emissions assumptions for IRP modeling purposes. Although 2050 is beyond the end of the IRP planning horizon, two of the three GHG curves modeled are on a path to achieving net-zero emissions by 2050 (assumed for modeling purposes as 0.5 MT of emissions or less).

[23] *Greenhouse Gas Emissions Regulations* made under subsection 28(6) and Section 112 of the Environment Act S.N.S. 1994-95, c. 1, O.I.C. 2009-341 (August 14, 2009), N.S. Reg. 260/2009 as amended to O.I.C. 2013-332 (September 10, 2013), N.S. Reg. 305/2013.

[24] *Sustainable Development Goals Act*, 2019, c. 26 – not proclaimed in force.

On January 1, 2019, Nova Scotia's Cap-and-Trade program came into effect. The *Cap-and-Trade Program Regulations*[25] include the annual free allowances for GHG emissions for Nova Scotia Power. Under the GHG cap-and-trade program, Nova Scotia Power is permitted to purchase a maximum of 5 percent of the GHG allowances available for sale in any auction. Nova Scotia Power forecasts that the GHG allowances available for the Company to purchase will be approximately 0.1 MT annually. Although bilateral GHG trades among participants are permitted, Nova Scotia Power does not anticipate being able to trade significant amounts of GHG allowances with other participants. Due to limited GHG allowance purchase opportunities, GHG credit purchase will not be the primary means of the utility's GHG compliance and they are not modeled in the IRP. The primary means of meeting the caps will be a reduction in generation from the existing coal-fired generating units by replacement with low-emitting sources of energy.

Similarly, significant uncertainty regarding the depth, liquidity, pricing, and duration of the cap and trade market, Nova Scotia Power has not modeled the ability to sell credits into the market as part of the IRP optimization model so as not to develop resource plans which rely on that revenue for optimality. The Company's current assessment is that the revenue stream of this market is not sufficiently well understood to, in isolation, justify incremental capital spending or programs given the current limited level of market certainty (2022 termination) and practical experience (one auction conducted to date). Nova Scotia Power believes that participating in the GHG allowance market in the short term and monitoring developments that could provide long term certainty sufficient for resource planning decisions are appropriate next steps as this market continues to develop and evolve.

Although the annual GHG allowances under the GHG cap-and-trade program were specified for each year from 2019 to 2022, as noted in Figure 17, the allowances can be redistributed in a four-year compliance period between 2019 and 2022 in order to reduce the cost of compliance.

[25] *Cap-and-Trade Program Regulations* made under Section 112Q of the *Environment Act* S.N.S. 1994-95, c.1 O.I.C. 2018-294 (effective November 13, 2018), N.S. Reg. 194/2018 amended to O.I.C. 2020-109, N.S. Reg. 48/2020.

Figure 17. Greenhouse Gas Free Allowances in 2021 and 2022

Year	Greenhouse Gas Allowances (Million metric tons)
2021	5.120
2022	5.087

For thermal facilities that meet the CO_2 emissions threshold for cap-and-trade (50,000 tonnes annually), Nova Scotia Power is not required to pay fuel surcharges on fuel consumed for electricity generation. Fuel consumed for on-site activities via mobile equipment is subject to a fuel surcharge under the *Cap-and-Trade Regulations*. As the Port Hawkesbury Biomass facility and the combustion turbine sites do not meet the emissions threshold, fuel consumed on those sites will be subject to fuel surcharges under the *Cap and Trade Regulations*.

The Nova Scotia *Air Quality Regulations*[26] specify emission caps for sulphur dioxide (SO_2), nitrogen oxide (NOx), and mercury (Hg) and have been amended to extend from 2020 to 2030. The amended regulations replace annual limits with multi-year caps for the emissions targets for SO_2 and NO_X.

In January 2020 the province introduced amendments to the *Air Quality Regulations* respecting the SO_2 cap for a three-year period from 2020 to 2022. The regulations also provide local annual maximums, as well as limits on individual coal units for SO_2. The revised emissions requirements are shown below in Figure 18.

[26] *Air Quality Regulations* made under Sections 25 and 112 of the Environment Act S.N.S. 1994-95, c. 1 O.I.C. 2005-87 (February 25, 2005, effective March 1, 2005), N.S. Reg. 28/2005 as amended to O.I.C. 2020-016 (effective January 21, 2020), N.S. Reg. 8/2020.

Figure 18. Emission Caps for SO_2, NOx, and Hg

Period	SO_2 (tonnes)	Annual Max SO_2 (tonnes)	NOx (tonnes)	Annual Max NOx (tonnes)	Hg (kg)
2020	60,900		14,955		35
2021-2022	90,000			14,955	35
2023-2024	68,000		56,000		35
2025	28,000		11,500		35
2026-2029	104,000	28,000	44,000	11,500	35
2030	20,000		8,800		30

3.3.2 RENEWABLE ELECTRICITY STANDARDS

The Nova Scotia *Renewable Electricity Standards* (RES) include a renewable energy requirement for Nova Scotia Power of 25 percent of energy sales starting in 2015, and 40 percent starting in 2020.

In addition to these requirements, Nova Scotia has a Community Feed-in-Tariff (COMFIT) for community-owned renewable generation projects connected to the distribution system and Net Metering legislation for individual customer renewable projects.[27] The current Net Metering program was initiated in July 2011, and implementation of the COMFIT program occurred in September 2011.

In 2016, the Province amended the *Renewable Electricity Regulations* to allow Nova Scotia Power to include COMFIT projects in its RES compliance planning. It also amended the Regulations to remove the "must-run" requirement of the Port Hawkesbury biomass generating facility.[28]

[27] Effective December 18, 2015, the *Electricity Act* reduced the maximum nameplate capacity for Net Metering from 1,000 kW to 100 kW. Net metering applications submitted on or after December 18, 2015 are subject to the new 100 kW limit. The legislation also closed the COMFIT program to new applications.

[28] *Renewable Electricity Regulations*, made under Section 5 of the *Electricity Act* S.N.S. 2004, c. 25 O.I.C. 2010-381 (effective October 12, 2010), N.S. Reg. 155/2010 as amended to O.I.C. 2020-147 (effective May 5, 2020), N.S. Reg. 74/2020 s. 5(2A).

Additional contracted RES-compliant electricity, the Nova Scotia Block, will be delivered via the Maritime Link. Given the risk of a delay in the delivery of the Nova Scotia Block due to COVID-19 and other factors, the Province has permitted Nova Scotia Power to comply with the RES Regulations through an alternative compliance plan for 2020 through 2022. See Section 3.3.5 for further information about the Maritime Link.

3.3.3 COAL PHASE-OUT REGULATIONS

Until the federal coal phase-out policy changes announced in the fall of 2016,[29] Nova Scotia Power's operation of, and planning for, its coal-fired generation units proceeded consistent with the provisions of the Agreement on Equivalency of Federal and Nova Scotia Regulations for the Control of Greenhouse Gas Emissions from Electricity Producers in Nova Scotia (the Equivalency Agreement). The Equivalency Agreement was finalized in May 2014 and became effective in July 2015, contemporaneous with the effective date for the current federal *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations.*

In November 2016, the Province of Nova Scotia announced that an agreement-in-principle had been reached with the Government of Canada to develop a new equivalency agreement that will enable the province to move directly from fossil fuels to clean energy sources while allowing Nova Scotia's coal-fired plants to operate at some capacity beyond 2030. The need for this new agreement was driven by amendments proposed by the Federal Government to the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations[30]. The Equivalency Agreement was renewed by the federal government on March 30, 2019. In the Renewal of the existing Equivalency Agreement, a Quantitative Analysis for the period to 2040 was examined, which has formed the basis for the second Equivalency Agreement.

[29] https://www.canada.ca/en/environment-climate-change/news/2017/11/taking_action_tophase-outcoalpower.html

[30] Vol. 152, No. 7 Canada Gazette Part I Ottawa, Saturday, February 17, 2018.

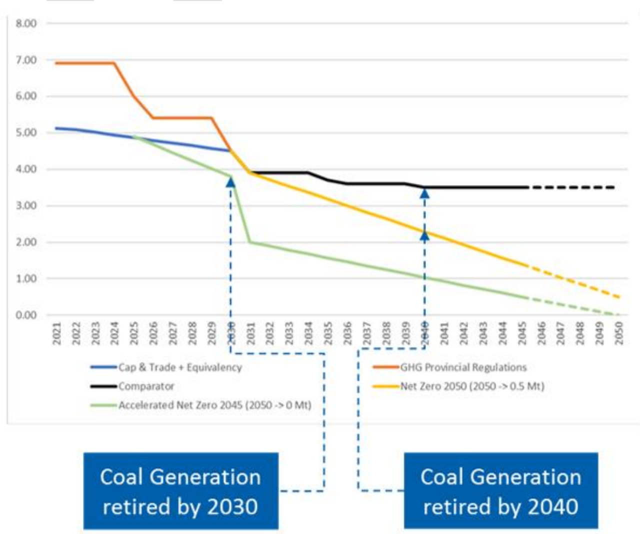
3.3.4 MODELING OF GHG EMISSIONS AND COAL UNIT RETIREMENTS

Nova Scotia Power, together with input from IRP participants, developed a set of modeling assumptions that combine the various regulations, targets, and other policy components described in the preceding sections. Nova Scotia Power is committed to contributing to the Provincial carbon-reduction efforts by setting corresponding goals in the IRP process. Nova Scotia Power has included two GHG trajectories that meet the goal of net-zero by 2050:

+ The "Net-Zero 2050" trajectory reaches a 1.4MT emission target by 2045 and sets a trajectory toward 0.5MT in 2050, equivalent to a 95 percent GHG reduction from 2005 levels. This trajectory assumes the remaining 0.5 MT emissions from the electricity sector in 2050 will be offset via other mechanisms.
+ The second "Accelerated Net-Zero 2045" trajectory represents a more aggressive GHG reduction target in which the electricity sector will reach a 0.5 MT target by 2045 and sets a trajectory toward 0 MT emission target by 2050, combined with an accelerated pace of reductions beginning in 2025.

In addition to the two net-zero GHG trajectories, Nova Scotia Power also included a reference GHG trajectory ("Comparator") that is consistent with the emissions reduction from the existing equivalency agreement and cap-and-trade program. The three GHG trajectories are shown in Figure 19.

Figure 19. Greenhouse Gas Emissions Trajectories and Coal Retirements



In combination with the three GHG trajectories, this IRP will model two coal retirement scenarios. The first scenario assumes that all coal units are retired by 2040, which assumes continuation of the ongoing Equivalency Agreement. The second and more aggressive scenario assumes all coal units retired by 2030 which follows the federal government's Coal-fired Electricity Regulations and assumes the Equivalency Agreement will not be retained.

The three GHG trajectories are paired with the two coal retirement schedules to produce three levels for GHG and coal retirement policy; these will be combined with other drivers to produce the IRP modeling scenarios.

1. Comparator
   - Emission trajectory is consistent with the emission reduction from the existing equivalency agreement and cap and trade program, reaching 3.5 MT in 2045
   - Coal retirement schedule: all coal plants retire by 2040

2. Net-Zero 2050
   - Emission trajectory reaches a 1.4 MT GHG emission target in 2045
   - Coal retirement schedule: all coal plants retire by 2040

3. Accelerated Net-Zero 2045
   - Emission trajectory reaches a 0.5 MT GHG emission target by 2045 with an accelerated pace of reductions beginning in 2025
   - Coal retirement schedule: all coal plants retire by 2030

3.3.5 MARITIME LINK

Nova Scotia is interconnected with Newfoundland via a 500 MW, +/-200kV DC Maritime Link tie that was placed into service on January 15, 2018 in preparation for receiving capacity and energy from the Muskrat Falls Hydro project and the Labrador Island Link DC tie between Labrador and Newfoundland. The Maritime Link is owned and operated by NSP Maritime Link Inc., a wholly owned subsidiary of Emera Newfoundland & Labrador.

On March 27, 2020 Nalcor Energy (Nalcor) announced that it temporarily paused construction activities at the Muskrat Falls project site in response to the COVID-19 pandemic.[31] Construction and commissioning of the Muskrat Falls hydro project resumed on May 30, 2020.

The IRP has assumed full energy and capacity availability from Muskrat Falls starting January 1, 2021. While the actual in-service date is currently understood to be delayed to later in 2021, this delay is not material from a long-term resource planning perspective and is not expected to significantly affect the optimized model results over the IRP planning horizon.

3.3.6 ECONOMY-WIDE DECARBONIZATION

As the Province's primary electricity provider, Nova Scotia Power recognizes that it must play a critical role in enabling the transition to a low-carbon economy, including decarbonizing its generation fleet, supporting energy efficiency and conservation, and enabling electrification. To better understand the scope and scale of emission reduction measures required to meet these climate goals, Nova Scotia Power commissioned E3 to perform an independent analysis of strategies to achieve long-term, province-wide GHG reductions, with a focus on electricity, buildings, and transportation sectors.

E3's modeling approach for this project relied on its deep decarbonization scenario tool, PATHWAYS. PATHWAYS is an economic, energy, and GHG emissions accounting tool. E3 developed a PATHWAYS model customized for Nova Scotia. The Pathways report modeled a reference (business as usual) scenario along with five other scenarios that assess deep decarbonization via varying levels of electrification.

Key conclusions from the Pathways report include:

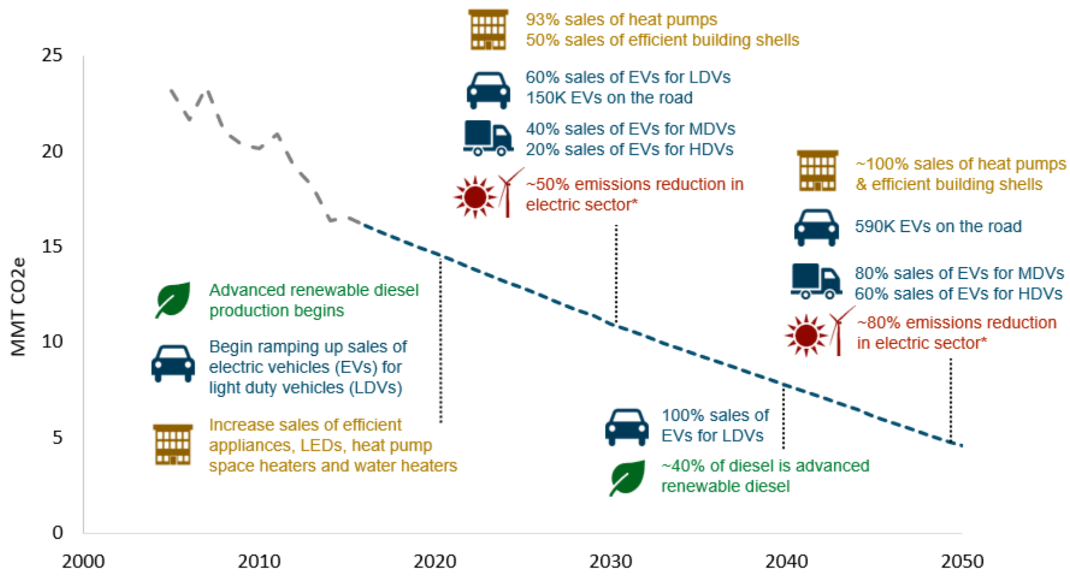
+ Synergistic action is needed across all sectors to achieve deep decarbonization
    - Reaching 80 percent GHG reductions, let alone net-zero emissions, by 2050 is challenging and not a given result

[31] https://muskratfalls.nalcorenergy.com/march-27-2020-covid-19-update-from-nalcor-on-the-muskrat-falls-project/

  - The initial stages of that transformation have begun, but need to be accelerated
- Low-carbon electricity is essential to achieving decarbonization by enabling emissions reductions in the electricity sector as well as complementary reductions in transportation and buildings
  - The electricity sector has already reduced emissions by more than 30 percent relative to 2005 levels
  - Maintaining this momentum requires continuing to integrate low-carbon resources, ensuring reliability and affordability, and allowing Nova Scotia Power to meet existing load and new load growth without emitting more carbon
- Low-carbon electricity is not enough to achieve 80 percent economy-wide reductions
  - All mitigation scenarios modeled, while leveraging electrification and low-carbon electricity, require additional measures and actions such as energy efficiency and zero-carbon fuels
- Long lifetimes require early action
  - Meeting 2050 goals may require measures to increase early adoption of electric or low-emissions infrastructure, such as public charging infrastructure to enable electric vehicle adoption
- Building electrification is dependent on reducing costs and enhancing incentives, which may be facilitated by the utility and the province
  - Consider rates, incentives, and infrastructure buildout to allow for consumer adoption
- Getting to net-zero will be an even greater challenge, requiring more direct reductions, and/or carbon removal technologies or carbon offsets

Figure 20 shows the pathway for economy-wide decarbonization in the High Electrification scenarios. Additional details on how the information from the Pathways study was incorporated into the IRP load forecast assumptions is provided in Section 4.1.2.

Figure 20. Milestones for Economy-Wide Decarbonization in High Electrification Scenario



**Electric sector emissions reductions relative to 2005 (10.7 MMT)*

4 Loads and Resources

4.1 Load Forecast

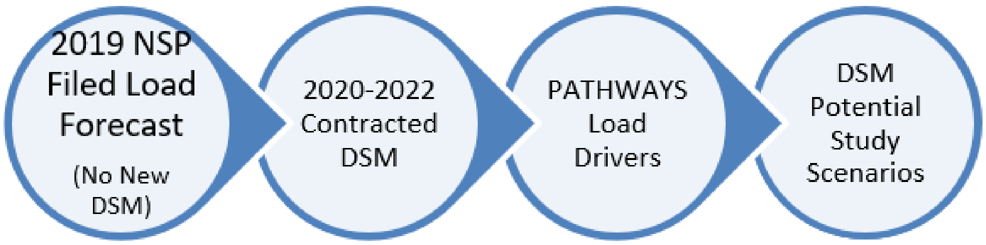
A key input to Nova Scotia Power's IRP process is the load forecast. In this IRP, Nova Scotia Power enhanced the load forecast methodology to incorporate uncertainty from potential increased economy-wide electrification as well as customer adoption of distributed technologies. The load forecast consists of the following components:

- **Base Load Forecast**: the long-term outlook for energy and peak demand builds on the "Base Load Forecast" from Nova Scotia Power's annual Load Forecast Report, as filed with the NSUARB in 2019.[32] The Base Load Forecast incorporates a wide range of assumptions, including the Conference Board of Canada economic growth forecast, seasonal and annual weather forecasts, and a conservative estimate for electric vehicle (EV) penetration based on Electric Mobility Canada's growth model.
- **Electrification:** the increase in load from building and transportation electrification is included in the load forecast. Nova Scotia Power developed three electrification scenarios (Low, Mid, and High) based on the E3 Pathways Report. For each scenario, the resulting electrification load impacts are layered onto the Base Load Forecast.
- **Demand Side Management (DSM)**: energy efficiency-based DSM alters the Base Load Forecast. E1 produced four DSM scenarios in the pre-IRP DSM Potential Study. The Base, Low, Mid, and Maximum achievable scenarios represent the various futures in which energy efficiency measures achieve different potential levels of load reduction.
- **Distributed Energy Resources (DER)**: customer adoption of distributed solar photovoltaic (PV) systems reduces the overall system load. The Base Load Forecast includes existing DER and some near-term growth to capture DER currently in contracting and development stages. Significant additional DER generation is included in several modeling scenarios and sensitivities.

[32] Matter M09191, Nova Scotia Power Inc., 2019 Load Forecast Report (April 30, 2019).

Nova Scotia Power created various combinations of these four elements to create the load forecasts for the capacity expansion models. In addition, Nova Scotia Power developed a COVID-19 sensitivity to explore potential impacts from the ongoing COVID-19 pandemic, which is discussed further in section 4.1.5. Figure 21 shows the steps of the load forecasting process.

Figure 21. Load Forecasting Process



4.1.1 BASE LOAD FORECAST

The Base Load Forecast relies on demographic and economic indicators (e.g. population and economic growth), historical sales data, weather variables (e.g. cooling degree days and heating degree days), and other factors. Details on the Base Load Forecast are available in Nova Scotia Power's 2019 Load Forecast Report, as filed with the NSUARB in 2019. [33]

Nova Scotia Power's largest customer is Port Hawkesbury Paper LP (PHP), representing approximately 10 percent of Nova Scotia Power's total annual energy sales. Between 2013 and 2019, PHP received service under Nova Scotia Power's Load Retention Tariff. The service term for PHP under the Load Retention Tariff ended on December 31, 2019. Effective January 1, 2020, PHP takes service under the Extra Large Industrial Active Demand Control (ELIADC) Tariff. The ELIADC Tariff is a new rate that adjusts annually and has an initial term of 2020-2023. Active Demand Control (ADC) service is the defining feature of the new Tariff. Under ADC, Nova Scotia Power can direct PHP to decrease or increase its load in response to system conditions and costs, to the benefit of the system and therefore all customers. Savings achieved from

[33] M09191, Nova Scotia Power Inc., 2019 Load Forecast Report (April 30, 2019).

ADC are shared through the terms of the Tariff, with 25 percent of any savings credited to PHP, and the remaining 75 percent of savings credited to Nova Scotia Power customers. The new Tariff must provide a minimum of $4/MWh towards fixed cost recovery.

The NSUARB found that the primary element of the ELIADC is its functionality as a demand response rate in that the fundamental behaviour of the Tariff serves to provide Nova Scotia Power with a significant tool in the management of its entire system load. This is a potentially significant benefit because the demand flexibility acts like an additional generator in Nova Scotia Power's generation fleet. As such, the Nova Scotia Power System Operator can use the ADC component of the Tariff to more effectively manage Nova Scotia Power's system load and reduce variable costs for all customers. The NSUARB found that this benefit is significant in terms of today's more complex generation mix, including significant renewable energy on the system.[34]

To reflect the nature of the ADC profile within both the load forecast and the IRP model, Nova Scotia Power modeled PHP's load profile separately in the PLEXOS model, using an hourly shape derived from historical data and matched to the base load shape. This isolates PHP's load from other load modifications used in the IRP to capture elements such as electrification level, DSM profile, and increased penetration of DERs. In addition, Nova Scotia Power shaped PHP's load, shifting load away from periods of system peak demand and toward periods of lower demand, on both an hourly and a seasonal basis, emulating the behaviour anticipated under the ELIADC Tariff.

Under the ELIADC Tariff, in addition to the ADC provisions, PHP maintains its status as a Priority Interruptible customer, enabling Nova Scotia Power to interrupt PHP on 10-minutes notice for the purposes of system security. As such, PHP and Nova Scotia Power's other interruptible customers[35] do not contribute to Nova Scotia Power's firm peak load and are not included in the firm peak load demand

[34] M09420; 2020 NSUARB 44; In the Matter of an application by Nova Scotia Power Incorporated for approval of an Extra Large Industrial Active Demand Control (ELIADC) Tariff under which Port Hawkesbury Paper LP will take electric service from NS Power: Decision, March 26, 2020, para 30.

[35] Customers that take service under the Shore Power Tariff or the Large Industrial Interruptible Rider.

forecast in the IRP. As a result, these customers do not impact capacity planning requirements in the long-term resource plans.

4.1.2 ELECTRIFICATION

The electrification load component is based on the range of electric load trajectories captured in E3's Pathways report, which assessed the potential impact of economy-wide decarbonization on the electricity sector in Nova Scotia. Section 3.3.6 and the Pathways report contain additional information on the methodology used to project the decarbonization of the transportation and heating sectors and estimate the load impact of electrification scenarios in particular.

Nova Scotia Power developed for use in the IRP scenarios:

+ Low Electrification represents the 2019 Load Forecast as filed with the NSUARB in April 2019 with no further modification.
+ Mid Electrification represents the 2019 Load Forecast, adjusted to reflect the incremental load anticipated due to partial electrification of buildings and vehicles as indicated in E3's "Moderate Electrification" Pathways scenario.
+ High Electrification represents the 2019 Load Forecast, adjusted to reflect the incremental load anticipated due to broad electrification of buildings and transportation as indicated in E3's "High Electrification" Pathways scenario.

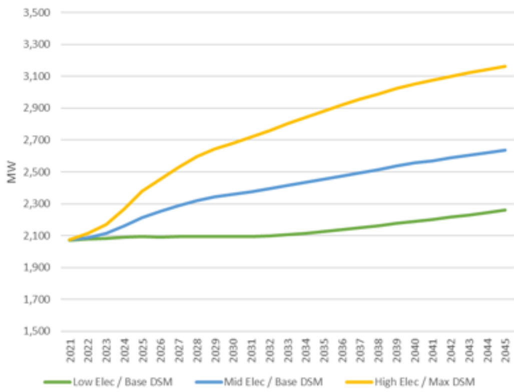
The economy-wide assumptions underlying each electrification scenario are summarized in Figure 22.

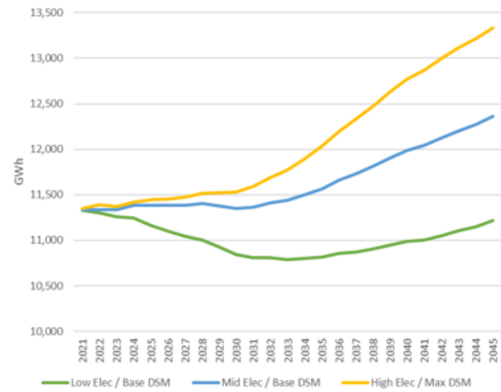
Figure 22. Electrification Scenario Details

	Low Electrification	Mid Electrification	High Electrification
Sales of electric heat pumps and water heaters	- 25% sales of air source heat pumps for space heating by 2050	- 50% sales of heat pump space heaters and water heaters by 2040 in the residential and commercial sectors	- 100% sales of heat pump space heaters and water heaters by 2030 in the residential sector - 98% sales of heat pump space heaters and 93% sales of heat pump water heaters by 2040 in the commercial sector
Electric vehicle penetration	- LDVs: 2% Zero Emission Vehicles (ZEV*) sales by 2050 - MDVs: 2% EV sales by 2050 - HDVs: 0.5% EV sales by 2050 - Buses: 5% EV sales by 2030	- LDVs: 50% EV sales by 2040 - MDVs: 90% diesel electric hybrid sales by 2050 - HDVs: 100% diesel electric hybrid sales by 2050 - Buses: 5% EV sales by 2030	- LDVs: 100% EV sales by 2040 - MDVs: 80% EV sales by 2040 and 9% diesel electric hybrid sales by 2050 - HDVs: 20% EV sales by 2030 and 60% EV sales by 2050 - Buses: 60% EV sales by 2040

Figure 23 shows the load forecasts used for the Low, Mid, and High Electrification scenarios. In all scenarios, the peak load grows over the IRP horizon. The Mid and High Electrification scenarios have significantly higher growth in the peak load. This is largely driven by the proliferation of electric heat pumps and water heaters. The Mid and High Electrification scenarios also have significantly higher growth in the annual energy load. This is driven by the electrification of heating and transportation end uses. In all scenarios, DSM mitigates peak load and annual energy load growth. In the Low Electrification scenario, DSM results in a net decline in load over the IRP horizon. DSM is described further in the next section.

Figure 23. Peak Load and Energy Load Forecasts





4.1.3 DEMAND SIDE MANAGEMENT

Demand Side Management (DSM) is an important component of the IRP modeling process, as the decision to pursue various potential levels of DSM has a significant impact on the future load required to be served by supply-side resources, and on future DSM-related costs to be borne by electricity customers. DSM reduces both energy and peak demand requirements on the electricity system; it can benefit customers through bill savings and benefit the electricity system by reducing the need to add new resources to meet both energy and peak demand needs. One of the outcomes of the IRP is to determine the most economic range of DSM programs to be pursued in future DSM procurement processes.

Nova Scotia Power has incorporated the impact of these considerations in its IRP load development approach. EfficiencyOne (E1) developed four potential DSM scenarios in its 2019 DSM Potential Study. The Low, Base, Mid, and Maximum Achievable DSM profiles represent the various programs in which the energy efficiency measures reach different potential levels and have different associated program administrator costs. All four of these profiles were developed by NS Power into modeling assumptions that can be combined with other policy drivers to create modeling scenarios.

Nova Scotia Power engaged directly with E1 and its consultants on a number of occasions throughout the IRP process to review its modeling approach for DSM and to confirm appropriate treatment of the Potential Study inputs. Nova Scotia Power and E1 also collaborated to establish the list of DSM sensitivities to analyze. The DSM programs developed in the Potential Study did not explicitly contemplate the mid and high electrification levels being modeled in this IRP; as a result, it is possible that incremental levels of DSM may be achievable under those load scenarios. This potential may be tempered by the assumption that new technology installed as part of economy-wide decarbonization and electrification programs is energy efficient in nature (e.g. cold climate heat pumps).

An output of the IRP will be avoided costs of capacity and energy that can be used to evaluate future DSM programs and individual DSM measures. These will be calculated against the resource plan designated as the Reference Plan, as defined in the IRP Terms of Reference. This calculation will be completed after the conclusion of the IRP Process.

In addition to the avoided costs for capacity and energy, DSM can also lead to cost savings on the Transmission & Distribution system. These costs are not easily captured in a production cost simulation and so are not calculated directly from the IRP model. Avoided T&D cost calculation methodologies are being updated separately in consultation with stakeholders via the DSM Advisory Group.

4.1.4 DISTRIBUTED ENERGY RESOURCES

The potential for customer adoption of Distributed Energy Resources (DER), such as rooftop solar PV, is taken into consideration in the IRP modeling. Distributed energy resources are not offered to the model as a supply side option but are examined via load modification scenarios.

Nova Scotia Power's base load forecast includes a forecast for ongoing, moderate adoption of DER, consistent with current market activity as modeled in the supporting study by Dunsky Energy Consulting.[36] Nova Scotia Power also examines a "Distributed Resources" resource strategy which assumes a high uptake of DER. In this scenario, customer solar PV adoption reaches approximately 820 MW by 2030 and approximately 1300 MW of installed capacity by 2045.

The costs of DER are not included in the IRP NPV and relative rate impact metrics as they are not assumed to be utility costs. However, Nova Scotia Power has estimated a range of costs for these resources, based

[36] M09191, Nova Scotia Power Inc., 2019 Load Forecast Report (April 30, 2019).

on the costs developed for the IRP Assumptions, and believes that it is important to consider these customer costs when evaluating the results of the Distributed Resources scenarios.

4.1.5 COVID-19 IMPACTS

The COVID-19 pandemic began affecting Nova Scotia in March 2020 during the Resource Screening and Initial Portfolio Study phases of the IRP process. Based on the anticipated potential impacts of the pandemic, and on input from several IRP participants, Nova Scotia Power developed a COVID-19 load sensitivity to test the potential effects of the pandemic on the optimized resource plans. This sensitivity assumes a 1 percent reduction in peak demand and a 5 percent reduction in energy in 2021, with both values returning to the original forecast levels by 2026. This sensitivity is only performed for the Low Electrification load level.

In the months since that assumption was developed, COVID-19 measures have resulted in many business and institutions temporarily closing or significantly scaling back operations, resulting in decreased load in the commercial and industrial sectors. This has been partially offset by increased sales in the residential sector with many people working from home. The impact was greatest in April and May of 2020 with total electricity sales declining by over 5 percent from forecast, and this impact has gradually diminished since that time. There are likely to be similar ongoing effects in the months ahead, but a material long-term impact on electricity sales is not expected.

4.2 Existing Resources

4.2.1 OVERVIEW

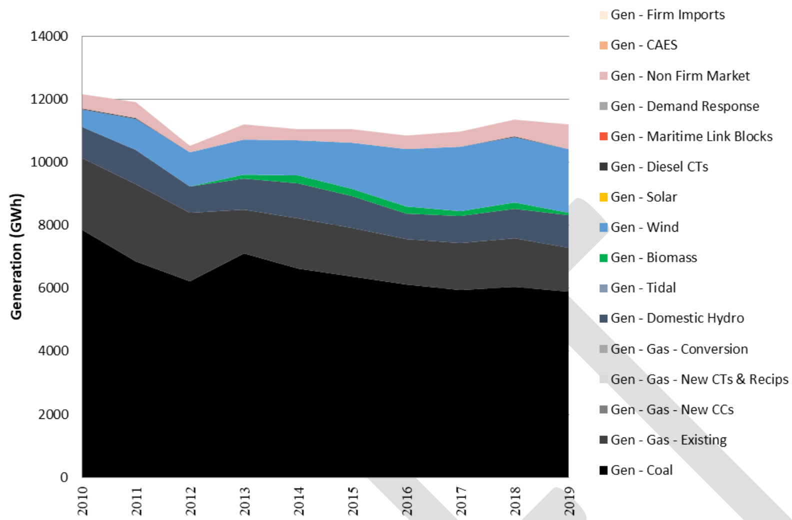
Nova Scotia Power's generation portfolio is composed of a mix of fuel and technology types that include coal, petroleum coke, light and heavy oil, natural gas, biomass, wind, tidal, and hydro. In addition, Nova Scotia Power purchases energy from independent power producers (IPPs) in the province and imports power across the Nova Scotia-New Brunswick intertie and the Maritime Link. Figure 24 shows the installed capacity by generation type, as of 2020.

Figure 24. Installed Capacity by Generation Type

Generation Type	Installed Capacity (MW)
Coal/Petcoke	1234
Natural Gas/Heavy Fuel Oil	318
Natural Gas Combined Cycle	144
Diesel Combustion Turbine	231
Hydro	374
Wind	595
Tidal	19
Biomass	43
Other IPP	34
Total	2992

Over the past 10 years, Nova Scotia Power has reduced coal generation and produced more electricity from renewable resources such as wind and biomass. In 2019, Nova Scotia supplied approximately 18 percent of annual energy demand with wind energy. Starting in 2021, the Maritime Link will provide 153 MW of firm capacity and associated zero-carbon hydro generation from Muskrat Falls, with access to additional volumes of non-firm market imports. Following the commencement of delivery of the Maritime Link energy and capacity blocks, Nova Scotia Power will retire one coal unit (Lingan Unit 2, 153 MW). Figure 25 shows Nova Scotia Power's historical generation for the period 2010-2019, highlighting a decline in coal generation and increase in renewable sources like wind and biomass.

Figure 25. Nova Scotia Power Historical Generation



4.2.2 RESOURCE SCREENING

Nova Scotia Power engaged E3 to perform a Resource Screening analysis for existing diesel combustion turbines and domestic hydro facilities. The goal was to determine whether it would be more economic to retire or sustain these facilities, based on assumptions consistent with the IRP. Resources that were determined to be economic were then kept online in all IRP scenarios. This allowed Nova Scotia Power to significantly reduce model complexity and computation time by narrowing the range of retirement decisions considered.

E3 utilized its proprietary RESOLVE capacity expansion model to estimate the value of the diesel and hydro facilities on Nova Scotia Power's system. RESOLVE adds new resources, retires existing resources, and dispatches the system to minimize the NPV of revenues requirements while satisfying reliability targets, decarbonization targets, and other criteria over the planning horizon. The Screening Analysis methodology utilizes RESOLVE to assess the relative economics of sustaining existing units or retiring them.

Results of the Screening Analysis are summarized below. Detailed results are available in the Initial Modeling Results;[37] they were also discussed at the July Stakeholder Workshop.[38]

4.2.2.1 Resource Screening – Diesel Combustion Turbines

The Screening Analysis evaluated the existing fleet of seven diesel combustion turbines (CTs) by comparing the cost of retirement (and replacement with alternatives) to the cost of sustaining the units. The Screening Analysis assessed the resource economics for two key scenarios: 1.0A (Comparator GHG Trajectory, Low Electrification, Current Landscape) and 2.1C (Net-Zero 2050, Mid Electrification, Regional Integration).

The Resource Screening analysis for diesel CT units uses an "in-and-out" methodology. In the "in" (or sustain) case, the RESOLVE model includes the sustaining capital investment and operating & maintenance (O&M) costs for the units. RESOLVE optimizes resource additions, resource retirements, and dispatch over the planning horizon to minimize costs while satisfying the Planning Reserve Margin (PRM), serving the Net System Requirement (NSR), and meeting other constraints (e.g. emissions compliance). In the "out" (or decommission) case, the units are decommissioned at the start of the planning period. In the "out" case, RESOLVE determines how to optimally replace the capacity and energy through the addition and dispatch of other resources. RESOLVE considers all potential replacement options for generation capacity and energy, in any combination, to minimize costs while satisfying all planning criteria.

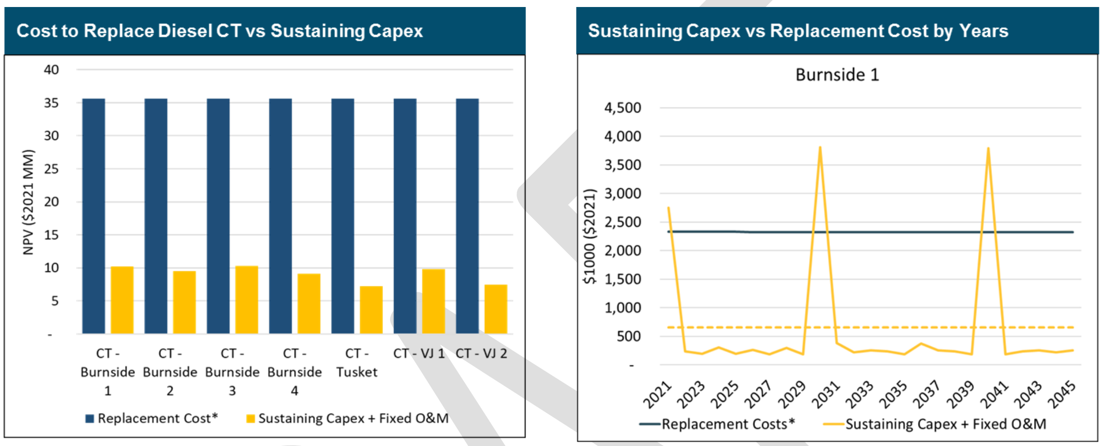
This analysis determined that sustaining all seven existing diesel CTs is the lowest-cost option to meeting system capacity requirements. The next lowest-cost alternative was replacement with an equivalent amount of new gas combustion turbine capacity; the new CT units were operated in a very similar manner as the existing units, predominately providing capacity and ancillary grid services with limited generation. Over a 25-year NPV, the replacement option was $240 million more expensive (with end effects) than the

[37] https://irp.nspower.ca/documents/modeling-results/, June 26, 2020.

[38].https://irp.nspower.ca/documents/presentations/, July 9, 2020 presentation.

sustaining option for the fleet. As shown in Figure 26 below, this analysis holds on an individual unit basis as well. While the sustaining costs of maintaining the existing CTs are higher in a small number of years when more significant investment is required, the cost to replace each unit with new resources exceeds the cost to retain the resources over the planning horizon.

Figure 26. System Value of Existing CTs (Scenario 2.1C)



** Replacement energy and capacity costs reflect net system savings adjusted for avoided sustaining capital and fixed O&M*

Dotted line reflects the levelized sustaining capital expenditures and fixed O&M

The Screening Analysis also included an additional set of sensitivities for the Victoria Junction site, which has two 33 MW diesel CT units. These sensitivities tested a lower PRM, as well as the option to replace the Victoria Junction units with generation located in the provincial load centre in Halifax. In all cases, sustaining the existing units was more economic by a significant margin.

The Screening Analysis finds that investment in the continued operation of the diesel CT fleet is the lowest cost option for customers; these units are sustained and not eligible to retire in the IRP Portfolio Study phases of the IRP analysis.

4.2.2.2 Resource Screening – Domestic Hydro

The Resource Screening analysis also evaluated the existing fleet of domestic hydro resources. The methodology followed was generally similar to the Diesel CT screening described in the previous section. The key modeling inputs for the hydro screening analysis included sustaining capital, O&M, and decommissioning costs; these inputs came from Nova Scotia Power's Hydro Asset Study (HAS)[39] and the IRP Final Assumptions. This analysis examined a 40-year horizon, to match the input data from the HAS and account for the long-lived nature of hydro assets. The Mersey and Wreck Cove systems were evaluated individually, while Nova Scotia Power's remaining hydro resources were modeled in two groups with similar operating characteristics, as shown in Figure 27. The analysis was performed for the same two key scenarios: 1.0A (Comparator GHG Trajectory, Low Electrification, Current Landscape) and 2.1C (Net-Zero 2050, Mid Electrification, Regional Integration).

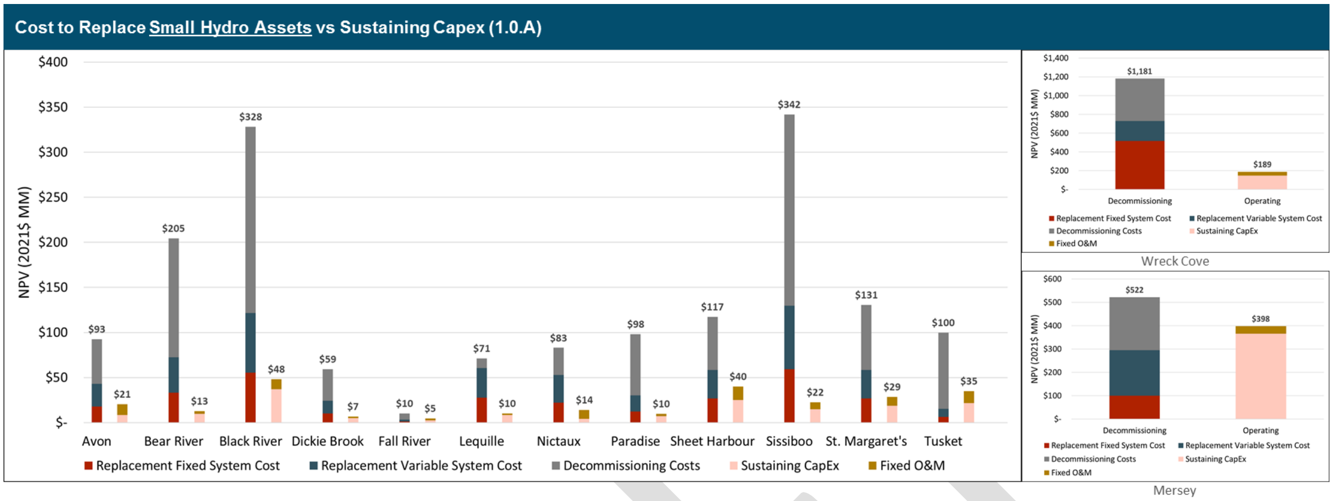
Figure 27. Grouping of Hydro Resources for Screening Analysis

RESOLVE Model Group	Hydro Units in Group	Total Nameplate Capacity (MW)
Hydro Group 1	Avon, Nictaux, Paradise, Tusket, Dickie Brook, Fall River	26.5
Hydro Group 2	Black River, Lequille, Sissiboo, Bear River, St Margaret's, Sheet Harbour	92.7
Wreck Cove	Wreck Cove	212.0
Mersey	Mersey	45.8

As shown in Figure 28, this analysis confirmed that, on an NPV basis, the costs to replace hydro systems with alternative resources (and decommission the existing hydro assets) exceed the costs to retain the resources over a 40-year horizon in all cases. This finding holds true under both scenarios considered. The hydro systems are slightly more valuable under the 2.1C scenario because this scenario follows the Net-Zero 2050 GHG trajectory, which has more stringent emissions limits; this result highlights the value of zero-carbon hydro generation under declining emissions caps.

[39] M08929, Exhibit N-2, Nova Scotia Power Hydro Asset Study, December 21, 2018.

Figure 28. Total Decommissioning Costs of Hydro Assets Relative to Sustaining Operations (1.0A)



Of note, the Mersey system will require redevelopment in the near future to ensure it can continue to operate safely and reliably. The specifics of the redevelopment plan and the business case supporting this investment will be outlined in a future capital work order and regulatory filing. Given the results of the Screening Analysis, all key scenarios in the PLEXOS Portfolio Studies assume continued operation of the Mersey system and account for all associated costs throughout the IRP horizon. Based on stakeholder feedback, Nova Scotia Power also analyzed a sensitivity that assumes retirement of the Mersey system. Additional details on this sensitivity are provided in Section 6.8.3.

The Screening Analysis indicates that investment in the continued operation of the domestic hydro systems is the lowest cost option for customers; these units were sustained and not eligible to retire in the IRP Portfolio Study phases of the IRP analysis.

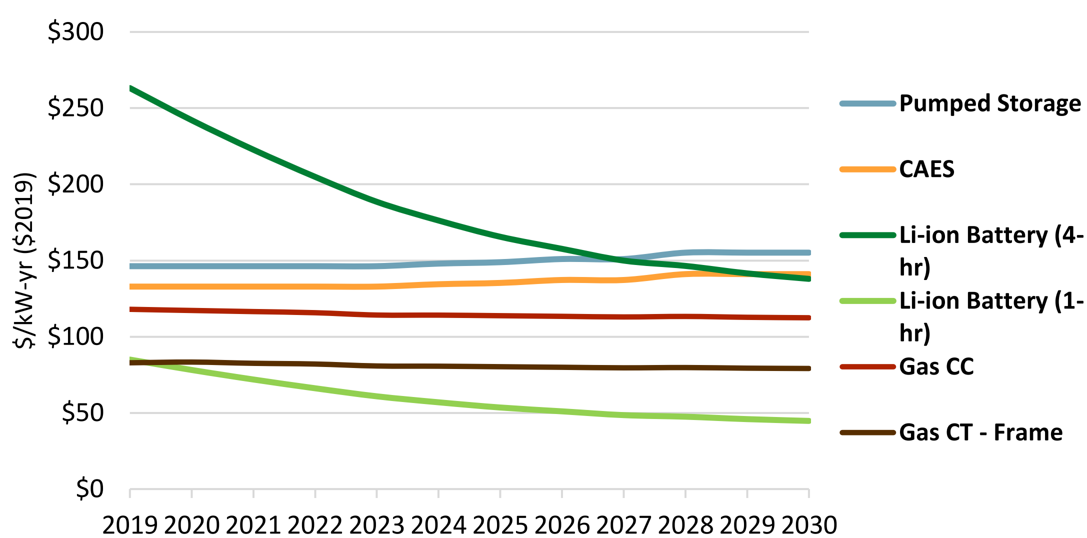
4.3 Future Supply Options

Nova Scotia Power evaluated a wide array of potential future resource options in this IRP, including renewable resources, energy storage resources, thermal resources, and firm contracts for imports.

Assumptions were developed via the Resource Options Study completed by E3[40] and were reviewed with stakeholders as part of the Pre-IRP and IRP Assumptions phases of the process. The resource characteristics and costs are used as inputs to the long-term capacity expansion models to inform potential future generation portfolios and the total system costs. A financial cash flow projection model is applied to publicly available cost projections to calculate the levelized costs of resources over time.

Figure 29 compares the levelized cost of capacity of various future resource options included in this IRP, including energy storage resources and fossil fuel resources. The levelized cost of capacity expresses the cost of a resource on a per unit of capacity (i.e. kW) basis. It includes capital and O&M costs but excludes fuel costs for fossil resources and charging costs for storage resources. The cost of a resource is levelized (i.e. annualized) using the resource's lifetime and financing costs. The cost of lithium-ion (Li-ion) batteries is projected to decline rapidly over the IRP planning horizon. Gas combustion turbines remain a low-cost capacity resource.

Figure 29. Projected levelized cost of capacity of energy storage resources and fossil resources in Nova Scotia (2019 CAD $/kW-yr)



[40] Results from the Resource Options Study are available on slides 33-39 of the Final Assumptions document, March 11, 2020, https://irp.nspower.ca/files/key-documents/assumptions-and-analysis-plan/20200311-IRP-Assumptions-Final.pdf and Appendix 1015.

The following sections describe assumptions and cost forecasts for each major resource category studied. All costs are reported in real 2019 Canadian dollars.

4.3.1 RENEWABLE RESOURCES

4.3.1.1 Wind

The installed cost for wind projects has declined significantly in the past decade since reaching a peak in 2010. Wind costs vary significantly by region and terrain. Onshore wind costs in Nova Scotia were estimated based on the wind resource potential of approximately 39 percent average capacity factor in the National Renewable Energy Laboratory's (NREL) techno-resource group 5 (TRG 5). Nova Scotia Power uses a base price for onshore wind capital cost of $2,100/kW, which is broadly consistent with NREL 2019 Annual Technology Baseline (ATB)[41] costs ($2,151/kW) and is informed by the utility's engineering estimates.

Offshore wind is considerably less mature than onshore wind and is subject to greater cost uncertainty and development risk. Based on its terrain, fixed-bottom turbines are more suitable and economical to Nova Scotia than floating turbines, which are significantly more expensive and only needed for water depths greater than 50-60 meters. Nova Scotia Power uses offshore wind capital cost of $4,726/kW, which is consistent with the WECC Survey[42] ($4,726/kW).

Wind costs are expected to continue to decline in the future. Further improvements in physical scale (hub height, blade length) will increase efficiency. Because offshore wind is not as mature as onshore wind, offshore capital cost decline is very likely, while significant onshore cost decline is less likely. The NREL ATB 2019 mid case (onshore TRG 5, offshore TRG 4) is used to estimate the capital cost reduction trajectory, which also includes high and low scenarios available for sensitivities.

[41] NREL 2019 Annual Technology Baseline: https://atb.nrel.gov/electricity/2019/

[42] WECC Survey: https://www.wecc.org/Administrative/E3-WECC Resource Cost Update-201905 RAC DS Presentation.pdf

Figure 30 summarizes the LCOE of wind resources in 2021 (first model year) through 2045 (last model year). Onshore wind LCOE is relatively stable with a slight decline. Offshore wind LCOE is projected with significant decline by 2040 but does not ever become less expensive than onshore wind.

Figure 30. LCOE for wind resources in Nova Scotia (2019 CAD $/MWh)

Year	Onshore	Offshore
2021	$56	$113
2030	$50	$91
2045	$44	$59

4.3.1.2 Utility-Scale Solar PV

Nova Scotia Power uses utility-scale PV capital costs of $1,800/kW AC, which is broadly consistent with the WECC Survey ($1,958/kW AC) but adjusted lower per Nova Scotia labor costs, terrain, and other factors. The PV cost estimate only considers single-axis tracking systems because solar tracking systems provide increased capacity factor for little to no premium in capital costs.

Future PV capital cost is assumed to continue the current decreasing trend and is estimated to decline by 20 percent by 2030 and 33 percent by 2045. This cost trend is consistent with the NREL 2019 ATB (mid case), based on continued declines in module pricing and balance of system costs from the previous decade. Figure 31 summarizes the LCOE of solar PV through 2045. Solar is relatively expensive in Nova Scotia given its lower estimated potential capacity factors, especially when compared to wind.

Figure 31. LCOE of Solar PV in Nova Scotia (2019 CAD $/MWh)

Year	$/MWh
2021	$89
2030	$77
2045	$65

4.3.1.3 Biomass

Nova Scotia Power estimates that a biomass project will require upfront capital investment costs of $5,300/kW, based on NREL 2019 ATB ($5,446/kW) but adjusted lower as informed by local engineering estimates. Figure 32 below summarizes key assumptions for new Biomass generation used in the IRP.

Biomass regulations in Nova Scotia limit the available amount of forecast biomass to 350,000 dry tonnes per year to contribute to the Renewable Electricity Standard.

Figure 32. Biomass Characteristics

Year	2021	2030	2045
Levelized Capital Cost ($/kW-yr)	$434	$438*	$421
Heat Rate	13,500 Btu/kWh		
Variable O&M	$7/MWh		

* The slight capital cost increase from 2021 to 2030 is due to change in capital cost allowance depreciation schedules according to federal tax law. Upfront costs of biomass project are assumed to decline slightly (by 9 percent) by 2045.

4.3.1.4 Municipal Solid Waste

Municipal solid waste capital costs are typically location specific. Nova Scotia Power estimates upfront capital costs of $8,470/kW. Figure 33 below summarizes key assumptions for municipal solid waste generation used in the IRP.

Figure 33. Municipal Solid Waste Characteristics

Year	2021	2030	2045
Levelized Capital Cost ($/kW-yr)	$597	$628*	$628
Heat Rate	18,000 Btu/kWh		

* Slight capital cost increase from 2021 to 2030 is due to change in capital cost allowance depreciation schedules according to federal tax law. Upfront costs of municipal solid waste projects are assumed constant through 2045.

4.3.1.5 Tidal

Nova Scotia Power estimates that a new tidal project will have a capital cost of $10,000/kW. Nova Scotia has been a global leader in developing tidal power, however, tidal power is still an expensive technology with limited commercial deployment. Figure 34 below shows the key assumptions for tidal power used in the IRP.

Figure 34. Tidal Characteristics

Year	2021	2030	2045
Levelized Cost of Energy ($/MWh)	$851	$888*	$888
Annual Capacity Factor	26%		

* Slight capital cost increase from 2021 to 2030 is due to change in capital cost allowance depreciation schedules according to federal tax law. Upfront cost of tidal project is assumed constant through 2045.

4.3.2 ENERGY STORAGE RESOURCES

4.3.2.1 Battery Storage

Battery costs vary significantly by system specifications. For modeling purposes, costs are commonly broken into two categories:

- Costs that scale with power ("capacity"), quoted in $/kW
- Costs that scale with energy ("duration"), quoted in $/kWh

Fixed "capacity" costs – including inverter and interconnection – vary significantly by project. Battery modules are the largest and best understood component of system costs that scale most linearly with duration. Longer duration batteries are lower cost per MWh of storage due to spreading of fixed costs. Cost estimates vary widely due to the early stage of technology and differences in scale and arrangement. Nova Scotia Power uses the following cost assumption for Li-ion batteries:

- Costs that scale with power ("capacity"): $310 per kW
- Costs that scale with energy ("duration"): $454 per kWh

The cost estimate for 4-hour storage is at $2,125/kW, which is close to the high end of the Lazard 5.0[43] range ($1,189 - $2,481 per kW) utilized per local labor costs and other factors.

Figure 35 shows the levelized capacity cost of 1-hour and 4-hour batteries. Short-duration battery storage is competitive with natural gas plants on an installed capacity basis. A larger decrease in battery costs is projected by 2030 as the technology matures.

Figure 35. Li-ion Battery Characteristics

Year	2021	2030	2045
1-hr battery, levelized capacity cost ($/kW-yr)	$50	$31	$27
4-hr battery, levelized capacity cost ($/kW-yr)	$223	$138	$118
Round trip efficiency	87%		
Extended warranty	1.5% of total capital cost, annually starting in Year 3		
Augmentation charge	3.3% of "duration" (kWh) cost component, annually		

4.3.2.2 Compressed Air Energy Storage

Compressed air energy storage (CAES) costs are highly site-specific and can vary considerably based on the characteristics of the site (geology, etc.). The lack of recent commercial projects adds to cost uncertainty. Nova Scotia Power estimates upfront capital project costs of $2,200/kW, which reflects regional estimates compared to the WECC survey ($2,836/kW).

Fuel cost of natural gas is an additional cost for CAES, and CAES is more competitive for longer duration storage. CAES is a synchronous generation source and can contribute to system inertia requirements. Figure 36 below summarizes the assumptions developed for CAES in the IRP.

[43] Lazard's levelized cost of storage analysis – version 5.0: **https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf**

Figure 36. Compressed Air Energy Storage Characteristics

Year	2021	2030	2045
Levelized capital cost ($/kW-yr)	$133	$141*	$141
Round trip efficiency	80%		
Hear rate for output	4,000 Btu/kWh		

* Slight capital cost increase from 2021 to 2030 is due to change in capital cost allowance depreciation schedules according to federal tax law. Upfront cost of CAES is assumed constant through 2045.

4.3.3 THERMAL RESOURCES

4.3.3.1 New Natural Gas Generation

Nova Scotia Power's IRP assumptions consider four different natural gas technologies for power generation. The upfront capital cost estimates are consistent with the WECC survey and NREL ATB 2019:

- Combined Cycle: $1,688/kW
- Combustion Turbine – Frame: $1,080/kW
- Combustion Turbine – Aero: $1,755/kW
- Reciprocating Engine: $1,823/kW

Capital costs for new natural gas plants include the several cost components: overnight capital cost, construction financing and nominal interconnection costs (i.e. a short gen-tie line). O&M costs include: (1) insurance, taxes, land lease payments, and other fixed costs; (2) annualized large component replacement costs over the technical life; and (3) scheduled and unscheduled maintenance.

As shown in Figure 37, Combustion Turbines are the lowest-cost source of capacity in each year of the projection.

Figure 37. New Natural Gas Plant Characteristics

	Year	Combined Cycle	Combustion Turbine – Frame	Combustion Turbine –Aero	Reciprocating Engine
Levelized capital cost ($/kW-yr)	2021	$116	$83	$123	$138
	2030	$112	$79	$118	$140
	2045	$108	$77	$113	$140
Variable O&M	($/MWh)	$3	$7	$7	$9
Heat Rate	(kBtu/kWh)	7,200	10,160	9,830	8,520

4.3.3.2 Coal-to-Gas Conversion

Nova Scotia Power has considered three coal units with nearby natural gas supply for coal-to-gas conversion. Figure 38 shows the capital cost for each of these coal units and Figure 39 shows the coal-to-gas conversion characteristics. Federal regulations limiting CO_2 emissions from natural gas-fired generation of electricity specify performance standards, which limit the allowable operating life of any repowered coal unit.

Figure 38. Coal-to-Gas Conversion Capital Cost Assumptions

Coal Unit	Capital Cost
Point Tupper Unit 2	$237/kW
Trenton Unit 5	$157/kW
Trenton Unit 6	$148/kW
Trenton Units 5+6	$127/kW

Figure 39. Coal-to-Gas Conversion Characteristics

	Year	Point Tupper Unit 2	Trenton Unit 5	Trenton Unit 6	Trenton Units 5+6
Levelized capital cost ($/kW-yr)	2021	$86	$64	$63	$59
	2030	$87	$65	$63	$59
	2045	$87	$65	$63	$59
Variable O&M	($/MWh)	$1	$2	$2	$2
Heat Rate	(kBtu/kWh)	10,000 kBtu/kWh			

4.3.3.3 New Gas Generation with CCS

New combined-cycle natural gas plants with Carbon Capture and Storage (CCS) are also considered in the IRP. CCS capital costs include the cost of capturing and compressing the CO_2, but not delivery and storage to a storage reservoir or industrial site for use. To account for the latter two cost components, Nova Scotia Power adds $4.76/MWh[44] to variable O&M costs to account for transport and storage costs. Figure 40Figure 40 below shows the assumptions used to model NGCC with CCS in the IRP.

Figure 40. Characteristics of new combined cycle natural gas plants with carbon capture and storage

Year	2021	2030	2045
Levelized capital cost ($/kW-yr)	$249	$232	$214
Variable O&M	$10/MWh		
Hear rate for output	7,530 Btu/kWh		

4.4 Future Demand Options

A variety of new technologies are emerging that allow greater load control and customer response. These demand response (DR) technologies can affect system operations primarily by changing the timing of electricity consumption. Rising penetrations of intermittent wind and solar generation have generated renewed discussion about the functions and value provided by DR technologies.

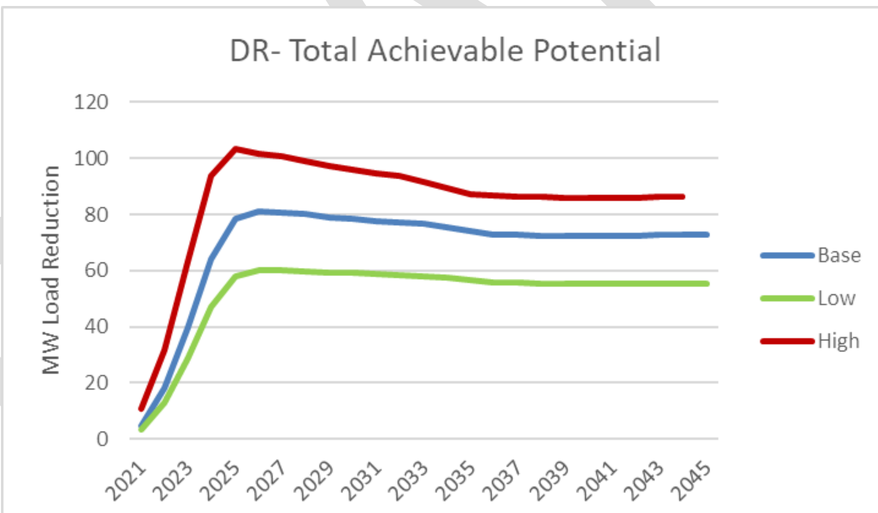
A variety of new technologies are emerging that allow greater load control and customer response. These demand response (DR) technologies can affect system operations primarily by changing the timing of electricity consumption. Rising penetrations of intermittent wind and solar generation have generated renewed discussion about the functions and value provided by DR technologies. Options considered

[44] This cost adder assumes $13/ton CO_2 transported (Rubin et al, 2015) and 0.36 tons/MWh captured (90 percent capture rate).

include Direct Load Control, curtailment, batteries and EV charging, Critical Peak Pricing, and behavioural demand response, illustrated in Figure ES-2 of the DSM Potential Study.[45]

Three DR profiles were provided to NS Power by E1: Low, Base, and High. The DR profiles were paired with corresponding DSM levels (e.g. the Base DR resource option was paired with the Base DSM assumption). This pairing of DSM and DR reflects the interactive effects of DSM and DR and were paired based on guidance from E1. These DR profiles provide a stream of annual costs and associated MW of available load reduction over the period 2021-2045, as shown in Figure 41. These profiles represent aggregated demand response programs and include only those programs that passed E1's cost effective testing.

Figure 41. Demand Response Achievable Potential



As the programs making up the DR profiles shift load, provide firm capacity, and have operational constraints (e.g. number of calls per annum, duration of DR event, and energy shifting impacts) DR can be modeled in the IRP optimization model in the same way that supply side resources are. For each model

[45] M08929, Exhibit N-1, Navigant - Nova Scotia Energy Efficiency and Demand Response Potential Study for 2021-2045, page 3.

run, the applicable DR profile was offered to the model as a resource option, which the model could select if economic.

NS Power offered the DR resource to the model in three models: 2021, 2025 and 2030. For model years after 2021, the MW capacity and cost profiles were shifted, with the cost profiles being escalated at the rate of inflation.

4.5 Regional Integration

Nova Scotia Power has achieved meaningful greenhouse gas emissions reductions in recent years via domestic infrastructure investments. As the transition to a low-carbon power system continues through the IRP planning horizon, it may become economic to look to external sources of dispatchable, low carbon energy and firm capacity to help meet the requirements of the Nova Scotia system. For this reason, this IRP explores regional integration options that seek to identify the benefits to Nova Scotia Power from improved interconnection with neighboring systems.

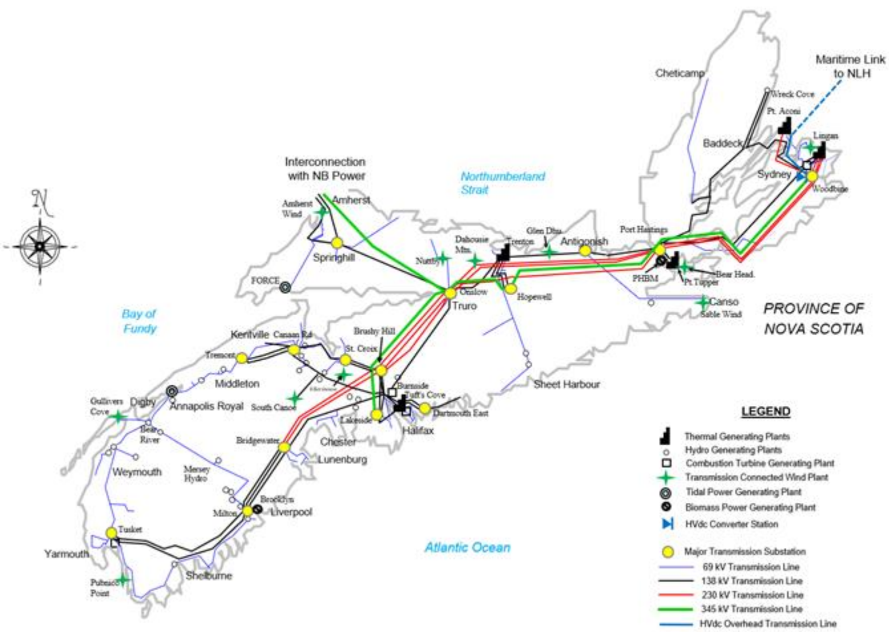
4.5.1 EXISTING TRANSMISSION INTERCONNECTIONS

Nova Scotia Power has two existing interconnections to neighboring regions: the Maritime Link connecting Nova Scotia to Newfoundland, and an existing AC interface connecting Nova Scotia to New Brunswick. Both interconnections are incorporated into the IRP model and scenarios. See Figure 42 for a map of Nova Scotia Power's transmission system and major facilities.

The Maritime Link is a 500 MW, +/-200kV HVDC interconnection which was placed in service in January 2018. This interconnection provides access to the committed Maritime Link Base and Supplemental blocks of energy and capacity, as well as access to additional non-firm market energy. Access to these capacity and energy resources is modeled in the IRP beginning on January 1, 2021. Lingan Unit 2 is assumed to be retired on the same date, as its capacity is replaced by the Maritime Link Base Block, and as a result that unit does not appear in our IRP modeling results.

The AC interface with New Brunswick is comprised of one 345 kV line and two 138 kV lines; this interface has been utilized for many years for a variety of services including economic energy import and export, balancing services, and reserve sharing. However, due to capacity constraints on this interface, the ability to import firm energy and capacity from the broader North American grid is currently very limited. Because the underlying 138kV interconnection cannot carry the full capacity of the 345kV line, there are also reliability limits in place when transacting for energy on this interface. In addition, although not directly captured in the IRP model, there are significant transmission planning considerations for this single contingency which affect many elements of the Nova Scotia system.

Figure 42. Map of Nova Scotia Power Transmission



Under the Regional Integration scenarios that were modeled, a limited amount (150 MW) of firm import capacity was modeled as being available over these two existing interconnections, tied to an annual capacity cost which is modeled separately from the energy price. These firm import candidate resources do not make incremental import energy available to the system; rather they were modeled as "firming" of currently available non-firm import energy to provide a contribution towards meeting the firm capacity requirements of the system.

4.5.2 TRANSMISSION EXPANSION OPTIONS

This IRP explored two transmission expansion options as part of the suite of integrated resources available to the model. The first is the development of a Reliability Tie, which allows for the integration of additional domestic wind or other inverter-based generation (as modeled in the pre-IRP Stability Study for Renewable Integration) and provides system inertia, but does not provide incremental access to firm capacity or energy. The second is the development of a Regional Interconnection, modeled as a further transmission expansion to neighbouring jurisdictions. This more significant project provides access to firm capacity as well as firm and non-firm energy, in addition to providing the reliability and wind integration benefits of the Reliability Tie. Both of these transmission expansion options are described in more detail below.

Reliability Tie

The Reliability Tie comprises development of a new 345 kV AC line between Onslow, Nova Scotia and Salisbury, New Brunswick. This transmission option was an available resource in all the key scenarios. During the Pre-IRP phase, Nova Scotia Power engaged Power System Consultants (PSC) to conduct a System Stability Study[46] to assess the ability to integrate additional inverter-based generation on the Nova Scotia System, particularly expanded wind capacity. This study identified the loss of the existing single 345 kV line to New Brunswick as a significant contingency for Nova Scotia Power, and determined that the addition of a second 345kV line would bring security and operating flexibility to the system and could enable the integration of an additional 400 MW of variable inverter-based generation. Additional potential system benefits of the Reliability Tie beyond renewable integration and system inertia are not analyzed in the IRP model.

This study also found that comparable amounts of wind capacity could be integrated by building both synchronous condensers and battery storage. These were also provided to the model as candidate resources, representing an alternate method for new wind development and integration. Modeling details and key assumptions for these resources are discussed in greater detail in Section 3.1.3.

[46] M08929, Exhibit N-8, PSC, Nova Scotia Power Stability Study for Renewable Integration Report, pages 365-436.

Regional Interconnection

In additional to the available Reliability Tie, the Regional Integration scenarios add two additional candidate transmission expansion options: 1) an HVDC line connecting Salisbury, New Brunswick to Quebec, and 2) a 345 kV AC line from Salisbury, New Brunswick to Coleson Cove, New Brunswick, which would provide access to the ISO New England power markets. Both are modeled as candidate resources available starting in 2026,[47] and both make available firm capacity as well as additional firm and non-firm imported energy.

The Regional Interconnection transmission expansion options are modeled to be flexible in terms of how they can be added to the system. They can be constructed to enter service in the same year as the Reliability Tie or can be staged from an already constructed Reliability Tie in a future year. In addition, once the model builds a Regional Interconnection transmission option, the amount of firm capacity purchased over that interface can vary in 50 MW blocks. This capacity is tied to an annual capacity charge. In addition, energy can be purchased as required over the new interconnection in hourly blocks. With this flexibility, the model can optimize the contributions of the transmission interconnection to both Planning Reserve Margin and to energy supply in each year of the planning horizon.

4.5.3 CHARACTERISTICS OF IMPORTED ENERGY AND CAPACITY

As discussed in the previous sections, both existing and candidate transmission options can provide energy, and in some cases firm capacity.[48] Depending on the import source and availability assumptions for the different transmission corridors, each import resource has specific on and off-peak provision limits, ramping limits, and daily, seasonal, or annual dispatch limits. Due to local system constraints there is are also seasonal limits on simultaneous imports over the existing New Brunswick tie and the Maritime Link. These limits are

[47] These resources are not made available sooner to account for the time it would take to contract, design, and build these new transmission resources.

[48] Firm transmission capacity is the amount of electricity that can be delivered in a reliable manner after consideration of surrounding system loads, voltages, and stability conditions. Non-firm transmission is the capacity that can be used for energy delivery but is subject to curtailment under different system conditions; as a result, additional in-province reserve requirements are modeled for non-firm energy.

individually set for each resource in the model, to govern operational availability and reliability contributions for capacity expansion.

Imports to Nova Scotia from other Canadian provinces are modeled as emissions-free, as those emissions are accounted for in the province in which the generation occurred under appropriate federal and/or provincial requirements. For the Regional Interconnection options, the energy available via the HVDC line to Quebec is modeled as emissions-free, while imports sourced via the Coleson Cove interconnection incorporate an emissions factor; as a result, energy imports from that source contribute to the modeled system emissions limits.

Firm import options have been modeled as sources of firm capacity for resource expansion, while non-firm imports are available exclusively for energy provision. In aggregate, modeled firm and non-firm import resources are shown below:

Firm Import Options:

- Access to firm capacity via existing transmission up to ~150 MW firm ("Existing Tx Firm"); and/or,
- Access to firm capacity via new transmission build up to ~450 MW firm ("New Tx Firm")

Non-Firm Import Options:

- Import energy via existing transmission (Maritime Link and New Brunswick tie-line); and/or,
- Import energy via new transmission (either HVDC to HQ, or AC to link to Coleson Cove/ISO-NE).

4.6 Resource Strategies

Nova Scotia Power developed three Resource Strategies for use in this IRP. These strategies are intended to capture different subsets of supply and demand side resources, to allow for a comparison of strategic alternatives that otherwise might not fall out of the optimization results. This approach was used to ensure that the IRP analysis covered key areas of importance and interest to Nova Scotia Power and IRP participants.

Each Resource Strategy is assigned a letter designation (A, B, C as detailed below) in order to allow for easy linking to the names of each key scenario and sensitivity modeled.

The first Resource Strategy is Current Landscape (A). This strategy models the availability of new in-province supply and demand resources but does not allow for new interconnections to other regions. The full suite of supply and demand side resources described in Sections 4.3 and 4.4 are available under this strategy.

The second strategy, Distributed Resources (B), is designed to model a future in which customers adopt significant amounts of Distributed Energy Resources (DERs) such as rooftop solar and consequently reduce their energy requirements from the grid. The adoption of behind-the-meter and distributed resources has increased significantly in recent years due to environmental objectives and technology price declines. Nova Scotia Power believes it is important to understand the potential impact of a significant increase in DER penetration on the bulk system, including the impact on rates, system operation, and on meeting the long-term GHG reduction goals. Under this resource strategy, all of the same resources are available as in the Regional Integration (C) scenarios and the load forecast is modified to reflect the impact of significant DER penetration. The capacity modeled is quite significant, representing approximately 1,300 MW of rooftop solar online in Nova Scotia by 2045; approximately 820 MW is online by 2030. This capacity is directionally similar to what has been envisioned by others in their environmental planning considerations, such as the HalifACT plan undertaken by the Halifax municipality.

The third and final strategy modeled is Regional Integration (C). Building new interconnections to access out-of-province resources could be an important element in meeting Nova Scotia Power's GHG reduction and reliability goals while maintaining affordability. Nova Scotia is located in proximity to provinces with abundant hydro resources as well as large, interconnected power systems with significant capacity and energy resources. These resources located outside of Nova Scotia can provide low-emitting energy along with firm and dispatchable capacity, both of which are valuable in a decarbonized grid. As described in Section 4.5, resource options for firm capacity imports on both existing and new transmission infrastructure are made available under this Resource Strategy.

These three Resource Strategies are combined with other levels of the main policy drivers to produce the key scenarios for modeling, as described in the next section.

5 Scenarios, Methodology, and Evaluation Framework

5.1 Key Scenarios

Nova Scotia Power's objective in this IRP is to model a wide range of potential future scenarios and use this range of results to identify near-term options that are common among many resource plans. In this way, a no regrets Action Plan and Roadmap can be developed. Through the development of the pre-IRP work, the IRP Assumptions, and consultation with IRP participants, Nova Scotia Power identified three key policy drivers to form the basis of the IRP key scenarios:

1. Decarbonization - GHG Scenario and Coal Retirement Date (described in Section 3.3.4)
2. Load - Electrification Level (described in Section 4.1.2)
3. Resource Strategy (described in Section 4.6)

Among the policy drivers, the decarbonization and electrification drivers represent the impact of various policies on electricity sector, including the SDGA and Federal coal closure policies. The resource strategy driver explores the key areas of importance and interest identified by Nova Scotia Power and IRP participants, such as the role of new interconnections and distributed resources in meeting future requirements.

Nova Scotia Power's next step was to combine these policy drivers to create key scenarios to be modeled. An initial DSM profile was also assigned to each key scenario, based on that scenario's properties. Additional discussion on this scenario development can be found in the Scenarios and Modeling Plan.

In order to consistently identify and differentiate scenarios throughout the IRP process, scenarios are identified according to the following naming convention based on the component policy drivers:

- Scenario ID = [Decarbonization driver ID].[Electrification driver ID][Resource Strategy driver ID]

For example, scenario "2.1C" represents a future in which coal plants are schedule to retire no later than 2040 and the electricity sector meets the Net-Zero 2050 GHG curve, which reaches a target of 1.4 Mt in 2045. In this future, the electrification level is specified as the mid electrification scenario based on the pre-IRP Pathways report, and the Regional Integration resource strategy is enabled meaning new transmission lines can be built to access additional imports. This scenario was paired with the Base DSM profile.

Nova Scotia Power's goal was to create and analyze a broad range of key scenarios to enable robust analysis of the IRP solution space. The key scenarios matrix shown in Figure 43 details how the three drivers discussed in the previous section were combined to create 13 key scenarios to be modeled in the Initial Portfolio Assessment phase.

Figure 43. Key Modeling Scenarios

Scenario	Decarbonization Driver	Load Driver	Resource Strategy
1.0 **Comparator**	Comparator GHG Trajectory Coal retires by 2040	Low Elec. Base DSM	A. Current Landscape C. Regional Integration
2.0 **Net Zero 2050** **Low Electrification**	Net Zero 2050 Trajectory Coal retires by 2040	Low Elec. Base DSM	A. Current Landscape C. Regional Integration
2.1 **Net Zero 2050** **Mid Electrification**	Net Zero 2050 Trajectory, Coal retires by 2040	Mid Elec. Base DSM	A. Current Landscape B. Distributed Resources C. Regional Integration
2.2 **Net Zero 2050** **High Electrification**	Net Zero 2050 Trajectory Coal retires by 2040	High Elec. Max DSM	A. Current Landscape C. Regional Integration
3.1 **Accelerated Net Zero 2045** **Mid Electrification**	Accelerated Net Zero 2045 Trajectory Coal retires by 2030	Mid Elec. Base DSM	B. Distributed Resources C. Regional Integration
3.2 **Accelerated Net Zero 2045** **High Electrification**	Accelerated Net Zero 2045 Trajectory Coal retires by 2030	High Elec. Max DSM	B. Distributed Resources C. Regional Integration

5.2 Sensitivity Analysis

In addition to modeling the key scenarios, Nova Scotia Power also conducted a series of sensitivities to understand how the optimal portfolio for a certain key scenario will vary given different assumptions for certain input parameters. DSM levels are varied to test the impact of various levels of DSM on both resource requirements and scenario costs. Technology cost sensitivities are conducted to investigate the impact of lower technology costs on the coal retirement schedule and the ultimate resource portfolio in 2045. Sustaining capital sensitivities were run to understand how these assumptions might impact retention of thermal generating units, and Mersey Hydro retirement was modeled as its own sensitivity. Finally, various operating sensitivities including inertia constraints, Reliability Tie parameters, and import availability are also conducted to understand the sensitivity of the model to these parameters. Figure 44 summarizes the sensitivity cases conducted.

Figure 44. Sensitivity Cases

Sensitivity Case	Base Case Assumption	Sensitivity Case Assumption
2.0A DSM-1	Base DSM	Mid DSM
2.1C DSM-2	Base DSM	Mid DSM
2.2C DSM-3	Max DSM	Mid DSM
2.0C DSM-4	Base DSM	Low DSM
2.0C DSM-5	Base DSM	Mid DSM
2.0C DSM-6	Base DSM	Max DSM
3.1C DSM-7	Base DSM	Mid DSM
2.1C WIND-1	Base case wind cost	Low wind cost
2.1C WIND-2	Base case wind and battery cost	Low wind and battery cost
2.1C WIND-3	Base synchronized inertia constraint: 3266 MW.sec in all hours	Low synchronized inertia constraint: 2200 MW.sec in all hours
2.1C WIND-4	Wind integration requirement + inertia constraint: 3266 MW.sec in all hours	No wind integration requirement and no inertia constraint

Sensitivity Case	Base Case Assumption	Sensitivity Case Assumption
2.1C MERSEY	Mersey hydro doesn't retire	Mersey hydro retires in 2025
2.1C IMPORT-1	Base import assumptions	Annual availability of non-firm imports is reduced by 0.8TWh
2.0A IMPORT-2	Can build the Reliability Tie	Cannot build the Reliability Tie
2.1C IMPORT-3	Reliability Tie contributes 100% of required system inertia once built	Reliability Tie contributes only 50% of required system inertia once built (i.e. 1633 MW.sec)
2.1C CAPEX-1	Base steam unit (coal and gas) sustaining capital assumptions	High steam unit (coal and gas) sustaining capital assumptions (50% from base)
2.1C CAPEX-2	Base steam unit (coal and gas) sustaining capital assumptions	Low steam unit (coal and gas) sustaining capital assumptions (-25% from base)
2.1C PRICES-1	Base Gas and Import Pricing	High Gas and Import Pricing

5.2.1 DEMAND SIDE MANAGEMENT

Nova Scotia Power completed seven sensitivities evaluating the impact of various DSM profiles on key scenarios. A complete analysis of the four available DSM profiles was studied against the 2.0C Low Electrification / Net Zero 2050 scenario; additional DSM sensitivities were modeled against various other scenarios to evaluate the effect of moving up or down from the DSM profile originally selected in the core scenario. The set of sensitivities modeled was developed in collaboration with EfficiencyOne.

5.2.2 WIND

To better understand the impact of technology costs and wind integration requirements on overall costs and portfolio build out, Nova Scotia Power conducted four sensitivities. The first two sensitivities investigated a future with low wind and battery capital costs, and the second two sensitivities relaxed system operational requirements by lowering and removing the system inertia and wind integration requirements. The sensitivities with relaxed system operational requirements are considered boundary cases rather than true sensitivities, because without sufficient system inertia and wind integration solutions, Nova Scotia Power may not be able to operate the system reliably. However, these two scenarios are helpful to understand how the model will perform under these boundary conditions.

5.2.3 MERSEY HYDRO

While the Mersey system was economically retained in the resource screening phase of the IRP, this sensitivity was completed to understand how capacity and energy would be replaced in the IRP PLEXOS model if the Mersey system is assumed to retire in 2025.

5.2.4 IMPORTS

Imported energy from outside of Nova Scotia and the Reliability Tie are components that are seen in all key scenario resource plans; they help Nova Scotia Power both meet future demand and integrate renewable resources. Nova Scotia Power conducted three sensitivities to understand the impact of changes to these resources. The first sensitivity limits the maximum quantity of annual non-firm imports to understand how that energy would be replaced. The other two sensitivities model a future in which the Reliability Tie either cannot be built, or where the Reliability Tie, once built, can only contribute to 50 percent of the required system inertia (down from 100 percent in the base case).

5.2.5 SUSTAINING CAPITAL

To understand the robustness of retaining the existing thermal steam fleet (both coal fired and gas/HFO fired), Nova Scotia Power executed two sensitivities on sustaining capital. These help to interpret the economic levels of sustaining capital spend under which these resources continue to be included in the optimal resource plan. Alternatively, they may identify how sensitive projected retirement dates are to sustaining capital assumptions.

5.2.6 GAS AND IMPORT PRICES

Because new natural gas and import resources are both important new resource options to replace retiring coal capacity, Nova Scotia Power tested a high price sensitivity to determine the robustness of those resources to higher prices. Gas and power prices both tie to similar market fundamentals in the Maritimes region and so are modeled as moving from Base to High together.

5.3 Methodology

5.3.1 DEVELOPING RESOURCE PORTFOLIOS

Nova Scotia Power utilized the PLEXOS capacity expansion and production simulation modeling software in developing the optimal resource portfolios during the Portfolio Study phase of the IRP. PLEXOS is a leading capacity expansion and production cost model software package that uses mathematical optimization to provide simulation capabilities for the electric power system. Nova Scotia Power used the Long-Term (LT) Plan module in PLEXOS to develop lowest-cost expansion plans. PLEXOS was used to develop the resource portfolio from 2021 to 2045 that minimizes the NPV of the investment and operation costs, including end effects estimates, while meeting system GHG reductions target and reliability constraints.

The PLEXOS Medium-Term Plan and Short-Term Plan (MT/ST) modules were used to model system operation and dispatch at an hourly level and to check the operability of scenarios after the resource portfolios are identified. Production costs and generation outputs for all runs in the Final Portfolio Study were completed using the PLEXOS MT/ST modules. PLEXOS was used to develop the resource portfolio from 2021 to 2045 that minimizes the NPV of the investment and operation costs while meeting system GHG reductions target and reliability constraints.

Investment and operation costs include fuel costs, import contract costs, sustaining capital costs, other variables and fixed costs, and the costs of building new generation resources and transmission lines. System constraints include the planning reserve margin constraint for reliability, the annual GHG emission targets, system reserve constraints, inertia constraints, renewable integration requirements, transmission limits, and the operational constraints for each generating resource.

5.3.2 ASSESSING RELIABILITY

One of the objectives of the IRP Portfolio Analysis is to ensure that the modeled resource plans meet the established reliability criterion (see Section 3.1 for details on the selection of a reliability criterion). It is important to emphasize the complexity of the reliability assessment process. This assessment incorporates both the Planning Reserve Margin, which is a reflection of the system as a whole, as well as each resource's capacity value which is a function of its interactions with other resources and must be considered in relation to the full portfolio and load patterns. The marginal capacity value of renewable resources tends to decline with saturation and the capacity value of traditional firm resources is affected by unit size, maintenance duration, outage rates and severity, which all impact outage patterns.

E3's RECAP model was used to support capacity expansion modeling in two stages. First, RECAP was used to confirm the required PRM of the existing system and capacity value for new and existing resources, as described in Section 3.1. Second, RECAP used after the completion of the Initial Portfolio Study to ensure that resulting optimal resource plans will meet NS Power's selected reliability criterion of 1 day in 10 years LOLE. Key scenarios that most closely inform the Action Plan and Roadmap, as well as scenarios with more aggressive renewable and storage buildouts, representing bookend cases, were selected for this screening step. Results of this assessment are discussed in Section 6.6.

5.3.3 ASSESSING OPERABILITY

To access the operational behaviour of the future resource portfolio, Nova Scotia Power conducted and reviewed hourly unit commitment simulations in PLEXOS MT/ST for several key scenarios, including scenarios that inform the Action Plan and Roadmap as well as scenarios that represent significant penetrations of variable generation and thermal unit retirements.

The chronological hourly simulation is intended to validate the operability of the proposed resource plan with all key constraints considered, including system operability constraints such as system inertia, import limits, and emission limits; unit operability constraints such as minimum thermal unit up/down time and ramp rates; and system reserve requirements such as spinning, ramping, and non-spinning reserves.

Results from the operability screening, such as the number of operating hours and number of unit starts per year, are also used to refine the sustaining capital assumptions prior to the Final Portfolio Study. Other refinements identified in the operability screening process were incorporated into the Final Portfolio Study to ensure all constraints were accurately represented while enabling the model to find feasible solutions.

5.3.4 ASSESSING RELATIVE RATE IMPACTS

As discussed in Section 3.2, Nova Scotia Power believes it is important to analyze and consider financial metrics in addition to Net Present Value of Revenue Requirement when assessing IRP modeling results. IRP participants also indicated during the IRP Process that a relative rate metric would be helpful in comparing scenarios with disparate load impacts, particularly since the effects of electrification are a key component of this IRP. To support this analysis, Nova Scotia Power created a relative rate impact model, the objective of which is to illustrate the net effect on Nova Scotia Power customer rates of the change in cost and load associated with varying levels of electrification, DSM, and DER deployment under different resource plans.

The hypothesis is that because so much of the Company's revenue requirement is fixed (approximately 50 percent due to the long-term nature of the underlying investments), additional revenues provided by the higher levels of sales associated with higher levels of electrification will more than offset the incremental cost to serve the higher load, thereby placing downward pressure on the unit cost to serve customers (i.e. rates).

The methodology developed incorporates the cost and load information developed in the IRP. However, because the IRP cost information includes only forward looking supply-side and demand-side costs, it is necessary to:

1. Develop an opening bundled service rate for comparison purposes; and

2. Recognize the additional fixed cost contribution provided by additional sales from higher levels of electrification.

Nova Scotia Power took following approach:

1. Began with the forward looking supply-side and demand-side annual revenue requirements developed in the IRP.
2. To this, added the fixed cost amounts currently embedded in customer rates from the most recent General Rate Application Test Year (2014).
3. The total of the IRP revenue requirement and 2014 foundation produces an estimate of total annual utility revenue requirement for the analysis period.
4. To incorporate the additional fixed cost recovery produced by the additional electrification sales, applied an FCR/MWh factor from the 2014 Test Year ($80/MWh) and multiplied this by the incremental (or decremental) sales under the various scenarios.
5. The net effect of utility revenue requirement less additional fixed cost recovery provides an estimate of the net revenue requirement to be recovered from customers annually under various levels of electrification.
6. A system rate is developed by dividing the total annual revenue requirement by total sales (i.e. net system requirement less losses).
7. Annual rate changes are calculated as the change in the rate year-over-year. A simple (i.e. non-cumulative) average rate change is created by averaging rate changes over the analysis period.

The analysis employs a number of simplifying assumptions including:

+ Electrification and the associated FCR is assumed to occur uniformly across customer classes. To the extent this occurs to a greater degree in classes with higher fixed cost recovery (e.g. the residential class), the FCR can be expected to be greater.
+ Changes in load from electrification are assumed to affect revenue proportionately (i.e. demand and energy billings increase at the same level).
+ This beginning fixed cost recovery is held constant over the analysis period. Effectively this assumes that the decline in existing rate base due to depreciation is offset by ongoing additions to T&D, General Property and other utility costs not captured in the IRP.

2020 costs are not modeled in IRP but used as a reference year to calculate the first year's rate change. Nova Scotia Power assumed a 1 percent decline from 2021 modeled costs under the Low Electrification Scenario to produce the 2020 cost used for all scenarios.

5.4 Evaluation of Resource Portfolios

One of the main objectives of the IRP is to develop a robust, risk-weighted lowest-cost long-term electricity strategy that delivers energy in a safe and reliable manner. In addition, Nova Scotia Power is committed to continue provincial decarbonization through addition of low- and non-emitting resources, where appropriate, and maintaining affordability for customers across a range of foreseeable future scenarios. During the IRP process, Nova Scotia Power developed, with input from IRP participants, the following series of metrics to evaluate resource portfolio performance against these targets. The primary metric for evaluating future resource portfolios is the 25-year Net Present Value of Revenue Requirement (NPVRR), incorporating end effects. Additional metrics are also calculated and compared to capture relative effects on electricity rates, system flexibility, reliability, and robustness.

- **Resource Plan Cost**

  Minimizing customer costs is one of Nova Scotia Power's central objectives. When evaluating the portfolios, scenarios are compared based on their 25-year NPVRR over the planning horizon (with and without end-effects adjustment). 10-year NPVRRs are also calculated to help understand how near-term costs vary between scenarios.

- **Rates**

  In addition to minimization of NPVRR, understanding variations in the magnitude and timing of electricity rate effects is an important metric in this IRP. The significance of this metric is more important than in previous studies since this IRP is comparing scenarios with different load levels due to assumptions on Electrification, DSM, and DER penetration.

- **Resource Adequacy**

  Ensuring a reliable electricity supply for customers is a priority for Nova Scotia Power. As described in Section 3.1, minimum reliability requirements were established for the IRP model, including the PRM requirement and other operating requirements and constraints. Feasible resource plans are required to meet these minimum constraints, and any notable risks specific to a particular key scenario or sensitivity are noted qualitatively in the Modeling Results.

- **Stability and Reliability**

  To ensure the stability and reliability of the grid, quantitative and qualitative assessments of the status of thermal unit operations and the status of essential grid services provision were conducted for each candidate portfolio, including system inertia and reserves. Feasible resource plans are required to meet these minimum constraints, and any notable risks specific to a particular key scenario or sensitivity are noted qualitatively in the Modeling Results.

- **GHG Emissions**

  The IRP examines annual GHG emissions and other source emissions from both Nova Scotia Power resources and imported energy (when applicable), to ensure emissions remain below the GHG limits set within each scenario. Nova Scotia Power also quantified the cumulative GHG emissions to meet load between 2021 and 2045.

- **Robustness and Flexibility**

  Qualitative assessments of the magnitude of the plan's exposure to changes in key assumptions, resiliency to risks, and flexibility relative to the timing of major investments.

6 Modeling Results

The assumptions, constraints, and scenarios developed through the initial stages of the IRP Process provide the inputs necessary to execute the Initial Portfolio Study, Reliability and Operability Analysis, and Final Portfolio Study. An overview of the modeling results from the Final Portfolio Study is presented in this section, with a particular focus on resource plan elements that are common to the range of low-cost plans. The complete series of IRP modeling results, including graphical and tabular model outputs for each scenario and sensitivity, are provided.

Nova Scotia Power's 2020 IRP confronts a high degree of uncertainty in the electricity planning environment. Ongoing changes in technology cost and availability, electricity demand and economy-wide electrification, GHG emissions regulations, and many other factors widen the range of potential futures that Nova Scotia Power's resource planning must be robust to. Fortunately, even when examining this wide range of scenarios, the modeling work has shown that low cost resource plans share many common elements in terms of both resource selection and timing.

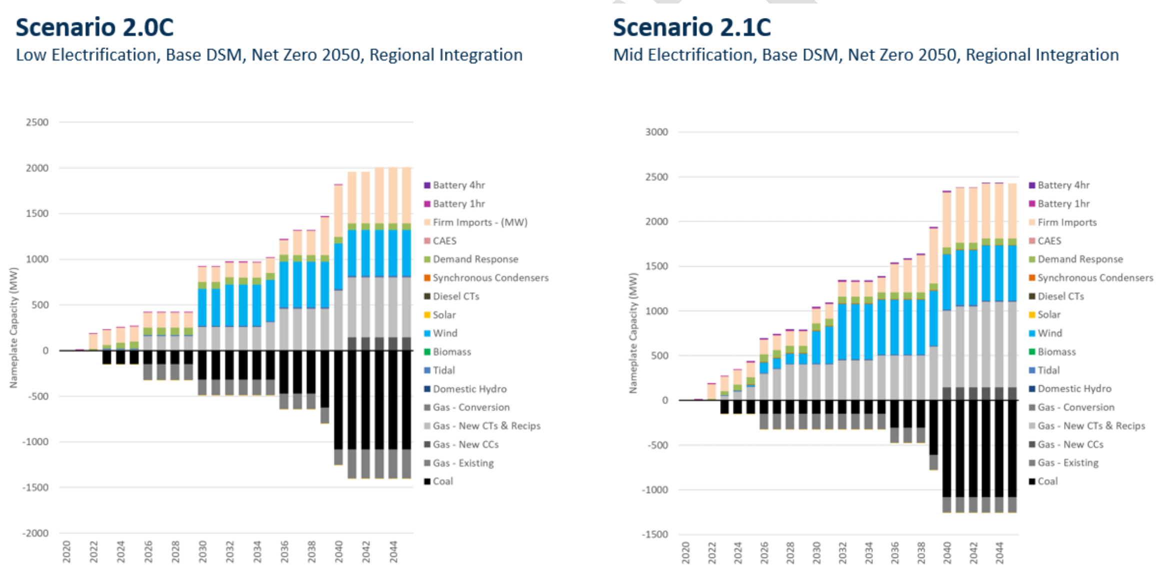
Of the key scenarios modeled in the Final Portfolio Study, Scenario 2.0C (Low Electrification / Net Zero 2050 / Regional Integration) has the lowest 25-yr NPVRR, incorporating end effects and accounting for DER costs (see Section 6.4 for details). Consequently, the resource plan optimized under this scenario has been designated the Reference Plan per the IRP Terms of Reference. It is important to note that this scenario is representative of many of the other low-cost resource plans modeled, particularly in the first ten years of the plan, and as a result it is this commonality that will inform Nova Scotia Power's "no regrets" IRP Action Plan and Roadmap.

Other low-cost scenarios which vary on a single policy driver or input assumption include 2.1C (Mid Electrification load), 3.1C (Accelerated Net Zero 2045 emissions), and 2.1C.WIND-1 (low wind cost) among others; the optimal resource plans developed under these scenarios are also discussed in this section to highlight commonalities. In addition, notes are provided to support the interpretation of the full set of IRP modeling results.

6.1 Resource Additions and Retirements

IRP resource plans are largely described via their resource additions and retirements. In order to communicate these plans, Nova Scotia Power has developed an incremental capacity diagram that has been used consistently through the IRP process and is provided for each resource plan in the full modeling results. Figure 45 below shows the incremental capacity diagrams for scenarios 2.0C and 2.1C.

Figure 45. Change in Installed Capacity in Scenarios 2.0C and 2.1C



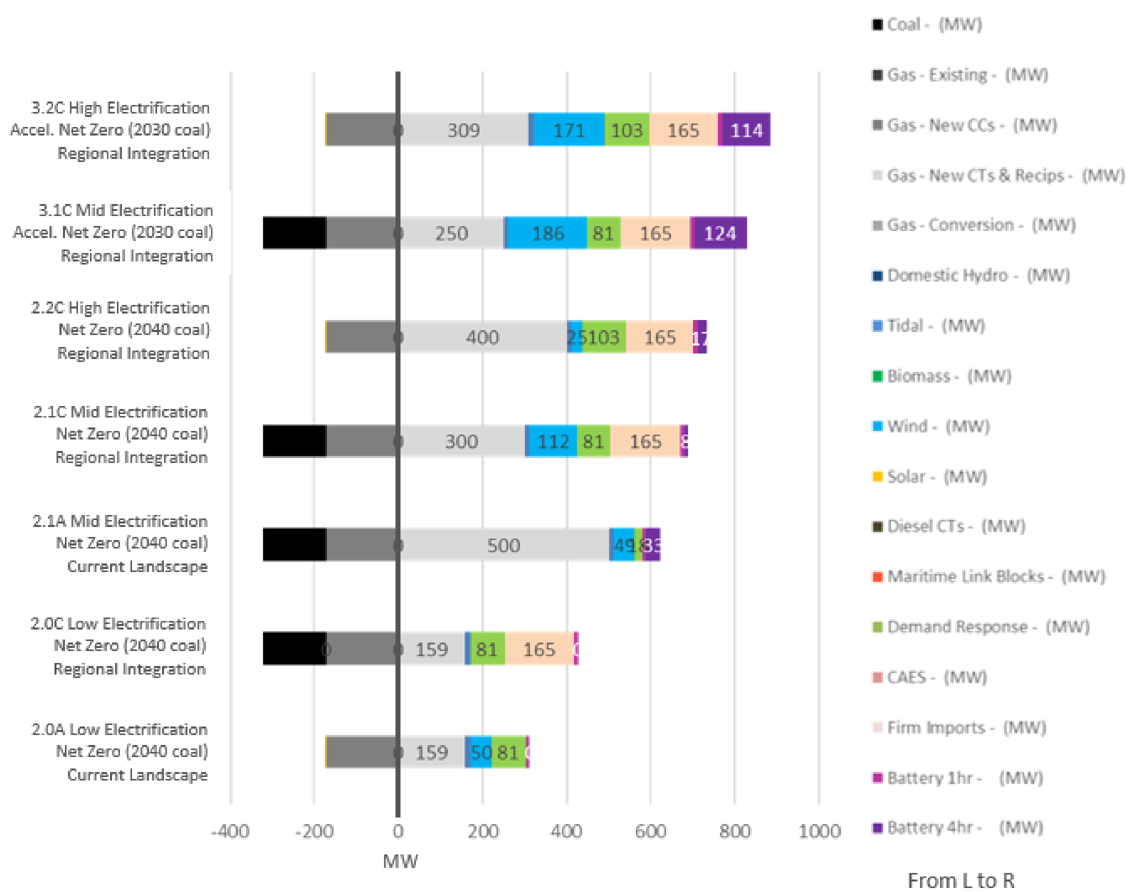
As can be seen above, there are many common elements to these two optimal resource plans. In the early 2020s, one coal unit is retired economically in both scenarios. Approximately 165 MW of firm import capacity is added and gas peaking units are built to replace the retired coal capacity, eliminate the current Planning Reserve Margin deficit, and meet and growing customer demand. Demand Response is also selected as an economic resource to offset firm generation capacity requirements in early 2020s.

In the mid-2020s, two less-efficient gas steam units are retired economically and new wind resources start to be added to the system. The installed capacity of wind increases significantly starting in 2030 as technology price declines continue and the GHG emissions target tightens. The Reliability Tie is built in 2030 to enable additional wind integration, and in 2.0C a second coal unit is retired economically.

The remaining coal-fired units are preserved until in the late-2030s, when they start to be retired due to the approaching model-imposed retirement date of 2040. To replace the capacity and energy provided by the retired coal units, new out-of-province firm imports, natural gas combustion turbines, and 145 MW of natural gas combined cycle plants are added to the system by 2040. A total of approximately 500-600 MW of wind is installed by 2040. The Regional Integration transmission line that enables the low- or zero-carbon firm imports from out-of-province resources is built in 2036 or 2037, at the start of the coal unit retirements. The resource plan stays relatively steady beyond 2040 with only small additions to manage peak load growth in both scenarios.

In the near term, the model shows a similar trend of capacity addition and retirement for many of the low-cost key scenarios. Figure 46 below provides a comparison of seven scenarios of interest.

Figure 46. Cumulative near-term capacity additions and retirements, selected key scenarios (2026)

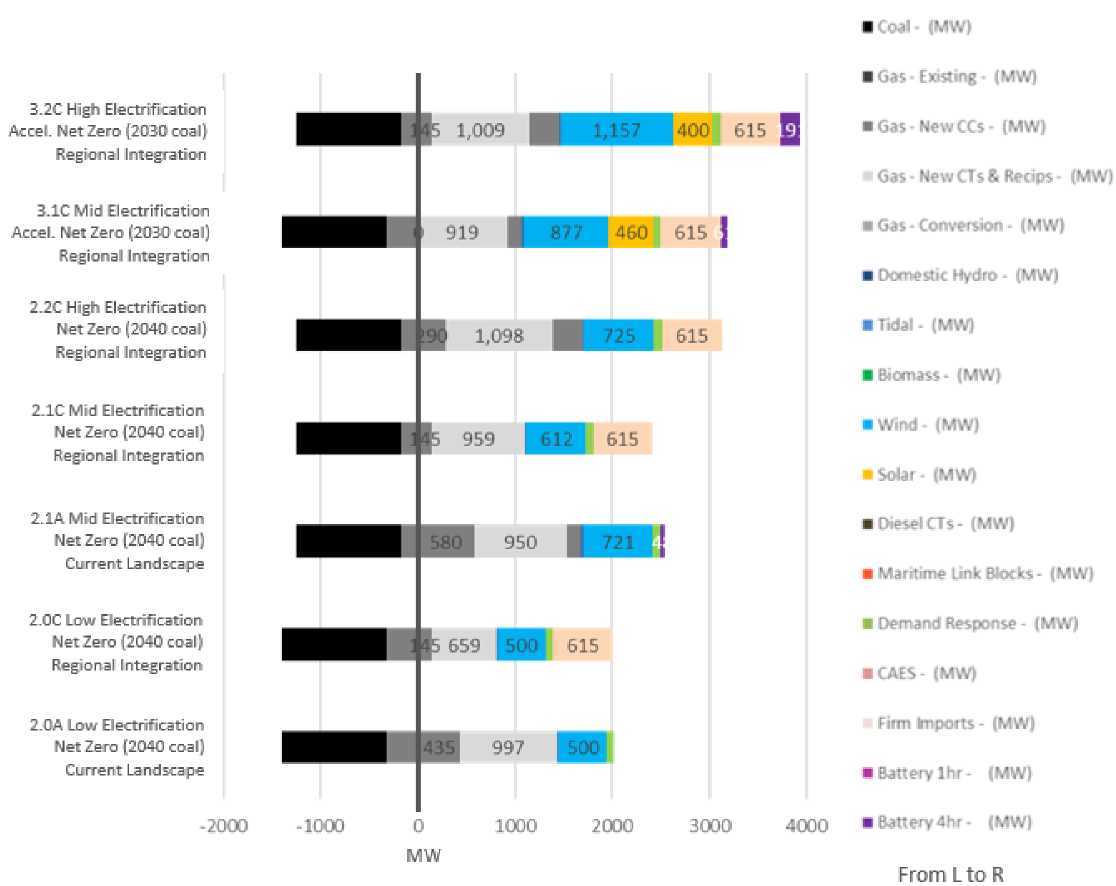


As can be seen in this incremental capacity comparison, two less-efficient gas units are retired economically in all scenarios. In addition, roughly half of the scenarios retire one coal unit economically by 2026. The coal unit is retained in the scenarios with higher load growth or in scenarios with less aggressive carbon emissions reduction targets. As for new capacity additions, all scenarios select gas peakers and DR programs to meet the capacity requirement. The installed capacity of new gas peakers ranges from 150 to 500 MW by 2026 depending on the scenario. More gas peakers are added in the Current Landscape scenarios when firm imports are not available (i.e. in scenarios 1.0A and 2.1A). Firm imports are selected economically whenever they are offered to the model via the Regional Integration resource strategy.

Up to 200 MW of wind is added by 2026 with a corresponding amount of Li-ion battery storage installed for wind integration. Scenarios with more aggressive GHG emission reduction targets (i.e. 3.1C and 3.2C) have more wind additions in the near term. An additional small amount of battery storage is installed to provide capacity and ancillary grid services in all scenarios.

Figure 47 below shows the same seven key scenarios in the last year of the planning horizon, 2045. By this time, the differences in key policy drivers such as electrification level, emissions scenario, and resource strategy have increased the variability among the optimal resource plans. Nevertheless, there are still common elements that can be observed in many of these plans.

Figure 47. Cumulative Capacity Additions and Retirements in the Long-Term (2045)



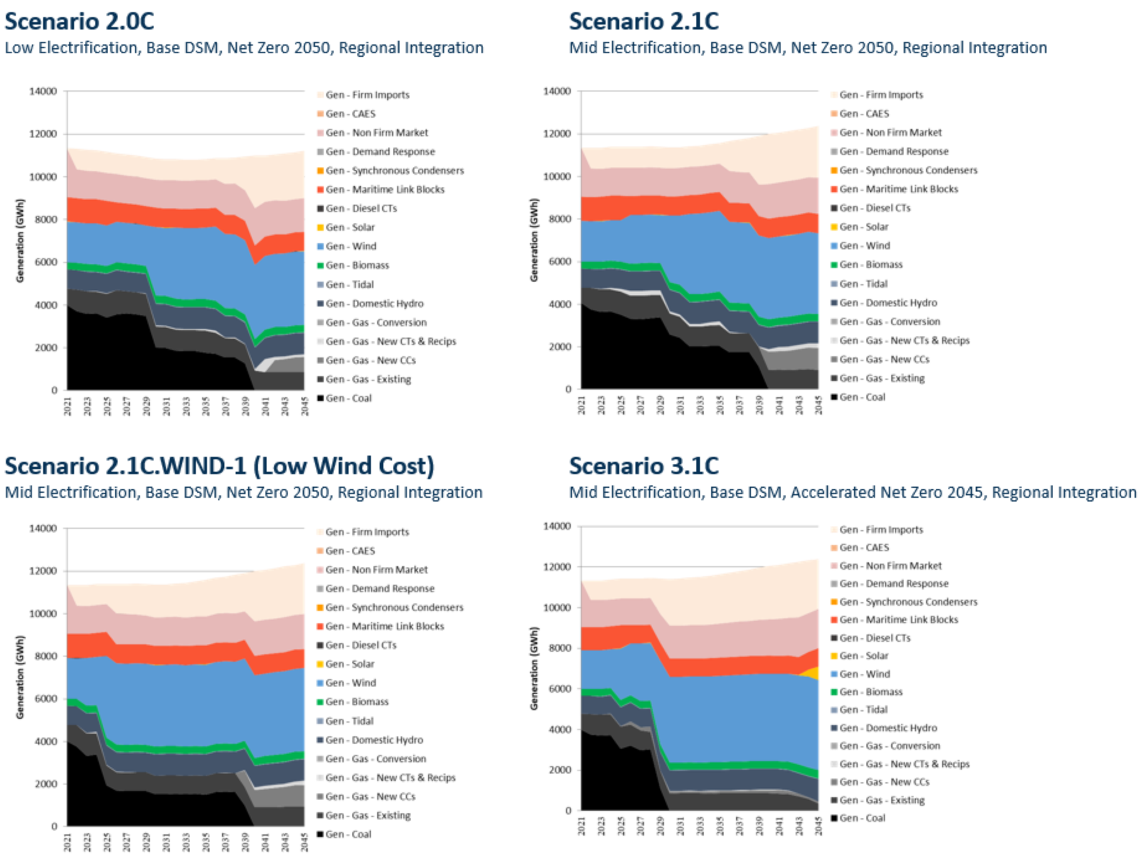
In the long run, all coal units are retired by 2030 or by 2040 depending on the scenario; in addition, by 2045, two to three existing gas-fired steam units are retired economically in all cases. To replace this retiring capacity and energy, new gas plants are built with the total new installed capacity ranges from 800–1700 MW depending on the scenario. In most scenarios, the majority of new gas capacity comes from fast-acting combustion turbines operating with low capacity factors. Coal-to-gas conversions are also built as capacity resources in about half of the scenarios. A smaller amount of new combined cycle gas generation is selected in six of the scenarios, with more combined cycle capacity required in the scenarios that did not have access to firm imported energy via Regional Integration.

The construction of a new Regional Interconnection is selected in all scenarios when it is available. The scenarios with more aggressive GHG emission reduction targets choose to build the interconnection as early as 2029 while other scenarios. Wind is built in all scenarios and the cumulative new installed capacity ranges from 500 MW to 800 MW in most cases, and up to 1150 MW in the most aggressive high-electrification and accelerated net-zero scenario (3.2C). The Reliability Tie is built in the early 2030s in most scenarios to integrate the additional wind. 60-400 MW of solar is added in 2044 in scenarios that follow the more aggressive accelerated net-zero GHG emission trajectory to help meet the GHG goals in 2045.

6.2 Energy Mix

Similar to the capacity addition and retirement chart, Nova Scotia Power has been using a consistent format to share annual energy mix results throughout this IRP process. Figure 48 below shows how the annual generation mix is modeled to evolve over the planning horizon under four scenarios of interest. As with all results in the Final Portfolio Study, these results are the output of hourly production cost simulations completed with PLEXOS MT/ST.

Figure 48. Projected Generation Mix in Select Scenarios



Once again, a significant degree of commonality can be observed in the energy mix results. With the delivery of Nova Scotia Power's contracted hydro blocks and energy imports via the Maritime Link, imported energy displaces coal, resulting in a significant decline in coal generation relative to recent historical production. The decline in coal generation continues through the rest of the planning horizon following the GHG emissions curves, gradually reducing to the model-imposed retirement dates. Wind generation and low-carbon imports (both firm and non-firm) increase to replace retiring coal and meet increasing energy requirements, making up a larger share of the generation mix. Existing renewable resources like biomass and domestic hydro maintain consistent output through the planning horizon.

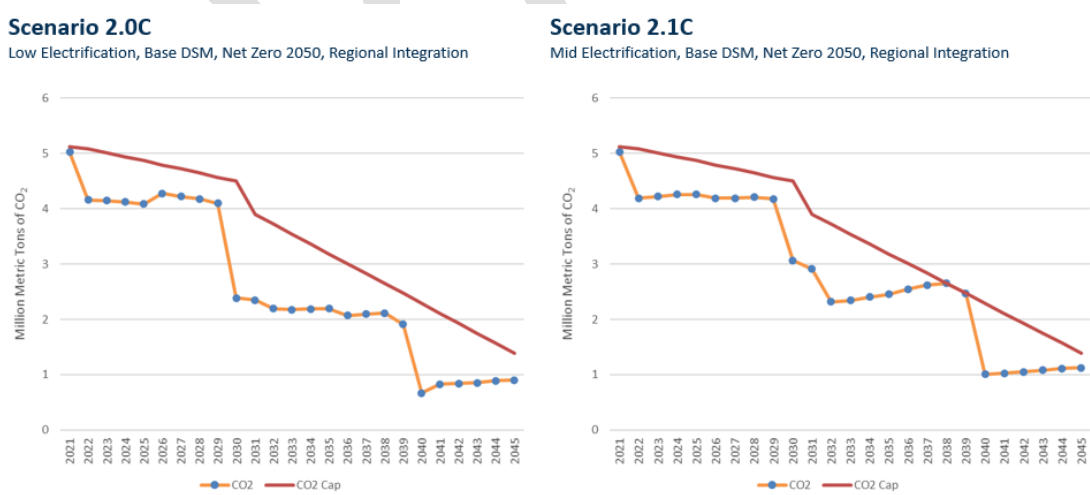
An important observation when comparing these charts to the capacity results presented previously is the continued separation of sources of energy and sources of firm capacity. For example, wind generation and non-firm imports provide a significant portion of the energy but relatively little firm capacity.

Conversely, new gas combustion turbines provide a significant share of the firm capacity that enables coal unit retirement but operate at very low capacity factors (less than 10 percent in most cases). This changing system dynamic is an important consideration when evaluating the operability of these future resource plans.

6.3 Greenhouse Gas Emissions

Figure 49 shows the GHG emissions over the planning horizon for the scenarios 2.0C and 2.1C. In both scenarios, Nova Scotia Power is able to meet the GHG emission requirement and lower overall GHG emissions from the electricity sector to 1.4 MT per year by 2045. Because of access to economic wind energy and low- and zero-carbon imports, and because of the influence of other emissions limits with declining hard caps through the period (Hg, SO_2, and NO_x), Nova Scotia Power is able to over-comply with the modeled GHG emissions hard caps in most years. The fact that capacity is being added and retired in blocks is also responsible for the shape of these curves as they optimize toward the end point in 2045.

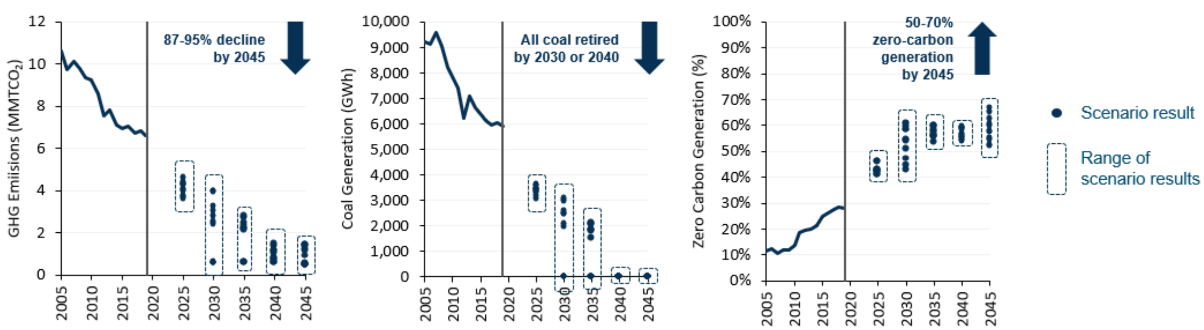
Figure 49. GHG Emissions in Scenarios 2.0C and 2.1C



As discussed in Section 3.3.1, potential revenue from emissions under the modeled caps is not incorporated into the IRP model objective function or NPVRR results. As additional certainty develops around the regulations for, and performance of, the Nova Scotia cap-and-trade market, this could enable additional value for incremental GHG emissions reductions. Nova Scotia Power has proposed an item in the IRP Roadmap to continue to monitor this potential and to adjust the optimal resource plan accordingly.

As summarized in Figure 50, all key scenarios modeled incorporate a significant reduction of GHG emissions by 2045. The significant declines come from the retirement of coal-fired generation and the increasing amount of zero-carbon generation provided by wind and clean imports. Coal-fired generators are retired in all scenarios by 2040 and zero-carbon generation makes up more than 60 percent of total generation by 2045.

Figure 50. GHG Emission, Coal Generation, and Zero-Carbon Generation by Years

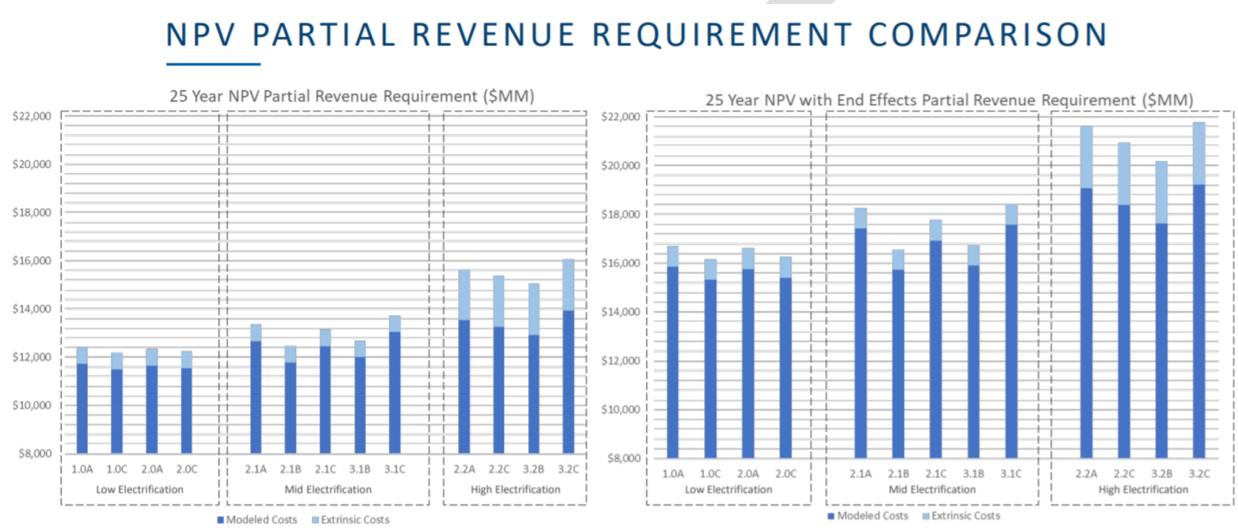


6.4 Resource Plan Cost

The NPV of partial revenue requirement for the IRP key scenarios is summarized in Figure 51 below. Results for scenarios are grouped based on their load level; the revenue requirements should only be compared across the scenarios with the same electrification and load levels, as serving more electricity will naturally lead to a higher revenue requirement. Similarly, Resource Strategy B (Distributed Resources) cannot be directly compared with the equivalent A (Current Landscape) and C (Regional Integration) Resource Strategies because Resource Strategy B assumes aggressive DER adoption, the costs of which are not included in the NPVRR as they are not assumed to be utility costs for IRP modeling purposes. An estimated range of the cost of these DER resources is \$1.6 billion to \$2.5 billion on an NPV basis.

When looking across the range of outputs, the C (Regional Integration) scenarios are lower cost than the equivalent A (Current Landscape) scenarios in all cases, both with and without end effects. Further, the Regional Integration scenarios are also lower cost than the Distributed Resources scenarios in all cases once the low end of the DER cost estimate range is added to the modeled NPVRR.

Figure 51 NPV of Revenue Requirement Across Scenarios



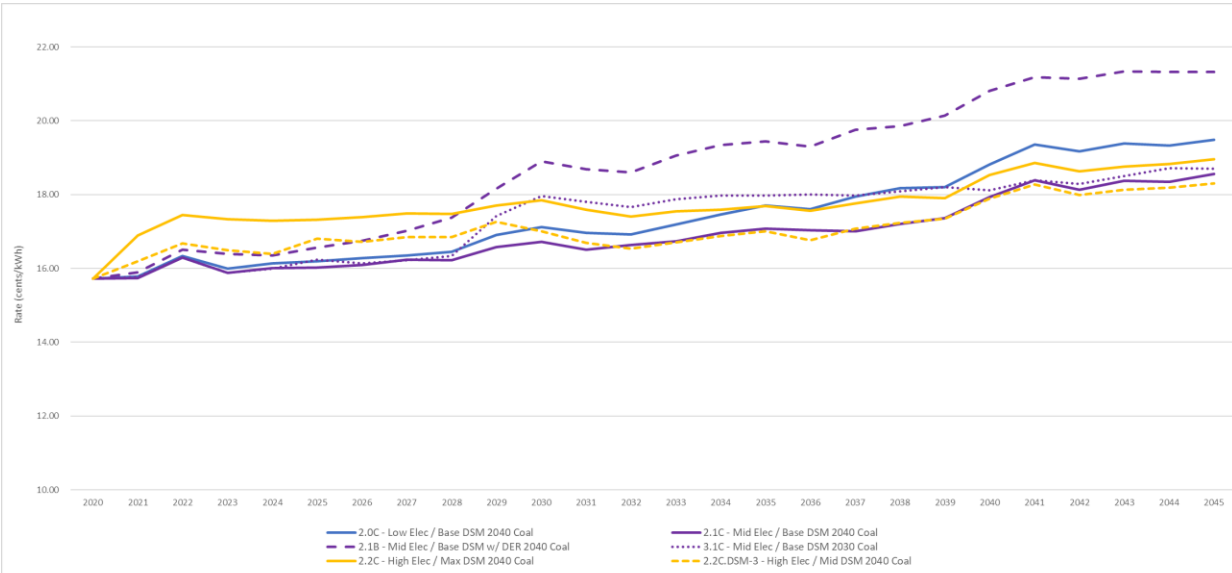
The comparison in this figure also shows that meeting a 2030 coal retirement date is more expensive, on an NPV basis, than a comparable scenario with a 2040 coal retirement date.

6.5 Relative Rate Impacts

In addition to comparing the NPVRR metrics, Nova Scotia Power also developed a simplified rate impact model to compare the relative rate impacts of each scenario. This analysis approximates the resource plan impact to customer rates over time, incorporating the effects of load changes due to Electrification, DSM level, and Resource Strategy. The details of this rate effect model are available in Section 5.3.3.

Figure 52 below shows the relative rates for select scenarios over the planning horizon. In addition to this visual comparison, the average annual partial rate impact is provided for each key scenario and sensitivity as part of the full set of IRP modeling results.

Figure 52. Relative Rate Impact Comparison – Selected Scenarios



These results indicate that higher levels of electrification, when paired with appropriate DSM investments, lead to lower rates for customers over time. This reduced rate pressure is in addition to savings customers may benefit from by reducing other components of their energy bills (e.g. heating oil, gasoline); this model also does not capture the economy-wide emissions reduction benefits that would accompany increased levels of electrification.

Conversely, the scenario modeled with the Distributed Resources strategy (2.1B) is shown to have a significantly higher relative rate impact over the planning horizon. This effect is a result of lower annual energy sales in the DER case, but with a similar optimal resource plan as the peak demand requirement is not affected by the presence of DER resources (which have no firm capacity value). Finally, the cost of the DER resources themselves is not included in these rate impact calculations but could be expected to add additional rate pressure if modeled.

The slight rate increases in 2030 for scenario 3.1C and in 2040 for the rest of the scenarios show that coal retirement has upward pressure on rates. Retiring the existing coal-fired plants requires Nova Scotia Power to procure new capacity and energy from other resources. Closing coal-fired plants by 2030 and by 2040 have similar cumulative rate impacts by 2045, as shown by comparing rates between scenario 3.1C and scenario 2.1C, but a 2030 coal closure date can be expected to add rate pressure during the 2030s without other mitigation.

6.6 Reliability

As described in Section 0, Nova Scotia Power included a Reliability Assessment phase in the IRP process due to the significant changes in generating capacity anticipated by the end of the planning horizon. Scenarios 2.0C, 2.1C, and 3.2C were selected for assessment as they are representative of the range of options studied in the IRP, including Mid and High Electrification cases with significant renewable energy penetrations by 2045.

For each case, the 2045 optimized resource portfolio and projected load were analyzed in E3's loss of load probability model, RECAP. This model completes a robust analysis against the established reliability criterion of 0.1 days/year (see Section 3.1.1 for details). Systems which achieve an LOLE at or below this limit are considered sufficiently reliable.

All three cases analyzed during the Reliability Assessment were found to meet the target reliability criterion and LOLE metric, as shown below in Figure 53. Further, the installed firm capacity above the minimum requirement for LOLE compliance is noted to be quite low in all 3 cases, and generally close to or smaller than the capacity of the lowest cost firm capacity unit offered to the model (a new frame combustion turbine).

Figure 53. Key Reliability Statistics – Reliability Screening of 2045 Resource Portfolios

	2.0.C	2.1.C	3.2.C
LOLE Target (days/yr)	0.10	0.10	0.10
Achieved LOLE (days/yr)	0.06	0.02	0.06
Achieved LOLh (hrs/yr)	0.18	0.08	0.21
PRM Target (UCAP)*	8%	8%	9%
Achieved PRM (UCAP)	9%	11%	10%
Excess Capacity (MW)	32	77	40

*RECAP estimates a PRM target endogenously given the system load characteristics and reserves in 2045, therefore it may differ slightly from the PRM target estimated for the 2020 system.

While these results provide confidence that these systems are sufficiently reliable, detailed modeling of electrification impacts on reliability is recommended as additional electrification shape data becomes available. More detailed modeling of the electrification load shapes has been added to the IRP Action Plan to develop a robust assessment of how electrification impacts might affect the PRM target in the long-term. This work is likely to include more detailed modeling of the peak impacts of electrification loads (particularly in buildings) as a function of expected extreme weather events or the extent to which vehicle charging load would coincide with peak events and the potential means to ensure flexible charging to avoid such coincidence.

Finally, while the excess capacity identified by this analysis is relatively small as a percentage of total peaks, and excess capacity above the target PRM can be attributable to economic optimization or the lumpiness of resource additions, Nova Scotia Power will continue to assess the appropriateness of the current PRM and its component parts, including the ELCC of batteries, wind and DR, as the power system matures in its transformation. Triggers have been added to the IRP Roadmap to indicate when an updated PRM analysis would be necessary.

6.7 Operability

For select scenarios, Nova Scotia Power used the PLEXOS MT/ST module between the Initial and Final Portfolio Studies in order to produce hourly production cost model outputs. These more granular simulations were reviewed to ensure that dispatch and reserve requirements, thermal unit operating parameters, and other model constraints were being correctly captured in IRP model.

This Operability Assessment phase was intended identify any changes required before undertaking the Final Portfolio Study. Nova Scotia Power conducted and reviewed hourly unit commitment simulations in PLEXOS MT/ST for the following four scenarios:

+ 2.0C – Low Electrification / Base DSM / Net Zero 2050 / Regional Integration
+ 2.1C – Mid Electrification / Base DSM / Net Zero 2050 / Regional Integration
+ 3.1C – Mid Electrification / Base DSM / Accelerated Net Zero 2045 / Regional Integration
+ 3.2C – High Electrification / Base DSM / Accelerated Net Zero 2045 / Regional Integration

The PLEXOS MT/ST simulations shows that the key model constraints were able to be met in all hours for all years modeled and the thermal unit operating constraints have been respected under the new resource plans, even under high renewable penetrations observed in the 3.2C resource plan. Minor refinements to import constraints were made so they would operate correctly in all hours for the Final Portfolio Study. The unit generation outputs of the PLEXOS MT/ST simulations were generally consistent with the PLEXOS LT results, indicating that the selected modeling parameters for PLEXOS LT were granular enough to be a sufficiently accurate representation of the system.

6.8 Sensitivity Analysis

In addition to the Final Portfolio Study, various model sensitivities were studied to understand how model outputs will vary with adjustments to key input parameters of interest. For each of the 18 sensitivities, a new capacity optimization run was completed, resulting in a new optimal resource plan. The change to the optimal portfolio (including resource technology and timing) and cost impact provides important information on the criticality of the sensitivity assessed. Many of these sensitivities were tested against key scenario 2.1C; this was selected as it is a central scenario for many of the input parameters and is the low-cost plan at the mid-electrification level. The detailed model outputs and additional results interpretation for these sensitivities are presented in the updated IRP Modeling Results of October 30, 2020.[49] The sensitivity results are summarized in the following categories: DSM Levels, Wind, Mersey System, Imports, Sustaining Capital, and Fuel Prices.

6.8.1 DSM LEVELS

Nova Scotia Power recognizes that DSM is an important component of the overall resource plan development and accordingly, completed a robust analysis of the four DSM levels developed by EfficiencyOne (Low, Base, Mid, and Max). This analysis included developing an initial DSM profile pairing for each of the 13 key scenarios, and then creating a set of sensitivity runs that model alternate DSM levels against different assumptions for Resource Strategy, GHG Trajectory and Coal Retirement Date, and Electrification Level. The list of seven DSM sensitivities executed was developed in collaboration with EfficiencyOne.

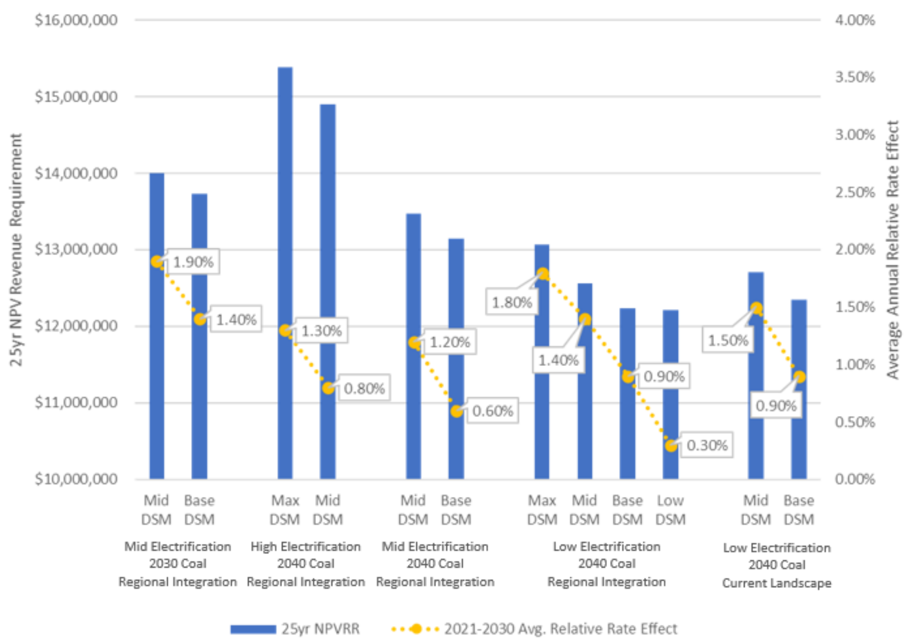
Complete details on each of the DSM sensitivities is available in the modeling results file. In general, DSM programs higher than the Base level resulted in increased costs to customers, on both an NPV basis and a relative rate basis. Higher DSM programs also generally resulted in earlier coal retirement, less new-built gas capacity by 2045, and lower CO_2 emissions over time because the overall load level is lower.

When comparing the significant number of DSM sensitivities studied, as shown in Figure 54, the Base DSM profile is shown to be more economic across financial metrics (NPV and relative rate impact) when compared to the Mid or Max DSM profiles at the low and mid levels of electrification, and when considering both 2030 and 2040 coal retirement dates. When comparing the Low and Base DSM profiles under low electrification, the Base DSM profile is economic when compared using the 25-year NPVRR with

[49] https://irp.nspower.ca/documents/draft-findings-roadmap-action-plan/

end effects metrics while the Low DSM profile is economic on other metrics; in particular there is a significant difference noted in the relative rate impacts over both 10 year and 25 year periods.

Figure 54. NPV Revenue Requirement and Relative Rate Impact Comparison for DSM Sensitivities



6.8.2 WIND

NS Power tested a series of sensitivities to investigate the potential impact of technology cost and integration requirements on both the level and timing of wind capacity builds. The results of the first two scenarios, 2.1C.WIND-1 (Low Wind) and 2.1C.WIND-2 (Low Wind + Low Battery), both indicate earlier installation of significant levels of wind. These builds are advanced from 2030 to the mid-2020s, while the overall resource portfolio in 2045 remains very similar to the base case. The Reliability Tie is also advanced to enable wind integration. The earlier wind energy seen in these scenarios also enables an additional early coal unit retirement relative to the base case. Earlier builds of wind generation enable a drop in CO_2 emissions between 2025 and 2030; emissions in 2031-2045 are largely unchanged. These sensitivity results indicate that the timing of wind development is sensitive to the cost of the new wind resources available.

A lower synchronized inertia requirement of 2200 MW.sec (3266 MW.sec in the base case) was modeled in scenario 2.1C.WIND-3 and is shown to have a limited impact on overall resource plans. There are slight changes the timing of building new wind, thermal units, and transmission lines, but the impact on resource plans and NPVRR is minimal. This is interpreted as indicating that determining the exact level of synchronized inertia required for stability and reliability on the Nova Scotia system, within the range of 2200 – 3266 MW.sec, is not critical for capacity expansion planning purposes.

A final run was conducted as a boundary case test of wind integration assumptions, 2.1C.WIND-4. In this scenario, the synchronized inertia constraint and the wind integration requirements (via the Reliability Tie and/or batteries and synchronous condensers) are both removed completely. The installed wind capacity under this scenario follows a generally similar trajectory to the other wind sensitivities (the timing of capacity additions is roughly between the base case and low price sensitivity) until the mid-2030s, at which point the model continues to add significant capacity due to the removal of wind integration requirements. This late wind additions incur significant curtailment (jumping from 5.2 percent in the base case to 13.4 percent in 2045), resulting in an NPV that is lower than, but relatively close to, the base case and suggesting that further analysis is required for incremental wind additions beyond those identified in the base scenarios and low price sensitivities. This run is intended as a test case to understand how the model performs with no synchronized inertia constraint and no integration requirements for wind; it is not considered to be a feasible resource plan based on these assumptions.

6.8.3 MERSEY SYSTEM

The Mersey Hydro system was analyzed during the Resource Screening phase of the IRP (described in section 4.2.2) and economically retained, based on the assumptions developed from Nova Scotia Power's Hydro Asset Study. This resulted in the Mersey system being modeled as retained in all IRP key scenarios and sensitivities. However, due to the significant costs associated with redeveloping the Mersey system (as described in the HAS), IRP participants expressed a desire to examine the Mersey system specifically via a PLEXOS sensitivity. Sensitivity 2.1C.MERSEY models how capacity and energy would optimally be replaced if the Mersey system is assumed to retire in 2025 rather than proceed with redevelopment. In order to properly compare the financial metrics of this sensitivity, the cost of the Mersey system decommissioning is added to the sensitivity outside of the model as an extrinsic cost.

The optimized resource portfolio of the sensitivity run indicates that Regional Integration is advanced by six years relative to the base case, and significant wind build occurs in 2030 rather than 2032. By the end of the planning horizon, the resource portfolio is very similar to the base case but with 40 MW of incremental CT capacity accounting for the retirement of the Mersey system. Replacement energy is sourced from a combination of Gas and Imports.

The results of this sensitivity indicate that redevelopment of the Mersey system is economic relative to decommissioning when comparing the 25-year NPVRR with end effects. The sensitivity is shown to be equivalent to the base case in terms of relative rate impact, while the decommissioning sensitivity was indicated a lower cost under the shorter NPVRR metrics (25-yr without end effects and 10-yr NPVRR). Nova Scotia Power notes that these are very close results in all cases, particularly for a long-lived hydro asset like the Mersey system; accordingly, additional economic analysis will be provided in any capital applications for Mersey system refurbishment.

6.8.4 IMPORTS

Because Regional Integration and the Reliability Tie play a key role in many of the optimal resource plans developed for the key scenarios, three import sensitivities were modeled in order to evaluate the robustness of this finding. All three show a relatively limited impact on the overall model results. The first, 2.1C.IMPORT-1, reduced the annual volume of non-firm imports available to the model. Under this scenario, the model builds wind earlier and adds an additional NGCC unit as an energy source, indicating this is the next best alternative to imported energy that fits within the modeled emissions constraints. The cost of this sensitivity increases significantly relative to the base case.

In the key scenarios modeled under the Current Landscape resource strategy, the Reliability Tie is still eligible to be built and was selected economically in all cases as a method of enabling wind integration and satisfying synchronized inertia constraints. Sensitivity 2.0A.IMPORT-2 models a Current Landscape case without the ability to build the Reliability Tie. In this case, wind is built via the local integration option (batteries + synchronous condensers), which also contribute to system inertia requirements. The total quantity of wind built is less and batteries are added for wind integration. The remainder of the resource plans are similar and the financial metrics, including NPVRR and relative rate impact, are higher compared to the base case. This result provides additional information on some of the value of the Reliability Tie, when isolated from its contribution to a larger Regional Integration build.

Nova Scotia Power also modeled a sensitivity (2.1C.IMPORT-3) to test the criticality of the assumption that the Reliability Tie can supply all of the power system's synchronized inertia requirements. In this scenario, the Reliability Tie contributes only 50 percent of required system inertia once built (i.e. 1633 MW.sec). Results show that the Reliability Tie and Regional Integration are built slightly earlier in this scenario, with some accompanying earlier retirements as well. These resource mix changes are interpreted as reactions to the model finding more economic ways (other than large steam units with long minimum up and down times) to satisfy the remaining 1633 MW.sec of synchronized inertia requirement. The generation mix is generally unchanged from the base case on an annual basis and the resulting costs are somewhat higher on all NPV metrics. The results of this scenario indicate that the IRP assumption that the Reliability Tie provides all of the Nova Scotia System's synchronized inertia requirement is not critical to the value of that asset.

6.8.5 SUSTAINING CAPITAL

Evaluating ongoing sustaining capital investments for existing generating units is an important part of the IRP process. In particular, during this period of significant system transformation, the sustaining capital investments in units which will be retiring during the planning horizon are evaluated to confirm at what levels they continue to be economically sustained, or to understand where retirement decisions might change. Replacement energy and capacity alternatives are considered in the IRP process, and compared to future capital investment requirements to maintain safe and reliable operation of existing units to match with each unit's expected operating profile.

In addition to the base sustaining capital forecast that was included in the IRP key scenarios, Nova Scotia Power developed and evaluated two alternate sustaining forecasts. The High sustaining capital forecast assumes a 50 percent increase from the base forecast, while the Low sustaining capital forecast assumes a 25 percent decrease from the base forecast. In the sensitivities described here, these adjustments were applied to all thermal steam units (all coal units, and Tufts Cove units 1-3).

Under sensitivity 2.1C.CAPEX-1 (High Sustaining Capital), we see a small number of changes in the resource plan. One coal unit retirement is advanced from 2040 to 2030, and one additional gas steam unit is retired in 2026. The remaining thermal units are sustained economically until their model-imposed retirement date. The earlier capacity retirements are replaced by advancing builds of the Reliability Tie / Regional Interconnection, and new combustion turbine builds.

Under sensitivity 2.1C.CAPEX-2 (Low Sustaining Capital), there is no change to the gas steam unit retirements from the base case. The early coal unit retirement previously seen in 2023 is deferred until 2038, while the Reliability Tie and Regional Interconnection are built 1-2 years later than in the base case. New combustion turbine and wind builds are delayed to match coal unit retirements, but the final resource plan in 2045 is essentially unchanged from the base case.

These sensitivities demonstrate that the resource plan developed in the base case is generally robust to a wide range of sustaining capital profile adjustments; timing of retirements and additions may be adjusted but the components of the final resource plan are consistent. These results also demonstrate that maintaining the existing coal fleet to the model-imposed retirement date is the most economic option for Nova Scotia Power customers within the range of sustaining capital cost evaluated.

6.8.6 GAS AND IMPORT PRICES

The optimal resource plans developed for the key scenario runs show that both new gas generation and new firm imports are selected as common resources across scenarios as part of the overall strategy to replace retiring coal capacity. In order to test the robustness of this result, Nova Scotia Power determined it would be important to test a high sensitivity case for both natural gas and import power prices. The results of this analysis are provided in sensitivity 2.1C.PRICES-1.

The results show only minor adjustments to the resource plan in the face of higher prices. There is an additional gas steam unit retirement and a one-year delay in the construction of the Regional Interconnection, both reflecting the price change. There are also small increments to solar and battery capacity late in the planning horizon relative to the base case. The overall resource plan cost and relative rate impact metrics are higher than the base case, as would be expected due to the increased commodity prices. This consistency in the resource plan indicates that the Regional Integration strategy and the common plan elements seen across IRP key scenario results are robust to a high commodity price environment.

7 Key Findings, Action Plan, and Roadmap

7.1 Key Findings

The Key Findings are compiled from the modeling results and other observations developed throughout the IRP Process, including the outputs of the Pre-IRP Deliverables. They are intended to capture the major outputs of the work as well as feedback from IRP participants where applicable. The Key Findings inform the IRP Action Plan and Roadmap that follow.

- **1 Steeply reducing carbon emissions in line with Nova Scotia's Sustainable Development Goals Act will require significant efforts from each sector of the economy, with the electricity sector playing a major role.**

  - **1a Key pillars of economy-wide decarbonization include greater reliance on non-emitting electricity supplies, focused demand side management, and electrification of end uses currently reliant on fossil fuels.**

    This result is informed by the Deep Decarbonization (Pathways) study, which was completed during the pre-IRP phase. This study evaluated feasible pathways for economy-wide decarbonization of at least 80 percent by 2050, a prerequisite on the path to the net zero target set by the SDGA. In particular, this work showed that low carbon electricity is essential to achieving economy-wide decarbonization, enabling emissions reductions in the electricity sector as well as complementary reductions in buildings and transportation. The analysis also demonstrated that building and transportation sectors – which make up over 40 percent of Nova Scotia's emissions today – can dramatically reduce emissions through adoption of heat pumps and electric vehicles. These new sources of load will require the utility to engage in proactively managing potential associated peak impacts. For additional detail on this work, please see the study.[50]

[50] Energy + Environmental Economics (E3), Deep Decarbonization in Nova Scotia: Phase 1 Report, February 2020. https://irp.nspower.ca/documents/assumptions-and-analysis-plan/

- **1b Increased electricity sales due to electrification can help to reduce upward pressure on electricity rates while facilitating carbon reductions in other sectors. The IRP rate analysis demonstrates the importance of managing the relative growth of peak and energy requirements, highlighting the need to pursue beneficial electrification.**

  This finding is based on the results of the relative rate impact analysis which was conducted using the Final Portfolio Study results. This analysis showed that higher electrification scenarios, when paired with an appropriate DSM program, result in lower average rate impacts than comparable low electrification scenarios. See section 6.5 for additional detail on the relative rate impact model created for this IRP. The impact of the relative growth of peak and energy requirements is most clearly observed when evaluating the Distributed Resources (B) scenarios, where energy requirements are reduced significantly while peak requirements are unchanged; this extreme case is shown to have a higher relative rate impact than other scenarios.

- **1c Nova Scotia Power's direct carbon emissions are reduced to between 0.5 Mt and 1.4 Mt per year by 2045 in all resource plans, representing an 87-95 percent reduction from 2005 levels. Earlier emissions reductions are possible at incremental cost relative to the lowest cost plans.**

  Nova Scotia Power's direct carbon emissions in 2005 measured 10.6MT. Significant emissions reductions have already occurred since that time, with NS Power's 2019 emissions measuring 6.6MT. Both of the SDGA compliant emissions curves modeled in the IRP require further emissions reductions, down to levels of 1.4MT (Net Zero 2050) and 0.5MT (Accelerated Net Zero 2045), representing reductions of 87 percent and 95 percent respectively. Many of the modeled resource plans achieve emissions reductions below these caps, particularly in the intermediate years of the planning horizon, as the generation mix transitions away from carbon-intensive sources and coal units retire.

+ 2 Decarbonizing Nova Scotia Power's electricity supply will require investment in a diverse portfolio of non- and low-emitting resources.

- **2a Regional Integration (i.e. investment in stronger interconnections to other jurisdictions) is an economic component of the least-cost plans under each load scenario. Both the Reliability Tie, which strengthens our connection to the North American electrical grid, and a Regional Interconnection, which enables access to firm capacity and energy imports, are shown to have value.**

This finding draws on the breadth of the IRP analysis plan and modeling results. When compared on a level basis (holding load, DSM, and emissions constraints constant and including the low cost estimate of the DER resources, when present), the Regional Integration (C) scenarios are demonstrated to have a lower NPVRR than equivalent Current Landscape (A) or Distributed Resources (B) scenarios for all 7 comparisons modeled.

The Reliability Tie is used in the IRP model to enable wind integration per the pre-IRP Renewable Stability Study and to reduce system synchronized inertia requirements. Additional reliability benefits of this investment and potential effects on contingencies were not modeled in the IRP. The Reliability Tie was enabled in Current Landscape (A) cases as a wind integration tool, and in addition for the Distributed Resources (B) and Regional Integration (C) cases the Reliability Tie could be constructed as the first phase of a larger Regional Interconnection transmission investment. In all cases, including sensitivities that reduced the modeled inertia benefit, the Reliability Tie is selected and in sensitivity 2.0A.IMPORT-2 where it was not allowed to be built, the resulting resource plan was $356 million more expensive.

Regional Integration was modeled as availability of both firm capacity and energy from jurisdictions external to Nova Scotia. The model was able to procure each resource (capacity and energy) to the level required once it had made the capital investment in required transmission infrastructure. Nova Scotia Power observes the model utilizing this flexibility in the results, as firm capacity purchases are generally added gradually as coal units are retired. Firm capacity could be purchased in 50 MW blocks up to a total of 450 MW while energy could be scheduled hourly in the model, with no minimum or maximum monthly or annual limits beyond the capacity of the tie itself. Like the Reliability Tie, Regional Integration was selected economically in every resource plan where it was offered to the model; timing of the investment generally varied with timing of coal unit retirements.

- **2b Wind is the lowest cost domestic source of renewable energy and is selected preferentially over solar in all resource plans. Incremental wind capacity in the range of 500 - 800 MW is selected by the model by 2045, with major installations paired with coal retirement dates to provide replacement emissions-free energy. The availability of lower priced wind is shown to accelerate the wind buildout in the mid-2020s, with up to 600 MW selected under the modeled low wind price, mid-electrification sensitivity.**

To enable wind additions beyond what was studied in the pre-IRP analysis (more than 100 MW incremental with the current system, or more than 400 MW incremental with identified wind integration investments), additional system stability studies are required.

Wind resources are a significant addition in all resource plans modeled during this IRP. Onshore wind is the lowest cost renewable energy resource based on the base LCOE assumptions developed at the start of the IRP. The incremental capacity of 500-800 MW identified above is drawn from the range of low- and mid-electrification modeling results; under high-electrification scenarios, this number can range higher as increased load enables additional wind integration on the system.

Due to the significance of wind to the resource plans, numerous sensitivities were developed and modeled to explore the behaviour of the system. These included both sensitivities on price (2.1C.WIND-1 Low Wind Cost, 2.1C.WIND-2 Low Wind + Low Battery Cost) and boundary cases on integration requirements (2.1C.WIND-3 Low Inertia, 2.1C.WIND-4 No Inertia / No Integration Requirements). These results indicated that the model is sensitive to resource cost when determining the timing of wind additions, but that the final quantity selected was similar. Results also indicate that lowering the inertia constraint from 3266 MW.sec to 2200 MW.sec (2.1C.WIND-3) did not have a significant change in terms of wind capacity or timing, indicating that this is not a critical assumption for wind modeling. The boundary case of no synchronized inertia constraint + no wind integration requirements (2.1C.WIND-4) indicates that these constraints do not significantly affect the wind build seen in both the base and low price sensitivities until the mid-2030s; as discussed in Section 6.8.2, results beyond that point suggest that further analysis is required for significant wind additions beyond those modeled in the base cases.

- **2c Coal units are generally sustained economically until their model-imposed retirement date, with capacity factors falling in line with declining emissions caps. Many resource plans incorporate economic retirement of one coal unit in the near term, as early as 2023, and some plans see economic retirement of a second coal-fired unit in 2030. New firm capacity is required to offset retiring coal units, to lower carbon emission intensity, and to meet growing electricity demand in all scenarios.**

It is shown that across the 13 key scenarios modeled, 6 incorporate a coal unit retirement in 2023. These retirements are tied to replacement capacity availability, generally via

Regional Integration but occasionally enabled by new combustion turbine capacity (e.g. 2.1A). Of the 9 key scenarios where coal units must retire by 2040, 3 retire a second coal unit in 2030 (and a fourth scenario retires 2 units in 2031).

In all scenarios, the majority of coal units are sustained economically until the final years before their model-imposed retirement dates (2030 or 2040), in alignment with the constraint limiting thermal unit retirements to a maximum of three per year. The lack of current capacity surplus, and flat or growing firm peak requirements in all scenarios, demonstrates that new sources of capacity are required in all cases to enable coal unit retirements.

- **2d Nova Scotia Power's existing domestic Hydro resources provide economic benefit to customers and are economically sustained through the planning horizon with the modeled level of sustaining capital investment. Economic justification as part of a capital application will be required to confirm decision to pursue Mersey hydro redevelopment, following the completion of the IRP.**

  Nova Scotia Power's existing hydro systems were analyzed during the Resource Screening phase of the IRP. This analysis showed that all hydro systems were sustained economically while incorporating the sustaining capital and decommissioning costs produced by Nova Scotia Power's Hydro Asset Study, which was reviewed with IRP participants during the assumptions development phase of the IRP. This analysis led to all existing hydro systems being modeled as sustained in the PLEXOS IRP scenarios.

  The Mersey hydro system was additionally evaluated via a specific sensitivity (2.1C.MERSEY), as described in Section 6.8.3. The results of this sensitivity indicate that redevelopment of that hydro system is economic relative to decommissioning when comparing the 25-year NPVRR with end effects. The two scenarios were shown to be equivalent in terms of relative rate impact, while the decommissioning case was lower cost when examining the shorter NPVRR metrics (25-yr without end effects and 10-yr NPVRR). Nova Scotia Power notes that these are very close results in all cases, particularly for a long-lived hydro asset like the Mersey system; accordingly, additional economic analysis will be provided in any capital applications for Mersey system refurbishment.

- **2e DSM energy efficiency programs and costs consistent with a range of the "Low" to "Base" profiles, per the EfficiencyOne Potential Study, are shown to be most economic relative to other options evaluated. A focus on peak demand mitigation is indicated and could be optimized into future DSM planning. Higher levels of DSM in**

resource plan sensitivities lead to reduced capacity needs and lower emissions, but DSM potential study costs do not indicate such plans are cost-effective.

DSM has been an important variable in this IRP, and Nova Scotia Power has modeled numerous DSM scenarios in both the key scenarios and sensitivities, incorporating significant engagement with EfficiencyOne as discussed in section 6.8.1. The Base DSM profile is shown to be economic across all financial metrics (NPV and relative rate impact) when compared to the Mid or Max DSM profiles under various scenarios for electrification and coal retirement. When comparing the Low and Base DSM profiles under low electrification, the Base DSM profile is economic when compared using the 25-year NPVRR with end effects metrics while the Low DSM profile is economic on other metrics; in particular there is a significant difference noted in the relative rate impacts.

+ 3 Firm capacity resources will be a key requirement of the developing Nova Scotia Power system in both the near and long term.

- **3a New combustion turbines, operating at low capacity factors, are currently the lowest cost domestic source of firm capacity and replace retiring thermal capacity in all resource plans. These units are also fast-acting, meaning they can quickly respond to changes in wind and non-firm imported energy. 50-150 MW is required by 2025, while 600-1000 MW of new capacity is required by 2045 to support retirement of steam units.**

  New combustion turbines are added economically in all resource plans over the planning horizon. The capacity ranges identified in this finding cover the range of low and mid electrification key scenarios, with high electrification scenarios showing increased capacity by 2045 in some cases. It is noted that in the Current Landscape (A) scenarios, combustion turbine capacities are higher due to the lack of firm capacity available from the Regional Interconnection. Significant resource additions are generally paired with steam unit retirements. Average annual capacity factors for the new combustion turbine units are less than 10 percent in most years when examining PLEXOS MT/ST results.

- **3b Nova Scotia Power's existing combustion turbine resources provide economic benefit to customers and are economically sustained through the planning horizon with the modeled levels of sustaining capital investment.**

  Nova Scotia Power's existing combustion turbines were analyzed during the Resource Screening phase of the IRP. This analysis showed that the retention of all seven existing diesel units was economic by a significant margin under a range of scenarios and sensitivities, indicating that these units continue to be a valuable source of both firm capacity and ancillary grid services.

- **3c Low-cost, low emitting generating capacity may be provided economically from coal to gas unit conversions, which are selected economically in many resource plans**

  Coal to Gas Conversions were selected economically in 8 of 13 key scenarios as part of meeting capacity requirements. These resources are dispatched as firm capacity resources enabling coal capacity retirements. Average annual capacity factors for the new combustion turbine units are less than 5 percent in all years when examining PLEXOS MT/ST modeling results.

- **3d Battery storage can enable wind integration while providing firm capacity and energy storage; however, its ability to substitute for firm capacity resources is limited by its relatively short duration. Up to 120 MW of storage by 2045 is selected in the portfolios with deployments of 30-60 MW by 2025 in many plans.**

  Battery storage was an integration method for wind capacity beyond 100 MW incremental which was identified during the pre-IRP PSC study and modeled paired with high inertia synchronous condensers. The ELCC of battery storage was modeled specifically on the Nova Scotia system for several storage durations as part of the E3 Capacity Study, also completed during the pre-IRP phase. In the IRP modeling results, we see a moderate amount of battery storage added across the key scenarios with the ranges above being representative of all scenarios modeled.

- **3e The aggregated Demand Response programs modeled in the IRP have economic value to the Nova Scotia system, offsetting firm generation capacity requirements. A DR program with a target final nameplate capacity of approximately 75 MW is shown to have value across all resource plans under IRP cost assumptions, while higher DR capacity is shown to be economic under high electrification scenarios.**

  The DR programs modeled in the IRP were taken from EfficiencyOne's potential study, completed during the pre-IRP phase. That study produced three DR programs, which are paired with one of the four DSM profiles for modeling in the IRP. The DR programs are modeled using a fixed capacity and cost profile, with 3 potential entry points (2021, 2025, and 2030). The IRP modeling results show that DR programs are selected in all resource plans in either 2021 or 2025. The target capacity of 75 MW is based on the size of the program paired with the Base DSM profile, however it is noted that in high electrification scenarios paired with the Max DSM profile, an approximately 100 MW DR program is available and selected economically.

- **3f A Planning Reserve Margin of 9 percent (on a UCAP basis, consistent with 20 percent on an ICAP basis for the current resource mix) is found to maintain supply reliability across the studied range of resource plans and electrification scenarios.**

  The E3 Capacity Study, completed during the pre-IRP phase, confirmed that an ICAP PRM of 20 percent with Nova Scotia Power's current generation resources was within the range of PRM targets (17.8-21 percent) required to achieve the 1 day in 10 years loss of load criteria that Nova Scotia Power is required to meet. This range is equivalent to a 9 percentPRM on a UCAP basis (for additional detail on ICAP and UCAP methodologies please see Section 3.1.1). As recommended by the Consumer Advocate and other IRP participants, Nova Scotia Power used the effective capacity values and UCAP PRM requirements to constrain the capacity expansion models. After the initial portfolio study phase was completed, Nova Scotia Power engaged E3 to complete a Reliability Screening study of three initial resource plans (one at each level of electrification). This study confirmed that the three resource plans met the 1 day in 10 year reliability criteria through the end of the planning horizon (2045), and further that the indicated capacity surplus was relatively small in each case, indicating that the 9 percent UCAP criteria continues to be appropriate for planning purposes and that the resource plans developed during the IRP are reliable.

+ **4 The SDGA-compliant key scenario which minimizes the cumulative present value of the annual revenue requirement of the 25-year planning horizon (adjusted for end effects) is 2.0C (Low Electrification / Base DSM / Net Zero 2050 / Regional Integration).**

- **4a During the Action Plan 5-year horizon, resource plans 2.0C and 2.1C (among others) include many common resource investments and retirement trajectories. This commonality informs NS Power's IRP Action Plan and ensures the resulting long-term electricity strategy is robust to a broad range of potential futures.**

  One of the objectives of Nova Scotia Power's IRP is to produce a robust long-term electricity strategy that can withstand realistic potential changes to key assumptions. By developing an Action Plan and Roadmap which are informed by a range of key scenarios, Nova Scotia Power is in part assuring that multiple potential futures are considered during the Action Plan horizon and that no regrets options are prioritized.

- **4b Similar resource plans are selected when considering both 2030 and 2040 coal unit retirement dates. The earlier retirement scenarios are less economic on an NPV basis but have similar cumulative rate implications by 2045.**

  Nova Scotia Power has modeled both 2040 mandatory coal retirements (2.X scenarios) and 2030 mandatory coal retirements (3.X scenarios). The IRP modeling results indicate that the 2030 scenarios are higher cost on an NPV basis and on a relative rate comparison basis than the 2040 scenarios, but that they have lower GHG emissions over the planning horizon due to the earlier coal retirements. The lowest cost resource strategy by 2045 is robust to either retirement date, indicating that Regional Integration strategy is preferred and a no regrets option. This observation indicates that Nova Scotia Power should continue to monitor for external factors that could influence coal retirement dates or provide opportunities to reduce the cost and relative rate gap between 2040 and 2030 coal retirement scenarios.

7.2 Action Plan

As set out in the IRP Terms of Reference, The IRP Action Plan describes the key tasks to be undertaken in the next five years to implement the long-term electricity strategy. These Action Plan items are built on the items identified as Key Findings, and further informed by the modeling results and observations.

+ 1 Develop a Regional Integration Strategy to provide access to firm capacity and low carbon energy while increasing the reliability of Nova Scotia's interconnection with North America. This Strategy will include:

- 1a Identifying opportunities for near term firm imports over existing transmission infrastructure
- 1b Immediately commencing the development of a Reliability Tie and Regional Interconnection via an appropriate regulatory process with target in-service dates as follows:
  - Reliability Tie: 2025-2029 (or earlier if practical and feasible)
  - Regional Interconnection: 2027-2035

- 1c In parallel with Regional Interconnection development, and working with neighbouring jurisdictions, conducting detailed engineering and economic studies for firm import options requiring new transmission investment and strengthened regional interconnections, including evaluations of availability and security of supply, emissions intensity, and dispatch flexibility.

+ 2 Electrification is a key variable in this IRP and results indicate that under economic resource plans it can support provincial decarbonization while reducing upward pressure on electricity rates for customers. NS Power proposes several Action Plan items from this IRP related to electrification:

- 2a Initiate an Electrification Strategy to understand options for encouraging beneficial electrification with the goals of maintaining rate stability while decarbonizing the Nova Scotia economy consistent with the Sustainable Development Goals Act.
- 2b Initiate a program to collect detailed data, including data on the quantity, flexibility and hourly load shape of incremental electrification demand, to assist with further system planning work.
- 2c Address electrification impacts on the Transmission & Distribution system as additional experience and data become available.

+ 3.0 Initiate a Thermal Plant Retirement, Redevelopment and Replacement Plan including:

- 3a Develop a plan for the retirement and replacement of Trenton 5, targeting 2023, while identifying required replacement capacity and energy in parallel. Begin decommissioning studies for NS Power's other coal assets and develop and execute a coal retirement plan including associated regulatory approval process; this coal retirement plan will include significant engagement with affected employees and communities.
- 3b Complete a thermal plant Depreciation Study to update depreciation rates and a recovery strategy to better align depreciation with updated useful lives for generation assets. Invest sustaining capital into individual thermal units appropriate to their retirement categorization.

- 3c Develop a plan for the redevelopment or replacement of existing natural gas-powered steam turbines to provide low-cost, fast-acting generating capacity to the Nova Scotia system. Fuel flexibility is a component of this work, including consideration for low/zero carbon alternative fuels.

- 3d Initiate a wind procurement strategy, targeting 50-100 MW new installed capacity by 2025 and up to 350 MW by 2030. This strategy will solicit Nova Scotia-based market pricing information which will inform the selected wind capacity profile and timing, informed by the IRP wind sensitivities.

  In parallel with other elements of the wind procurement strategy, complete system stability studies to determine whether additional dynamic system inertia constraints, operating limits, and/or provision of alternate services like Fast Frequency Response (FFR), are required to enable higher levels of wind integration on the Nova Scotia system, particularly in advance of the commissioning of integration measures such as the Reliability Tie.

+ 4 Create a Demand Response Strategy targeting 75 MW of capacity, for deployment by 2025. Available resource cost, flexibility, and reliability may inform pursuit of additional Demand Response capability.

- 4a The strategy will be closely linked to the Electrification Strategy being developed in parallel. The strategy will build on learnings from NS Power's Smart Grid Project, NS Power's Time Varying Pricing application, the DR Joint Working Group between NS Power and Efficiency One, the ELIADC tariff, and the Large Industrial Interruptible Rider.

+ 5 NS Power will calculate Avoided Costs of DSM (capacity and energy) for scenarios 2.0C and 2.1C. 2.0C will be used as the Reference Plan and 2.1C will be available for additional reference.

7.3 Roadmap

As described in the IRP Terms of Reference, the IRP Roadmap is designed to identify signposts to monitor and decision gates to be addressed in order to enable the appropriate triggering of changes to the

Strategy, based on future changes in the planning environment. Nova Scotia Power has developed the following Roadmap items to establish variables in the planning environment to be monitored in order to understand when portions of the long-term Strategy require refinement or re-examination. Some of the Roadmap items identified will require Nova Scotia Power to undertake additional work or studies during the Action Plan period, in order to determine the outcome of the uncertain variable.

+ 1 Advance engineering study work on coal to gas conversions at Trenton and Point Tupper Generating Stations. Monitor cost outputs of this work relative to IRP assumptions and update the balance of new and converted capacity resources accordingly.

+ 2 Complete detailed system stability studies under various current and future system conditions, reflective of both stressed system states and normal operating conditions, while considering higher quantities of installed wind capacity as seen in the IRP modeling results. This work will also consider the impacts of grid service provision from inverter-based generators (such as wind turbines) and how the introduction of new ancillary services like Fast Frequency Response might affect existing services such as Synchronized Inertia. Monitor results for significant divergence from wind integration assumptions modeled in the IRP and trigger an update as needed.

+ 3 Pursue economic reinvestment in existing hydro and combustion turbines with individual capital applications as applicable; economic justification as part of a capital application will be required to confirm decision to pursue Mersey hydro redevelopment. Continue sustaining capital investment in thermal units, aligned with their projected retirement classification. Monitor required levels of sustaining capital investment for significant changes from IRP assumptions and, if observed, trigger a unit-specific analysis of alternatives. Monitor unit reliability for significant changes from IRP assumptions and, if observed, trigger an ELCC calculation and/or PRM study as required.

+ 4 Monitor the development of low/zero carbon fuels that could replace natural gas in powering generating units to provide firm, in-province capacity.

+ 5 Continue to track the installed costs of wind, solar, and energy storage to look for variations from the trajectories established in the IRP (in particular, monitoring for divergence from the “Base” to the “Low” pricing scenarios). NS Power will solicit Nova Scotia-based market information which will inform this as needed.

+ 6 Track the ongoing development of the Nova Scotia Cap-and-Trade Program, including auction results and developing regulations. In particular, monitor GHG market size for indications that value from incremental allowance sales (beyond the projected economic emissions reductions shown in the IRP results) can be incorporated into long-term resource planning decisions with greater certainty. Significant changes in the value of incremental GHG reductions could influence resource plan components including non-emitting generation procurement, DSM levels, and coal retirement trajectories.

+ 7 Monitor electrification growth in Nova Scotia to understand at what point the provincial load profile starts to move from Low, to Mid, to High levels of electrification. An observed transition will, among other impacts, inform the use of DSM avoided costs in related proceedings and trigger a PRM study using actual peak, energy, and load shape data.

+ 8 Continuously refine the Action Plan and Roadmap items via an evergreen IRP process. This process should facilitate annual updates as conditions change and technology or market options develop, and as Action Plan items are completed. NS Power will include a summary of updates as part of IRP Action Plan reporting.

Appendices

Appendices will be attached with the IRP Final Report; links have been provided in footnotes above to materials currently available on the IRP website for the purposes of reviewing the IRP Draft Report.