2020 INTEGRATED RESOURCE PLAN (IRP): DRAFT ASSUMPTIONS SET

JANUARY 20, 2020

Nova Scotia POWER
An Emera Company

INTRODUCTION

- The following materials represent a preliminary working draft of the Input Assumptions to be used in the 2020 IRP Modeling.

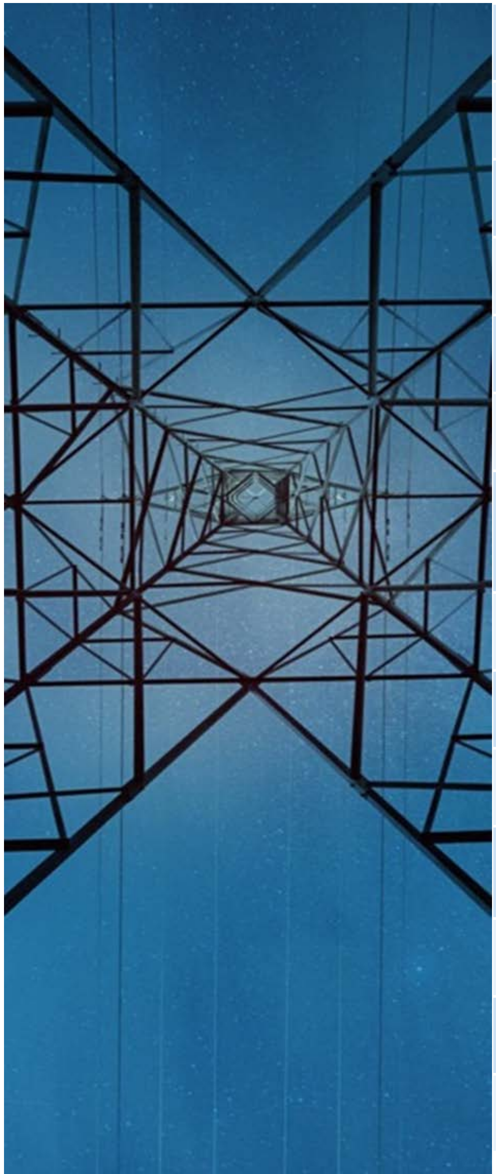
- These Draft Input Assumptions are being brought forward for discussion with stakeholders.

- The details of these assumptions will continue to be further refined as the IRP team addresses stakeholder feedback and reviews emerging information.

The final view of the Input Assumptions to be used in the 2020 IRP model will be circulated to stakeholders on February 7, 2020, following discussion and refinement.

2020 IRP ASSUMPTIONS TABLE OF CONTENTS

Click on page number below to go to slide



2020 IRP:
FINANCIAL ASSUMPTIONS

JANUARY 28, 2020

Nova Scotia POWER An Emera Company

FINANCIAL ASSUMPTIONS

Weighted Average Cost of Capital (WACC):*

Pre-tax = 6.62%

After-tax = 5.64%

Inflation Rate:

25-year Average = 2%

Based on Conference Board of Canada CPI growth forecast for NS

Revenue Requirement Profiles:

- Supply-side options that represent a capital investment require a revenue requirement profile
- Revenue requirement profiles for input into Plexos will be developed outside of the model using E3's Pro Forma financial model

*Utility and Review Board M09498 – Approval of pre-tax WACC/AFUDC rate for both capital and non-capital matters

EXCHANGE RATES

US Foreign Exchange Rate

Year	2021	2022	2023	2024
Forecasted USD/CAD	1.31	1.35	1.35	1.35

2020 is an average of 6 banks
2021 is an average of 5 banks
2022 and beyond is an average of 2 banks

Nova Scotia POWER An Emera Company

2020 IRP:
LOAD ASSUMPTIONS

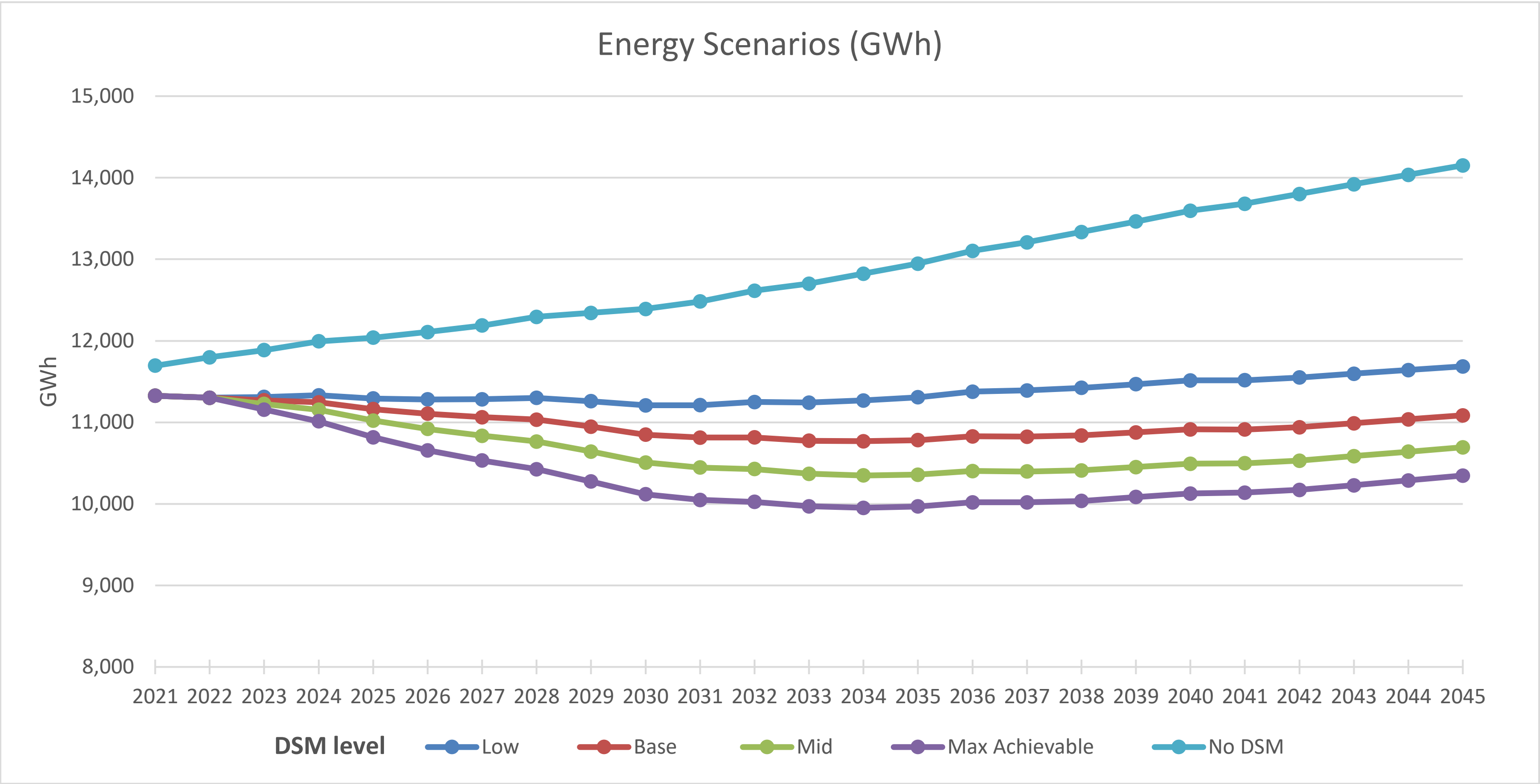
JANUARY 20, 2020

Nova Scotia POWER
An Emera Company

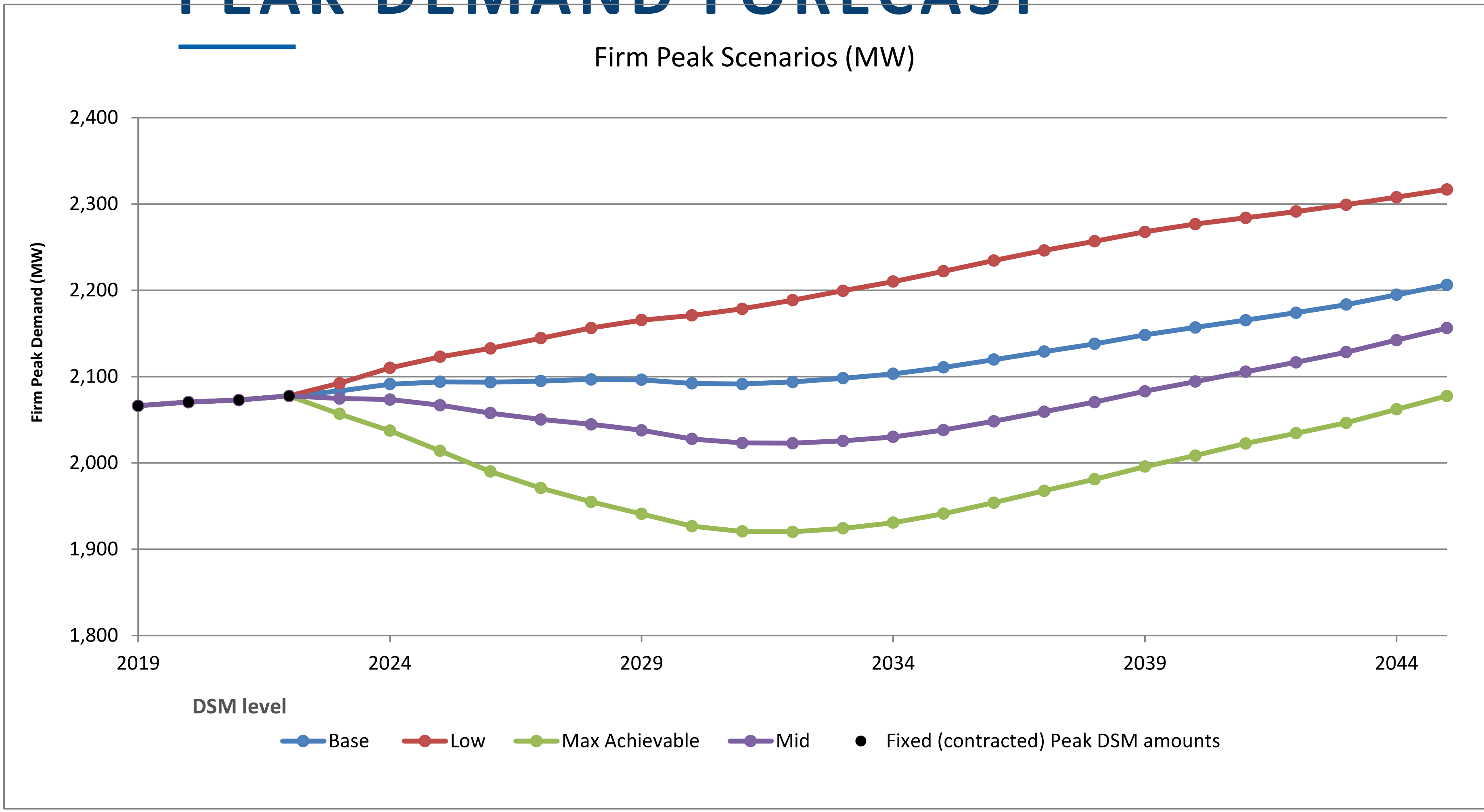
LOAD ASSUMPTIONS OVERVIEW

- The underlying data for the “Base Load Forecast” is based on NSP’s annual Load Forecast Report, as filed with the UARB in 2019.
- The “Scenarios” applied to the Base Load level are the DSM scenarios from E1’s Potential Study work, as well as a “No DSM” scenario, which is required for calculated the Avoided Cost of Demand Side Management.
- The Sustainable Development Goals Act (which established a “net zero” goal for all sectors by 2050) will likely drive significant electrification of other sectors (e.g. heating, transportation, etc.). NSP’s consultants, E3, are working to understand the potential load impacts of these levels of electrification, and whether they fit within the bounds of the scenarios as proposed (e.g. the load with “No DSM” could in fact represent a scenario where both electrification and energy efficiency is ongoing).
- We will continue to discuss potential other scenarios with stakeholders.

BASE LOAD FORECAST WITH VARIATIONS



PEAK DEMAND FORECAST



BASE LOAD FORECAST

Base Load Forecast assumptions include:

- Economic forecast from Conference Board of Canada
- EV penetration based on conservative estimate of Electric Mobility Canada’s growth model
- EV includes estimate for peak mitigation
- 10-year average used for normal weather

Nova Scotia POWER
An Emera Company

DEMAND SIDE MANAGEMENT IN THE LOAD SCENARIOS

- The 4 DSM scenarios (Base, Low, Mid, Max Achievable) were subtracted from the "no DSM" forecast.
- 2020-2022 in all scenarios is based on the current 3-year supply agreement. The 4 Potential Study scenarios were shifted to a starting year of 2023, after the current agreement expires.
- The scenarios are assumed to include all DSM, including:
  - Cost-effective electricity efficiency and conservation activities provided by the franchise holder
  - Initiatives that may be pursued by NS Power as permitted under the Public Utilities Act
  - Consumer behaviour and investments
  - Energy efficiency codes and standards
  - Initiatives undertaken by other agencies
  - Technological and market developments

2020 IRP:
ENVIRONMENTAL ASSUMPTIONS (EXISTING & DEFINED POLICY)

JANUARY 20, 2020

Nova Scotia POWER
An Emera Company

APPLICABLE LEGISLATION

- Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations
- Regulations Limiting Carbon Dioxide Emissions from Natural Gas-Fired Generation of Electricity
- Greenhouse Gas Emissions Regulations
- Greenhouse Gas Pollution Pricing Act
- Cap and Trade Regulations
- Clean Fuel Standard

APPLICABLE LEGISLATION (CONT.)

- Air Quality Regulations
- Renewable Electricity Regulations

The following slides provide an overview of each of the regulations above as well as the current existing values of these policies. Scenarios with varying degrees of change to these values will be examined (likely mostly based on potential outcomes of the Sustainable Development Goals Act). NSP will be discussing potential scenarios with stakeholders in its January IRP workshop.

REDUCTION OF CARBON EMISSIONS FROM COAL FIRED GENERATION

These Federal regulations require coal units to meet greenhouse gas (GHG) emissions intensity of 420t/GWh (via conversion to other fuel) or shut down at the end of "useful life", as defined by the regs based on commissioning dates, and would cause conversion or retirement by the following years for the NSP fleet:

- 2019 – Trenton 5
- 2021 – Point Tupper
- 2029 – Lingan 1, 2, 3 & 4
- 2030 – Trenton 6 & Point Aconi

- Nova Scotia's Equivalency Agreement with the Federal Government enables NS Power to continue to operate coal units after these dates.
- SCENARIO NOTE: At least one modeling scenario will examine a portfolio where all coal units are retired by Dec 31, 2029 in accordance with the 2018 Federal Coal Regulations.

GREENHOUSE GAS EMISSIONS REGULATIONS

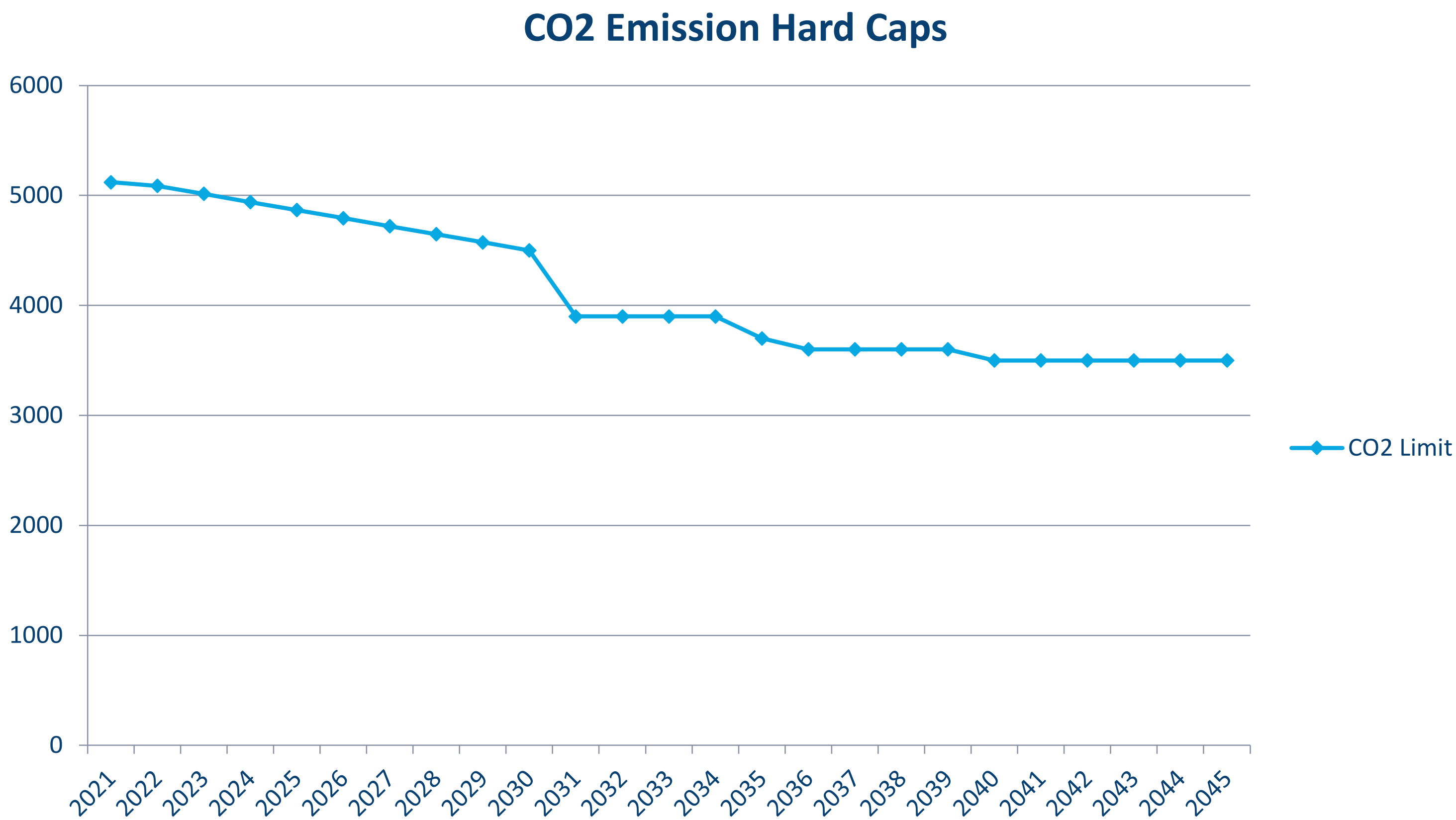
- These Provincial regulations stipulate GHG emission limits from 2010 to 2030 for all facilities in the province that emit greater than 10,000 tonnes GHG per year.

- Nova Scotia's equivalency agreement with the Federal government enables NS Power to meet the *Greenhouse Gas Emissions Regulations* as opposed to the requirements of the *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*

- Nova Scotia's equivalency agreement has been renewed from 2020-2024 with agreement on future methodology from 2025-2040.

- Nova Scotia's equivalency agreements must meet evolving Federal requirements.

FORECASTED CO2 EMISSION HARD CAPS*



*Source: Greenhouse Gas Emission Regulations & Quantitative Analysis of 2019 NS Equivalency Agreement

Nova Scotia POWER An Emera Company

GREENHOUSE GAS POLLUTION PRICING ACT

- This act is the implementation of the Federal carbon pollution pricing system.
- Introduces an output-based pricing system (OBPS) for large industrial emitters.
- Provinces are free to choose an OBPS or cap-and-trade system if they meet the minimum Federal pricing and emissions reduction targets.
- Nova Scotia has opted for a cap-and-trade system, therefore, this act does not currently affect NS Power in the form of a carbon tax.

CAP AND TRADE PROGRAM REGULATIONS

- Provincial regulations that outline framework and requirements for cap and trade program.
- Stipulate free allocations for NS Power GHG emissions
- Meets the Federal *Greenhouse Gas Pollution Pricing Act* requirements

Greenhouse Gas Free Allowances 2021-2022

Year	GHG Free Allowances Million tonnes
2021	5.120
2022	5.087

Nova Scotia POWER An Emera Company

CLEAN FUEL STANDARD

- Federal government published a regulatory framework for the Clean Fuel Standard which will apply to liquid, solid and gaseous fuels combusted for the purposed of creating energy.
- Coal combusted at facilities covered by *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations* will be exempt
- Draft regulations have not yet been published.
- Expecting requirements for liquids to come into force by 2022 and for gaseous fuels by 2023.
- For IRP, NSP expects “high” fuel price sensitivities to capture impact of this standard (e.g. no explicit assumption required for modeling).

AIR QUALITY REGULATIONS

- Provincial regulations that stipulate NS Power emission limits for Sulphur dioxide (SO_2), nitrogen oxides (NOx) and mercury (Hg) from 2010 to 2030.
- Outlines requirements for mercury diversion program and stipulates NS Power can use credits for compliance from 2020 to 2030.

Emissions Multi-Year Caps (SO2, NOx)

Multi-Year Caps Period	SO_2 (t)	NO_X (t)
2015 – 2019 (equal outcome)	304,500	96,140
2020	60,900	14,955
2021-2022	90,000	
2023-2024	68,000	56,000
2025	28,000	11,500
2026 – 2029	104,000	44,000
2030	20,000	8,800

Nova Scotia POWER An Emera Company

AIR QUALITY REGULATIONS (CONT.)

Emissions Annual Maximums (SO_2, NOX)

Year	SO_2 Annual Maximum (t)	NO_X Annual Maximum (t)
2015 – 2019	72,500	21,365
2021 – 2024	36,250	14,955
2026 – 2029	28,000	11,500

Individual Unit Limits (SO_2)

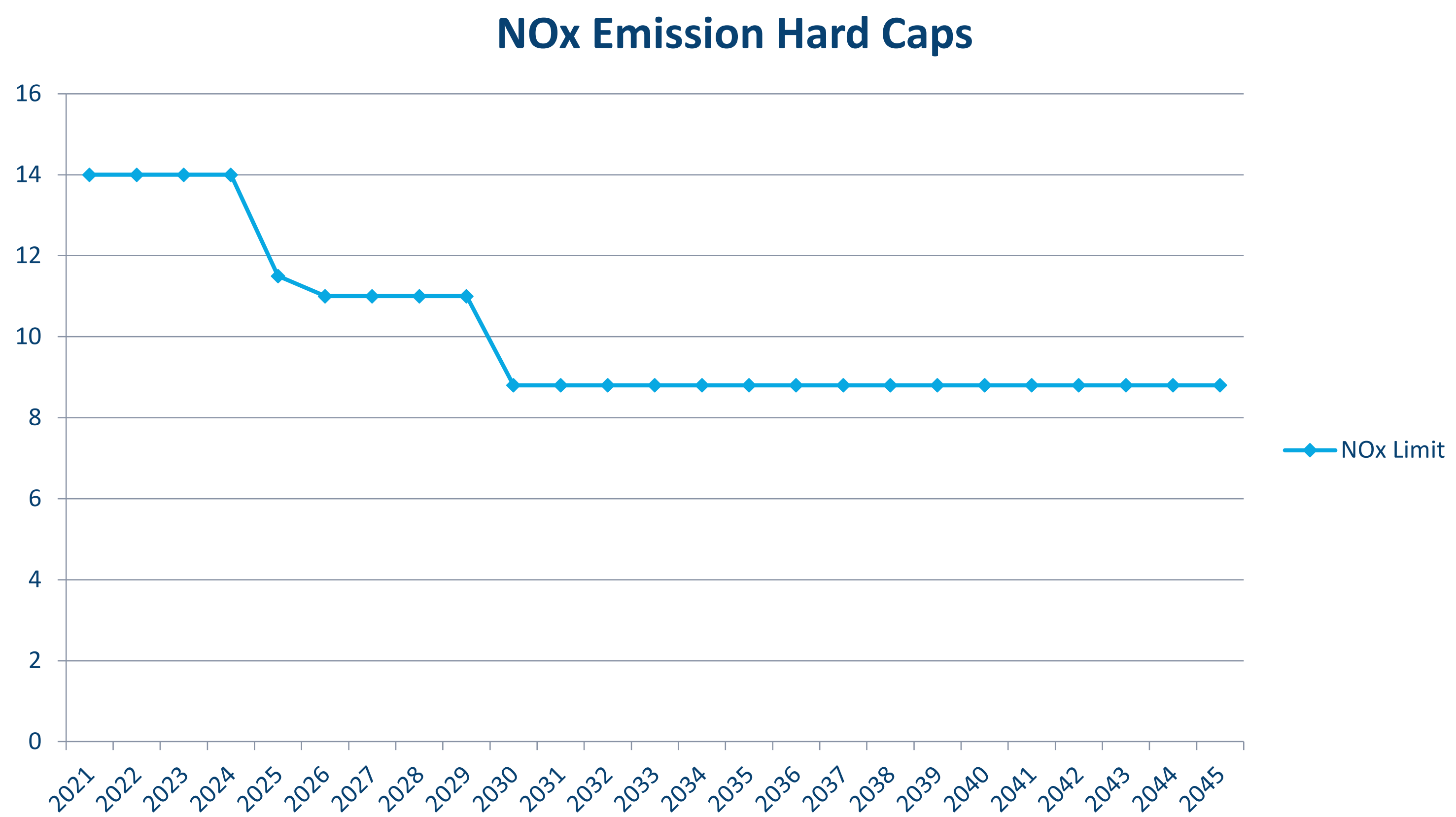
Year	SO_2 Individual Unit Limit (t)
2015 – 2019	42,775
2020 – 2024	17,760
2025 – 2029	13,720
2030	9,800

Mercury Emissions Caps

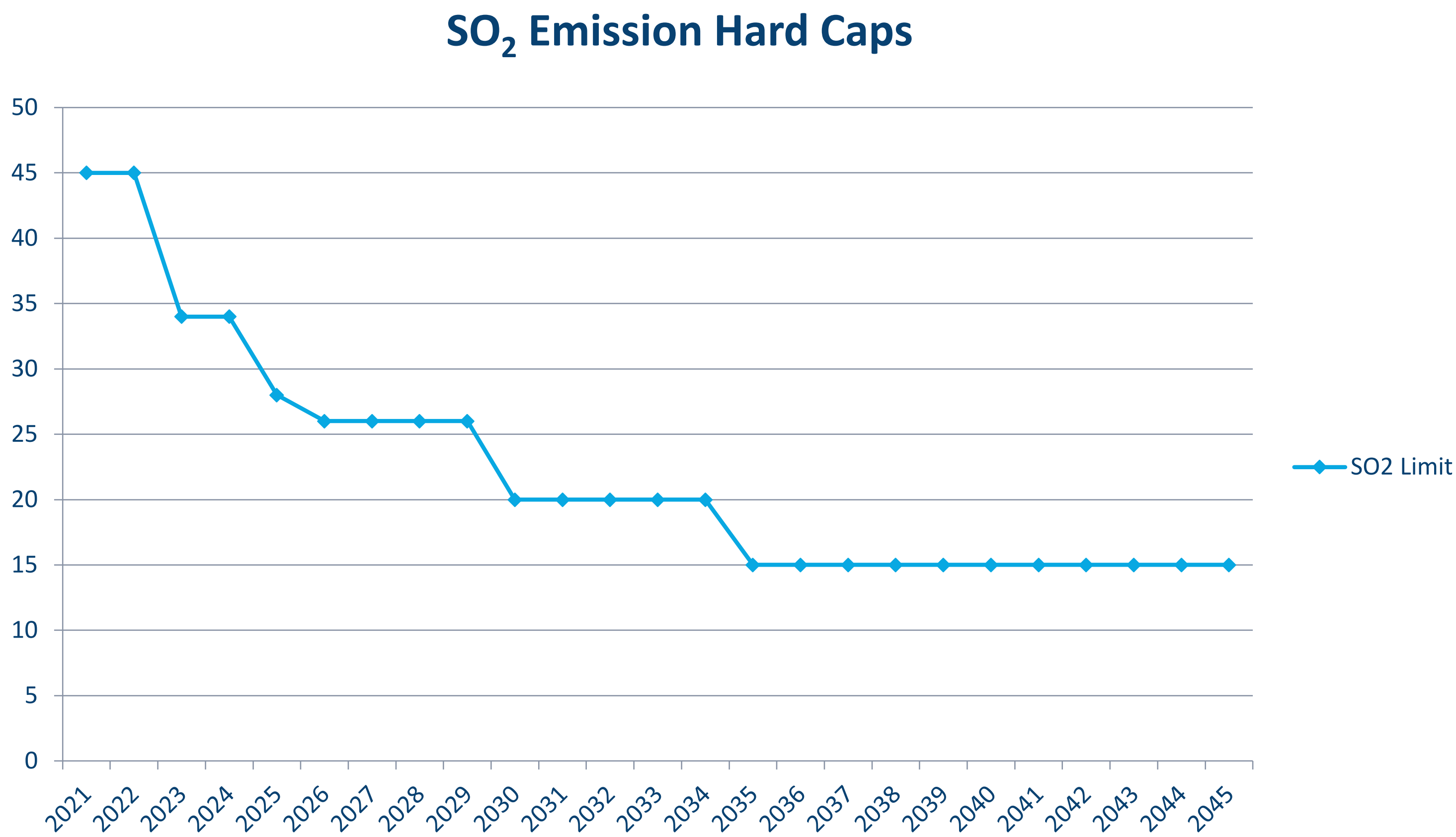
Year	Hg Emission Cap (kg)
2010	110
2011	100
2013	85
2014	65
2020	35
2030	30

Nova Scotia POWER An Emera Company

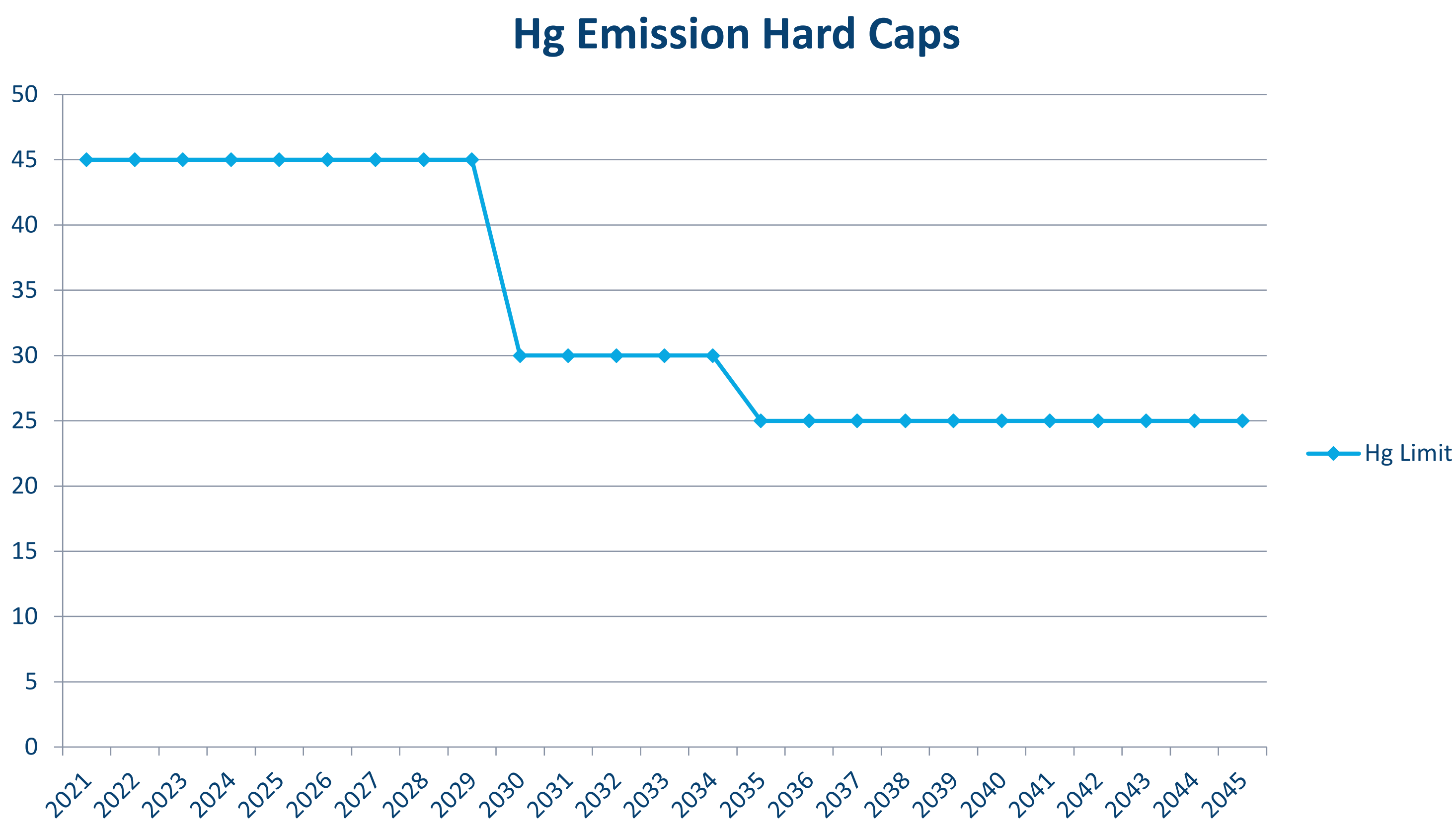
FORECAST NO_X EMISSION HARD CAPS



FORECAST SO_2 EMISSION HARD CAPS



FORECAST MERCURY EMISSION HARD CAPS*



*Air Quality Regulations outline requirements for mercury diversion program and stipulates NS Power can use credits for compliance from 2020 to 2030.

RENEWABLE ELECTRICITY REGULATIONS

- Provincial regulations that require 40% renewable energy by 2020.
- Stipulates that no more than 350,000 dry tonnes of primary forest biomass may be used annually to meet the standard.
- NS Power does not anticipate future specific renewable energy standards (RES). Intent will have been met by drive to net-zero carbon emissions from the *Sustainable Development Goals Act*.

2020 IRP:
NEW SUPPLY SIDE OPTIONS

JANUARY 20, 2020

Nova Scotia POWER An Emera Company

SUPPLY SIDE OPTIONS OVERVIEW

- The assumptions for the costs of new bulk grid scale resources (capital costs and fixed and variable operating costs) will be based on the E3 Resource Options Study from the Pre-IRP Analysis.
- Since the Pre-IRP Work was completed, several of the public sources for pricing assumptions have released late 2019 datasets. NSP and E3 are reviewing these updates and will adjust to reflect these updates where possible.
- The following slides summarize the “base case” prices from the Pre-IRP work. The full report also includes “Low” price sensitivities to be tested.
- The assumptions for the cost of new distributed resources are in the following section.

Energy+Environmental Economics

NSPI Resource Options Study

Nova Scotia Power

July 2019

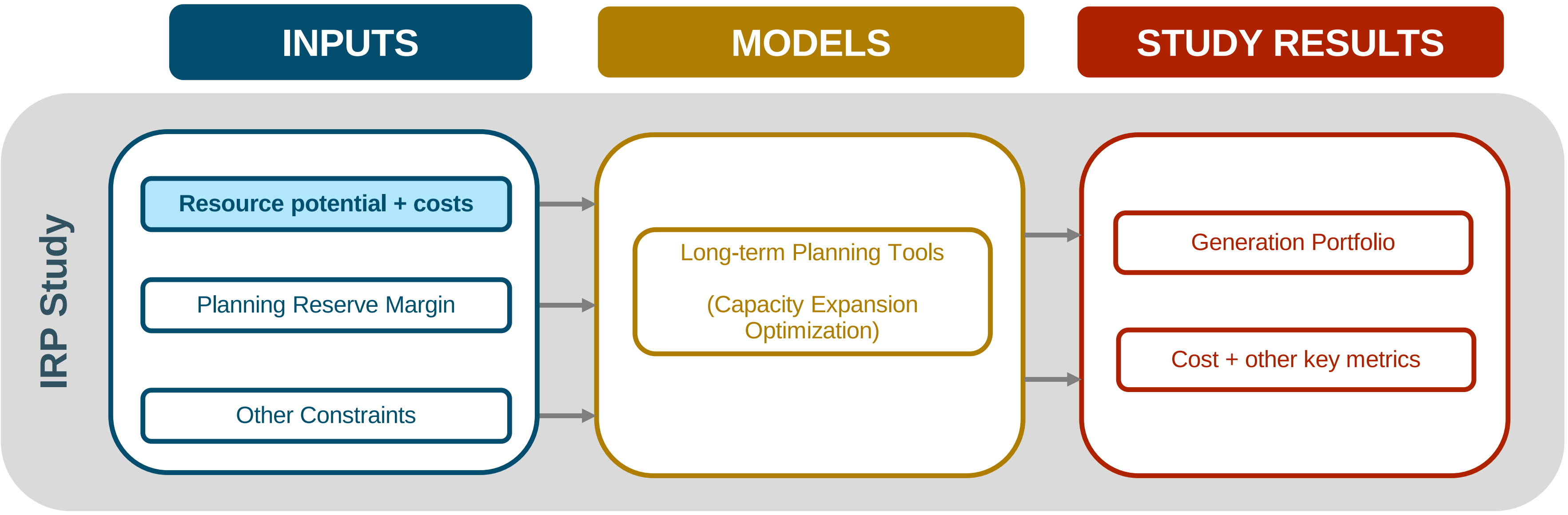
Aaron Burdick, Sr. Consultant
Charles Li, Consultant
Sandy Hull, Sr. Consultant
Zach Ming, Sr. Managing Consultant

Energy+Environmental Economics

Resource options study approach

Approach

+ **In preparation for its upcoming integrated resource plan, NSPI has asked E3 to provide guidance on resource costs and potential**
  - **Cost:** what are the costs (capital, O&M, fuel) associated with developing and operating each new resource? What future changes are expected?
  - **Performance:** what are the operational constraints associated with each resource (e.g. hourly profiles for wind/solar)
  - **Potential:** how much of the resource can be developed within Nova Scotia (or remotely)?



Resource Cost Modeling
Fixed vs. Variable Costs for New Resources

- **Fixed costs: expenditures required to install and maintain generating capacity, independent of operations**
  - Capital costs:
    - Overnight capital cost (equipment cost, balance of systems, development costs, etc.)
    - Construction financing
    - Nominal interconnection costs (i.e. a short spur line, not longer lines required for remote renewables)
  - Fixed O&M:
    - Operations and maintenance costs incurred independent of energy production
    - Insurance, taxes, land lease payments and other fixed costs
    - Annualized large component replacement costs over the technical life (aka sustaining capital)
- **Variable costs: marginal costs for each MWh of generation, based on modeled operations**
  - Variable O&M:
    - Operating and maintenance costs (parts, labor, etc.) incurred on a per-unit-energy basis
  - Fuel cost:
    - Commodity costs for fuel ($/MMBtu * heat rate MMBtu/MWh = $/MWh)
- **Capacity factor: annual energy production per kW of plant capacity**
  - Used to estimate variable costs as well as the spread of fixed costs over expected generation

Resource Options Considered

+ **Fossil fuels:** coal-to-gas, coal-to-biomass *, natural gas (CC, CT, reciprocating engine, CC w/ carbon capture and storage)
+ **Renewables:** biomass, municipal solid waste, solar PV, tidal, wind (onshore and offshore)
+ **Energy storage:** li-ion batteries, compressed air, pumped hydro
+ **Emerging technologies**: modular nuclear

** Conversion from coal is not an overly viable option. There has been pushback from running the existing NSPI biomass facility, so the social license for biomass in NS may not exist.*

Resource Cost Modeling

Step 2: Pro-Forma Financial Model

Resource Costs
Nova Scotia, 2019-2050

Capital Costs (Step 1) | O&M Costs | Fuel Prices

+

Resource Performance
Nova Scotia specific

Local Capacity Factors | Heat Rates | Degradation

+

Financing Assumptions
Based on NSPI Financing

NSPI Cost of Capital | Canadian Tax Incentives | Financing Terms

=

Levelized Cost Forecasts
Costs to NSPI, 2019-2050

Levelized Costs (Energy $/MWh, Capacity $/kW-yr)

Summary of Proposed Assumptions

Capital Costs (1 of 2) – Renewables and Storage

		Capital Cost (2019 CAD $/kW)		
Technology	**Subtechnology**	**2019**	**2030**	**% Change**
Wind	Onshore	$2,100	$1,959	-7%
	Offshore	$4,726	$3,340	-29%
Solar PV[a]	Tracking	$2,250	$1,803	-20%
Biomass	Grate	$5,300	$5,010	-5%
	Municipal Solid Waste	$8,470	$8,470	0%
Tidal	n/a	$10,000	$10,000	0%
Storage	Li-Ion Battery (1 hr)	$814	$410	-50%
	Li-Ion Battery (4 hr)	$2,325	$1,172	-50%
	Compressed air	$2,200	$2,200	0%
	Pumped Storage	$2,700	$2,700	0%

[a] Solar PV costs reported in $/kW-ac, reflecting an inverter loading ratio of 1.3

Summary of Proposed Assumptions

Capital Costs (2 of 2) – Fossil and Nuclear

		Capital Cost (2019 CAD $/kW)		
Technology	**Subtechnology**	**2019**	**2030**	**% Change**
Coal	Coal-to-gas conversion (102 – 320 MW)	$127 – 237	$127 – 237	0%
Natural Gas	Combined Cycle (145 MW)	$1,688	$1,609	-5%
	Combined Cycle w/ carbon capture and storage (145 MW)	$3,376	$3,101	-8%
	Combustion Turbine – Frame (50 MW)	$1,080	$1,031	-5%
	Combustion Turbine – Aero (50 MW)	$1,755	$1,676	-5%
	Reciprocating Engine (50 MW)	$1,823	$1,823	0%
Nuclear	Small modular reactor (100 MW)	$8,073	$7,731	-4%

Summary of Proposed Assumptions
Operating Costs – All Technologies

Technology	Subtechnology	Operating Cost Fixed O&M ($/kW-yr)	Operating Cost Variable O&M ($/MWh)
Wind	Onshore	$54	$0
	Offshore	$108	$0
Solar PV	Tracking	$20	$0
Biomass	Grate	$162	$7
	Municipal Solid Waste	$162	$0
Tidal	n/a	$338	$0
Storage	Li-Ion Battery (1 hr)	$8	$0
	Li-Ion Battery (4 hr)	$27	$0
	Compressed air	$20	$0
	Pumped Storage	$32	$0
Coal	Coal-to-gas conversion	$37-$45	$1
Natural Gas	Combined Cycle	$14	$3
	Combustion Turbine - Frame	$12	$7
	Combustion Turbine - Aero	$17	$7
	Reciprocating Engine	$27	$9
Nuclear	Small modular reactor	$203	$0

All O&M costs assumed to escalate at 2% per year.

2020 IRP:
DISTRIBUTED ENERGY RESOURCES (DERs)

JANUARY 20, 2020

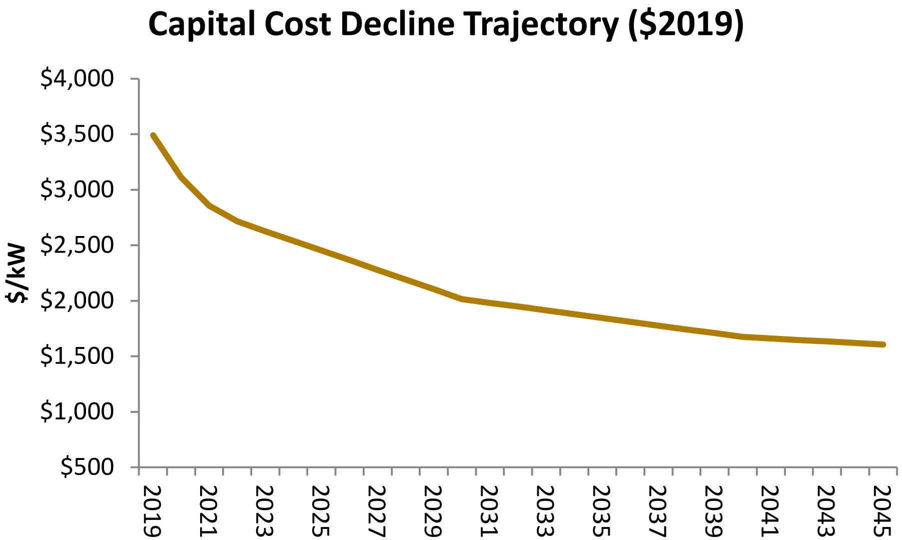
DISTRIBUTED ENERGY RESOURCES OVERVIEW

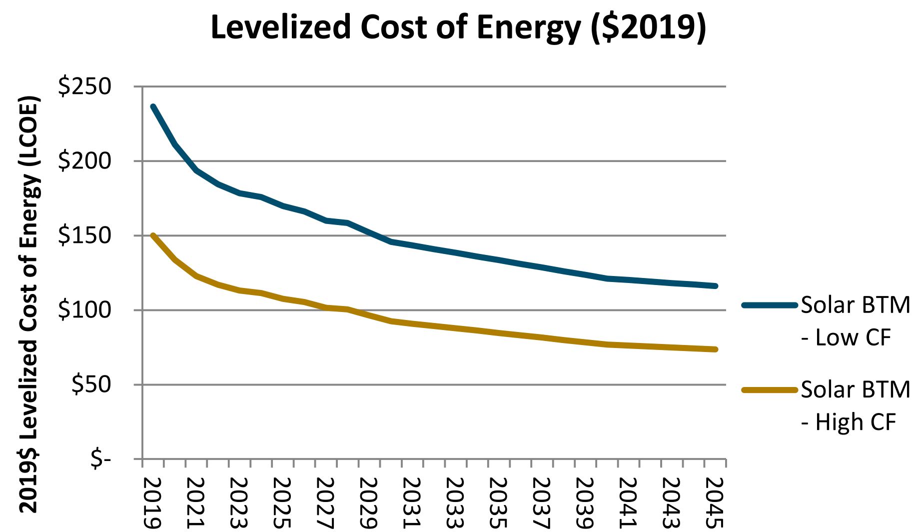
- As the grid becomes increasingly decentralized and more customers adopt distributed energy resources (DERs), long-term resource planners must address issues associated with evaluating their impact on the electricity system, including:
    - DERs introduce both system-level and distribution-level costs and benefits
    - DERs can be deployed and operated by utilities or customers and third parties
    - Although adoption and generation decisions can be influenced through incentives and rate design policy goals can also influence adoption (e.g., RPS, CO_2 targets)
    - Short panel of historical data and rapidly evolving technology costs/performance exacerbate uncertainty around these resources.
    - Capacity optimization models (as employed in the IRP), may not be granular enough to capture cost/benefits, particularly locational value.

DISTRIBUTED RESOURCES MODELING

- Given the challenges with the scale of DERs vs the granularity of IRP modeling, these resources will be examined via scenarios in the 2020 IRP (e.g. “plugs” of DERs will be mandatory in some model runs to ensure they are examined even if they would not have been economically selected based on the model constraints).
- NSP will work with stakeholders to ensure both the costs and benefits of DERs are evaluated at a reasonable level in the IRP.
- The proposed approach is for DERs to be accounted for in the model as a load modifier, with costs and benefits separately evaluated/discussed in the evaluation of each resource portfolio.

DISTRIBUTED SOLAR: COST ASSUMPTIONS





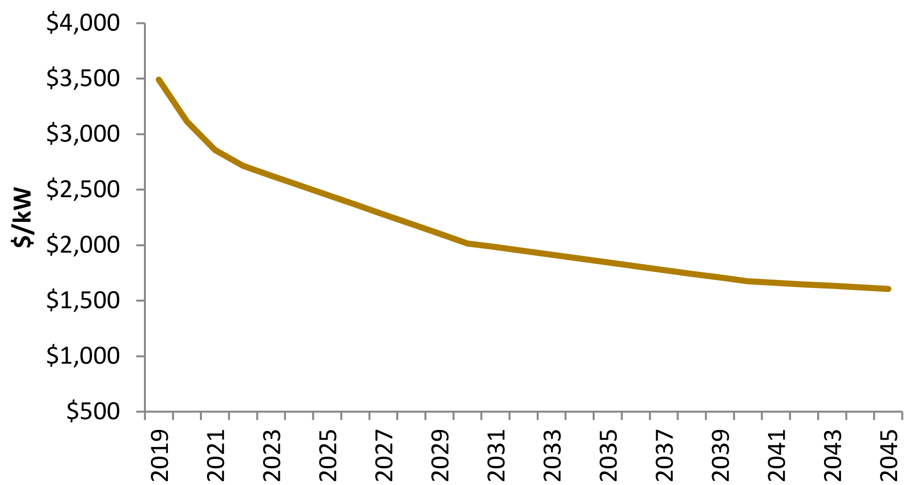
Input	Low Capacity Factor	High Capacity Factor
Capacity Factor	12%	19%
$/kW$_{2019}$	$3492	$3492
FO&M ($/kW-Yr)	21	22
Financing Lifetime (Years)	25	25
Degradation (%/year)	0.5%	0.5%

Nova Scotia POWER An Emera Company

BTM BATTERY STORAGE : COST ASSUMPTIONS

Input	1HR	4HR
$\$/kW_{2019}$	$1021	$2533
FO&M ($/kW-Yr)	$8.34	27.35
Financing Lifetime (Years)	20	20
Annual Warranty (% of Capital Cost)	1.5%	1.5%
Annual Augmentation (% of Capital Cost	1.7%	2.7%

Capital Cost Decline Trajectory ($2019)



Nova Scotia POWER An Emera Company

ELECTRIC VEHICLES (EVs)

- Currently, electric vehicle market share is low—across Canada penetration was about 2.2% of sales in 2018, with sales in Nova Scotia much lower, at 0.18%.*
- The pace of growth is difficult to predict and dependent on assumed cost trajectories of input commodities and components, fuel price projections, and marketing/rebate programs, among other factors
- Uncertainty around customer charging behavior in addition to adoption amounts further complicates both the energy and demand forecasts

*EV sales source: https://emc-mec.ca/wp-content/uploads/EMC-Sales-Report-Rapport-de-ventes-M%C3%89C-2018.pdf;
All vehicle sales source https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2010000201&pickMembers%5B0%5D=1.7

Nova Scotia POWER An Emera Company

ELECTRIC VEHICLES (EVs) (CONT.)

- For these reasons, some utilities are beginning to model a baseline level of EV adoption in their planning processes, usually built off established government or utility targets for near-term penetration, and then consider load growth possibilities in higher electrification scenarios

- New federal rebates for zero-emission vehicles (ZEVs) implemented in 2019, and the recent economy-wide "net neutral" by 2050 legislation, are likely to increase EV adoption during the planning period. As described in the Load Forecast section, E3 and NSP are evaluating potential impacts of this adoption.

- NS Power proposes to model bookended scenarios via load modifier approach to compare resource needs both under a baseline adoption forecast and a high electrification scenario.

2020 IRP:
PLANNING RESERVE MARGIN

JANUARY 20, 2020

Nova Scotia
POWER
An Emera Company

*PLANNING RESERVE MARGIN AND CAPACITY VALUE STUDY

NS Power engaged E3 to undertake a PRM and capacity value study. This study provides an update to several important assumptions to be used in the IRP process to ensure an appropriate level of resource adequacy, so that it can continue to provide reliable and affordable power to its customers.

Resource adequacy is the ability of an electric power system to serve load across a broad range of weather and system operating conditions, subject to a long-run reliability standard. The resource adequacy of a system thus depends on the characteristics of its load—seasonal patterns, weather sensitivity, hourly patterns—as well as its resources—size, dispatchability, outage rates, and other limitations on availability such as the variable and intermittent production of renewable resources.

While a variety of approaches are used, the industry best practice for resource adequacy is to establish a reliability metric and target value and then calculate what quantity of planning reserve are required to achieve that reliability target.

*Planning Reserve Margin and Capacity Value Study, Energy + Environmental Economics, July 2019

PLANNING RESERVE MARGIN (PRM)

Planning Reserve Margin (PRM)

- The quantity of planning reserves that should be held above the forecast annual firm peak load, calculated as a % of annual firm peak

- In order to meet a 0.1 days/year loss of load expectation (LOLE) target, NSPI should maintain between a 17.8% -21.0% planning reserve margin (PRM). The range in target PRM is due to a higher and lower estimate of operating reserve ("OR") requirements for the NSPI system.

- NS Power is proposing to maintain its existing PRM of 20% as the base case assumption, and iterate on portfolios to determine specific PRM requirements as illustrated in the Analysis Plan overview.

2020 IRP:
WIND, SOLAR, STORAGE AND DEMAND RESPONSE – EFFECTIVE LOAD CARRYING CAPACITY (ELCC)

JANUARY 20, 2020

Nova Scotia
POWER
An Emera Company

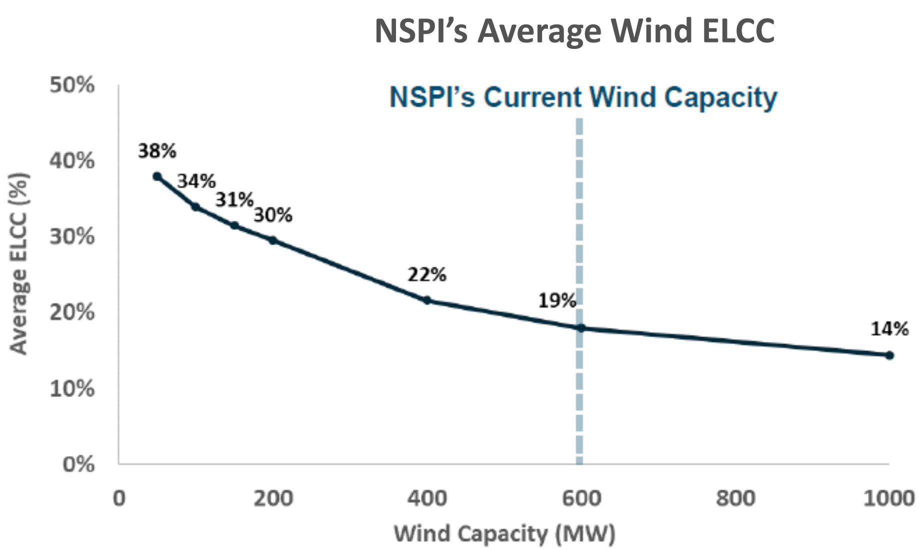
*EFFECTIVE LOAD CARRYING CAPABILITY (ELCC)

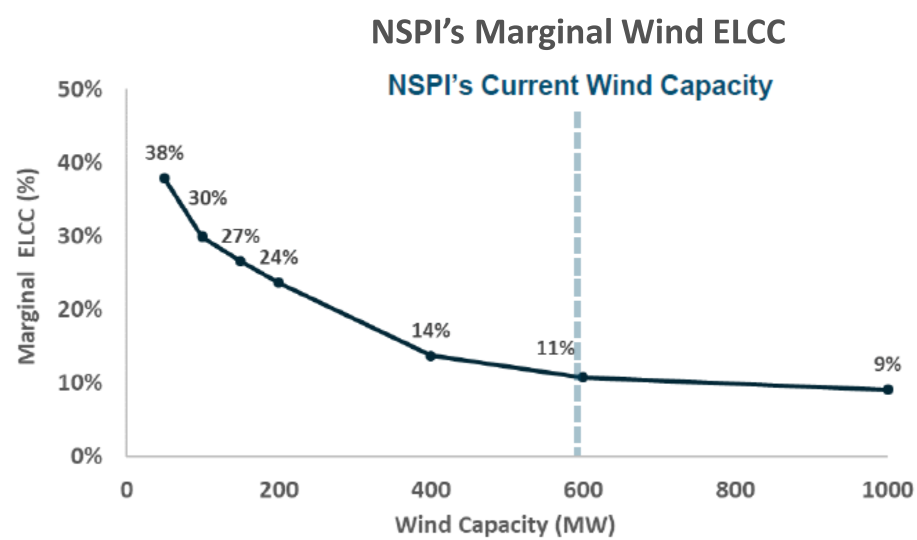
- The information from the Planning Reserve Margin and Capacity Value Study undertaken by E3 as part of the 'Pre-IRP' work will be used as the basis for the ELCC assumptions.
- Dispatch-limited resources like wind, solar, storage, and demand response can contribute effective load carrying capability (ELCC) toward meeting the planning reserve margin requirement, but have diminishing returns as additional capacity is added to the system to maintain reliability.
- The calculations of the ELCC for the portfolio of dispatch-limited resources are included in the full E3 Study provided with the Pre-IRP Report.

*Planning Reserve Margin and Capacity Value Study, Energy + Environmental Economics, July 2019

ELCC OF WIND

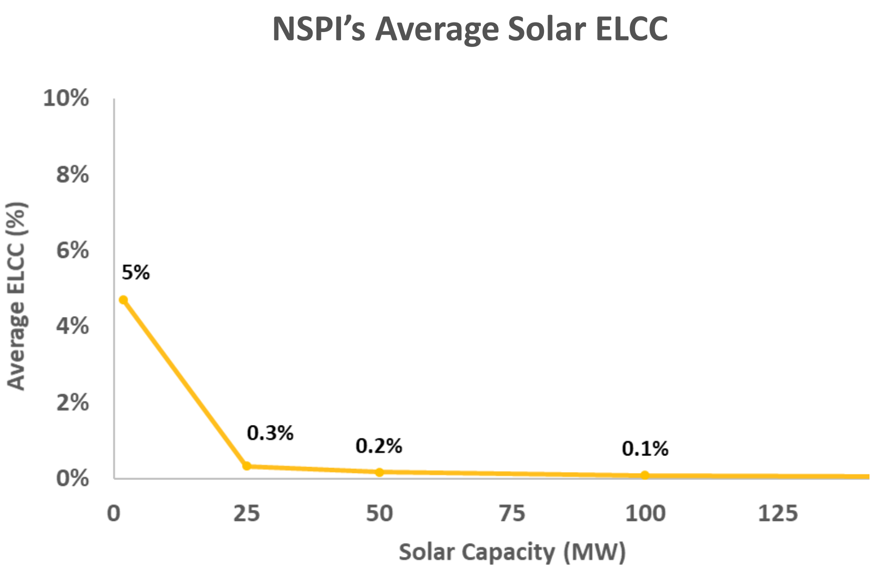
The average ELCC of the 596 MW of wind currently installed on the NSPI system is 19% or 111 MW. The ELCC value of adding new wind to the NSPI system is measured by the marginal ELCC and is currently at 11%, meaning that each additional MW of wind contributes 0.11 MW of firm capacity to PRM requirements.

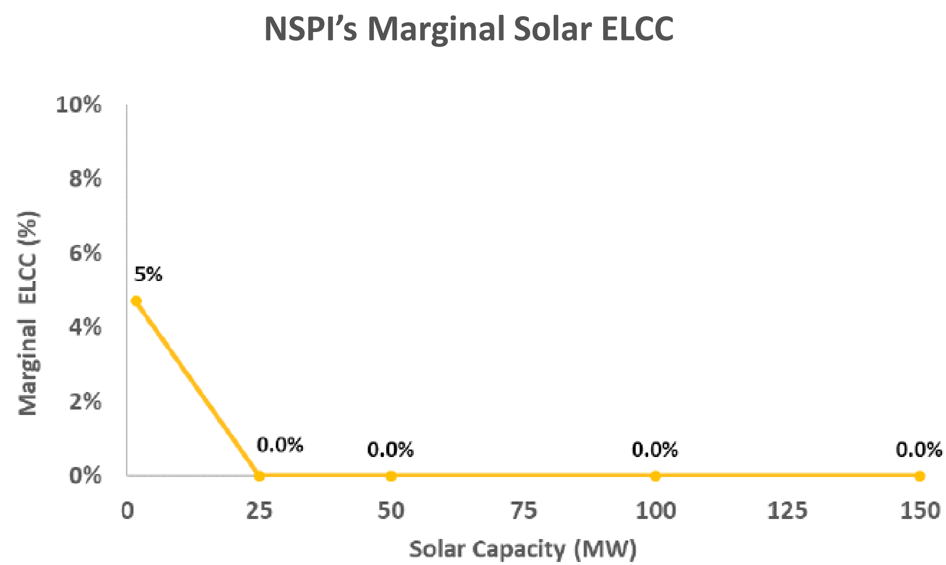




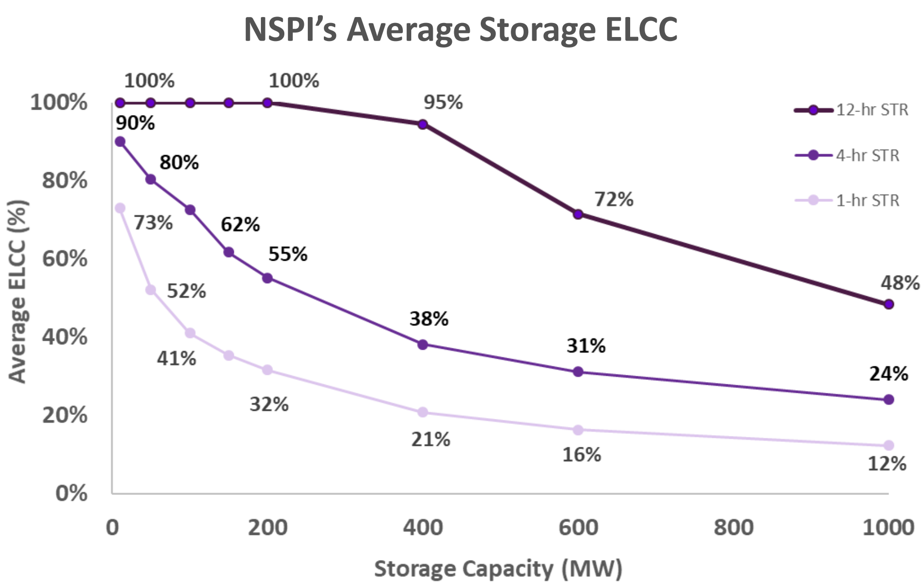
ELCC OF SOLAR

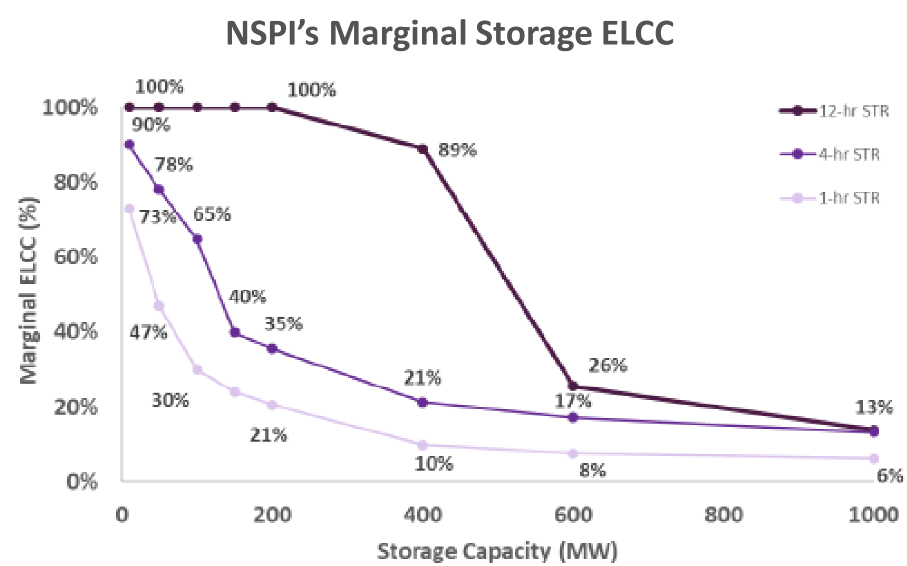
The NSPI system currently has a very small amount of solar capacity at only 1.7 MW which has an average and marginal ELCC of 5%. Solar has very limited ELCC in Nova Scotia due to poor correlation with the net peak load hours, which primarily occur on winter evenings. Beyond initial penetrations of solar capacity, the marginal capacity value declines to 0%.





ELCC BATTERY STORAGE

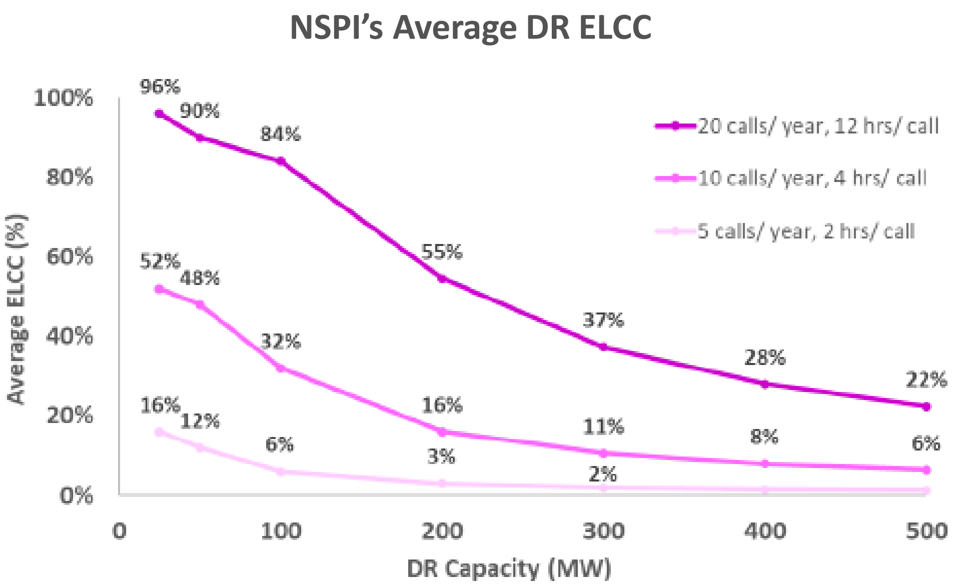


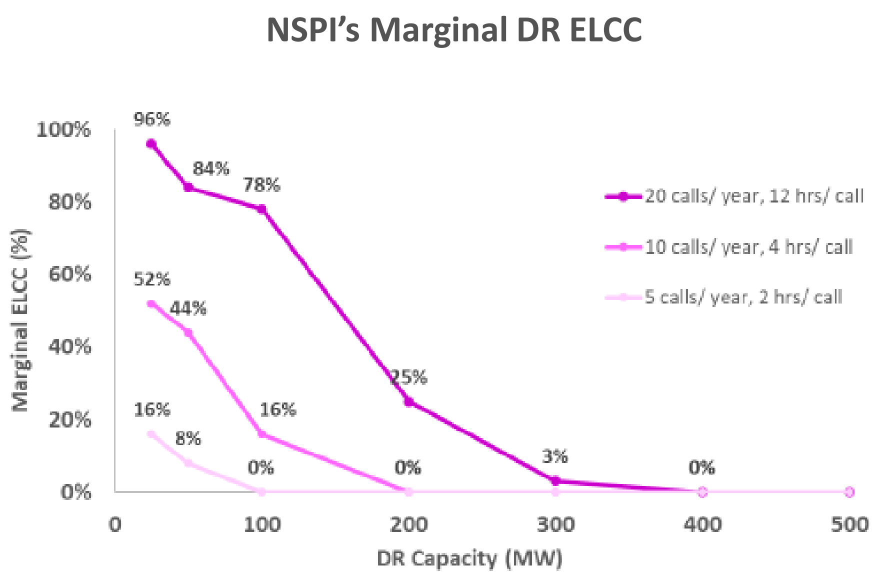


Nova Scotia POWER An Emera Company

ELCC OF DEMAND RESPONSE

These represent illustrative demand response (DR) programs with different numbers of calls and durations. These results are not meant to map directly to specific existing DR programs but rather inform system planners of the ELCC value that a DR program with similar attributes might provide. As with all the previous results, DR exhibits diminishing average and marginal ELCC values. The ELCC of a DR program will depend on its specific characteristics.





Nova Scotia POWER
An Emera Company

2020 IRP:
DSM

JANUARY 2O, 2020

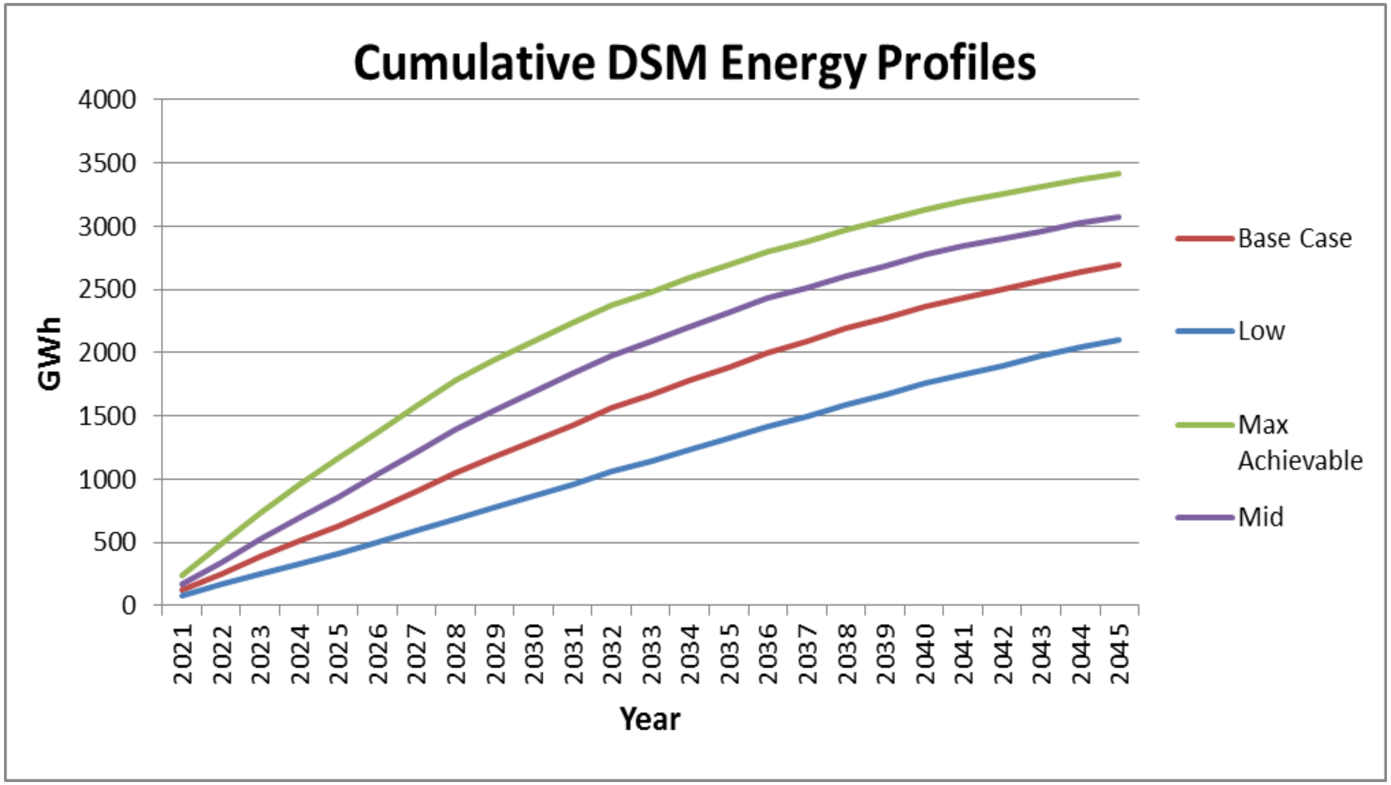
Nova Scotia POWER An Emera Company

*ENERGY EFFICIENCY (EE)

- Energy Efficiency (EE) data for the 25-year period (2021-2045) provided by EfficencyOne's (E1) Potential Study.
- The data provided by E1 is proposed to be used in the IRP as a load modifier. The load modifier approach has been used in past IRP's.
- A load modifier is depicted as a decrease in energy consumption/load as a result of the increased energy efficiency.
- The scenarios are assumed to include all DSM, including:
  - Cost-effective electricity efficiency and conservation activities provided by the franchise holder
  - Initiatives that may be pursued by NS Power as permitted under the *Public Utilities Act*
  - Consumer behaviour and investments
  - Energy efficiency codes and standards
  - Initiatives undertaken by other agencies
  - Technological and market developments.

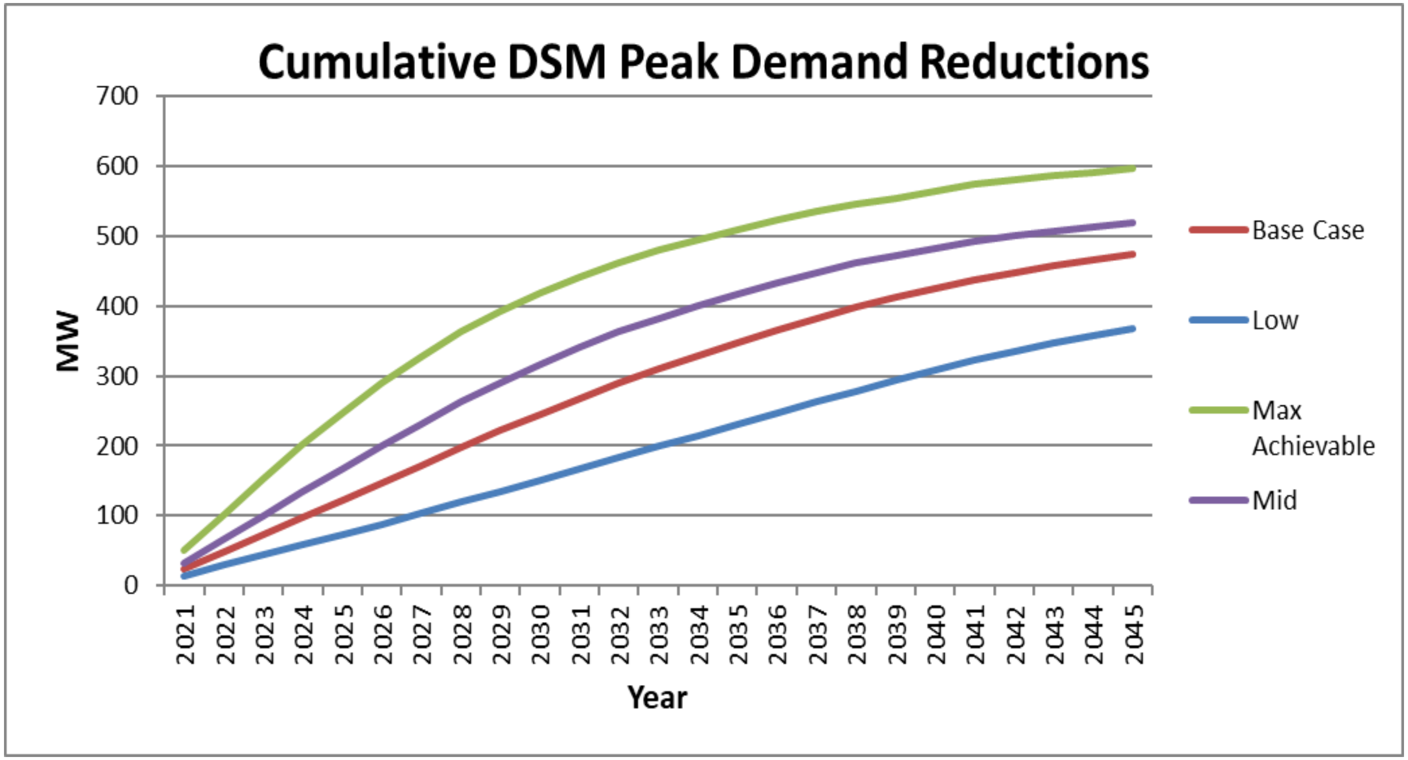
*Data Provided by EfficiencyOne(E1) in 2019 Potential Study

*ENERGY EFFICIENCY (EE)



*Data Provided by EfficiencyOne(E1) in 2019 Potential Study

*DSM PEAK REDUCTION



*Data Provided by EfficiencyOne(E1) in 2019 Potential Study

2020 IRP:
DEMAND RESPONSE

JANUARY 20, 2020

Nova Scotia
POWER
An Emera Company

*DEMAND RESPONSE (DR)

- Demand Response (DR) programs for the 25-year period (2021-2045) have been provided by E1's Potential Study, along with the 3 specific programs proposed by NSP in the Pre-IRP Work.

- The data provided by E1 could be used as a load modifier or as a resource option (bundled options).

- The load modifier approach had been used in past IRPs. A load modifier is depicted as a decrease in energy consumption/load as a results of the increased energy efficiency.

*Data Provided by EfficiencyOne(E1) in 2019 Potential Study

*DEMAND RESPONSE (DR) (CONT.)

- The resource option approach would allow Plexos to optimize which DR options to select and requires additional details/ a break down of the programs provided by E1 as well as additional time to construct the required bundling options (i.e. construct bundles, costs, profile or load reductions) when compared to the load modifier approach.

Demand Response can be largely broken into two buckets: Load Management and Demand Management.

- Load Management is often utility-controlled and dispatchable and is used to temporarily reduce peak load.
- Demand Management is usually customer-controlled and is managed by utilities in rate structures (such as Time Of Use or TOU).

*Data Provided by EfficiencyOne(E1) in 2019 Potential Study

*DR OPTIONS SUMMARY (E1)

		DR Option	Brief Description	Eligible Customer Classes	End Use
DR bundles to be screened for consideration as Plexos Optimization Resource Options.	✓	DLC-Direct Load Control	Control of electric loads by a thermostat and/or load control switch.	Residential Small Commercial Small Industrial	Electric Furnace [3] Heat pump [4] HVAC [5] Hot Water
	✓	BNI Curtailment	Firm capacity reduction commitment. $/kW payment based on delivered capacity, administered through third-party aggregators.	Large Commercial Large Industrial Interruptible	HVAC Lighting Water Heating Total Facility
	✓	BTM Battery Control	Use of batteries for load shifting and dispatching to the grid.	All classes	Batteries
	✓	EV Charging Control	Charging modulation to reduce EV demand during peak periods	EV	EV
DR bundles to be evaluated within the Load scenarios.	✗	Critical Peak Pricing (CPP)	A rate schedule with significantly higher peak prices to discourage consumption during peak times	All classes	Total Facility
	✗	Behavioural Demand Response (BDR)	Targeted notifications and incentives are provided to customers to encourage peak shaving	Residential	Total Facility

Source: Navigant

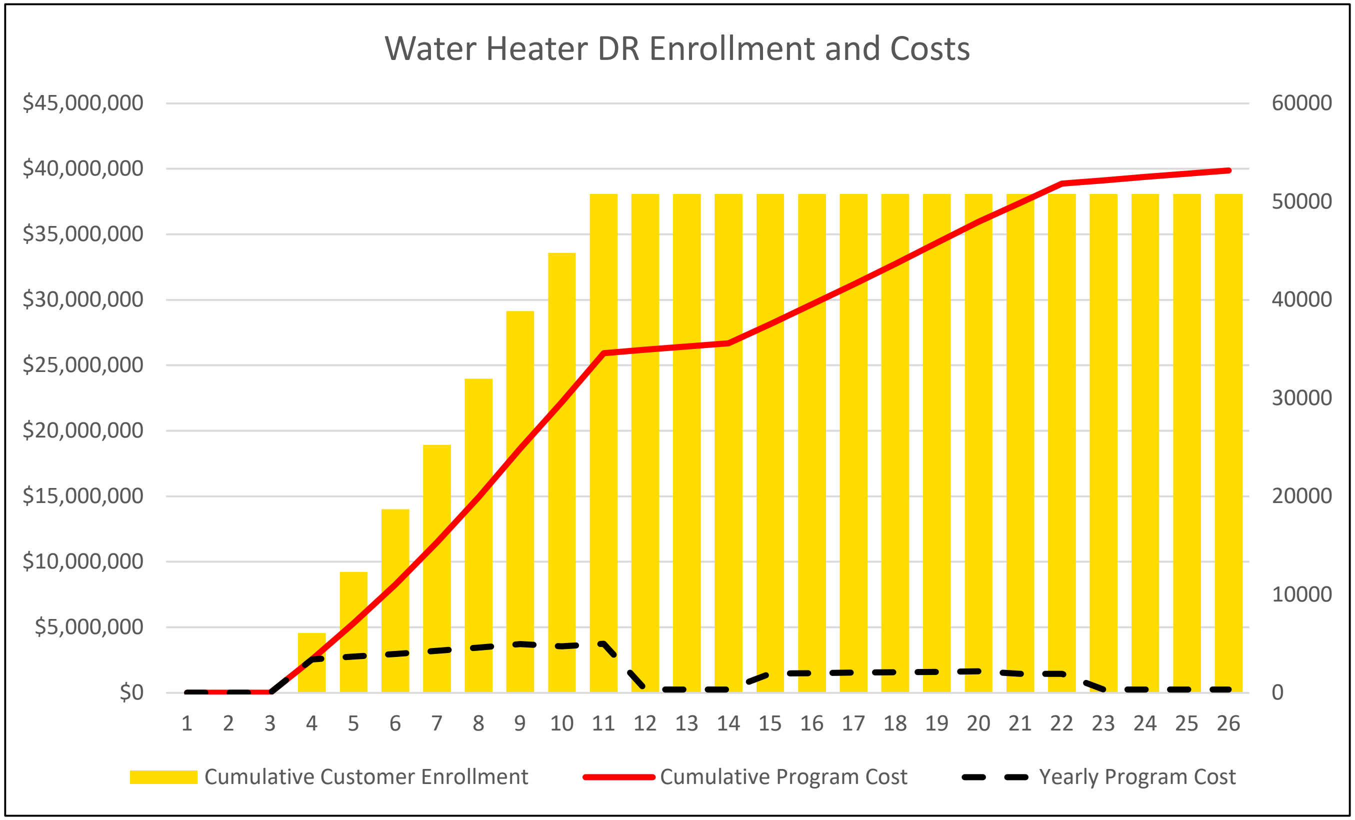
Nova Scotia POWER An Emera Company

*Data and further details can be found in the EfficiencyOne(E1) in 2019 Potential Study

DR OPTIONS SUMMARY (NS POWER)

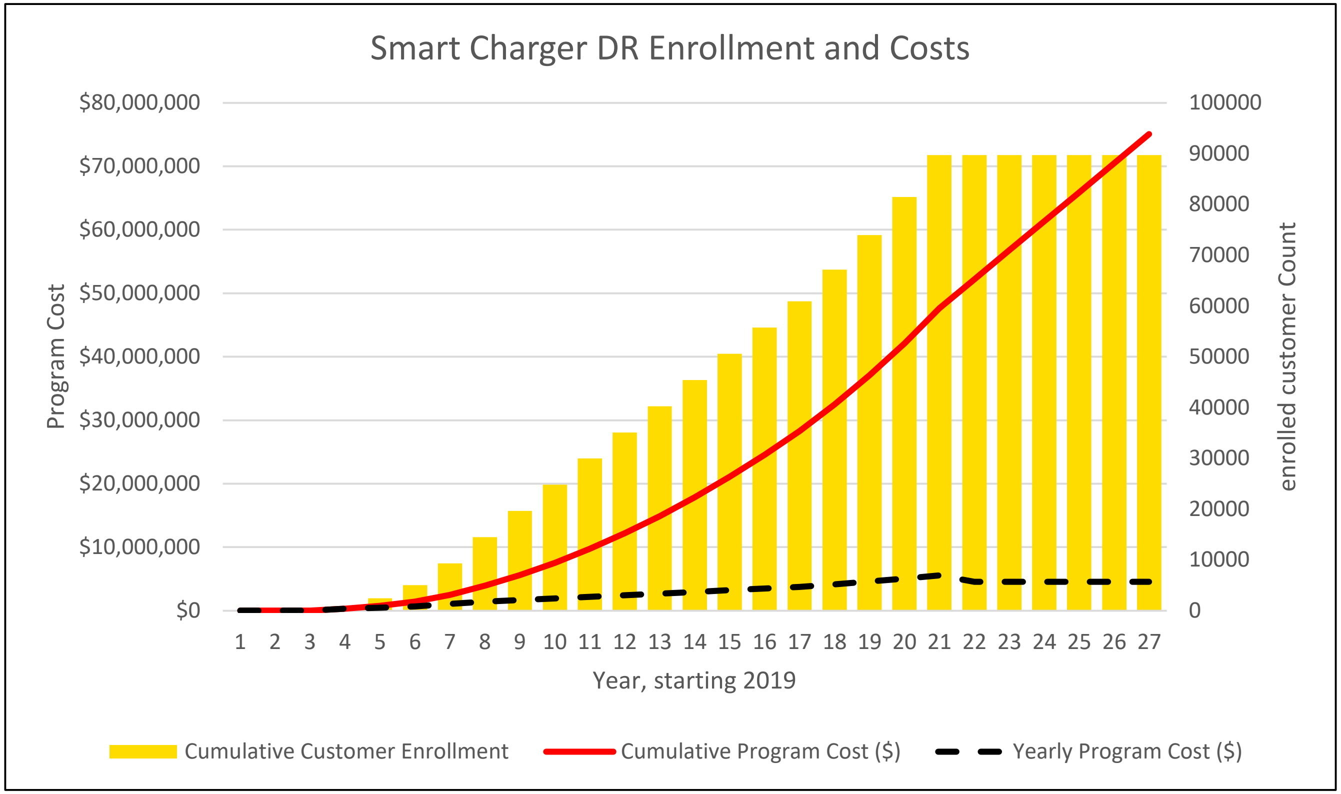
Device	Program	Peak shaving potential (kW/device)	Customer Incentive [1]	Participation Scenario (in year 25)	NSP Total Program Costs (25-yr)
Water Heater	Controller installed on customer WH and used during peak shifting events	0.5	$25 enrollment, $25/yr when compliant to program criteria	Cumulative 50,779 participants (10% of market), 27 MW peak shaving potential	$1.4M/MW
EV Supply Equipment	Customer owned and installed EVSE with peak shifting participation incentives	0.7	$150 enrollment, $50/yr when compliant to program criteria	Cumulative 89,704 participants (70% of market), 63 MW peak shaving potential	$0.75M/MW
Residential Battery	Customer contribution comparable to diesel generator installation, utility control for up to defined number of system peak events	2.5	$2500 customer contribution, Balance of battery cost covered by NSP and funding where available.	Cumulative 4000 participants, 6.25 MW peak shaving potential	$7.16M/MW

DR OPTIONS SUMMARY (NS POWER) CONT.



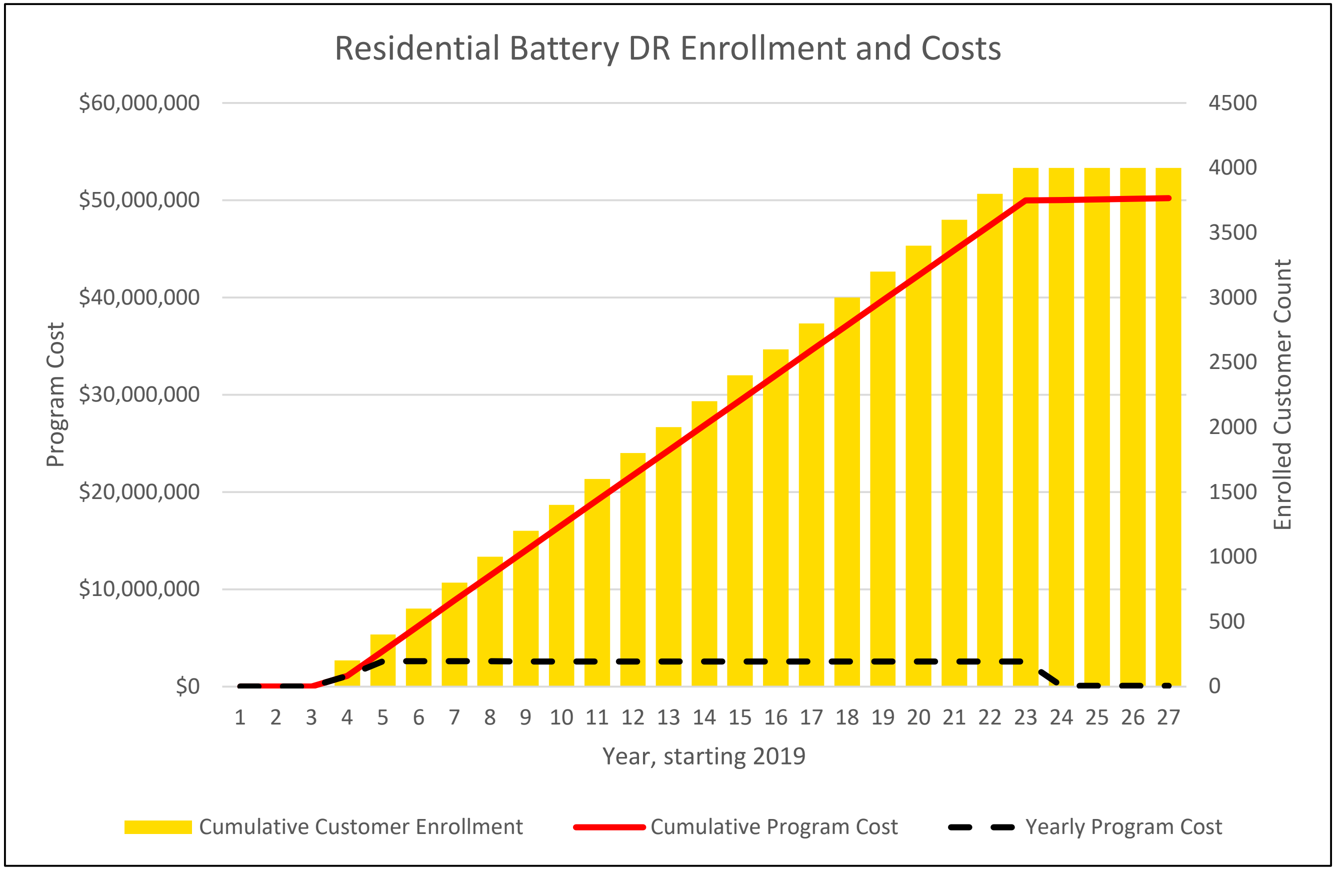
Nova Scotia POWER
An Emera Company

DR OPTIONS SUMMARY (NS POWER) CONT.



Nova Scotia POWER An Emera Company

DR OPTIONS SUMMARY (NS POWER) CONT.



2020 IRP:
IMPORTS

JANUARY 20, 2020

Nova Scotia POWER
An Emera Company

SUMMARY – FIRM IMPORTS

- Firm imports could support the transition to lower GHG emissions and the replacement of coal-fired generation capacity via greater regional interconnection.
- Firm Transmission is required for each option and is obtained via existing transmission or assumed new transmission, depending upon the import source and assumption regarding existing transmission availability.
    - **Firm transmission capability is the amount of electricity that can be delivered in a reliable manner after consideration of surrounding system loads, voltages and stability conditions.**
    - **Non-firm transmission is the additional capability that can be used for energy delivery from time to time but is subject to curtailment under different system conditions.**

SUMMARY – FIRM IMPORTS (CONT.)

Firm Import Options :

- Access to firm capacity via existing transmission up to ~150 MW firm; and/or,
- Access to firm capacity via new transmission build up to ~800 MW firm.

Non-Firm Import Options:

- Import energy via existing transmission (Maritime Link and New Brunswick tie-line); and/or,
- Import energy via new transmission per above.

ENABLING TRANSMISSION INVESTMENT

The Qualitative Benefits of Transmission:

- Enhanced system reliability (voltage support, reserve sharing, etc.).
- Expansion of renewable generation integration.
- Option Value (greater market access through congestion reduction; supplier alternatives support energy purchase negotiations).
- When coupled with an energy and capacity contract, the opportunities are expanded.

Quantitative Benefits of accompanying energy and capacity contract :

- Firm capacity import enabler (to support coal capacity retirement).
- Renewable energy imports (to reduce air emissions and avoid carbon costs).
- Expanded economic energy imports.

PRICING FOR FIRM IMPORTS

- Pricing for capacity provision is based on Platts Analytics forecast.
- Pricing for energy provision derived from Platts Analytics forecast.
- All import energy options will be priced as sourced by “clean energy” options (i.e. no associated carbon dioxide emissions)

2020 IRP:
FUEL PRICING

JANUARY 20, 2020

Nova Scotia POWER An Emera Company

SERVICE PROVIDER

S&P Global Platts analytics (formerly PIRA Energy group)

- Long time service provider to NSPI
- World-wide perspective and insight
- Forecasts utilized in Maritime Link, 2009 IRP and 2014 IRP

Forecasting approach

- NS Power Fuels, Energy & Risk Management (FERM) utilised commercially available long-term prices forecasts for Natural Gas, Oil and Power which it subsequently adjusted for delivery to NS based on:
    - Current and Expected Transportation (Transmission) Costs and Tolls
    - Market Insight and Proprietary Views on Long-Term Market Development, including High, Low and Expected Scenarios (by third parties and NSPI)

FUNDAMENTAL PRICE FORECASTS

Commodity	Pricing Point	Provider	Updated
Nat. Gas	(N.A.) Henry Hub	S&P Global Platts' Analytics (formerly PIRA Energy Group) Scenario Planning Service Quarterly Update	Q4 2019
	(LNG) TTF, Spot (International Natural Gas) JKM (Asian Natural Gas)		
	AECO Basis Dawn Basis	S&P Global Platts' Analytics (formerly PIRA Energy Group) (LT) S&P Global Platts' Analytics (formerly PIRA Energy Group) (ST)	JUNE 2019 NOV 2019
Fuel Oil	New York Harbour	S&P Global Platts' Analytics (formerly PIRA Energy Group) Scenario Planning Service Quarterly Update (Brent) InterContinental Exchange (ICE)	Q4 2019 DEC 2019

2020 IRP:
FUEL PRICING (NATURAL GAS)

JANUARY 20, 2020

Nova Scotia POWER
An Emera Company

NATURAL GAS OPTIONS - SUMMARY

- NS Power’s 2020 IRP will evaluate natural gas units (combustion turbines/combined cycle/reciprocating units/steam turbines) as potential capacity replacements for the aging coal fleet for either economic or policy reasons;

- Continuing improvements in natural gas plant flexibility, fuel efficiency and fuel supply is leading to, in certain jurisdictions, competitive advantages over coal, particularly given the faster pace of grid operations driven by variable generation;

- Gas typically plays a role in backing up renewables- especially during the extremes when wind and solar could be at a minimum;

NATURAL GAS OPTIONS – SUMMARY (CONT.)

- While the installed cost of new gas units are well documented, the all-in levelized cost of energy is subject to significant uncertainty associated with the delivered cost of natural gas, particularly given the supply constraints in Nova Scotia;

- During peak winter conditions, heating demands from firm natural gas customers in the Northeastern U.S. and Eastern Canada increase natural gas demand, create upward pressure on prices, and limit the amount available to customers who do not have firm pipeline contracts;

- With the shutdown in production from domestic sources (Sable Island and Deep Panuke), Nova Scotia will be reliant on natural gas imported via U.S. pipelines, LNG tankers, or an all Canadian Path, via Western Canada;

NATURAL GAS OPTIONS – SUMMARY (CONT.)

- New natural gas plants must have a firm source of gas supply to reliably generate power during winter peaks;

- Operational Mode/utilization must be considered (i.e. primarily for capacity or for energy and capacity);

- Three supply paths have been developed that consider existing supply arrangements and compare and contrast possible new paths to move gas to Nova Scotia for possible new gas units as represented in the system optimization.

Nova Scotia POWER An Emera Company

NATURAL GAS PRICE ASSUMPTIONS

The three supply paths developed are:

- **Option 1: Existing Gas (**TCPL Empress-East Hereford via North Bay Junction-tolls modelled as a fixed cost)
    - Existing 20,000 MMBtu/day pipeline capacity
- **Option 2: Peaking Gas** (LNG Winter-Dawn plus Tolls Summer)
    - Unlimited LNG sourced from Repsol's Canaport terminal in the winter, up to 100,000 MMBtu/day sourced at Dawn in the summer
- **Option 3: Base Loaded Gas** (New supply sourced at AECO plus tolls)
    - Up to 100,000 MMBtu/day
    - Fixed Cost adder to be applied to gas units in model for this option.

- For each options, 3 scenarios have been priced: Base Case (Expected), High Case, and Low Case.

FUNDAMENTAL NAT GAS SCENARIOS (S&P GLOBAL PLATTS ANALYTICS) HENRY HUB

	Likelihood (S&P Global)	Highlights
Base Case (Expected)	50%	-US Demand growth expected to slow post 2020 -Gas consumption in the power sector has become saturated -More locations are banning or restricting the use of gas -The US technically recoverable resource was raised to 3,024 TCF an increase of 560 TCF, the largest change ever -Prospects for additional LNG export terminals achieving FID have increased with the apparent progress in US/China trade talks
High Case	25%	-Prolonged pipeline/regulatory review process impede future infrastructure expansion -Tightened environmental/regulatory policy inhibits shale gas & oil development. -Accelerated US coal/nuclear retirement and/or increased US electricity demand increase demand for gas -Increased N. American LNG export capability along with less new global capability
Low Case	25%	-Associated gas tied to liquids rich production is more abundant than currently envisioned (will have to be tied to pipeline additions) -Shale gas production surprises to the upside -Non-fossil fuel electric generation grows at a faster rate than forecast -LNG exports from the US face stiffer offshore competition -More anti-fossil fuel sentiment limits electric and industrial demand growth

NS CASE DEVELOPMENT (NAT GAS)

	Highlights
Existing Gas: TCPL North Bay Junction	-20,000 MMBtu/day pipeline capacity contracted starting Nov 1, 2021 for 15 years, with an assumed extension to cover the full IRP modeling period -Fixed tolls from Empress to North Bay Junction for the 25 years -Base/High/Low pricing
Peaking Gas: LNG Winter-Dawn Summer	-Unlimited LNG winter supply; 100,000 summer supply -Swing gas for daily dispatch, no long term contract/pipeline commitment underpinning - Base/High/Low pricing
Baseload Gas: from AECO	-Up to an additional 100,000 MMBtu/day firm contract -Base/High/Low pricing

Nova Scotia POWER An Emera Company

NATURAL GAS – EXISTING GAS (TCPL NBJ 20,000 MMBTU/DAY)

Delivered Price	=	Commodity	+	Basis	+	Transportation	+	Market Premium
Base	=	Henry Hub Source: Global Platts Analytics (4Q2019) Reference Case	+	AECO Source: Global Platts Analytics (June 2019)	+	Fuel & Tolls Nova + Fuel & Tolls Westbrook to Tufts Cove modelled as variable, TCPL Empress to E. Hereford and PNGTS to Westbrook modelled as fixed costs	+	Nil
Low	=	Henry Hub Source: Global Platts Analytics (4Q2019) Low Case	+	AECO Source: Global Platts Analytics (June 2019)	+	Fuel & Tolls Nova + Fuel & Tolls Westbrook to Tufts Cove modelled as variable, TCPL Empress to E. Hereford and PNGTS to Westbrook modelled as fixed costs	+	Nil
High	=	Henry Hub Source: Global Platts Analytics (4Q2019) High Case	+	AECO Source: Global Platts Analytics (June 2019)	+	Fuel & Tolls Nova + Fuel & Tolls Westbrook to Tufts Cove modelled as variable, TCPL Empress to E. Hereford and PNGTS to Westbrook modelled as fixed costs	+	Nil

Nova Scotia POWER An Emera Company

NATURAL GAS – PEAKING GAS (LNG WINTER, DAWN SUMMER)

Delivered Price	=	Commodity	+	Basis	+	Transportation	+	Market Premium
Base Winter	=	TTF Spot Source: Global Platts Analytics (4Q2019) Reference, Low or High Case	+		+	Fuel & Tolls: Baileyville to Tufts Cove		LNG Regasification cost US $2.50/MMBtu
Base Summer	=	Henry Hub Source: Global Platts Analytics (4Q2019) Reference, Low or High Case	+	Dawn Source: Global Platts Analytics (June 2019) Reference, Low or High Case	+	Fuel & Tolls: Dawn to Tufts Cove Source: Current or negotiated Tolls		Nil

Nova Scotia POWER
An Emera Company

NATURAL GAS – BASELOAD

Delivered Price	=	Commodity	+	Basis	+	Transportation	+	Market Premium
Base	=	Henry Hub Source: Global Platts Analytics (4Q2019) Reference Case	+	AECO Source: Global Platts Analytics (June 2019)	+	Tolls Nova to Tufts Cove modelled as fixed costs Fuel & Usage Nova to Tufts Cove modelled as variable costs	+	Nil
Low	=	Henry Hub Source: Global Platts Analytics (4Q2019) Low Case	+	AECO Source: Global Platts Analytics (June 2019)	+	Tolls Nova to Tufts Cove modelled as fixed costs Fuel & Usage Nova to Tufts Cove modelled as variable costs	+	Nil
High	=	Henry Hub Source: Global Platts Analytics (4Q2019) High Case	+	AECO Source: Global Platts Analytics (June 2019)	+	Tolls Nova to Tufts Cove modelled as fixed costs Fuel & Usage Nova to Tufts Cove modelled as variable costs	+	Nil

OTHER ALTERNATIVES

- Other possible natural gas supply arrangements are possible, however not every potential supply arrangement can be tested in an IRP model, as it would result in modeling complexity that may prove unsolvable

- Other possible arrangements that are not included in the IRP include (but are not limited to):

    1. Dual Fuel capability
    2. Natural Gas Storage
    3. LNG Alternatives

- Should the IRP Action Plan indicate further investment in natural gas resources, these options can be considered in a more detailed analysis to determine optimal supply sources following the conclusion of the IRP.

DUAL FUEL CAPABILITY

Given the known challenges associated with securing a cost-effective firm natural gas supply source, the economics and permit ability of ULSD oil use in lieu of high cost of pipeline infrastructure would be considered in the future if natural gas units prove to be a no-regrets supply option in the IRP.

DUAL FUEL CAPABILITY (CONT.)

Benefits

- State-of-the-art combined-cycle plants and peakers can burn ULSD, kerosene or distillate oil efficiently without jeopardizing the cycling range and quick-start capability associated with the technologies
- Use of oil to support a reliable fuel supply portfolio would supplant natural gas when delivery constraints arise
- Oil supply arrangements are much more flexible than those associated with firm gas because they do not require major infrastructure expansions to enable delivery

DUAL FUEL CAPABILITY (CONT.)

Challenges

- Duel-Fuel capability has an assumed cost adder of 7%
- Switching on the fly from natural gas to oil or vice versa poses operational challenges and can jeopardize unit availability
- Increased emissions associated with burning oil in lieu of natural gas for fuel assurance
- Oil refill during the peak heating season has proved challenging for both barge- and truck-delivered oil supply during cold snaps

DUAL FUEL CAPABILITY (CONT.)

Challenges

- Increased Compliance Cost - Switching from gas to ULSD or HFO when pipeline constraints into or within Nova Scotia prevent the use of gas will increase CO_2 emissions during those events by a factor of roughly 50% on a tonnes per MWh basis
- Tank farm permitting
- Challenging to model in the long term due to the granularity needed to test value proposition

NATURAL GAS STORAGE

- AltaGas is developing an underground gas storage facility in Alton, Nova Scotia, which would be connected to M&NP pipeline
- Heritage Gas Ltd. has contracted for the first phase of capacity
- It is possible that NS Power could contract for capacity – the economics of usage would need extensive analysis (e.g. the amount of turns and resultant withdrawal rates, etc.)
- As per the Dual Fuel Capability option, NS Power will study this option in detail if new gas units are part of the IRP recommendation

LNG ALTERNATIVES

As an alternative to traditional pipeline transportation, a number of companies have begun to develop “virtual pipelines” by shipping LNG or compressed natural gas (CNG) via truck or boat to sites that do not have pipelines connections or cannot receive gas due to pipeline constraints.

2020 IRP:
SUSTAINING CAPITAL

JANUARY 28, 2020

Nova Scotia POWER
An Emera Company

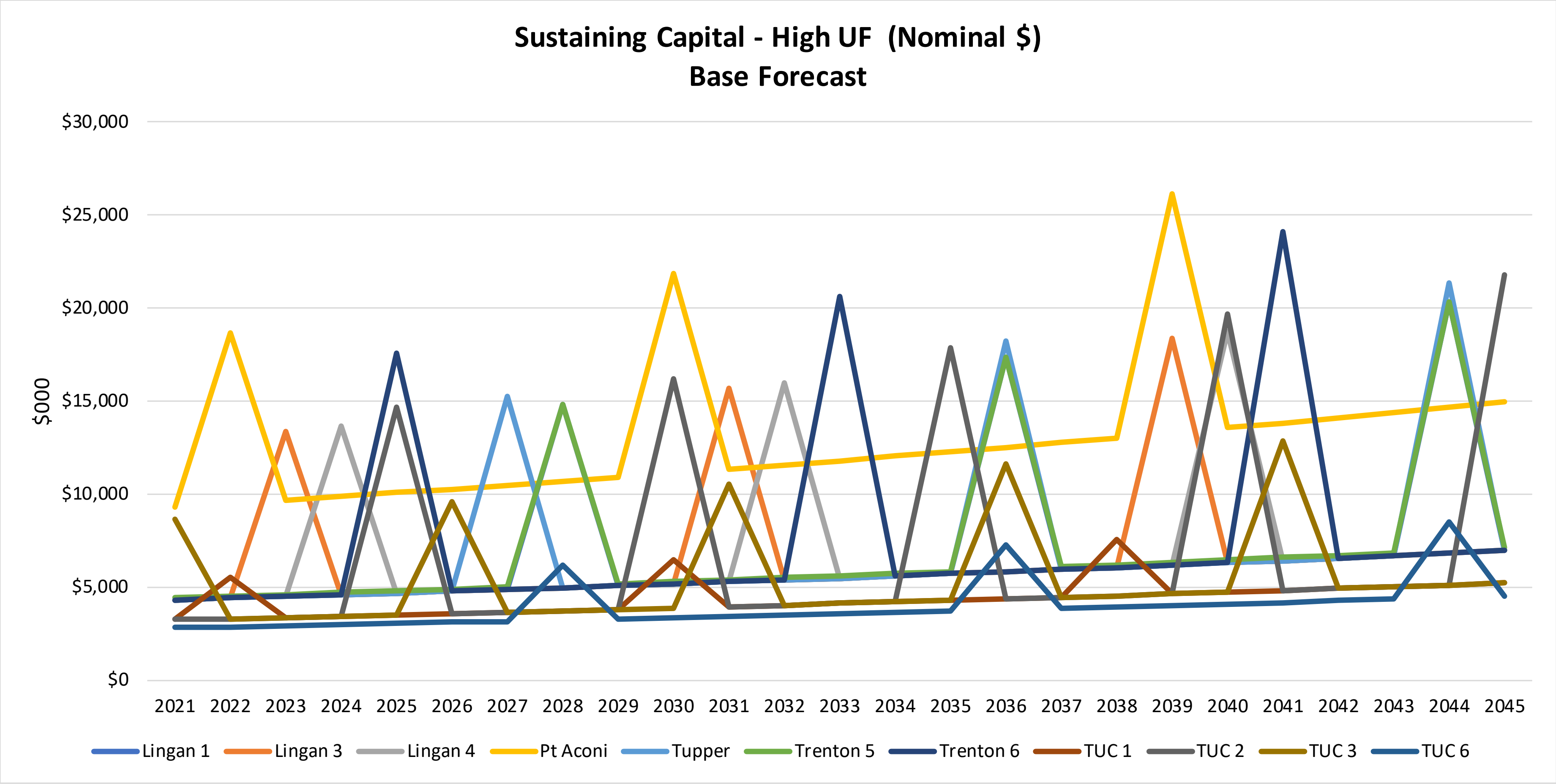
SUSTAINING CAPITAL FORECAST – COAL UNITS

- The sustaining capital cost Base forecast assumes a high utilization factor (UF) for all thermal units, which will represent the forecast investment required to address wear on components driven by a high capacity factor, cycling, operating hours, flexible use, or a combination thereof (i.e. the uses of the machines that drive the highest investment requirements)

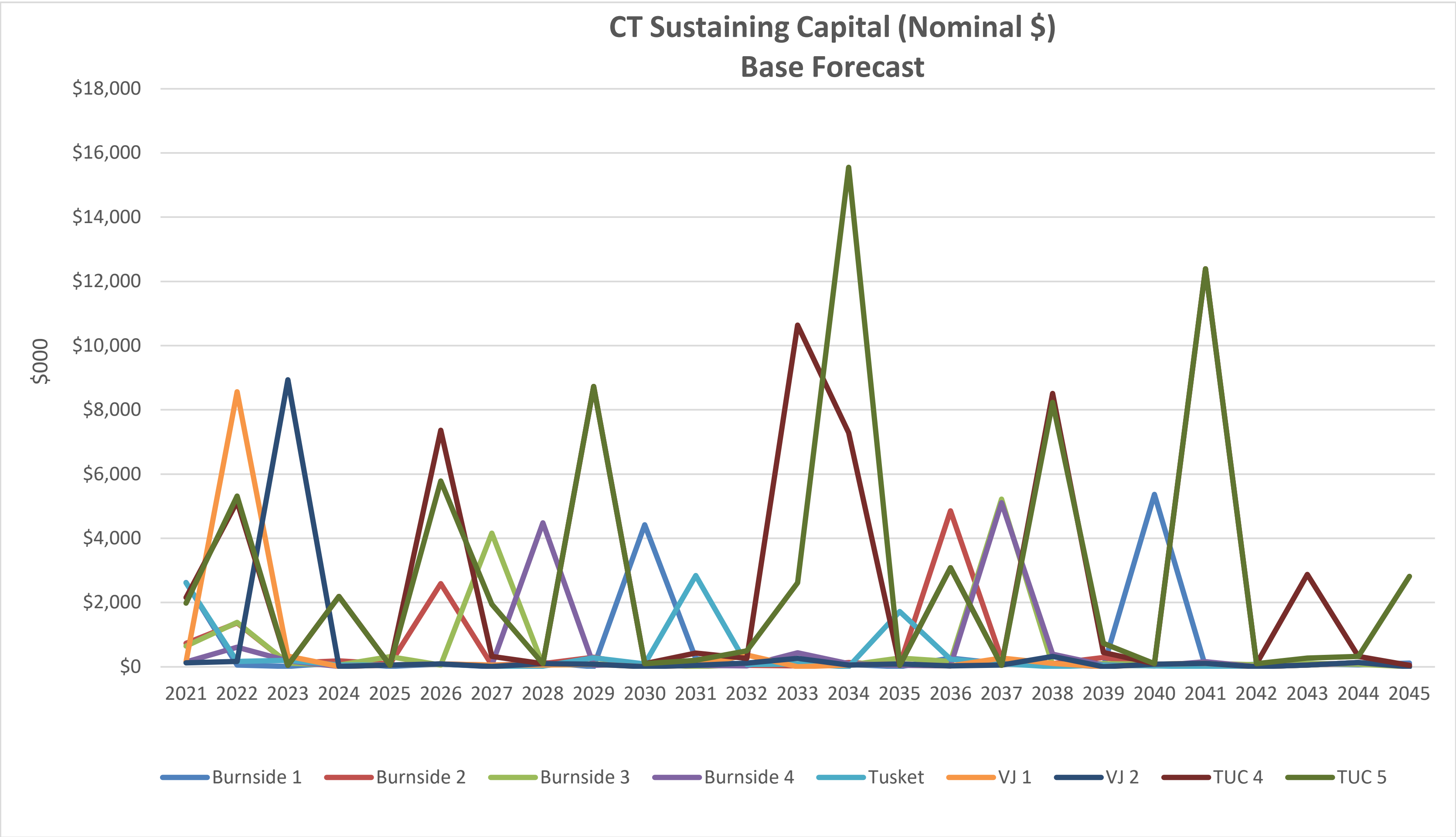
- The high UF puts all the units on an equal basis in terms of their operation in order to appropriately compare economics.

- NSP proposes that the High and Low sustaining capital cost sensitivities will assume the following:
    - High = Base + 50%
    - Low = Base – 25%

SUSTAINING CAPITAL FORECAST – COAL (BASE)



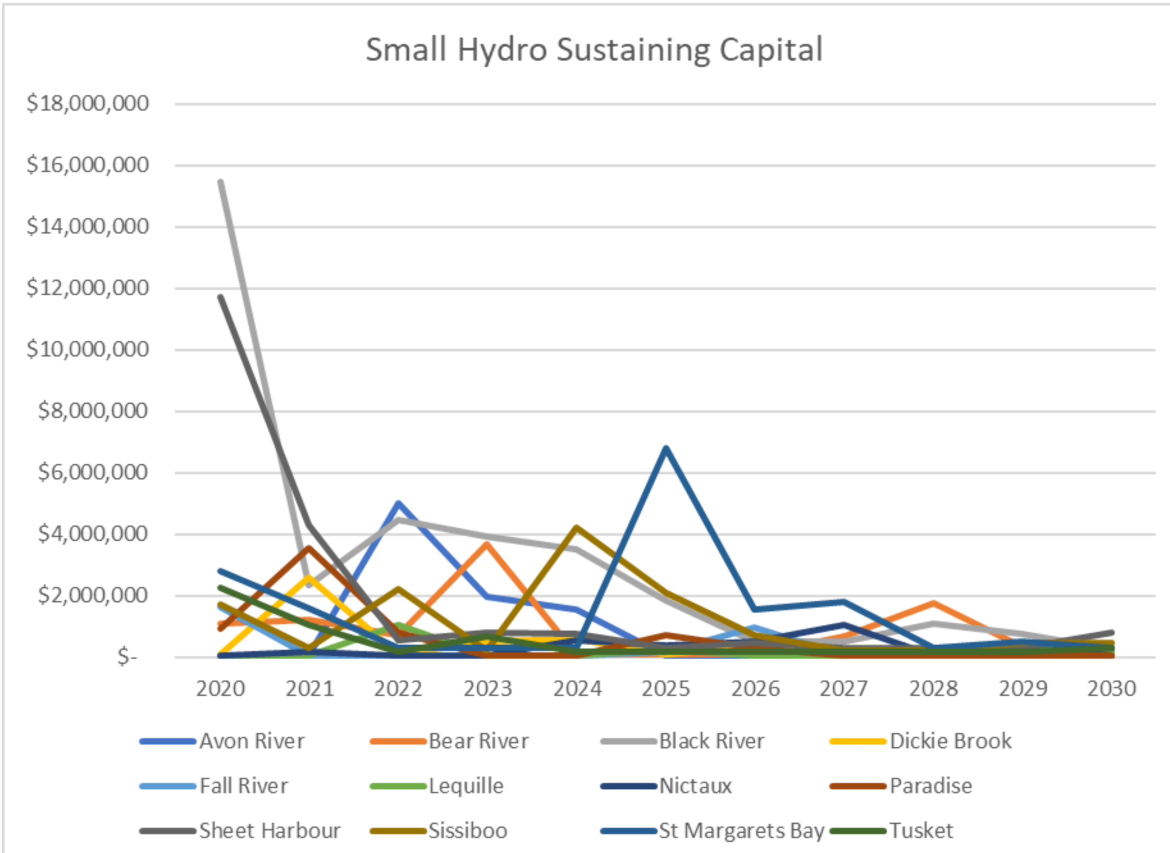
SUSTAINING CAPITAL FORECAST – CTs



Nova Scotia POWER An Emera Company

SUSTAINING CAPITAL FORECAST – SMALL HYDRO

- The sustaining capital forecast for hydro assets will be based on the Hydro Asset Study.*



*Updated project cost estimates for Wreck Cove LEM and Mersey redevelopment projects will be provided to stakeholders during the Assumptions workshop.

2020 IRP:
RENEWABLE INTEGRATION REQUIREMENTS

JANUARY 20, 2020

Nova Scotia
POWER
An Emera Company

SUMMARY

- Unlike previous IRPs, the next 25 years will likely be characterized by a drastic transformation in the electric utility business as it moves further towards complete decarbonization.
- Theories and physics of Power Systems were developed around synchronous machines that were the backbone of the power system for a very long time.
- This IRP will test the retirement of major large synchronous generators with replacement by inverter-based non-synchronous generation (or other lower emitting generators).
- The retirement of coal fired generators will not only impact the system adequacy (capacity and energy) but also will create a major shift in the provision of essential grid services which have historically been provided as ancillary benefits of large synchronous machines.

SUMMARY (CONT.)

- For IRP modeling, assumptions about cost and operational constraints to address these services will be considered. The assumptions have been developed by NS Power and its consultants using the PSC Stability Study from the Pre-IRP Work as the basis for assumptions. Further detailed study to establish firm opportunities and constraints for inverter-based energy sources will continue to be required as the system changes.

- Dispatch cases of selected resource plans will be tested via transient stability and system dynamic studies in the "operability screening" phase of the modeling, as described in the Analysis Plan.

SUMMARY (CONT.)

- For the NS Power system, the following has been identified as the grid services that need to be addressed to accommodate additional inverter-based generation to maintain stable and secure operation of the system.
  - **Ramping reserve and net load following capabilities**
  - **System strength and short circuit ratio**
  - **Volt-Ampere-Reactive support**
  - **Kinetic energy and synchronous inertia requirement**
- A value for the minimum requirement of each of these essential grid services will be represented in the model as dynamic constraints, which will enable the model to integrate renewable resources at any level by ensuring provision of the services.