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FIRM WIND & SOLAR POWER GENERATION IN NOVA SCOTIA WITH FULLY ELECTRIFIED TRANSPORTATION & BUILDING SECTORS

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Prepared by Clean Power Research

EXECUTIVE SUMMARY

This report examines the feasibility and cost-effectiveness of firm renewable power generation in Nova Scotia under a 100% renewable power generation scenario considering future (2050) full electrification of buildings and transportation. The analysis builds upon Phase 1 findings and incorporates additional factors such as thermal storage deployment, heat pump penetration ratio, battery cost forecasts, offshore wind viability, inter-provincial power trade, hydrogen generation and EV load management strategies.

Key findings include:

- The electrification of buildings and transportation sectors will increase the 2050 provincial electrical energy demand to 20 TWh/year (+80% relative to 2019), with a peak demand reaching 3.7 GW (+87% relative to 2019).
- Retaining Phase 1 financial and performance specifications for the considered storage and renewable technologies — PV, wind and e-fuel — the optimal power generation mix capable of firmly meeting demand 24/365 at the lowest possible cost consists of 4.23 GW of PV, 5.24 GW of onshore wind, and 2.55 GW of e-fuel thermal generation, supported by 4.65 GW of batteries with 4.75 hours of energy capacity. This optimum configuration results in a firm power levelized cost of electricity (LCOE) of 6.29 C¢/kWh for the province. This compares favorably to the current fuel-based power generation cost on the Nova scotia power grid at 10+ C¢/kWh.

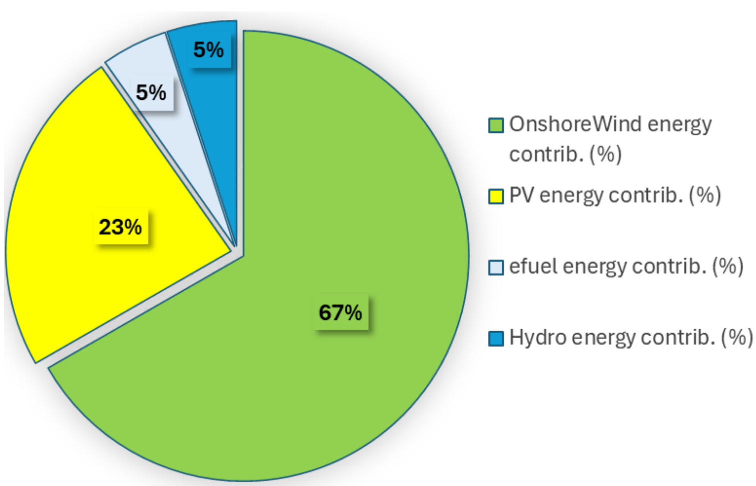

Fig. ES-1: Energy contribution from each generating resources – including a small must-run, i.e., non-firm hydropower component — amounts to respectively 23% for PV, 67% for onshore wind, and 5% each for dispatchable e-fuel generation and must-run hydro.

- Increasing heat pump adoption to 75% of the provincial building stock from a base case assumption of 50% heat pumps and 50% baseboards can reduce winter peak demand by 10%, and annual electrical energy demand by 5% while slightly increasing the optimum proportion of PV (27%) relative to wind (63%).
- Managing intraday electric vehicle (EV) charging fluctuations (amounting to ~ 700 MW daily ramps) from the [firm renewable power] supply-side rather than from the demand side slightly raises the provincial LCOE to 6.44 C¢/kWh without any significant impact on the optimum generation blend. Further considering that some of the generation assets (PVs and batteries) could be deployed on distribution circuits, the case can be made that a regional 100% renewable power generation strategy could also resolve future EV and PV hosting capacity issues on these circuits.
- Allowing interprovincial power trade within existing allowances reduces firm power LCOE to 5.06 C¢/kWh by leveraging cheaper flexible imports (displacing expensive dispatchable e-fuel generation) and monetizing excess variable renewable energy (VRE) output. However, this solution may not be sustainable in the long term if neighboring provinces adopt similar firm VRE power solutions.
- Higher battery storage cost estimates from NREL's 2023 Annual Technology Baseline (ATB) — a ~100% increase over base case assumptions from the 2020 ATB — increase LCOE by only 13% as the cost impact can be largely mitigated by increased reliance on implicit storage (i.e., VRE curtailment).
- Thermal storage, while cost-effective for heating loads, only slightly reduces overall firm power LCOE unless battery cost assumptions are sensibly higher (as would be the case for user-sited batteries).
- Offshore wind, even with improved capacity factors from higher (150 meter) turbines, remains costlier than onshore wind, requiring at least a 55% cost reduction to be competitive.
- The utilization of essentially free, but highly variable curtailed VRE electricity to produce hydrogen can only be marginally market competitive if electrolyzer capacity is limited to capture only a third of the available free energy. Increasing implicit storage (VRE curtailments) beyond firm power generation optimum can lower hydrogen costs but slightly raise firm power costs.

Overall, the study makes a solid case for a predominantly onshore wind and PV-based firm power system, supplemented by limited e-fuel thermal generation, battery storage, and strategic interprovincial trading to achieve cost-effective renewable energy integration. The study also raises questions that would merit to be addressed in follow-on phases, including:

- Whether other Canadian provinces with different renewable resource characteristics and demand requirements (e.g., electric heat requirements in colder continental provinces) could also reach acceptable 100% renewable solutions, and if so: (1) how would these differ from Nova Scotia and (2) whether these solutions could sustain economically sound interprovincial power trades.
- To which extent possible concerns and limits on onshore wind deployments are warranted. This could be answered by conducting detailed analyses of where PV, wind and BESS resources can be deployed (including distribution circuits for PV and BESS) and quantifying their full deployment potentials.
- Whether PV and storage assets (including thermal storage and BESS) deployed on distribution circuits could capture distribution-side values (e.g., alleviating the need for substation upgrades) and to which extent such value can balance their higher distributed cost with respect to regional firm power generation.
- How would optimal regional firm power generation configurations be effectively managed by Virtual Power Plants (VPP) aggregators and what regulations and market rules should be

considered to facilitate seamless deployments that can gradually displace conventional generation with minimal disruptions.

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1. INTRODUCTION

This second phase of research builds upon an initial phase that identified firm renewable power generation solutions for the province of Nova Scotia, Canada. The report for this initial phase is attached in Appendix 1.

Firm power generation, as defined by the IEA [1, 2], refers to an ensemble of resources' ability to meet electrical load at all times. Traditionally, this role has been filled by conventional baseload and dispatchable generation (hydro, nuclear, coal, and natural gas).

The weather-driven variable renewable energy resources (VREs) considered here – wind and solar – are not inherently firm but can be cost-effectively transformed into firm resources using key strategies including wind/solar blending, battery storage (BESS), overbuilding (implicit storage), and supply-side flexibility from exogeneous dispatchable 100% renewable GHG-free e-fuel thermal generation[1] [1,2].

Once firmed VREs can generate power that is proportional to the load served at all times, thus enabling their seamless transition to potentially 100% penetration. In practice, firm renewable generation would likely be managed by virtual power plant (VPP) aggregators controlling the VREs and their firm power enablers (real and implicit storage, supply-side flexibility, etc.) in response to grid operator signals and the weather conditions underlying the VRES. This operational aspect is a key research topic of the newly launched IEA PVPS Task 19 on grid integration [3]. Figure 1 illustrates how VPP aggregators would likely run the firm power generation assets considered in this study.

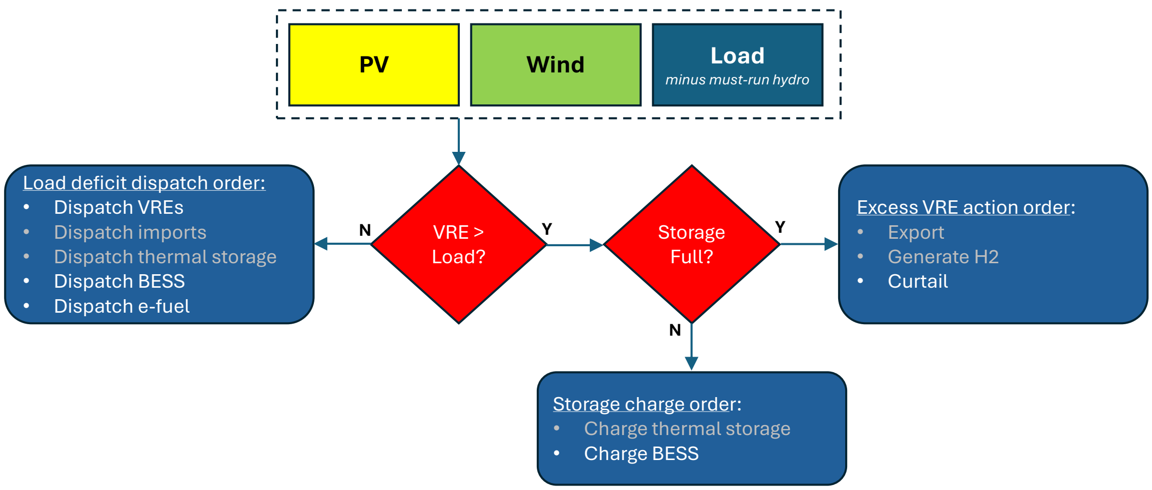

Fig. 1: Firm VRE power generation logistical diagram — *note that items in light gray are optional assets/strategies analyzed in specific scenarios (see below).*

[1] E-fuels are chemically identical to fossil fuels — for instance, e-methane is identical to natural gas, hence can be used with existing thermal gen infrastructure — but they are chemically built by combining green hydrogen (produced with PV and/or wind via electrolysis) with biogenic carbon (e.g., from industrial emissions, crops, or directly captured from the atmosphere) and atmospheric oxygen. Although e-fuels are expensive (4-5 times more expensive than fossil fuels) the IEA has shown that, when optimally applied (here, about 5% of total generation), the flexibility they add to the VRE blend acts as a catalyst that can minimize the overall cost of firm power generation. The e-fuels considered here are exogeneous, i.e., imported from least-cost production regions (high wind and/or solar resource regions).

For a given [regional] use case, the cost-optimal firm VRE configuration is a function of the temporal characteristics of the considered VRES and of the load to be served, as well as of their capital and operating cost and that of the firming technologies/strategies mentioned above. The optimization logistics applies the operational aggregator strategy illustrated above to time-coincident power generation and load data time series and extract the asset configuration that yields the lowest levelized cost of energy (LCOE) capable of firmly meeting demand 24/365.

In phase 1, the optimal configuration to firmly serve the provincial load (minus 10% served by must-run hydropower) was determined from one year's worth of hourly wind, PV production, and load data (2019), applying the capex, opex and financial assumptions from Table 3 (below). The optimal VRE configuration capable of cost-optimally meeting the 11 TWh annual provincial load 100% of the time was, in terms of energy, determined to consist of 70% onshore wind, 25% PV, and 5% e-fuel, operating with 2.6 GW/11.8 GWh of BESS and about 20% VRE curtailment. This renewable 'Integrated Resource Plan' with built-in resource adequacy – thanks to e-fuel flexibility – involves the deployment of 2.1 GW PV, 2.4 GW onshore wind, 1.65 GW e-fuel thermal, and 18 GWh BESS that could deliver unsubsidized firm power at a levelized cost of energy (LCOE) of 6.4 C¢/kWh (applying future – 2050 – technology costs) and 10.2 C¢/kWh (applying 2025 technology costs). This unsubsidized near-term production cost is comparable to current conventional (largely fossil-fuel based) power generation costs on the provincial grid (11 C¢/kWh).

Phase 1 considered no change in the future provincial load size or shape. In this second phase, we consider future (2050) load requirements transformed by a complete electrification of the province's building and transportation sectors.

In addition to load growth, we also investigate:

- The impact of factors influencing the future load, including:
  - The proportion of heat pumps vs. baseboards underlying the building heat fraction of the load,
  - Whether intraday vehicle charging ramps are or are not smoothed out on the demand-side (e.g., with smart charging stations, or effective charging tariffs).
  - The possibility of exporting/importing power to/from interconnected neighboring provinces within current energy and capacity allowances (phase 1 assumed that Nova Scotia was 100% autonomous electrically).
- The impact of future battery cost assumptions.
- The deployment of thermal storage in lieu of batteries for the heating fraction of the load.
- Applying enhanced offshore wind technology operating at lower cost and higher capacity factor thanks to higher turbines than considered in phase 1 (where offshore was cost-optimally excluded from the VRE blend.)
- The possibility of using optimally curtailed VRE output (i.e., using essentially free electricity) to generate hydrogen at a market-acceptable cost.

2. FUTURE (2050) ELECTRICAL LOAD

We consider two important volume and load shape modifiers: building heat electrification and transportation electrification.

For building heat, thanks to the considerable proportion of building using electricity for heat representing about half of the current building stock (Table 1) , it is possible to extract the present electric heating load signal from the existing (2019) load by quantifying a ~ linear relationship between ambient temperature and the load below an estimated balance point of ~15°C (figure 2). The hourly electric heating load signal can be disaggregated from the total load by applying this relationship (figure 3). This signal can then be calibrated to the number of buildings using electricity for heat, including a large majority of electric baseboards, and about 10% each for heat pumps and wood/electric systems — for the latter we assume an electric utilization of 50%, and for heat pumps we conservatively assume an existing/historical coefficient of performance (COP) equal to about two thirds of the COP considered for future electrification (see below).

The signal can then be extrapolated to 2050 conditions by assuming 100% electric heat penetration and accounting for a 0.4% annual growth of the building stock [4]. In addition, we assume, as a base case, that half the buildings would be using heat pumps and apply a cutting-edge coefficient of performance (COP) that will likely be prevalent in years to come – see figure 4. The remaining half of the buildings are assumed to continue using conventional electric baseboards.

Table 1
Nova Scotia historical and projected building stock and heating sources

	2000	2018	2019	2020	2021	2022	2050 est
Total Buildings (thousands)	378	446	450	454	458	461	508
Heating System Stock by Heating System Type (thousands of buildings)							
Heating Oil – Normal Efficiency	91	1	**-**	-	-	-	
Heating Oil – Medium Efficiency	105	134	**134**	131	131	130	**-**
Heating Oil – High Efficiency	-	-	**-**	-	-	-	**-**
Natural Gas – Normal Efficiency	1	0	**-**	-	-	-	**-**
Natural Gas – Medium Efficiency	2	2	**2**	2	2	1	**-**
Natural Gas – High Efficiency	2	9	**10**	11	11	12	**-**
Electric	86	195	**199**	204	207	210	**254**
Heat Pump	12	21	**22**	22	23	23	**254**
Coal/propane	8	9	**10**	10	10	11	
Wood	15	11	**11**	11	11	11	
Wood/Electric	23	26	**26**	26	26	26	**-**
Wood/Heating Oil	32	35	**35**	35	35	36	**-**
Natural Gas/Electric	-	-	**-**	-	-	-	**-**
Heating Oil/Electric	1	2	**2**	2	2	2	**-**

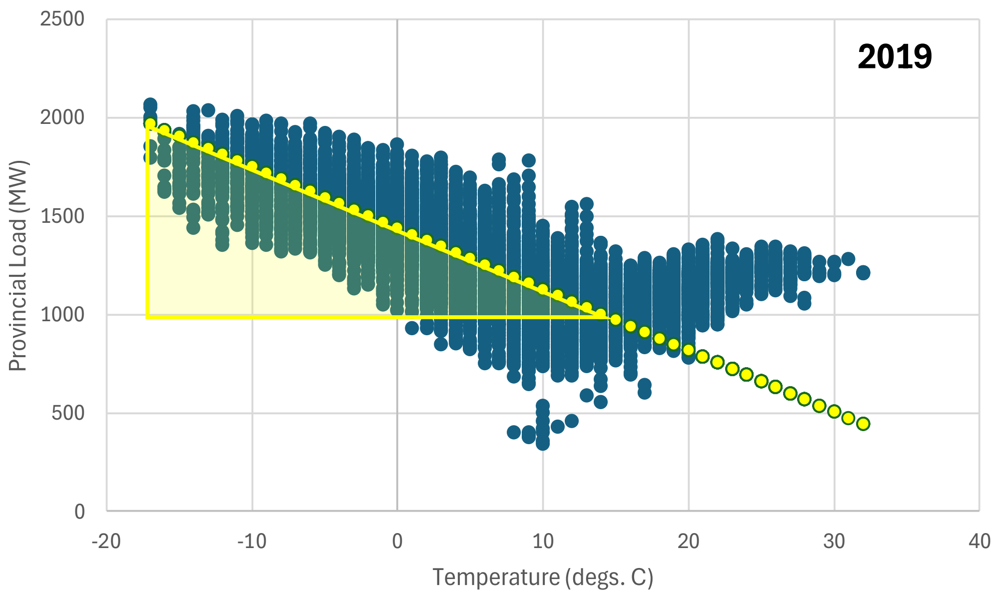

Fig. 2: 2019 hourly provincial load plotted as a function of ambient temperature. The shaded area represents an estimate of the load fraction that is attributable to building heat.

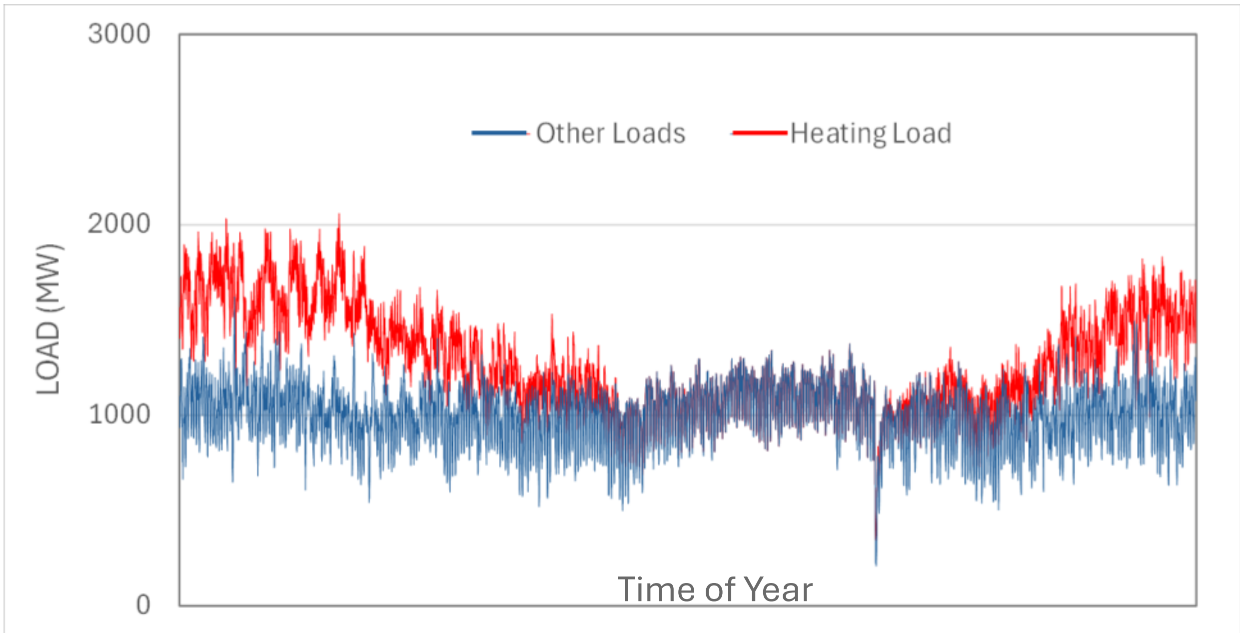

Fig. 3: 2019 disaggregated hourly provincial load showing the fraction attributable to electric heat.

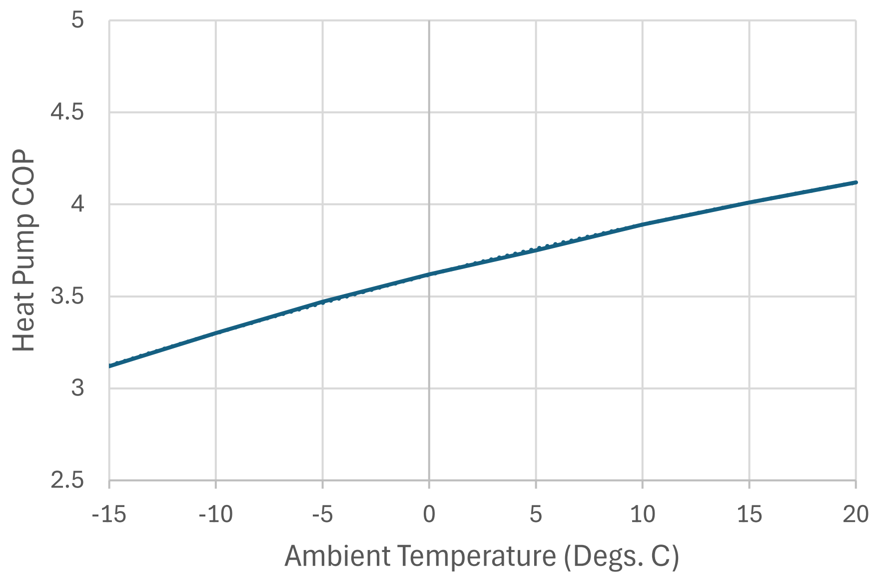

Fig. 4: Assumed Coefficient of Performance for future deployed heat pumps [5]

For transportation, we assume a complete electrification of light and heavy-duty vehicles from their 2019 nearly zero current level to 100%. The number of vehicles, annual mileage and electric consumption assumptions are detailed in Table 2 [6, 7, 8, 9, 10]. We also apply expected annual and daily relative charging profiles identified by [11] from experimental data and shown in figure 5.

Table 2
Considered number of light and heavy-duty vehicles in 2050's Nova Scotia, nominal annual mileage, and electric consumption (sources [6-10])

Number of electric cars	620,000
km driven by car annually	16,600
electric consumption (Wh/km)	180
Number of trucks, buses and heavier duty vehicles	120,000
km driven by utility vehicles	50,000
electric consumption (Wh/km)	800

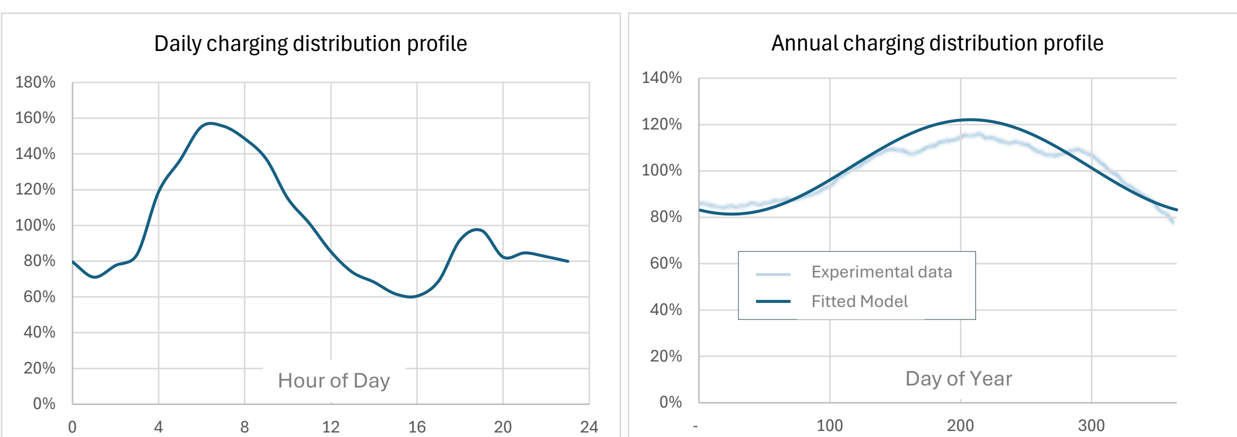

Fig. 5: Assumed intraday (left) and annual (right) vehicle charging profiles normalized to mean daily and mean annual charging load [11].

The new estimated (2050) hourly load and its underlying heating and transportation components are plotted in Figure 6. The thick lines represent 20-day running means, helpful to better visualize seasonal trends. We assume no change in other (non-heating) loads.

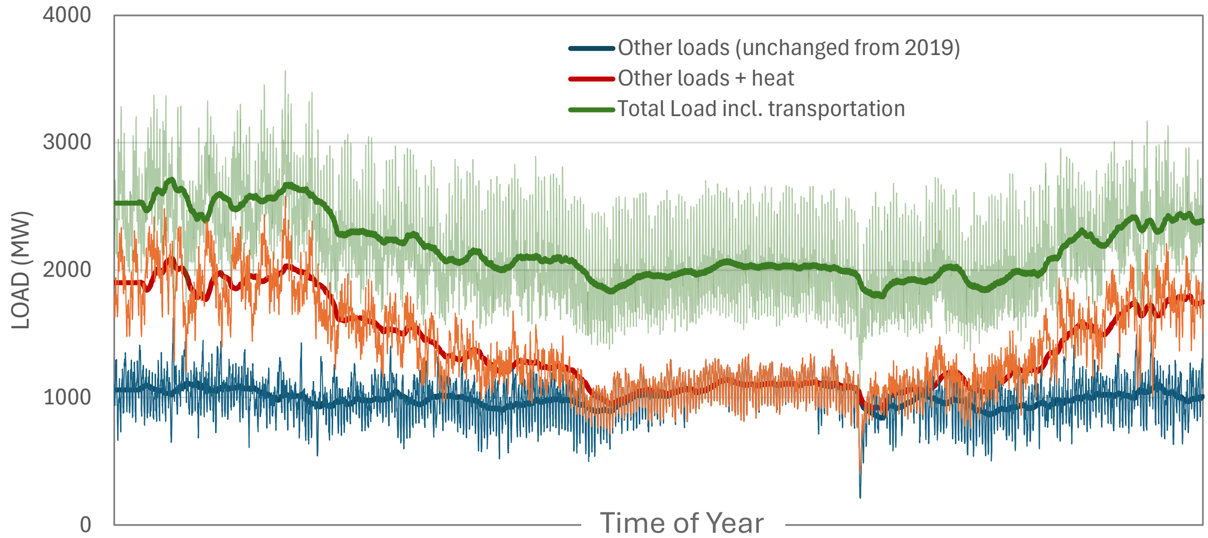

Fig. 6: Estimated 2050 provincial load including its hearting and transportation components.

The projected 2050 load amounts to 20TWh/year, that is 80% higher than the 2019 load considered in phase 1. It peaks at 3.7 GW, 82% higher than the 2019 peak.

3. FIRM POWER SCENARIOS

3.1 BASE CASE

As a base case we apply the utility-scale economic (Table 3) and flexibility (5% e-fuel) assumptions from Phase 1. As mentioned above, 100% renewable e-fuels are chemically identical to fossil fuels, hence can use existing technology such as combined cycle or peaking gas turbines to provide flexible, on-demand power generation without global warming impact.

Optimum firm power configurations are determined by applying the clean power estimator (see Phase 1 report in appendix 1) to the estimated 2050 hourly load minus existing hydropower generation (~1 TWh) that is considered a must-run resource. The base case scenario further assumes that intra-day vehicle charging variability is entirely handled on the demand side so that charging demand appears constant intraday to the firm power supply-side resulting in the load shown in Figure 7.

Table 3
Economic and financial utility-scale assumptions from Phase 1 and applied in the base case scenario

		2050
CapEx	PV	C$633/kW
	Wind Onshore	C$747/kW
	Wind Offshore	C$2769/kW
	BESS *	C$92/kWh
		C$70/kW
	e-fuel Thermal Gen	C$1210/kW
OpEx	PV	C$16/kW/y
	Wind onshore	C$34/kW/y
	Wind offshore	C$85/kW/y
	BESS *	C$2.8/kWh/y
		C$1.4/kW/y
	e-fuel Thermal Gen	25.6 C¢/kWh
Weighted Average Cost (WACC) of Money		4%

Note BESS cost estimates are based on lithium-ion technology. Lower future prices could be possible if other technologies with equivalent functionality (e.g., flow batteries) successfully develop.

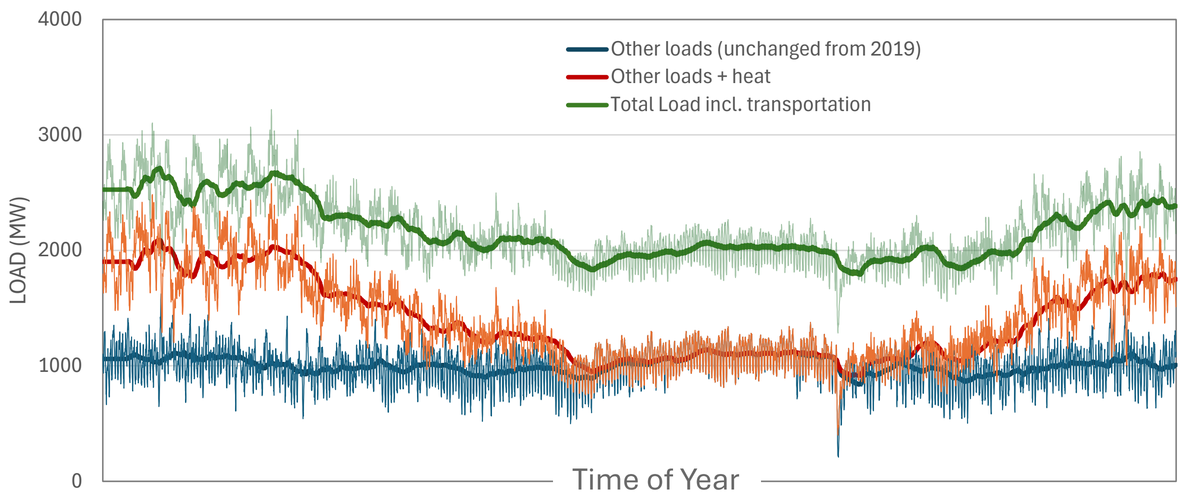

Fig. 7: Estimated 2050 provincial load components used for the base case, assuming intraday charging cycles are handled on the demand-side and at user-expense.

The base case assumptions lead to a future (2050) firm power LCOE of 6.29 C¢/kWh. The optimum firm power generation configuration consists of 4.23 GW of PV, 5.24 GW of onshore wind and 2.55 GW of e-fuel thermal generation on the supply side operating with 4.65 GW of BESS with an energy capacity of 4.73 hours and an implicit storage capacity amounting to 19.2% of wind/PV curtailment. In terms of supply-side firm energy contribution, the shares of PV, wind, and e-fuel amount respectively to 23.5%, 66.7% and 4.8% — exclusive of the non-firm must-run hydro amounting to ~ 5% of the total generation (figure 8).

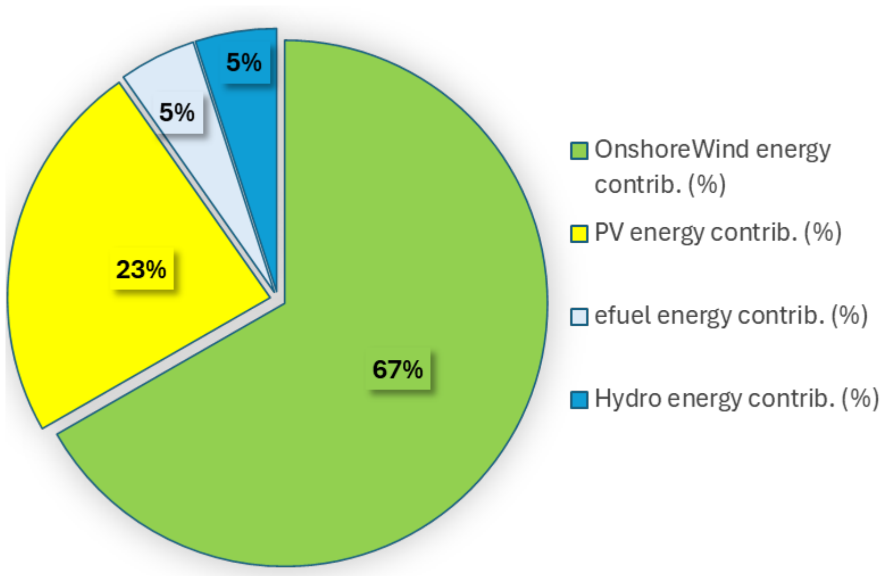

Fig. 8: Base case supply side resources' energy contribution to the 2050 Nova Scotia power grid. (Note that hydro is must-run unconstrained. All other resources are optimized to deliver firm 24/365 power generation.)

Figure 9 illustrates a few days of firm power dispatching operations and allocations of resources in the base case.

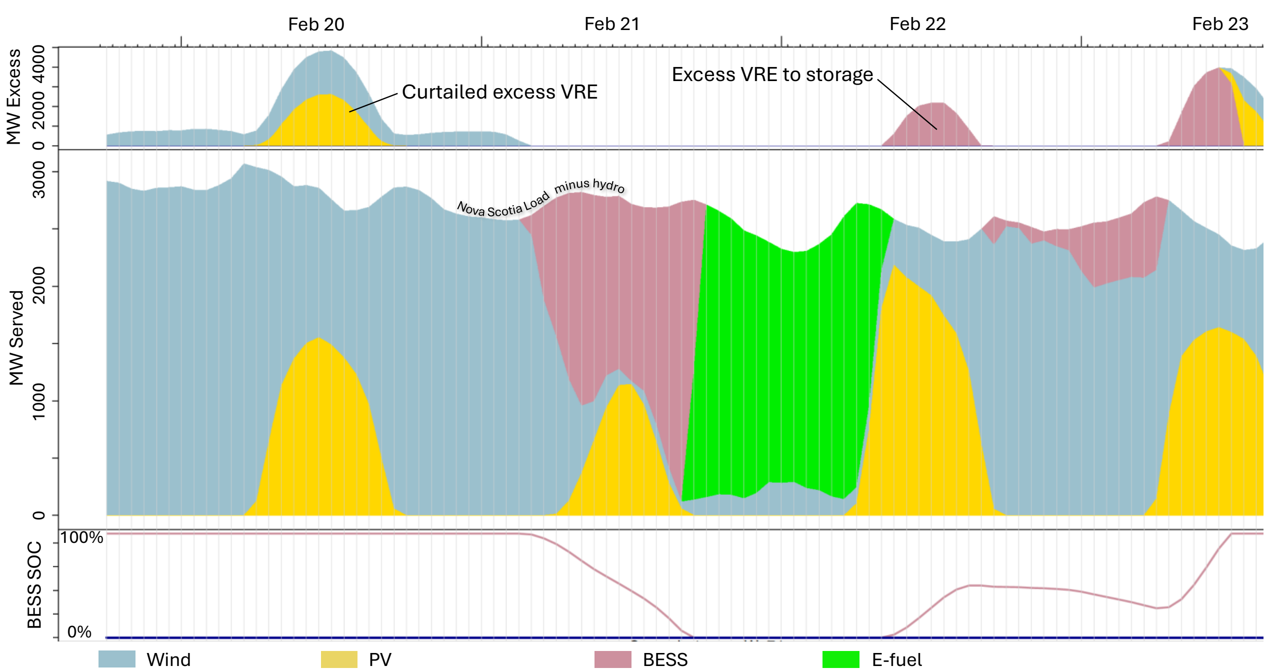

Fig. 9: Illustrating resources dispatching for four winter days showing allocation of resources to directly meet demand (central graph) and manage physical storage (BESS) charging and implicit storage function, i.e., curtailing (top graph). Note that the scale on the top graph has been compressed compared to the central graph. The bottom graph represents physical storage state of charge.

Other dispatching examples for other seasons and scenarios are accessible electronically as part of the data files made available to NRCAN (see Appendix 2).

3.2 LOAD SENSITIVITY

Heat pump adoption — We investigate an increase in heat pumps vs. Electric baseboards from 50% in the base cast to 75%.

Because of the coefficient of performance effect, the higher proportion of heat pumps has a significant impact on the load. It reduces the provincial [winter] peak load by about 10%. In terms of annual energy requirements, the induced load reduction amounts to ~ 1 TWh or about 5%.

The winter heating load reduction influences the optimum VRE configuration by increasing the proportion of PV (a summer peaking resource) relatively to wind that is winter peaking (see Appendix 1). The resulting supply-side energy contributions amount to respectively to 26.8%, 63.4% and 4.8% for PV, wind, and e-fuel generation (figure 10). In terms of capacity, this amounts to 4.56 GW of PV, 4.71 GW of onshore wind and 2.25 GW of e-fuel thermal operating with 4.78 GW of BESS with an energy capacity of 4.32 hours and an implicit storage — VRE curtailment — of 18.9%.

While the overall load reduction is significant, aside from a small redistribution of resource towards more PV, the impact on the LCOE bottom line is minuscule at 6.28 C¢/kWh compared to 6.29 C¢/kWh for the base case.

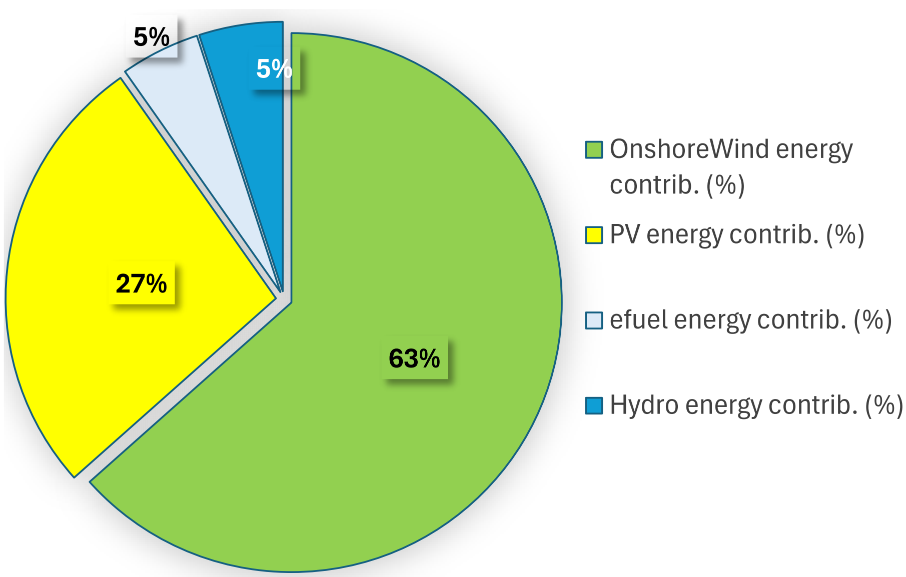

Fig. 10: Supply-side resources' energy contribution to the 2050 Nova Scotia power grid assuming a 75% proportion of heat pumps (vs. 50% in the base case)

Intraday vehicle charging fluctuations — In the base case, we assumed that the intraday variability was handled on the user side (e.g., with a combination of effective tariffications, and smart, buffered charging stations) with the cost of this smoothing borne entirely by the demand-side (i.e., not impacting the firm power LCOE). The transportation load to be served by grid generation is thus seen as constant intraday. Here we investigate the cost of having grid-side generation and storage assets handling the intraday variability and meet the more variable load shown in figure 6.

The added duty of handling intraday charging ramps on the supply side only translates in a minor increase of the firm LCOE to 6.44 C¢/kWh and BESS energy capacity (+4%). The quantities of PV, wind and implicit storage remain nearly unchanged.

This small change in configuration and cost, in contrast to the large intraday charging ramps that must be managed — over 0.6 GW in size — is understandable because a firm power configuration designed to handle extended VRE resource droughts to supply electricity firmly and reliably 24/365 has more than enough storage assets capable of also handling short term [intraday] fluctuations.

Importantly, some of the PV and BESS assets participating in the regional firm power generation objective can be deployed on distribution circuits and directly contribute as well to smoothing the charging ramps that would be primarily occurring on feeders below substations. Note that while distributed PV/BESS assets may be pricier than the utility scale assts considered above, they would have additional benefits such as deferring substations upgrades that are not quantified here. In addition, we have also shown that feeder-deployed PV and BESS assets that directly contribute the regional firm power generation function can also boost distributed PV hosting capacities by several 100%, also contributing to deferring or eliminating the need for distribution system upgrades [12].

Provincial interties We assume that power can be exported and imported as needed at a predefined price/cost and within predefined capacity and energy allowances specified in Table 4. These allowances are based on existing interties with neighboring regions.

Table 4
Export/Import Intertie Specifications

Maximum Export power flow	825 MW
Maximum Import power flow	775 MW
Maximum annual energy Exports	1200 GWh
Maximum annual energy Imports	4% of gross load
Value of exported energy	C$68/Mwh
Cost of imported energy	C$63/MWh

Imports are simulated as a flexible resource that can displace a fraction of the more expensive dispatchable e-fuel thermal generation.

Exports are simulated as load modifiers that add value to a fraction of the optimally curtailed VRE output that would otherwise not be monetized.

The impact of cheaper import flexibility and adding value to implicit storage has a significant impact on the bottom line, pushing the firm power LCOE down to C¢5.05/kWh (20% lower than the base case) . The optimum PV/Wind/BESS/Implicit storage configuration and energy contribution remain largely unchanged, but the e-fuel generating capacity is reduced to 1.78 GW and its annual energy contribution down to 2.2% (figure 10).

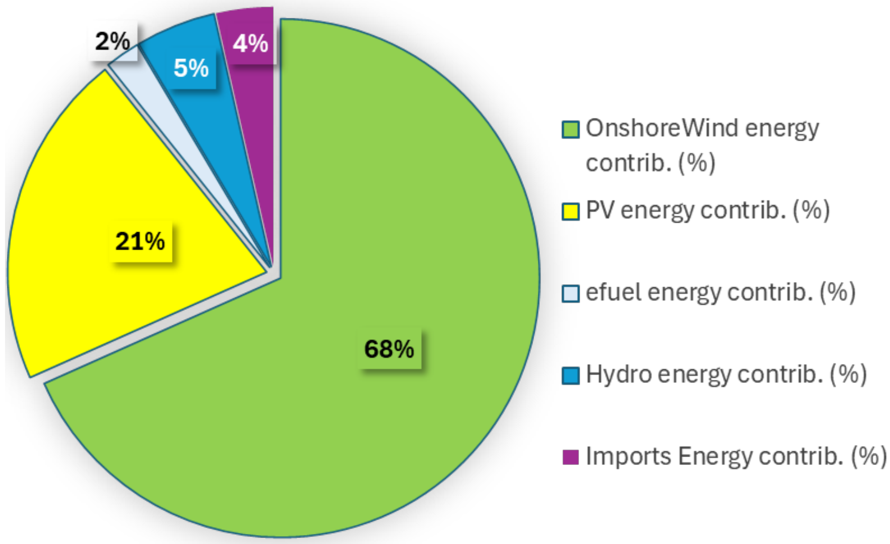

Fig. 11: Optimized supply side resources' energy contribution to the 2050 Nova Scotia power grid with flexible import/export resources. (Note that hydro is must-run unconstrained. All other resources are optimized to deliver firm 24/365 power generation.)

While the modest provincial interties considered here show a considerable positive impact on firm power economics in Nova Scotia, we caution that this option may not be fully sustainable in the long-term if neighboring provinces also adopt similar firm VRE power generation strategies with largely coincident periods of VRE droughts and production excess. There may be an exception for neighboring provinces that can massively exploit other forms of renewable generation (e.g., hydropower in Quebec).

3.3 FUTURE BESS COST ASSUMPTIONS

For the base case we retained Phase 1 economic assumptions presented in Table 3. These estimates are based on the 2020 NREL Annual Technology Baseline (ATB) [13], predictions from Natural Resource Canada [14] and are consistent with current international appraisals such as Bloomberg's [15].

For sensitivity purposes we also evaluate the more recent 2023 ATB [16] cost estimates for BESS that have evolved upward considerably. These are reported in Table 5.

Table 5
2023-ATB BESS Utility-scale Cost Estimates for 2050

BESS Capex	C$176/kWh
	C$162/kW
BESS Opex	C$5.7/kWh/y
	C$2.8/kW/y

The more than two-fold BESS cost increase for the 2023 ATB compared to the 2020 ATB only translates in a moderate (13%) firm power LCOE cost increase — C¢7.13/kWh vs. C¢6.29/kWh for the base case. This is because the BESS cost increase can be largely absorbed by a decrease in optimum physical storage —

35% less in energy capacity — and an increase in implicit storage with 9% more capacity for both wind and PV, and curtailment approaching 27% instead of 19% (figure 12).

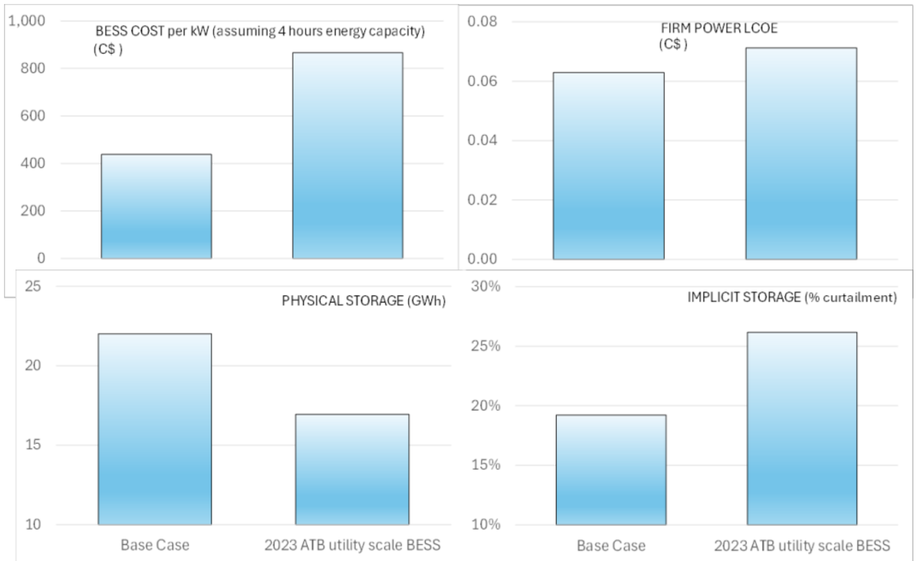

Fig. 12: Contrasting the battery cost increase over base case (top left) to the LCOE firm power increase (top right) and impact on optimal physical storage (bottom left) and implicit storage sizes (bottom right)

3.4 THERMAL STORAGE

We consider two cost scenarios for the thermal storage technology: conservative and advanced (Table 6). The technology consists thermal-mass storage units designed to be deployed on the demand-side (unlike the utility-scale BESS considered above). Costs are derived from actual thermal storage units currently in pilot deployment in several Canadian provinces. The values in Table 6 are extrapolated from such units — rated 11.6 kW / 69 kWh -- estimated to cost C$9,000 (conservative) and C$4,000 (advanced) .

Table 6
Building thermal storage specs and cost Assumptions for 2050

	Conservative	Advanced
Capex	C$ 130 / kWh	C$ 58 / kWh
Opex	C$ 0 / kWh	C$ 0 / kWh
Rnd trip efficiency	98%	98%

The firm power optimization algorithm (see figure 1 and appendix 1, figure A-3) utilizes the two sources of physical storage: thermal storage and BESS, prioritizing the former. However, because the thermal storage technology can only operate with the heating fraction of the load, the total thermal storage discharge availability is capped by the size of the thermal load at any point in time — thermal load ranges from zero in summer months to 1.5 GW the coldest hour (1.1 GW when assuming 75% heat pumps proportion) . All other storage requirements above this cap are assumed to be met by BESS.

Thermal storage is substantially less expensive than BESS in terms of energy capacity, especially for the advanced case. However, because thermal storage is only relevant for the heating fraction of the load, electrochemical batteries are still needed to balance the other load components. As a result of this limitation, even when using advanced thermal storage economics, the bottom line LCOE — C¢6.21/kWh — is only slightly less expensive than if BESS alone are used to handle the entire load (base case scenario). In fact, the overall need, hence the required amount of storage (of all types), is a function of load/resource gaps that may occur in the non-heat part of the load where the thermal storage cannot operate. As a result, thermal storage cannot displace enough BESS to significantly reduce the bottom line. Of course, this assertion only applies because of this study's 100% renewables (VREs, e-fuel, hydro) assumption. Assuming another generation mixes, with conventional resources or higher imports may could lead to different BESS/thermal storage tradeoffs.

Indeed the 2.36GW[2] thermal storage with 9.5 hours of energy capacity — optimized for the advanced technology case — only reduce the BESS requirements by 0.39 GW and 0.63 hours' worth of energy capacity together with a small reduction in VRE capacity (-1.5%) and implicit storage (-0.5%).

The conservative thermal storage option (LCOE = C¢6.68/kWh) is comparatively more expensive than the BESS-only option (LCOE = C¢7.12/kWh).

This changes considerably if we consider higher future utility scale BESS cost assumptions from the 2023 ATB. The advanced thermal option does become sensibly less expensive than the BESS-alone option — C¢6.66/kWh vs C¢7.12/kWh.

To further elaborate on the impact of thermal and BESS cost assumptions we looked at two additional scenarios where the BESS resource would consist of more expensive user-sited residential/commercial assets (Table 7)

Table 7
2023-ATB Residential/commercial blend BESS Cost Estimates for 2050

BESS Capex	C$199/kWh
	C$370/kW
BESS Opex	C$5.7/kWh/y
	C$2.8/kW/y

Considering smaller scale user-sited BESS results in firm power LCOEs respectively equal to C¢7.12/kWh and C¢7.55/kWh for the advanced and conservative thermal storage cases. Both are less expensive that if user-sited BESS alone was considered without application of thermal storage. Importantly, while these costs are higher than for utility-scale BESS scenarios from a strict supply-side perspective, user-sited BESS (in combination with user-sited thermal storage) can capture distributed values (e.g., substation upgrade deferral) that could possibly exceed the supply-side cost difference. This type of distribution level investigation is out of the scope of the present study but could merit attention if future work.

[2] Note that this is the optimized charging capacity, since discharge is limited by the thermal size of the load (peak at 1.5 GW)

Figure 13 summarizes all the scenarios analyzed to up this point by intercomparing firm power LCOEs and highlighting tradeoffs between thermal and electrochemical storage as a function of their respective costs.

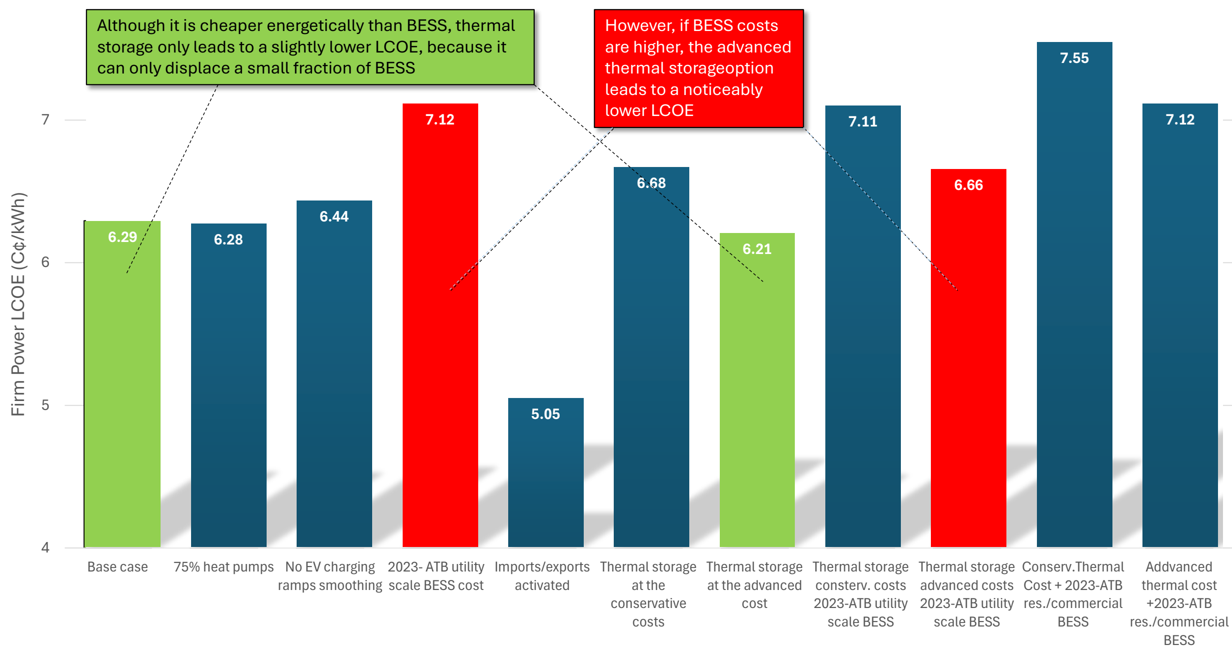

Fig. 13: Comparing LCOEs for all scenarios presented above and evaluating tradeoffs between application of thermal storage and BESS only scenarios

3.5 OFFSHORE WIND

In phase 1 we had considered 10 locations for wind power generation: 5 offshore and 5 offshore (see Appendix 1 figure A-5). Offshore production was not retained for the optimal VRE blend. Its small capacity factor advantage over onshore was not enough to compensate for the large capital/operational cost difference (see table 3 above). Anticipating possible land availability concerns for onshore wind deployment, we revisit the feasibility of the offshore wind option by (1) evaluating higher turbines (150 m instead of 100m) with the same capital/operational cost, and (2) investigating the offshore cost reduction that would be necessary to match onshore firm power generation economics.

Modeling the higher hub height wind speeds [17] substantially raises the offshore mean capacity factor for the five offshore sites to an average of 50.4%, considerably higher than the five onshore sites' mean at 36.3% (figure 14). However, this is not enough to make up for the capital cost difference between the two. If offshore alone were used instead of onshore, the overall firm power LCOE would rise to C¢8.4/kWh. The offshore option would also considerably increase the optimum contribution of PV to 36% assuming the same contribution from e-fuel (5%).

Splitting the wind resource equally between onshore and offshore would result in a firm power LCOE of C¢7.3/kWh (with a 31% PV and 5% e-fuel contribution). This is still 16% higher than the onshore-only option. Interestingly, if land availability is the driving factor to replace some of the onshore resource with offshore, the same LCOE bottom line could be achieved without considering offshore by increasing the proportion of PV by 140% while decreasing onshore wind's contribution by nearly 50%.

Even reducing the cost of the offshore capex by 25% would still result in a higher LCOE than the onshore-only option: C¢6.8/kWh for the blend vs. C¢6.29/kWh for the onshore-only option.

The cost of offshore wind would have to decrease by 55% to match the results obtained in the base case with onshore-only deployments. When considering the advanced thermal storage scenario with base case assumptions for the other technologies, the cost of offshore technology would 'only' have to be reduced by 53% to match the onshore-only solution.

Fig. 14: comparing the 30-day running means for the capacity factors for offshore and onshore power generation. Each curve represents the mean of the five considered locations for each technology.

4. UTILIZATION OF CURTAILED VRE ENERGY FOR HYDROGEN PRODUCTION

The optimally curtailed VRE power generation is plotted in figure 15 for the base case scenario.

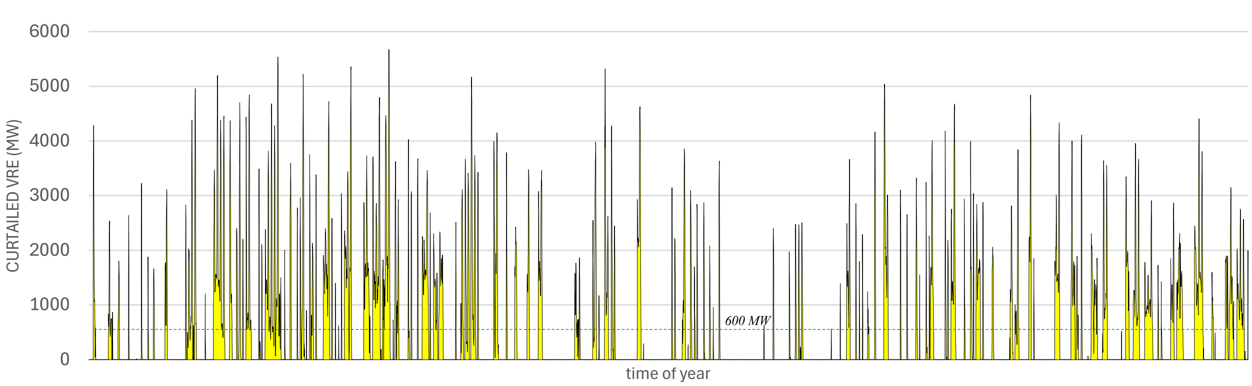

Fig. 15: Curtailed, non-monetized VRE output in the base case scenario. The thin dotted line at 600 MW shows the truncation that would be necessary to achieve a capacity factor high enough for electrolyzers to produce hydrogen at a market acceptable cost.

This apparently ‘wasted’ energy resulting from implicit storage utilization is essentially free since it does not need to be monetized to yield the optimum least-cost firm power LCOE. The question we pose here is weather this free, highly variable electricity with a low (8%) capacity factor is suitable to generate hydrogen at a market competitive price.

With free electricity at hand, the cost of hydrogen production is primarily a function of the cost and specs of the electrolyzing technology (Table 9) as well as a function of its utilization capacity factor. Other cost components include the on-site storage of hydrogen before it can be sold to market — we assume that one month’s worth of hydrogen production is stored on site before it can reach markets. For this evaluation we do not account for other smaller logistical cost components such water access/purification, infrastructures, etc., that would be needed for an industrial H2 production framework.

Table 9
Considered hydrogen generation financial and technical specifications

Assumed H2 market value	C$3000/ton
Electrolyzer Capex per kW	C$1435/kW
Electrolyzer O&M	C$65/kW/yr
Electrolyzer efficiency	70%
Hydrogen storage cost	C$750 /ton

Figure 16 illustrates the breakeven cost of H2 based on the above specs, plotted as a function of the electrolizer’s utilization capacity factor. Sizing the electrolyzer resource’s capacity to match the peak of the curtailed output shown in figure 15 (5.75 GW), as an attempt to capture the totality of this output, would, with 8.6% utilization capacity factor, lead to a hydrogen production cost of $11,000/ton, i.e., well above market price. For the production to fall below the assumed $3,000/ton market value, the electrolyzer capacity would have to be capped at roughly 10% of the curtailed output’s peak (600 MW), reaching a 28% utilization capacity factor. Thus capped, the electrolyzers could only capture one third of the firm power curtailed energy (bellow the thin dotted line in figure 15).

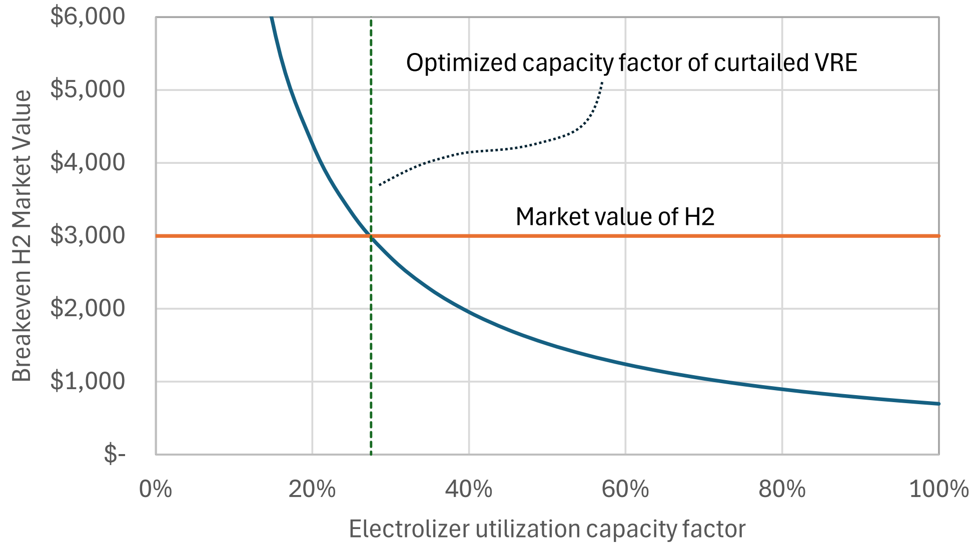

Fig. 16: Hydrogen breakeven production cost as a function of electrolyzer utilization capacity factor.

In effect, the ‘free’ electricity that would result from optimally achieving the least possible firm power generation LCOE with implicit storage can only be exploited partially (~1/3) and would only lead to low profitability in the marketplace. A small dip in the value of green hydrogen would entirely eliminate this market opportunity.

Interestingly, increasing the amount of implicit storage could capture lower H2 breakeven production costs as a tradeoff against slightly higher firm power. Figure 17 superimposes firm power LCOE isolines (in white) and breakeven H2 production isolines (in black) as a function of implicit storage (VRE curtailment) on the X axis, and the PV/wind blend on the Y axis. Because the minimum “sweet spot” for firm power generation is the low point of a shallow extended low-cost region, there may be a tradeoff to be exploited between slightly higher LCOE capturing a markedly lower H2 production cost. Overbuilding renewables (solar/wind) beyond the optimum capacities found in the base case, increases the amount of curtailed energy enough that the capacity factor of the electrolyzer is now high enough to produce H2 at a much lower price without overly penalizing the firm power LCOE. For instance, an 82%/18% PV wind split with 32% curtailment (see the “x” mark on figure 16) would lead to a breakeven H2 production cost of C$2,100 (a 30% decrease) to be assessed against a 4% increase in LCOE.

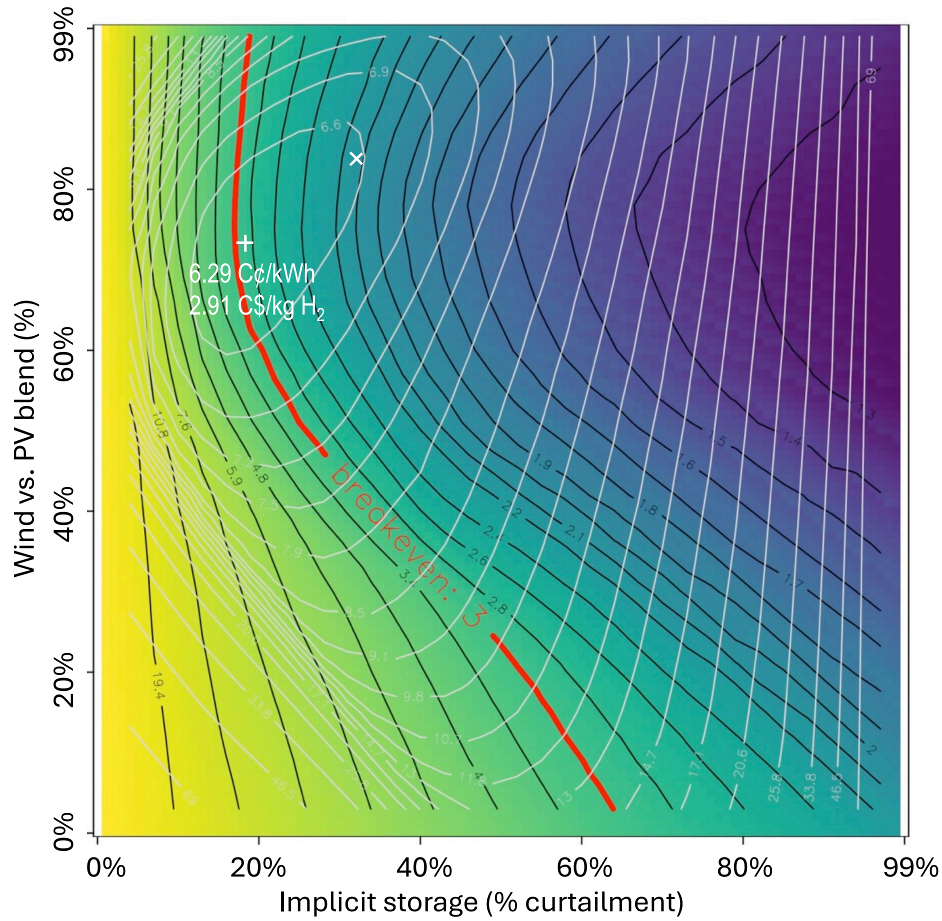

Fig. 16: Firm power LCOE and breakeven H2 market price as a function of implicit storage (% curtailment) and wind/solar % blend in the base case scenario.

5. CONCLUSIONS

This study demonstrates that a fully electrified Nova Scotia can achieve firm, 100% renewable electricity by 2050 with a cost-effective mix of onshore wind, solar PV, battery storage, and limited e-fuel thermal generation. The base case scenario yields an LCOE of 6.29 C¢/kWh, appreciably less expensive than current fossil fuel-based electricity costs estimated at over 10 C¢/kWh [18].

Key insights include:

- With regards to building heat electrification, increasing the heat pump-to-electric baseboard proportion can significantly reduce peak winter demand and overall energy demand but has minimal impact on the unit cost (LCOE) of firm power generation.
- It is well understood that demand-side EV charging management can reduce strong daily ramps and flatten the load seen by the supply-side generating assets. However, results show that optimum supply-side firm power asset configurations are capable of absorbing these short ramps at little additional cost. Importantly, as some of these assets can be located on distribution circuits, they could also resolve possible future EV and PV hosting capacity issues and postpone upgrades.

- Interprovincial power trade (amounting to 3-4% of total demand) presents significant cost advantages but may face long-term sustainability challenges.
- Rising battery storage costs can be offset in large part by increased VRE curtailment – aka implicit storage.
- The utilization of thermal storage slightly reduces firm power LCOE when compared to low-cost-utility scale batteries. This is because thermal storage can only address the heating fraction of the load and cannot displace enough BESS still needed for the non-heat fraction of the load, resulting in redundant storage asset situation. This changes if one considers higher cost [demand-side] batteries. In this case the tradeoff against thermal storage, an inherently demand-side technology, would favor thermal storage deployment.
- Offshore wind remains uncompetitive compared to onshore under current cost assumptions. However, assigning a small fraction of the wind resource to offshore to alleviate possible land use deployment issues could be considered without excessively penalizing the provincial firm power LCOE.
- The utilization of essentially free, but highly variable curtailed electricity to produce hydrogen is only marginally competitive , resulting in low profitability. Increasing implicit storage beyond firm power generation optimum can lower hydrogen costs but slightly raise firm power costs.

Finally, the results of this study suggest important questions for future research including:

- Can other provinces with different resources/needs also achieve 100% renewable solutions?
- Where can VREs be optimally deployed given for land use and grid architecture constraints?
- Can PV and [thermal/BESS] storage on distribution circuits provide enough value to offset cost tradeoffs compared to utility scale assets.
- How should VPP aggregators manage regional firm power generation, and what regulations are needed to enable such management and seamless VRE deployments?

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ANALYSIS OF FIRM POWER IN NOVA SCOTIA USING SOLAR PV AND WIND POWER GENERATION

Final Report, Natural Resources Canada Contract # 23240-220001
Prepared by Clean Power Research

EXECUTIVE SUMMARY

Objective: The objective of this study is to investigate pathways for Canadian jurisdictions to meet their electricity needs with reliable renewable power (up to 100%) by 2050, using Nova Scotia as a case study, and to research options and potential for renewable energy generation and storage systems to provide grid services. This study supports NRCan's work to reach the Government of Canada's net-zero goals by developing innovative techniques and pathways to use renewable energy to reliably meet the energy needs of Canadians while ensuring a sustainable future. Its results will be used to provide guidance to NRCan and its partners stakeholders, utilities, policy makers, and other government agencies.

Approach: the objective of 100% renewable power generation implies *firm* renewable power generation, i.e., the renewable supply must be able to meet demand with certainty 24/365. Because the two renewable resources with the highest deployment potential in the world – wind & solar – are variable, 100% renewable power generation therefore also implies a transformation of these variable renewable energy (VRE) resources from intermittent to firm.

Building upon the work of the International Energy Agency's PV Power Systems Program (IEA-PVPS) Task 16 under the co-leadership of this report's authors, the study explores, for the Province of Nova Scotia, cost-optimal solutions to transform wind and solar resources into reliably firm generation that can complement other existing or prospective renewable resources (e.g., local hydropower) so that the integrated renewable supply can cost-optimally meet the province's electrical demand 100% of the time. The IEA work shows that the transformation of the VREs from intermittent requires energy storage that can be minimized by properly blending and overbuilding the VREs. The cost-optimal blend/storage/overbuild configuration is a function of the demand/VRE supply relationships (quantified by time-coincident load and VRE time series) as well as the specifications and cost of the considered technologies to generate power and to transform this power from intermittent to firm.

The renewable power generation technologies considered for Nova Scotia are wind (onshore and offshore), solar PV , and optionally, clean dispatchable generation using 100% renewable, carbon neutral electro-fuels (e-fuels). The considered intermittent-to-firm transformation technologies include battery storage and implicit storage (i.e., overbuilt VREs). The firmed-up VRE resources are optimized to complement existing hydropower generation so as to meet the entirety of the province's electric demand. Multiple simulations were conducted analyzing two years' worth of hourly load and renewable power generation data with near-term (2025) and long-term (2050) technology cost assumptions, varying assumptions regarding VRE deployments (PV array geometry and geographical distribution, respective contribution of onshore and offshore wind resources), the possible utilization of a small fraction of dispatchable thermal power generation, and varying assumptions on projects' financing conditions quantified by the weighted average cost of money.

Results: The study demonstrates that wind/solar generation plus existing hydro could entirely supply the existing demand of the Nova Scotia power grid at an electricity production cost ranging from 7.7 C¢/kWh (2050 tech cost assumptions) to 12.9 C¢/kWh (2025 tech cost assumptions). Allowing for a small fraction (5%) of expensive e-fuel dispatchable thermal generation could reduce these costs to respectively 6.4 C¢ and 10.2 C¢/kWh, confirming the catalytic impact of e-fuels noted in IEA investigations. For the latter economically optimal configuration, renewable and storage requirements would amount to

approximatively 2.1 GW of PV, 2.4 GW of onshore wind, 1.65GW of e-fueled dispatchable thermal generation, and 4 GW of battery storage with 4.5 hours energy capacity. In terms of supply-side energy, the contributions of PV, wind and e-fuel would respectively amount to 30%, 65% and 5% of the load fraction (90%+) that is not met by existing hydro. VREs would have to be 26% overbuilt to achieve this outcome. Importantly, avoiding overbuilding in an attempt to utilize 100% of the VRE-generated output would lead to a firm power generation cost penalty of 300%, confirming the critical (albeit counterintuitive) role played by overbuilding and curtailing VREs.

BACKGROUND

Firm Renewable Power

A recently released IEA report [1, 2] defines firm power generation as "the capability for an electricity generating resource or an ensemble of resources to meet a given electrical load (e.g., the demand of a power grid) 24 hours a day and 365 days a year". Electricity generation on power grids has historically involved a mix of controllable power sources like nuclear, large hydro, and coal, which reliably meet constant baseline needs, and flexible sources like natural gas generation (combined cycle and peaking units) and dispatchable hydro, that can adjust output based on changing demand. These conventional sources are designed to reliably fulfill their allocated load requirements, making them firm power resources.

Wind and solar energy show important potential for development and could entirely replace the conventional generation technologies that have negative environmental impacts [3]. However, these weather-driven Variable Renewable Energies (VREs) do not meet the criteria for firm power. Currently, they depend on the core of conventional baseload and dispatchable generation and operate at the periphery of this core. Proper management of the underlying conventional generation is essential to integrate VREs and ensure continuous supply-demand match. As the penetration of VREs increases (see figure A-1, left), their marginal operation adds complexity to the management of the underlying dispatchable resources, leading to steeper dispatching ramps, deeper duck curves, the need for larger spinning reserves, eventually reaching the limits of grids' hosting capacities [2].

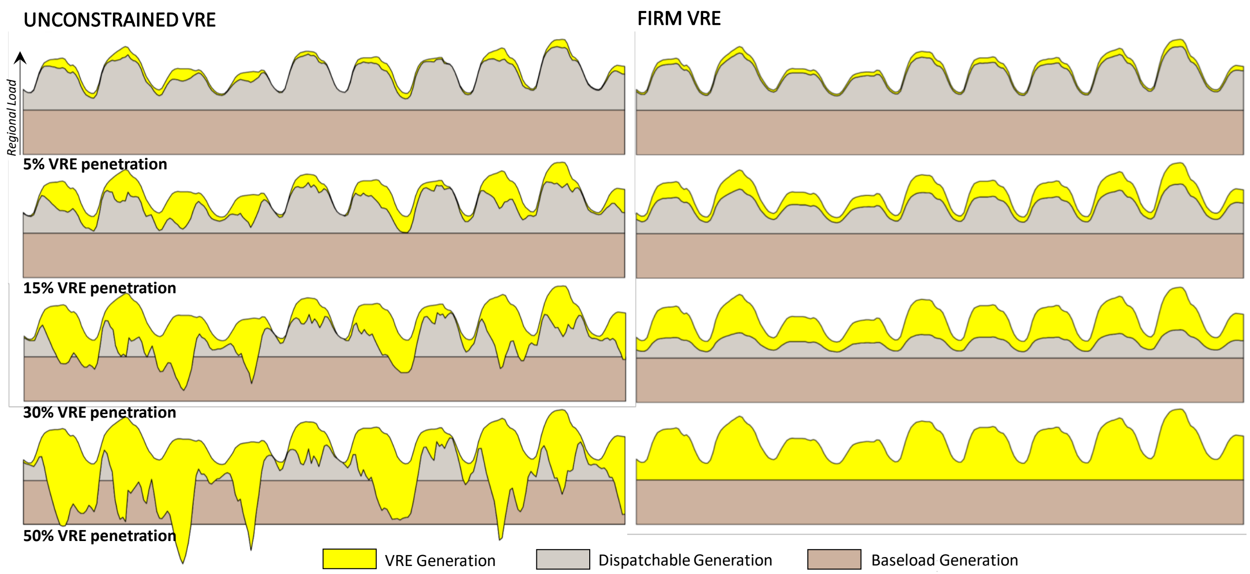

Figure A-1: Illustrating VRE's grid penetration impact with several days' worth of electrical demand on a regional power grid* conventionally supplied by baseload and dispatchable resources. In this qualitative example, the considered VREs consist of a locally generated 50%/50% blend of wind and PV. At left, VREs operate unconstrained at the margin of the conventional core. Their increasing penetration rapidly leads to unpredictability and complexities in the management of the underlying resources: at 15% energy penetration, VREs start impacting baseload. At ~ 35% energy penetration the VREs exceed hosting capacities and must be [non-optimally] curtailed because of excess production, while baseload generation management is heavily impacted. At right, the VREs are transformed into firm power generators (see below) producing an output signal matching the output of dispatchable generation. Firmed-up VRE penetration gradually and seamlessly displaces the underlying dispatchable resources (note that this particular example assumed that baseload did not need to be displaced by VREs, e.g., consisting of large renewable hydropower generation). ** This illustrative load profile is that of zone J of the New York Independent system operator (NYISO).*

Replacing the underlying conventional generation requires a transformation of VREs from inherently intermittent to firm, so they can grow seamlessly and meet demand 24/365 by themselves (Figure A-1, right). Such a transformation can be enacted with a portfolio of strategies and technologies, which the IEA terms firm power enablers [1]. These enablers include the following conventional and well-known technologies and strategies:

- Energy storage
- The optimum blending of VREs (PV and Wind) as well as other renewables (e.g., hydro) [1]
- Geographic dispersion, which reduces the VREs' inherent variability [4].
- Load flexibility, i.e., modulating the load VREs must serve to better match their availability. Flexibility can be procured on the demand-side via customer-side demand response, or on the supply-side, by operating an acceptable fraction of conventional dispatchable resources in the firm VRE power generation blend.[1]

However, a growing body of work [1,5] demonstrates that to be economically viable, the variable-to-firm transformation must also entail overbuilding and proactively curtailing the VREs – aka, applying implicit storage. This counter-intuitive enabler is also the most effective at reducing firm VRE power generation cost, as will be apparent in the results section. Figure A-2 illustrates the 'implicit storage effect' of overbuilding, where a substantial portion of expensive storage can be replaced with less costly VRE overbuilding.

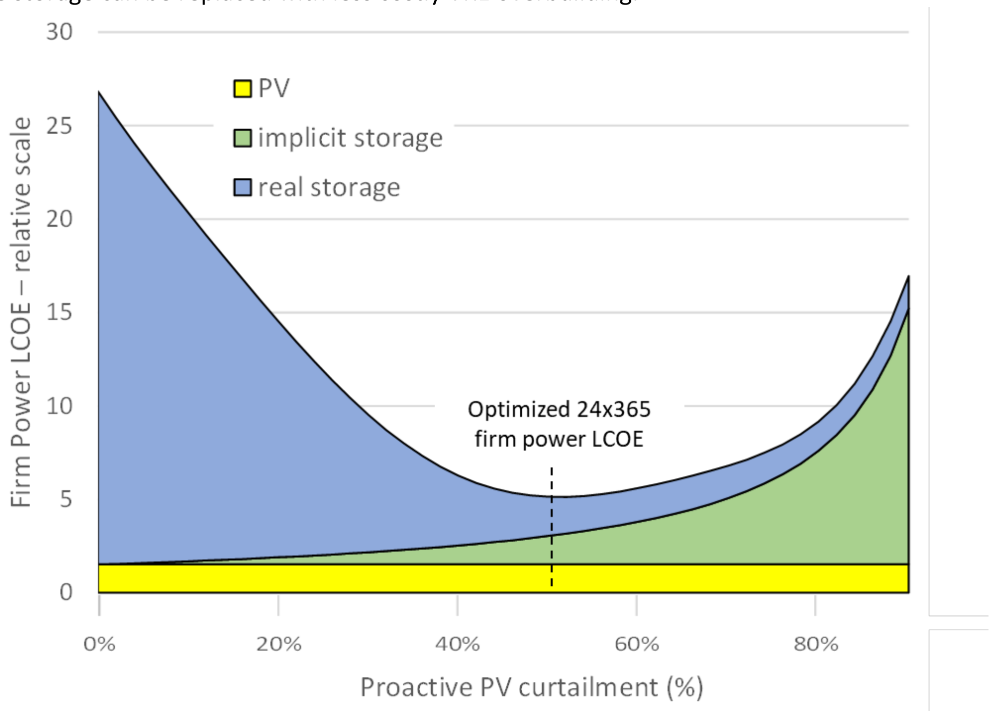

Figure A-2: Illustration of the implicit storage effect [1]. This illustration shows a simplified grid-supply configuration including PV, physical storage, and implicit storage, and their respective contributions to firm power generation cost. Implicit storage is the overbuilt portion of the PV resource that is operationally curtailed and not used. The currently prevailing VRE operational practice to maximize output and avoid curtailment leads to considerably higher firm power generation costs than if real and implicit storage contributions are optimized.

The optimal blending of VREs and enablers determines the lowest cost firm power configuration for a particular region. This optimization depends on economic and operational factors including:

- the CapEx (capital cost) and OpEx (operational cost) of the considered VREs,
- the CapEx and OpEx of energy storage,
- the CapEx and OpEx of flexibility,
- the CapEx and OpEx of grid strengthening if considering large scale geographic dispersion,
- the characteristics of the electrical load served,
- the characteristics of the considered VREs.

The optimization metric is the levelized cost of electricity (LCOE) for firm power generation determined per equation (1).

$$LCOE = \frac{\sum_i \frac{C_i + O_i}{(1+r)^i}}{\sum_i \frac{E_i}{(1+r)^i}} \qquad (1)$$

where i represents the year increment of a considered life cycle (here 30 years), C_i and O_i are the capital and operational expense occurring in year i, E_i is the electricity generated in that year, and r is the weighted average cost of capital or WACC.

In practice, for a given power grid, the minimum LCOE 'sweet spot' point is determined empirically from coincident time series of electrical load and VRE generation, by scanning the costs/curtailment solution space of an operational firm power system involving a selected set of generating resources and firm power enablers. The operational approach to transform the VREs and enablers (real and implicit storage) into firm power generation is illustrated in Figure A-3. This Figure also illustrates how the least-cost solution is determined by applying nested non-linear optimization loops [6] to determine the VRE blend and the real/implicit storage balance.

Importantly, the IEA notes that firm power generation is not monetizable per se at present. The issue arises because renewable energy (at all scales from residential to utility-scale) is valued based on the energy it produces, reflecting market frameworks (e.g., merit order auctions) that have been designed for traditional dispatchable generation. This means that renewables are valued in comparison to the conventional energy they replace, lacking recognition for the grid services they can provide independently. These market rules do not align well with their variable nature that is subject to seasonal and weather-related fluctuations. It is therefore important, if firm VRE power generation is to become a reality, to implement effective market rules that will foster this objective. The authors of the IEA report have suggested that effective monetization pathways should be capacity-based (as opposed to energy based) and be implemented in parallel to, and independently of conventional electric power markets [2].

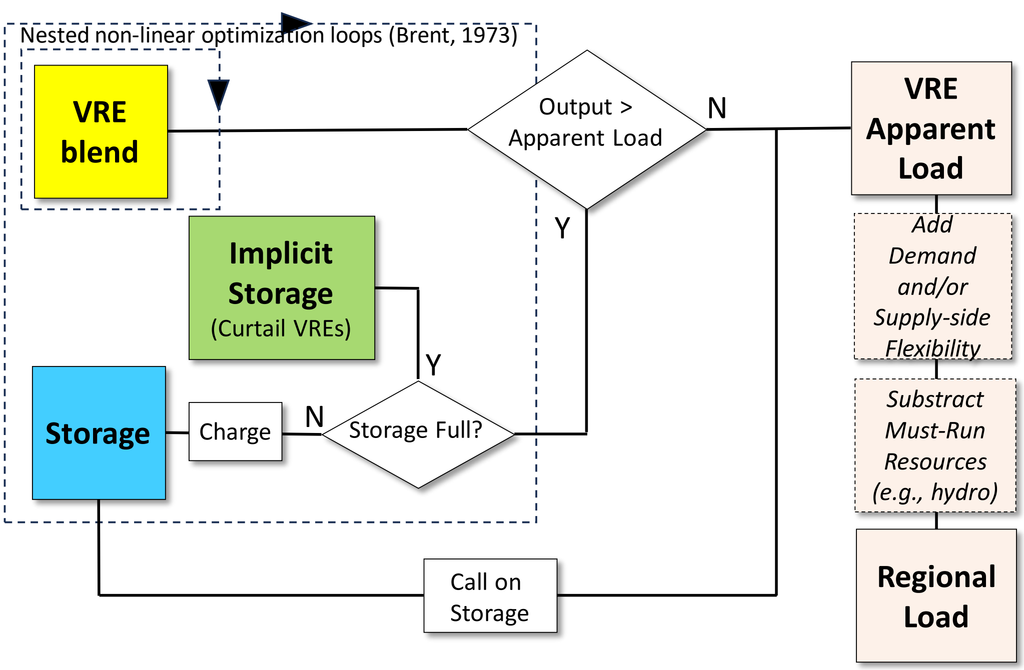

Figure A-3: Firm VRE power generation operational flow-chart also showing the LCOE-minimization process by optimization of the VRE blend and storage/curtailment contributions.

Early Grid-Connected Applications for Grid-Connected Storage

Electric Battery Energy Storage Systems (BESS) – optimally blended with other enablers – constitute an indispensable element of firm VRE power generation.

Ideally, BESS should be deployed to optimally support firm renewable power generation at all scales. However, before effective market rules can facilitate this type of storage deployments, grid-connected storage resources have

started developing at the margin, taking advantage of existing remuneration pathways. Storage systems are increasingly deployed to provide ancillary services.
Ancillary services encompass several operations aimed at ensuring that generation and demand precisely match on transmission and distribution circuits. The literature refers to two ancillary service categories, namely short-term ancillary services, and long-term ancillary services [7].

- Short-term ancillary services include supplying reactive power (lagging or leading VARs), voltage support, frequency regulations, and black-start capability.
- Long-term ancillary services include peak shaving, congestion relief, and VRE (wind/solar) power smoothing.

For North American utilities, ancillary services are typically grouped in Regulation and Reserves (spinning and non-spinning) categories – broadly corresponding to the short-term (regulation) and long-term (reserves) terminology from the academic literature.

Regulation aims at automatically balancing small demand/supply fluctuations that impact frequency. Generators and/or BESS units providing regulation service must be able to respond to automatic generation control (AGC) signals from grid operators within seconds and are compensated for participating in this service through markets managed by grid operators such as Independent System Operators (ISOs), Regional Transmission Operators (RTOs), or regional distributed utilities as would be the case for Nova Scotia. Some markets compensate participating units only after monitoring their performance at reacting to control signals and ensuring that their performance is acceptable.

Reserves are units that must be able to react rapidly to larger discrepancies between supply and demand resulting from forced power outages or, increasingly, from gaps between forecasted and available VRE output. Spinning reserves are grid-synchronized online units (typically thermal generation) operating below their full generating capacity and on stand-by for ramp-up calls. Non-spinning reserves are offline but must be capable of reacting to contingency calls. Both spinning and non-spinning reserves are typically required to ramp up to their expected output within 10-15 minutes. As for regulation, reserve units are compensated through markets managed by grid operators.
Specific regulation and reserves market rules are generally grid operator-specific both in US and Canada. For instance, the New York Independent System Operator (NYISO) requires an immediate response for regulation in response to automated signal while the Mid-continent Independent System Operator (MISO) requires such a response within 5 minutes, but with guarantees of grid synchronization. Spinning and non-spinning reserves must be operative within 10 minutes for MISO, while NYISO has four reserve categories, fast-response spinning (grid-synchronized) and non-spinning reserves that must come online within 10 minutes, and slower-response spinning and non-spinning reserves that have a 30-minute signal-to-action response time [8].
Markets should in principle be open to all types of units that can reliably provide the needed regulation or reserve services, noting that market rules may not always be keeping up with evolving technological capabilities. Participating units typically include fast reacting thermal generators, user-sited [diesel] generators, dispatchable hydro, energy storage including BESS, and demand-response, as long as these units are not already committed in energy markets (e.g., day-ahead markets).
The bulk of ancillary services, particularly for long-term/reserve has traditionally been supplied by thermal generating units, but fast reacting BESS are now making an accelerated entry in these markets. A big advantage for BESS over generating units (particularly non-spinning reserves) in addition to their fast response (seconds) is their capability to act for both up (not enough generation) and down (too much generation) regulation and reserve calls.
Nova Scotia is exploring rules for new utility-scale VRE installations to provide ancillary services via on-site BESS dedicated for this purpose [9].
It is informative to compare the size of ancillary service markets and bulk electricity markets in terms of engaged energy or financial volumes (see Fig. A-4, [10]). The current markets for grid connected storage include ancillary services and real time markets (note that the distinction between the reserves services and real time market services is largely of a contractual type since they are both tackling unforeseen supply/demand gaps.) in terms of relative

BESS market size, prospective firm power applications would be commensurate with the sum of day-ahead, bilateral contracts and capacity markets, i.e., orders of magnitude larger than their current ancillary market realm.

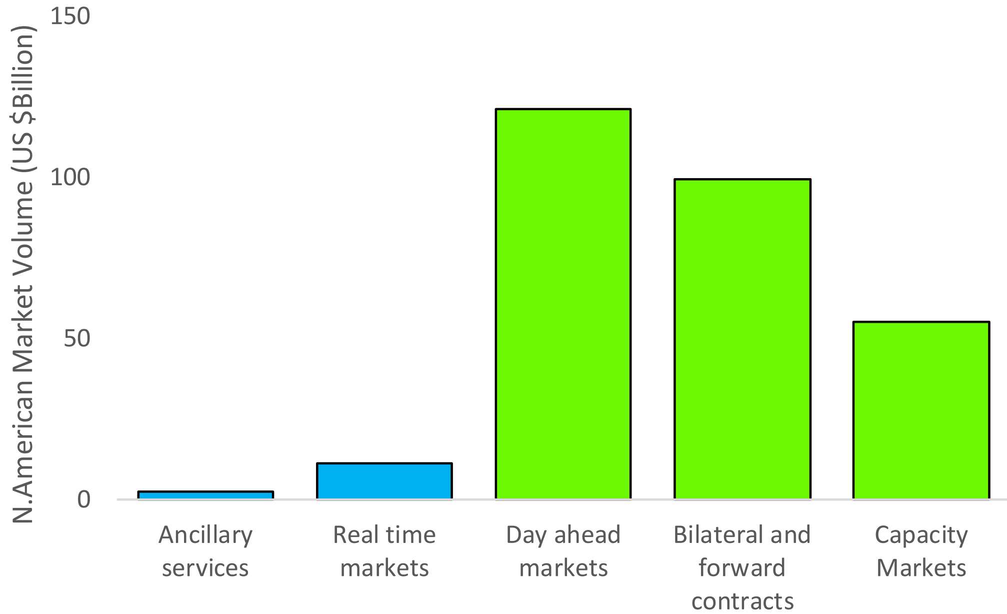

Figure A-4: Comparing financial volumes engaged in ancillary services and real time power markets where BESS applications are currently developing (blue), to bulk energy and capacity markets, where BESS applications in support of firm VRE power generation could prospectively develop (green) [10].

We initiated conversations with US companies involved in BESS deployments and taking part in ancillary services markets to obtain a field-level operational view of how storage systems are penetrating the ancillary service and other grid-connected markets. One of these companies serves the New York metro electrical region of the Pennsylvania-New Jersey-Maryland Interconnection (PJM) system.

The company indicates that most of the grid-connected storage units it has deployed to date are not directly configured and monetized to participate in ancillary services but are typically used for demand-side backup power. Many of these systems also indirectly participate in real-time/ancillary markets but on the demand-side by enabling effective demand response if the customer participates in such program, and/or maximizing demand-side energy arbitraging and peak shaving.

The company reports no applications for Voltage support or VARs to date. These services are typically needed on distribution circuits, and no market has been setup yet in this PJM region – regulations that would enable distribution utilities to pay for these services are still in development. Existing ancillary services markets are only for transmission-level frequency regulation operated by the local grid operator (PJM). Units that want to participate in this market must qualify for it by proving they can follow automated signals. These units can then bid in on every hour in 100kW increment for 15 minutes' worth of injecting or absorbing power. Units are controlled by their owners through hired grid operator-licensed curtailment providers ingesting grid operator-initiated AGC signals. These licensed providers often take control of BESS operations via telemetry against a fraction of the systems' revenues.

BESS Financing mechanisms can also straddle customer-side benefits and grid operator contracts: An example would be to contractually participate in reserves for 5 system PJM peak events (typically occurring in early July) and use the BESS for customer-side retail rate arbitraging or peak shaving the rest of the time. All things considered, the New York metro company indicates that, at this stage of customer-sited/ancillary service market development, the storage systems they deploy are economically viable typically generating revenues $0.1 million per MW per year for 3-hour storage configurations.

Black start ancillary services are not part of the ancillary services offered/monetized in the NY metro region. However, conversation is building up on this topic and legislation monetizing this service is likely to follow on. Interestingly, large natural gas power generators already operate storage units next to generation for system black start purposes.

FIRM VRE POWER IN NOVA SCOTIA

Data and Methodology

The least-cost firm power 'sweet spot' point is determined from time-coincident time series of electrical load and VRE generation following the modeling approach described above and illustrated in Figure A-3.

The VRE and load time series analyzed for this report cover 2019 and 2022 (note that 2020 and 2021 were not considered because of COVID-related demand-side anomalies).

The selected VREs include onshore wind, offshore wind, PV (considering both latitude-fixed-tilt, and East-West single axis tracking geometries) as well existing hydropower generation. Hydro is assumed to be a must-run resource, therefore, the VRE firm power optimization is only performed on wind and solar, with hydro acting as a load modifier from a solar/wind standpoint.

In addition to the VREs we also consider the possibility of using clean dispatchable generation (e-fueled thermal generation) as a supply-side flexibility resource amounting to up to 5% of total electricity generation. For this scoping study, we make the approximation that these resources can be instantly dispatched when needed (in practice they would require a small quantity of BESS amounting to a minor fraction of the BESS engaged for firm power generation.

Wind power generation data.

Five onshore and five offshore wind farm locations were selected based on the results of scoping analyzes undertaken by Aegir [11] for offshore and by CanWEA [12] and the Government of Canada [13] for onshore resources. The selected windfarm locations are displayed in Figure A-5.

Hourly wind power generation for each location was simulated from ERA5 Reanalysis [14] hourly wind speed data at 10m and 100m. The ERA5 data have a native resolution of 0.25x0.25 degrees amounting to 18x25km at the considered latitude. Wind power generation data were simulated from the ERA5 data by extrapolation to turbine hub height (100 meters) using measurement tower-validated wind shear models [15] and processed into wind power generation nominal turbine power curves [16].

As a base case we consider that the wind power generation available to the power grid is distributed equally among all locations, amounting to a 50%/50% onshore/offshore blend. As explained below, we also conduct a sensitivity analysis on this assumption by varying the onshore/offshore contributions.

Figure A-6 Illustrates the annual profile of the wind power generation for the 10-site integrated output, applying a 15-day running to minimize short-term variability and facilitate viewing.

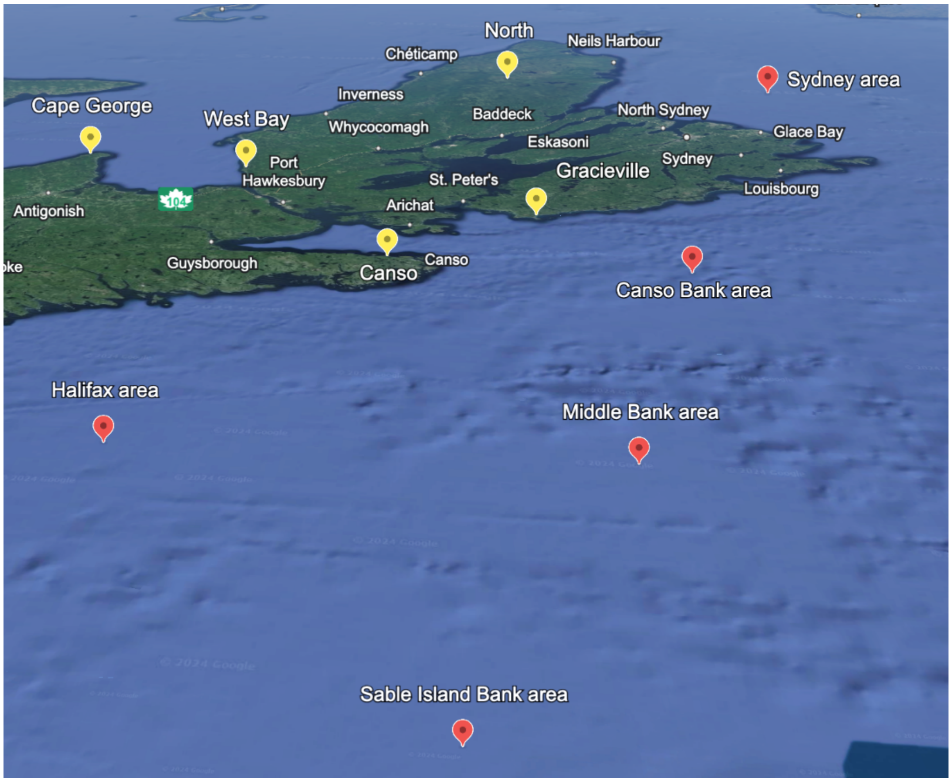

Figure A-5: Location of assumed onshore (yellow) and offshore (red) wind farm generation location.

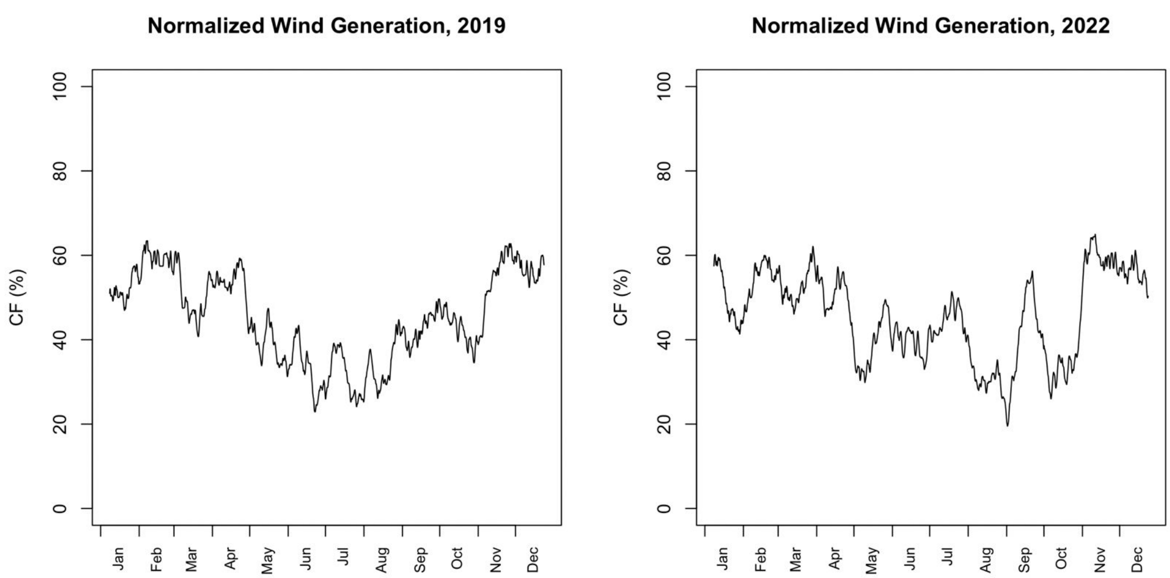

Figure A-6: Annual generation capacity factor of 10-sites-integrated wind power generation for 2019 and 2022. Note: a 15-day running mean has been applied to the underlying hourly data to facilitate viewing

Solar power generation data.

Photovoltaic power generation was simulated from hourly SolarAnywhere irradiance data [17] with a ground resolution of 0.1x0.1 degrees amounting to 7x10 km for the considered region.

The base-case power plant configuration is fixed-tilt at latitude. For sensitivity purposes we also considered an East-West horizontal single axis tracking geometry. The East-West tracking orientation is effective for northern locations such as Nova Scotia as it produces seasonal sun-tracking (as opposed to intraday-day sun-tracking with north-south axes used for the typical utility-scale plants deployed at lower latitudes). Seasonal/multi-day variability has been identified as the most important factor to consider in the optimal transformation of VREs from intermittent to firm [1].

We assume that PV production is distributed homogeneously throughout the province. Figure A-7 illustrates the annual PV generation profile for each array configuration and year analyzed. We also conducted a sensitivity analysis of the results by assuming a geographical PV distribution influenced by demography.

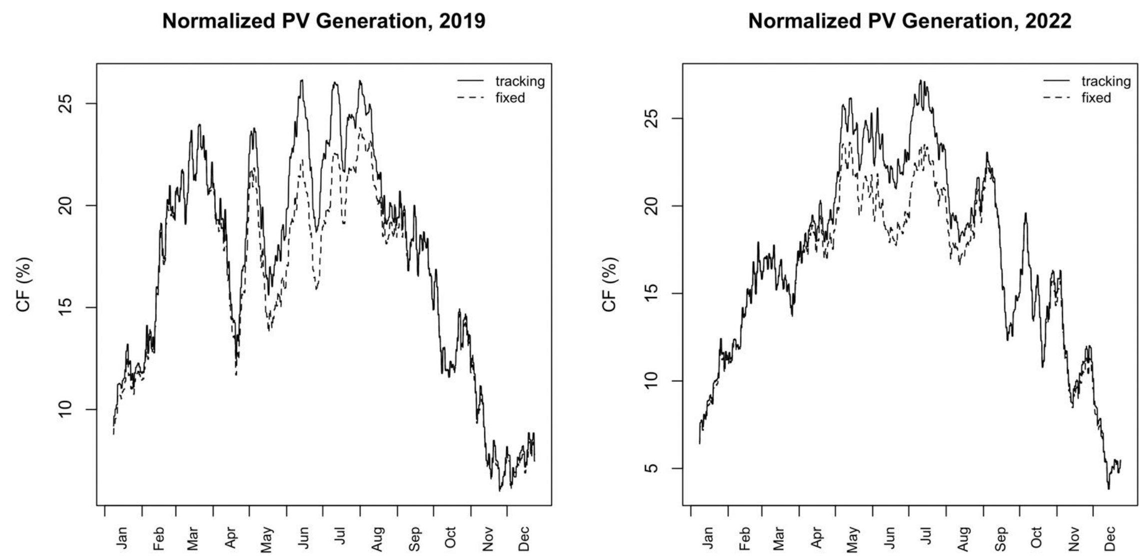

Figure A-7: Annual PV generation capacity factor for each considered year and array geometry. As in Figure A-6, a 15-day running mean is applied to the underlying hourly data to facilitate viewing.

Hydropower generation data.

Monthly actual 2019 and 2022 hydropower generation data for the province were obtained from Statistics Canada [18]. The monthly data were downscaled to hourly data internally at Natural Resources Canada [19] by apportioning the recorded monthly production to the hourly demand on the Nova Scotia power grid.

Hydropower supplies approximately 9% of the total power generation in the province.

Figure A-8 illustrates the annual hydropower generation profile for each considered year using the same 15-day running mean as above for wind and PV.

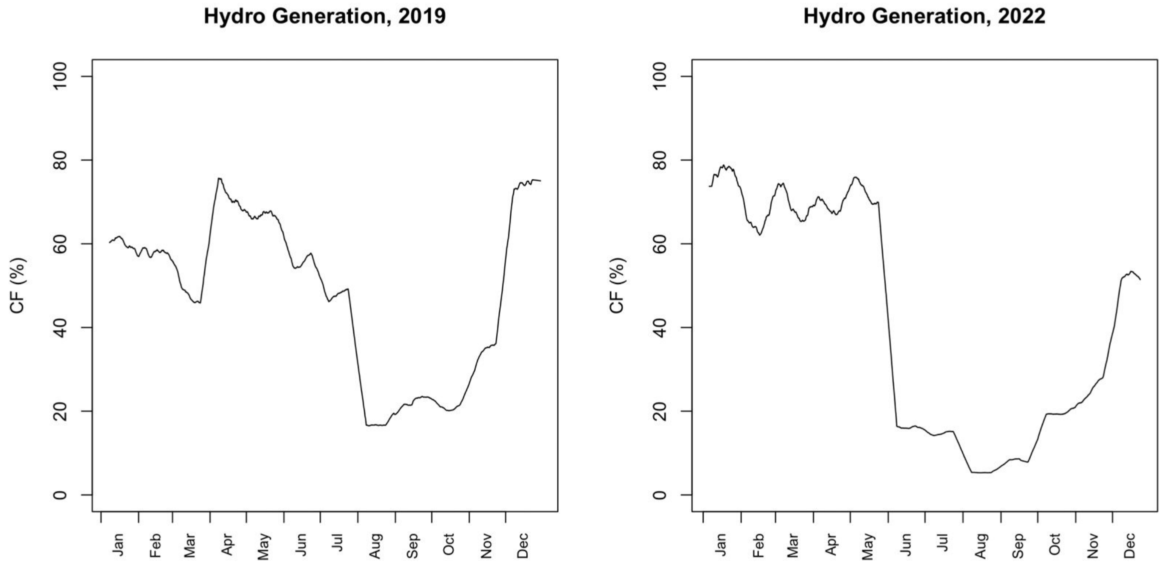

Figure A-8: Annual Hydropower capacity factor for 2019 and 2022 applying a 15-day running mean to the underlying hourly data. Note that hydropower generation amounted to nearly 10% of the load in 2019 and 8% in 2022.

Importantly, hydropower is considered as an existing must-run resource, i.e., not subject to the firm power transformation/optimization applied to the PV and wind resources. In effect, the apparent load to be firmly met by these VREs is the actual Nova Scotia load minus the hydro production.

Electrical Load Data

Hourly total net load data for the province were obtained from Nova Scotia Power [20] for 2019 and 2022. Net load represents the load seen by utility scale generators on the N. Scotia grid, exclusive of onsite-generation from e.g., existing user-sited renewable systems. We assume that such small existing on-site generation would remain unchanged and must-run, hence that the load to be prospectively served by firmed-up VREs consists of the existing net load (minus existing hydro). Annual net load distribution profiles are illustrated in Figure A-9.

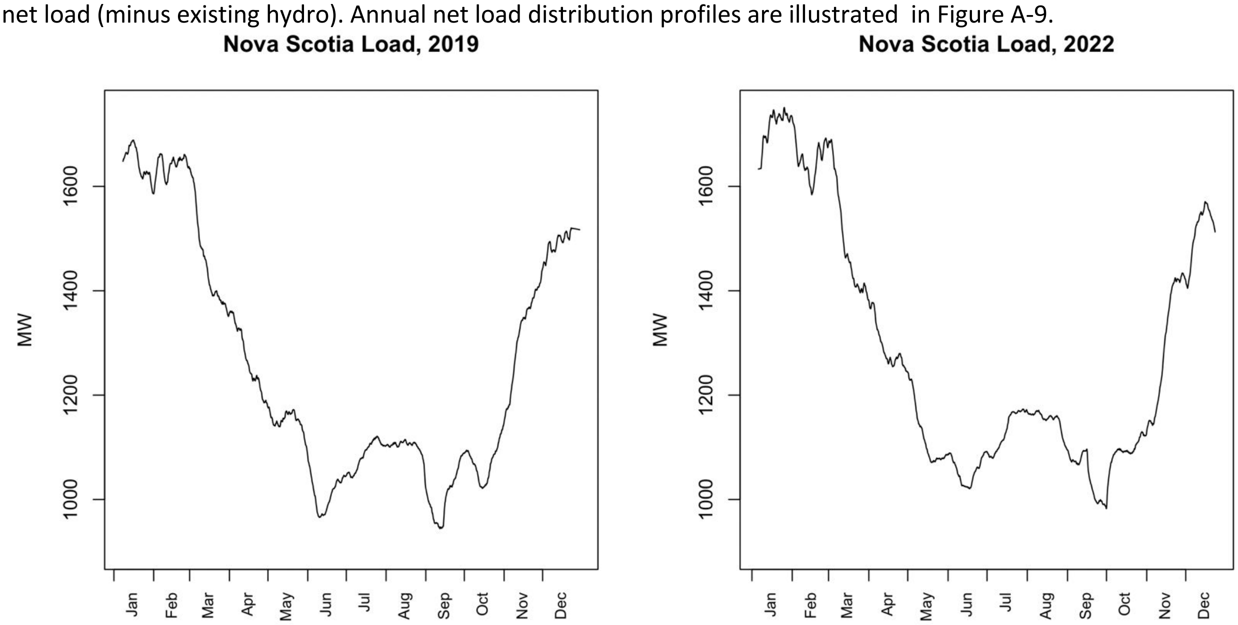

Figure A-9: Annual N. Scotia Power net load profile for 2019 and 2022 (with a 15-day running mean to the underlying data)

Economic and Technical Inputs and Assumptions

In addition to load and VRE profile characteristics quantified by the above time series, the optimum firm power configuration depends on the technical and economic characteristics of the technologies involved.
Economic characteristics are quantified by the considered technologies' capital and operating costs (resp Capex and Opex). We consider two base assumptions for these costs: one for the near future (2025) and one for a 2050-time horizon, accounting for expected VRE Capex reductions. Cost assumptions are based upon NREL's Technology Baseline [21] and are consistent with NRCAN's cost projection sensitivities [19]. These are reported in Table A-1 (note that the NREL-derived cost projections have been converted to Can$ by applying a 1.35 currency exchange rate)

TABLE A-1
Simulation Economic Inputs

		2025	2050
CapEx	PV	C$1409/kW	C$629/kW
	Wind Onshore	C$1665/kW	C$709/kW
	Wind Offshore	C$3762/kW	C$2627/kW
	Battery *	C$144/kWh	C$88/kWh
		C$108/kW	C$66/kW
	e-fuel Thermal Gen	C$1150/kW	C$1150/kW
OpEx	PV	C$26/kW/y	C$15/kW/y
	Wind Onshore	C$54/kW/y	C$32/kW/y
	Wind Offshore	C$126/kW/y	C$81/kW/y
	Battery	C$4/kWh/y	C$3/kWh/y
		C$3/kW/y	C$1.4/kW/y
	e-fuel Thermal Gen	24 C¢/kWh	24 C¢/kWh

** Note that Battery Capex, unlike often reported, includes 2 components per kW and kWh capacities*

For storage, we assume that electric batteries have 90% round-trip efficiency and that, to meet the cost targets in Table A-1, consist of utility-scale, centralized units for the majority. These units are assumed to be located near utility scale VRE generation, or at distribution substations for smaller scale PV systems in order to minimize grid hosting capacity concerns. Indeed, wind +nearby storage units or solar + nearby or substation storage units would inject a clean signal onto the grid that would never exceed the fraction of their assigned load.
E-fuel thermal generation is used here as a form of easily quantifiable, albeit inherently expensive, supply side-flexibility resource following the approach developed in the IEA investigations [1]. E-fuel thermal generation is technologically equivalent to existing natural gas power generation (same Capex) but with a considerably higher operating costs since synthetic renewable electro fuels (including methane) that are generated with 100% renewable electricity – and as necessary, imported from high VRE resource production sites nationally or internationally – are estimated to cost several times that of conventional fuels at full maturity (before accounting for conventional fuels environmental externalities), e.g., see [22]. We conservatively assume here that the Opex cost difference between e-thermal generation and conventional thermal generation is fourfold, following assumptions applied in the Firm PV power generation for Switzerland study [23].
Concerning the power grid, we make the assumption that no build-up would be necessary because (1) wind/storage units or solar/PV units would inject complementary fractions of clean load shape signal, not exceeding the output of current centralized generation units, and (2) that these VRE/storage units, especially for the PV part could be strategically located near the current fuel power plant hubs they would replace. However, grid modernization in terms of communications, controls and security would have to occur in order in to effectively operate the composite wind/solar/storage/e-fuel resource and implementing optimum charge/discharge, e-fuel dispatch, VRE curtail signals in real time as a function of demand and weather conditions,.

Firm Power Optimization Simulations

We consider eight base case scenarios using a combination of the three following inputs:

- Year analyzed (2019 or 2022)

- Technical cost assumptions (2025 or 2050)
- E-fuel supply-side flexibility (yes or no)

The key metric resulting from the simulations is the Levelized Cost of Electricity (LCOE) for firm 24/365 generation, i.e., effectively applying the most stringent resource adequacy criterion possible. This LCOE depends on the Weighted Average Cost of Capital (WACC) which is assumed to be 4% for the base scenarios, a number that is representative of the utility industry in non-inflationary conditions.
The optimum "sweet spot" LCOE can be directly compared to the firm power LCOE that would result without implicit storage (no curtailment).
Other important quantities produced by the simulations include:

- The required wind, PV, and storage capacities to be deployed,
- As appropriate, thermal generation capacities,
- The fractional amounts of VRE overbuilding (implying that excess production is proactively curtailed),
- The optimum energy split between wind and PV contributions.

In addition to the eight base case scenarios, we also conduct sensitivity analyses on:

- The geographical distribution of PV, either homogenously distributed or as a function of population density,
- The PV arrays geometry (fixed vs. seasonal tracking),
- The repartition of wind generation between onshore and offshore ,
- Considering wind only (no PV),
- Considering PV only (no wind),
- Higher cost of capital (respectively 6% and 8%),
- Battery cost estimates, looking at 50% and 200% of the base assumptions from Table A-1.

Results

Table A-2 displays results obtained for the eight base case scenarios.

TABLE A-2
Base Case Simulation Results (LCOEs in Canadian Currency)

Scenarios			Results										
Year	E-fuel contribution	Capex time horizon	Overbuild (%)	LCOE w/o overbuild/ curtail (cts/kWh)	**Optimum LCOE (cts/kWh)**	PV energy contribution at Optimum	Wind energy contribution at optimum	E fuel energy Contribution	PV Capacity at Optimum (GW)	Wind Capacity at Optimum (GW)	BESS Capacity at Optimum (GW)	BESS Hours at Optimum	Thermal (efuel) Capacity (GW)
2019	0	2025	32%	66.34	**14.29**	28%	72%	0%	2.73	2.39	2.91	16.9	0
2019	0	2050	32%	40.28	**8.39**	28%	72%	0%	2.73	2.38	2.90	17.0	0
2019	5%	2025	23%	34.81	**11.46**	25%	70%	5%	2.23	2.16	2.25	6.6	1.63
2019	5%	2050	24%	26.56	**7.54**	30%	65%	5%	2.73	2.01	2.52	5.5	1.63
2022	0	2025	44%	65.32	**15.48**	18%	82%	0%	2.05	3.06	3.05	18.7	0
2022	0	2050	64%	75.33	**8.87**	52%	48%	0%	6.66	2.03	5.59	6.9	0
2022	5%	2025	25%	55.26	**11.82**	25%	70%	5%	2.41	2.28	2.64	6.2	1.63
2022	5%	2050	26%	38.64	**7.76**	31%	64%	5%	3.04	2.09	3.13	4.8	1.63

Near term (2025) firm power LCOEs range from 11.46 to 15.48 C¢/kWh depending on flexibility assumptions and the year analyzed. Applying 2050 future technology cost estimates results in ~40% lower LCOEs.
Flexibility from e-fuel thermal generation, even though very expensive on its own, yields firm power renewable LCOEs that are 27% lower on average. This catalytic effect is fully consistent with what was observed in the Switzerland study [1, 2]. Firm power 100% renewable LCOEs below 8 CAD cents per kWh are achievable when applying 5% supply side e-fuel-based flexibility (amounting itself to 24 CAD cents per kWh).
Implicit storage (overbuilding and by design shedding a fraction of VREs' output) has a major influence on firm power generation cost. Figure A-10 shows implicit storage optimization curves for the year 2019. Firm power LCOEs would be 500% higher on average when operating the VREs to maximize output and avoid curtailment (see Figure A-10). As shown in Figure A-2, implicit storage acts by replacing expensive storage with less expensive VRE overbuilding but does not eliminate it. Indeed, storage remains an indispensable element of the supply-side resource mix. The BESS that remains at the optimum point would be applied more effectively, with frequent cycling events (every 2-3 days on average, i.e., equivalent to an ancillary service duty cycle) compared to the no-curtailment storage case where

the bulk of storage would be cycled only once or twice a season. More frequent cycling may affect the life span of storage, noting that this would remain well within specs compared to electric vehicle applications.

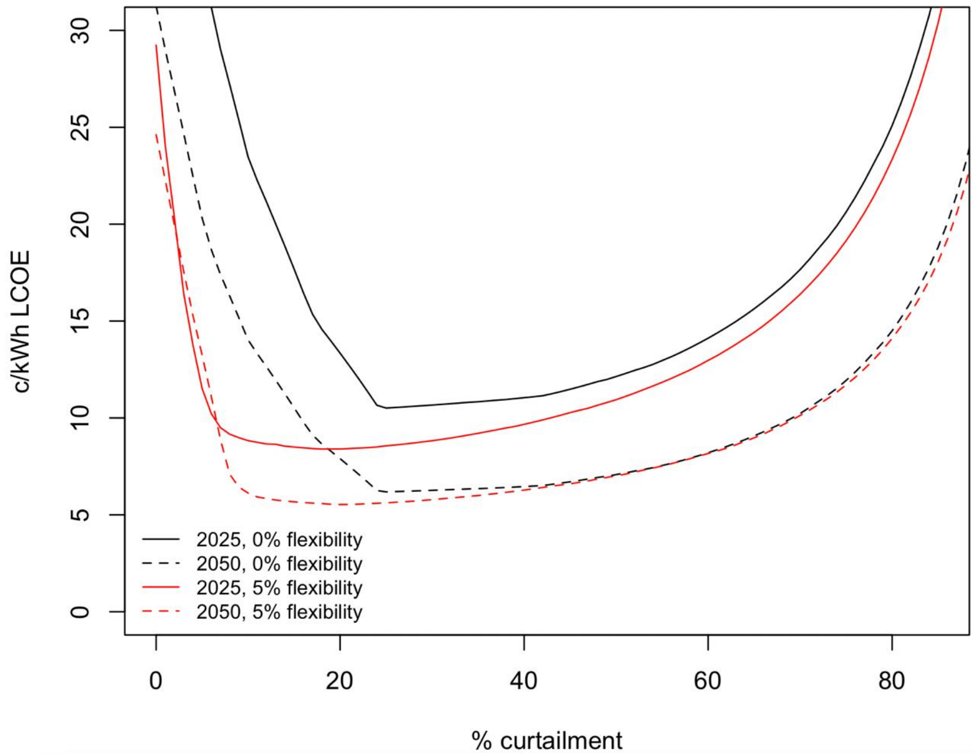

Figure A-10: Implicit storage 'sweet spot' optimization curves for 2019 base case scenarios.

Both years analyzed show consistent results, although overall LCOEs are 6% higher in 2022. A likely reason for this is the longer drought in summer's hydropower resource (see Figure A-8). Interestingly, the year-to-year difference decreases down to only 2.5% for the flexible e-fuel scenarios. This confirms that supply-side flexibility is not only an effective cost-catalyst but is also very effective at reducing the impact of any extreme VRE drought event.

PV's energy contribution to the generation mix is ~ 29% on average. This relatively high proportion was not expected, given the seasonal solar resource/load mismatch compared to wind (contrast Figures A-6, A-7, and A-9), and a PV capacity factor less than half that of wind. The likely reasons for this are the favorable economics of PV both in terms of capex and opex, and less prevalence for prolonged multi-day solar droughts compared to wind droughts as has been previously reported in the literature [24].

Looking at the sensitivity impact of other input variables, we first note that the geographical distribution of PV (homogeneous, vs. population dependent) has no influence on the bottom line (less than 0.1%).

The choice of PV array geometry has only a minimal influence on the bottom line. Tracking arrays results in LCOEs that are about 0.5% smaller than fixed arrays' (while considering no capital or operational cost differences between the two).

Blending the VRE resources is very important. Considering either PV alone or wind alone would lead to considerably higher firm power production numbers, especially in the case of PV alone, where the optimum LCOE numbers shown in Table A-2 would be 140% higher. In the case of wind alone, optimum LCOEs would be 35% higher. It is therefore critical to optimally blend the wind and solar resources (Figure A-11)

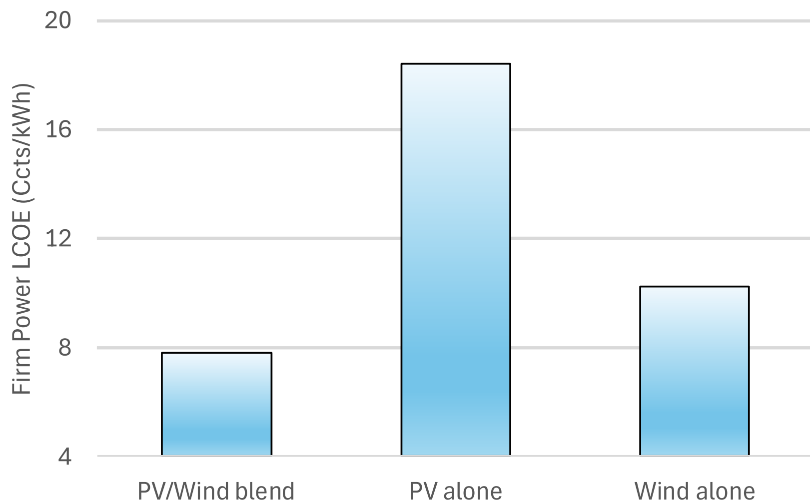

Figure A-11: Comparing the firm power LCOEs achieved with an optimal PV/wind blend to that achieved with either PV alone or wind alone (considering the 2050 flexible scenarios)

The distribution of the wind resource between offshore and onshore has a significant influence on the bottom line as well. Although the offshore resource is slightly higher (47.2% capacity mean factor the offshore plants compared to 44.5% for onshore) the capital and operating cost difference between the two more than makes up for the resource difference. LCOEs are 15% less expensive than for the base case when considering a pure onshore wind resource and 22% higher than the base case when considering a pure offshore resource as shown in Figure A-12.

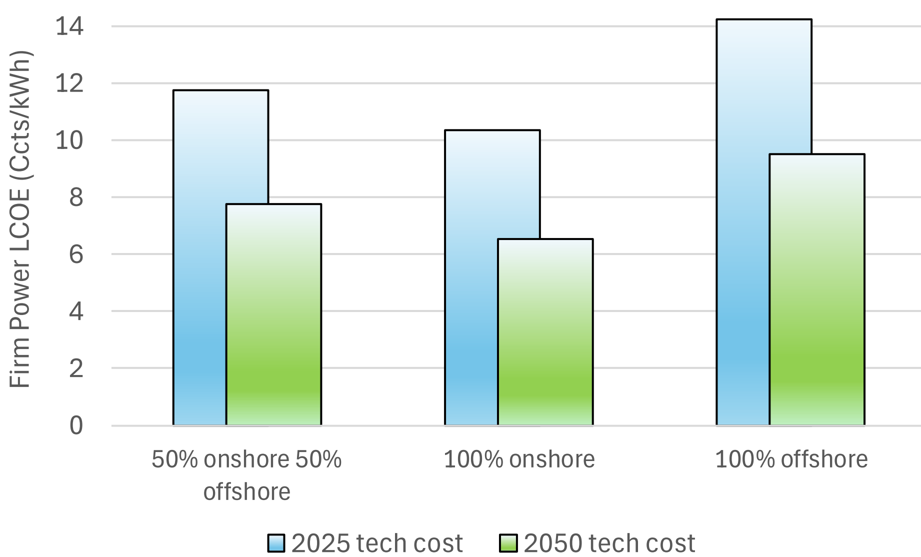

Figure A-12: Assessing the impact of wind resource distribution on firm power LCOE

The CapEx of battery storage has a measurable influence on the bottom line, as well as on the size and impact of implicit storage (overbuilding). Figure A-13 compares 2025 and 2050 LCOEs for battery cost assumptions amounting to respectively 50% and 200% of base case assumptions, with LCOE respectively 7% lower and 17% higher than base case.

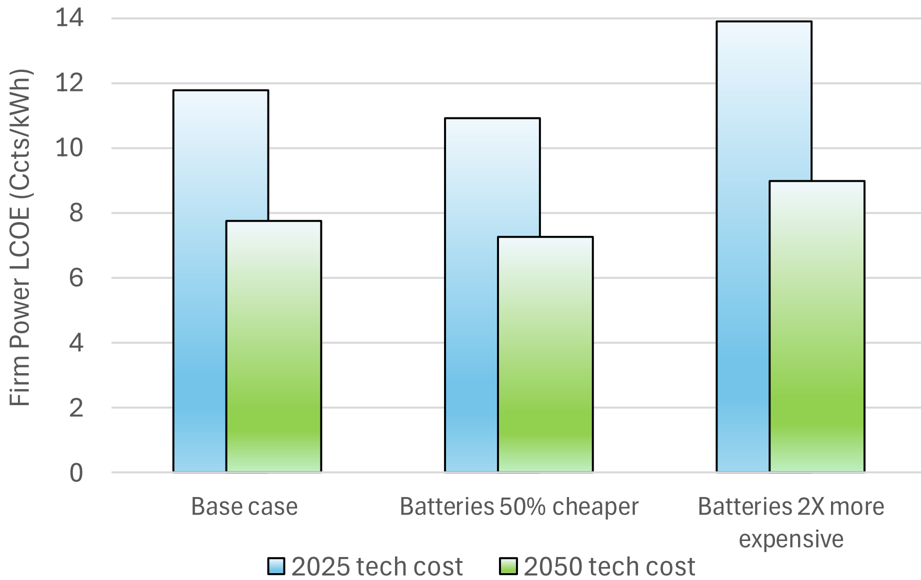

Figure A-13: Assessing the impact of batteries cost assumptions on firm power LCOE

The impact of BESS cost on VRE oversizing requirements is substantial, with 25% less VRE overbuilding when batteries are 50% cheaper and 30% more VRE oversizing when batteries are twice as expensive than base case assumptions. Importantly, the need for implicit storage remains significant in all cases, as penalties for not avoiding curtailment are multifold as shown Figure A-14.

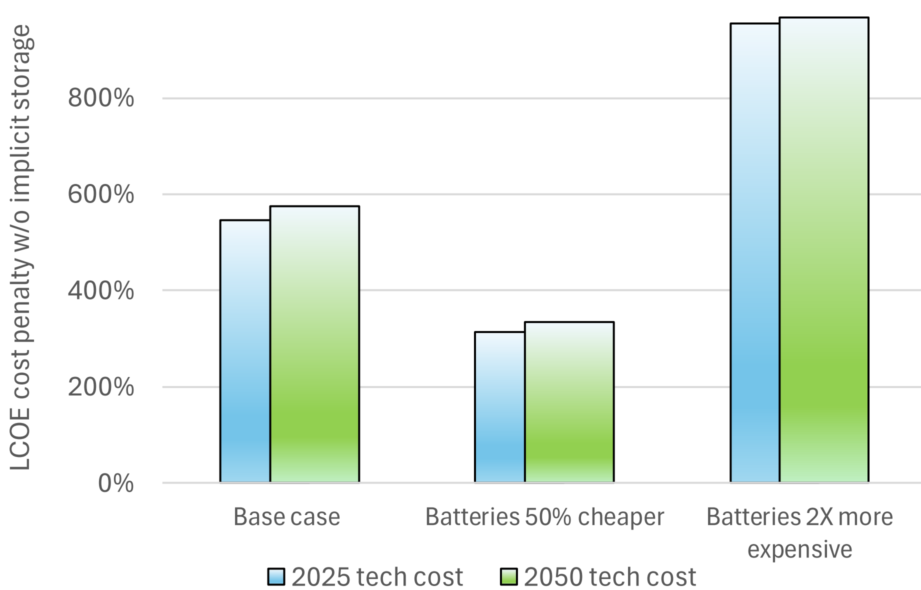

Figure A-14: Firm power LCOE cost penalty incurred without implicit storage, when operating the VREs to maximize output and avoid curtailment as a function of battery cost assumptions

Finally, we observe that the financing environment (quantified by the WACC) cannot be ignored, as LCOEs would increase by respectively 15% and 30% when applying WACCs of 6% and 8% compared to base case WACC set at 4% (see figure A-15).

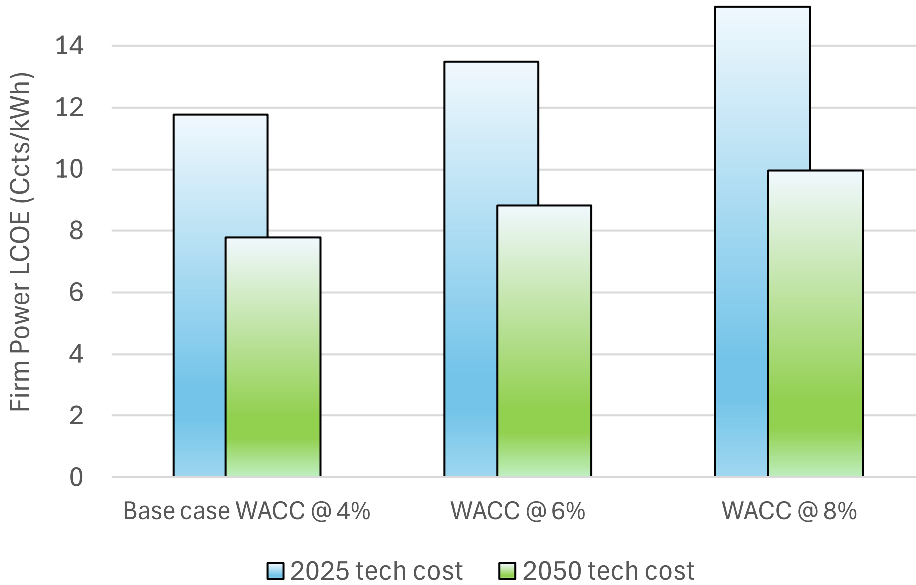

Figure A-15: Firm power LCOE cost as a function of weighted average cost of capital

Firm Power Operations
The operation of an optimized firm renewable power system is illustrated in Figure A-15 for several days in 2019. This example considers future (2050) technological costs with 5% e-fuel flexibility and shows the dispatch of PV, wind, hydro, e-fuel thermal and storage resources to firmly meet Nova Scotia power grid's net load.

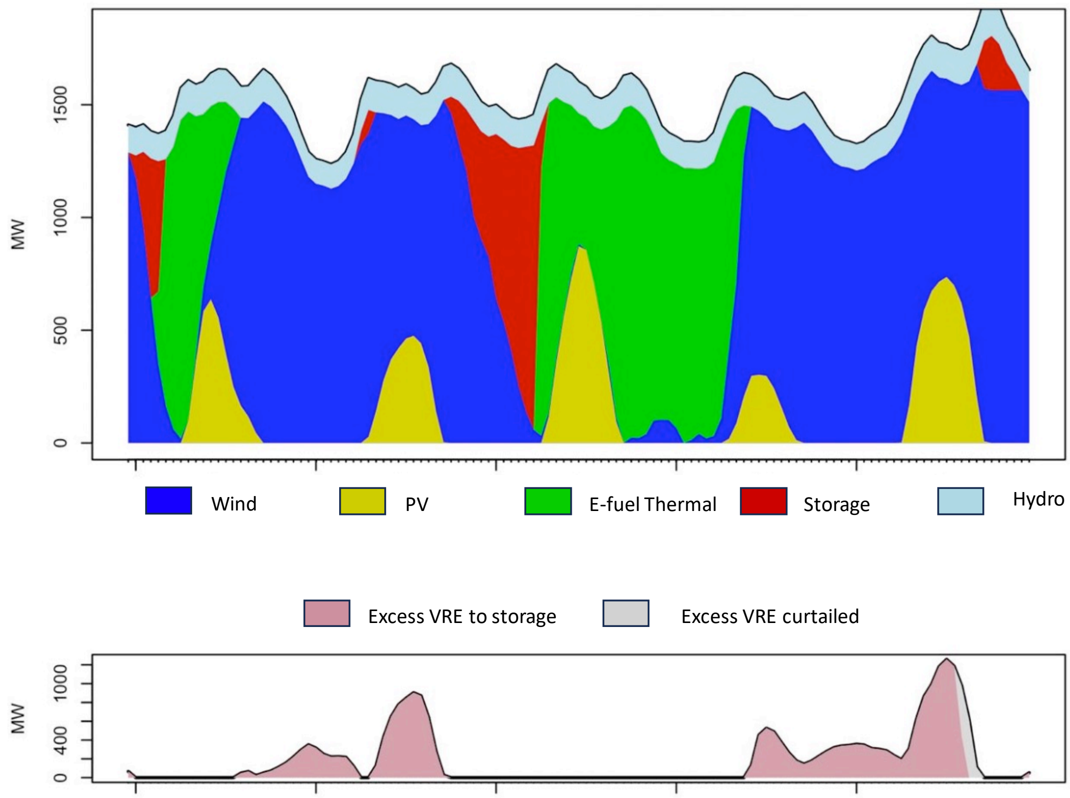

Figure A-15: Example of supply-side and BESS resources dispatch for few days in winter 2019. The bottom plot illustrates excess VRE output that is either curtailed or directed to storage recharge.

As part of this contract's deliverable, grid dispatch time series underlying the above illustrations for the year 2019 and 2022 are made available to Natural Resources Canada, along with time series for all model inputs, including: 10 windfarms, homogeneous and population-based PV for fixed and tracking systems, net load, and hydropower time series.

Conclusions & Recommendations for Future Work

The most important conclusion of this study is that 100% renewable power firmly supplying the current electric load of Nova Scotia is an economically sound proposition. When applying current or near-current (2025) technology costs, the most effective firm power configuration analyzed (with 70% onshore wind, 25% PV and 5% dispatchable e-fuel generation) could deliver firm power at a levelized cost of 10.2 C¢/kWh reliably complementing the province's existing hydropower resource (amounting to 9% of energy demand). When applying future (2050) technology costs, the firm power generation LCOE for this configuration would reduce to 6.4 C¢/kWh. For this optimum configuration, VRE and storage requirements would respectively amount to 2.1, 2.4, 1.65 and 4 GW for PV, wind, e-fuel thermal, and BESS, with 4-5 hours' worth of energy capacity for the latter.

These renewable power generation numbers are well in line with current generation costs on the Nova Scotia power grid that amounted to nearly 7 C¢/kWh in 2023 for fuel generation costs only, adding 4-5 C¢/kWh for non-fuel generation costs ([25].

Implicit storage is central to achieving such low firm power generation numbers. Without overbuilding PV and wind resources by 25-30% (hence operationally curtailing 20-25% of their energy output) firm power generation costs achieved with physical storage alone in an attempt to avoid curtailment would be 3 times higher in the above configuration, i.e., too expensive for VREs to be contemplated as a solution to displace current conventional generation.

The catalyst effect of [expensive] e-fuel thermal power generation, with a capex of C$1150/kW and an operational cost of 24 C¢/kWh, identified in the author's previous work for Switzerland, is also quite apparent through the present results. Without the supply-side flexibility procured by allowing e-fuels to provide 5% of the electricity generation mix, LCOEs would be respectively 30% higher with 2025 technology costs, and 12% higher with 2050 technology costs.
The optimal blending of PV and wind resources is also key to achieving reasonable LCOEs that would be respectively 35% and 140% higher with wind alone and PV alone. The relatively high optimum proportion of PV ranging from 20-40% energy contribution depending on the scenario analyzed was unexpected for this Canadian province given its marked winter peaking load seasonally matching the wind resource and given PV's low-capacity factor compared to wind. Reasons for this include PV's low cost compared to wind, and a tendency for less pronounced long-term (multi-day) droughts. Technology cost is also the driving reason an onshore-only configuration would be preferable for achieving the lowest possible LCOEs.
While the results of this study are encouraging, it leaves several open questions that should be addressed in follow-on work.

- Evaluating whether other Canadian provinces – with different VRE resources, different load requirements, specific hydropower, and/or nuclear availabilities – could also exhibit economically effective high VRE penetration configurations.
- Evaluating whether Nova Scotia's future load, incorporating transportation and building electrification, could continue to be economically served by a 100% renewable electricity supply. Building electrification via heat pumps in particular could affect the seasonal load profile in several ways depending on the heating source that is displaced (fuel or electric resistances) and the cost-effectiveness of long-term thermal storage solutions.
- Investigating how the deployment of cost-optimal firm power VRE configurations and their operational management could be enabled by appropriate regulations and policies (as noted by the IEA, currently prevailing market rules cannot monetize optimum firm power solutions or their optimum management – in particular, implicit storage is not a monetizable entity.)
- Assessing the role that could be played by electric vehicles (EVs), both on the demand-side by providing demand flexibility, and possibly on the supply-side where Vehicle-to-Grid (V2G) technology could complement static BESS to reduce overall firm power costs.

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GLOSSARY

AGC	Automatic Generation Control
BESS	Battery Energy Storage Systems
EV	Electric Vehicle
IEA-PVPS	International Renewable Energy Agency – PV Power Systems Program
ISO	Independent System Operator
MISO	Mid-continent Independent System Operator
NYISO	New York Independent System Operator
PJM	Pennsylvania-New Jersey-Maryland Interconnection
RTO	Regional Transmission Operator
V2G	Vehicle to Grid
VAR	Volt-Amp Reactive
VRE	Variable Renewable Energy

APPENDIX 2

Overview of Timeseries Data

In a zip directory (Timeseries.zip), we have collected constituent timeseries allowing NRCAN to visualize the elements that contribute to firmly meeting load across selected scenarios. The contents of this directory are listed in Table 1.

The filenames reflect the scenario in question with some additional and relevant information linked to the scenario and allowing differentiation. For instance, Scenario 4.1, where limits on onshore wind deployment were investigated in terms of the relevance of offshore wind with corresponding LCOE impacts has 9 separate files associated with it. Each individual file has a unique percentage of offshore in the optimization: 0-100%.

Each timeseries csv reflects the firm-power-optimal degree of curtailment/overbuilding optimized form a cost perspective. This was sought out in the optimization by seeking minimum LCOE through optimizing the degree of overbuilding using nonlinear optimization.

Table 1: contents of Timeseries.zip

Filename	MB
Scenario.1 -->:: W: 74.csv	1.4
Scenario.1.old -->:: W: 78.csv	1.4
Scenario.1.residual.load.only -->:: W: 65 :: C: 2050.2020.ATB.csv	1.4
Scenario.1.residual.load.only -->:: W: 72 :: C: 2050.2020.ATB.with.2023.storage.costs.csv	1.5
Scenario.1.thermal.load.only -->:: W: 90 :: C: 2050.2020.ATB.csv	1.6
Scenario.1.thermal.load.only -->:: W: 96 :: C: 2050.2020.ATB.with.2023.storage.costs.csv	1.6
Scenario.2.1 -->:: W: 70 :: HP.pct = 75.csv	1.4
Scenario.2.2 -->:: W: 73 :: smooth.EV = F.csv	1.4
Scenario.2.3 -->:: W: 76 :: C: 2050.2020.ATB.with.2023.storage.costs.csv	1.4
Scenario.2.4 -->:: W: 77.csv	1.4
Scenario.3.1 -->:: W: 77.csv	1.6
Scenario.3.2 -->:: W: 75.csv	1.6
Scenario.3.3 -->:: W: 78.csv	1.6
Scenario.3.4 -->:: W: 74.csv	1.6
Scenario.3.5 -->:: W: 83.csv	1.6
Scenario.3.6 -->:: W: 81.csv	1.7
Scenario.4.1 -->:: W: 63 :: onshore.pct = 0%.csv	1.4
Scenario.4.1 -->:: W: 65 :: onshore.pct = 10%.csv	1.4
Scenario.4.1 -->:: W: 66 :: onshore.pct = 30%.csv	1.4
Scenario.4.1 -->:: W: 67 :: onshore.pct = 40%.csv	1.4
Scenario.4.1 -->:: W: 69 :: onshore.pct = 60%.csv	1.4
Scenario.4.1 -->:: W: 70 :: onshore.pct = 70%.csv	1.4
Scenario.4.1 -->:: W: 71 :: onshore.pct = 80%.csv	1.4
Scenario.4.1 -->:: W: 72 :: onshore.pct = 90%.csv	1.4
Scenario.4.1 -->:: W: 74 :: onshore.pct = 100%.csv	1.4
Scenario.4.2 -->.Offshore.cost.Ratio 0.75:: W: 69 :: onshore.pct = 0%.csv	1.4
Scenario.4.2 -->.Offshore.cost.Ratio 0.75:: W: 70 :: onshore.pct = 20%.csv	1.4
Scenario.4.2 -->.Offshore.cost.Ratio 0.75:: W: 71 :: onshore.pct = 40%.csv	1.4
Scenario.4.2 -->.Offshore.cost.Ratio 0.75:: W: 72 :: onshore.pct = 70%.csv	1.4
Scenario.4.2 -->.Offshore.cost.Ratio 0.75:: W: 73.csv :: onshore.pct = 90%.csv	1.4
Scenario.4.2 -->.Offshore.cost.Ratio 0.75:: W: 74.csv :: onshore.pct = 100%.csv	1.4
Scenario.4.3 -->.Offshore.cost.Ratio 0.455735523024333:: W: 76.csv	1.4
Scenario.4.4 -->.Offshore.cost.Ratio 0.448547144821713:: W: 83.csv	1.6
Scenario.5.1 -->:: W: 74.csv	1.3
Scenario.5.2 --> E.capex: 0.5 x :: W: 76.csv	1.3
Scenario.5.2 --> E.capex: 1 x :: W: 76.csv	1.3
Scenario.5.2 --> E.capex: 2 x :: W: 76.csv	1.4
Scenario.5.3 -->:: W: 76.csv	1.5
Scenario.5.4 --> onshore.pct: 0 % :: W: 76.csv	1.3
Scenario.5.4 --> onshore.pct: 10 % :: W: 76.csv	1.4

Scenario.5.4 --> onshore.pct: 100 % :: W: 76.csv	1.3
Scenario.5.4 --> onshore.pct: 20 % :: W: 76.csv	1.3
Scenario.5.4 --> onshore.pct: 30 % :: W: 76.csv	1.3
Scenario.5.4 --> onshore.pct: 40 % :: W: 76.csv	1.3
Scenario.5.4 --> onshore.pct: 50 % :: W: 76.csv	1.3
Scenario.5.4 --> onshore.pct: 60 % :: W: 76.csv	1.3
Scenario.5.4 --> onshore.pct: 70 % :: W: 76.csv	1.3
Scenario.5.4 --> onshore.pct: 80 % :: W: 76.csv	1.3
Scenario.5.4 --> onshore.pct: 90 % :: W: 76.csv	1.3

Within the context of each individual csv, there are 20 columns, the format, units, and context of which are outlined Table 2 below.

Table 2: Columns within each scenario .csv .

Column Name	Content
datetime	Datetime in Y/M/D H:M format
l	Load served in given scenario (MW)
w	Wind generation (MW)
p	PV generation (MW)
e.push	Battery storage discharge (MW)
e.pull	Battery storage charge (MW)
e.soc	Battery storage state of charge (MWh in storage)
t.push	Thermal storage discharge (MW)
t.pull	Thermal storage charge (MW)
t.soc	Thermal storage state of charge (MWh in storage)
H2.generation	H2 generation in (T H2)
H2.drawdown	H2 generation from storage (T H2)
H2.SoC	H2 storage state of charge (T H2 in storage)
electrolyzer.dispatch	Electrolyzer operation (MW)
curtailment	Curtailed electricity (MW)
Renewables.served	Renewables directly serving load (MW)
Dispatchable.dispatch	Dispatchable Resources serving load (MW)
imports	Imports serving load (MW) - a dispatchable resource
exports	Exports (MW)
efuel	E-fuel serving load (MW) - a dispatchable resource

Overview of Plots

Using these files, three representative multi-page collections of stacked area plots have been generated, one for each individual scenario and permutation thereof reflected in the timeseries list outlined in Table 1. The three collections each reflect four-day periods in three separate seasons (winter, summer, and fall) to visually demonstrate the way in which:

(1) load is firmly met (whether storage, imports, renewables are meeting load),
(2) excess energy is used (stored, curtailed, exported, or used for H2 production),
(3) storage (H2, battery or thermal) state of charge is behaving

Each of these pdf collections has as many pages as there are scenarios (listed in Table 1), visualizing the same week within the given season and allowing for easy cross-comparison. There is an extra (50^{th}) page with a legend to allow users to identify what the colors in each of the plots represent.

APPENDIX 2

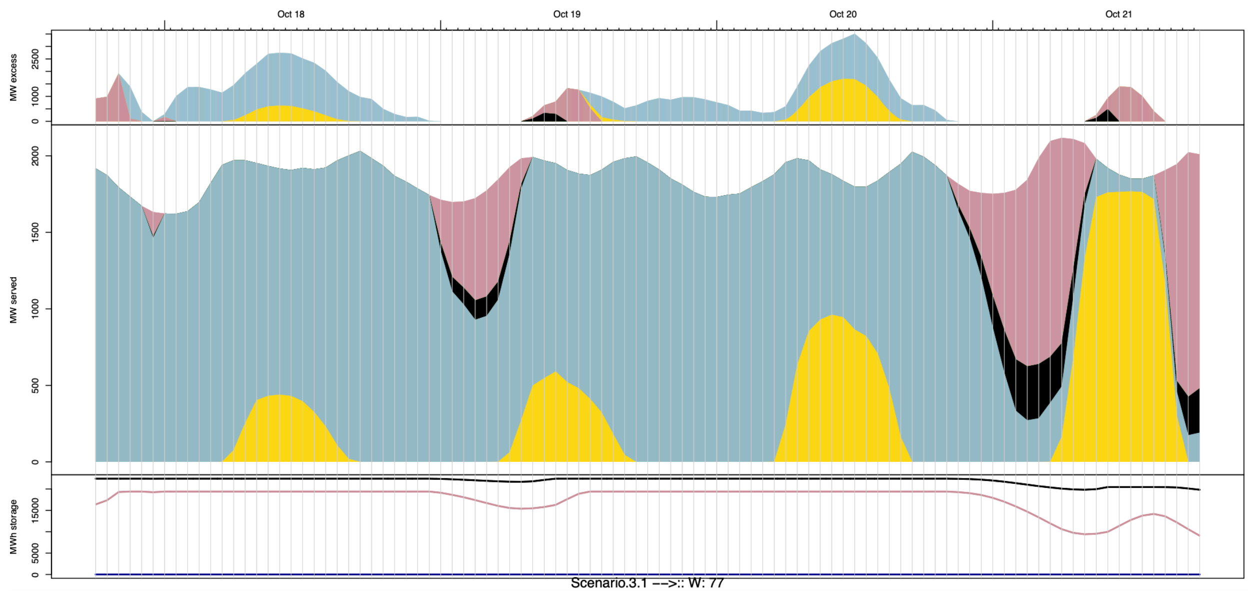

Figure 1: Sample plot from the TS.plots.fall.pdf collection.

Figure 1 shows one such plot for scenario 3.1. On each page of this document (TS.plots.fall.pdf), a plot like this is represented. This plot has three subplots.

(1) **Central subplot**: represents what is happening within the load. All units are in MW and the date is indicated at the top of the plot window with vertical grey lines separating hours.
   a. The top of the stacked area is the load within the given scenario.
   b. Light blue represents what is being met directly by wind power.
   c. Gold represents what is being met directly by solar PV.
   d. Pink represents what is being energy charging the batteries.
   e. **Black** represents thermal storage being charged.

(2) **Top subplot**: represents what is happening with excess generation. Like the central subplot, the units are in MW and the date is indicated above with vertical grey lines separating each hour.
   a. The top of the stacked area is the excess energy within the given scenario.
   b. Light blue represents wind curtailment
   c. Gold represents solar PV curtailment
   d. Pink represents what is being dispatched by the batteries.
   e. **Black** represents what is being dispatched by thermal storage.

(3) **Bottom subplot:** represents what is happening with storage state of charge. Units are in MWhs for thermal and battery storage and in Tons for H_2 (not pictured in this subplot). Same temporal framing as the previously outlined subplots. The line being flat at the bottom of the plot window indicates the storage is empty and backup is dispatching while flat at the top indicates the storage is full and curtailment is

happening. A descending line indicates storage being emptied while a rising line indicates storage being filled.

   a. **Black** represents the state of charge of the thermal storage.
   b. **Pink** represents the state of charge of the batteries.

Text beneath the subplots indicates the scenario and permutation thereof, in the case of Figure 1, Scenario 3.1 “Base and include thermal storage at the conservative costs (use the low Phase 1 study battery costs)” with optimized wind at 77% and curtailment optimized at 18.1% as indicated by the csv containing all of the results outlined earlier in the report.

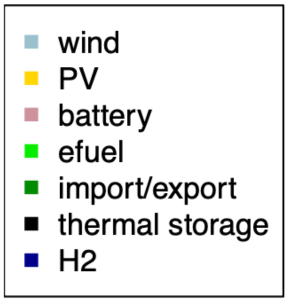

Figure 2: Legend to assist with plot interpretation.

Figure 2 indicates the extracted full legend, some elements of which are not pictured in Figure 1 but which are present in other pages of the collection. Notably, **import/export** (represented in the central and top subplots), **H2** (represented in the top and bottom subplots), and **e-fuel** (represented in the central and top subplots). Note that the legend is also available on the last page of each of the three seasonal plot collections.