Beyond the Coal Phase-Out:
Evaluating the Potential of Long-Duration Energy Storage in Nova Scotia's Clean Energy Transition

Technical Report

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Executive Summary

This report evaluates the potential of long-duration energy storage (LDES) to enable a deeply decarbonized electricity system for Nova Scotia. Through comprehensive technology assessment and advanced power system modeling, we examine how LDES could support the province's clean energy transition beyond the 2030 coal phase-out toward a net-zero emissions grid by 2050.

Study Context and Motivation

Nova Scotia's electricity sector faces an urgent transformation challenge. Currently relying on fossil fuels for 48% of its generation, the province must phase out all coal-fired generation and achieve 80% renewable electricity by 2030 to meet federal and provincial mandates. This transition requires new approaches to maintain reliability as the province shifts from dispatchable fossil generation to variable renewable energy (VRE), such as wind and solar.

The province operates a relatively small electricity grid with limited interconnections to neighboring systems. As more VRE sources come online, maintaining supply continuity during periods of low wind or limited sunlight poses significant challenges under current infrastructure. Traditional battery energy storage systems (1-4 hours duration) can manage short fluctuations but will not suffice for multi-day renewable shortfalls or seasonal demand variations.

This study investigates whether LDES—defined as storage systems capable of discharging electricity for 10+ hours—could provide a cost-effective solution to bridge these gaps and enable deeper decarbonization.

Methodology and Approach

Our analysis employs a two-part framework:

Part I: Technology Screening and Evaluation

We assessed six LDES technologies across performance characteristics, economic parameters, geographical constraints, and deployment readiness. Technologies evaluated include pumped storage, adiabatic compressed air energy storage, hydrogen storage, lithium-ion batteries, sodium-ion batteries, and vanadium redox flow batteries.

Part II: Power System Modeling

Using an hourly-resolution capacity expansion model tailored to Nova Scotia's electricity system, we analyzed how different LDES technologies would perform within the province's grid from 2025-2050. Our model incorporates:

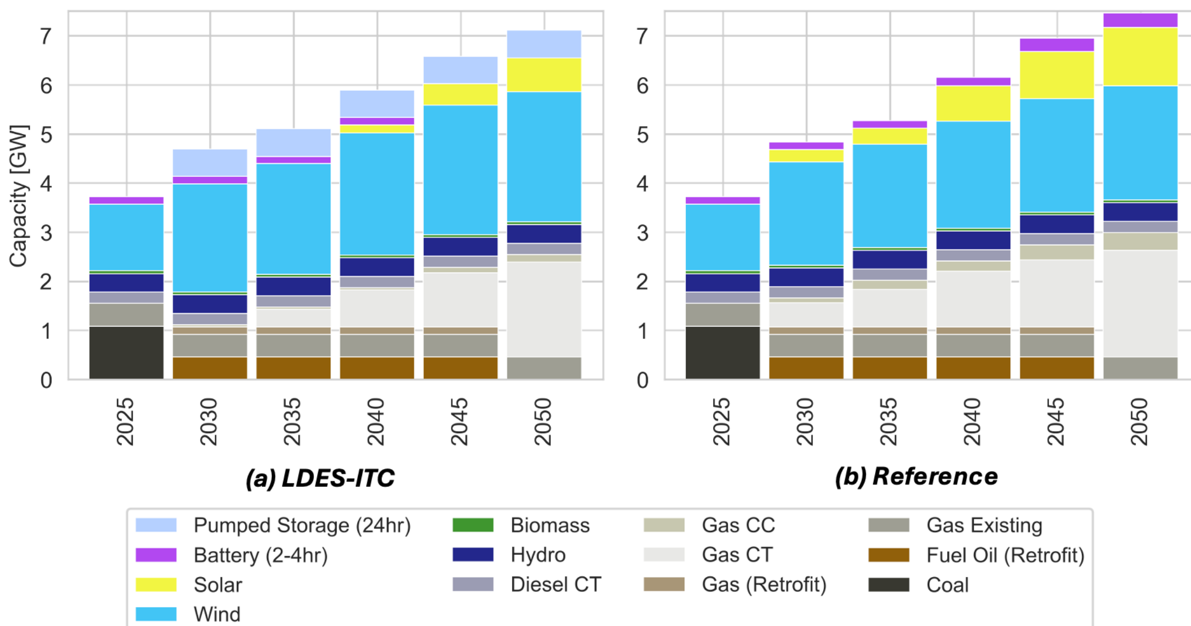
- Nova Scotia-specific VRE generation profiles
- Provincial load forecasts including electrification trends
- Detailed representation of existing and potential new resources, including LDES technologies
- Grid integration constraints based on system stability requirements
- Current and forthcoming policy mandates
- Economic parameters including federal investment tax credits

We compared three primary scenarios: an 'LDES-ITC' case that allows LDES deployment, a 'Reference' case that does not allow LDES deployment, and a sensitivity case examining deployment without the incentive of the federal investment tax credits.

Key Findings

1. Optimal Technology and Deployment Strategy

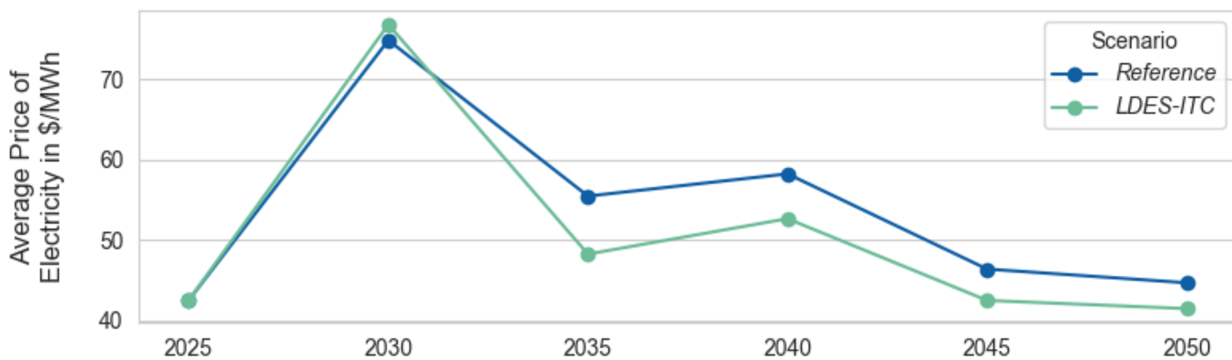
Among all LDES options evaluated, 24-hour pumped storage emerges as the most economically viable LDES solution for Nova Scotia. The model selects 560 MW / 13,440 MWh of pumped storage capacity deployed at two sites (Cape Breton Highlands and near Parrsboro) by 2030 in the LDES-ITC scenario. In the absence of LDES availability, the Reference scenario expands the province's battery capacity.



Optimal capacity mix for the scenarios allowing (a) and prohibiting (b) LDES deployment.

2. Economic Benefits

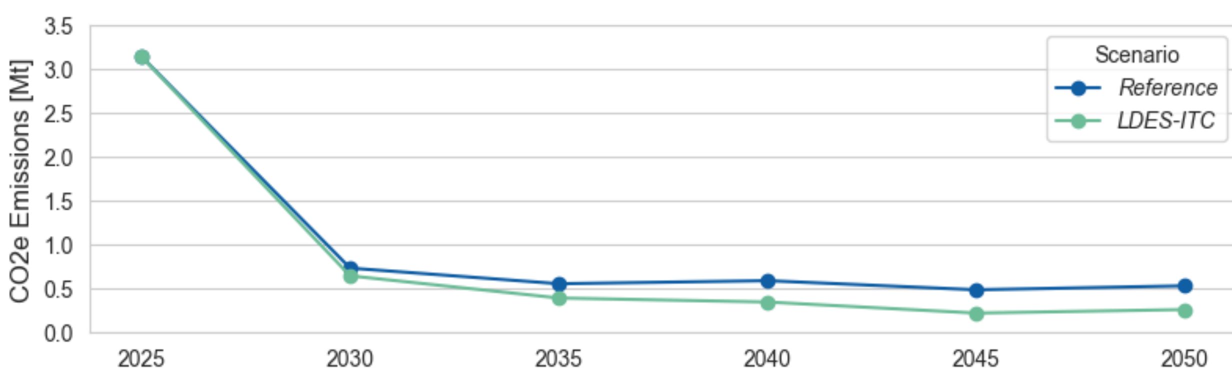
Incorporating LDES reduces the net present value of total system costs (2025-2050) by 5.8% compared to the Reference scenario. On a per-MWh basis, the total system cost drops from approximately $42.99/MWh to $40.52/MWh. LDES also leads to lower wholesale power prices after 2030, benefiting consumers through reduced price volatility.



Average wholesale electricity prices across the two modelled scenarios.

3. Emissions Reduction

LDES enables a 55% reduction in post-2030 carbon emissions compared to the Reference case. By allowing renewable resources to meet a larger share of electricity demand, including during periods that would otherwise require gas generation, LDES substantially improves emissions performance.



Annual power sector CO2e emissions across the two modelled scenarios.

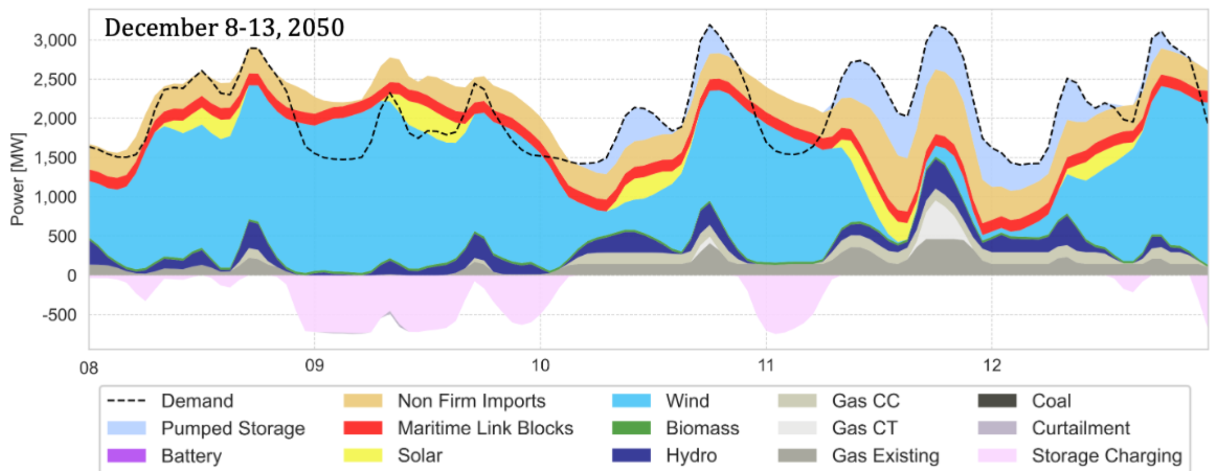
4. Renewable Integration

Compared to the Reference scenario, LDES significantly increases wind power deployment. Nova Scotia possesses world-class wind resources, and LDES creates favorable conditions for large-scale implementation. LDES deployment results in 13% higher wind and solar generation relative to the Reference case while substantially improving renewable utilization by reducing curtailment. By 2040, the LDES-ITC scenario achieves 7.5% renewable curtailment versus 14.4% in the Reference case. Additionally, LDES facilitates cost-effective investment in grid stabilization equipment (synchronous condensers) that enables higher instantaneous renewable penetration

5. Operational Value

The model operates pumped storage through weekly cycles (approximately 75 full cycles annually), absorbing excess renewable generation during windy periods and discharging during multi-day low-wind events. This pattern confirms LDES can function effectively as a "shock absorber" for a renewables-dominated grid.

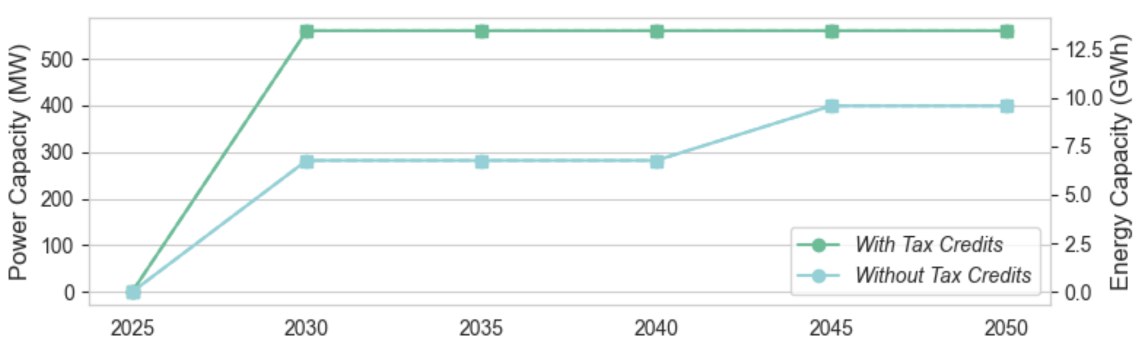
Importantly, LDES significantly reduces the frequency and magnitude of supply shortfalls but doesn't eliminate the need for some fast-response peaking capacity or imports during severe combination events of high demand and low renewable output.



Hourly dispatch for a sample December week in 2050.

6. Policy Sensitivity

Even without federal investment tax credits, LDES remains economically attractive, though with a more measured deployment trajectory. This finding indicates the fundamental value proposition of LDES is not dependent on particular incentive structures but derives from intrinsic system benefits.



Optimal LDES capacities with and without the federal Clean Technology Investment Tax Credit

Recommendations

Based on these findings, we recommend:

1. **Initiate Site-Specific Feasibility Studies** for the identified pumped storage locations to confirm technical viability and refine cost estimates.
2. **Establish Regulatory Frameworks** to compensate storage for its full range of services, including capacity value, renewable integration, and grid stabilization.
3. **Coordinate LDES and Renewable Development** to ensure complementary deployment timelines and maximize value.
4. **Develop Provincial Policy Support** given the long development timeline for pumped storage projects and the limited window for federal investment tax credits.
5. **Incorporate LDES in Grid Planning**, particularly regarding transmission and stability requirements for a high-renewable system.
6. **Maintain Alternative Deployment Strategies** in parallel with pumped storage development efforts, recognizing implementation challenges including environmental considerations, upfront capital requirements, and potential project risks. Should pumped storage prove unfeasible, lithium-ion batteries (up to 6-hour duration) represent the next-best alternative. While this approach would increase total system costs by approximately 5.8%, it offers advantages in deployment flexibility, scalability, and significantly reduced development timelines.

Conclusion

LDES—specifically pumped storage—represents not just a technical solution but an economically advantageous pathway toward a reliable, affordable, and deeply decarbonized electricity system for Nova Scotia. Strategic investments in LDES now can position the province to achieve its energy transition goals while maintaining system reliability and managing costs. The modular nature of battery alternatives provides a risk mitigation strategy that allows for incremental capacity additions capable of adapting to changing system needs and technology improvements, albeit at higher overall system costs.

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List of Acronyms

LDES	Long-Duration Energy Storage
VRE	Variable Renewable Energy
PS	Pumped Storage
ACAES	Adiabatic Compressed Air Energy Storage
LFP	Lithium-Ion Batteries
SI	Sodium-Ion Batteries
VRF	Vanadium Redox Flow Batteries
IRP	Integrated Resource Plan
H2	Hydrogen Storage
LCOS	Levelized Cost of Storage
WACC	Weighted Average Cost of Capital
OBPS	Output-Based Pricing System
RPS	Renewable Portfolio Standard
ITC	Investment Tax Credit
DSM	Demand Side Management
ELCC	Effective Load Carrying Capability

1 Introduction

1.1 Project Objectives and Team

This study aims to evaluate the potential of long-duration energy storage (LDES) in enabling a deeply decarbonized electricity system for Nova Scotia. The overarching objective is to determine how LDES technologies could support Nova Scotia's clean energy transition beyond the 2030 coal phase-out, up to a net-zero emissions electricity grid by 2050. This analysis focuses on techno-economic feasibility, including cost-effectiveness, technical performance, and grid integration potential, to inform investment and deployment decisions.

The project is led by Sutubra Research Inc., a consulting firm specializing in energy system research and optimization modelling, in collaboration with Dalhousie University's Renewable Energy Storage Laboratory. Key contributors include Cameron Wade of Sutubra Research and Dr. Lukas Swan and Nicholas Legge of Dalhousie University. Cameron Wade, founder and principal of Sutubra Research, provides expertise in power system modelling and analysis to clients across North America. Dr. Swan is a professor of Mechanical Engineering and is a leading expert in energy storage technologies and electric power systems. Nicholas Legge is an electrical engineering student at Dalhousie. The work is supported under the province of Nova Scotia and Net Zero Atlantic's Emerging Concepts and Technologies program, reflecting a partnership between academic, industry, and government stakeholders to explore innovative solutions for the province's energy sector.

1.2 Motivation and Research Questions

Nova Scotia's aggressive decarbonization targets and unique grid challenges motivate this study. The province is currently reliant on carbon-intensive generation, with 31% of electricity in 2023 coming from coal and 17% from natural gas [1]. Federal and provincial mandates require a complete coal phase-out by 2030 and 80% renewable electricity by that year, with the ultimate goal of net-zero emissions by 2050. Replacing such a large portion of baseload generation with variable renewable energy (VRE), such as wind and solar, in a small, relatively weakly interconnected electricity grid will require new strategies to maintain reliable supply.

Traditional battery energy storage systems (BESS) with durations of 1-4 hours can shift VRE output or address peak loads for a few hours, but will not suffice for multi-day renewable shortfalls or seasonal demand peaks. LDES, defined in this report as systems capable of discharging electricity at rated power for 10+ hours, has emerged as a promising solution to bridge these gaps. However, its role in Nova Scotia's context remains unclear.

This research addresses two key questions:

1. **What role can LDES play in decarbonizing Nova Scotia's electricity grid?** – We investigate how multi-day to seasonal storage could facilitate high levels of renewable integration and reduce reliance on fossil fuels or imported power.

2. **What are the economic and technical implications of deploying LDES?** – We assess cost-effectiveness under different scenarios, system cost impacts, and operational considerations that affect grid reliability.

By answering these questions, the study will inform policymakers and industry stakeholders about the feasibility and value of investing in LDES as part of Nova Scotia's clean energy transition strategy.

1.3 Report Structure and Approach

This report is organized into a background section followed by two complementary parts that systematically address the potential role of LDES technologies in Nova Scotia's energy transition.

Background: Information regarding Nova Scotia's present electricity sector is reviewed, and the impact of Federal and Provincial mandates on that sector over the coming decades is projected. LDES technologies are then briefly introduced and focused for the region of Nova Scotia. Finally, present energy modelling methods are considered, along with the limitations of modelling LDES in current power system planning models.

Part I: *Technology Screening and Evaluation*, provides a comprehensive examination of promising LDES technologies. We begin by cataloging and categorizing the diverse range of long-duration storage options, identifying six key technologies with potential applicability in Nova Scotia's context. For each technology, we conduct a detailed technical assessment, evaluating performance characteristics, economic parameters, geographical constraints, and deployment readiness. This section concludes with a comparative analysis that establishes the relative strengths and limitations of each storage option. This analysis provides a foundation for the modelling work that follows.

Part II: *Power System Modelling*, translates these technology assessments into a robust evaluation of how LDES can contribute to Nova Scotia's electricity system transformation. We employ advanced capacity expansion modelling at an hourly resolution to properly capture the temporal value of LDES. Using the technology parameters established in Part I, we analyze various deployment scenarios to determine the optimal role, timing, and scale of LDES integration. This analysis examines system impacts under different policy frameworks, resource mixes, and demand projections. It places particular focus on achieving the province's 2030 coal phase-out and renewable energy targets, as well as its longer-term net-zero aspirations.

Together, these complementary sections provide a comprehensive framework for understanding both the technological capabilities of LDES solutions and their practical value within Nova Scotia's evolving electricity landscape. This framework supports informed decision-making by policymakers and industry stakeholders.

2 Background

2.1 Nova Scotia's Electricity System and Decarbonization Goals

Nova Scotia's electricity sector is among the most carbon-intensive in Canada. Fossil fuels accounted for 48% of generation in 2023 (31% coal/petcoke, 17% natural gas), while renewables contributed 35% (primarily wind, hydro, and biomass) [1]. Despite progress since 2005—when 74% of generation came from coal—the province has struggled to meet legislated renewable targets and has faced penalties for non-compliance.

This continued reliance on coal and other fossil fuels has driven greenhouse gas emissions well above the national average on a per-kWh basis. In response to federal regulations and climate commitments, Nova Scotia has set ambitious goals to decarbonize its power supply. Federal and Provincial law now mandates that by 2030 the province:

- Phase out all coal-fired electricity generation.
- Achieve 80% of electricity generation from renewable sources.
- Reduce power-sector GHG emissions by more than 90% from 2005 levels.

By 2050 the province aspires to reach net-zero electricity sector emissions, in line with national targets. These goals are driving a major transition: aging coal plants are scheduled for retirement, and procurement of wind farms and other renewable projects is accelerating to meet the 2030 milestone.

However, this rapid transition poses significant challenges for grid reliability and integration, especially given Nova Scotia's geographic and electrical constraints. The province operates a relatively small and isolated grid with limited links to neighbouring systems. It is connected to New Brunswick and the broader Eastern Interconnection by a single 345 kV high-voltage alternating current (AC) transmission line[1], and to Newfoundland via a 500 MW high-voltage direct current (HVDC) undersea line (the Maritime Link). With only these two interconnections, the province cannot easily draw on external markets to balance variable renewable energy (VRE) output from sources like wind and solar.

At the same time, integrating a much higher share of renewable energy poses technical challenges on the local grid. As more VRE sources come online, maintaining a continuous supply during periods of low wind or limited sunlight will be difficult under the current infrastructure. Furthermore, replacing conventional thermal power plants with inverter-based resources (like wind and solar facilities that use power electronics instead of large spinning generators) raises concerns about maintaining grid frequency control, voltage support, and overall stability. Studies indicate that pushing toward 80% renewables by 2030 will significantly reduce the number of synchronous generators (traditional generators that rotate in sync with the grid), creating new hurdles for frequency regulation and system strength (the grid's ability to withstand disturbances and remain stable) [2]. Nova Scotia has already encountered issues integrating wind power, including forced curtailment of wind turbines

[1] Nova Scotia and New Brunswick are currently constructing the NS-NB Reliability Tie, a second 345 kV line between the two provinces. The reliability tie aims to allow increased wind integration in Nova Scotia and is not expected to significantly affect trade between the two provinces.

during low-demand periods and difficulties managing storm-related disruptions such as severe icing events. Moreover, electricity demand is expected to become more variable and uncertain as more end-use services—such as space heating and transportation—are electrified.

These factors underscore the need for flexible resources that can quickly respond to fluctuations in supply and demand to ensure reliability. Nova Scotia is already pursuing short-term measures like fast-ramping gas turbines, battery storage banks with 1–4-hour duration, and demand response programs. However, the province's clean energy plan will eventually require solutions for longer-duration balancing for managing multi-day lulls and seasonal fluctuations in renewable output.

2.2 Introduction to LDES Technologies

Long-duration energy storage refers to a class of energy storage systems capable of discharging electricity at rated power for extended periods—typically 10 hours or more, far beyond the 1–4 hour duration of today's utility-scale lithium-ion batteries. In practical terms, LDES includes technologies that can store large amounts of energy and release it steadily over many hours, days, or even weeks. This capability provides temporal flexibility to the grid, allowing surplus energy from times of high renewable production (for example, windy nights or summer solar peaks) to be saved and used later during periods of low generation or high demand. By decoupling generation and consumption over longer timescales, LDES can smooth out the intermittency of wind and solar resources. Additionally, LDES systems often have high power ratings, enabling them to effectively manage short-term grid fluctuations.

Key advantages of LDES over short-duration storage include the ability to prevent renewable curtailment during prolonged surplus periods and to maintain supply through multi-day weather events (e.g., several consecutive calm or overcast days) that might otherwise necessitate firing up fossil backup plants. Additionally, LDES systems provide firm capacity contributions, meaning they can be available at full output during critical peak demand periods or emergencies, thereby improving resource adequacy and resilience of a renewable-heavy grid.

A wide array of technologies fall under the LDES category, each at varying stages of maturity. Pumped hydro storage, which leverages gravitational potential energy by moving water between reservoirs, is the most established form of long-duration storage. It has been used for decades at scale; however. Nova Scotia's geography offers limited opportunities for new large pumped hydro facilities. Other mechanical storage options include compressed air energy storage (CAES), where surplus power is used to compress air (often in underground caverns) and later generate electricity via expansion; CAES plants can offer 8-24+ hours of storage, but they require suitable geology and have seen only a few prototype deployments globally.

Furthermore, thermal storage concepts, such as molten salt systems tied to concentrated solar power or newer ideas like storing heat for later electricity production, also qualify as LDES if they can supply power over long durations.

In recent years, the biggest advances have come in electrochemical and chemical LDES technologies beyond conventional lithium-ion batteries. Flow batteries (e.g., vanadium redox or zinc-bromine) store energy in liquid electrolytes and can be scaled up in energy capacity independently of power, targeting durations of 10–100 hours with moderate efficiency. Emerging battery chemistries like iron-air have received significant attention for their potential to provide extremely long discharge times at low cost—for instance, the U.S. startup Form Energy has developed an iron-air battery capable of approximately 100 hours of discharge. This technology is moving out of the lab into deployment; a 10 MW / 1,000 MWh (100-hour) pilot project was recently announced in Washington state to demonstrate multi-day grid storage using iron-air batteries [3]. Similarly, initiatives like the U.S. Department of Energy's Long Duration Storage Shot aim to reduce the cost of 10+ hour storage by 90% this decade, spurring commercialization of new solutions.

While some LDES technologies are already in limited use (e.g., small flow battery installations and the first compressed air and liquid air storage plants), many are still in the early demonstration or pre-commercial stage. As of now, their capital costs are relatively high and operational track records short, which has hindered widespread adoption. However, rapid innovation and supportive policies worldwide (such as government grants and capacity market incentives for long-duration projects) are helping to drive down costs and improve the performance of LDES. These trends suggest LDES technologies will move from pilot projects to integral components of electricity grids, providing services ranging from daily load shifting and renewable firming to seasonal energy shifting—a feature that could be especially valuable in a province like Nova Scotia with significant winter heating demand peaks and seasonal variations in wind resources.

2.3 Challenges in Modelling LDES in Power System Planning

Power system planning models, commonly known as capacity expansion models (CEMs), are computational tools used by utilities and policymakers to determine the optimal mix of generation, transmission, and storage resources needed to meet future electricity demand. These models typically minimize total system costs (capital and operational) while satisfying reliability constraints and policy targets such as emissions limits. By simulating both investment decisions (what to build and when) and operational decisions (how to dispatch resources), CEMs provide insights into how electricity systems should evolve over planning horizons spanning decades. Traditional CEMs were designed for systems dominated by dispatchable fossil fuel generators, where operational constraints were relatively simple and resource availability was predictable.

Integrating LDES into long-term power system planning models is a complex task, and such resources have traditionally been underrepresented in capacity expansion studies. Computational constraints force these models to make significant abstractions in how they represent time, space, and power system physics. Most notably, rather than modelling all 8,760 hours in a year chronologically, capacity expansion models typically sample only a small set of representative days (12-20 days per year) to keep calculations tractable when optimizing investments and dispatch over multi-decade horizons. This temporal abstraction fundamentally disrupts the chronological relationship between consecutive days, making it impossible to capture multi-day weather patterns or extended renewable energy droughts. Without the ability to model the sequential nature of time, storage devices in these models cannot carry surplus energy from one representative day to another several days later—effectively preventing the model from recognizing the core value proposition of LDES. The models also fail to capture short-term service benefits that LDES can provide, such as regulation and ramp-rate compensation, as these happen at very high timestep resolutions. Additionally, inter-temporal constraints (like maintaining state-of-charge continuity across long periods) increase mathematical complexity, especially for longer durations. These limitations often lead models to undervalue or entirely omit LDES contributions, suggesting investments in long-duration storage are uneconomic when, in reality, the limitation lies in the modelling approach itself rather than the technology's actual merit.

Because of these methodological challenges, LDES has often been omitted or undervalued in resource plans, and there is growing recognition in the research community that new modelling techniques are needed. Recent studies highlight that a failure to properly represent LDES can lead to suboptimal or misleading decarbonization strategies. For example, research has shown that without improved temporal detail, models will underestimate the role of multi-day storage and show much higher system costs to achieve deep emissions cuts than are necessary [4]. In other words, if the model "forgets" that a week-long wind lull can be mitigated by stored energy from previous days, it might over-build peaking gas plants or overestimate curtailment, skewing the optimal capacity mix.

Another study similarly argues that many existing capacity expansion models were designed for legacy grids and are not equipped for high-storage, high-renewable scenarios [5]. As a result, they risk recommending grids that are either more expensive or less reliable than intended. Their review of the literature calls for better modelling frameworks that capture the full value stream of storage—from arbitraging energy over time to providing capacity and ancillary services—in order to guide investment decisions and policy. Some improvements are already underway: researchers are testing methods like linked representative periods (where consecutive days are connected in the model to allow energy carry-over) and advanced solvers to handle finer time resolution without grossly increasing computational requirements [6]. Open-source tools (for instance, the *GenX* [7] and *PyPSA* [8] planning models) are incorporating these best practices to better model long-duration storage.

Nonetheless, significant gaps remain in our ability to fully simulate LDES in large-scale planning. Capturing seasonal storage behavior may require modelling the grid over multiple years of weather data, and accounting for uncertainty (e.g., year-to-year hydro inflows or extreme events) is an additional challenge. This study takes these complexities into account by adopting state-of-the-art modelling techniques drawn from the latest research, ensuring that LDES options are treated with an appropriate level of detail in scenario analyses. By doing so, we aim to provide a more realistic assessment of LDES potential in Nova Scotia—one that acknowledges modelling limitations and addresses them—thereby offering actionable insights for planners on how long-duration storage could fit into the province's future grid.

Recent research has increasingly recognized the importance of long-duration energy storage in deeply decarbonized grids. Jenkins and Sepulveda emphasize that while short-duration storage can manage daily fluctuations, LDES is necessary to cover prolonged renewable shortfalls, especially in systems targeting near-zero emissions [9]. Dowling et al. found that LDES significantly reduces system costs in high-renewable grids, particularly when modeled over multi-year horizons to capture seasonal variability [10]. Meanwhile, studies from Li et al. [11] and Staadecker et al. [12] have demonstrated that LDES can substitute for firm generation when integrated strategically, with the cost-effectiveness of different storage technologies varying by regional resource availability. Additionally, recent California-based modelling efforts have explored how LDES can complement grid flexibility as fossil fuel generators retire, highlighting both opportunities and challenges in implementation [13]. By building upon these insights, this study contributes a novel perspective by applying high-resolution modelling techniques to assess the role of LDES in Nova Scotia's specific regulatory, technical, and geographic context.

Part I: Technology Screening and Evaluation

3 Long-Duration Energy Storage Technology Overview

Long-duration energy storage encompasses a diverse portfolio of technologies, each operating on distinct principles and at varying stages of commercial maturity. To systematically evaluate these options, we categorize LDES technologies into four fundamental classes—mechanical, chemical, electrochemical, and thermal—based on their underlying energy conversion and storage mechanisms.

While numerous LDES concepts exist in literature and early demonstration projects, this study focuses on technologies with meaningful potential for implementation in Nova Scotia. Through an initial screening process, we identified six promising technologies for detailed assessment, excluding options that presented fundamental limitations for the province's context.

Several technologies were deliberately omitted from our analysis. Emerging gravity-based systems that utilize stacked concrete blocks or similar mechanical arrangements were excluded due to their relatively low energy density and mechanical complexity. Power-to-fuel pathways producing synthetic fuels such as methanol or ammonia were set aside given their significant conversion losses and dependence on external markets for utilization. Similarly, early-stage technologies like iron-based flow batteries and certain thermal storage approaches (using molten salt or solid media) did not advance to detailed evaluation due to efficiency limitations and their pre-commercial development status.

The six LDES technologies selected for comprehensive assessment offer complementary characteristics across key parameters including discharge duration, round-trip efficiency, siting flexibility, and deployment readiness. These technologies, detailed in the following sections, provide a foundation for evaluating how long-duration storage could contribute to Nova Scotia's evolving electricity system.

3.1 Mechanical Storage – Pumped Hydro and Adiabatic CAES

3.1.1 Pumped Storage (PS)

Technology Overview: Pumped hydroelectric storage is a well established and widely deployed form of long-duration energy storage globally. The technology has demonstrated commercial viability for decades, with approximately 270 operational facilities worldwide providing approximately 160 GW of power capacity and collectively storing around 9,000 GWh of energy [14]. Typical facilities can sustain generation for more than two days, with an average discharge duration of approximately 56 hours at full capacity [15].

The fundamental operating principle of pumped storage involves two water reservoirs positioned at different elevations, connected through a reversible hydroelectric system. During periods of surplus electricity generation—such as nighttime hours with high wind production—the system operates in pumping mode, moving water from the lower to the upper reservoir and effectively converting electrical energy into gravitational potential energy. When electricity demand exceeds available generation, the system reverses: water flows downward through hydraulic turbines, generating electricity to supply the grid. This closed hydraulic circuit functions as a highly scalable energy storage system, with the reservoirs serving as the energy storage medium and the pump-turbine equipment controlling power conversion. Figure 1 illustrates a typical configuration[2].

Pumped storage facilities are distinguished by their substantial scale, long operational lifespans, and proven reliability. Projects typically deliver hundreds of megawatts of power capacity with energy storage durations determined primarily by reservoir volumes. Once constructed, these facilities can operate for 50-60 years or longer—significantly exceeding the service life of most alternative storage technologies. Modern pumped storage systems achieve round-trip efficiencies of approximately 75%, with energy losses occurring primarily through hydraulic friction and motor-pump and turbine-generator conversion efficiencies.

A defining characteristic of pumped storage is its strict geographical requirements. Viable development demands sites with significant elevation differential—typically 100 meters or greater—and suitable locations for both upper and lower reservoirs. The lower reservoir presents particular challenges, often requiring either an existing natural depression or substantial excavation work. Each potential site necessitates careful evaluation of environmental impacts, including ecosystem disruption, water quality considerations, and habitat alterations.

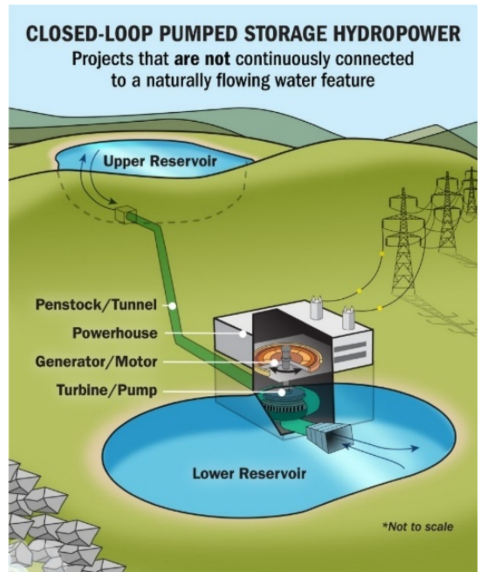

Figure 1: Diagram of closed loop PS

In Nova Scotia's coastal context, utilizing the ocean as a lower reservoir generally proves impractical due to multiple technical constraints, including saltwater intrusion into freshwater systems, accelerated equipment corrosion, and heightened ecological concerns in sensitive marine environments. Nevertheless, the province's topography features areas with moderate elevation changes and numerous existing lakes or reservoirs that could potentially support pumped storage development. These geographical features suggest pumped storage remains technically viable within Nova Scotia, albeit requiring meticulous site selection, extensive civil engineering, and substantial upfront capital investment.

Pumped storage technology enjoys widespread global deployment with a well-established operational track record. If suitable sites can be identified, this technology could provide Nova Scotia with reliable, long-duration energy storage capacity while simultaneously supporting grid stability through ancillary services such as frequency regulation and voltage support.

Example Project: TC Energy's proposed pumped storage facility in Meaford, Ontario offers a valuable Canadian reference point for understanding contemporary pumped storage development. This large-scale project, presently in the pre-development stage, will have 1,000 MW power capacity and 8,000 MWh energy storage capability, would create a closed-loop system between a purpose-built upper reservoir and Georgian Bay, utilizing approximately 210 meters of elevation difference.

[2] Closed Loop PS [Digital Image]. U.S. Department of Energy. https://www.energy.gov/eere/water/pumped-storage-hydropower

With an estimated capital investment of CAD $3.3 billion, the project's projected emissions reduction of approximately 0.5 megatonnes annually demonstrates the potential contribution of pumped storage to decarbonization efforts at the provincial scale [16]. Figure 2 illustrates a proposed layout for the facility[3].

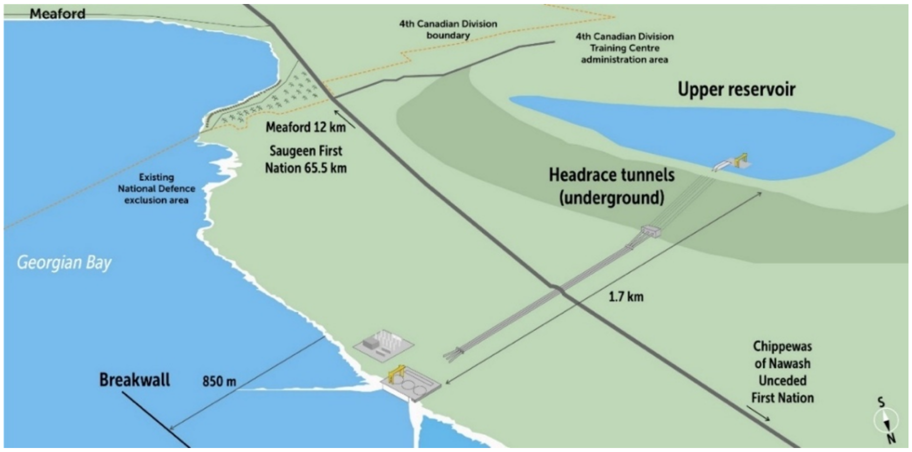

Figure 2: Site map of the proposed Meaford pumped storage facility

3.1.2 Adiabatic Compressed Air Energy Storage (ACA)

Adiabatic Compressed Air Energy Storage is a mechanical storage approach that leverages the potential energy of pressurized air without requiring fossil fuel combustion. During the charging process, surplus electricity drives industrial compressors that inject high-pressure air into sealed underground caverns—typically formed within salt formations. A distinguishing feature of the adiabatic design is its thermal management system, which captures and preserves the substantial heat generated during air compression. This thermal energy is maintained in dedicated thermal storage media, preventing efficiency losses that would otherwise occur through heat dissipation, or require heat addition by natural gas or other similar fossil fuel sources. During discharge operations, the system reintroduces this stored heat to the air as it expands through turbine generators, producing electricity [17]. Figure 3 illustrates a flow diagram of the power in to power out process[4].

ACA facilities can provide extended discharge durations ranging from 8 to 24+ hours depending on cavern volume, positioning the technology firmly within the long-duration storage category. While still in the early deployment phase, ACA has advanced significantly beyond initial demonstration projects. Hydrostor, a Toronto-based company, exemplifies this progression through its development pipeline, which includes a 500 MW / 8,000 MWh (16-hour) facility in Ontario targeted for commercial operation by 2028 [18]. This large-scale project builds upon operational experience gained from their 1.75 MW / 10+ MWh Goderich demonstration facility, photographed in Figure 4[5]. The company is simultaneously advancing international projects, including a 200 MW / 1,600 MWh system in Australia and a 500 MW / 4,000 MWh installation in California.

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[3] Shawn Parkinson [Digital Image]. The Narwhal. https://thenarwhal.ca/ontario-pumped-storage-projects/
[4] Adiabatic Compressed Air Energy Storage. [Digital Image]. European Association for Storage of Energy. https://ease-storage.eu/wp-content/uploads/2016/03/EASE_TD_ACAES.pdf
[5] Goderich Energy Storage. [Photograph]. Hydrostor. https://hydrostor.ca/projects/the-goderich-a-caes-facility/

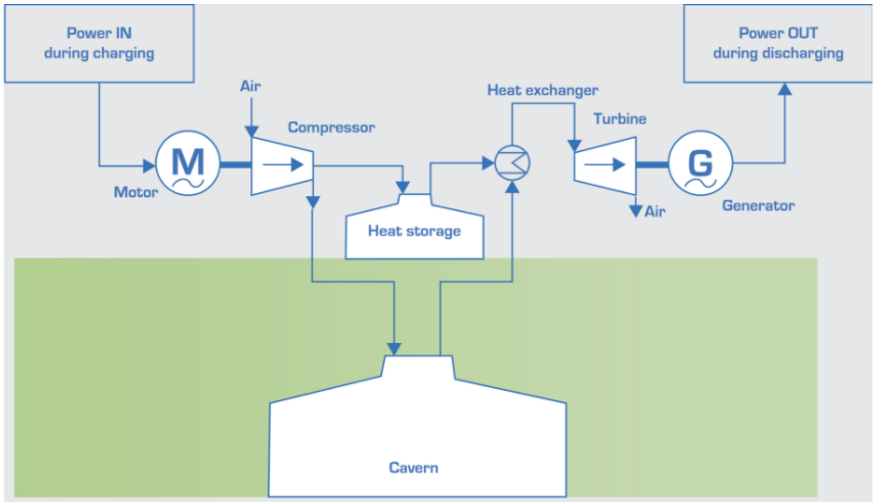

Figure 3: Schematic of ACA energy storage

The technology achieves moderate round-trip efficiency—approximately 55%—reflecting thermodynamic limitations inherent to compression and expansion processes, though it operates with zero direct emissions during operation. Notably, Nova Scotia's geological characteristics present particularly favorable conditions for ACA implementation. The province contains extensive salt deposits suitable for solution mining to create the underground caverns necessary for air storage. Significant salt dome formations exist throughout the region, with notable concentrations in the Windsor Basin and along the North Shore, featuring documented formations exceeding 200 meters in depth with substantial horizontal dimensions.

Figure 4: Hydrostor Goderich ACA demonstration facility

The province has previous experience with underground salt cavern development through the Alton Natural Gas Storage project, which received regulatory approval in 2007 for creating natural gas storage caverns near the Shubenacadie River. Although this project was ultimately discontinued in 2022 following sustained community opposition, it established the technical viability of developing such geological structures in Nova Scotia [19]. This precedent highlights an important consideration: while the province's subsurface conditions can physically accommodate CAES infrastructure, navigating regulatory requirements and securing social acceptance remain essential factors for successful project implementation.

3.2 Chemical Storage – Hydrogen Energy Storage

3.2.1 Hydrogen Storage (H2)

Hydrogen energy storage represents a chemical pathway for long-duration storage that leverages the conversion of electrical energy into hydrogen as an energy carrier. In a complete hydrogen storage system, surplus renewable electricity powers electrolysers that split water molecules into hydrogen and oxygen through electrolysis. The produced hydrogen can then be compressed and stored—either in pressurized vessels for shorter durations or in underground salt caverns for multi-day to seasonal applications. During periods of electricity demand, the system operates in reverse, with the stored hydrogen converted back to electricity through fuel cells or hydrogen-capable turbines, producing only water vapor as a byproduct [20]. Figure 5 serves as a visualization for the process of hydrogen energy storage[6].

For analytical consistency throughout this report, we evaluate hydrogen storage systems configured with underground salt cavern storage and fuel cell reconversion technology. This configuration aligns with established cost and performance benchmarks in current literature and enables meaningful comparisons with other LDES technologies. Our assessment considers the complete energy pathway from electricity input to electricity output, encompassing all major system components: electrolysers, compression equipment, underground storage infrastructure, and fuel cell arrays.

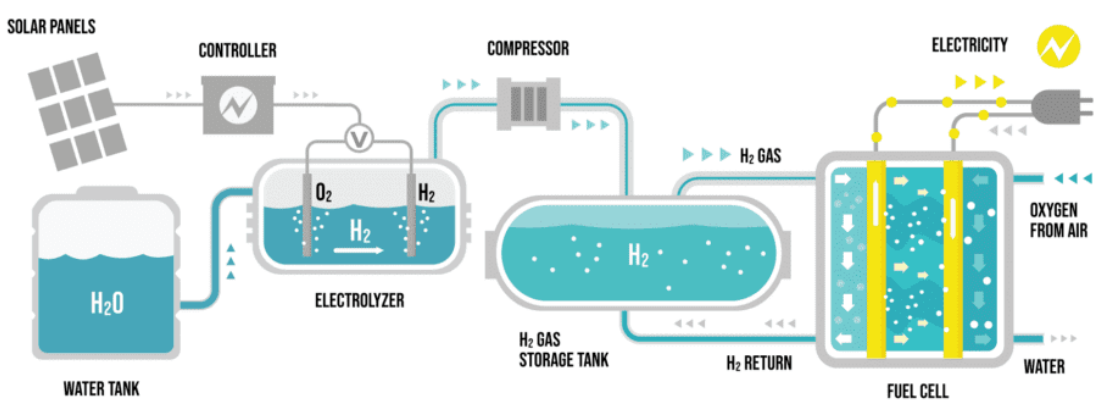

Figure 5: Schematic of a hydrogen energy storage system

Hydrogen storage offers a distinctive advantage in its capacity for extended duration storage. Once produced and compressed, hydrogen can remain in storage for weeks, months, or potentially years with minimal degradation, constrained primarily by the available cavern volume rather than self-discharge limitations. This characteristic, along with substantially higher energy density than ACA,

[6] Green Hydrogen Fuel Cell Energy. [Digital Image]. Totalshield. https://totalshield.com/blog/electrolyzer-and-hydrogen-fuel-cell-safety/

positions hydrogen as a uniquely suited option for addressing seasonal energy imbalances. Furthermore, expanding storage capacity requires only additional cavern development, providing a scalable approach to increasing energy capacity without proportional increases in conversion equipment.

The primary limitation of hydrogen energy storage lies in its round-trip efficiency. The sequential energy conversions—from electricity to hydrogen via electrolysis, compression for storage, and reconversion through fuel cells—result in cumulative losses that yield overall system efficiencies of approximately 30-40%. Despite this efficiency challenge, significant commercial momentum is building behind large-scale hydrogen storage initiatives. The Advanced Clean Energy Storage Delta project in Utah exemplifies this development trajectory. This pioneering facility will integrate 220 MW of electrolysis capacity with two substantial salt caverns, collectively capable of storing approximately 300 GWh of green hydrogen. The stored hydrogen will supply an 840 MW combined-cycle power plant, demonstrating grid-scale hydrogen storage feasibility. The project, scheduled to commence operations in 2025, secured a $504 million loan guarantee from the U.S. Department of Energy, indicating growing institutional confidence in hydrogen's role in long-duration energy storage [21]. Figure 6 shows a visual rendering of the facility[7].

Figure 6: Rendering of Utah's advanced clean energy storage delta project

3.3 Electrochemical Storage – Lithium-Ion, Sodium-Ion, and Flow Batteries

3.3.1 Lithium-Ion (LFP) Batteries

Lithium-ion battery technology has established itself as the predominant solution for short-duration energy storage applications and is increasingly being deployed for extended durations. Among various lithium-ion chemistries, lithium iron phosphate (LFP) has emerged as the preferred variant for grid-scale installations due to its superior thermal stability characteristics, elimination of cobalt from its material composition, and more favorable cost structure compared to alternative formulations.

[7] Advanced Clean Energy Storage I. [Digital Rendering]. Mitsubishi Power Americas. https://www.energy-storage.news/department-of-energy-confirms-us504-million-loan-to-300gwh-utah-hydrogen-energy-storage-hub/

The fundamental operating mechanism of LFP batteries relies on lithium-ion intercalation processes. During charging operations, lithium ions migrate from the iron phosphate cathode and insert themselves into a graphite-based anode structure, effectively storing energy within the resulting chemical potential. Upon discharge, this process reverses as ions transfer back to the cathode, releasing the stored energy as an electrical current. This self-contained electrochemical system achieves exceptional round-trip efficiency—typically 85-90%—while providing the rapid response capabilities essential for dynamic grid management applications [22].

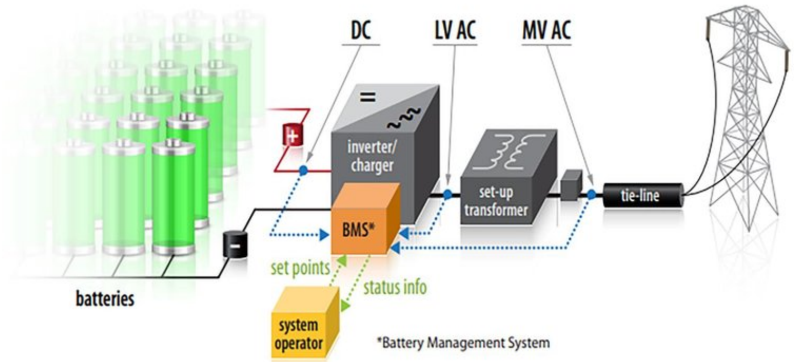

Figure 7: LFP battery energy storage process

LFP storage systems offer significant deployment flexibility through their modular design architecture, which allows installation at virtually any location with suitable environmental protection and grid interconnection capability, enabling strategic placement of storage resources throughout the network. However, a fundamental constraint for long-duration applications emerges from the technology's inherent energy-to-power characteristics. Conventional lithium-ion systems are optimized for discharge durations of approximately 4-6 hours at rated capacity; extending this duration necessitates proportional increases in battery modules, and may become economically prohibitive beyond 8-10 hours of storage capacity as the power capability is no longer fully utilized. Furthermore, LFP systems typically exhibit shorter operational lifespans than mechanical storage alternatives, with expected service periods of 15-20 years or several thousand complete charge-discharge cycles (so 15-30 years) before requiring substantial refurbishment. Figure 7 visualizes the process of using LFP batteries for grid-scale energy storage[8].

While lithium-ion technology currently faces economic challenges for extended duration applications, ongoing research and manufacturing advances continue to drive substantial cost improvements. The National Renewable Energy Laboratory's Annual Technology Baseline [23]—a reference dataset utilized by Nova Scotia Power in its Integrated Resource Plan modelling—projects significant reductions in lithium-ion energy storage costs. Under moderate-case scenarios, the analysis anticipates a 21% reduction in unit energy capacity costs by 2030, expanding to a 49% reduction by 2050, relative to 2025 baseline values. As these technological advancements and

[8] Representation of Lithium-ion Battery Energy Storage. [Digital Image]. https://doi.org/10.1016/j.est.2022.104018

manufacturing efficiencies continue to materialize, the economic feasibility of longer-duration lithium-ion storage may progressively improve.

3.3.2 Sodium-Ion (SI) Batteries

Sodium-ion battery technology operates on electrochemical principles similar to lithium-ion systems, utilizing the movement of ions between electrode materials to store and release energy. The fundamental distinction lies in the use of sodium ions (Na^+) rather than lithium ions as the charge carrier, with electrode chemistries specifically engineered for sodium intercalation. This alternative chemistry presents potential advantages in resource availability and manufacturing economics, given sodium's natural abundance in the earth's crust and substantially lower extraction costs compared to lithium resources.

Contemporary sodium-ion battery designs frequently incorporate cathode materials such as sodium nickel manganese oxides or other sodium-intercalation compounds optimized for electrochemical performance [24]. While these systems currently demonstrate marginally lower energy density and round-trip efficiency (approximately 80% compared to 85-90% for lithium-ion), they present compelling potential as a cost-effective alternative for grid-scale applications where volumetric density is less critical than in mobile applications. A significant manufacturing advantage emerges from sodium-ion's compatibility with established lithium-ion production processes and equipment, potentially enabling accelerated commercial scaling through adaptation of existing manufacturing infrastructure.

The technology's current maturity can be characterized as early-stage commercialization. Functional prototype systems have been developed and validated, with several large-scale demonstration projects currently under development, though widespread commercial deployment remains several years behind lithium-ion technology. A significant milestone in sodium-ion deployment is the 100 MW / 200 MWh battery installation in Hubei Province, China, which represents the world's largest sodium-ion energy storage facility [25]. This project illustrates the technology's transition from laboratory to grid-scale implementation and signals potential for rapid commercial advancement. Figure 8 shows a photograph of the facility[9].

Figure 8: Chinese SI battery energy storage facility

[9] Sodium-ion battery storage station. [Photograph]. China Southern Power Grid Energy Storage. https://cnevpost.com/2024/05/13/china-1st-large-sodium-battery-energy-storage-station-operation/

Like their lithium-based counterparts, sodium-ion batteries maintain excellent siting flexibility, requiring only standard environmental protection and grid interconnection infrastructure. This deployment versatility aligns well with Nova Scotia's distributed storage requirements, including potential applications for community-level energy resources or transmission upgrade deferral. Operationally, the technology offers performance characteristics comparable to lithium-ion systems, including rapid response capabilities and modular scaling.

Despite these advantages, sodium-ion technology requires further validation in large-scale grid applications before widespread adoption. While Nova Scotia should maintain awareness of sodium-ion developments—particularly as a strategic hedge against potential lithium supply chain constraints—lithium iron phosphate technology represents the more established option in the near term. As sodium-ion manufacturing matures and benefits from manufacturing advancements in the broader battery sector, it may emerge as an increasingly viable alternative for Nova Scotia's energy storage portfolio, potentially offering comparable performance with improved economics and resource security.

3.3.3 Vanadium Redox Flow (VRF) Batteries

Vanadium redox flow battery technology represents a fundamentally different approach to electrochemical energy storage compared to conventional battery systems. Rather than storing energy within solid electrode materials, flow batteries utilize liquid electrolytes containing active chemical components held in external storage tanks. During operation, these electrolytes are circulated through an electrochemical cell stack where energy conversion occurs. In vanadium-based systems, both the positive and negative electrolytes contain vanadium ions in different oxidation states, serving as charge carriers. During charging, electrochemical reactions at the cell membrane cause vanadium ions in one electrolyte to undergo oxidation (releasing electrons) while ions in the second electrolyte experience reduction (accepting electrons). Upon discharge, this process reverses, generating electrical current for external utilization [26]. A visualization of this process being used for grid-scale energy storage is shown in Figure 9[10].

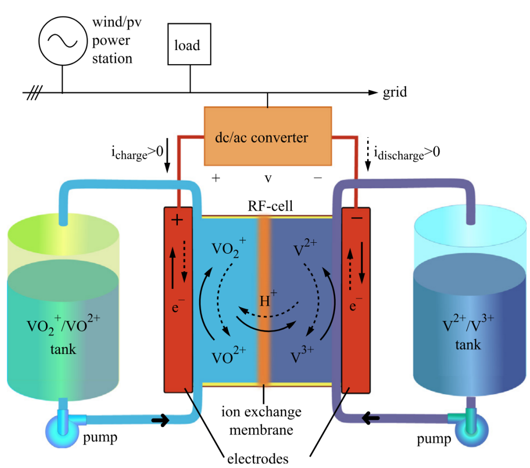

Figure 9: VRF energy storage process diagram

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[10] Redox flow batteries for the storage of renewable energy. [Digital Image]. https://doi.org/10.1016/j.rser.2013.08.001

A distinctive characteristic of flow battery architecture is the physical separation between power and energy subsystems. The power capacity is determined by the electrochemical cell stack size and membrane surface area, while energy capacity depends solely on electrolyte volume and concentration. This inherent decoupling enables independent sizing of power and energy parameters—extended discharge durations can be achieved simply by expanding electrolyte tank capacity without proportional increases in the more costly power conversion equipment. Additionally, vanadium flow systems have the potential for exceptional cycle life performance, as the liquid electrolytes experience minimal degradation through normal operation. With appropriate maintenance (regeneration of electrolytes), these systems can maintain performance for 20+ years of operation and tolerate complete discharge without the capacity degradation observed in many conventional battery technologies.

Despite these operational advantages, vanadium flow technology faces several implementation challenges. The system's round-trip efficiency (typically 65-75%) is lower than lithium-ion alternatives, primarily due to pumping energy requirements and membrane resistance. The technology also exhibits lower volumetric energy density compared to solid-state batteries, necessitating a greater installation footprint for equivalent storage capacity. However, these limitations are counterbalanced by the technology's extended operational lifespan and the ability to independently scale energy capacity, creating favorable economics for longer-duration applications.

Vanadium flow technology currently occupies a transitional position between demonstration and early commercial deployment for long-duration applications. Several utility-scale projects with capacities reaching tens of megawatts have been installed globally, primarily addressing applications requiring 6-10+ hours of storage duration. A significant validation project underway in North America involves the installation of a 525 kW / 12.6 MWh (24-hour) vanadium flow system at the Pacific Northwest National Laboratory research campus in Washington State. Supported by the U.S. Department of Energy, this installation will use Invinity's VRF batteries to evaluate the technology's performance in daily solar energy shifting and grid resilience applications, representing one of the earliest implementations of flow battery technology with full 24-hour discharge capability [27]. Figure 10 shows a photograph of one of Invinity's VRF battery storage systems[11].

Figure 10: Invinity VRF battery storage system

[11] Invinity VRF battery. [Photograph]. Invinity Energy Systems. https://www.pnnl.gov/publications/pnnl-install-24-hour-flow-battery-richland-campus

4 Nova Scotia Context

This section evaluates how Nova Scotia's specific geographical features, existing infrastructure, and regulatory environment affect the practical implementation of LDES technologies. Rather than reassessing general technology characteristics, this section focuses on the province's unique attributes that create opportunities or constraints for each storage option, supplemented by local project data and regional studies.

4.1 LDES Suitability

The physical geography of Nova Scotia creates distinct advantages and limitations for different LDES technologies, with crucial implications for their deployment potential.

Pumped Storage (PS): Nova Scotia's topography presents significant constraints for traditional pumped hydro development. The 2023 WaterPower Canada assessment [28], using the Australian National University's GIS-based site screening tool [29] identified only six locations with "medium realistic potential" for pumped storage development and none with "high potential." These medium-potential sites generally feature modest elevation differences where existing water bodies could be engineered into viable reservoirs. As depicted in Figure 11, five of these sites are in the Cape Breton Highlands, and one is near Parsboro, not far from the now defunct Fundy tidal energy project[12].

The Wreck Cove area in the Cape Breton Highlands represents the most promising identified location, where an existing hydroelectric station and surge reservoir at elevation provide foundational infrastructure. The site offers approximately 285 m of head height between potential upper and lower reservoirs, making it technically suitable for pumped storage development.

Facing natural topographic limitations, innovative approaches are emerging. A notable initiative involves investigating the repurposing of the decommissioned Touquoy gold mine in Moose River into a closed-loop pumped hydro system with an engineered upper reservoir and the flooded pit as a lower reservoir [30]. This adaptive reuse approach could overcome the scarcity of natural sites with sufficient elevation differentials, potentially creating a model for similar post-industrial site conversions.

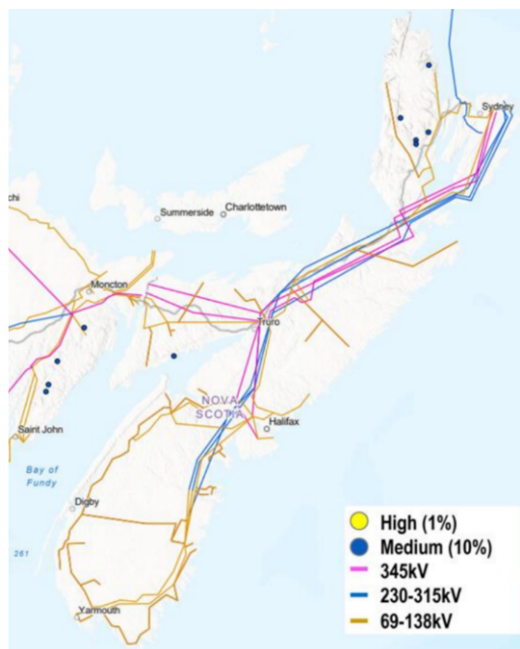

Figure 11: The five identified PS sites in Nova Scotia with 'Medium' potential. From the Stantec report for WaterPower Canada

Geologic Storage (ACA and H2): In contrast to pumped hydro limitations, Nova Scotia possesses extensive salt

[12] Realistic Potential in Nova Scotia and New Brunswick [Digital Image]. Stantec. https://waterpowercanada.ca/wp-content/uploads/2023/08/stantec_ps_final_en.pdf

formations well-suited for underground energy storage. The Windsor Basin and North Shore regions contain substantial salt deposits at appropriate depths for cavern development. A 2012 Newalta Corporation survey further identified promising formations at the Alton, Kingsville, and Orangedale deposits [31]. Dalhousie University researchers also identified locations like the Malagash salt structure in northeastern Nova Scotia that could support vertical caverns approximately 200 m tall by 65 m in diameter (roughly 800,000 m^3 volume) [32].

The Alton site, despite the project's ultimate cancellation, demonstrated the technical feasibility of creating large storage caverns (700+ m deep) in Nova Scotia's salt formations. Solution mining could create caverns with volumes sufficient for multi-day or even seasonal energy storage using either compressed air or hydrogen. The proximity of many salt formations to coastal areas with strong wind resources creates potentially advantageous siting opportunities for renewable energy integration.

Nova Scotia's salt geology could theoretically support multiple large-scale ACA or hydrogen storage facilities, with individual caverns capable of storing GWh+ equivalent of energy. This geological advantage partially offsets the province's pumped hydro limitations, providing an alternative pathway for multi-day to seasonal storage. However, environmental considerations, particularly regarding brine disposal during cavern creation, require careful management as demonstrated by the Alton experience. Figure 12 indicates the areas in Nova Scotia that contain the province's salt geology in black[13].

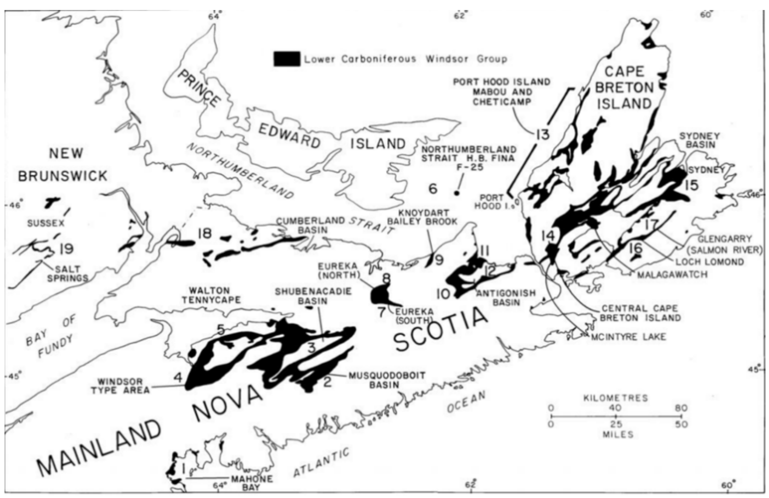

Figure 12: Nova Scotia salt geology

While our assessment primarily evaluates the fuel cell pathway for electricity generation, it merits noting that Nova Scotia Power has explored hydrogen-compatible generation in its recent Integrated Resource Plan [33] through dual-fuel natural gas facilities that could potentially transition to hydrogen combustion. This alternative approach could offer an additional implementation pathway for hydrogen in the provincial power system. However, to maintain analytical consistency with our

[13] Location Map for Salt Deposits in Nova Scotia. [Digitized Illustration]. https://publications.gc.ca/collections/collection_2024/isde-ised/c23/C23-263-1986-eng.pdf

referenced performance and cost parameters, this report concentrates on the electrolyser-to-fuel-cell configuration for hydrogen energy storage evaluation.

Battery Technologies: Without specific geographical constraints, battery systems offer deployment flexibility across Nova Scotia. This versatility enables strategic placement at grid congestion points, renewable generation sites, or load centers. The province's transmission topology, with several relatively isolated load pockets connected by limited transmission capacity, creates potential value for distributed storage deployment that battery technologies can uniquely address.

Nova Scotia's climate conditions (cold winters, coastal humidity, occasional extreme weather) do present operational considerations for battery deployment, potentially favoring technologies with appropriate thermal management systems and robust enclosures. These factors influence technology selection and facility design rather than fundamental deployment feasibility.

4.2 Implementation Experience and Prior Studies

Several Nova Scotia-specific assessments provide crucial data on LDES implementation feasibility and economics:

Pumped Storage in Nova Scotia: The 2012 Landsvirkjun Power/Verkís detailed evaluation of the Wreck Cove pumped storage opportunity [34] identified several configuration options, with Option 4 (using Surge Lake as the upper reservoir and Wreck Cove Brook Valley as the lower reservoir) being most attractive due to its synergistic benefits for the existing facility, shorter waterways, and minimal environmental impact. A satellite image of the proposed option is shown in Figure 13[14].

Figure 13: Surge Lake satellite image

The assessment produced cost estimates approximately $169 million (CAD 2012) for a 88 MW facility with 12-hour storage capacity (1,056 MWh). Adjusted for inflation to 2025 value, this would equate to approximately $225 million total. The cost advantage derives partially from utilizing existing infrastructure rather than building an entirely new facility, highlighting the potential value of retrofitting existing water control structures [34].

Advanced Compressed Air Energy Storage: In 2020, Hydrostor, a Canadian company specializing in CAES, provided Nova Scotia Power a preliminary analysis regarding ACA energy storage project in the province [35]. The Hydrostor report is brief but provides useful details on project costs. The all-in capital cost projection (including equipment, construction, interconnection, contingencies, etc.) for an illustrative 250 MW / 3,000 MWh facility was projected at $510 million.

Hydrogen Energy Storage: A comprehensive 2020 study on hydrogen in the Maritimes examined the prospects for large-scale hydrogen production and storage in Nova Scotia and New Brunswick. It

[14] Satellite Image of Surge Lake, Nova Scotia. [Digital Image]. Google Earth. https://earth.google.com/web/

reinforced that engineered salt caverns are the preferred method for storing hydrogen for large amounts of hydrogen gas because of their ample capacity and sealing capability. The same geological formations that could serve CAES can likewise be used for hydrogen. In fact, the canceled Alton project site has been noted as a potentially ideal location to pilot underground hydrogen storage in the future if it were ever revived or re-purposed.

As of 2024, two green hydrogen projects have been announced in Nova Scotia by Bear Head Energy and EverWind Fuels, which plan to produce hydrogen or ammonia for export. These projects initially focus on production and conversion rather than underground storage, but their presence indicates growing momentum in the hydrogen sector. Any move toward hydrogen energy storage within Nova Scotia's grid (for instance, storing surplus wind energy as hydrogen and later re-electrifying it) would likely rely on salt cavern storage, and the groundwork of geological surveys and regulatory frameworks will be key. Nova Scotia currently does allow hydrocarbon storage in salt caverns under its "Underground Hydrocarbons Storage Act", but using caverns for hydrogen may require new regulatory considerations and community consultations akin to those of the Alton project.

Battery Storage (Lithium-ion and others): Electrochemical storage has been the focus of recent deployments rather than studies, but some research has examined optimal deployment of grid batteries in Nova Scotia. Given the province's limitations with pumped hydro and the early-stage nature of CAES and hydrogen projects, Nova Scotia has tended to battery storage for near-term needs. Nova Scotia Power has already installed a 2.3 MWh Tesla PowerPack system in Elmsdale Nova Scotia in 2017, pictured in Figure 14.

Figure 14: Elmsdale Tesla Powerpack system

As lithium-ion technology represents a commercially mature and readily available solution that Nova Scotia has already begun larger scale implementing within its electricity infrastructure. Nova Scotia Power is currently executing a substantial battery deployment program with installations totaling 150 MW power capacity and 600 MWh energy capacity distributed across multiple strategic locations within the province. Figure 15 displays a rendering of one of these sites[15]. This CAD $354 million

[15] NSP Typical Grid Scale Battery Storage Facility. [Rendering]. Nova Scotia Power. https://www.nspower.ca/cleanandgreen/innovation/grid-scale-batteries

investment, scheduled for completion in 2025, ranks among Canada's most significant battery storage initiatives and will enhance system stability while facilitating higher penetration of variable renewable generation [36].

Figure 15: Nova Scotia Power battery energy storage facility rendering

4.3 Regulatory and Strategic Considerations

Nova Scotia's regulatory framework and system planning processes create additional context for LDES deployment:

Grid Integration Constraints: Based on comprehensive system studies, Nova Scotia Power has established specific technical parameters for renewable energy integration within their long-term planning models. These include both a "Maximum Hourly Dispatch Constraint" and a "Maximum Instantaneous Wind/Solar Penetration Constraint" that limit non-synchronous generation. These constraints address the stability challenges inherent to Nova Scotia's relatively small isolated grid and directly influence the operational requirements for energy storage technologies.

As the province moves toward 80% renewable electricity by 2030, these integration constraints will increasingly influence the quantity and performance requirements of storage resources needed to maintain reliability. LDES technologies that can provide synchronous inertia or grid-forming capabilities may offer particular value in this context.

Existing Infrastructure Leverage: The province has opportunities to repurpose existing assets for storage applications. Beyond the Wreck Cove hydro facility and potential mine site conversions, retiring coal plants present valuable opportunities for new LDES sites, as the existing grid infrastructure eliminates several costs and obstacles. Grid interconnection costs for projects in recent years have increased, and the lead time for related infrastructure, such as transformers, is growing.

Cape Breton, which hosts most of the province's coal generation capacity, is also the windiest region in Nova Scotia. Historically, transmission constraints between Cape Breton and mainland Nova Scotia have limited economic wind development in this resource-rich area. As coal plants retire, the freed-up transmission capacity could enable new, cost-competitive wind generation balanced by strategically located storage resources—creating a potential synergy that leverages both existing infrastructure and superior renewable resources.

A notable example of repurposing generation sites is the recent proposal by a group of Nova Scotian businesses and First Nations to install 150 MW of battery energy storage in Trenton, Nova Scotia – home of the recently shutdown 310 MW Trenton coal-fired generating station. Previously, such a system was suggested for Tuft's Cove generating station upon its retirement [37]. According to WM Limited's February 2025 announcement, this project aims to utilize existing transmission infrastructure while supporting grid stability and renewable integration.

Market Structure Implications: Nova Scotia is undergoing significant electricity market reform. In February 2024, the province introduced legislation to modernize the electricity system, including the creation of an independent system operator (ISO) and the restructuring of Nova Scotia Power. This transformation from a vertically integrated utility model to a more open market structure will fundamentally change how storage resources are valued, procured, and operated.

Under the new framework, LDES projects may benefit from increased market access and potentially new revenue streams. While the transition is still underway, the move toward an ISO model suggests future opportunities for storage to participate in more clearly defined capacity, energy, and ancillary service markets. Projects in development now should anticipate this evolving regulatory landscape and its implications for business models and revenue structures.

These Nova Scotia-specific factors create a distinct environment for LDES deployment that differs from both neighbouring provinces and other jurisdictions pursuing deep decarbonization. The combination of (1) geographical characteristics, (2) existing infrastructure, and (3) the evolving regulatory framework will shape technology selection, project design, and implementation timelines as the province advances toward its clean electricity targets. Additionally, while 1 large scale transmission interconnect was recently finished (Maritime Link to NL) and one is presently being built (Reliability Link to NB), further large scale transmission projects have been canceled (Atlantic Loop) and so emphasis has been refocused onto domestic generation and storage.

5 Evaluation Framework and Comparative Analysis

5.1 Technology Assessment Methodology

To systematically evaluate long-duration energy storage (LDES) technologies for Nova Scotia's context, we developed a structured assessment framework combining qualitative and quantitative metrics. This approach enables objective comparison across technologies with different characteristics and maturity levels while highlighting their respective strengths and limitations for deployment in the province.

5.1.1 Evaluation Metrics and Criteria

Our assessment framework incorporates six key metrics, selected to capture both technical performance and economic factors relevant to Nova Scotia's electricity system needs:

1. **Siting Flexibility -** Does the technology require specific geography or site conditions (such as elevation differences or salt caverns)? Technologies that can be deployed anywhere (e.g. batteries) score better, as they offer deployment flexibility, whereas those needing unique sites are inherently limited to certain locations in the province. This can add costs (i.e. transmission grid extensions) and forego value streams (i.e. being sited at zones that face high levels of curtailment or grid congestion).
2. **Technology Maturity -** Assesses commercial readiness and operational track record. Mature technologies with established performance history score higher than emerging options with limited deployment experience due to both technical and economic risk.
3. **Capital Cost – Power Component ($/kW)** – The unit cost to build the power-conversion equipment, measured per kW of capacity. Lower power costs are advantageous for meeting peak power needs.
4. **Capital Cost – Energy Component ($/kWh)** – Quantifies the expense of adding storage duration. Technologies with low $/kWh costs better support long-duration applications by enabling economical energy capacity scaling.
5. **Calendar Life (Years)** – Represents the expected operational lifetime before major refurbishment or replacement. Longer-lived assets spread capital costs over more years, improving lifetime economics.
6. **Round-Trip Efficiency (RTE)** – Indicates the percentage of input energy retrievable during discharge. Higher efficiency reduces operational costs and the amount of renewable generation needed to deliver equivalent services.

Additional factors examined qualitatively include self-discharge rates, operational flexibility, and maintenance requirements. These were not formally scored but inform the overall assessment of each technology's suitability.

For consistent evaluation, we established a three-tier rating system (favorable=green, moderate=yellow, challenging=red) for each metric, with specific thresholds determined through literature review and industry benchmarking:

Geographical	PDS	CapEx (Energy)	CapEx (Power)	Calendar Life	Energy Efficiency	Self-discharge	OpEx
0 Factors	Mature	<$100/kWh	<$500/kW	>50 years	>70%	Not enough data to evaluate	Values are too similar to properly evaluate
1 Factor	Demonstration or Deployment	$100 - $300/kWh	$500 - $1000/kW	20 - 50 years	50-70%		
2+ Factors	Development	>$300/kWh	>$1000/kW	<20 years	<50%		

Table 1: LDES technology evaluation criteria

Table 1 provides the framework for a categorized and standardized basis for comparison while acknowledging that the optimal technology selection ultimately depends on the specific application requirements and the system into which it's being integrated.

5.2 Data Sources and Cost Methodology

5.2.1 Primary Data Sources

To ensure analytical consistency and credibility, we established a standardized approach to data collection and cost estimation:

1. **Cost and Performance Parameters** - The Pacific Northwest National Laboratory (PNNL) Energy Storage Cost and Performance Database (2024) served as our primary reference for most technologies [38]. This database synthesizes information from vendor quotes, literature, and demonstrated projects to provide technology-specific cost and performance estimates.
2. **Real-World Project Data** - We complemented PNNL data with Nova Scotia-specific project information gathered from direct industry consultation and recent project announcements, including the Hydrostor advanced compressed air initiative, Wreck Cove pumped storage assessment, and Nova Scotia Power's lithium-ion battery installations.
3. **Peer-Reviewed Literature** - For emerging technologies (particularly sodium-ion batteries) with limited representation in commercial databases, we incorporated findings from recent academic and industry research publications.

All cost data was standardized to 2023 Canadian dollars using a 1.3× USD-to-CAD exchange rate and adjusting for inflation where necessary because of different data source years. By maintaining consistent conversion factors across all technologies, we ensure fair comparative evaluation.

5.2.2 Cost Component Analysis Methodology

For each LDES technology, we disaggregated costs into power-related components ($/kW) and energy-related components ($/kWh) to better understand scaling economics across different durations:

- **Power components** include conversion equipment such as turbines, fuel cells, electrolysers, and power electronics that determine maximum charge/discharge power rates (kW).
- **Energy components** comprise storage media such as reservoirs, caverns, and battery materials that determine total storage capacity (kWh).

This disaggregation allows more accurate modelling of how costs scale with increasing duration—a critical consideration for LDES applications where durations may range from 10 to 100+ hours.

5.2.3 Cost Projection and System Sizing

For our forward-looking analysis, we utilized 2030 cost projections from the PNNL database, reflecting anticipated technology improvements and manufacturing scale. These projections incorporate learning rates and industry roadmaps while maintaining conservative assumptions about technology advancement.

Our analysis focused on utility-scale implementations (100+ MW, 1+ GWh) to reflect realistic LDES deployment scales for Nova Scotia's grid needs. We filtered data to concentrate on systems with durations between 10 and 100 hours, corresponding to the multi-day to seasonal storage applications most relevant for deep decarbonization.

5.3 Comparative Technology Assessment Results

Our assessment reveals distinct performance profiles across the six evaluated LDES technologies, with each exhibiting unique strengths and limitations. Table 2 presents a comparative scorecard giving both values and color categorizations that summarize our findings across the key metrics.

	PS	ACA	H2	LFP	SI	VRF
Geographical	2 Factors	1 Factor	1 Factor	0 Factors	0 Factors	0 Factors
PDS	Mature	Deployment	Deployment	Mature	Development	Deployment
CapEx (Energy)	$31/kWh	$62/kWh	$7/kWh	$320/kWh	$570/kWh	$477/kWh
CapEx (Power)	$2750/kW	$1641/kW	$3742/kW	$87/kW	$87/kW	$151/kW
Calendar Life	60 years	30 years	30 years	20 years	20 years	12 years
Efficiency	75%	55%	31%	85%	80%	65%
Self-discharge	N/A	N/A	N/A	2%-3% per month	2% per month	N/A
OpEx (FOM)	$27/kW-year	$16/kW-year	$15/kW-year	$16/kW-year	$22/kW-year	$19/kW-year

Table 2: Comparative LDES technology assessment results

5.3.1 Technology-Specific Performance Insights

Pumped Storage (PS) demonstrates low energy capital costs ($31/kWh), long operational lifetime (60+ years), and high efficiency (75%). However, it faces significant geographical constraints in Nova Scotia, with limited viable sites primarily concentrated in Cape Breton Highlands. Its high power-related costs ($2,750/kW) reflect substantial civil engineering requirements but are partially offset by long asset life and proven reliability.

Adiabatic Compressed Air Energy Storage (ACA) offers a balanced profile with moderate energy costs ($62/kWh) and efficiency (55%). While requiring specific geological formations (salt caverns), Nova Scotia's extensive salt deposits along the Windsor Basin and North Shore provide multiple potential development locations. ACA remains in the deployment phase with several demonstration projects but is progressing toward commercial readiness.

Hydrogen Storage (H2) excels in energy-related costs ($7/kWh)—the lowest among all evaluated technologies—making it potentially attractive for very long-duration applications. This is because it uses similar salt caverns to ACA, but stores more energy per volume. However, this advantage is counterbalanced by high power component costs ($3,742/kW) and the lowest round-trip efficiency (31%) in our assessment. Like ACA, hydrogen storage requires salt cavern formations but could utilize the same geological features.

Lithium Iron Phosphate Batteries (LFP) offer outstanding siting flexibility, high efficiency (85%), and mature commercial status. Their primary limitation is high energy capital costs ($320/kWh), which makes scaling to longer durations economically challenging. Despite a shorter calendar life (20 years) compared to mechanical alternatives, LFP's deployment simplicity and operational flexibility provide significant value for shorter-duration applications. Additionally developers often leave additional footprint such that the energy capacity can be “augmented” in the future by addition of battery modules.

Sodium-Ion Batteries (SI) share many characteristics with lithium-ion technology but remain in the development stage. While theoretically offering cost advantages through more abundant materials, current energy costs ($570/kWh) exceed those of LFP. The technology shows promise but requires further maturation and manufacturing scale to realize its potential advantages.

Vanadium Redox Flow Batteries (VRF) occupy a middle ground between conventional batteries and mechanical storage. Their decoupled power and energy architecture theoretically enables economical scaling to longer durations, but current energy costs ($477/kWh) limit this potential. With moderate efficiency (65%) and deployment-stage status, VRF technology requires further commercial development to fully capitalize on its architectural advantages.

5.3.2 Cross-Technology Comparison and Insights

Several important patterns emerge from the comparative assessment:

1. **Complementary Technology Strengths** - No single technology excels across all metrics, suggesting potential value in a diversified LDES portfolio approach. Mechanical and chemical technologies (PS, ACA, H2) offer superior economics at very long durations but face geographical constraints, while electrochemical options (LFP, SI, VRF) provide deployment flexibility but at higher cost for extended durations.
2. **Inverse Cost Structure** - Mechanical/chemical and electrochemical technologies demonstrate fundamentally different cost structures. Mechanical/chemical options feature high power costs but low energy costs, while electrochemical technologies show the opposite pattern. This creates distinct economic "crossover points" where different technologies become optimal depending on required duration. But it also speaks to the fact that you pay for energy storage systems one way or the other; either per power rating or per energy rating.
3. **Efficiency Trade-offs** - Technologies with higher round-trip efficiency require less renewable generation to deliver equivalent storage services but often come with higher capital costs or geographical limitations. This trade-off becomes increasingly significant in systems with high renewable penetration.

4. **Maturity-Cost Balance** - More mature technologies (PS, LFP) generally demonstrate better technical performance but may not offer the lowest long-term costs. Emerging technologies (ACA, H2) show promise for cost reduction but carry greater development risk.

These findings illustrate that LDES technology selection must be approached as a multi-dimensional and geographical optimization problem rather than a simple cost minimization exercise. This is especially pertinent to PS, ACA, H2 due to siting uncertainty and project scale being larger singular units; whereas batteries are deployable almost anywhere and in a piecemeal fashion, mitigating construction risks. The relative importance of different evaluation criteria will depend on specific application needs, available sites, and integration with Nova Scotia's broader energy transition strategy.

5.4 Levelized Cost of Storage Analysis

To provide a standardized economic comparison across technologies with different cost structures, lifespans, and performance characteristics, we conducted a detailed Levelized Cost of Storage (LCOS) analysis. This approach quantifies the average cost per megawatt-hour (MWh) of electricity delivered by each storage system over its operational lifetime. While LCOS offers a useful metric for basic energy arbitrage valuation, it does not fully capture other significant value streams such as capacity provision, congestion relief, transmission investment deferrals, and ancillary services that vary based on a system's energy capacity and deployment context.

5.4.1 LCOS Methodology

Our LCOS calculation incorporates:

- Annualized capital costs (using technology-specific discount rates and lifespans)
- Fixed and variable operation and maintenance costs
- Charging electricity costs
- Round-trip efficiency losses
- Utilization patterns (cycling frequency and depth)

We applied consistent financial assumptions across all technologies to ensure fair comparison:

- Weighted average cost of capital (WACC): 6.5%
- Average charging electricity cost: $0.04/kWh
- System usable capacity: 80% of nameplate
- Operating days per year: 350
- Daily cycling for 10-hour systems
- Bi-weekly cycling for 100-hour systems

To capture how economics shift with duration, we evaluated two representative cases: medium-duration (10-hour) and long-duration (100-hour) storage.

5.4.2 LCOS Results for Medium-Duration Applications (10-Hour)

		Equation	PS	ACA	H2	LFP	SI	VRF
A	**Output Power (kW)**	Assumed	**1**	**1**	**1**	**1**	**1**	**1**
B	**System Duration (hours)**	Assumed	**10**	**10**	**10**	**10**	**10**	**10**
C	**Sales per Cycle (kWh)**	A*B =	**10**	**10**	**10**	**10**	**10**	**10**
D	**Usable Capacity (%)**	Assumed	**80%**	**80%**	**80%**	**80%**	**80%**	**80%**
E	Energy Capacity (kWh)	C/D =	12.5	12.5	12.5	12.5	12.5	12.5
F	Energy Capex ($/kWh$_{rated}$)	PNNL Report	31	62	7	320	570	477
G	Energy Capex ($)	E*F =	388	775	88	4000	7125	5963
H	Power Capex ($/kW$_{rated}$)	PNNL Report	2750	1641	1241	87	87	151
I	Power Capex ($)	A*H =	2750	1641	3812	87	87	151
J	Total Capex ($)	G+I =	3138	2416	3900	4087	7212	6114
K	Calendar Life (y)	PNNL Report	60	30	30	20	20	12
L	WACC (%)	Assumed	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%
M	Annuity ($)	Formula	209	185	299	371	655	749
N	OpEx ($/kW-y)	PNNL Report	27	16	15	16	22	19
O	Potential Cycles/y	Assumed	365	365	365	365	365	365
P	Operating Days/y	Lazard Report	350	350	350	350	350	350
Q	Elec Sold (kWh/y)	C*O*(P/365) =	3500	3500	3500	3500	3500	3500
R	Efficiency (%)	PNNL Report	75%	55%	31%	85%	80%	65%
S	Elec Purchased (kWh)	Q/R =	4667	6364	11290	4118	4375	5385
T	First Year Cost of Elec ($/kWh)	Lazard Report	0.04	0.04	0.04	0.04	0.04	0.04
U	Elec Costs ($/y)	S*T =	187	255	452	165	175	215
V	Total Costs ($/y)	M+N+U =	422	456	765	552	852	984
W	**Levelized Cost of Storage ($/kWh)**	V/Q =	**0.121**	**0.130**	**0.219**	**0.158**	**0.243**	**0.281**
X	**Electricity Arbitrage Spread ($/kWh)**	W-T =	**0.081**	**0.090**	**0.179**	**0.118**	**0.203**	**0.241**

Table 3: LCOS results for 10-hour duration

For 10-hour storage applications, our analysis reveals a clear economic hierarchy:

1. **Pumped Storage** achieves the lowest LCOS at $0.121/kWh, driven by low energy-related capital costs and moderate efficiency despite significant power-related capital expenditures.
2. **Adiabatic CAES** follows closely at $0.130/kWh (only 7.4% higher than PS), benefiting from balanced capital costs and acceptable efficiency. It also has additional siting locations throughout Nova Scotia but it not as technologically mature.
3. **Lithium-ion (LFP)** remains competitive at $0.158/kWh despite higher energy-related capital costs, leveraging high round-trip efficiency and modest power-related expenses. This cost is 30% higher than PS, but comes with the advantage of scalability, no siting restrictions, and shorter project life that can take advantage of new technologies and cost reductions over the next 20-30 years.
4. **Hydrogen Storage** shows higher costs at $0.219/kWh, driven primarily by its low round-trip efficiency (31%) which necessitates significantly more input electricity per unit of output.
5. **Sodium-ion** and **Vanadium Redox Flow** batteries present the highest costs in this duration category ($0.243/kWh and $0.281/kWh respectively), reflecting their early commercial status and current higher capital costs. It is important to re-evaluate these in the next few years as manufacturing capacity grows, costs decline, technology matures, and experience is gained.

The cost structure breakdown reveals distinctive patterns across technologies. For PS, capital costs (49.4%) and electricity costs (44.2%) contribute almost equally to total LCOS, with minimal O&M impact (6.4%). In contrast, electrochemical technologies show dominant capital cost contributions (67-77%), while hydrogen exhibits the opposite profile with electricity costs representing 79.5% of its total LCOS due to its low energy efficiency.

Overall, while PS is lowest LCOS for a 10 hour system, the benefits of LFP of scalability, siting, and operating period (20-30 years before a LFP replacement that is likely more efficiency and lower cost) likely outweigh the 30% increase in LCOS.

5.4.3 LCOS Results for Long-Duration Applications (100-Hour)

		Equation	PS	ACA	H2	LFP	SI	VRF
A	**Output Power (kW)**	Assumed	**1**	**1**	**1**	**1**	**1**	**1**
B	**System Duration (hours)**	Assumed	**100**	**100**	**100**	**100**	**100**	**100**
C	**Sales per Cycle (kWh)**	A*B =	**100**	**100**	**100**	**100**	**100**	**100**
D	**Usable Capacity (%)**	Assumed	**80%**	**80%**	**80%**	**80%**	**80%**	**80%**
E	Energy Capacity (kWh)	C/D =	125	125	125	125	125	125
F	Energy Capex ($/kWh$_{rated}$)	PNNL Report	31	62	7	320	570	477
G	Energy Capex ($)	E*F =	3875	7750	875	40000	71250	59625
H	Power Capex ($/kW$_{rated}$)	PNNL Report	2750	1641	3812	87	87	151
I	Power Capex ($)	A*H =	2750	1641	3812	87	87	151
J	Total Capex ($)	G+I =	6625	9391	4687	40087	71337	59776
K	Calendar Life (y)	PNNL Report	60	30	30	20	20	12
L	WACC (%)	Assumed	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%
M	Annuity ($)	Formula	441	719	359	3638	6474	7327
N	OpEx ($/kW-y)	PNNL Report	27	16	15	16	22	19
O	Potential Cycles/y	Assumed	26	26	26	26	26	26
P	Operating Days/y	Lazard Report	350	350	350	350	350	350
Q	Elec Sold (kWh/y)	C*O*(P/365) =	2493	2493	2493	2493	2493	2493
R	Efficiency (%)	PNNL Report	75%	55%	31%	85%	80%	65%
S	Elec Purchased (kWh)	Q/R =	3324	4533	8042	2933	3116	3836
T	First Year Cost of Elec ($/kWh)	Lazard Report	0.04	0.04	0.04	0.04	0.04	0.04
U	Elec Costs ($/y)	S*T =	133	181	322	117	125	153
V	Total Costs ($/y)	M+N+U =	601	916	696	3771	6621	7499
W	**Levelized Cost of Storage ($/kWh)**	V/Q =	**0.241**	**0.368**	**0.279**	**1.513**	**2.656**	**3.008**
X	**Electricity Arbitrage Spread ($/kWh)**	W-T =	**0.201**	**0.328**	**0.239**	**1.473**	**2.616**	**2.968**

Table 4: LCOS results for 100-hour duration

At 100-hour duration, the economic landscape transforms dramatically:

1. **Pumped Storage** maintains the leading position at $0.241/kWh, though its LCOS approximately doubles compared to 10-hour duration. In essence, the addition 90 hours of storage (above and beyond the 10 hours of the previous section), which gets called on less frequently to operate, raises costs substantially.

2. **Hydrogen Storage** rises to second position at $0.279/kWh (only 15.8% higher than PS), benefiting from its extremely low energy capacity costs as duration extends.

3. **Adiabatic CAES** follows at $0.368/kWh, with its moderate energy costs yielding reasonable economics at longer durations.

4. **Electrochemical technologies** become prohibitively expensive, with LCOS values 5-12 times higher than at 10-hour duration. LFP reaches $1.513/kWh, while SI and VRF exceed $2.50/kWh. These are likely entirely unpalatable to rate payers.

This transformation illustrates the fundamental principle that different technologies occupy distinct economic niches across the duration spectrum. As storage duration increases, the energy component dominates total system cost, giving technologies with low $/kWh metrics significant advantage despite higher power costs or lower efficiencies. We expect to see the LDES model in Part II tend to choose PS for applications of 100 h LDES, as ACA is 50% greater LCOS.

5.4.4 Economic Implications and Price Sensitivity

The required electricity price arbitrage for economic operation—the ratio between discharge and charge prices needed to cover costs—ranges from 3.0-7.0 for 10-hour storage. These values align with realistic market conditions in neighbouring electricity markets and suggest viable economic operation in energy shifting applications.

However, for electrochemical technologies at 100-hour duration, required arbitrage ratios reach 37.8-75.2, far exceeding typical market price spreads. This confirms their economic unsuitability for very long-duration applications under current and projected cost structures.

An important observation is the sensitivity of different technologies to various economic factors:

- **Capital-dominated technologies** (LFP, SI, VRF) are highly sensitive to interest rates and capital cost reductions but less affected by electricity price fluctuations.
- **Efficiency-dominated technologies** (particularly H2) are extremely sensitive to electricity price spreads but less affected by capital cost variations.
- **Balanced technologies** (PS, ACA) show moderate sensitivity to both factors.

These sensitivities have important implications for policy design and risk assessment in LDES procurement strategies.

5.5 Cost Validation with Recent Projects

To validate our cost modelling approach, we compared PNNL database estimates with real project costs from operational or proposed LDES initiatives in Nova Scotia and neighbouring regions, as shown in Table 5. For the PNNL data, we used the cost estimates for the project parameters most closely resembling the real project, and not necessarily those from Table 4[16].

[16] Table 5 notes: (i) The project Capex for the TC Energy project includes transmission cost whereas the PNNL estimate does not. (ii) For the projects who costs were given as a total project cost, we have apportioned them assuming the same proportions as the PNNL data.

LDES Project	Project Capex	PNNL Capex	Percent difference
PS: TC Energy	$34/kWh $3017/kW	$31/kWh $2750/kW	9% 10%
ACA: Hydrostor	$53/kWh $1402/kW	$62/kWh $1641/kW	-17% -17%
LFP: Nova Scotia Power	$478/kWh $130/kW	$457/kWh $110/kW	5% 19%
SI: Datang Hubei Energy	N/A	N/A	N/A
VRF: Invinity Energy	$783/kWh $249/kW	$622/kWh $299/kW	26% -17%

Table 5: LDES cost comparison: this report vs. reported project costs

The validation results demonstrate reasonable alignment between our model and actual projects, with variations typically within ±20%. These differences reflect project-specific factors like site conditions, regulatory requirements, and infrastructure needs not captured in generalized cost databases.

Notably, earlier-stage technologies (VRF) show wider cost variations than mature technologies (PS, LFP), consistent with greater uncertainty in emerging technology economics. Additionally, Nova Scotia Power's lithium iron phosphate deployment costs exceed database estimates by 5-19%, suggesting that regional implementation may carry cost premiums relative to generalized industry benchmarks.

This validation strengthens confidence in our economic modelling while acknowledging the inherent variability in project-specific costs, particularly for technologies with geographical dependencies.

5.6 Key Findings and Implications

Our assessment yields several critical insights for Nova Scotia's LDES strategy:

1. **Technology-Duration Alignment** - Mechanical and chemical storage technologies (PS, ACA, H2) present economically viable options across a wide duration range (10-100+ hours), while electrochemical technologies (LFP, SI, VRF) remain economically constrained to shorter-duration applications (10 hour) under current and projected cost structures.
2. **Site-Specific Considerations** - For technologies requiring specific geographical features (PS, ACA, H2), detailed site assessment becomes critical to accurate project economics. While our analysis provides generalized cost estimates, actual implementation costs may vary significantly based on location-specific factors.
3. **Staged Implementation Strategy** - Nova Scotia's diverse LDES needs may be best served in the near term by deploying commercially mature technologies, such as LFP for shorter durations and in phases, and PS where geographically viable, for one large project, while

monitoring developing options (ACA, H2, SI, VRF) for longer-duration applications as they mature.

4. **Technology Complementarity** - The distinct advantages of different LDES technologies suggest potential value in a diversified portfolio approach, with electrochemical systems serving shorter-duration needs and mechanical/chemical systems addressing longer-duration requirements.
5. **System Value Beyond Economics** - While LCOS provides a standardized economic comparison, the full system value of LDES includes additional benefits not captured in this metric, such as transmission deferral, resilience enhancement, and enabling higher renewable penetration by providing firm capacity.

These findings inform the modelling approach in Part II of this study, where we integrate LDES options into Nova Scotia's electricity system planning to assess their role in enabling the province's clean energy transition.

Part II: Power System Modelling

6 Integrated Power System Modelling

6.1 Modelling Framework Overview

Electricity system capacity expansion models are optimization-based tools used in system planning to determine the least-cost combination of resources needed to meet future electricity demand under various constraints. These models simulate investment and dispatch decisions over a long-term horizon, ensuring that generation, storage, and transmission expansions satisfy constraints such as generation/load balance, resource adequacy, and policy targets.

For this study, we employ Temoa (Tools for Energy Model Optimization and Analysis [39]), an open-source energy system optimization model, as the backbone of our capacity expansion analysis. This approach allows us to evaluate LDES technologies within the context of Nova Scotia's entire electricity system evolution over multiple decades. Temoa has been used in recent intercomparison studies and is noted for its flexible structure – it supports detailed tracking of resource vintages, incorporates both perfect foresight and limited myopic optimization modes, features multiple tools for uncertainty analysis, and can handle age-based or economic generator retirements [40]. These capabilities make it well-suited for investigating long-term decarbonization pathways.

We use a custom version of Temoa tailored specifically to Nova Scotia's power system [41]. The open-source nature of Temoa allows us to implement Nova Scotia-specific policies and operational constraints directly into the model framework, extending Temoa's standard capabilities. Custom functionalities we added include:

- **Output-Based Pricing System (OBPS)** for carbon pricing – capturing the federal-provincial carbon pricing framework as it applies to NS Power's generating units, which significantly influences the economic competitiveness of different generation technologies.

- **Clean Electricity Regulations (CER)** – a constraint reflecting the proposed federal requirement for a net-zero electricity grid by 2035 (included as a sensitivity case in our scenarios).

- **Renewable Portfolio Standard (RPS)** – enforcing Nova Scotia's legislated target of 40% renewable electricity supply today, and 80% renewable electricity by 2030 within the model.

- **Hydroelectric generation fleet constraints** – custom operational limits for the province's hydroelectric resources (e.g., energy availability and flow constraints) to reflect their seasonal flows and storage potential.

- **Grid integration constraints** – Nova Scotia-specific stability limits on variable renewable output, such as maximum hourly dispatch from wind/solar and maximum instantaneous renewable penetration levels, based on utility studies.

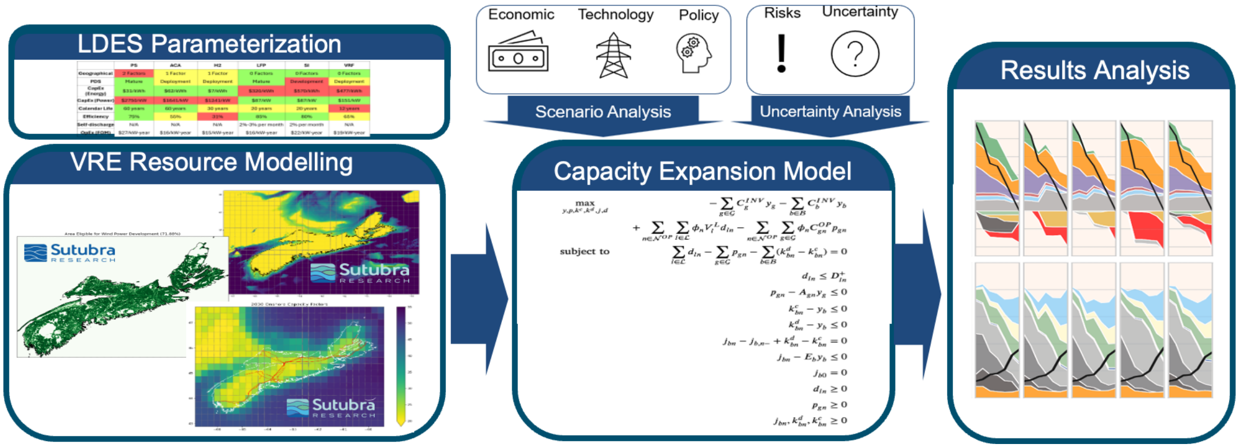

Figure 16: Schematic outlining the integrated power system modelling framework.

The framework integrates three key analytical components, as illustrated in Figure 16:

1. **LDES Technology Parameterization**: Drawing from Part I of this study, we incorporate detailed technical and economic characteristics of selected LDES technologies, including their cost structures, efficiencies, and operational constraints.
2. **VRE Resource Modelling**: High-resolution wind and solar resource assessment provides spatially and temporally explicit renewable generation profiles, capturing their natural variability and correlation with electricity demand patterns.
3. **Capacity Expansion Optimization**: The core model determines optimal investment decisions for the 2025-2050 planning horizon, co-optimizing generation, storage, and transmission resources to meet Nova Scotia's energy transition goals.

Our modelling framework, illustrated in Figure 16, addresses a critical challenge in LDES assessment: the need for high temporal resolution to capture multi-day to seasonal storage dynamics. While traditional capacity expansion models often employ representative periods or time sampling techniques to reduce computational complexity, such approaches fundamentally compromise the ability to evaluate LDES technologies, whose value proposition centers on bridging extended periods of mismatches between supply and demand.

To overcome this limitation, we maintain full chronological resolution (8,760 hours per year, or 'timesteps') with no temporal aggregation in the optimization. This approach—computationally intensive but methodologically necessary—enables our model to accurately assess how LDES technologies can mitigate extended wind and solar generation shortfalls, reduce curtailment during surplus periods, and provide capacity value across multi-day system peaks.

6.2 Key Methodological Components

Wherever feasible, we align inputs and assumptions with the Nova Scotia Power 2022 Integrated Resource Plan (IRP) – Evergreen Update [33] to ensure consistency with utility planning practices and assumptions. We also use recent regulatory filings and NSP outlooks to keep the assumptions as current as possible.

6.2.1 Financial and Economic Parameters

All costs are expressed in 2023 Canadian dollars, with an exchange rate of 1.3 CAD per USD applied to any inputs sourced in USD. We apply a real weighted average cost of capital (WACC) of 4.33%, corresponding to the approximately 6.33% nominal pre-tax WACC and 2% long-term inflation rate used in the IRP.

These financial assumptions govern both the evaluation of existing assets and the economic comparison of new investment options, ensuring our analysis reflects the actual cost structure facing Nova Scotia's electricity system planning decisions. The relatively low real WACC of 4.33% reflects the regulated utility environment and has significant implications for capital-intensive technologies like pumped storage, improving their competitiveness relative to operational cost-dominated alternatives.

It is important to note that exchange rate fluctuations could impact the relative economics of different technologies. At the time of writing, the USD/CAD exchange rate has increased to approximately 1.44, which may affect the comparative economics presented in this analysis. Technologies with higher import content, such as lithium iron phosphate batteries, would likely experience greater cost impacts from a weakening Canadian dollar compared to solutions with significant local content, such as pumped storage, where civil works represent a substantial portion of overall costs. While our analysis maintains consistency with the IRP assumptions, this exchange rate sensitivity represents an additional economic risk factor for import-dependent technologies.

6.2.2 Temporal Structure

Our analysis spans 2025 to 2050 in five-year increments, with each period modeled at full hourly resolution (8760 hours per year).

We implement a sequential myopic optimization approach for computational efficiency. The model solves each period independently, using the capacity decisions from previous periods as fixed inputs rather than attempting to optimize the entire 25-year horizon simultaneously. We begin by simulating 2025, then use those results as the starting point for 2030, continuing this process through 2050. This approach:

- Reflects realistic decision-making without perfect foresight of distant future conditions
- Allows examination of near-term investment decisions under policy uncertainty
- Captures the path-dependency of energy infrastructure development
- Significantly improves computational tractability while preserving hourly temporal detail

Each period's simulation determines both capacity expansion decisions and hourly operational patterns (generation dispatch, storage cycling, import/export flows) for that specific model year, with new resources becoming available in the next period.

6.2.3 Network Resolution and Transmission Modelling

The model divides Nova Scotia into six interconnected zones based on the existing transmission network topology, as illustrated in Figure 17. This spatial representation captures several critical geographical factors:

- Regional renewable resource quality variations, particularly Cape Breton's superior wind resources
- Transmission constraints between generation hubs and major load centers
- Local infrastructure availability (e.g., gas pipeline access for thermal generation)
- Geological suitability for site-specific LDES technologies such as elevation differences, water reservoirs, and subterranean salt domes.

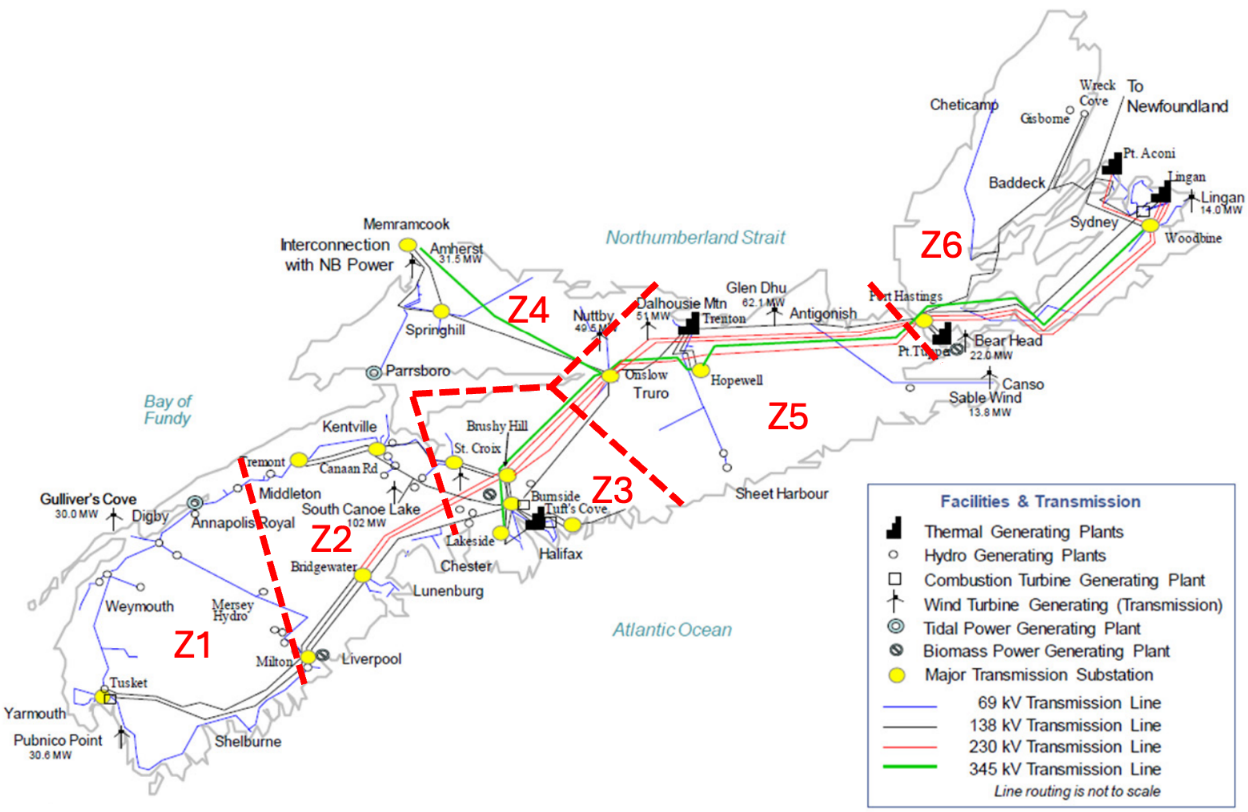

Figure 17: Map of Nova Scotia Power's generation facilities and transmission infrastructure. The red text overlay (Z1-Z6) indicates the six operational zones established for power system modeling in this study. Image source: [1]

Each zone represents a distinct area of the province with its own generation resources, demand centers, and connection points to neighbouring zones. Existing transmission corridors between zones are modeled with their current capacity limits, as shown in Table 6.

Interface	Z1-Z2	Z2-Z3	Z3-Z5	Z4-Z5	Z5-Z6
Existing Capacity (MW)	240	660	1,000	500	1,000
Distance (km)	150	90	106	96	266
Capex ($/kW)	1,014	609	717	649	1,799

Table 6: Existing capacity, distance, and assumed capex for interzonal transmission lines.

Inter-zonal power transfers are limited by these capacities, reflecting the actual network topology of Nova Scotia's grid. The model can invest in transmission reinforcement if economically justified, based on an assumed capital cost of $6,763/MW-km derived from the reported costs and distances of the NB-NS reliability tie[17]. This cost is similar to the calculated costs of the new 345 kV line from Coleson Cove to Norton in New Brunswick ($7,197.05/MW-km), but are substantially higher than the upper estimates from the Transmission Cost Estimation Guide prepared by the Midcontinent Independent System Operator (MISO) ($4,442/MW-km).

Transmission line distances between zones were determined using a combination of utility documentation and geospatial analysis. For lines documented in Nova Scotia Power materials, we identified that the Z5-Z6 line corresponds to the Woodbine-Onslow corridor, the Z3-Z5 line represents the Lakeside-Onslow connection, and the Z4-Z5 line reflects the Nova Scotia portion of the reliability tie project (from the Nova Scotia border to Onslow). For remaining connections without explicit documentation, distances were calculated using Google Earth measurements between major substations, with the Z1-Z2 distance measured between Tusket and Bridgewater substations, and the Z2-Z3 distance measured between Bridgewater and Lakeside substations.

Geographic restrictions ensure realistic resource siting—natural gas plants can only be built where fuel delivery infrastructure exists, while certain LDES technologies like compressed air energy storage are limited to regions with appropriate geological formations. Existing generation resources are fixed at their current locations, while new resources can be placed optimally within zones that have suitable conditions for their development.

This zonal approach enables the model to identify location-specific investment strategies, including the potential for transmission expansion to alleviate network constraints when economically justified, trading off network reinforcement against localized generation and storage deployment.

6.2.4 Electricity Demand

Our analysis employs NSP's "Base DSM" load forecast, which incorporates projected demand growth, energy efficiency measures, and electrification trends. This forecast provides hourly load profiles through 2050, capturing both seasonal patterns (including higher winter heating demand) and daily variations (such as evening peaks characteristic of Nova Scotia's demand profile).

[17] We take a capital cost estimate of $811.5 million over 160 km and assume a line rating of 750 MW.

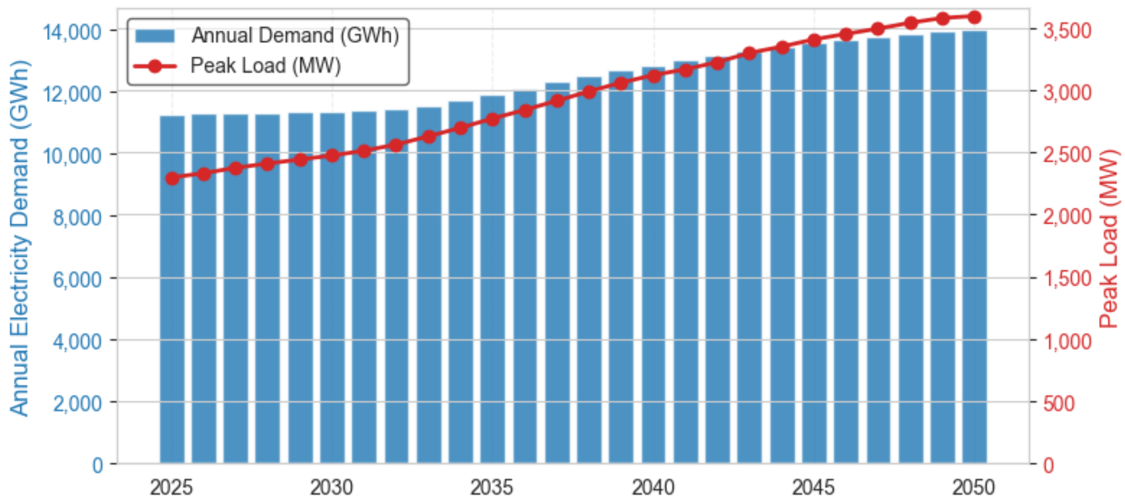

Figure 18: Electricity demand forecast (2025-2050). Annual demand (blue) and peak load requirements (red) both show steady growth through 2050.

The hourly resolution of this forecast is particularly important for LDES evaluation as it preserves the temporal correlation between demand patterns and renewable resource availability[18]. This temporal detail allows the model to accurately assess when storage charging and discharging would occur and how effectively different LDES technologies can bridge supply-demand mismatches across varying timeframes. The Base DSM scenario reflects moderate adoption of demand-side management programs, representing a central case for electricity consumption growth in the province.

As shown in Figure 19, while baseload demand levels remain relatively stable throughout the forecast period, we can observe a significant increase in peak demand. This growth primarily stems from end-use electrification of heating, cooling, and transportation sectors, which adds substantial load during specific hours of the day. Particularly notable is the projected winter peak demand in 2050, which shows a much more pronounced evening peak compared to 2025, reflecting the electrification of residential and commercial heating systems.

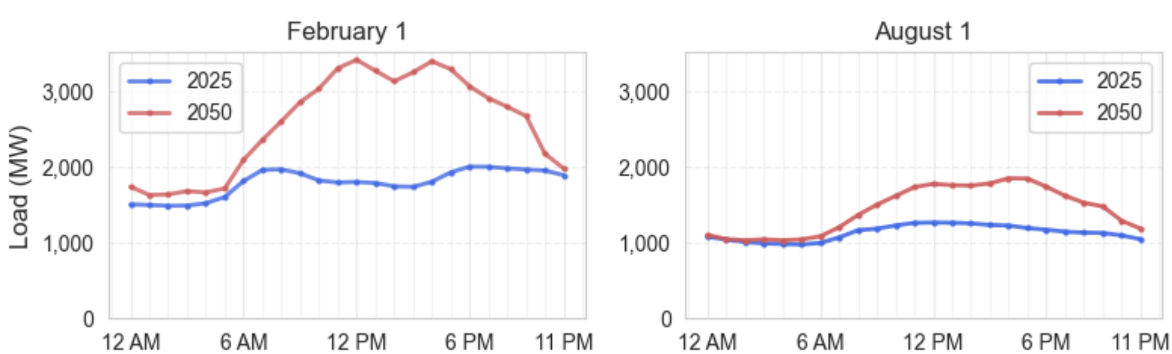

Figure 19: Comparative Daily Load Profiles (2025 vs. 2050). The graphs display hourly electricity demand patterns for a representative winter day (February 1, left) and summer day (August 1, right).

[18] The load forecast and the renewable profiles (see Section 6.2.6) are both based off the 2018 weather year.

6.2.5 Policy and Environmental Constraints

The model explicitly incorporates Nova Scotia's current and forthcoming policy requirements as binding constraints on system evolution:

Carbon Pricing: Our model implements Nova Scotia's Output-Based Pricing System (OBPS), which uses performance standards rather than a simple carbon tax. Under this system, electricity generators are assigned emissions intensity benchmarks. Facilities pay the carbon price only on emissions exceeding their benchmark, calculated as output multiplied by the performance standard. This approach provides a stronger incentive for efficiency improvements within existing thermal generation while gradually increasing the economic advantage of zero-emission alternatives.

The model applies the federally mandated carbon price trajectory (reaching \$170/tonne CO_2 in 2030) and maintains this real price through 2050, creating a strengthening economic signal for emissions reduction over time.

Renewable Portfolio Standard (RPS): Enforces Nova Scotia's legislated target of 40% renewable electricity supply today, and increasing to 80% in 2030. This constraint serves as a primary driver for renewable capacity expansion in the near term.

Federal Coal Phaseout: Requires the retirement of Nova Scotia's coal-fired generating units by 2030, eliminating a significant portion of the province's current firm capacity.

Clean Technology Investment Tax Credits (ITC): Our model reflects the federal Investment Tax Credit program, which provides a 30% tax credit for wind, solar, energy storage (including LDES), and nuclear SMR technologies. We implement this as a 27% reduction to capital expenditures to account for typical tax equity transaction costs. These incentives apply to projects constructed through 2034, influencing near-term investment decisions in our analysis.

These policy constraints, in combination with technical system limitations, create the framework within which LDES technologies must compete with alternative solutions for decarbonization.

6.2.6 Resource Options and Characterization

The model evaluates a comprehensive portfolio of generation and storage technologies, incorporating both existing assets and potential new investments:

Existing Assets: All current generation facilities in Nova Scotia are represented with their specific technical characteristics, fixed and variable costs, and planned retirement dates [1]. We also include resources currently under development, such as the 350 MW of new wind capacity and 150 MW/600 MWh of battery storage scheduled for completion by 2025. These are summarized by model zone in Table 7.

Technology	Sub-Technology	Existing Capacity in 2025 (MW)						
		Z1	Z2	Z3	Z4	Z5	Z6	Total
Coal	Lingan						608	608
	Trenton					306		306
	Tupper						153	153
	Point Aconi						168	168
Natural Gas Tufts Cove	Steam Turbine			318				318
	Combined Cycle			144				144
Hydro		68	68	17		14	212	379
Diesel Combustion Turbine		33		132			66	231
Bioenergy			30				30	60
Wind		190	163	304	263	330	104	1354
Solar			5		2	2		9
Li-Ion Battery	4 Hour		100	50				150

Table 7: Provincial generation capacity organized by model zones (Z1-Z6).

New Build Options: A diverse set of potential new resources is available for selection, with conventional generation options (natural gas plants, etc.) and battery storage systems parameterized using data from NREL's Annual Technology Baseline 2024 [23]. For LDES technologies, we incorporate the detailed parameters developed in Part I of this study, including capital costs, round-trip efficiencies, and operational lifespans. We include all LDES technologies at 10-, 24-, and 100-hour duration options, in accordance with the techno-economic parameters presented in Section 5.

Technology	Sub-Technology	Operating Life (years)	FOM ($/kW-year)	VOM ($/MWh)	2030 Capex ($/kW)	2040 Capex ($/kW)
Wind*	Onshore	30	38.0	-	1,716	1,534
Solar*	1-axis tracking	30	23.4	-	1,382	930
Natural Gas	Combustion Turbine	55	32.5	9.0	1,352	1,238
	Combined Cycle	55	41.0	2.7	1,536	1,397
Nuclear	SMR	60	176.8	3.4	8,450	6,825
Coal-to-Gas	Point Tupper	20	40.0	1.2	219	-
Coal-to-HFO	Lingan	20	21.6	1.2	1.33	-
LFP Battery	2 Hour	20	26.3	-	1,051	907
	4 Hour	20	42.3	-	1,690	1,430
	6 Hour	20	58.2	-	2,329	1,953
	8 Hour	20	90.2	-	3,607	2,999

* The model includes 42 wind resources and 18 solar resources, whose cost and performance data are spatially resolved. The numbers presented here represent the median values of those resource bins.

Table 8: Summary of techno-economic assumptions for new resource options.

Several potential generation technologies were deliberately excluded from our analysis. Fixed-mount solar was omitted as the NREL ATB only provides comprehensive data for 1-axis tracking systems. Offshore wind was not included as resource characterization is still ongoing, though this aligns with NSP IRP findings that have consistently found it uneconomical. Natural gas with carbon capture and storage was excluded due to insufficient understanding of sequestration potential and associated costs in Nova Scotia. Geothermal power was omitted given limited resource characterization in the region. Finally, tidal energy was excluded based on preliminary economic assessment..

Renewable Resources: Wind and solar generation potential is characterized using ERA5 global reanalysis data, which provides hourly weather information at approximately 30 km x 30 km resolution [42]. Our methodology is as follows:

1. Calculates site-specific capacity factors using turbine-specific power curves for wind and appropriate performance models for solar PV
2. Determines land availability through geospatial analysis of land cover, protected areas, and terrain constraints, and translates this land availability to resource potential in MW
3. Estimates interconnection costs based on proximity to existing transmission infrastructure and published spur line costs
4. For wind resources, it selects the 7 most economically viable resource sites in each region for inclusion in the model. It selects the top 3 sites for solar PV.

Each resource site is then defined with spatially explicit derived costs, hourly resource strength, and total resource potential in MW. This approach captures Nova Scotia's exceptional wind resource quality, particularly in Cape Breton and coastal areas, while accounting for the more modest solar potential in the region.

This is pictured in Figure 20, where the left panel displays the land eligible for VRE development, removing areas containing water, farmland, built environment, protected land, and wetlands. The centre panel displays the 2025 LCOE for solar PV at per grid cell, and the right panel displays the 2025 LCOE for wind per grid cell.

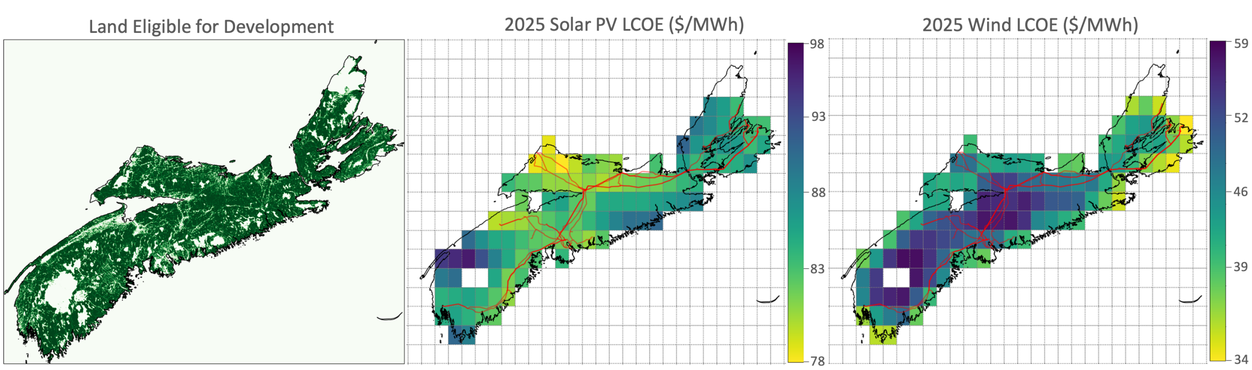

Figure 20: Summary of the VRE resource characterization for Nova Scotia. Left: land parcels eligible for VRE development across the province. Centre: computed solar LCOE values for 2025. Right: computed wind LCOE values for 2025.

Table 9 displays the summary statistics for the selected sites per zone.

		Z1	Z2	Z3	Z4	Z5	Z6
Wind	Capex ($/kW)	2,029	1,924	1,951	1,946	2,012	1,902
	Capacity Factors (%)	50.5	41.8	42.9	43.7	48.5	52.0
	LCOE ($/MWh)	38.1	44.3	43.6	42.7	39.0	35.3
Solar	Capex ($/kW)	1,764	1,742	1,725	1,755	1,751	1,729
	Capacity Factors (%)	18.3	18.2	18.1	19.4	18.7	17.8
	LCOE ($/MWh)	82.8	80.1	81.5	77.9	80.4	83.7

Table 9: Regional comparison of wind and solar resource options.

Demand Side Measures: Finally, demand-side options like demand response or additional utility energy efficiency were not modeled as explicit resources for selection. While NSP's load forecast already assumes a certain DSM trajectory (the "Base DSM" case), we did not include *expandable* demand response programs in the optimization due to lack of concrete cost and availability data. This keeps our focus on supply-side and storage solutions, with demand-side savings treated exogenously via the load forecast.

LDES Resource Availability: The deployment potential of different LDES technologies is constrained by specific geographical requirements, which we have incorporated as explicit model constraints based on Nova Scotia's physical characteristics. Our model incorporates these spatial limitations to ensure realistic siting of potential storage projects:

- **Pumped Storage:** We limit PS projects to zones Z4 and Z6 – as these were host to the five prospective sites identified by Stantec for WaterPower Canada [28].
- **Adiabatic Compressed Air Energy Storage:** ACA deployment is restricted to zones Z3, Z4, Z5, and Z6, where suitable geological formations—specifically salt domes—exist for creating underground storage caverns.
- **Hydrogen Storage:** Hydrogen storage is limited to zones Z5 and Z6, representing areas where current hydrogen infrastructure development is underway and where appropriate salt dome formations exist for underground storage. While zones Z3 and Z4 also contain suitable geology, the economic constraints of hydrogen transportation make co-location of production and storage facilities advantageous and we therefore do not consider these zones as there are currently no plans for hydrogen production.
- **Battery Technologies**: In contrast to the geographically constrained mechanical and chemical storage options, battery-based technologies (Lithium-ion, Sodium-ion, and Vanadium Redox Flow) can be deployed in any zone, offering significantly greater siting flexibility. This allows these technologies to be strategically placed near load centers or renewable generation to maximize their system value.

Expansion Decision Modelling: All capacity expansion decisions are modeled as continuous (fractional) builds rather than indivisible unit investments. In other words, the optimization can add, say, 50.3 MW of a technology, instead of being forced to build in increments of a whole unit size. This linear approach to capacity avoids integer variables and significantly reduces solve times. While in reality one cannot build half a power plant, this approximation is reasonable given the scale of investments and allows the solver to efficiently explore the optimal capacity to add for each technology.

6.2.7 System Operations and Reliability

To ensure the model produces technically feasible and reliable solutions, we implement several key operational constraints:

Resource Adequacy: A planning reserve margin requirement of 20% (translating to approximately 9% on an Unforced Capacity basis) ensures sufficient capacity to meet peak demand under contingency conditions. Each resource type contributes to this margin according to its Effective Load Carrying Capability (ELCC). ELCC represents the percentage of nameplate capacity that can be reliably counted on during peak demand periods, reflecting each technology's availability characteristics and correlation with system needs.

Where possible, ELCC values are taken from NSP documents, with conventional thermal resources valued at approximately 90% of nameplate capacity, existing wind resources at 20%, new wind resources at 10%, and solar resources at 0%. For novel LDES technologies, in absence of local precedent, we base their ELCC on literature and other system studies. Accordingly, we assign LDES resources a higher capacity credit (70%-90%) consistent with their ability to contribute across multi-day peak events (sourced from PJM's preliminary ELCC class ratings for 2026–2035 [43]). Our ELCC assumptions for storage technologies are presented in Table 10.

Storage Duration (hours)	2	4	6	8	10	24	100
ELCC	35%	49%	61%	65%	73%	85%	90%

Table 10: Effective load carrying capability assumptions for storage technologies by duration.

Renewable Integration Limits: As Nova Scotia integrates more wind and solar, system stability constraints limit the instantaneous penetration of nonsynchronous generation. We implement two key operational constraints based on NSP's studies:

1. A **maximum hourly dispatch limit** caps the instantaneous output from wind and solar resources based on system stability requirements. With the reliability tie to New Brunswick in operation, this limit is set at approximately 1200 MW and increases as grid-supporting technologies are added. In particular, this limit increases by 2 MW for every 1 MW of storage *and* 1 MVA of synchronous condenser capacity[19].
2. A **maximum instantaneous penetration** constraint restricts the percentage of load that can be met by non-synchronous generation in any hour. Based on NSP's system studies, this is set at 70% through 2030, increasing to 90% from 2031-2040 and 100% thereafter as grid

[19] Synchronous condensers help integrate variable renewable energy (VRE) by providing inertia, voltage support, and short-circuit strength, stabilizing the grid as inverter-based resources replace traditional synchronous generation. We assume a capital cost of $520,000 per MVA, consistent with industry estimates.

technologies mature. Here, “load” includes the electricity demand plus any charging demand from storage.

Transmission Constraints: Inter-zonal power transfers are limited by the thermal capacity of existing transmission corridors, reflecting the actual network topology of Nova Scotia's grid. The model can invest in transmission reinforcement if economically justified, trading off network expansion against localized generation and storage.

These operational constraints ensure that the system evolution respects both the physical limitations of the grid and the reliability standards required for safe and dependable electricity supply. More information on the assumed network topology is presented in Section 6.2.3.

6.2.8 Electricity Imports and Fuel Cost Assumptions

Interconnections and fuel supply play a critical role in Nova Scotia's planning. We include the following assumptions for imports and fuel costs:

Electricity Imports: Nova Scotia's interconnections to neighbouring grids are modeled. The Maritime Link (475 MW HVDC to Newfoundland) is fully operational in our model. We include the scheduled imports from Muskrat Falls via the Maritime Link as per existing contracts (the Nova Scotia block and supplemental energy deliveries). Beyond those contracts, the model can utilize any remaining Maritime Link capacity for market imports if economic. We model the Nova Scotia block as firm – i.e., providing 150 MW of firm capacity towards the planning reserve margin.

We also represent the intertie to New Brunswick (NB) which serves as a reliability and trade interconnection. We assume the reliability tie is in service by 2025, resulting in a transfer limit of 500 MW. We assign no firm capacity to this intertie (i.e. it does not contribute to the planning reserve margin).

To guide economic imports, we developed an import price forecast based on NSP's Atlantic Loop study, which provided seasonal on-peak/off-peak pricing projections through 2050. These prices reflect the marginal cost of electricity in neighbouring markets, and the model will import energy when it is cost effective to do so.

Fuel Prices: Fuel cost assumptions follow the U.S. EIA Annual Energy Outlook 2023 for New England region fuel prices, converted to CAD and adjusted for Nova Scotia where appropriate.

Finally, it should be noted that this modelling framework sets the stage for evaluating the role of LDES in Nova Scotia’s grid transformation. The methodologies described in this section ensure that the subsequent scenario results are grounded in a rigorous and Nova Scotia–specific analytical foundation, following best practices in capacity expansion modelling and incorporating the province’s unique policy and technical constraints.

7 Modelling results

This section presents key findings from the capacity expansion modeling outlined in Section 6, focusing on the role of LDES in Nova Scotia's electricity system transformation. We analyze results across two core scenarios:

- **LDES-ITC**: Base case with LDES technologies eligible for deployment, including the federal clean technology investment tax credit (ITC).
- **Reference**: No LDES technologies permitted (only 2-8-hour lithium-ion batteries).

Additionally, we examine a sensitivity case (**LDES-noITC**) that explores LDES deployment without Clean Technology Investment Tax Credits at specific points in our analysis.

The following analysis synthesizes these modeling results to illuminate how different LDES technologies perform under varying conditions and how their inclusion affects capacity mix, operational patterns, costs, emissions, and renewable integration.

7.1 Optimal Resource Mix and LDES Deployment

7.1.1 Generation and Capacity Mix

Incorporating LDES fundamentally shifts the optimal capacity mix by enabling higher renewable builds and reducing reliance on thermal generation. In the LDES-ITC scenario, the model aggressively expands wind and solar capacity in 2030 to capitalize on available tax credits, facilitated by LDES in the form of PS to balance their variability. This early adoption of storage allows the system to integrate more variable renewables than the Reference case, which must instead install additional gas turbines for capacity and flexibility services.

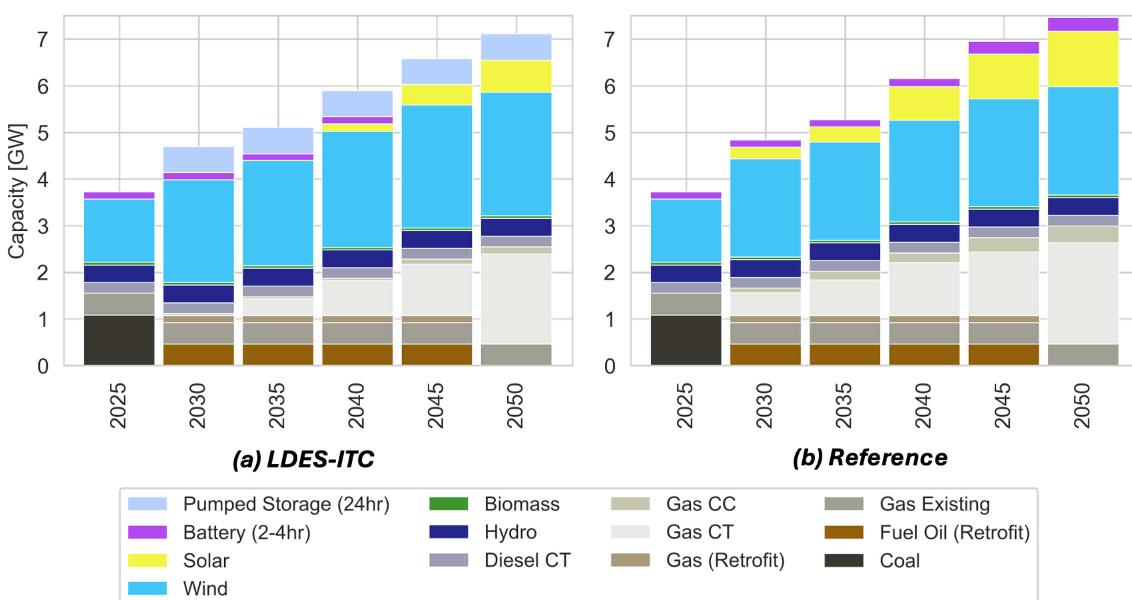

Figure 21: Optimal resource capacity mixes for the (a) LDES-ITC and (b) Reference scenarios

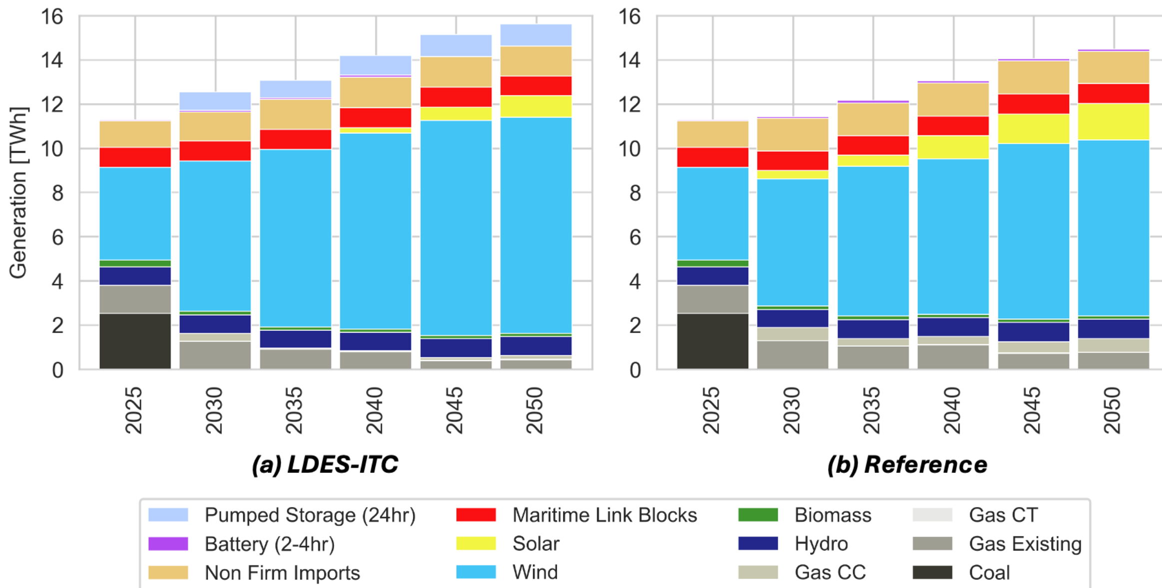

Figure 22: Optimal generation mixes for the (a) LDES-ITC and (b) Reference scenarios

The Reference scenario diversifies with more solar capacity to hedge against wind output correlation. Without storage to absorb excess wind generation, adding too much wind causes steep diminishing returns from price cannibalization and curtailment, prompting the model to incorporate solar to distribute renewable supply more evenly throughout the day. By contrast, with LDES, the system maximizes wind deployment (Nova Scotia's most economical renewable resource) and uses storage to smooth its variability and reduce curtailment.

As a result, the LDES-ITC case achieves a higher renewable share by 2030 (84.4% vs. 80.0% in the Reference case). The early deployment of LDES also has long-term implications: from 2035 onward, the Reference case relies on 1.5–3 times more fossil generation (gas-fired output) than scenarios with LDES.

7.1.2 LDES Technology Selection and Deployment Strategy

Despite evaluating a diverse menu of LDES technologies (adiabatic CAES, hydrogen, flow batteries, etc.), the model consistently selects 24-hour pumped storage (PS) as the most economically viable option. This aligns with the cost analysis from Section 5, which identified pumped storage as the lowest levelized cost option at multi-day durations. Though 10-hour battery technologies were expected to compete favorably, the model's preference for a 24-hour solution underscores the value of longer-duration capability in meeting Nova Scotia's specific needs beyond daily cycling.

The model does not select smaller-scale or shorter-duration LDES technologies, indicating that under current cost and performance assumptions, they do not provide sufficient system value compared to large pumped storage projects. With that said, perhaps a more spatially granular model might find more value in battery storage systems to provide congestion and/or curtailment relief at specific grid locations.

LDES Type	Zone	Capacity	2025	2030	2035	2040	2045	2050
PS	Z4	Power (MW)	0	126	126	126	126	126
		Energy (MWh)	0	3,024	3,024	3,024	3,024	3,024
	Z6	Power (MW)	0	434	434	434	434	434
		Energy (MWh)	0	10,416	10,416	10,416	10,416	10,416
	Total	Power (MW)	0	560	560	560	560	560
		Energy (MWh)	0	13,440	13,440	13,440	13,440	13,440

Table 11: Summary of cost optimal LDES deployment in the LDES-ITC scenario

Deployment Timing and Location: The model determines it is optimal to build pumped storage as soon as possible—by 2030 in both LDES scenarios—highlighting its urgent contribution for post-coal reliability. In the LDES-ITC case, 560 MW / 13,440 MWh of pumped storage capacity is deployed at two prospective sites (one in the Cape Breton Highlands and one near Parrsboro), taking advantage of the tax credit window and addressing the immediate need for firm capacity after the 2030 coal phase-out. This finding has significant policy implications: given the multi-year development timeline for pumped storage projects, planning and approval processes would need to begin immediately to achieve operational status by 2030.

7.1.3 Alignment with Utility Planning

These capacity mix findings align broadly with Nova Scotia Power's recent Integrated Resource Plan (IRP) modeling[20], with some notable differences. Both our LDES-enabled scenario and the utility's plan identify wind and solar as dominant new resources, but they diverge on firm capacity provision. While the IRP did include storage options, its use of representative days in modeling significantly limited the ability to properly value multi-day or seasonal storage benefits. Consequently, their plan projected additional gas generation and eventually a small modular reactor (SMR) around 2050 to meet reliability needs once the Lingan and Tupper retrofits retire.

In our LDES-ITC case, **pumped storage fulfills this long-term firm capacity role, eliminating the need for new nuclear while maintaining resource adequacy.** Both pumped storage and nuclear SMRs represent large, complex infrastructure projects with associated risks and uncertainties. However, pumped storage presents fewer risks given its technological maturity and operational track record.

We also observe more solar deployment in our results than the IRP projects, particularly in later years. This difference stems from our higher assumed solar capacity factors with single-axis tracking versus the IRP's fixed-tilt assumption. **Overall, by providing multi-day balancing, LDES enables a cleaner, more cost-effective pathway that meets or exceeds the province's renewable and emissions targets, whereas a no-LDES strategy necessitates costlier or higher-carbon alternatives to maintain reliability.**

[20]Our modelling is most similar to the CE1-E1-R1 scenario in the NSP IRP.

7.2 Operational Value and Renewable Integration

7.2.1 Dispatch Patterns with LDES

Examining hourly dispatch across representative time periods reveals how LDES transforms system operations and enables greater renewable integration. In a sample spring week of 2025, even with coal still on the system, we observe periods where wind energy is curtailed despite fossil generators running—a consequence of grid stability requirements that limit instantaneous renewable penetration.

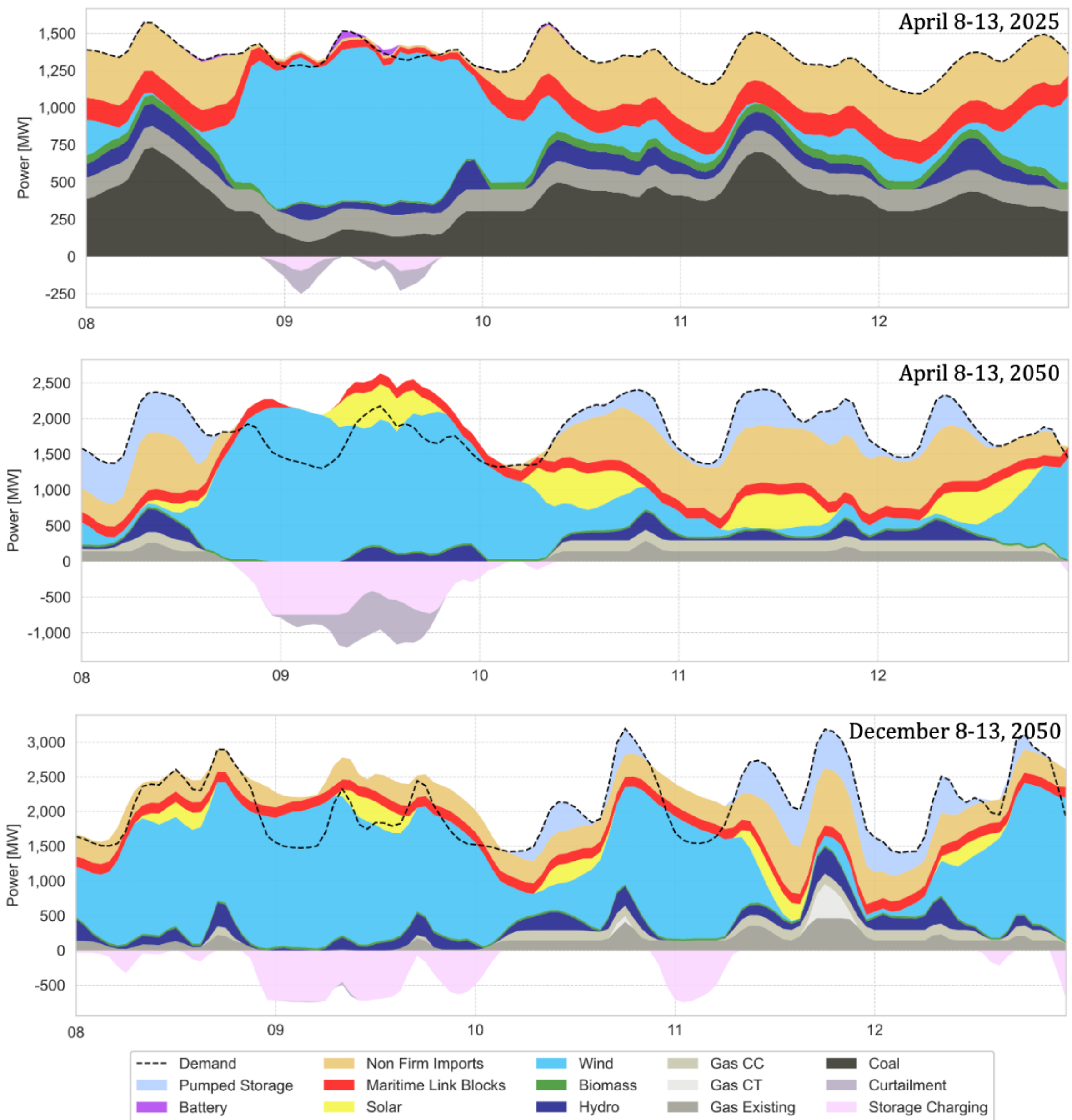

Figure 23: Hourly System Dispatch Patterns (2025-2050). The panels illustrate generation mix dynamics across three sampled periods: a spring week in 2025 (top), the same spring week in 2050 (middle), and a winter week in 2050 (bottom). Note that vertical axis scales differ between panels.

By 2050, the same spring week's dispatch pattern changes dramatically. The pumped storage system absorbs most excess power during windy periods, particularly on April 9. Some curtailment persists due to power capacity limitations (the 560 MW pumped storage capacity), renewable integration constraints, and minimum flow requirements for hydro resources. Nevertheless, compared to 2025, LDES substantially reduces curtailment and enables renewables to meet a greater portion of demand.

While imports via the Maritime Link and the province's hydro resources provide flexibility, LDES handles the majority of surplus generation that would otherwise be curtailed. Even with these resources, some renewable curtailment remains in the 2050 scenario due to integration constraints (primarily driven by transient stability constraints). Storage and other flexible resources manage most variability, but system operational rules still require occasional renewable curtailment to maintain reliability margins.

The winter scenario for 2050 demonstrates even greater LDES value during high-load periods with variable wind output. During this colder week, wind generation fluctuates significantly while overall electricity demand remains elevated. The pumped storage system captures virtually all excess renewable energy without hitting curtailment thresholds and releases this stored energy during subsequent wind lulls.

On the evening of December 11, we observe an extreme case of low wind and solar output coinciding with peak demand. Even with LDES, the system requires peaking gas turbines to meet this peak. This operational pattern highlights a critical insight: **LDES significantly reduces the frequency and magnitude of supply shortfalls but doesn't eliminate the need for some fast-response peaking capacity or imports during severe combination events of high demand and low renewable output.** LDES handles multi-day energy shifting and prevents many shortfall events, but the model still finds it economically optimal to maintain a modest gas peaking capability for rare events rather than massively overbuilding renewables and storage.

7.2.2 Storage Cycling and Utilization

The operational profiles reveal valuable insights about storage cycling requirements and utilization patterns. For lithium-ion batteries (4-hour duration), the model's dispatch results translate to approximately 136 full equivalent cycles per year on average, well aligned with the battery lifecycle assumptions from Section 5. The PNNL database reports a cycle life of 8,800 equivalent cycles for these systems, corresponding to 20 years at observed utilization levels. This validates that the expansion plan isn't over-stressing the battery assets.

Storage Type	Duration (Hours)	Year	Equivalent Full Cycles	Average Cycle Duration (Hours)	(Days)
Battery (4hr)	4	2030	126	69	2.9
		2040	147	60	2.5
Pumped Storage (24hr)	24	2030	73	119	5.0
		2040	75	117	4.9
		2050	79	111	4.6

Table 12: Storage cycling statistics calculated from the operational data

For 24-hour pumped storage, the cycling profile shows approximately weekly full cycles (73-79 full equivalent cycles annually), representing 4.6-5.0 days per cycle on average. This pattern indicates that pumped storage would primarily function as a weekly balancing resource rather than a daily cycler, capturing excess weekend generation for use during weekday peaks and bridging multi-day weather patterns—precisely the role that shorter-duration batteries struggle to fulfill.

7.2.3 Renewable Integration Benefits

LDES fundamentally improves Nova Scotia's ability to integrate variable renewable energy while respecting operational constraints. The model enforces the same integration requirements as the utility, including a 70% maximum instantaneous penetration limit for non-synchronous generation in 2030, gradually relaxing to 90% by 2035 as grid stabilization equipment is added, as well as maximum dispatch limits.

In the LDES-ITC scenario, storage enables a comprehensive integration strategy: pumped storage absorbs excess renewable generation when approaching stability limits, while the model simultaneously invests in synchronous condensers (approximately 116 MVA by 2030, increasing to 274 MVA by 2035) to cost-effectively raise maximum dispatch limits. This combined approach allows the system to safely approach the 90% instantaneous renewables threshold by 2035 without reliability compromises.

Scenario		2025	2030	2035	2040	2045	2050
LDES-ITC	Generation (GWh)	4,197	6,801	8,028	9,066	10,223	10,576
	Curtailment (GWh)	227	1,461	474	680	571	572
	Curtailment Fraction	5.4%	21.5%	5.9%	7.5%	5.6%	5.4%
Reference	Generation (GWh)	4,197	6,077	7,170	7,931	9,059	9,376
	Curtailment (GWh)	226	2,059	1,047	1,145	938	958
	Curtailment Fraction	5.4%	33.9%	14.6%	14.4%	10.4%	10.2%

Table 13: VRE generation and curtailment statistics

By contrast, the Reference scenario has limited ability to accommodate excess renewables and consequently invests in less synchronous condenser capacity (only 34 MVA in 2030, increasing to 150 MVA by 2035). Without long-duration storage capability, this system must curtail significantly more renewable output to maintain stability requirements. While both scenarios experience noticeable curtailment in 2030 due to the strict 70% limit, the divergence becomes pronounced thereafter. By 2040, the curtailed fraction of renewable generation in the LDES-ITC scenario falls to 7.5%, whereas the Reference case maintains approximately 14.4% curtailment levels.

This difference persists through 2050, with the Reference case effectively wasting a more substantial fraction of its renewable investments. Without LDES to modify the economic calculus, the model finds it optimal to accept higher curtailment levels rather than invest in more expensive integration solutions. The LDES scenarios fundamentally change this dynamic by providing cost-effective storage capacity that captures otherwise curtailed energy.

These operational and integration results demonstrate that LDES profoundly alters system dispatch patterns by:

1. Reducing renewable curtailment by serving as a flexible absorption mechanism
2. Supplying energy during extended low-renewable periods to displace fossil generation
3. Smoothing the supply-demand balance across multiple days and weather patterns

Grid reliability is maintained across all scenarios, but with LDES it is achieved with minimal fossil fuel consumption—limited to brief operation of peaking resources during exceptional conditions—rather than requiring frequent thermal generation or accepting substantial renewable curtailment. This operational profile confirms that LDES can effectively function as a "shock absorber" for a renewables-dominated grid, operating within its technical limits while materially enhancing the system's ability to manage variability.

7.3 Economic Benefits and System Costs

7.3.1 Total System Cost and Cost-Effectiveness

Enabling LDES yields a clear economic benefit at the system level. The net present value (NPV) of total system cost (2025–2050) in the LDES-ITC scenario is 5.8% lower than in the Reference scenario. This represents a substantial reduction in long-term costs for Nova Scotia's ratepayers, achieved through more efficient resource utilization—the storage allows cheaper renewable energy to replace more expensive fuel-based generation while avoiding overbuilding of capacity.

On a per-MWh basis, the average cost of electricity supply decreases from approximately $42.99/MWh in the Reference case to $40.52/MWh with LDES. While a $2.5/MWh reduction might appear modest, across the entire provincial grid this translates to significant savings on the order of tens of millions of dollars annually. These figures represent system-optimal costs from the model's co-optimization of investments and operations to minimize total expenditures rather than market prices. Nevertheless, the trend clearly indicates that incorporating LDES reduces the long-run cost of achieving Nova Scotia's energy and climate objectives.

7.3.2 Wholesale Price Impacts

To assess consumer price implications, we post-processed the model results to estimate wholesale energy prices (locational marginal prices, or LMPs) for each hour and computed annual load-weighted average prices. In the near term (2025 and 2030), the average wholesale price remains virtually identical across scenarios, reflecting similar generation mixes and constraints in these early years before LDES assets are fully integrated.

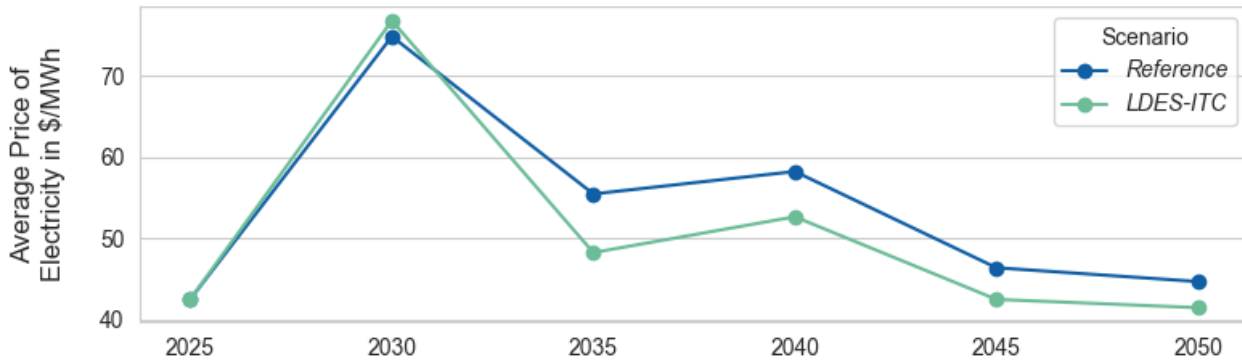

Figure 24: Average wholesale electricity prices in the Reference and LDES-ITC scenarios

This suggests that LDES not only reduces total system costs but also stabilizes or lowers market clearing prices for electricity in a high-renewable system. While total system cost reduction doesn't automatically translate to lower wholesale prices in all market designs, our analysis shows that LDES accomplishes this by changing which generators are on the margin during peak periods—replacing high-cost peaking units with stored renewable energy. Though Nova Scotia currently operates under a regulated market structure rather than a competitive wholesale market, this analysis of marginal costs provides valuable insight into how customer rates might be affected. Investing in LDES creates a hedge against future price volatility and upward pressure from fuel costs by enabling more consistent utilization of inexpensive renewable energy.

7.3.3 LDES Value Streams and Utilization Economics

The model's economic dispatch of storage reveals that LDES derives value from multiple revenue streams. For the storage technologies deployed in the LDES-ITC scenario, we calculated the average price spread between charging and discharging electricity prices throughout the study period.

Storage Type	Duration (Hours)	Year	Average Charge Price ($/MWh)	Average Discharge Price ($/MWh)	Average Price Spread ($/MWh)
LFP	4	2025	52.69	55.27	2.56
LFP	4	2030	93.07	99.84	5.29
LFP	4	2035	54.40	76.32	16.06
LFP	4	2040	58.19	79.00	17.08
PS	24	2030	92.76	101.80	9.04
PS	24	2035	51.61	84.81	33.20
PS	24	2040	55.60	85.71	30.11
PS	24	2045	24.84	84.93	60.09
PS	24	2050	24.75	81.41	56.66

Table 14: Average electricity prices during charging and discharging events for each storage technology deployed in the LDES-ITC scenario.

The realized price spreads for 24-hour pumped storage range from $7.82/MWh in 2030 to $54.27/MWh in 2050. These spreads are sufficient to cover operating costs and contribute to capital recovery when considered alongside the storage's capacity value. Notably, these modeled spreads are generally lower than the breakeven values calculated in our simplified Levelized Cost of Storage analysis from Section 5, which estimated a 10-hour pumped storage system would require roughly an $81/MWh arbitrage spread to recover costs on energy arbitrage alone.

This discrepancy highlights an important insight: simple LCOS or arbitrage analyses understate LDES value. The model selects pumped storage despite narrower energy price spreads because it provides substantial additional system benefits not captured in a pure arbitrage view. These include capacity value (deferring new gas plants or imports), reduced curtailment, congestion relief, and ancillary services. Storage can be economically viable even when energy market spreads are smaller than its standalone cost, provided it delivers the reliability and renewable integration benefits the system requires.

While Table 15 also includes data for 4-hour lithium iron phosphate batteries, these shorter-duration systems display notably different economic characteristics than true LDES technologies like pumped storage. The data shows 4-hour LFP batteries operating with consistently smaller price spreads ($2.56-17.08/MWh) compared to pumped storage ($7.82-60.99/MWh). This pattern reflects LFP's less capital-intensive cost structure, which allows it to economically perform daily arbitrage even with narrower price differentials.

It's worth noting that our planning model uses deterministic optimization with perfect foresight, which doesn't capture real-world uncertainties like forced or unforced generator outages that could create additional scarcity events and price spikes. While this approach may underestimate certain revenue opportunities for storage operators, it also optimistically assumes perfect timing of storage operations, which maximizes theoretical profitability. In practice, actual investment decisions would necessarily incorporate additional revenue mechanisms such as capacity payments or reliability contracts beyond energy arbitrage, particularly for capital-intensive LDES technologies where cost recovery might require structured capacity payments supplemented by arbitrage profits.

Policy mechanisms may be needed to capture these full value streams for LDES investors in Nova Scotia's regulated market context. Options include incorporating storage into resource adequacy planning or establishing a capacity market signal for LDES. Nevertheless, from a societal cost perspective, the model's results make a compelling case that long-duration storage is cost-effective for Nova Scotia.

7.4 Emissions

The inclusion of long-duration storage has a direct and significant impact on power sector emissions. By enabling higher renewable penetration and displacing fossil fuel generation, the LDES scenarios consistently achieve lower CO_2-equivalent (CO_2e) emissions each year compared to the Reference case.

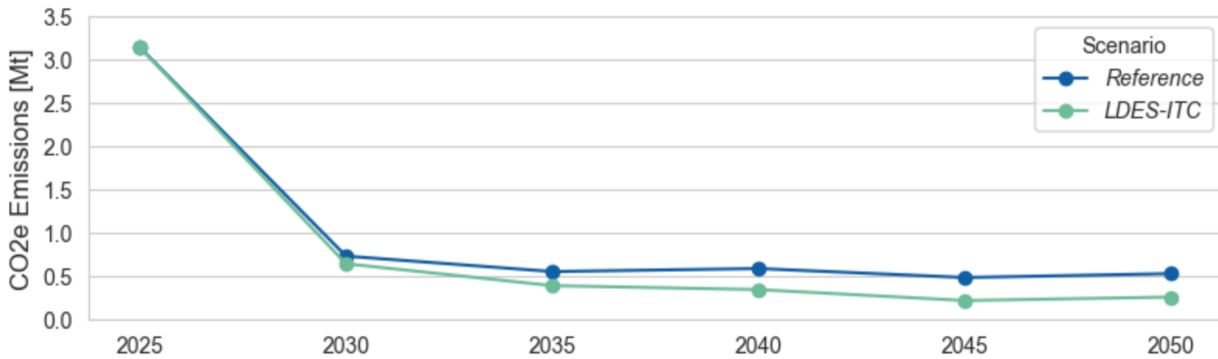

Figure 25: Annual power sector CO2e emissions for the Reference and LDES-ITC scenarios

After the 2030 coal phase-out, the emissions difference becomes pronounced: the average annual emissions in the Reference scenario for 2030 onward is approximately 580 kilotonnes CO_2e, which is 55% higher than the LDES-ITC scenario's average of roughly 375 kt. In other words, integrating LDES cuts expected post-2030 emissions nearly in half relative to a path without LDES as a resource option. This represents a profound improvement in environmental performance, highlighting LDES as a key enabler of deeper decarbonization.

The storage allows renewable energy to cover more of the load (including periods that would otherwise be served by natural gas or imports), leading to fewer hours of gas-fired generation and thus lower greenhouse gas output. These findings reinforce the concept from literature that LDES is instrumental for achieving near-zero emissions grids at reasonable costs. It provides the bridge to cover prolonged renewable shortfalls, thereby avoiding a situation where fossil backup runs extensively.

Notably, our results indicate that without LDES, Nova Scotia might meet the 80% renewable by 2030 goal but struggle to eliminate the last 20% of fossil generation by 2050 without resorting to new zero-carbon firm capacity like nuclear or unabated gas with carbon capture. The LDES scenario, however, shows a viable pathway to meet reliability needs with storage instead of fossil fuel, yielding much lower cumulative emissions.

In summary, **LDES delivers substantial emissions reductions in the modeled pathways, underlining its value not just economically but also in terms of climate strategy.** Policymakers looking to exceed the 80% renewables mandate and approach net-zero emissions would find long-duration storage to be a pivotal asset, as it directly enables renewable energy to become the dominant, on-demand energy source year-round.

7.5 Policy Sensitivity: LDES Deployment Without Federal Tax Credits

While our primary analysis focuses on the Reference and LDES-ITC scenarios, examining LDES deployment without federal investment tax credits provides valuable insights on the technology's intrinsic economics and policy sensitivity.

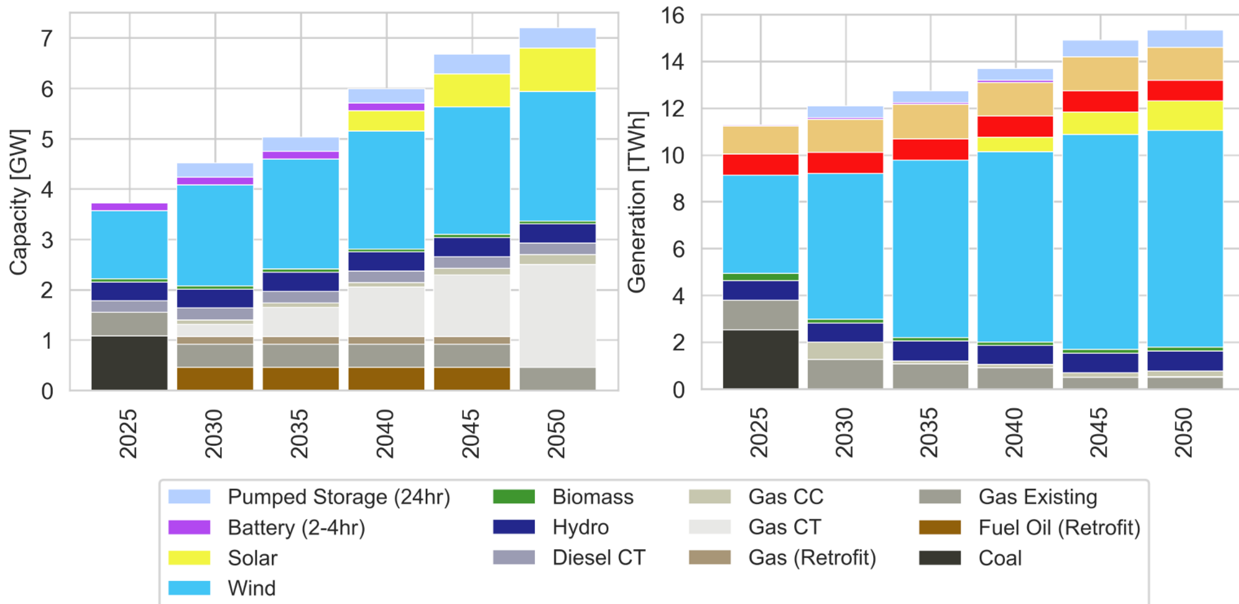

Figure 26: Capacity mix (left) and generation mix (right) for the LDES-noITC scenario

LDES Type	Zone	Capacity	2025	2030	2035	2040	2045	2050
PS	Z4	Power (MW)	0	81	81	81	107	107
		Energy (MWh)	0	1,944	1,944	1,944	2,568	2,568
	Z6	Power (MW)	0	201	201	201	292	292
		Energy (MWh)	0	4,824	4,824	4,824	7,008	7,008
	Total	Power (MW)	0	282	282	282	399	399
		Energy (MWh)	0	6,768	6,768	6,768	9,576	9,576

Table 15: Summary of LDES deployment in the LDES-noITC scenario

The LDES-noITC scenario demonstrates that even without federal incentives, pumped storage remains economically attractive, though with a modified deployment trajectory. In this case, approximately 282 MW / 6,768 MWh of pumped storage is built by 2030 (roughly half the capacity of the LDES-ITC scenario), distributed across the same two optimal sites in Nova Scotia. As load growth continues and renewable costs decline, the model finds it economical to expand this capacity to 399 MW / 9,576 MWh by 2045.

It should be noted that the Z4 pumped storage project (in Parrsboro) at only 107 MW may be smaller than what is typically considered economically viable for pumped storage developments, which often benefit from economies of scale at larger capacities. Similarly, the incremental capacity expansion approach shown in the model might not align with operational realities of pumped storage development. Nevertheless, these results demonstrate the fundamental value of LDES, and actual deployment decisions can be informed by this analysis while considering practical implementation constraints.

Several key insights emerge from this sensitivity analysis:

1. **Intrinsic Economic Value**: Even without tax incentives, LDES provides sufficient system value to justify significant investment. The model selects pumped storage based on its fundamental contribution to reliability, renewable integration, and cost reduction.
2. **Deployment Timing Effects**: The absence of the ITC primarily affects the timing and scale of initial deployment rather than the ultimate decision to build storage. This suggests that policy support mainly accelerates benefits rather than fundamentally altering the technology's viability.
3. **Policy Implications**: Given that the federal ITC expires in 2034, which could precede the completion of large-scale pumped storage projects due to their lengthy development timelines, Nova Scotia may need to develop alternative support mechanisms to realize timely LDES deployment.
4. **Scale Considerations**: While the model can continuously size pumped storage capacity, real-world project economics may favor larger minimum project sizes than those shown in the no-ITC scenario. This highlights that actual implementation might require policy or contractual frameworks that recognize the full system value of LDES to overcome initial development hurdles.

The LDES-noITC scenario reinforces that the fundamental case for long-duration storage in Nova Scotia's clean energy transition remains strong even without federal incentives. This finding suggests that while policy support is valuable for accelerating deployment, provincial decision-makers should view LDES as a strategic infrastructure investment with inherent economic merit rather than as a policy-dependent solution.

8 Conclusions and recommendations

This study has evaluated the potential role of long-duration energy storage (LDES) in enabling a deeply decarbonized electricity system for Nova Scotia. Through comprehensive technology screening and detailed power system modeling, we have assessed how LDES could support the province's clean energy transition beyond the 2030 coal phase-out through to a net-zero emissions electricity grid by 2050. Our analysis yields several high-level conclusions and specific recommendations for policymakers, utilities, and other stakeholders.

8.1 Key Findings

Our assessment reveals that LDES, particularly in the form of pumped storage, offers substantial value for Nova Scotia's electricity system transformation:

Optimal Technology Selection: Among various LDES options evaluated, 24-hour pumped storage consistently emerges as the most economically viable solution for Nova Scotia. Despite examining diverse alternatives including advanced compressed air energy storage, hydrogen storage, and flow batteries, the model selects pumped storage for its favorable combination of cost, efficiency, and operational characteristics.

This finding is particularly significant given that pumped storage represents a proven, mature technology with decades of operational experience globally, reducing implementation risk compared to emerging alternatives. The province's geography offers viable sites for this technology, presenting an opportunity to leverage established solutions rather than waiting for emerging technologies to mature.

System Cost Reduction: Incorporating LDES reduces the net present value of system costs by 5.8% compared to a scenario without LDES, translating to lower average electricity costs ($40.52/MWh versus $42.99/MWh). These savings arise from more efficient renewable integration and reduced reliance on fossil fuel generation.

Emissions Mitigation: LDES enables a 55% reduction in post-2030 carbon emissions compared to the Reference case by allowing renewable resources to meet a larger share of electricity demand. This translates to approximately 200,000 tonnes of CO_2e avoided annually by 2050, contributing significantly to Nova Scotia's climate commitments while providing a pathway to exceed the 80% renewable electricity mandate.

Renewable Integration Enhancement: Storage significantly reduces renewable curtailment, with curtailment levels reaching 5.4% by 2050 in the LDES scenario compared to 10.2% without LDES. This improved utilization maximizes the value of renewable investments and helps overcome grid stability constraints.

Policy Sensitivity: The economic case for LDES remains robust even without federal investment tax credits, though policy support accelerates deployment. This finding indicates the fundamental value proposition of LDES is not dependent on particular incentive structures but is intrinsic to the technology's system benefits.

Implementation Pathway: Geographical analysis confirms viable sites for pumped storage development in Nova Scotia, particularly in the Cape Breton Highlands and near Parrsboro. These locations align with the province's transmission topology and renewable resource potential.

8.2 Recommendations for Implementation

Based on these findings and considering the policy landscape outlined in Net Zero Atlantic's "Energy Storage Policy and Practice Report" [44], we recommend the following actions to advance LDES deployment in Nova Scotia:

Initiate Site-Specific Feasibility Studies: Conduct detailed engineering and environmental studies for the two identified pumped storage locations to confirm technical viability, refine cost estimates, and identify any potential development constraints.

Establish Regulatory Framework for LDES Valuation: Develop clear mechanisms within Nova Scotia's electricity market framework to compensate storage for its full range of services, including capacity value, renewable integration, and grid stabilization benefits. This aligns with value-stacking approaches identified in the recent Net Zero Atlantic "Energy Storage Policy and Practice Report" [44].

Coordinate LDES and Renewable Development: Align LDES planning with renewable energy procurement to ensure complementary deployment timelines. The maximum value of storage will be realized when it enters service alongside substantial new renewable capacity.

Incorporate LDES in Grid Planning: Integrate LDES considerations into transmission planning and grid stability studies, particularly regarding the synchronous condensers and other grid-forming technologies needed to maximize renewable penetration.

Develop Provincial Policy Support: Given the long development timeline for pumped storage projects and the limited window for federal investment tax credits (expiring in 2034), establish provincial support mechanisms to ensure LDES projects can advance in a timely manner.

Investigate Additional LDES Options: While pumped storage emerges as the most economical option currently, continue monitoring technological developments in other LDES technologies, particularly compressed air energy storage, which shows promise given Nova Scotia's favorable salt geology.

8.3 Areas for Future Research

Several areas warrant further investigation to refine the understanding of LDES in Nova Scotia:

Detailed Operational Studies: As an immediate priority, conduct more granular operational analysis including dynamic stability studies to better quantify the grid services LDES can provide, particularly under contingency events.

Multi-Year Weather Analysis: Model several decades of weather data to better assess LDES performance across diverse wind and load patterns. This extended timeframe would provide more robust valuations of storage technologies by capturing the full range of renewable resource variability Nova Scotia might experience.

Climate Resilience Assessment: Evaluate how LDES can enhance system resilience to extreme weather events, particularly ice storms that commonly disable provincial wind generation for multiple days. As climate change intensifies weather volatility, understanding storage performance during these critical reliability events would better quantify the full value proposition of LDES technologies.

Hydrogen System Integration: As hydrogen initiatives advance in Nova Scotia, examine potential synergies between hydrogen production, storage, and power system flexibility needs.

8.4 Concluding Observations

Nova Scotia stands at a critical juncture in its energy transition. As the province moves toward phasing out coal by 2030 and achieving an 80% renewable electricity supply, long-duration energy storage emerges as a vital enabling technology. Our analysis demonstrates that LDES—specifically pumped storage—represents not just a technical solution but an economically advantageous pathway toward a reliable, affordable, and deeply decarbonized electricity system.

By making strategic investments in LDES now, Nova Scotia can position itself to achieve its energy transition goals while maintaining system reliability and managing costs. The time-sensitive nature of these findings calls for near-term action to begin the development process for LDES resources, ensuring they can be operational to support the post-coal grid when needed most.

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