2022 EVERGREEN IRP UPDATED ASSUMPTIONS

JANUARY 26, 2023

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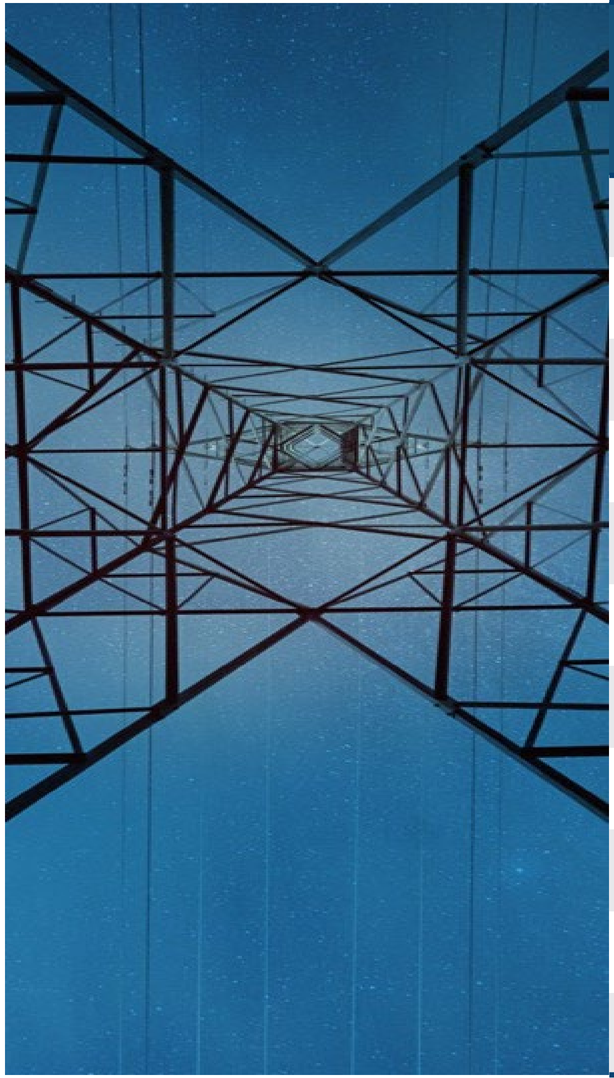

FINANCIAL ASSUMPTIONS & PLANNING HORIZON

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PLANNING HORIZON

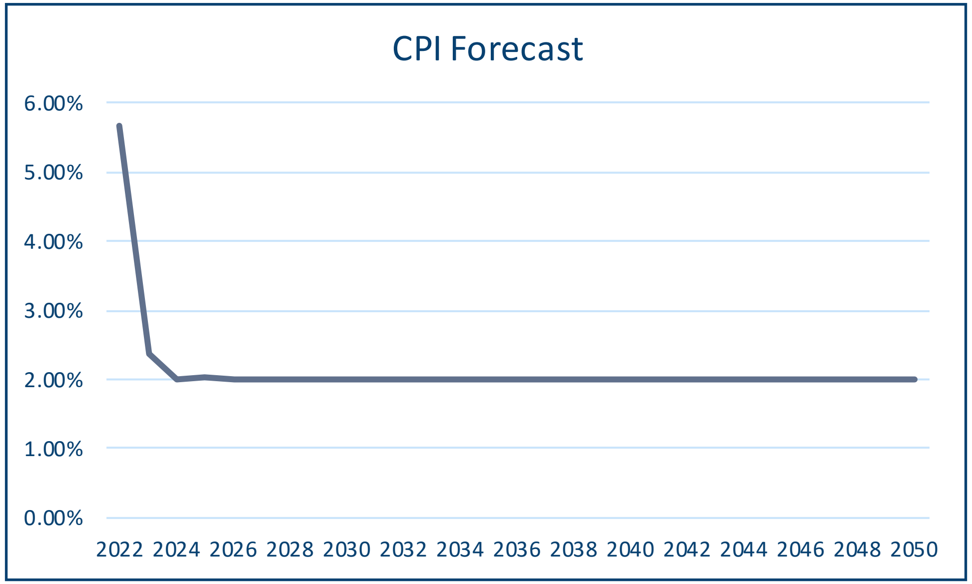
- NS Power has developed assumptions for a planning horizon spanning the period 2025-2050
- This lengthens the standard 25 year IRP planning horizon in order to cover the electricity system and economy-wide transition to net zero carbon emissions by 2050, consistent with the nature of the IRP as a long-term planning exercise
- Partial Net Present Value of Revenue Requirement calculations will be presented in 2025$

FINANCIAL ASSUMPTIONS

Weighted Average Cost of Capital (WACC, January 2022):

- Pre-tax = 6.33 %

- Average Inflation Rate (2025-2050) = 2%



Exchange Rate Forecast:

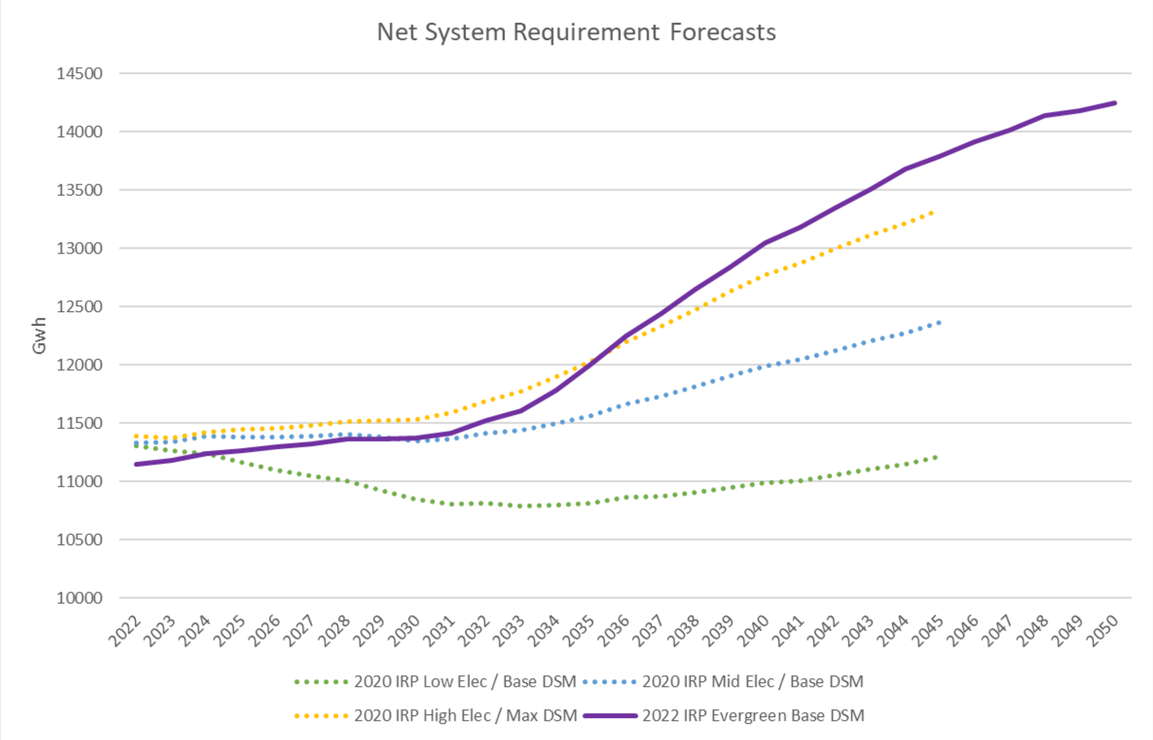
Year*	2022	2023	2024	2025	2026 +
Forecasted CAD/USD	1.25	1.26	1.28	1.28	1.28

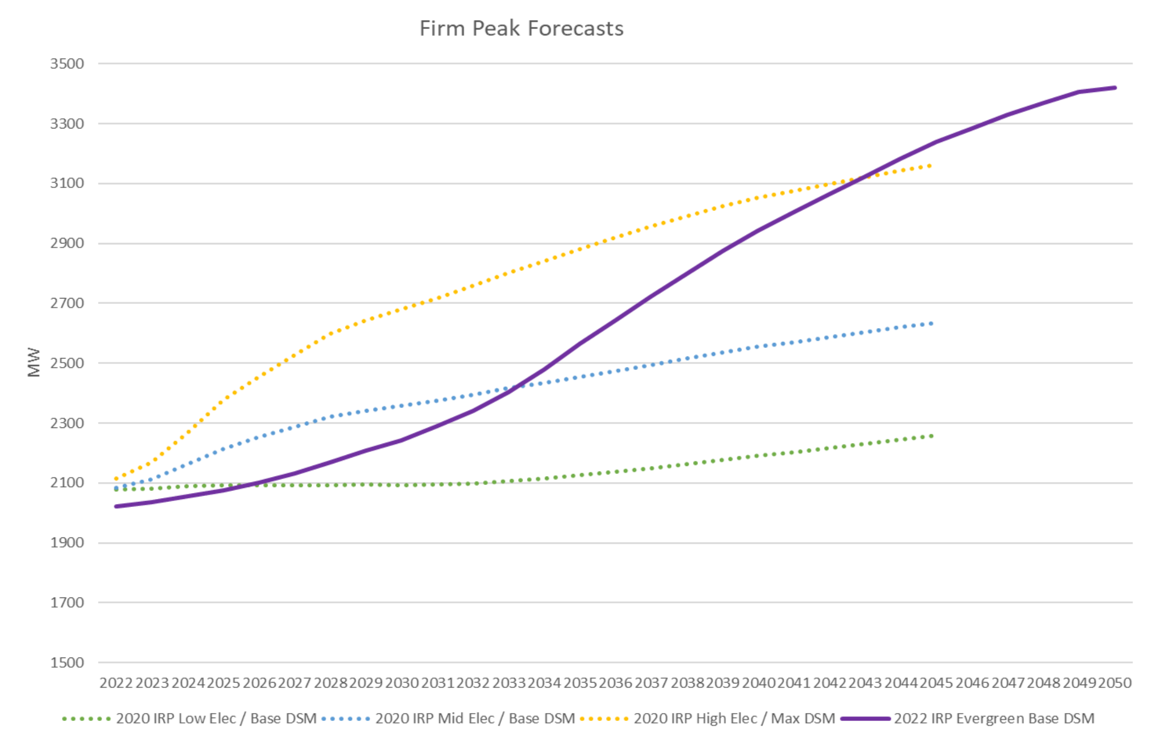
**2022-23 are an average of 5 bank forecasts*
2024-2026+ are an average of 2 banks forecasts

LOAD ASSUMPTIONS

LOAD ASSUMPTIONS OVERVIEW

- Load assumptions will be based on the 2022 Load Forecast Report, extended to 2050
- The forecast parallels the 2020 IRP Mid Electrification scenario through 2030, then shifts toward 2020 IRP High Electrification.
- The graphs below provide a comparison to the 2020 IRP load forecasts as a point of reference





NS Power notes that historical load growth between 1966 and 1975 (at an average of 10% annual NSR growth) is consistent with the steepest parts of the forecast curve (post-2030)

ELECTRIFICATION SCENARIOS

1. *Current Policy and Trends* - reflects heat pump adoption based on current policy and trends.
2. *Hybrid Peak Mitigation* – reflects a mix of heat pump adoption and retaining back-up fuel heating for peak (cold weather) conditions; has the impacts of reducing peak load requirement and modifying the load shape

In both scenarios, PLEXOS load modeling will be improved relative to the 2020 IRP by incorporating hourly shapes for incremental EV and heat pump load to capture impacts on the base load shape.

Heat Pump load shapes will reflect stock rollover toward achieving economy-wide net zero 2050 targets. These shapes were developed by E3.

Electric Vehicle (EV) load shapes will reflect changes in shape as stocks roll over and penetration increases. These shapes were developed by E3, based on a bottom-up forecast of transportation load based on simulations of EV driving and charging behavior, using travel survey data.

ENVIRONMENTAL ASSUMPTIONS

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APPLICABLE LEGISLATION CHANGES

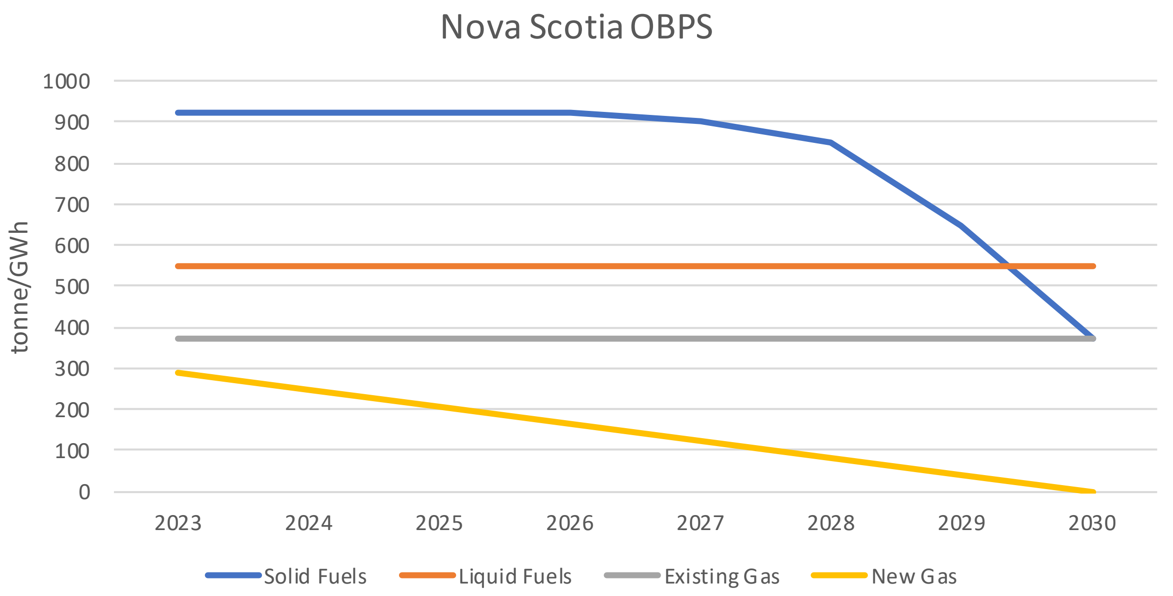
- The following environmental policy items have been amended/created since the 2020 IRP
  - Renewable Electricity Standard (RES) of 80% by 2030
  - Environmental Goals and Climate Change Reduction Act (2030 coal phase-out, 30% Zero Emission Vehicle (ZEV) sales in 2030)
  - Federal Carbon Price Framework
  - Federal discussion paper on a Net Zero 2035 Electricity System (Clean Electricity Standard)
- The following slides describe the policy items and provide a summary of the resulting updates to the modeling assumptions
- Existing legislation for other air emissions limits (Hg, SO_2, NO_x) will be modeled as in the 2020 IRP
- For a broader summary of these regulations and legislation, please see NS Power's IRP Action Plan Update for 2021 available in the Document Library at https://irp.nspower.ca/

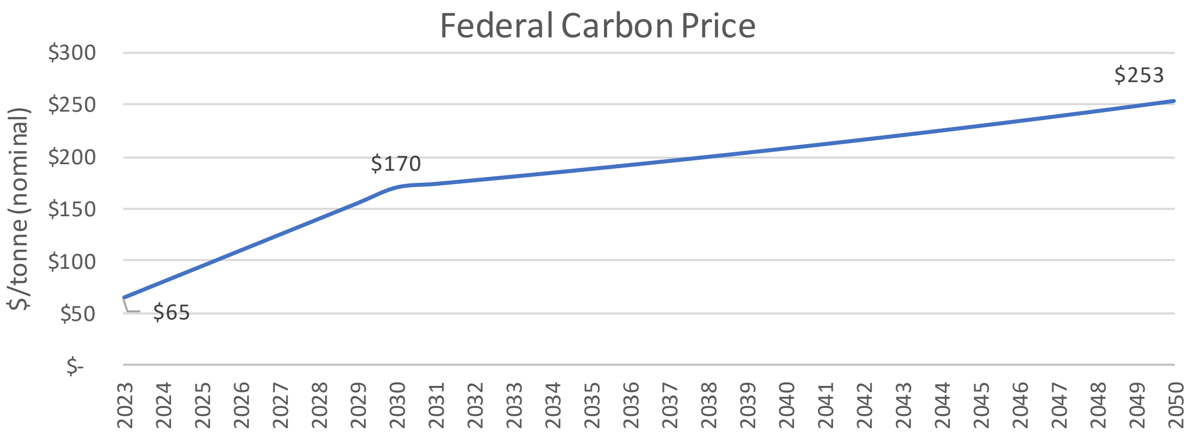
RES AND COAL PHASE-OUT

- The IRP modeling will have the following Renewable Electricity Standard (RES) constraints:
  - 2025-2029: 40% RES as a percent of total sales
  - 2030-2050: 80% RES as a percent of total sales
- Modeling will assume 1100GWh/350MW of new wind is on the system, anticipated to be procured via the Rate Based Procurement Program (100MW in service 2024, 250MW in service 2025).
  - This may be updated prior to final modeling as the RFP process proceeds in 2022
- Phase out of coal fired electricity generation by 2030

NOVA SCOTIA OBPS**

- An OBPS sets an emissions intensity limit for each facility subject to the program (covered facilities). This emissions limit is calculated using an emissions-intensity performance standard for a given activity (e.g. electricity generation by fuel type).
    - Facilities that emit above the applicable emissions intensity limits must provide compensation for the excess emissions, priced according to the Carbon Tax Trajectory.
    - For modeling purposes, NS Power escalates the $170/tonne figure in 2030 by 2% annually for 2031 to 2050 in order to preserve the real dollar value of the carbon price.
- The Province has updated the Environment Act legislation to indicate a transition from the current cap and trade system to a provincial OBPS system (Nova Scotia OBPS) beginning in 2023
- The Province has received federal approval for the "NS OBPS", which establishes a performance standard by fuel type for the electricity sector. Regulations to support this standard are anticipated in 2023.
- NS Power will include the proposed provincial performance standards in the model for the 2023 to 2030 period





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***January 2023 Update*

NET ZERO 2035/2050 ELECTRICITY SYSTEM CLEAN ELECTRICITY STANDARD

- Provincial legislation in Nova Scotia is targeting a Net Zero economy by 2050, including electricity generation
- Environment and Climate Change Canada (ECCC) is currently engaged in discussions on a potential Clean Electricity Standard enabling a net-zero electricity system by 2035
- Consistent with the CES discussion paper and aligned with the 2020 IRP, NS Power will assume that a Net Zero 2035 or Net Zero 2050 (NZ35/NZ50) electricity system will have maximum annual GHG emissions intensity of 50 g/kWh from the electricity sector
    - This intensity limit will be modeled as a series of annual carbon caps derived from the input load to each scenario
    - Any emissions beyond 2035 will be taxed at the effective Federal Carbon Tax rate if not addressed through offsetting measures
- To assess the potential impacts of offsetting measures required for remaining emissions in the electricity sector, NS Power proposes to model a higher carbon offset cost in some scenarios. This offsetting cost is a proxy for activities that result in negative emissions (e.g. direct air capture, forestry initiatives, methane recovery, etc.).
    - As considerable uncertainty exists on future costs of offsetting measures, NS Power proposes to impose this offsetting cost in the model in certain sensitives, and not as a core assumption.

CARBON OFFSET ASSUMPTIONS

- Carbon offsets are anticipated to be required to enable net zero electricity system targets
- There are a range of offsetting measures identified as enabling levers
    - Current literature points to examples of Direct Air Carbon Capture (DACC) with associated cost metrics
    - Other options are being investigated but understanding the duration of impact and cost are still in their infancy (example: forestry initiatives, methane recovery)
- For the purposes of the 2022 evergreen IRP model, carbon offset costs will be modeled as follows:
  - Price of $500/tonne:
    - Based on existing reference points (IEA range, current pilot projects)
    - Accounts for a reduction in price based on market growth for DACC offset options

SUPPLY SIDE OPTIONS

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SUPPLY OPTION COST ESTIMATE METHODOLOGY

- NS Power's starting point for the 2022 evergreen IRP was the Supply Options Study completed for the 2020 IRP; costs were reviewed against current industry data and updated where required
- For cost estimates of new resources, NS Power primarily utilized three public sources (EIA, NREL, Lazard), and where applicable, internal engineering estimates or estimates from other public sources*
- For natural gas technologies, a 7% cost adder has been incorporated into the proposed capital cost input to reflect the requirement for units to be dual-fuel capable (natural gas and light oil)
- Base-year estimates applicable to each source were escalated at historic inflation and adjusted for foreign exchange to 2022$ CAD
- Future year estimates for adjusted based on forecasted inflation and foreign exchange
- Where construction financing was not estimated for a particular cost source or sub-technology, the NREL ATB estimate was used
- NS Power's recommended Evergreen IRP assumption is based on, where available, the mid-point of the source estimates ranges
- Cost Trajectories are based on NREL ATB Real Dollar estimates. For NS Power's cost modeling, trajectories are converted to nominal trajectories based on forecasted inflation

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** Assumptions to the Annual Energy Outlook 2022: Electricity Market Module (eia.gov)*
https://atb.nrel.gov/electricity/2021/index
https://www.lazard.com/media/451905/lazards-levelized-cost-of-energy-version-150-vf.pdf
https://www.lazard.com/media/451882/lazards-levelized-cost-of-storage-version-70-vf.pdf

FEDERAL INVESTMENT TAX CREDIT (ITC)**

The Federal Government announced an investment tax credit for clean technologies, with a focus on net-zero technologies and battery storage solutions to incent progress towards a net-zero economy

- The plan as announced would provide a refundable tax credit equal to 30% of capital cost of investments
- Qualifying clean technologies include solar, SMRs, wind, storage systems that do not use fossil fuels in their operation, low carbon heat equipment and industrial zero-emission vehicles and related charging or refueling equipment
- A clean hydrogen investment tax credit also exists but is understood to apply to hydrogen production equipment and not hydrogen-fueled generators

The investment tax credit will be available for eligible investments made starting in the first year of the planning horizon (2025):

- The net zero technology credit will be subject to phase out as early as 2032 with the program ending in 2035
- For the evergreen IRP modeling assumptions, the capital costs of qualifying clean energy/storage technologies will reflect the impacts of the ITC during eligible years

***January 2023 Update*

CAPITAL COST ESTIMATES ($/KW)

Technology	Sub-technology	EIA	NREL ATB	Lazard	Other****	2020 IRP Estimate (2022$)	NSPI Proposed Evergreen Input (2022$)	CapEx Trajectory 2030 (2022$)
Wind	Onshore	$2,447	$1,772	$1,664		$2,110	$1,772	$1,292
	Offshore	$8,658	$4,561	$4,397		$4,591	$4,561	$3,397
Solar PV	Tracking	$1,868	$1,708	$1,208		$1,802	$1,708	$1,055
Storage	Li-ion Battery (4hr)	$1,816	$1,632	$1,219		$1,756	$1,632	$1,066
Natural Gas	Combined Cycle	$1,592	$1,416	$1,339		$1,753	$1,515	$1,453
	Combined Cycle w/ carbon capture and storage	$4,215	$3,236			$3,471	$3,463	$3,152
	Combustion Turbine - Frame	$1,194	$1,243	$1,088		$1,132	$1,278	$1,183*
	Combustion Turbine - Aero	$1,897	N/A		$2,380	$1,839	$2,029	$1,879*
	Reciprocating engine	$2,896	N/A		$2,008	$1,935	$2,149*	$1,989
Geothermal	EGS	$11,644	$24,569	$7,466	$7,644		$7,644	$5,630
Nuclear	Small Modular Reactor	$11,892	$11,089**		$7,226	$9,742	$11,089**	$10,802**
*****Long Duration Storage**	TBD				$3,500		$3,500	$2,286
Hydrogen	Combustion Turbine - H_2 Capable				$2,211		$2,211	$2,047
Tidal	n/a					$10,612	$10,612	$10,612
Coal-to-Gas	Point Tupper				$219*		$219	$219
	Trenton				$278*	$135-252	$278	$278
HFO Operation	Coal units operated on HFO only (cost per unit)				$1.33		$1.33	$1.33

**August 2022 Update*
***January 2023 Update – updated to reflect SMR specific capex trajectory that was added to 2022 NREL forecast*
****Proxy cost estimate for applicable technologies including; BESS, Pumped Hydro, CAES. Cost Trajectory assumes a short duration Li-Ion, 12HR of storage, with Li-Ion round trip efficiency and a 95% ELCC*
*****The "Other" cost estimates for Combustion Turbine-Aero, Geothermal and Small Modular Reactor are from Pacificorp IRP 2021 – adjusted to 2022$ using the same adjustment methodology as other source estimates*

OPERATING COST ESTIMATES

Technology	Sub-technology	EIA		NREL ATB		Lazard		**Other		NSPI Proposed Evergreen Input	
		FO&M ($/kW-yr)	VO&M ($/MWh)	FO&M ($/kW-yr)	VO&M ($/MWh)	FO&M ($/kW-yr)	VO&M ($/MWh)	FO&M ($/kW-yr)	VO&M ($/MWh)	FO&M ($/kW-yr)	VO&M ($/MWh)
Wind	Onshore	$35.5	$0.0	$57.0	$0.0	$41.2	$0.0			$41.2	$0.0
	Offshore	$148.2	$0.0	$141.0	$0.0	$97.3	$0.0			$141.0	$0.0
Solar PV	Tracking	$20.6	$0.0	$29.9	$0.0	$15.1	$0.0			$20.6	$0.0
Storage	Li-ion Battery (4hr)	$33.4	$0.0	$40.8	$0.0	$63.7	$0.0			$40.8	$0.0
Natural Gas	Combined Cycle	$16.4	$2.5	$37.1	$2.4	$22.1	$3.9			$22.1	$2.5
	Combined Cycle w/ carbon capture and storage	$37.2	$7.9	$88.5	$7.8					$88.5	$7.8
	Combustion Turbine - Frame	$9.4	$6.1	$28.4	$6.7	$18.9	$4.6			$18.9	$6.1
	Combustion Turbine - Aero	$22.0	$6.3	NA	NA	NA	NA	-	$12.1	$22.0	$6.3
	Reciprocating engine							$27.0	$10.7	$27.0	$6.0
Geothermal	EGS	$197.64	$1.7	$347.8	$0.0	$17.41	$29.46	$139.3	$1.3	$266.1	$0.8
Nuclear	Small Modular Reactor	$128.0	$4.0							$128.0	$4.0
Long Duration Storage	TBD							$87.5*	$0.0	$87.5	$0.0
Hydrogen	Combustion Turbine - H_2 Capable							$52.8	$4.2	$52.8	$4.2
Tidal	n/a							$359		$359	
Coal-To-Gas	Point Tupper							$40*	$1.2*	$40	$1.2
	Trenton							$40*	$1.7*	$40	$1.7
HFO Operation	Coal units operated on HFO only							$21.6*	$1.2*	$21.6	$1.2

**August 2022 Update*

***The "Other" cost estimates for Combustion Turbine-Aero, Geothermal and Small Modular Reactor are from Pacificorp IRP 2021 – adjusted to 2022$ using the same adjustment methodology as other source estimates; coal-to-gas and HFO Operation are internal NS Power engineering estimates*

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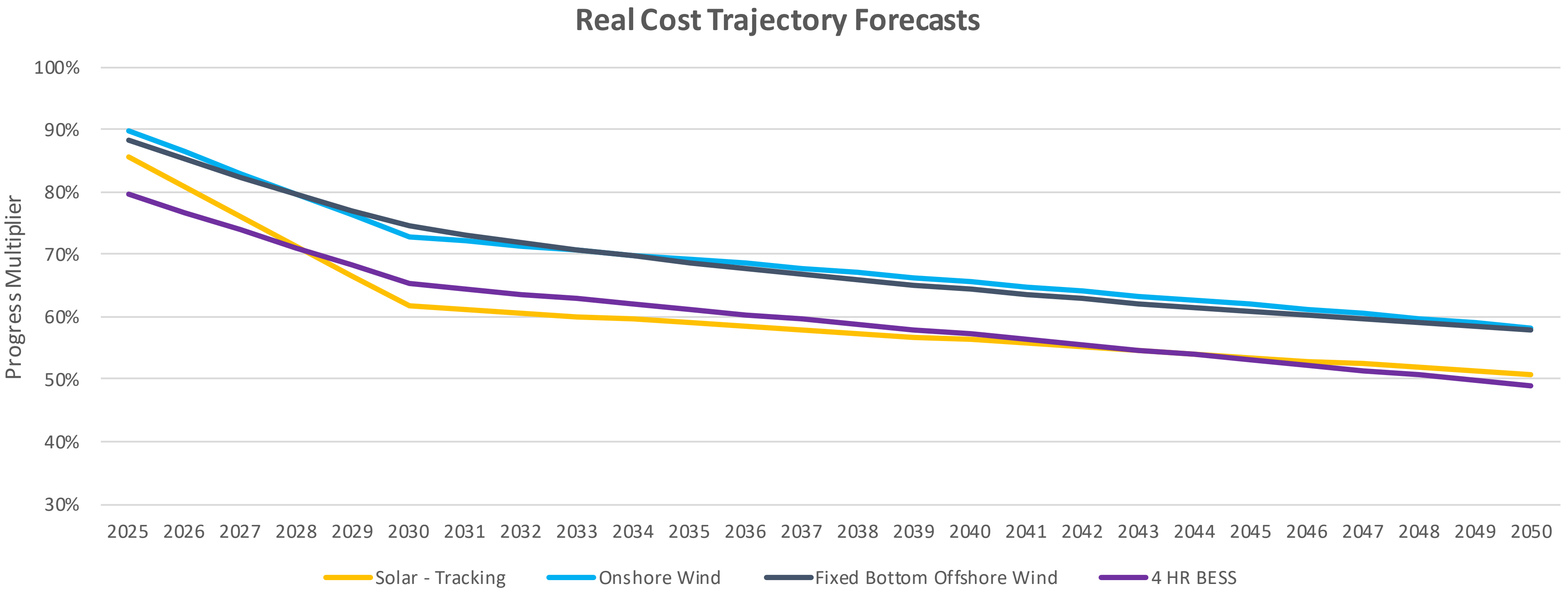
NEW RESOURCES – UNIT CHARACTERISTICS

Technology	Sub-technology	Build Increments (MW)	Operating Life (Years)	Earliest Build (Years)
Wind	Onshore	Linear (1MW)	25	2026
	Offshore	Linear (1MW)	25	2028
Solar PV	Tracking	Linear (1MW)	25	2025
Storage	Li-ion Battery (4hr)	Linear (1MW)	20	2025
Natural Gas	Combined Cycle	145	35	2026
	Combined Cycle w/ carbon capture and storage	145	35	2030
	Combustion Turbine – Frame	150	35	2026
	Combustion Turbine – Aero	50	35	2026
	Reciprocating engine	20	35	2026
Geothermal	EGS	32**	40	2035**
Nuclear	Small Modular Reactor	100	35	2035
Long Duration Storage	TBD	100	20*	2028*
Hydrogen	Combustion Turbine - H_2 Capable	50	35	2028
Tidal	n/a	10	35	2030
Coal-To-Gas	Point Tupper	150	20	2024
	Trenton	150	20	2025
HFO Operation	Coal units operated on HFO only	150*	20	2025

**August 2022 Update*

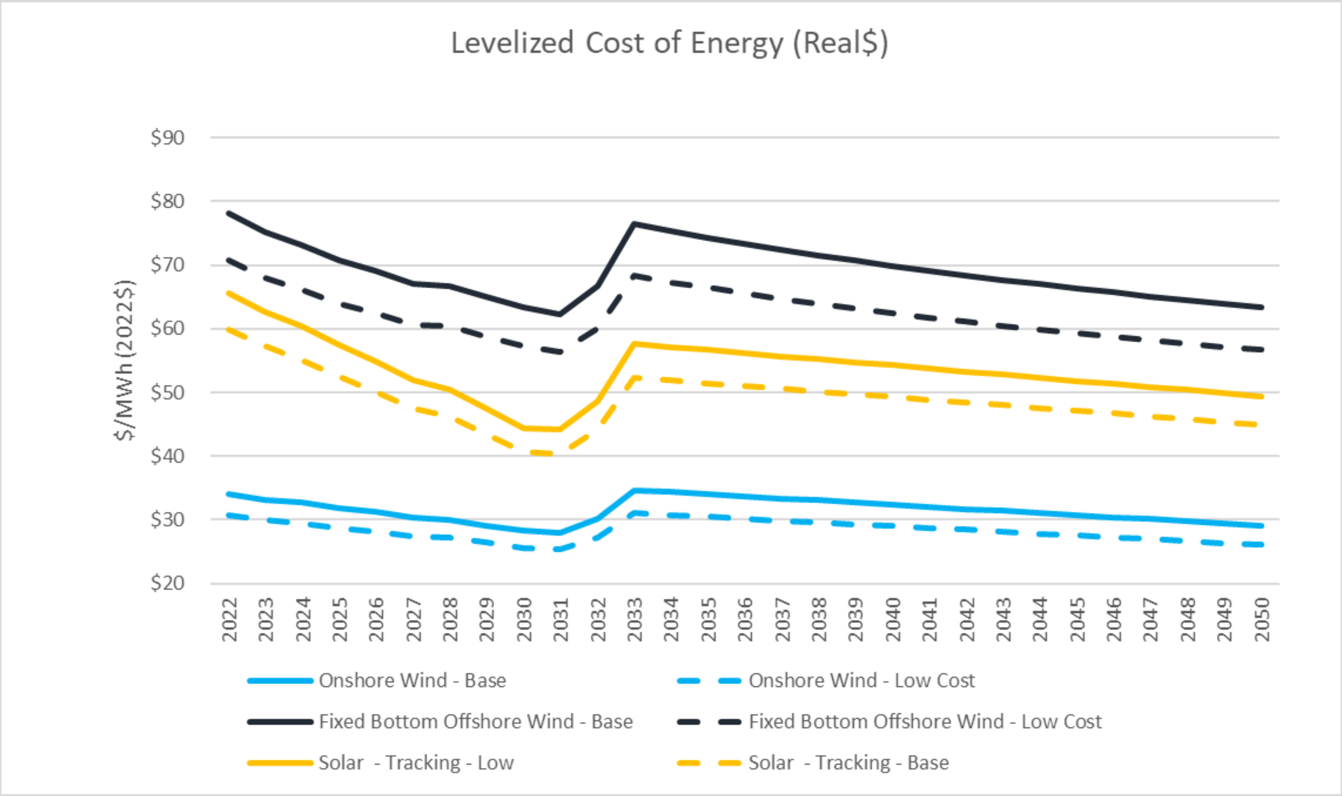
***January 2023 Update – updated assumptions for geothermal capacity additions include a constraint on total capacity (max 64MW) and an earliest build date of 2035, which aligns with the exploratory nature of deep geothermal in Nova Scotia (highest value use-case currently identified for geothermal is for local direct heat use)*

RENEWABLES AND STORAGE - COST TRAJECTORIES



Trajectories are based on NREL ATB 'Moderate' price trajectory forecasts
Reflect pre-ITC trajectories (impact of ITC demonstrated on following slide)

LEVELIZED COST OF ENERGY – RENEWABLES**



This chart reflects the updated LCOE values for renewable generating resources included in the updated evergreen IRP assumptions.

The shape of the LCOE trajectory between 2023 and 2033 is a result of the Investment Tax Credit (ITC) for qualifying renewables combined with technology cost decline forecasts.**

Sub-Technology	Capacity Factor
Onshore Wind	39%
Offshore Wind	45%*
Solar	17%

'High' capacity factor assumption for the 2020 IRP

Capacity Factor estimates for renewable resources will use the 2020 IRP Assumptions from the Resource Option Study (mid-point of Low/High range estimate)
**August 2022 Update*
***January 2023 Update*

EMERGING TECHNOLOGIES

- Recent Federal Policy discussion papers* point to emerging technologies as a pathway to future net zero targets and include the following:
  - Generating Resources
    - Hydrogen as a fuel source (for use in hydrogen-enabled CT units)
    - Small Modular Reactors (SMRs)
    - Geothermal
    - Tidal
  - Storage
    - Long duration Storage (12hr+)
- The range of emerging technology options are in the early stages of development and advancement in technical and, in some cases, enabling policy are required to achieve greater certainty for both cost and timing
- The Evergreen IRP scenarios include those with net zero electricity system targets; accordingly, NS Power will model emerging generating resources and storage options using currently available public information. These resource types are understood to be subject to ongoing development, and a risk-weighted lens will be applied to scenarios incorporating these resources.

*[A clean electricity standard in support of a net-zero electricity sector: discussion paper - Canada.ca]

EMERGING TECHNOLOGIES - HYDROGEN

- The potential transition to the use of hydrogen (H_2) as a fuel source has been referenced as a key lever in meeting net zero electricity generation targets
- For the purposes of the evergreen IRP modeling, the following will be considered:
  - Availability of hydrogen fuel (considering both import and domestic production scenarios)
  - Availability & timing of hydrogen compatible combustion turbines and the extent of hydrogen blending potential
- The following table outlines the assumptions for modeling hydrogen enabled generation (please see slides 16 – 18 for cost details):

Input	Unit	Value	Additional Details
Domestic H_2 Availability	Year	2028	Domestic H_2 production in proximity to CT
Import H_2 Availability	Year	2028	
70% Hydrogen Capable Units	Year	2028	Assume 100% H_2 capital cost (max blend will be 70% to 2035)
100% Hydrogen Capable Units	Year	2035	Assume 100% H_2 capital cost
Annual Domestic H_2 Load Requirement	GWh	1230	100 MW X 2 PEM Electrolyzer Unit Assume 70% utilization
Emissions Reduction Profile of H_2			Use trajectory demonstrating volumetric blend impact on emissions reduction

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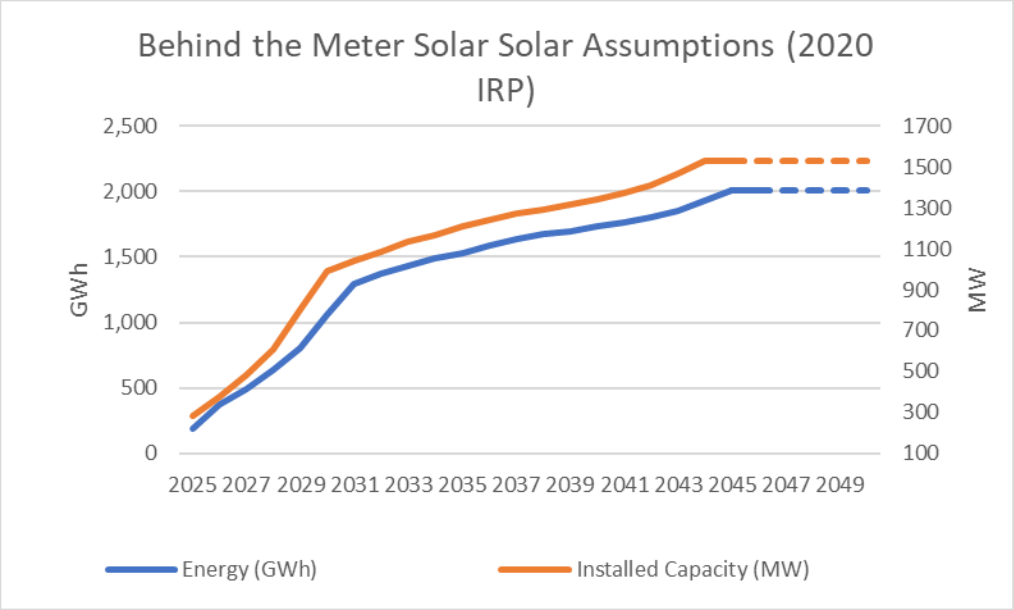
DISTRIBUTED ENERGY RESOURCES (DERS)

DISTRIBUTED ENERGY RESOURCES

- In the 2020 IRP, a 'Distributed Resources' Resource Strategy was evaluated.
  - These resources were assumed to represent rooftop solar and were modeled as reductions in load served by NS Power. Energy reductions and assumed nameplate capacity to generate the energy are provided in *'Behind The Meter Solar Assumptions (2020 IRP)'*
- High Distributed Energy Resources cases (High DER) will continue to be assessed via the Evergreen update
  - NS Power will model these resources as invertor-based generators in the system dispatch with operating characteristics developed during the 2020 IRP (i.e. capacity factor, seasonal energy shape, etc.).
  - These resources will be subject to the same integration requirements as other invertor-based variable resources (wind, utility scale solar)



Modeling assumes 15% annual capacity factor

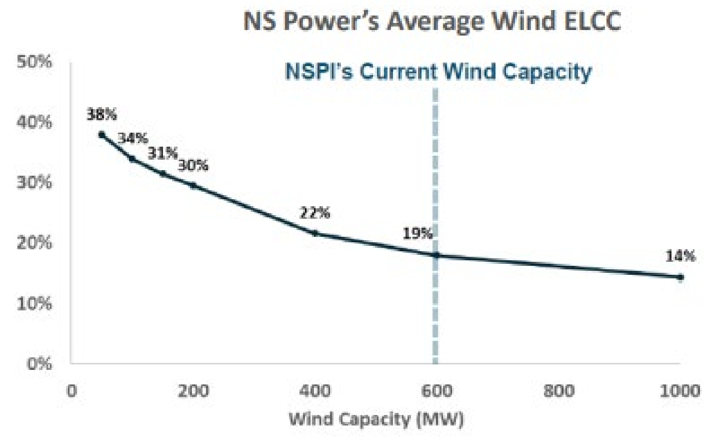
PLANNING RESERVE MARGIN

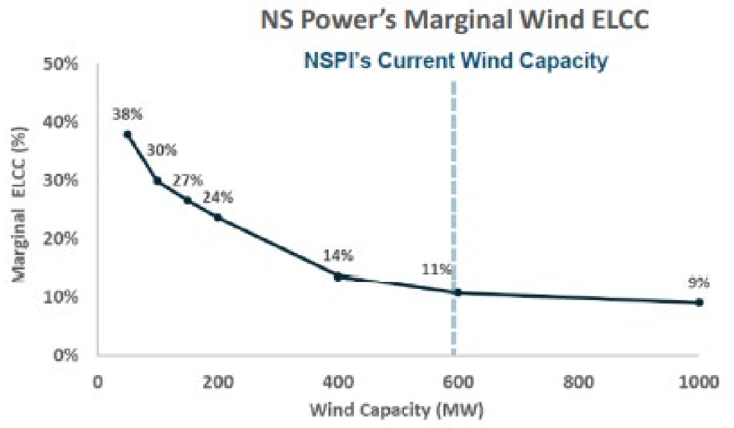
PLANNING RESERVE MARGIN AND CAPACITY VALUE

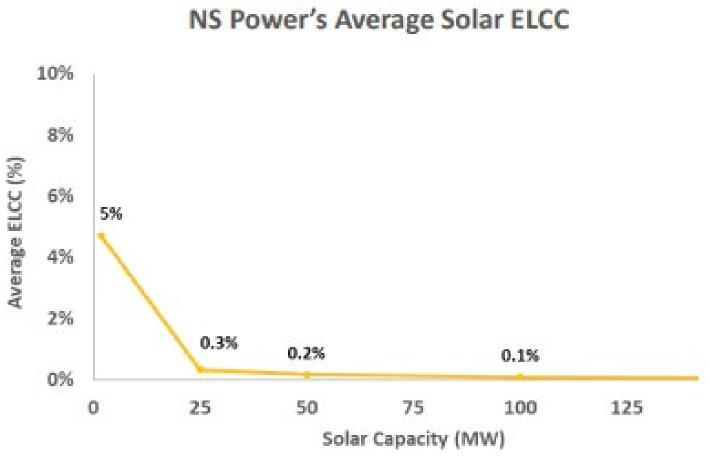
- Inputs derived from the 2020 Pre-IRP Planning Reserve Margin and Capacity Value Study will be retained, including Planning Reserve Margin (PRM) and Effective Load Carrying Capability (ELCC) of variable renewable and dispatch limited resources. For PRM, NS Power will continue to translate the ICAP calculated PRM (20%) to a UCAP (9%) metric for capacity expansion modeling.

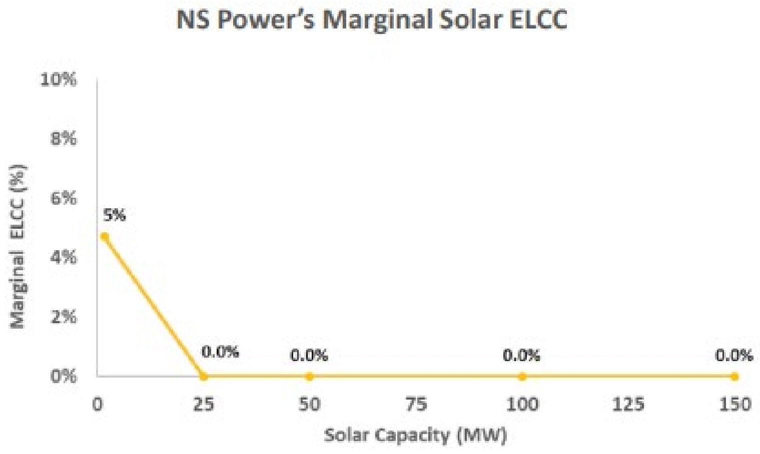
- New wind will have a marginal ELCC contribution of 10%.

- 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%.









DSM AND DR ASSUMPTIONS

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DEMAND SIDE MANAGEMENT (DSM)

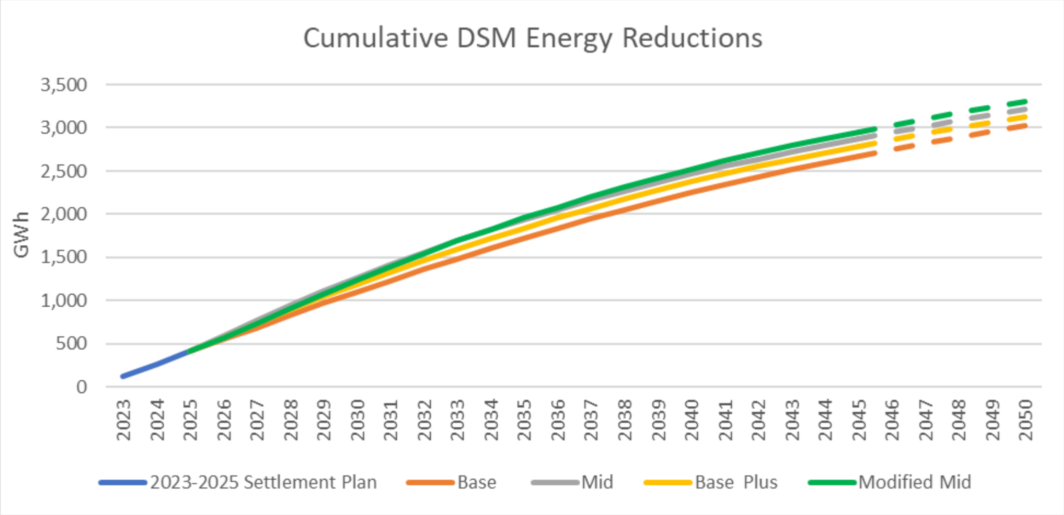
- In early 2022, E1 submitted their Demand Side Management Resource Plan for 2023 – 2025 (“Settlement Plan”)
  - This includes bundled DSM and Demand Response programing targeting energy and demand savings per the table here:

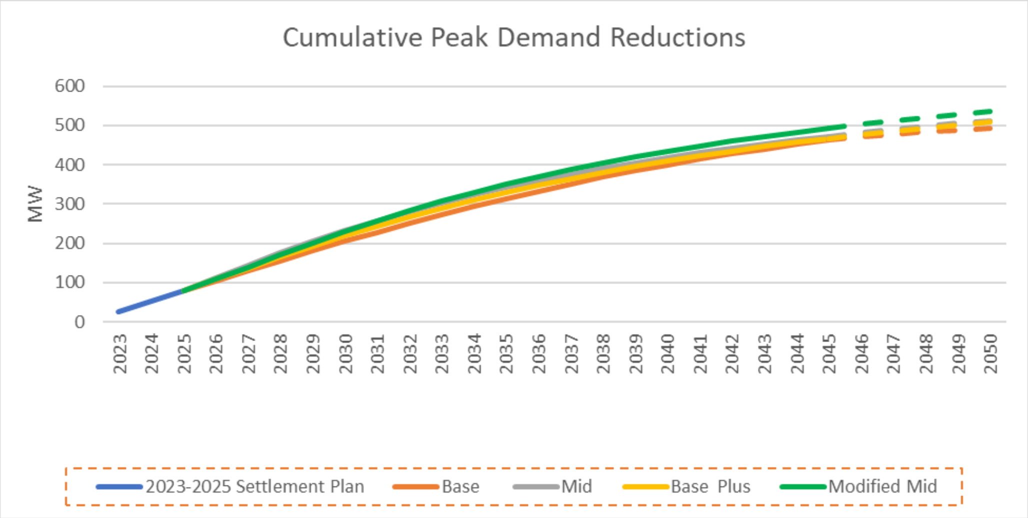
2023-2025 Settlement Plan

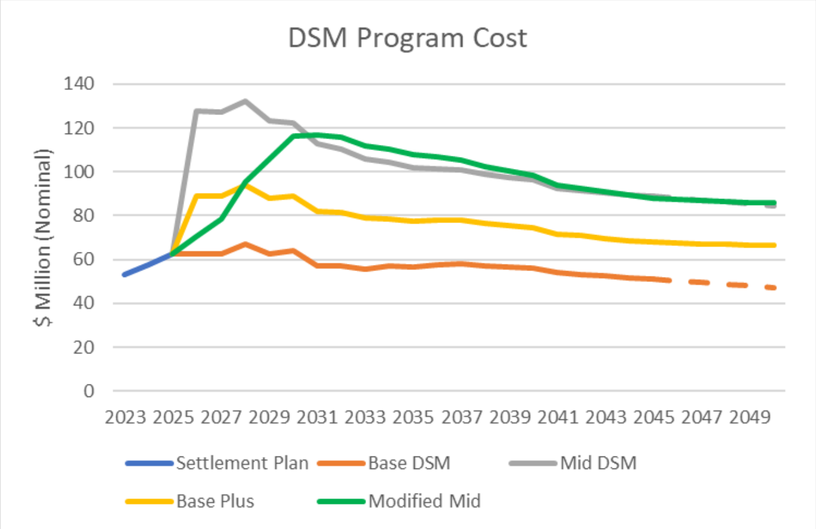
Year	First Year Energy Savings	Peak EE Demand Savings (MW)	Investment ($Million)
2023	120.7	26.9	$53.1
2024	142.6	25.6	$57.5
2025	149.5	26.3	$62.5

- Beyond the Settlement plan period (2026+), DSM Programming assumptions from the 2019 DSM Potential study will be used. The Base DSM profile will be used except in the case of DSM sensitivities.
- Similarly, DSM investments will use Settlement Plan period investments and the applicable programing level investments from the 2019 DSM Potential study, adjusted for historical actual CPI inflation and forecast inflation
- NS Power extended energy, demand and investment assumptions for the periods beyond 2045 at late-period trend growth rates
- Demand Response (DR) programming, as modeled in the 2020 IRP, are now included in the 2022 Load Forecast and being implemented as part of the IRP Action Plan. Accordingly, DR as a candidate supply side resource will not be tested in the 2022 Evergreen IRP.

ENERGY EFFICIENCY (EE)**







***January 2023 Update – corrected Base and Mid DSM profiles, Base+ and Modified Mid DSM profiles included*

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IMPORT ASSUMPTIONS

SUMMARY – IMPORT ASSUMPTIONS**

Continuing the approach taken in the 2020 IRP, the 2022 Evergreen IRP model will have access to capacity and energy imports available from outside of Nova Scotia in some scenarios. Available options have been updated to reflect progress on NS Power's IRP Action Plan, presented to stakeholders at the April 2022 workshop.

- **Capacity Imports**
  - No access to near-term firm imports over existing transmission**
  - Atlantic Loop via new transmission - up to 550MW
- **Firm Energy Imports (Long-Term Contracted)**
  - Atlantic Loop via new transmission – up to 550MW
  - Other Regional Import via new transmission – up to 120MW
- **Non-Firm Energy Imports**
  - Energy via existing transmission (NB and ML interties)
  - Energy via new transmission (HQ and NE)

***January 2023 Update*

RELIABILITY TIE ASSUMPTIONS

- The Reliability Tie is a second 345kV AC transmission line from Onslow, NS to Salisbury, NB
- This enhanced transmission interconnection is modeled as providing the following system benefits:
    - Increased integration / reduced curtailment of domestic wind (or other inverter-based) generation
    - Reductions to minimum online generation constraints in order to meet system synchronous inertia requirements
    - Allow for expansion into a Regional Interconnection via further transmission expansion beyond Salisbury, NB
- The development of the Reliability Tie was identified as an IRP Action Plan element during the 2020 IRP
- In the 2022 evergreen IRP the Reliability Tie will be included in all scenarios, modeled with an in-service date of 2027
- Cost will be modeled based on subsequent submittal estimate presented in NS Power's ACE 2022 filing

ATLANTIC LOOP ASSUMPTIONS

APPROACH

- Reflecting the interprovincial collaborative nature of the Atlantic Loop project, for the 2022 evergreen IRP, the Atlantic Loop will be modeled as a Resource Strategy which is either fixed "in" or "out" in 2030 for each scenario
- For modeling purposes the Atlantic Loop represents an HVDC line from Salisbury, NB interconnecting with the Hydro-Quebec system

CAPITAL COST

- The capital cost of the Atlantic Loop will be modeled as $1.7B ($2019); this is a modeling assumption for the portion of the capital cost to be funded by Nova Scotia Power customers and is in-line with the assumptions used in the 2020 IRP and the Atlantic Clean Power Roadmap.

ENERGY COST

- Based on updated NE market forecast, adjusted to represent Quebec import source
- Energy will be RES-compliant

CAPACITY COST

- Based on updated NE market forecast, adjusted to represent Quebec import source
- Capacity can be economically purchased in blocks (consistent with 2020 IRP)

OTHER REGIONAL IMPORT ASSUMPTIONS

APPROACH

- Available for economic selection in 2030 and beyond
- Reflects updates provided in 2021 IRP Action Plan Update on anticipated limited available of energy and capacity from New England
- For modeling purposes the Other Regional Import represents an AC line from Salisbury, NB to Coleson Cove, NB

CAPITAL COST

- The capital cost of the transmission expansion will be modeled as $0.36B ($2019); this is a modeling assumption for the portion of the capital cost to be funded by Nova Scotia Power customers and is in-line with the assumptions used in the 2020 IRP.

ENERGY COST

- Based on updated NE market forecast
- Energy will not be RES-compliant

FUEL & POWER PRICING

EVERGREEN IRP FUEL PRICING ASSUMPTIONS

Service providers and approach are consistent with 2020 IRP

- S&P Global Platts analytics (Natural Gas, Oil) and Energy Ventures Analysis (EVA) (Coal, Petcoke)
    - Established service providers to NS Power
    - Global view of commodity pricing
    - Forecasts supported other large projects
- Forecasting Approach
    - Traditional energy commodity pricing forecasts produced via Service Providers - long term fundamental forecasts. Their forecasts are adjusted based on:
        - Current and expected transportation costs and tolls
        - Market insight and propriety views on long-term market development, including high and low fuel pricing
        - Foreign exchange and inflation expectations as forecasted and described in *Financial Assumptions*
- Hydrogen price forecasts were based on market research and publicly available data and adjusted using the above forecasting approach

NATURAL GAS

- Nova Scotia remains constrained for pipeline capacity and has no domestic supply source of natural gas
- Based on the 2020 IRP and 2022 evergreen Early Insight modeling, new gas units are expected to operate at low capacity factors with correspondingly low natural gas offtake. Thus, for new gas resources, NS Power will model a supply source that can serve this need without long-term infrastructure upgrades, requiring long-term fixed commitments. This is consistent with Option 2: Peaking Gas from the 2020 IRP
  - Peaking Gas (LNG winter-Dawn plus tolls summer)
    - As this source does not have firm transportation, NS Power is assuming that new gas resources will be dual-fuel capable and has priced this requirement into the capital cost of new gas resources. Future reliability considerations include fuel storage and contracting provisions.

HYDROGEN

- Includes assumptions for both Domestic and Imported Hydrogen – for use as a blended fuel source (2028+) for hydrogen-capable combustion turbine units
- Assume domestic hydrogen production is co-located with CT generation to minimize transportation costs

Commodity/ Scenario	Price Basis	Transportation Assumptions
Imported Hydrogen	EIA Hydrogen Price Reference Plus Transportation Cost*	Shipping (Ammonia - price includes reprocessing) Trucking (compressed gas)
Domestic Hydrogen	EIA Hydrogen Price Reference	Co-locate domestic hydrogen production plant with demand

*Source: Argonne National Laboratory – Hydrogen Delivery Scenario Analysis Model (HDSAM)

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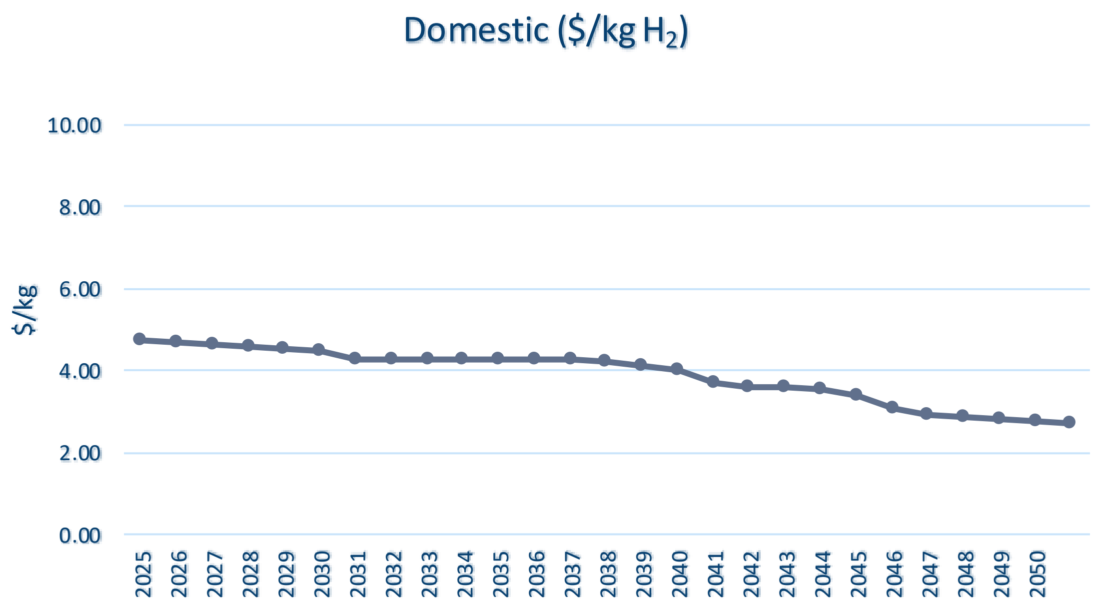
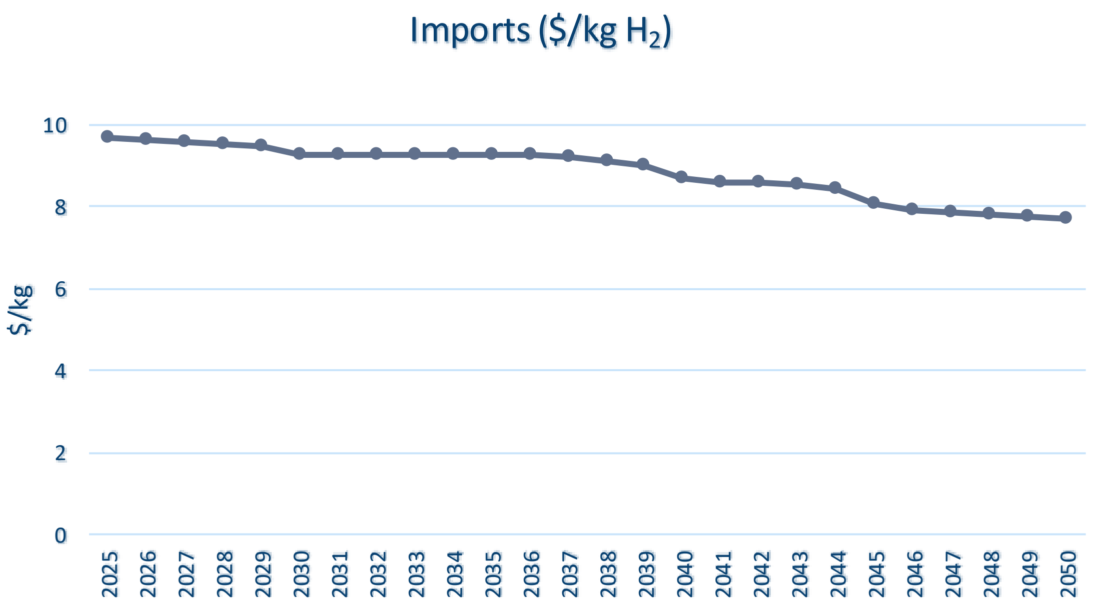
HYDROGEN FUEL PRICE TRAJECTORY





SUSTAINING CAPITAL

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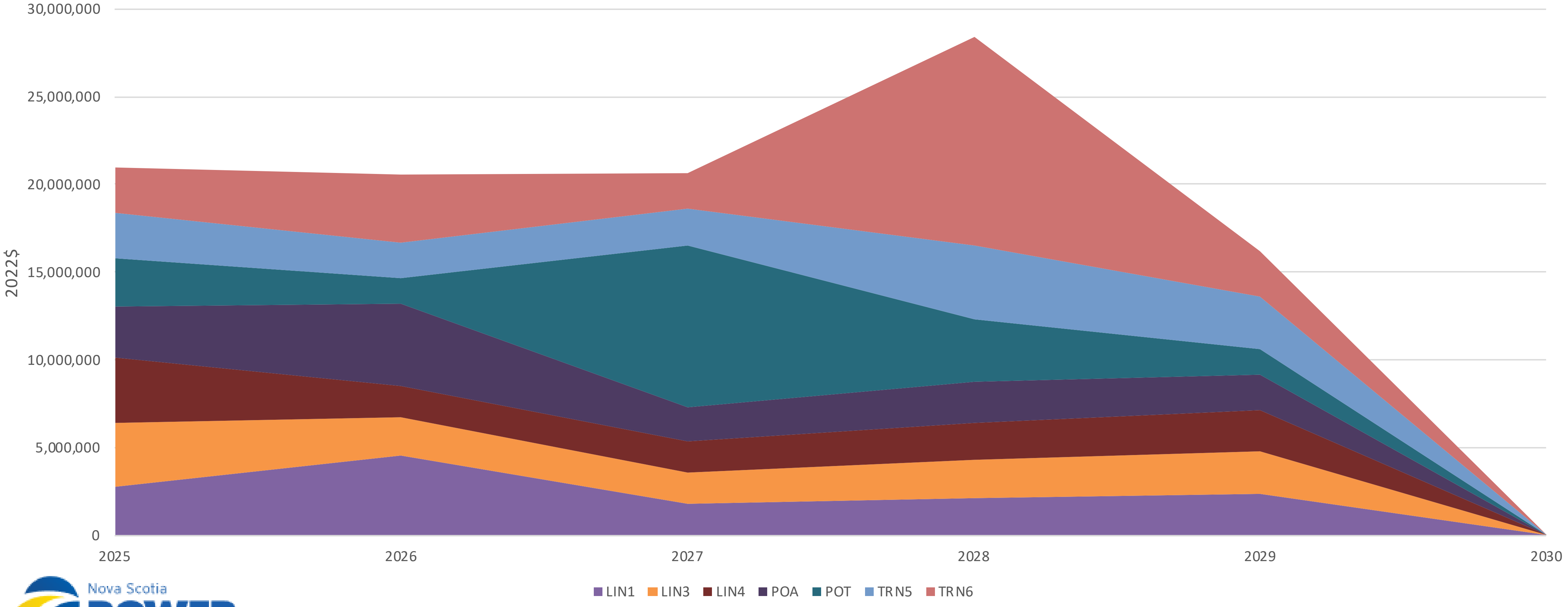
THERMAL SUSTAINING CAPITAL – METHODOLOGY

- In the 2020 IRP, sustaining capital estimates for existing thermal assets were based on a *High Utilization Factor* approach (HUF)
  - HUF represents the forecast investment required to address wear on components driven by a high capacity factor, cycling, operating hours, flexible use, or a combination thereof

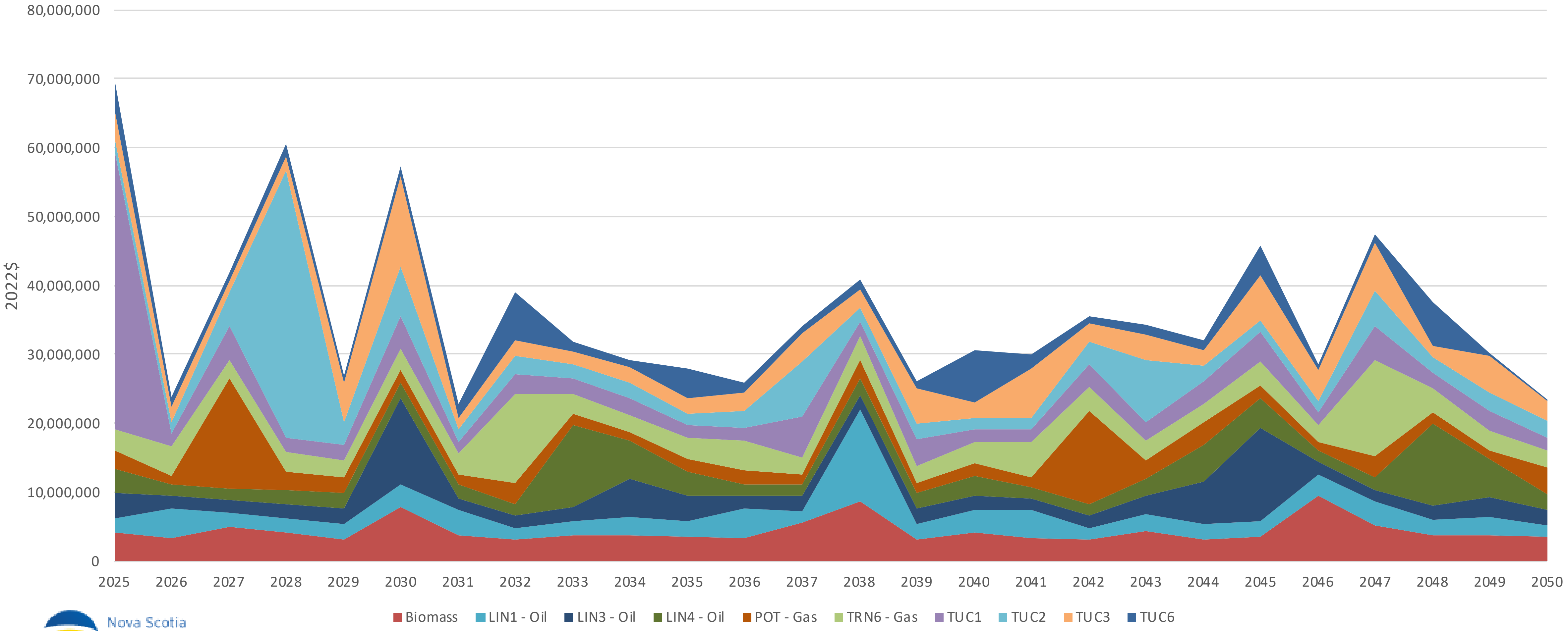
$$U^{\text{tilization}}F_{\text{actor}} = fn\left\{ \boxed{\text{Capacity Factor}} \; \boxed{\text{Service Hours}} \; \boxed{\text{Cycles}} \; \boxed{\text{Asset Health}} \right\}$$

- For the 2022 Evergreen IRP forecast, NS Power reviewed thermal plant utilization for the *Early Insights* model. From a thermal utilization perspective, the model is subject to Output Based Pricing (carbon price) which leads to low (or lower than HUF) utilization on most existing thermal generation assets.
  - The Sustaining Capital Forecast for thermal resources is based on forecast utilization from these models
  - For the Evergreen IRP, sustaining capital will model both fixed and variable investment components. Fixed costs include those costs not materially impacted by utilization and includes an estimate for major investment intervals ($/kW-yr). Variable costs components are tied to those investments driven by utilization ($/MWh)
    - This methodology provides a more accurate price signal for capacity expansion modeling on how utilization impacts the economics of retention vs retirement and replacement and more closely aligns required investment spending influenced by utilization
    - Methodology is aligned with how new candidate resource costs are modeled; estimates are based on initial capital cost, fixed and variable costs ($/kW, $/kW-yr and $/MWh respectively)

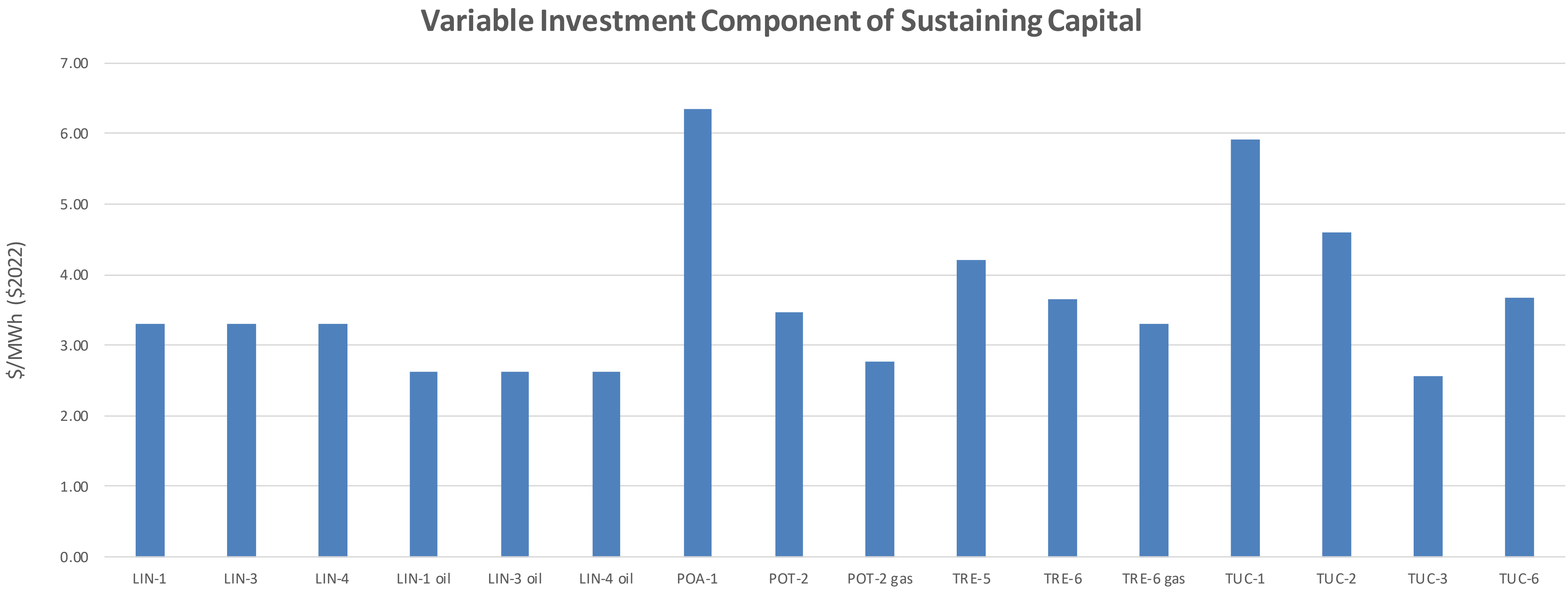
COAL UNIT SUSTAINING CAPITAL – FIXED PORTION



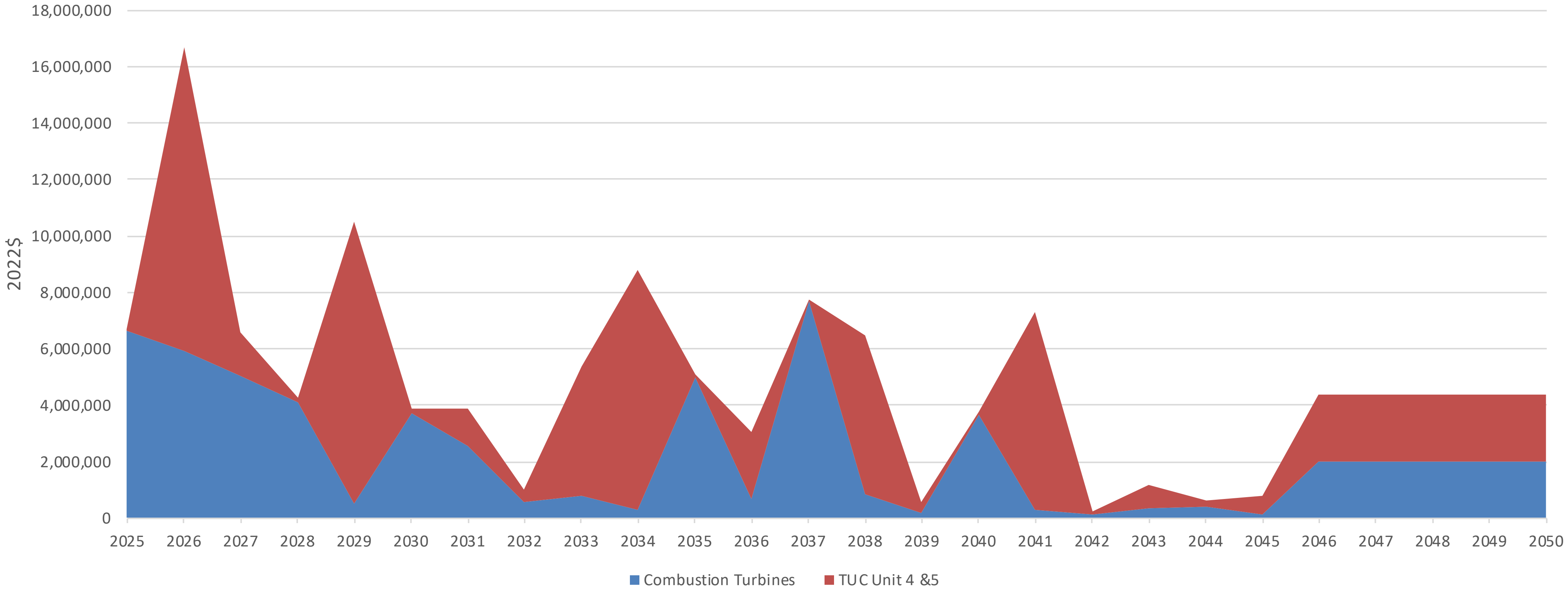
THERMAL SUSTAINING CAPITAL (OIL/GAS/BIOMASS) – FIXED PORTION



THERMAL SUSTAINING CAPITAL – VARIABLE PORTION



COMBUSTION TURBINE SUSTAINING CAPITAL



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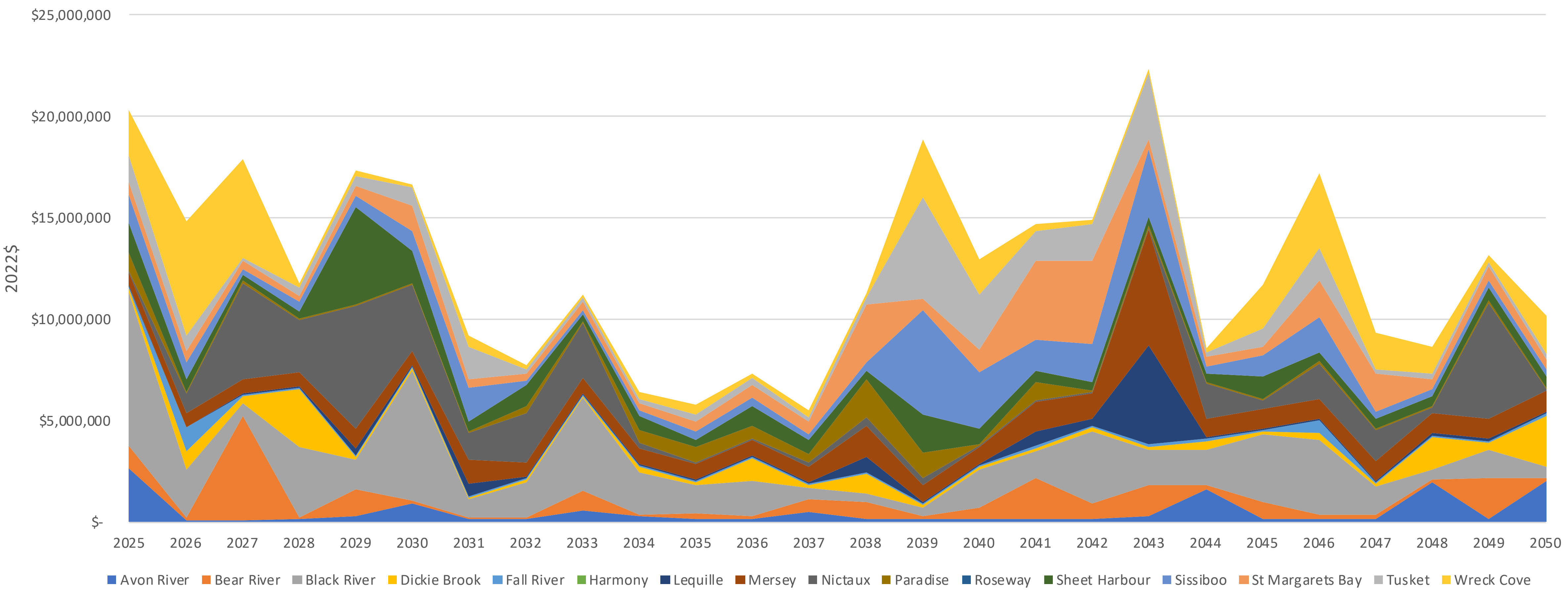
SMALL HYDRO SUSTAINING CAPITAL



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RENEWABLE INTEGRATION REQUIREMENTS

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RENEWABLE INTEGRATION 2020 IRP APPROACH

- In the 2020 IRP NS Power used the PSC Stability Study, completed as part of the pre-IRP deliverables, as the basis for the assumptions. Generally, two possible options were identified that enabled the expansion of wind capacity beyond 700MW:
  - Interconnection Option : A second 345 kV AC tie between Onslow NS and Salisbury NB
  - Local mitigation Option : A 200 MVA Synchronous Condenser and 200 MW Battery

2020 IRP: Summary Integration Options for Incremental Wind (for reference)

Incremental Wind Available (MW) by Electrification Level	No Integration Requirements*	Reliability Tie	Domestic Integration* (Batteries + Sync. Condenser)	Total Incremental Wind Available
Low Electrification	100	400	400	900
Mid Electrification	100	500	500	1100
High Electrification	100	600	600	1300

**Local integration requirements to be determined via specific System Impact Studies*

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RENEWABLE INTEGRATION
UPDATED 2022 EVERGREEN IRP APPROACH

- NS Power has considered the input from stakeholders relating to the 2020 IRP integration methodology and has refined this constraint for the 2022 Evergreen IRP
- Wind and Solar capacity additions as optimized by PLEXOS in the Capacity Expansion Module will no longer require specific integration assets as described in the previous slide. Instead, an hourly dispatch constraint will be implemented. This updated methodology will improve the optimizer's ability to consider the economics of additional variable renewable energy expansion vs the need to curtail output in certain hours to a level that ensures the system remains stable. These dispatch levels are based on the PSC Stability Study and use the 'Mid Electrification' assumption:

2022 Evergreen IRP – Variable Renewable Integration Assumptions (max. hourly dispatch constraint)

Wind +Solar Curtailment	Current System with no integration assets (MW)	Reliability Tie (MW)	*Domestic Integration(MW) (200MW BESS + 200 MVA Sync. Condenser)
Instantaneous Wind Curtailment above	700	Current System + 500MW + Domestic Integration	Current System + 400MW + Reliability Tie

**Constraint is linearized such that the capacity expansion module optimizes enabling dispatch assets on a MW basis (e.g. 1MW of BESS & Synchronous Condensers enables 2.0MW of incremental instantaneous wind dispatch capability)*

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RENEWABLE INTEGRATION UPDATED 2022 EVERGREEN IRP APPROACH

Maximum instantaneous penetration (max penetration)

- In addition to the *max hourly dispatch constraint*, NS Power will also impose a **maximum instantaneous penetration constraint**, which imposes a maximum allowable instantaneous penetration of variable renewable energy constraint in any given hour. The easing of this constraint reflects anticipated technological improvements facilitating the ability to reliability absorb very large penetrations of variable renewable energy reliably over the planning horizon.

Max Instantaneous Wind/Solar Penetration Constraint

Period	Max Instantaneous penetration
2025-2030	70%
2031-2040	90%
2041-2050	100%

- With this refined approach, wind and solar additions are freely optimized by the PLEXOS capacity expansion module. The dispatch constraint will have the impact of curtailing variable renewable energy in stressed conditions that have been shown to negatively impact system stability.
- The Capacity Expansion module will consider the impacts of curtailment vs. other system constraints and the overall cost minimization objective.
- The regulation reserve requirements and the minimum synchronous inertia constraint from the 2020 IRP will be retained.

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