2021 Economic Study: Future Grid Reliability Study Phase 1

Appendix C: Resource Adequacy Results

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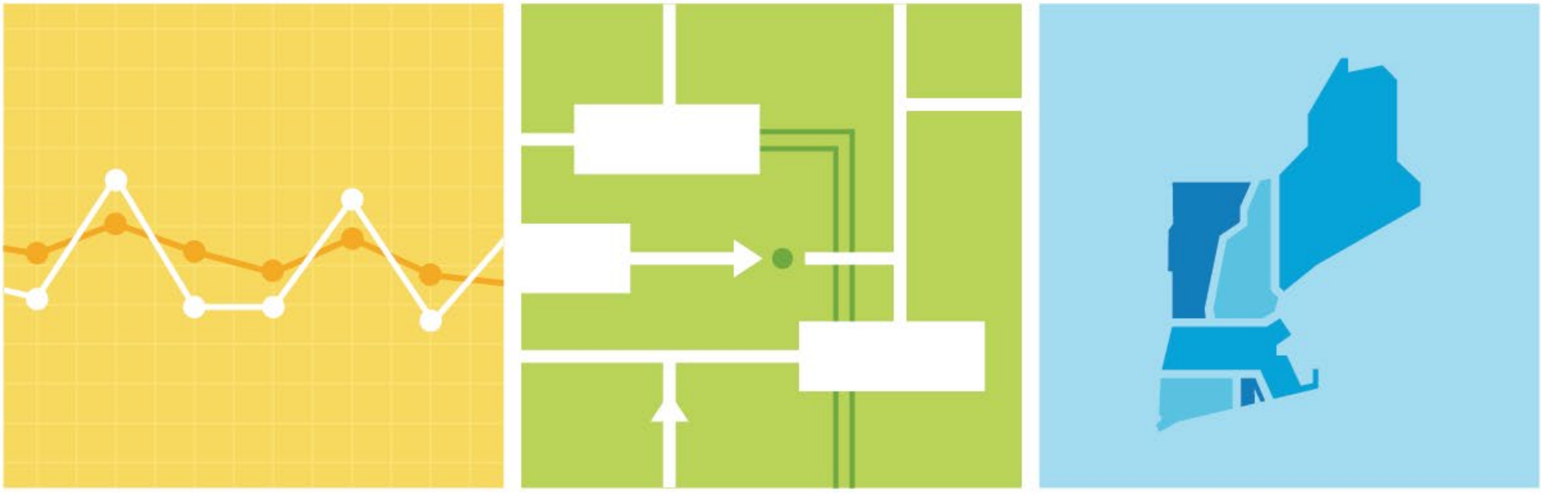

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Section 1: Introduction and Background

1.1 Background

In recent years, lawmakers across the New England states have enacted ambitious legislation designed to dramatically reduce greenhouse gas emissions over the next several decades. Five of the six New England states have committed to reducing their carbon dioxide emissions by at least 80% in the coming years, and the quantity of wind and solar resources supplying electricity to our power grid is expected to grow exponentially in order to meet these goals. As electrification of heating and transportation rapidly accelerates, demand on the grid will also increase.

In order to assess and evaluate this transformed future grid, the "Transition to Future Grid" Initiative was proposed by NEPOOL at the March 2020 NEPOOL Participants Committee, with ISO New England directed to conduct the study. The study's objective was to assess and discuss the future state of the regional power system in light of current state energy and environmental policies. Beginning in April 2020 and culminating in March 2021, the joint Markets & Reliability Committees of NEPOOL met to discuss and define a scope of work for the initiative, now known as the **Future Grid Reliability Study,** or the FGRS.

As part of the FGRS, four Scenarios for a future grid, and a set of "sub" Scenarios, or Alternatives, were used to represent various possible future grid configurations. These Scenarios will be explained in-depth in Section 2. ISO New England conducted three main types of analysis on these Scenarios: **production cost (Appendix A)**, **ancillary services (Appendix B)** and **resource adequacy (this report, Appendix C)**.

1.2 Study Objective

The resource adequacy analysis of the FGRS simulated the reliability of a future renewable-dominant New England grid using Resource Adequacy Screen (RAS) and Probabilistic Resource Availability Analysis (PRAA).

RAS and PRAA help analyze system reliability by considering the uncertainties associated with the output of intermittent renewable resources due to weather risks, interactions between different types of resources, and load conditions in both the summer and winter peak load periods as well as shoulder seasons. Resource adequacy examines the frequency and duration of reliability risk events, calculates loss-of-load probability, and identifies risk trends. Resource adequacy analysis helps anticipate conditions under which there may not be sufficient resources to meet the reliability criterion, typically expressed as a Loss of Load Expectation (LOLE) criterion, predicts when those conditions might occur, and assesses whether there may be a need for certain quantities and categories of resources in order to meet this reliability criterion.

The RAS simulations of the FGRS help identify a Scenario's associated Installed Capacity Requirement (ICR) under the study baseline market rules as of December 2020. ICR determines the capacity based on existing and expected resources needed to meet the region's resource adequacy criterion of disconnecting firm load customers no more often than 0.1 days per year LOLE[1]. It is the quantity of resources that the ISO would need to procure through its Forward Capacity Market (FCM) auctions to meet the resource adequacy criterion. The RAS simulations follow the

[1]LOLE is a Reliability criterion. For every hour of every day studied, probability of insufficient resources to serve load can be quantified. The sum of loss-of-load probabilities over the study period is called LOLE.

methodology and resource assumptions associated with the current FCM rules and guidelines as described in Market Rule 1, Section 12, with one exception: resources are modeled with both their summer and winter Qualified Capacity[2] instead of just their summer Qualified Capacity as is currently done for ICR calculations. ICR is calculated as part of the Forward Capacity Market (FCM) and used as an input into the Forward Capacity Auction (FCA) for each capacity commitment period (CCP). In short, the ICR is a metric that is useful for determining the quantity of resources necessary for system reliability, given their unique characteristics.[3]

The RAS analysis in the FGRS helps explore how the large penetration of renewable resources and accompanying regional electrification efforts assumed in many of the study Scenarios may affect New England's ICR. Two particular objectives of the FGRS were to identify whether current resource modeling approaches and methodologies are appropriate for modeling the future renewable resource mix, and what additional resources would be required for this mix to meet the reliability criterion.

The majority of input assumptions and modeling for RAS and PRAA in the FGRS were similar, except for the ways in which they modeled wind and solar resources. PRAA simulates Scenarios by modeling hourly variations of wind and solar resources probabilistically according to years of assumed historical weather conditions. RAS models these resources according to average performance based on the predetermined reliability hours stipulated by the current FCM rules and captured in the resources' Qualified Capacity. The goal of PRAA in the FGRS was to analyze how modeling hourly output of solar and wind renewable resources may change overall system resource needs. RAS has traditionally been adequate for modeling resources mixes where renewables form a small percentage of total resources. PRAA, however, allows for a more nuanced picture of a future where renewables dominate the resource mix and some existing fossil fuel powered resources are retired.

This appendix summarizes the study Scenarios and their associated assumptions, describes the simulation approaches used to conduct the Resource Adequacy Screen and the Probabilistic Resource Availability Analysis, documents the simulation results and offers observations and recommendations based on those results.

[2] Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

[3] For more on ICR, see the ICR Reference Guide.

Section 2: Scenario Assumptions

The first half of this section details the main and alternative Scenarios of the FGRS and the assumptions that were common to all analyses. This is followed by a description of the Scenarios and assumptions specific to the RAS and PRAA.

2.1 Main Scenarios

The final set of FGRS Scenarios included 32 iterations, each evaluating a different set of assumptions. Though none of these Scenarios should be interpreted as a complete forecast of a future grid, trends and relationships between Scenarios can provide an idea of how different assumptions will affect the planning and operation of a future grid.

These 32 iterations included four "main" Scenarios, shown in Table 2-1. Each main Scenario represented a different view of the future grid, with varied assumptions about generator retirements, wind and solar additions, new transmission lines, and other properties. These main Scenarios were numbered zero through three.

Table 2-1: Load and Resource Matrix for Scenarios studied in the FGRS

Resource	Scenario 1 (Peak, MW)	Scenario 1 (Energy, TWh)	Scenario 2 (Peak, MW)	Scenario 2 (Energy, TWh)	Scenario 3 (Peak, MW)	Scenario 3 (Energy, TWh)
Gross Summer Peak	33,707	172.6				
Gross Winter Peak	27,970					
Energy Efficiency	6,777	37.7	6,777	37.7	6,777	37.7
Transportation Electrification	1,817	7.3	3,578	17.9	9,956	40
Heating Electrification	5,214	9.6	2,991	5.4	22,250	38.9
Total Summer Peak [1]	28,060	151.3	30,316	158.2	35,711	213.8
Total Winter Peak [1]	25,767		26,971		43,816	
Total Minimum Load [1]	11,202		11,863		14,102	
BTM Solar [2]	7,681	10.3	11,899	15.6	12,671	16.9
Net Summer Peak [3]	26,555	141.1	28,317	142.7	33,162	196.9
Net Winter Peak [3]	25,767		26,971		43,814	
Net Minimum Load [2,4]	8,562		6,745		8,427	
Onshore Wind [5]	2,582	8.6	2,747	8.6	2,585	8
Offshore Wind [5]	8,029	32.7	8,029	32.4	16,662	69.8
Utility Scale Solar [5]	8,104	9.7	8,820	10.4	15,467	18.8
Battery Storage	2,000	-	3,940	-	600	-

[1] Total Peak load is the max coincident peak value for summer and winter after profiles are combined.
[2] Net Peak load is the total load after the BTM solar profile is added to the load profile.
[3] BTM PV is a resource assumption but added to this slide to show 'net' load profile effect.
[4] BTM PV is a curtailable resource, final Net Min Load could be higher.
[5] Energy values are all pre-curtailment.

2.1.1 Scenario 0 (Baseline Decarbonization)

Scenario 0 is also referred to as the reference case or **Baseline Decarbonization** case. It is a projected version of the current system in the year 2040, assuming current growth trends based on the 2021 CELT Report. Scenario 0 consisted of extensions of current ISO trends and forecasts for various resources, with generator retirements and additions through Forward Capacity Auction (FCA) 15 - the ISO's three-year-out installed capacity market. Scenario 0 included ~3.3 GW (note all values given are nameplate values) of offshore wind farms with state contracts at the end of 2020. The model also contained the contracted New England Clean Energy Connect (NECEC) tie-line. Scenario 0 did not include any additional heating or transportation electrification beyond extrapolating the 2021 CELT electrification forecasts to 2040. The CELT heating electrification load in this Scenario represented 4.9% of the total load energy, while the CELT transportation electrification[4] load represented 6.8% of the total load energy. Other Scenarios included additional heating and transportation electrification load on top of the CELT load. Overall, Scenario 0 was the most similar to the current day ISO system, with the lowest penetrations of wind and solar, minimal retirement of generators, and CELT baseline adoption of heating and transport electrification.

2.1.2 Scenario 1 (Moderate Decarbonization)

Scenario 1 assumptions were derived from 2020's Economic Study: Interregional Storage's Capability to Facilitate the Effective Use of Clean Energy Resource requested by National Grid. That 2020 Economic Study built upon a 2019 Economic Study request by NESCOE. Scenario 1, also known as the **Moderate Decarbonization** case, modeled a moderate penetration of renewable energy, with moderate heating and transportation electrification. Scenario 1 assumed the retirement of all generators that have announced a planned retirement, along with the retirement of all remaining coal units and 75% of the remaining oil units. To compensate for these retirements, Scenario 1 included 8 GW of offshore wind and 2 GW of BESS units. The Scenario increased the total solar nameplate capacity to 15.8 GW. Additional heating and transportation load was 9.6 TWh (5.8% of the total load) and 7.3 TWh (4.4% of the total load) respectively. Scenario 1 utilized an import-priority threshold price order, where wind and utility solar resources were curtailed before tie-line imports.

2.1.3 Scenario 2 (Import-Supported Decarbonization)

Scenario 2 assumptions were derived from Eversource's (unreleased) Grid of the Future Study. Scenario 2, or the **Import-Supported Decarbonization** case, assumed similar properties to Scenario 1, but with a number of adjustments. Scenario 2 retired 8.4 GW of fossil fuel units, including all remaining coal and oil. For additional resources, Scenario 2 included 8 GW of offshore wind, 4 GW of BESS units plus a new 1 GW tie-line with Hydro Québec. Total solar nameplate was 20.3 GW. More emphasis was placed on the electrified transportation load than the electrified heating load, with 3.3% of the total load coming from additional electrified heating and 10.8% of the total load coming from additional transportation electrification. Instead of Import Priority threshold price order, a REC-Inspired (renewable energy credit – an outside electric market payment certain clean resources can earn) threshold order was used where tie-lines were curtailed before wind and solar resources.

2.1.4 Scenario 3 (Deep Decarbonization)

Scenario 3 is a winter peaking system and its assumptions were derived from the "All Options Pathway" of the Massachusetts 2050 Deep Decarbonization Roadmap Study and imagined heavy

[4] Transportation electrification refers to modeled electric vehicles (automobiles) only

renewable penetration and electrification loads. Scenario 3, also known as the **Deep Decarbonization** case, modeled all retirements through FCA 15 plus all remaining coal, oil. Refuse-burning plants were reduced to
5-8% of their nameplate capacity. Renewable additions were significant, with 16 GW of offshore wind (a doubling from Scenario 2), 28 GW nameplate of solar (a 38% increase from Scenario 2), 600 MW of BESS plus an additional new tie-line with Hydro Québec. Both heating and transportation electrification load additions were substantial. Scenario 3 load was borrowed from the Massachusetts 2050 Deep Decarbonization Roadmap Study. This data originally used the 2012 weather year but was recast into the 2019 weather year for the FGRS.

While all other Scenarios modeled import-only transmission lines, Scenario 3 assumed bi-directional lines during times of surplus renewable energy, allowing New England to export power to New York, New Brunswick, and Québec after curtailing import power. The threshold order pricing in Scenario 3 curtailed renewables only after maximum export capability was reached. Finally, Scenario 3 introduced interchange with New York, while other Scenarios only assumed imports from Québec and New Brunswick. New York imports/exports were not modeled in Scenarios 0, 1, and 2, or in previous Economic Studies. In prior studies, this was to avoid "relying" on New York to serve New England's load when these two regions could be expected to have similar supply and demand conditions. The Massachusetts 2050 Deep Decarbonization study assumed an increase in interconnections in the northeastern United States and, notably, between New England and New York. The results of that study showed significant interchange between New England and New York driven by additional paths to energy storage resources in the Québec reservoirs. This meant that energy could flow from New England to Québec via New York and also into New England from Québec across the New York system.

2.2 Alternative Scenarios

In addition to the main Scenarios, there were several alternative "sub" Scenarios applied to some or all of the main Scenarios. Table 2-2 overviews the alternatives and which main Scenarios they were applied to. The alternatives were named A-G, and were applied to Scenarios 1, 2, and 3 unless otherwise noted below. After running each alternative, the output metrics were compared to the base Scenario to determine the effects of the changes in assumptions.

2.2.1 Alternative A

Alternative A added an unconstrained bi-directional high-voltage direct current (HVDC) tie-line from Québec to Northeast Massachusetts (NEMA), and Québec hydro reservoirs were available for use to function as long-term energy storage. To avoid curtailment, surplus renewable energy could be exported out of New England and reimported later to displace fossil-fuel generation. Threshold prices for triggering the export of energy were defined in order to model the new storage opportunity. The purpose of modeling this new tie-line and storage was to decrease curtailment of renewable resources and displace fossil fuel generation with the reimported energy. Alternative A explored the benefits of increased and bi-directional interregional power exchange between New England and Québec.

2.2.2 Alternative B

Alternative B explored utilizing a portion (25%) of 8 million electric vehicle batteries as vehicle-to-grid 100 GW storage, also called EV Flex. This concept allows vehicles to both charge and discharge to the grid, rather than only charge. The EVs in this alternative were distributed throughout New England proportional to existing load distributions. The EV batteries would provide price arbitrage to compensate the owners for the increased battery cycling. It was theorized that these batteries would help reduce renewable curtailment and displace fossil fuel generation. Alternative B was only applied to the winter peaking Scenario 3.

2.2.3 Alternative C

Alternative C retired all remaining nuclear generation in New England, removing ~3.4 GW of high-capacity factor carbon-free capacity. New England depends on a relatively small number of nuclear generators for a large portion of its energy. Nuclear energy is used as base generation, meaning it provides a steady amount of energy throughout the day and throughout the year. As of today, each unit of the New England nuclear fleet has been in service for between 35 and 50 years and each of these units will someday retire. Alternative C was identified to show what the New England grid would look like without these resources.

2.2.4 Alternatives D & E

Alternative D retired all fossil fuel generation and added significant amounts of wind, solar, and BESS units. The resulting grid was a carbon-free system, with only nuclear and hydro units remaining from the old fleet. The Alternative D fleet reflected the goal of full decarbonization, as there would be no emissions in this alternative Scenario. Alternative E had the same assumptions as Alternative D, except the offshore wind interconnection points were redistributed to reflect theoretical offshore grids. Connecting significant amounts of offshore wind using only Southeast Massachusetts (SEMA), Connecticut (CT), and Rhode Island (RI) zones as interconnection points is expected to cause major congestion. This Scenario's objective was to analyze different impacts of onshore and offshore grids by bypassing existing constraints of the onshore grid to deliver the offshore wind to load centers as suggested in the 2020 Brattle/GE/CHA study. Alternative E was applied to Scenarios 1, 2 and 3.

2.2.5 Alternative F

Alternative F changed the threshold prices to 'import-priority' order. It is uncertain how future REC prices will affect the order in which resources are more and less economical to run. Significant penetrations of wind and solar will result in periods of oversupply, and the dynamics of RECs will determine which resources can afford to continue operations when LMPs become negative. Scenario 1's assumption of import priority prices may reflect how the future system operates by illustrating the incremental utilization of wind and solar after imports on existing interconnections are fully committed. Modeling both methods of priority price orders allows stakeholders to understand what LMPs and curtailment figures would look like under both possible Scenarios. Alternative F was only applied to Scenario 2 and Scenario 3, as Scenario 1 already modeled 'import-priority' order.

2.2.6 Alternative G

Alternative G disabled all tie-lines with New York. Using historical flows with New York may not accurately portray a future grid. For example, if New England has a significant excess of solar power in the middle of the day, New York will likely be experiencing similar conditions. Using historical import/export assumptions could model New England's grid as having sufficient power to meet demand when this power may not be available in 2040 at the times it was in past years. Alternative G was designed to isolate the impact of the New York import/export assumption on the results. Alternative G was only applied to Scenario 3.

2.2.7 Additional "Unbalanced" Scenarios

The main Scenarios assumed that the pace of electrified load increase and renewable energy development would be comparable. Two additional Scenarios explored what might happen if one outpaced the other or were "unbalanced." Scenario 2, load 3, resource 2 (S2_L3R2) mixed and matched assumptions from different Scenarios, taking the Scenario 3 EV and heating loads and placing them into a Scenario 2 case. The resulting Scenario had high electrification loads with moderate penetrations of renewables. Another Scenario, Scenario 2, load 2, resource 3 (S2_L2R3) took the Scenario 2 assumptions and replaced the wind, solar, BESS, and generator retirement assumptions with Scenario 3 levels. The resulting model had high penetrations of renewable resources with only moderate electrified loads. These cases were meant to show the effects of uneven advancements in the clean energy transition, as it is unclear whether New England will maintain a balance between development of electrified loads and renewable resources.

Table 2-2: Application of Alternative Scenarios to Main Scenarios

Alt	Description	S1	S2	S3
A	**Energy Banking with Canada**	**X**	**X**	**X**
B	**Vehicle-to-Grid**			**X**
C	**Nuclear Retirements**	**X**	**X**	**X**
D	**100% Carbon-free Energy**	**X**	**X**	**X**
E	**Alt. D with Offshore Grid**	**X**	**X**	**X**
F	**Curtailment Priority**		**X**	**X**
G	**No NY Interchange**			**X**

2.3 Alternative Scenarios

The RAS and PRAA did not cover all the study scenarios covered by the production cost and ancillary services analysis conducted for the FGRS. In addition to the main Scenarios, the RAS and PRAA covered selected alternative "sub" Scenarios and applied them to some of the main Scenarios. Although seven alternative scenarios (named A-G) were developed for the FGRS, only three alternatives (B, C and D) were utilized in the RAS and PRAA. Table 2-2 tabulates main Scenarios and their associated alternative Scenarios, followed by a description of the Alternative Scenarios for RAS and PRAA. The Table also indicates whether the analysis considered regional transmission constraints, which is described further in section 4.5.2.

Table 2-3: Alternative Scenarios and Sensitivities Applied to RAS and PRAA Main Scenarios

Alternative Scenario	Description	Resource Adequacy Screen			Probabilistic Resource Availability Analysis		
		S1	S2	S3	S1	S2	S3
Base	Main Scenarios	U	U	U	C&U	C&U	C&U
A	Energy Banking with Canada						
B	Vehicle-to-Grid			U			C&U
C	Nuclear Retirement				C&U	C&U	C&U
D	100% Carbon-free Energy				C&U	C&U	C&U
E	Alt. D with Offshore Grid						
F	Curtailment Priority Order						
G	No NY Interchange						
P0	Perfect Capacity						U
P1	Resources Retained for Reliability and CTs						U
P2	BESS Units Only						U
P3	Only OFSW Resources						U
P4	Only ONSW Resources						U
P5	Only PV Resources						U
P6	ONSW and BESS Resources						U
P7	Scaled PV/Wind/BESS Resources Mix from Pathways Study						U
P8	P7 + 3000 MW Dispatchable Resource Scaled PV/Wind/BESS Resources Mix from Pathways Study						U

C= Constrained Transmission

U = Unconstrained Transmission

2.3.1 Alternative B

Alternative B explored utilizing a portion (25%) of 8 million electric vehicle batteries as vehicle-to-grid storage, also called EV Flex. This concept allows vehicles to both charge from and discharge to the grid, rather than only charge. The EVs in this alternative were distributed throughout New England proportional to existing load distributions. The EV batteries would provide price arbitrage to compensate the owners for the increased battery cycling. It was theorized that these batteries would help reduce renewable resource curtailment and increase displacement of fossil fuel generation. Alternative B was only applied to Scenario 3 of RAS and PRAA.

2.3.2 Alternative C

Alternative C retired all remaining nuclear generation in New England, removing ~3.4 GW of high-capacity factor carbon-free capacity. New England depends on a relatively small number of nuclear generators for a large portion of its energy. Nuclear energy is used as base generation, meaning it provides a steady amount of energy throughout the day and throughout the year. As of today, each unit of the New England nuclear fleet has been in service for between 35 and 50 years and each of these units will someday retire. Alternative C was analyzed to show what the New England grid would look like without these resources. Alternative C was applied to Scenarios 1, 2 and 3 of PRAA.

2.3.3 Alternative D

Alternative D retired all fossil fuel generation and added significant amounts of wind, solar, and BESS units. The resulting grid was a carbon free system, with only nuclear and hydro units remaining from the old fleet. The Alternative D fleet reflected the goal of full decarbonization, as there would be no emissions in this alternative Scenario. Alternative D was applied to Scenarios 1, 2 and 3 of PRAA.

Because internal transmission constraints were not represented, Alternative E would be very similar to Alternative D, and it was not analyzed.

2.4 Special Proxy Resource Mix Scenarios for PRAA

ISO New England conducted additional PRAA simulations using proxy resource scenarios associated with Scenario 3 to explore different types of resource mix to meet LOLE criterion. Nine Proxy Scenarios (Proxy 0 – 8) were conducted. The following describes these Scenarios:

2.4.1 Proxy 0 – Perfect Capacity

A perfect capacity scenario assuming 0% EFORd and no maintenance outages was designed to identify the minimum MW of resources Scenario 3 would need to meet the reliability criterion under perfect resource availability conditions. It provides a baseline for comparing the other proxy Scenarios.

2.4.2 Proxy 1 - Resources Retained for Reliability and CTs

This proxy Scenario was designed to explore what might result if resources retired under Scenario 3's initial assumptions were instead included in the simulation.

2.4.3 Proxy 2 - BESS Units Only

Scenario 3, P2 explored the possibility of using BESS units to meet reliability criterion.

2.4.4 Proxy 3 - Only Offshore Wind Resources

This proxy Scenario was designed to evaluate what impact offshore wind resources (OFSW) might have on the reliability metrics of Scenario 3.

2.4.5 Proxy 4 – Only Onshore Wind Resources

This proxy Scenario was designed to evaluate what impact onshore wind resources (ONSW) might have on the reliability metrics of Scenario 3.

2.4.6 Proxy 5 - Only PV Resources

This proxy Scenario was designed to evaluate whether the reliability concerns of Scenario 3 could be solved through solar resources alone.

2.4.7 Proxy 6 - Onshore Wind and BESS Resources

Scenario 3, P6 explored the possibility of solving Scenario 3's reliability challenges using a combination of ONSW and BESS. As compared to Pathways Study: Evaluation of Pathways to a Future Grid Scenario 3 had similar amounts of OFSW but less ONSW and BESS, so this proxy case involved increasing ONSW and BESS alone to better mimic Pathways Status Quo and explore the impact of adjusting only these resources.

2.4.8 Proxy 7 - Scaled PV/Wind/BESS Resources Mix from Pathways Study

As with Scenario 3, P6, Scenario 3, P7, also known as **Resource-Adequate Deep Decarbonization**, adapted Scenario 3 to better match the Pathways Study Status Quo mix. However in P7, Scenario 3's renewable and BESS mix was replaced with the mix from the Pathways Study Status Quo and was then scaled up to meet reliability criteria.

2.4.9 Proxy 8 - P7 + 3000 MW Dispatchable Resource: Scaled PV/Wind/BESS Resources Mix from Pathways Study

This proxy Scenario was similar to the base Scenario 3, P7 proxy Scenario, but replaced ~20.8 GW of the Scenario 3, P7 renewable and BESS resource capacity mix with 3,000 MW of dispatchable resource capacity. These dispatchable resource proxy units were modeled using a similar outage rate as combustion turbines.

2.5 Modeling Assumptions

2.5.1 Load Modeling

The RAS and PRAA simulations relied on a load model similar to the model used in ICR calculations. Various components of the load model were designed to capture the impact of particular factors that have an impact on load. The base 2040 study year loads did not account for reductions associated with behind-the-meter photovoltaic (BTM PV), which were modeled as a separate load component, or reductions from Passive Demand Capacity Resources (energy efficiency), which are modeled as resources. In addition, the base loads excluded the additional load associated with forecasts of transportation electrification, which were modeled as separate load component, but include the additions associated with forecasts of heating electrification load (e.g., air-source heat pumps (ASHP)). To reflect the load forecast uncertainty associated with weather, 25-year weather history data was included, with adjustments for the winter months to account for additional volatility associated with the assumed ASHP load. These modifications helped reflect the associated load forecast uncertainty.

The 2040 monthly peak loads were developed based on monthly peaks and the growth of those peaks between the last two years (2029 and 2030) assumed in the 2021 CELT. These loads were then extrapolated to the year 2040. Using 2019 as a base weather year, monthly peaks were scaled to the 50/50 monthly peaks[5] for 2040. The winter peak of January and the summer peak of August were scaled to the 80/20 peak loads[6] to reflect seasonal peaks. To provide a clean transition between months, a linear feathering method was applied to each hour between monthly peaks. This feathering scaled the hourly loads from monthly peak to monthly peak to prevent a potential sudden jump in load between the hours of one month and the hours of the next month.

To develop the hourly load shape, ISO New England used the 2002 summer (year of a heat wave) hourly peak loads and 2013-2014 winter (year of a cold snap) hourly peak loads to develop a composite hourly load shape for 2040. The load reduction associated with BTM PV reflected the profiles used in FGRS production cost simulations and the hourly profiles by Regional System Plan (RSP) subarea to create a composite hourly load profile reflecting the 2002 summer and 2013-2014 winter weather. The hourly PV production uncertainty was modeled by randomly selecting a daily profile within a 7-day window (+/- 3 days) for the base load day under study. The hourly load of the heating load component associated with the ASHP was scaled to the adoption target specified for each Scenario of the study. The transportation electrification load was modeled as an addition to the base load using a deterministic hourly charging profile provided for each Scenario.

2.5.2 Resource Modeling

2.5.2.1 Conventional Thermal Generation Resources

The Scenarios reflected all existing resources qualified for FCA 16, while reflecting the assumed retirements specific for each Scenario. The resources were modeled with their seasonal Qualified Capacity ratings, EFORd and maintenance requirement availability parameters.

2.5.2.2 Wind Resources

For RAS, the wind resources were modeled deterministically using the ICR modeling methodology for Intermittent Power Resources (IPR), which were their seasonal Qualified Capacity (QC) ratings at 100 percent availability. The ratings for existing wind resources were consistent with the QC ratings for FCA 16, while the ratings for future wind resources were determined based on market rule (Market Rule 1, Section 13) as of December 31, 2020 for determining ratings for new wind resources. The on-shore/off-shore nameplate ratings of wind resources were de-rated to achieve a QC equivalent. The percentage de-rate factors for on-shore wind summer/winter were 22%/42% respectively, whereas for off-shore resources the de-rate factors were summer/winter 30%/60% respectively. These de-rate factors were based on the historical qualification of these wind resources in FCM.

PRAA modeled the wind resources probabilistically using aggregated hourly profiles by Regional System Plan (RSP) subarea. The simulations used hourly profiles consisting of 10 years (2001, 2005, 2008, 2011, 2012, 2014, 2015, 2017, 2019 and 2020). Wind profiles for these years were based on profiles developed by DNV and selected to be conservative because they had the lowest average output during the top 10 load hours each day over the course of the year.

[5] 50/50 peak forecast is a value within the distribution that peak demand has a 50% probability of exceeding

[6] 80/20 peak forecast is a value within the distribution that peak demand has a 20% probability of exceeding

2.5.2.3 PV Resources (In front of the meter resources)

For RAS, the PV resources were modeled deterministically using the ICR modeling methodology for IPR, which is their seasonal Qualified Capacity rating at 100 percent availability. The ratings for existing PV resources were consistent with the QC ratings for FCA 16 while the ratings for future PV resources were determined based on market rule (Market Rule 1, Section 13) as of December 31, 2020 for determining ratings for new PV resources. The solar resources nameplate ratings were de-rated to achieve a QC equivalent. The percentage de-rate factor applied was 40%. These de-rate factors were based on the historical qualification of PV resources in FCM.

PRAA modeled the PV resources probabilistically using the same methodology for modeling the BTM PV as described in Section 2.5.1.

2.5.2.4 Intermittent Power Resources

For RAS and PRAA, non-wind and non-PV IPR are modeled deterministically using the ICR modeling methodology consisting of seasonal Qualified Capacity ratings at 100 percent availability.

2.5.2.5 Passive Demand Resources

For RAS and PRAA, the passive demand resources were modeled using their projected seasonal peak load reduction values by RSP subarea at 100 percent availability as defined for FCA 16.

2.5.2.6 Active Demand Resources

For RAS and PRAA, the active demand resources were modeled deterministically using their Qualified Capacity ratings and EFORd and maintenance requirements availability parameters of FCA 16.

2.5.2.7 Battery Storage Systems (BESS)

For RAS and PRAA, BESS were modeled using the same modeling methodology as used for FCA 16 ICR calculations. For RAS and PRAA, BESS were modeled using the same modeling methodology as used for FCA 16 ICR calculations. BESS Stand-alone were modeled using their class model with a round trip efficiency of 84 percent, one cycle per day. The BESS IPRs were represented by their seasonal Qualified Capacity and assumed 100 percent available.[7]

2.5.2.8 Capacity Imports

For RAS and PRAA, the NECEC capacity import is modeled at 1,200 MW of Qualified Capacity similar to modeling thermal resources. Additional import capacity from Quebec, New Brunswick and New York is Scenario-specific and modeled similar to a thermal resource.

2.5.2.9 Tie Benefits

For RAS, the tie reliability benefits were assumed to be the same as those calculated for the FCA 16 ICR calculations for all the Scenarios. The annual values used were 1,065 MW for Quebec ties, 478 MW for Maritime (New Brunswick) ties, and 287 MW for New York ties, totaling 1,830 MW.

[7] ICR Reference Guide: Link icr-reference-guide.pdf (iso-ne.com). Section 5.7

For PRAA, seasonal tie reliability benefits were assumed for the Scenarios. Table 2-4 summarizes the assumptions.

Table 2-4: Summer and Winter Tie Benefits Assumptions for PRAA Scenarios

	Quebec Ties (MW)	Maritimes Ties (MW)	New York Ties (MW)	Total (MW)
Summer*	1,065	478	287	1,830
Winter**	287	72	287	646

*Summer reflects the months of June through September
** Winter reflects the months of October through May

2.5.2.10 Load Relief from Operating Procedures

For RAS, load relief obtainable from implementing Operating Procedure No. 4, Action During a Capacity Deficiency (OP 4) were assumed to be 1% of the net seasonal peaks.

For PRAA, no load relief from OP 4 implementation was assumed to reflect the increase uncertainty and challenges associated with the high penetration of intermittent resources in the operation of the grid.

2.5.2.11 Minimum System Operating Reserve Requirement

For RAS and PRAA, it was assumed that the system would hold 700 MW of minimum operating reserve requirement at all times.

2.5.2.12 Transmission Interface Limits

For RAS and PRAA simulations to identity the quantity of resources needed to meet the 0.1 days/year LOLE criterion, internal transmission interface limits were not enforced. In other words, all these simulations assumed unlimited transmission transfer capability within New England (a copper sheet approach). For RAS and PRAA simulations to identify the impact of transmission constrained, internal transmission interface limits[8] were enforced.

2.5.2.13 Proxy Resources

For RAS and PRAA, the first 900 MW of capacity needed for the system to meet the 0.1 days per year LOLE would rely on the installation of 150 MW of stand-alone grid connected BESS. Capacity

[8] For internal transmission interface limit assumptions, please see Appendix I of the April 14 2021 presentation to the PAC at: https://www.iso-ne.com/static-assets/documents/2021/04/a8_2021_economic_study_request_assumptions_part_1_rev2_clean.pdf

needs above the 900 MW would be 100 MW natural gas fired combustion turbines with NERC GADS average availability parameters.

Section 3: Analysis Methodology

3.1 Resource Adequacy Simulations

GE MARS uses a sequential Monte Carlo simulation to compute the reliability of a power system comprised of several interconnected areas and their respective generation and load. This process simulates the year repeatedly to evaluate the impacts of a wide range of possible random combinations of generator outages. GE MARS models the transmission system using transfer limits (constraints) on the interfaces between interconnected areas. Chronological system histories are created by combining a set of randomly generated generator operating histories and inter-area transfers with hourly chronological loads. For each hour of the year, the program computes the isolated area margins based on the available capacity and demand of each area. It then transfers capacity from resources to loads in the most efficient way possible given the transmission path and associated limitations (a transportation algorithm). This helps determine the extent to which areas with a capacity surplus can assist areas with the capacity deficit, subject to the available transmission transfer constraints between those areas. During its simulation of each hour, the program collects statistics related to reliability indices and proceeds to the next hour. After simulating all of the hours of the modeled year, the program then computes reliability indices for that year and tests whether additional sampling of different probability outcomes will alter the expected results in a convergence test.[9] If this additional sampling produces results outside of the acceptable level (i.e., the simulation has not converged to an acceptable criterion), the program replicates another version of the current study year; otherwise, it moves on to the next study year.

RAS and PRAA base scenario simulations modeled New England as a single-bus system, and did not therefore model internal transmission constraints. However, some sensitivities that recognize the impact of the transmission system were incorporated by modeling the thirteen subareas of the Regional System Plan with assumed transmission interface constraints.

3.2 Resource Adequacy Criterion

Both RAS and PRAA simulations in the FGRS used the New England resource adequacy planning criterion as their reliability metric. This criterion is defined in Section III.12 of the ISO New England Market Rule 1[10] – Standard Market Design (Market Rule 1), which reads:

"The ISO shall determine the Installed Capacity Requirement such that the probability of disconnecting non-interruptible customers due to resource deficiency, on average, will be no more than once in ten years. Compliance with this resource adequacy planning criterion shall be evaluated probabilistically, such that the Loss of Load Expectation ("LOLE") of disconnecting non-interruptible customers due to resource deficiencies shall be no more than 0.1 day each year. The forecast Installed Capacity Requirement[11] shall meet this resource adequacy planning criterion for each Capacity Commitment Period."

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[9] Power system modeling and simulation methods use a number of assumed values in initial runs. These values are then adjusted as the solution is developed through the chosen method. During this solution development numerous iterations occur. Select values are tracked as part of solution development; when these values are within a given mismatch tolerance the solution is completed and is said to have converged. Not all simulations will converge, a simulation that does not converge is not a valid result.

[10] https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf

[11] For a complete description of the ICR calculation formula, please see the ICR Reference Guide.

A Capacity Commitment Period (CCP) refers to 12 months covering the time period from June 1 of a given year to May 31 of the following year in which capacity resources that have cleared the FCA for this CCP are committed to providing their capacity (termed capacity supply obligations (CSO)) to participate in the energy markets. The New England resource adequacy planning criterion is consistent with the NPCC Full Member Resource Adequacy Criterion (Resource Adequacy R4), which reads:

"Each Planning Coordinator or Resource Planner shall probabilistically evaluate resource adequacy of its Planning Coordinator Area portion of the bulk power system to demonstrate that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year.

Make due allowances for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

The RAS and PRAA simulations in the FGRS identified the quantity of capacity resources needed to meet this resource adequacy planning criterion for the study year.

3.3 At-criterion and As-is Simulations

RAS and PRAA Scenarios were simulated under both at-criterion and as-is conditions. The at-criterion conditions identified the quantity of resources needed for New England to meet the 0.1 days/year LOLE. If the system had a surplus of capacity (i.e., the system LOLE was lower than 0.1 days/year), results indicated the system's additional load carrying capability (ALCC). The ALCC represents the additional demand the system could support without violating the 0.1 days/year LOLE criterion. If the system was short of capacity (i.e., the system LOLE was higher than 0.1 days/year), proxy resources were added to meet the criterion. The as-is condition calculated the system LOLE based on assumed load and resources conditions without any attempt to meet the 0.1 days/year LOLE. The as-is simulations were conducted to reveal the reliability risks of a given Scenario whereas at-criterion simulations were conducted to identify the quantity of resources needed to meet the LOLE criterion. Both simulations helped to provide high-level observations about the reliability risks of possible versions of the future grid.

Section 4: Results

4.1 Resource Adequacy Screen Overview

4.1.1 At-criterion Conditions

In most of the studied Scenarios, RAS analysis revealed a surplus of resources available to serve load. Simulations of Scenarios 0, 1 and 2 showed a surplus ranging between 3,500 MW to 6,000 MW of ALCC. Scenario 1 experienced a lower reserve margin required to meet the 0.1 days/year LOLE compared to Scenario 0 and Scenario 2 due to the better-performing resource mix in Scenario 1; retiring units in this Scenario had higher EFORds (Equivalent Forced Outage Rate Demand – a metric that describes how reliable resources are; higher EFORds are correlated with less reliable resources) compared to the fleet average.

The majority of the load loss risks in Scenarios 0, 1 & 2 occurred in the summer months. Some risks were observed in the winter months, but these risks were smaller due to the model's use of winter QC, which were higher than their summer QC. No risks were observed during the shoulder months.

In contrast, Scenario 3 experienced a resource shortage and required 8,600 MW of proxy units to meet the reliability criterion. The proxy units consisted of 900 MW (total) of 150 MW 4-hour batteries and 7,700 MW (total) of 100 MW combustion turbine units. All the load loss risks in Scenario 3 occurred in the winter months. Scenario 3 was winter peaking as a result of its high quantities of air source heat pumps (ASHP). Some of Scenario 3's daily peaks shifted from evening hours to morning hours (7am and 8am).

Scenario 3 Alternative B's at-criterion condition required a total of 800 MW of 100 MW CT proxy units to bring the system to LOLE criterion. Since the excess renewable energy was insufficient to fully utilize the vehicle-to-grid storage capabilities inherent in the Scenario, adding more proxy battery resources to meet criterion was not a viable solution.

4.1.2 As-is Conditions

Scenario 0's as-is condition produced very small risks during the summer months of July and August. The system was long in capacity, with ~4,000 MW of additional load carrying capability.

Scenario 1's as-is condition produced zero LOLE, LOLH, and EUE values for all months. This system was long in capacity, with ~6,000 MW of additional load carrying capability.

Scenario 2's as-is condition produced very small risks during the summer months of July and August. The system was long in capacity, with ~3,500 MW of additional load carrying capability.

Scenario 3's as-is condition was short of capacity for the winter months from November to March, necessitating a total of 8,600 MW proxy units to meet reliability criterion.

Scenario 3 Alternative B incorporated 100 GW (200 GWh) of two-hour vehicle-to-grid batteries. The as-is condition of this Scenario was short of capacity during the winter months of December through March, and in particular was short 5,700 MWh of energy in January. Despite the large amount of available storage assumed in this Scenario, insufficient resources were available to charge the storage.

4.2 Resource Adequacy Screen Detailed Results

This section provides the results of the RAS simulations in numerical form, with descriptive explanation where needed.

4.2.1 Reliability Metrics

The RAS (and PRAA) simulations produced common reliability metrics such as LOLP, LOLE, LOLH and EUE. These metrics are described in more detail below.

4.2.1.1 LOLP

LOLP is a concept used to determine the probability or likelihood of events due to insufficient capacity. LOLP can be developed for each hour in a day or for the highest risk period in a day. This concept is expressed as a probability of occurrence and its values range between 0 and 1 per period.

4.2.1.2 LOLE

LOLE is the summation of the LOLPs for the highest risk period in a day. A system that is certain to experience a capacity shortage every day would have an annual LOLE of 365 days/year (if only weekdays were included in the analysis, then the upper limit would be 260 days/year).

4.2.1.3 LOLH

LOLH is the summation of the LOLPs for all hours in the year. A system that is certain to have a capacity shortage every hour would have an annual LOLH of 8,760 hours/year.

4.2.1.4 EUE

EUE is the summation of the estimated size of all the loss of load events in a year. EUE is sometimes viewed as a preferred metric when investigating changes in load shapes or energy limitations.

In probabilistic studies, LOLE, LOLH and EUE are all highly correlated and may be used interchangeably. However, because each metric provides a nuance that a particular reader or analyst may prefer, they will generally be presented together.

4.2.2 LOLE and ICR Results for Scenarios 0, 1, 2, 3 and Alternative B Scenario 3

Table 4-1 summarizes the resource and load assumptions used in the study's RAS simulations along with the results in a typical ICR and net ICR presentation format.[12] Table 3 tabulates the quantity of assumed resources and MW of load relief available from implementing Operating Procedure No. 4, Action During a Capacity Deficiency for the study Scenarios.

Table 4-1 also shows the results of the GE MARS simulations in the form of ALCC. Please note that scenarios S0, S1 and S2 are summer peaking scenarios while S3 and S3_B are winter peaking scenarios. The loads and resources reflect their respective seasonal values. For the Scenarios short of capacity, proxy units were added to meet the LOLE of 0.1 days/year.

[12] For more information on the development of ICR and relevant terms refer to the ISO guide on this subject, https://www.iso-ne.com/static-assets/documents/2021/06/icr-reference-guide.pdf

The ICR and net ICR values were calculated using the ICR calculation formula[13] listed below:

$$Installed\ Capacity\ Requirement\ (ICR) = \frac{Capacity - Tie\ Benefits - OP4\ Load\ Relief}{1 + \frac{ALCC}{APk}} + HQICCs$$

Apk (Annual Peak) is the forecast gross 50/50 peak load net of BTM PV, which included both the transportation and heating electrification forecast.

The reserve margin with and without HQICCs is a deterministic metric that identifies the quantity of resources above the forecast gross 50/50 peak load net of BTM PV (or Apk) needed to meet the 0.1 days/year LOLE criterion.

Table 4-1: RAS LOLE and ICR Results Based on Seasonal QC and Tie Benefit, as Appropriate

Total MW Breakdown	FGRS RAS S0 ICR (MW)	FGRS RAS S1 ICR (MW)	FGRS RAS S2 ICR (MW)	FGRS RAS S3 ICR (MW)	FGRS RAS S3_B ICR (MW)
Generating Capacity Resources	28,858	25,528	21,361	26,019	26,019
Other Generating Resources					
Solar	2,697	3,241	3,528	-	-
On Shore Wind	-	568	604	1,085	1,085
Off Shore Wind	941	2,409	2,409	9,997	9,997
Battery	600	2,000	3,940	600	600
Demand Resources	6,031	6,031	6,031	760	760
Import Capacity Resources	1,200	1,200	2,200	2,200	2,200
Tie Benefits	1,830	1,830	1,830	646	646
OP-4 Actions 6 & 8 (Voltage Reduction)	263	263	263	204	204
Minimum System Reserve	-700	-700	-700	-700	-700
Proxy Units-Battery	-	-	-	900	-
Proxy Units-CT	-	-	-	7,700	800
Total MW (Capacity)	**41,720**	**42,370**	**41,466**	**49,411**	**41,611**

[13] For a complete description of the ICR calculation formula, please see the ICR Reference Guide.

Installed Capacity Requirement Calculation Details	FGRS RAS S0 ICR (MW)	FGRS RAS S1 ICR (MW)	FGRS RAS S2 ICR (MW)	FGRS RAS S3 ICR (MW)	FGRS RAS S3_B ICR (MW)
Annual Peak - net BTM PV **(APk)**	31,547	30,908	31,959	42,996	42,996**
Total Capacity	41,720	42,370	41,466	49,411	41,611
Tie Benefits	1,830	1,830	1,830	646	646
HQICCs	923	923	923	249	249
OP-4 Actions 6 & 8 -Voltage Reduction **(OP 4 Load Relief)**	263	263	263	204	204
Minimum System Reserve **(OP 4 Load Relief)**	-700	-700	-700	-700	-700
ALCC	4,138	5,904	3,502	36	78
Installed Capacity Requirement	**36,573**	**35,328**	**37,038**	**49,469**	**41,634**
Net ICR	**35,650**	**34,405**	**36,115**	**49,220**	**41,385**
Reserve Margin with HQICCs	15.93%	14.30%	15.89%	15.05%	N/A
Reserve Margin without HQICCs	13.01%	11.31%	13.00%	14.48%	N/A

All values in the table are shown in MW except the reserve margin, which is shown in percent.

** The annual peak reflects the net peak and it does not capture the activities of the Vehicle-to-Grid batteries and their impact on load is difficult to estimate. This resulted in a non-comparable and non-applicable (N/A) reserve margin

4.2.3 Monthly Reliability Indices

The monthly reliability indices shown in Table 4-2 illustrate which months the system experienced risks, i.e., the times of the year when the assumed resources were not able to meet the corresponding hourly peak loads. Months with non-zero values are months that experienced load loss risks in RAS simulations.

As detailed in section 4.1.2, an as-is version of each Scenario was modeled to better understand system conditions, whether or not those conditions were sufficient (or more than sufficient) to meet peak load. Subsequently, an at-criterion system was modeled either by scaling load or adding proxy units in order to bring the particular Scenario to 0.1 days/year LOLE criterion. Since the current New England system is a summer peaking system, these indices provide insights into the capacity situation of a future system with greater renewable penetration and the possibility of a winter-peaking system.

Table 4-2: Monthly RAS Reliability Indices

Scenario	Condition	Metric	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Annual
S0	As-Is	LOLE	0	0	0	0	0	0	0.00003	0.00052	0	0	0	0	0.00055
		LOLH	0.00001	0	0	0	0	0	0.00005	0.00106	0	0	0	0	0.00112
		EUE	0.005	0	0	0	0	0	0.015	0.526	0	0	0	0	0.546
	At-Criterion	LOLE	0.0014	0.00006	0	0	0.00002	0.00048	0.03267	0.06429	0.00022	0	0	0.00083	0.09997
		LOLH	0.00302	0.00009	0	0	0.00006	0.00103	0.11706	0.26181	0.00048	0	0	0.00141	0.38496
		EUE	1.558	0.035	0	0	0.023	0.525	134.212	381.506	0.228	0	0	0.681	518.767
S1	As-Is	LOLE	0	0	0	0	0	0	0	0	0	0	0	0	0
		LOLH	0	0	0	0	0	0	0	0	0	0	0	0	0
		EUE	0	0	0	0	0	0	0	0	0	0	0	0	0
	At-Criterion	LOLE	0.00019	0	0	0	0	0.00051	0.03492	0.0641	0.00007	0	0	0.0001	0.0999
		LOLH	0.00035	0.00001	0	0	0	0.00113	0.18078	0.33448	0.00018	0	0	0.00016	0.51709
		EUE	0.155	0.002	0	0	0	0.526	252.254	609.854	0.086	0	0	0.077	862.954
S2	As-Is	LOLE	0	0	0	0	0	0	0.0001	0.00192	0	0	0	0	0.00202
		LOLH	0	0	0	0	0	0	0.00018	0.00445	0	0	0	0	0.00463
		EUE	0	0	0	0	0	0	0.08	2.432	0	0	0	0	2.513
	At-Criterion	LOLE	0.00002	0	0	0	0	0.00019	0.03361	0.06586	0.00003	0	0	0.00001	0.09973
		LOLH	0.00003	0	0	0	0	0.00044	0.13721	0.26724	0.0001	0	0	0.00001	0.40503
		EUE	0.013	0	0	0	0	0.22	175.841	456.222	0.056	0	0	0.003	632.355
S3	As-Is	LOLE	1.19875	0.31092	0.19921	0.00002	0	0	0	0	0	0	0.01284	1.89199	1.89199
		LOLH	12.37788	1.5733	0.78292	0.00005	0	0	0.00001	0	0	0	0.06403	16.64351	16.64351
		EUE	37515.76	2965.003	1233.665	0.018	0	0	0.001	0	0	0	62.922	46131.11	46131.11
	At-Criterion	LOLE	0.08891	0.00632	0.00008	0	0	0	0	0	0	0	0	0.00451	0.09982
		LOLH	0.54639	0.01277	0.0001	0	0	0	0	0	0	0	0	0.02462	0.58389
		EUE	984.22	13.519	0.044	0	0	0	0	0	0	0	0	18.632	1016.415
S3_B	As-Is	LOLE	0.1864	0.00083	0.00039	0	0	0	0	0	0	0	0	0.00097	0.18859
		LOLH	1.33316	0.00504	0.00094	0	0	0	0	0	0	0	0	0.00501	1.34415
		EUE	5727.468	8.37	1.731	0	0	0	0	0	0	0	0	20.197	5757.766
	At-Criterion	LOLE	0.09931	0.00017	0.00014	0	0	0	0	0	0	0	0	0.0003	0.09993
		LOLH	0.77066	0.00096	0.00028	0	0	0	0	0	0	0	0	0.00126	0.77316
		EUE	3673.283	1.577	0.436	0	0	0	0	0	0	0	0	4.23	3679.525

** LOLE is units of days/yr, LOLP is units of hrs/yr, and EUE is in units of MWh/yr*

4.3 Probablistic Resource Adequacy Analysis Overview

This section and the following section detail the PRAA results for the modeled Scenarios.

The as-is conditions for Scenario 0 and Scenario 1 contained adequate resources, with an ALCC of 2,000 MW and 2,700 MW, respectively. These values are approximately 2,000 – 3,000 MW lower than the RAS values of ~4,000 MW and ~6,000 MW seen under the RAS simulation for the same cases. Conversely, the as-is conditions for Scenario 2 and Scenario 3 were short of resources, with an additional need of 600 MW and 12,800 MW of proxy units respectively. These values represent a shortage of approximately 4,000 MW more than the RAS based values; the RAS based values showed a positive ALCC value of ~3,500 MW for Scenario 2 and the need for ~8,600 MW of proxy units for Scenario 3. The various proxy mixes added to serve the additional need in Scenario 3 are detailed in section 4.8.

Additional new resources were also required to replace the retirement of the nuclear units in all Alternative C scenarios. Additional risk occurred during the summer months in Alternative C for Scenarios 0, 1 and 2, with additional risks in the winter months in Alternative C.

Under at-criterion condition the expected loss of load hours for all Scenarios for Alternative C was ~0.4 hours/year, the expected unserved energy was ~600 MWh/year, the expected outage duration was ~3.5 hours/outage, and the expected outage frequency was~0.11 outages/year.

4.4 Probablistic Resource Adequacy Analysis Detailed Results

Table 4-3 summarizes the results of the PRAA simulations. Each condition (both as-is and at-criterion) was simulated to calculate the quantity of capacity resources needed for meeting 0.1 days/year LOLE and the corresponding resulting reserve margin.

Table 4-3: PRAA LOLE and Reserve Margin Results

Condition	Scenario	Loss-of-Load Expectation (LOLE)	Loss-of-load hours (LOLH)	Expected Unserved Energy (EUE)	Frequency	Duration
		(days/yr)	(hrs/yr)	(MWh/yr)	(outg/yr)	(hrs/outg)
As-Is	**S0**	0.02	0.057	48	0.021	2.763
	S1	0.01	0.028	23	0.013	2.148
	S1_C	0.138	0.521	710	0.179	2.907
	S1_D	0	0	0	0	0
	S2	0.137	0.481	729	0.15	3.201
	S2_C	1.3	4.995	8,997	1.371	3.643
	S2_D	0	0	0	0	0
	S3	6.271	42.494	1,26,187	6.44	6.598
	S3_B	0.193	1.708	8,739	0.162	10.546
	S3_C	17.686	122.659	3,75,690	18.266	6.715
	S3_D	0	0	0	0	0
Condition	**Scenario**	**LOLE**	**LOLH**	**EUE**	**FREQUENCY**	**DURATION**
		(days/yr)	**(hrs/yr)**	**(MWh/yr)**	**(outg/yr)**	**(hrs/outg)**
At-Criterion	**S0**	0.1	0.347	444	0.102	3.419
	S1	0.1	0.381	546	0.128	2.968
	S1_C	0.1	0.39	560	0.135	2.9
	S1_D	0.1	0.587	715	0.105	5.58
	S2	0.1	0.358	528	0.117	3.067
	S2_C	0.1	0.355	536	0.117	3.035
	S2_D	0.1	0.548	651	0.105	5.24
	S3	0.1	0.426	850	0.104	4.089
	S3_B	0.1	0.83	4132	0.087	9.524
	S3_C	0.1	0.427	852	0.104	4.118
	S3_D	0.1	0.567	448	0.109	5.178

A review of the metrics for the At-Criterion cases shows the correlation between LOLE, LOLH, and EUE that renders these metrics approximately interchangeable for comparing results.

Table 4-4, Table 4-5 and Table 4-6 summarize the Monthly Reliability Indices of all eleven Scenarios. Months with non-zero values are months that experienced risk in PRAA simulations.

Table 4-4: PRAA Monthly Reliability Indices (S0, S1, S1_C and S1_D)

Scenario	Condition	Metric	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Annual
S0	As-Is	LOLE	0	0	0	0	0	0	0.00254	0.00837	0	0	0	0	0.02036
		LOLH	0	0	0	0	0	0	0.00296	0.01486	0	0	0	0	0.0574
		EUE	0	0	0	0	0	0	0.142	0.863	0	0	0	0	48.015
	At-Criterion	LOLE	0.00022	0.00001	0	0	0.00001	0.0005	0.02732	0.07105	0.00047	0	0	0.00034	0.09991
		LOLH	0.00045	0.00001	0	0	0.00002	0.00112	0.09632	0.24756	0.00107	0	0	0.00057	0.34714
		EUE	0.183	0.003	0	0	0.008	0.585	106.807	335.959	0.55	0	0	0.259	444.354
S1	As-Is	LOLE	0	0	0	0	0	0	0.00154	0.00797	0	0	0	0	0.00952
		LOLH	0	0	0	0	0	0.00001	0.00379	0.02435	0	0	0	0	0.02816
		EUE	0	0	0	0	0	0.002	2.093	20.941	0	0	0	0	23.037
	At-Criterion	LOLE	0.00012	0.00002	0	0	0.00001	0.00086	0.02484	0.07368	0.00013	0	0	0.00029	0.09994
		LOLH	0.00025	0.00002	0	0	0.00002	0.00215	0.09899	0.27877	0.00031	0	0	0.00057	0.38108
		EUE	0.128	0.018	0	0	0.014	1.27	132.946	410.902	0.2	0	0	0.423	545.901
S1_C	As-Is	LOLE	0.0005	0.00009	0	0	0.00004	0.00139	0.03451	0.10089	0.0004	0	0	0.00056	0.13839
		LOLH	0.00096	0.00013	0	0	0.00006	0.00403	0.13325	0.38047	0.00086	0	0	0.00119	0.52095
		EUE	0.52	0.064	0	0	0.018	2.557	177.037	528.617	0.439	0.001	0	0.86	710.114
	At-Criterion	LOLE	0.00021	0.00003	0	0	0.00002	0.0008	0.02455	0.07399	0.00015	0	0	0.00026	0.10001
		LOLH	0.00044	0.00005	0	0	0.00002	0.00222	0.10131	0.28501	0.00036	0	0	0.00064	0.39005
		EUE	0.197	0.038	0	0	0.004	1.389	138.821	419.025	0.187	0	0	0.538	560.198
S1_D	As-Is	LOLE	0	0	0	0	0	0	0	0	0	0	0	0	0
		LOLH	0	0	0	0	0	0	0	0	0	0	0	0	0
		EUE	0	0	0	0	0	0	0	0	0	0	0	0	0
	At-Criterion	LOLE	0.00001	0	0	0	0	0.00001	0.00251	0.0974	0	0	0	0.00028	0.10021
		LOLH	0.00001	0	0	0	0	0.00001	0.01062	0.57614	0	0	0	0.00056	0.58735
		EUE	0	0	0	0	0	0.009	13.109	701.906	0	0	0	0.123	715.148

** LOLE is units of days/yr, LOLP is units of hrs/yr, and EUE is in units of MWh/yr*

Table 4-5: PRAA Monthly Reliability Indices (S2, S2_C and S2_D)

Scenario	Condition	Metric	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Annual
S2	As-Is	LOLE	0.0002	0.00001	0	0	0.00001	0.00142	0.03508	0.10017	0.00023	0.00002	0	0.00019	0.13733
		LOLH	0.00033	0.00001	0	0	0.00002	0.00386	0.12787	0.34822	0.00055	0.00003	0	0.00044	0.48133
		EUE	0.185	0.014	0	0	0.011	2.81	196.499	528.302	0.325	0.014	0	0.347	728.508
	At-Criterion	LOLE	0.00007	0	0	0	0	0.00077	0.0249	0.07422	0.00007	0	0	0.00009	0.10012
		LOLH	0.00011	0.00001	0	0	0.00001	0.00198	0.09706	0.25823	0.00018	0.00001	0	0.0002	0.35779
		EUE	0.053	0.009	0	0	0.003	1.292	143.774	383.02	0.115	0.006	0	0.163	528.436
S2_C	As-Is	LOLE	0.02691	0.00973	0.00013	0.00002	0.00507	0.02666	0.37365	0.81398	0.01544	0.00816	0.00059	0.01922	1.29957
		LOLH	0.06477	0.024	0.00019	0.00004	0.01591	0.09041	1.49941	3.17948	0.04712	0.0188	0.00119	0.05387	4.9952
		EUE	70.744	23.332	0.085	0.03	15.369	119.793	2732.69	5898.31	56.334	14.895	0.964	64.086	8996.63
	At-Criterion	LOLE	0.00005	0	0	0	0	0.00077	0.02364	0.07524	0.00008	0	0	0.00005	0.09983
		LOLH	0.00008	0	0	0	0.00001	0.00174	0.0928	0.2596	0.00021	0	0	0.00012	0.35455
		EUE	0.054	0	0	0	0.003	1.089	138.981	395.192	0.102	0	0	0.124	535.545
S2_D	As-Is	LOLE	0	0	0	0	0	0	0	0	0	0	0	0	0
		LOLH	0	0	0	0	0	0	0	0	0	0	0	0	0
		EUE	0	0	0	0	0	0	0	0	0	0	0	0	0
	At-Criterion	LOLE	0	0	0	0	0	0.00002	0.00238	0.09757	0	0	0	0.00007	0.10004
		LOLH	0	0	0	0	0	0.00003	0.0105	0.53772	0	0	0	0.0001	0.54834
		EUE	0	0	0	0	0	0.008	11.432	639.709	0	0	0	0.018	651.167

** LOLE is units of days/yr, LOLP is units of hrs/yr, and EUE is in units of MWh/yr*

Table 4-6: PRAA Monthly Reliability Indices (S3, S3_B, S3_C and S3_D)

Scenario	Condition	Metric	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Annual
S3	As-Is	LOLE	2.43779	1.43288	0.58513	0.029	0.00786	0.01429	0.12068	0.11732	0.05826	0.04631	0.30505	1.11607	6.27063
		LOLH	19.5468	7.85254	3.07073	0.0945	0.02105	0.0363	0.3764	0.38478	0.18739	0.13903	1.78769	8.99632	42.4936
		EUE	66046.3	21713.1	7824.77	107.396	17.477	34.787	428.902	391.663	148.097	139.918	3810.65	25524	126186
	At-Criterion	LOLE	0.06334	0.02219	0.00337	0	0	0	0	0	0	0	0.00008	0.01108	0.10006
		LOLH	0.30397	0.051	0.00779	0	0	0	0	0	0	0	0.00018	0.06266	0.42559
		EUE	651.715	80.281	11.693	0	0	0	0	0	0	0	0.077	105.769	849.534
S3_B	As-Is	LOLE	0.14392	0.00813	0.00275	0	0	0	0	0	0	0	0.00035	0.03772	0.19287
		LOLH	1.27487	0.05596	0.01778	0.00002	0	0	0	0	0	0	0.00248	0.35706	1.70817
		EUE	6920.865	250.263	65.583	0.11	0	0	0	0	0	0	9.275	1493.377	8739.473
	At-Criterion	LOLE	0.07907	0.00291	0.00096	0	0	0	0	0	0	0	0.00009	0.01686	0.09989
		LOLH	0.65853	0.01761	0.00587	0.00001	0	0	0	0	0	0	0.00062	0.14722	0.82986
		EUE	3460.945	73.461	18.492	0.013	0	0	0	0	0	0	2.04	577.209	4132.159
S3_C	As-Is	LOLE	4.8471	3.328	1.60993	0.1912	0.13349	0.21575	1.03412	1.51431	0.78163	0.27462	0.90037	2.85579	17.6863
		LOLH	43.8964	21.993	9.6783	0.7341	0.50513	0.67161	3.77361	5.97628	2.93183	1.07696	5.90311	25.5185	122.659
		EUE	166717	67705	27018.6	1043.73	613.173	775.955	5341.72	7433.46	3000.43	1453.56	14501.6	80084.4	375690
	At-Criterion	LOLE	0.0625	0.0224	0.00309	0	0	0	0	0	0	0	0.00001	0.0119	0.09999
		LOLH	0.30187	0.0518	0.00696	0	0	0	0	0	0	0	0.00004	0.06584	0.42657
		EUE	649.662	81.856	10.253	0	0	0	0	0	0	0	0.014	110.202	851.988
S3_D	As-Is	LOLE	0	0	0	0	0	0	0	0	0	0	0	0	0
		LOLH	0	0	0	0	0	0	0	0	0	0	0	0	0
		EUE	0	0	0	0	0	0	0	0	0	0	0	0	0
	At-Criterion	LOLE	0.06134	0.01254	0.00248	0	0	0	0	0	0	0	0	0.02351	0.09988
		LOLH	0.34436	0.04957	0.01108	0	0	0	0	0	0	0	0	0.16156	0.56657
		EUE	292.243	43.954	5.158	0	0	0	0	0	0	0	0	106.188	447.544

** LOLE is units of days/yr, LOLP is units of hrs/yr, and EUE is in units of MWh/yr*

4.5 Hourly Risk Distribution

4.5.1 Risk Distribution for Main Scenarios

Hourly risk analysis of PRAA at-criterion runs found that summer risks for Scenario 0, Scenario 1, and Scenario 2 occurred between the hours of 14:00 to 22:00. However, in Scenario 3, risks occurred at all hours of the day, and were highest in the morning (6:00 to 8:00) during the winter months. The hourly risk analysis for each Scenario is illustrated in Figure 4-1.

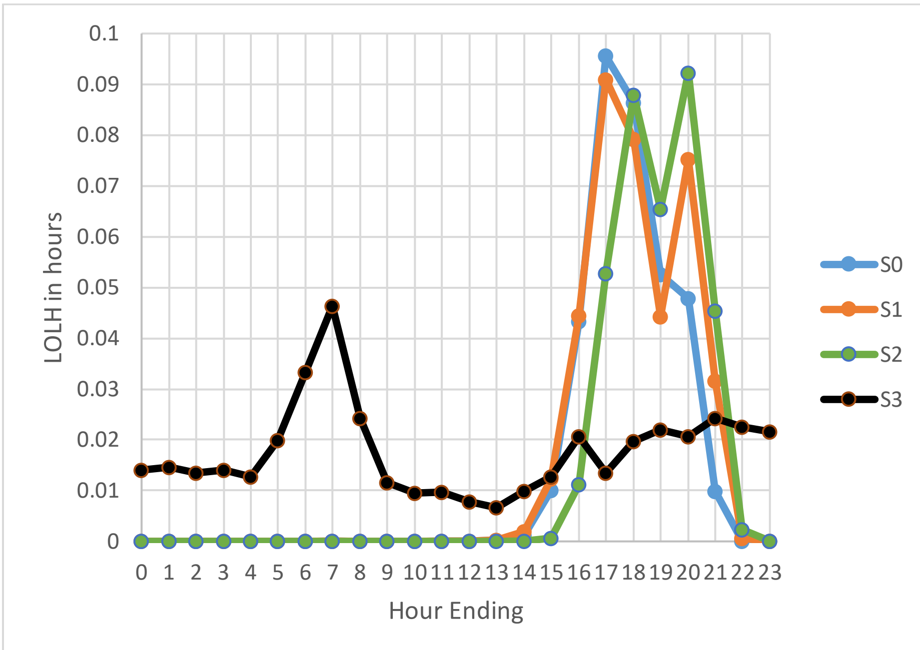

Figure 4-1: Hourly Risk Analysis of Main Scenarios

The hourly risk distribution and levels for Alternative C were similar to the main Scenarios for Scenarios 1 through 3, suggesting the retirement of nuclear units would not significantly alter the risk exposure hours in the modeled year, though the magnitude of risk was altered. These curves are shown in Figure 4-2, Figure 4-3 and Figure 4-4.

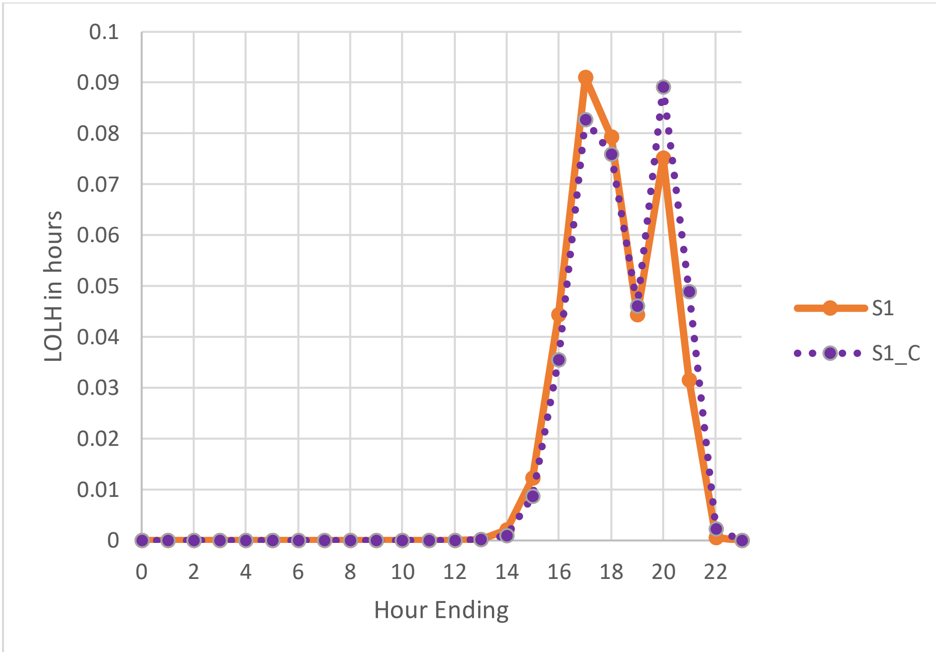

Figure 4-2: Hourly Risk Analysis of Scenario 1 and Alternative C Scenario 1

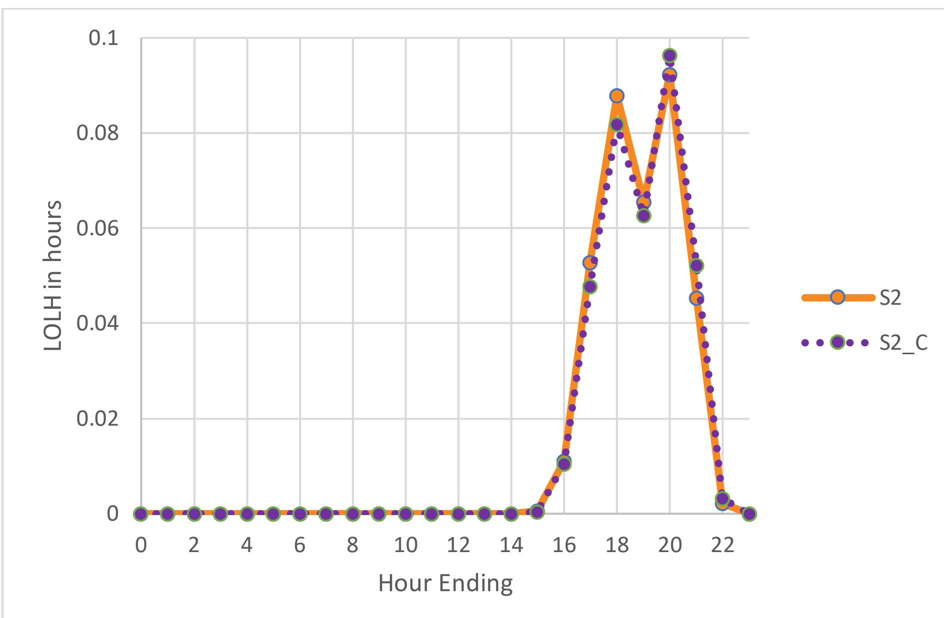

Figure 4-3: Hourly Risk Analysis of Scenario 2 and Alternative C Scenario 2

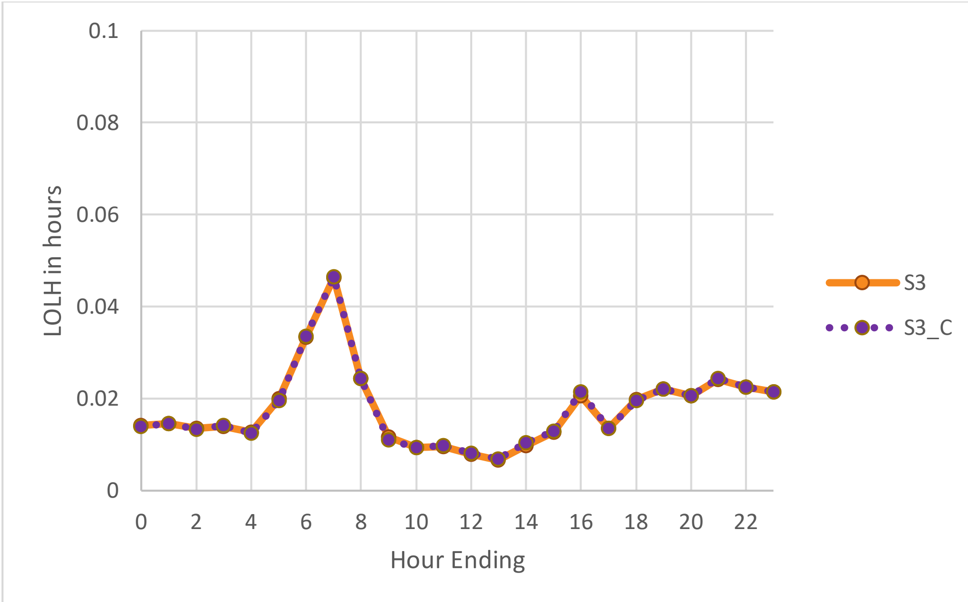

Figure 4-4: Hourly Risk Analysis of Scenario 3 and Alternative C Scenario 3

4.5.2 Transmission Interface Constraints

Transmission interface constraints were evaluated under as-is condition only. Since transmission results depend not just on *how many* but also *where* in the grid resources are added or removed, the results of this analysis depend closely on the chosen location of the proxy units. Conceptually, market rules and interconnection procedures would discourage the addition of proxy units in areas where their reliability contribution would be diminished by transmission constraints. Thus, these constraints were considered out-of-scope for at-criterion assessments.

Reliability metrics for as-is conditions were recorded with and without internal transmission interface limits and are illustrated in Table 4-7. Changes in interface flow patterns and reliability metrics were compared in order to identify constrained interfaces. It is important to note that GE MARS does not provide statistical information regarding the interface binding condition. Additionally, the Boston Import and Southeast New England (SENE) Import were modeled as two independent interfaces at the same limit (5,250 MW).

Table 4-7: Reliability Metrics With and Without Transmission Constraints

Scenario	LOLE (days/yr)		LOLH (hrs/yr)		EUE (MWh/yr)		Frequency (outg/yr)		Duration (hr/outg)		Constrained Interfaces
	w/o constraints	w/ constraints	w/o constraints	w/ constraints	w/o constraints	w/ constraints	w/o constraints	w/ constraints	w/o constraints	w/ constraints	
S0	0.020	0.327	0.057	1.708	48	580	0.021	0.329	2.763	5.197	ME/NH; Bos Import
S1	0.010	0.102	0.028	0.448	23	181	0.013	0.109	2.148	4.097	ME/NH; Bos Import
S1_C	0.138	0.418	0.521	1.725	710	2,015	0.179	0.502	2.907	3.435	ME/NH; Bos Import
S1_D	0	0	0	0	0	0	0	0	0	0	None
S2	0.137	0.804	0.481	3.350	729	3,180	0.150	0.858	3.201	3.903	ME/NH; Bos Import
S2_C	1.300	2.649	4.995	11.171	8,997	18,343	1.371	2.817	3.643	3.966	ME/NH
S2_D	0	0	0	0	0	0	0	0	0	0	None
S3	6.271	17.455	42.494	129.492	126,187	227,244	6.440	18.219	6.598	7.108	West/East; Bos Import
S3_B	0.193	1.808	1.708	19.299	8,739	39,832	0.162	1.575	10.546	12.254	West/East; Bos Import
S3_C	17.686	27.667	122.659	219.863	375,690	537,720	18.266	29.324	6.715	7.498	West/East; Bos Import
S3_D	0	0.025	0	0.231	0	305	0	0.023	0	9.829	Bos Import

4.6 Comparison of Resource Adequacy Study Methods (RAS and PRAA)

RAS and PRAA results differed for all main Scenarios, and some high-level observations can be drawn from these differences. Since the Scenarios modeled in the FGRS assumed high penetrations of renewable resources, which PRAA can model in a more nuanced fashion, the PRAA results better reflected the risk of common-mode wind and solar lulls that would impact reliability. From this result, PRAA modeling generally suggested that either more resources are required to meet reliability criterion than RAS or the capacity valuation of wind and solar resources decline as penetration increases. This effect is illustrated in the column labeled “Difference” in Table 4-8.

Table 4-8: ALCC and Proxy Results for RAS and PRAA for all Main Scenarios

Scenario	RAS ALCC/Proxy	PRAA ALCC/Proxy	Difference (MW)
S0	4,138 ALCC	2,000 ALCC	2,138
S1	5,904 ALCC	2,700 ALCC	3,204
S2	3,502 ALCC	600 Proxy	4,102
S3	8600 Proxy	12,800 Proxy	4,200

These results suggested that assumptions regarding renewable resources in the RAS analysis (modeled at the Qualified Capacity rating) overstated their capacity contribution to serve the system during the peak demand. While RAS assumptions have functioned well for current solar and wind penetrations, at higher penetrations these QC assumptions had a larger impact on the studied future Scenarios.

4.7 Additional Scenarios

Using PRAA modeling, ISO New England conducted simulations of Scenarios testing additional types of proxy resource mixes. These simulations provided insights into the viability of different resource mixes that may help the region achieve its emissions goals by 2040, a key stakeholder concern. Table 4-9 shows the different renewable proxy mixes that were assumed to meet 0.1 days/year LOLE. These proxy mixes and their effect on reliability metrics are discussed in the following sections.

Table 4-9: Additional PRAA Scenarios Studied

Total MW Breakdown	S3_P0 Perfect Capacity	S3_P1 (Resources Retained for Reliability and CT)	S3_P2 (Only BESS Resources)	S3_P3 (Only OFSW Resources)	S3_P4 (Only ONSW Resources)	S3_P5 (Only PV Resources)	S3_P6 (ONSW and BESS Resources)	S3_P7 (Solar/Wind/BESS Resources Mix from Pathways Status Quo Scaled)
Generating Capacity Resources	26,018	30,414	26,018	26,018	26,018	26,018	26,018	26,618
Other Generating Resources								
Solar	28,131	28,131	28,131	28,131	28131	28,131	28,131	19,428
On Shore Wind	16,662	16,662	16,662	16,662	16662	16,662	16,662	4,401
Off Shore Wind	2,585	2,585	2,585	2,585	2,585	2,585	2,585	16,014
Battery	600	600	600	600	600	600	600	12,953
Demand Resources	760	760	760	760	760	760	760	760
Import Capacity Resources	2,200	2,200	2,200	2,200	2200	2,200	2,200	2,200
Tie Benefits	646	646	646	646	646	646	646	646
OP-4 Actions 6 & 8 (Voltage Reduction)	204	204	204	204	204	204	204	204
Minimum System Reserve	-700	-700	-700	-700	-700	-700	-700	-700
Proxy Units - Perfect Capacity	11,750							
Proxy Units - CT		9,000						
Proxy Units - Solar						N/A		13,600
Proxy Units - On Shore Wind					85,000		9,867	3,081
Proxy Units - Off Shore Wind				155,000				11,210
Proxy Units - Battery			N/A				29,000	9,067
Total MW	**88,856**	**90,502**	**N/A**	**232,106**	**162,106**	**N/A**	**115,973**	**119,481**
Winter Peak	42,996	42,996	42,996	42,996	42,996	42,996	42,996	42,996
Reserve Margin	107%	110%	N/A	440%	277%	N/A	170%	178%
LOLE	0.09798	0.09812	N/A	0.09691	0.09899	N/A	0.09858	0.09326

4.7.1 Scenario 3, P0: Perfect Capacity

The initial proxy Scenario was designed to provide a baseline for comparing the other proxy Scenarios. Perfect capacity resources have 0% EFORd and no maintenance outages, so the results of this simulation provided useful data regarding the minimum number of resources Scenario 3 would need to meet reliability criteria under perfect conditions. The proxy Scenario that relied on perfect capacity resources required 11,750 MW of these resources to meet the reliability criteria. The LOLE, LOLH and EUE curves for this proxy Scenario are shown in Figure 4-5, Figure 4-6 and Figure 4-7.

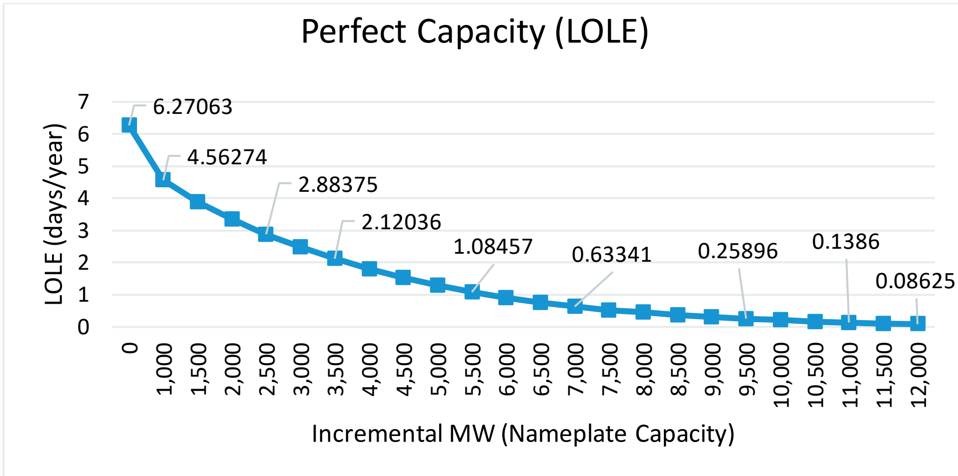

Figure 4-5: LOLE Curve of Perfect Capacity Proxy Scenario

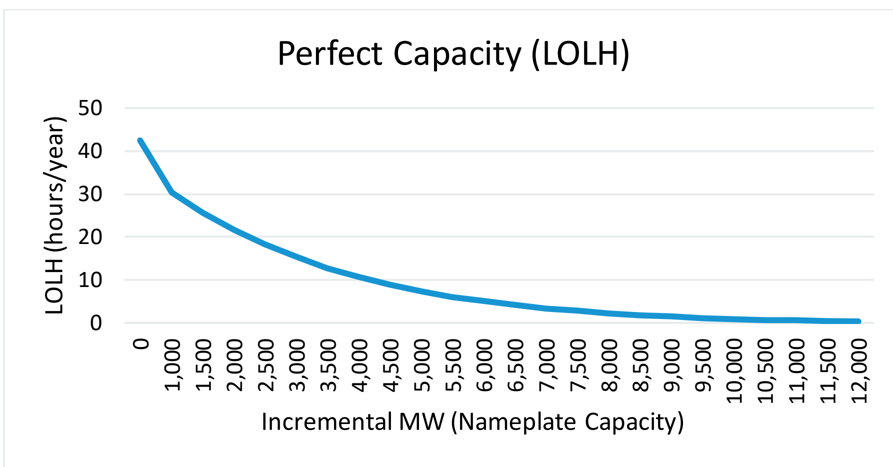

Figure 4-6: LOLH Curve of Perfect Capacity Proxy Scenario

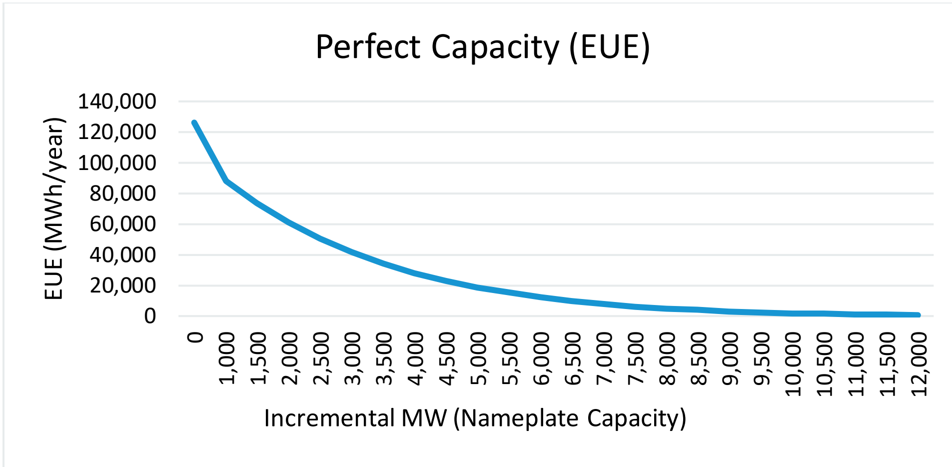

Figure 4-7: EUE Curve of Perfect Capacity Proxy Scenario

4.7.2 Scenario 3, P1: Resources Retained for Reliability and CTs

This proxy Scenario was designed to simulate what might occur if resources retired under Scenario 3's initial assumptions were instead retained. Reliability did indeed improve in this proxy Scenario, since the previously retired units provided 4,396 MW of capacity. An additional 9,000 MW of CTs were needed beyond the previously retired units in order to meet the reliability criteria. The LOLE, LOLH and EUE curves for this proxy Scenario are shown in Figure 4-8, Figure 4-9 and Figure 4-10.

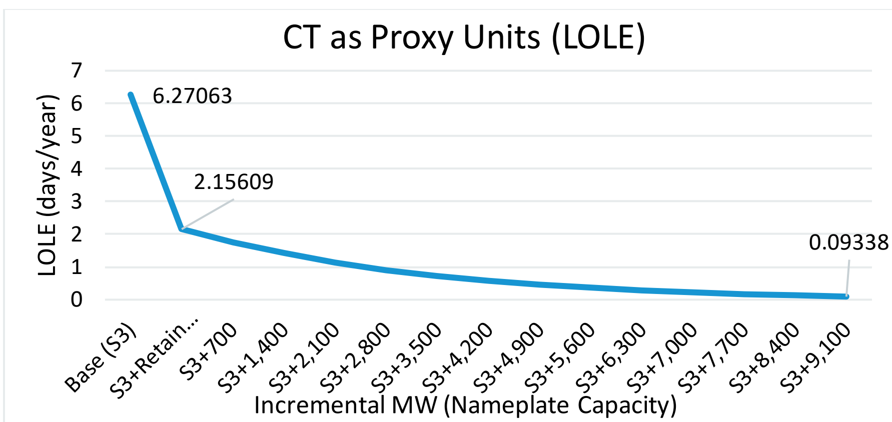

Figure 4-8: LOLE Curve of CT as Proxy Units Proxy Scenario

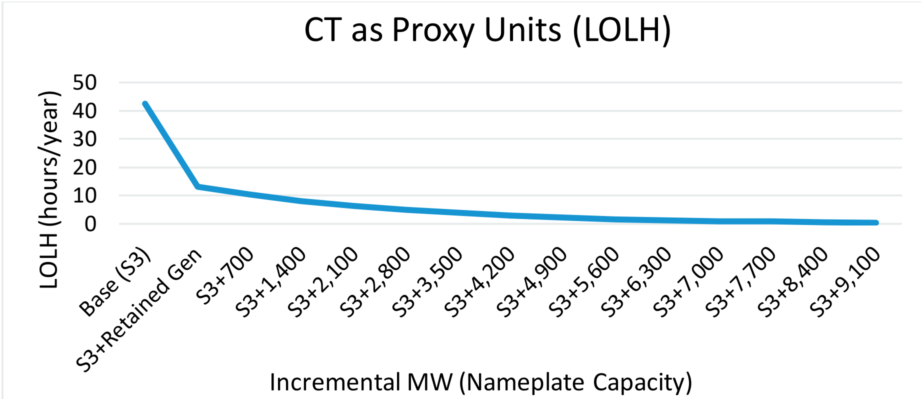

Figure 4-9: LOLH Curve of CT as Proxy Units Proxy Scenario

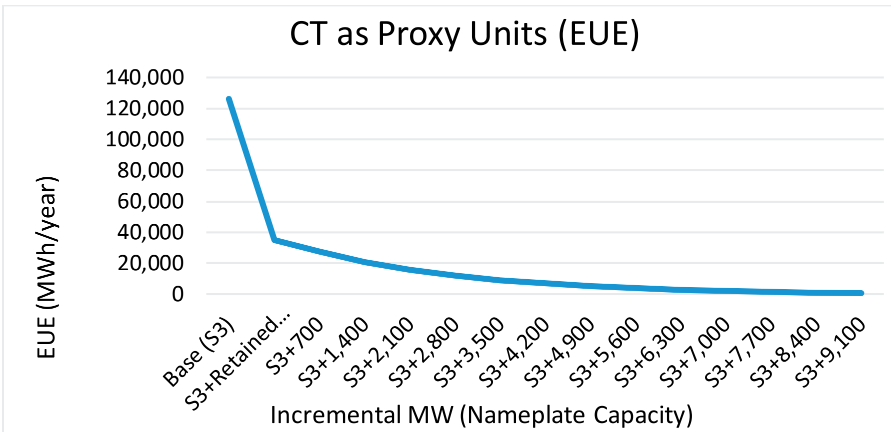

Figure 4-10: EUE Curve of CT as Proxy Units Proxy Scenario

4.7.3 Scenario 3, P2: BESS Units Only

Scenario 3 P2 explored the possibility of using BESS units to meet reliability criterion, however BESS units alone were not sufficient to bring the system to the reliability criteria. However, a key finding from this simulation revealed that the first 25 GW of batteries had the largest impact on reliability metrics. The LOLE, LOLH and EUE curves for this proxy Scenario are shown in Figure 4-11, Figure 4-12 and Figure 4-13.

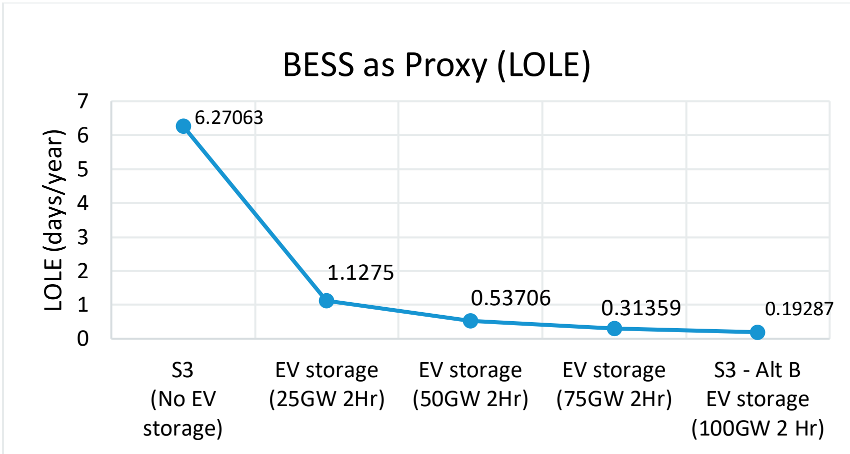

Figure 4-11: LOLE Curve of BESS as Proxy Units Proxy Scenario

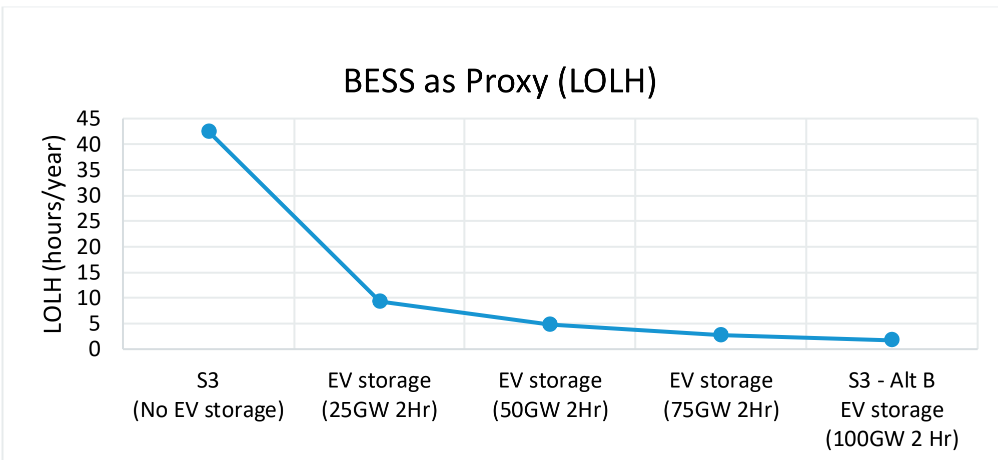

Figure 4-12: LOLH Curve of BESS as Proxy Units Proxy Scenario

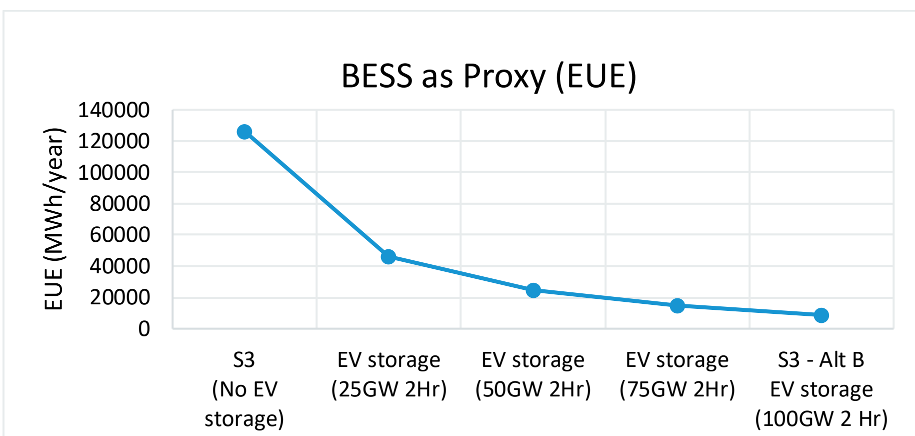

Figure 4-13: EUE Curve of BESS as Proxy Units Proxy Scenario

4.7.4 Scenario 3, P3: Only OFSW Resources

This proxy Scenario was designed to evaluate what impact offshore wind resources (OFSW) might have on the reliability metrics. The first 45 GW of OFSW had a large impact on reliability metrics, but offshore wind's effect on reliability metrics decreased significantly as penetration levels increased. Since hourly outputs of OFSW for different locations were closely correlated with each other, and since there are comparatively fewer data inputs available for OFSW than onshore wind, wind droughts had an outsized adverse effect on reliability. Only infeasibly large amounts of OFSW (155 GW) brought the system to criteria, indicating that OFSW alone is not a realistic path to meeting reliability criteria. The LOLE, LOLH and EUE curves for this proxy Scenario are shown in Figure 4-14, Figure 4-15 and Figure 4-16.

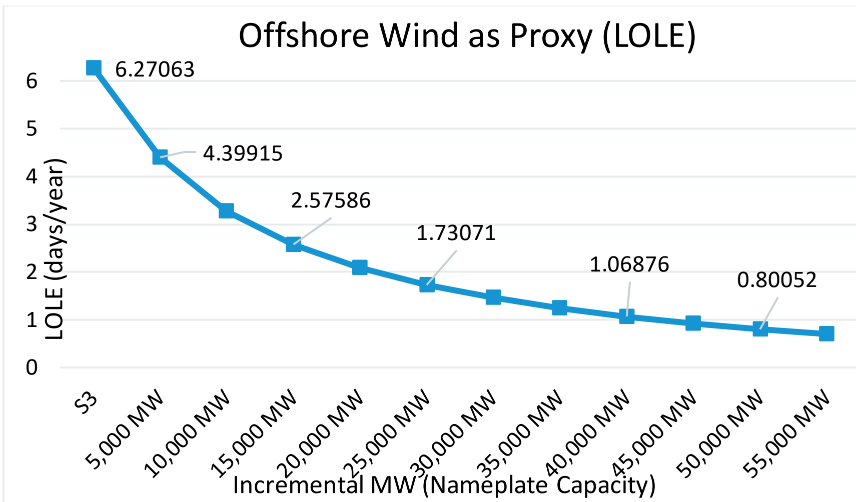

Figure 4-14: LOLE Curve of OFSW as Proxy Units Proxy Scenario

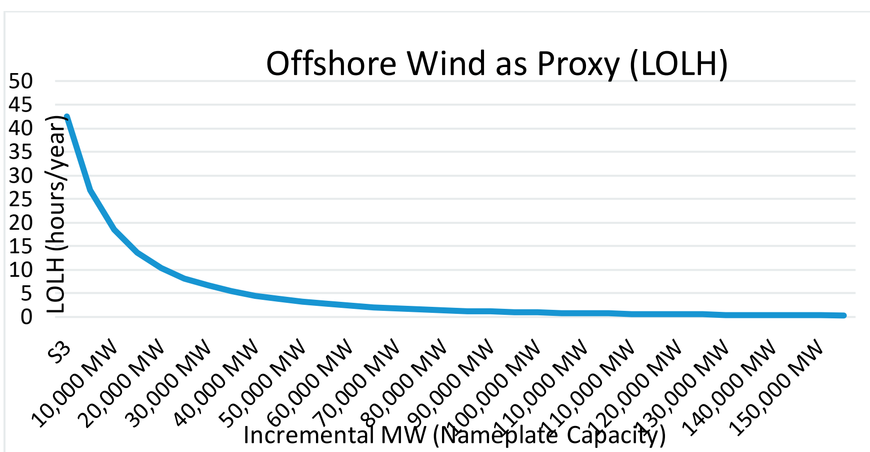

Figure 4-15: LOLH Curve of OFSW as Proxy Units Proxy Scenario

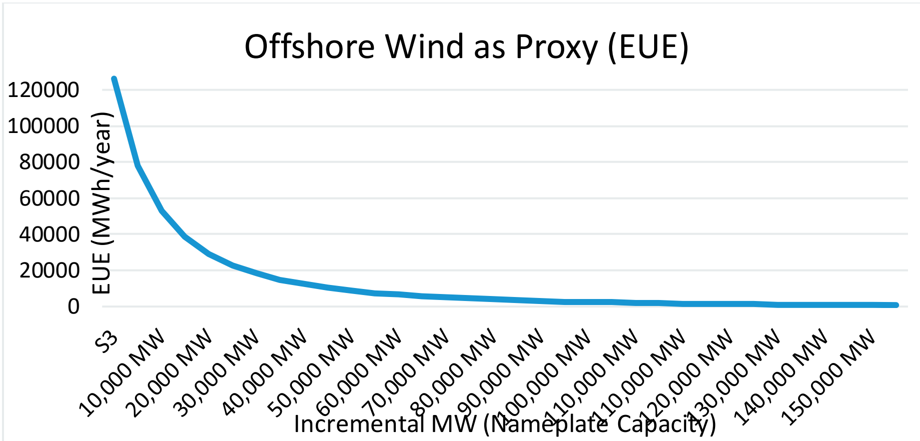

Figure 4-16: Curve of OFSW as Proxy Units Proxy Scenario

4.7.5 Scenario 3, P4: Only ONSW Resources

This proxy Scenario was designed to evaluate what impact onshore wind resources (ONSW) might have on the reliability metrics of Scenario 3. The first 20 GW of ONSW had a large impact on reliability metrics, and 85 GW of ONSW brought the system to reliability criteria. Since ONSW have more diverse locations than OFSW and there are more data points available regarding their average output, the hourly outputs of ONSW were more diverse, and wind droughts had a less widespread effect on reliability. The LOLE, LOLH and EUE curves for this proxy Scenario are shown in Figure 4-17, Figure 4-18 and Figure 4-19.

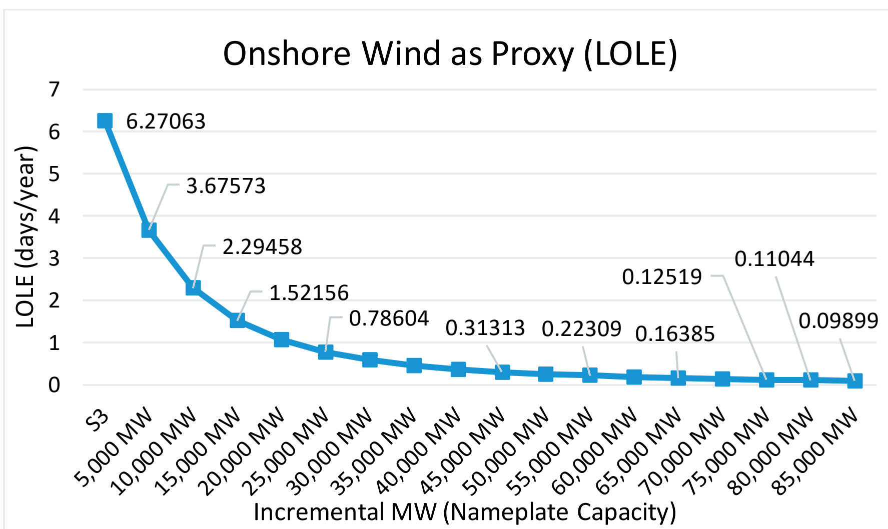

Figure 4-17: LOLE Curve of ONSW Wind as Proxy Units Proxy Scenario

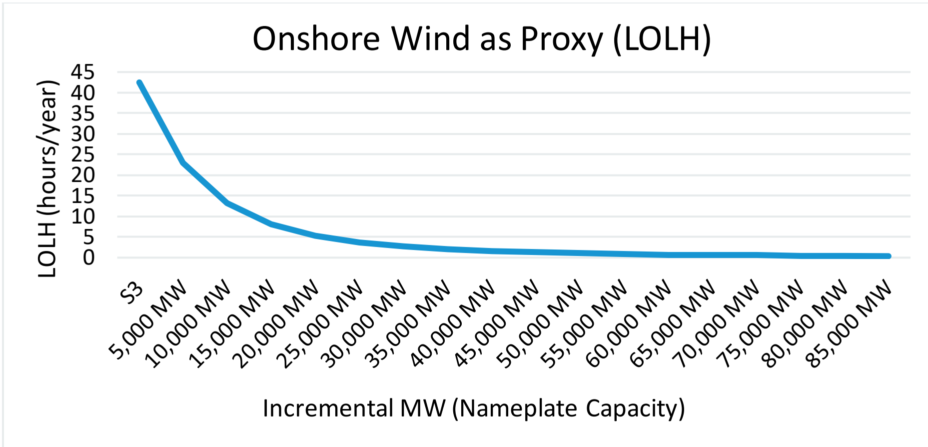

Figure 4-18: LOLH Curve of ONSW Wind as Proxy Units Proxy Scenario

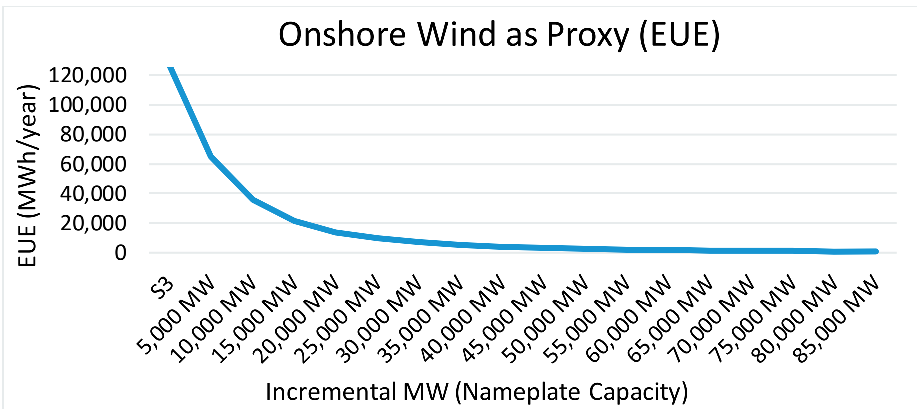

Figure 4-19: EUE Curve of ONSW Wind as Proxy Units Proxy Scenario

4.7.6 Scenario 3, P5: Only PV Resources

This proxy Scenario was designed to evaluate whether the reliability concerns of Scenario 3 could be solved through solar resources alone. However, since Scenario 3 was a winter peaking system, additional solar resources alone were not sufficient to meet system reliability criteria, reflected in Figure 4-20.

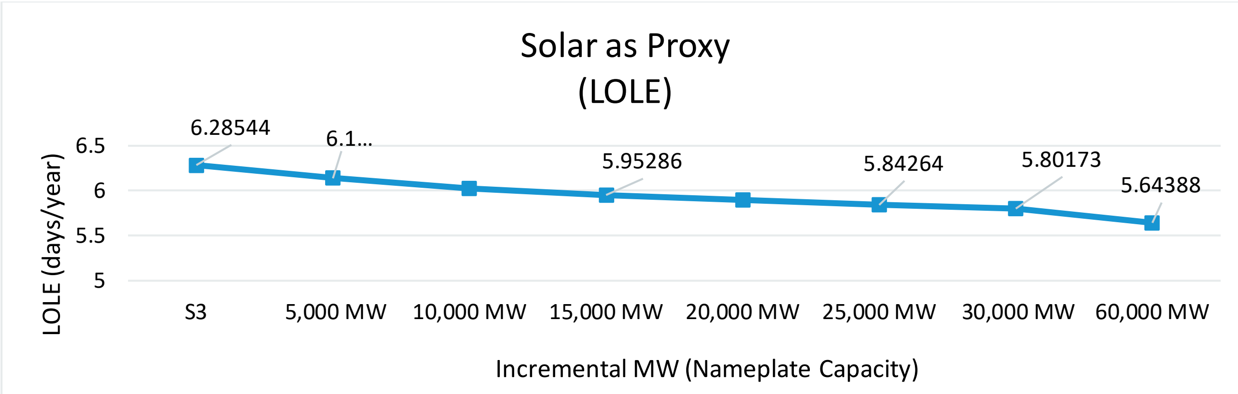

Figure 4-20: LOLE Curve of Solar as Proxy Units Proxy Scenario

4.7.7 Scenario 3, P6: ONSW and BESS Resources

Scenario 3, P6 explored the possibility of using a combination of ONSW and BESS. As compared to Pathways Status Quo, Scenario 3 had similar amounts of OFSW but less ONSW and BESS, so this proxy case involved increasing ONSW and BESS alone to better mimic the Pathways Status Quo resources and explore the impact of adjusting only these resources. An additional 9,800 MW of ONSW and 29,000 MW of BESS (four-hour duration) were needed to bring the system to reliability criteria. The LOLE, LOLH and EUE curves for this proxy Scenario are shown in Figure 4-21, Figure 4-22 and Figure 4-23.

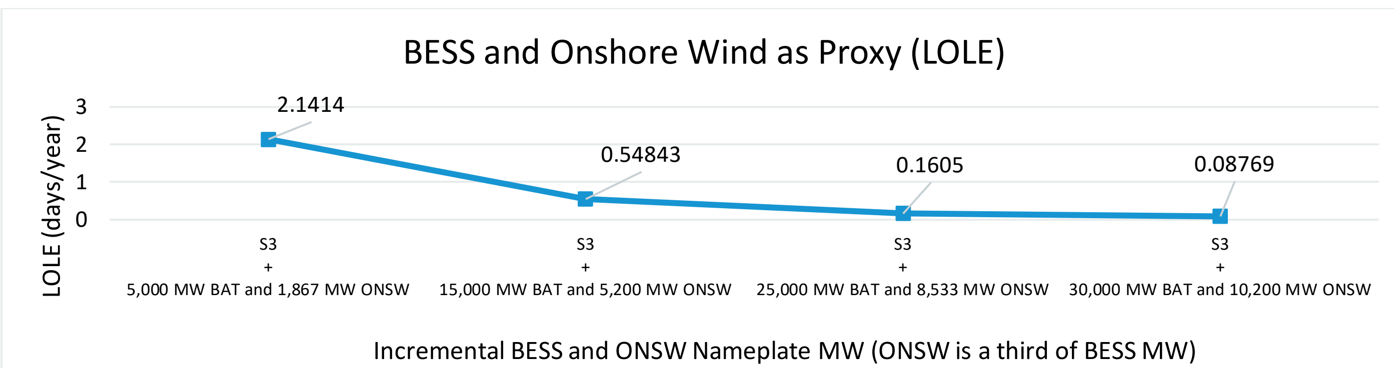

Figure 4-21: LOLE Curve of BESS and ONSW as Proxy Units Proxy Scenario

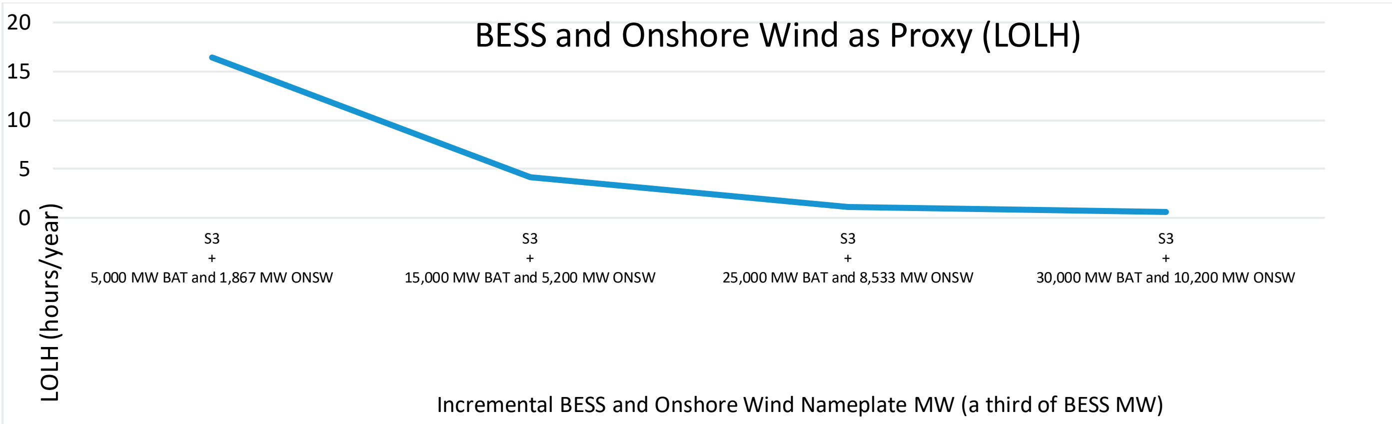

Figure 4-22: LOLH Curve of BESS and ONSW as Proxy Units Proxy Scenario

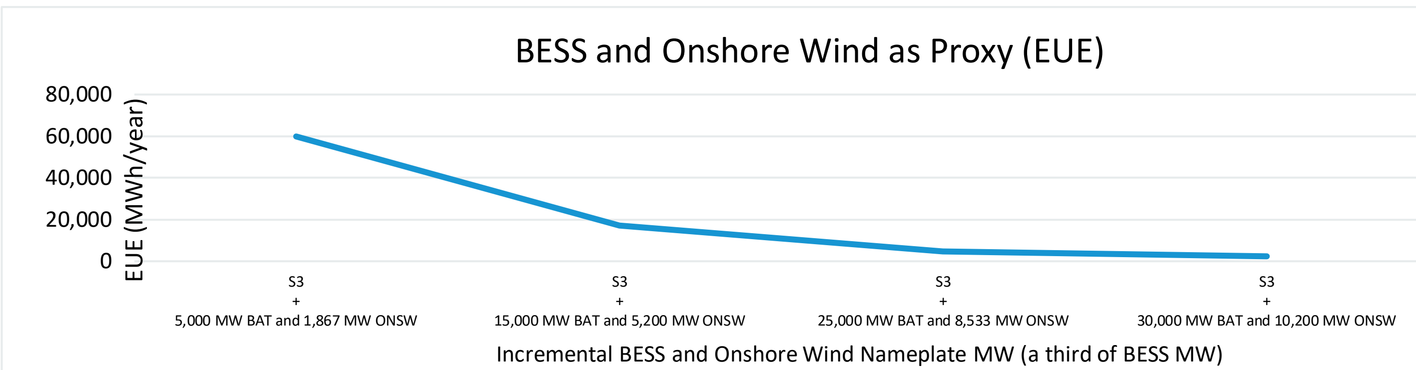

Figure 4-23: EUE Curve of BESS and ONSW as Proxy Units Proxy Scenario

4.7.8 Scenario 3, P7: Scaled PV/Wind/BESS Resources Mix from Pathways Study

As with Scenario 3, P6, Scenario 3 P7, also known as **Resource-Adequate Deep Decarbonization**, adapted Scenario 3 to better match the Pathways Study Status Quo mix. However, in P7, Scenario 3's renewable and BESS mix was replaced with the mix from the Pathways Study Status Quo and was then scaled up to meet reliability criteria. A 70% increase of the renewable and four-hour duration BESS mix was needed to bring the system to reliability criteria (a total renewable/BESS mix of ~89 GW). The total amounts of renewables and BESS are as follows: ONSW: ~7,400 MW; BESS: ~22,000 MW; Solar: ~33,000 MW; OFSW: ~27,000 MW. The LOLE, LOLH and EUE curves for this proxy Scenario are shown in Figure 4-24, Figure 4-25 and Figure 4-26.

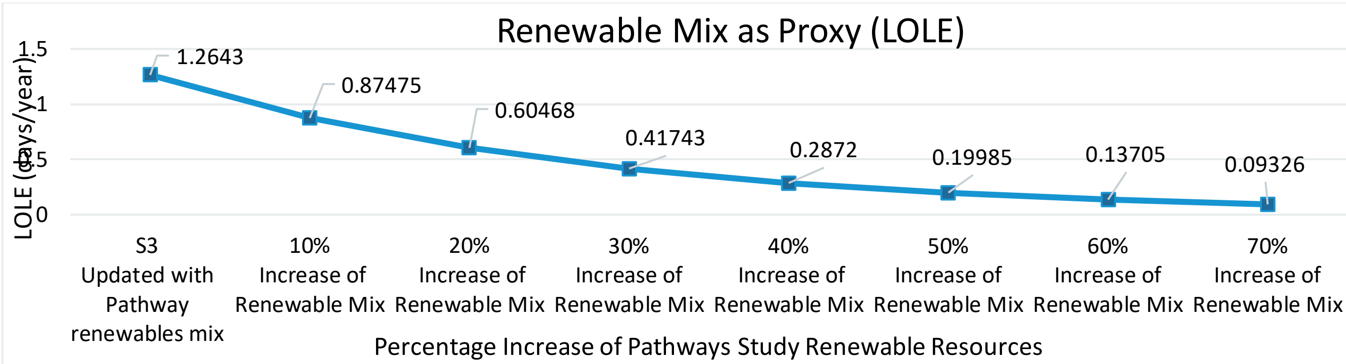

Figure 4-24: LOLE Curve of Renewables Mix as Proxy Units Proxy Scenario

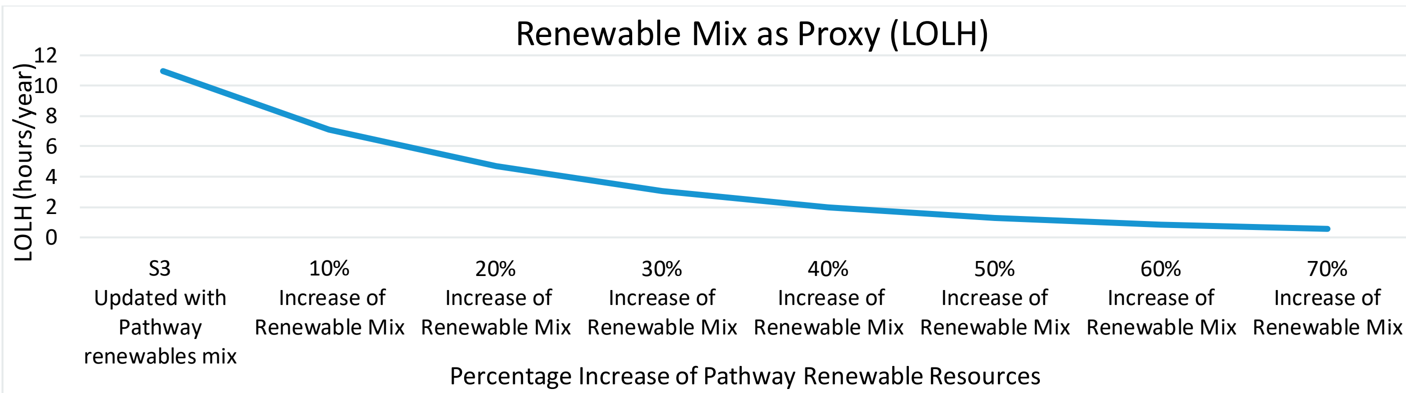

Figure 4-25: LOLH Curve of Renewables Mix as Proxy Units Proxy Scenario

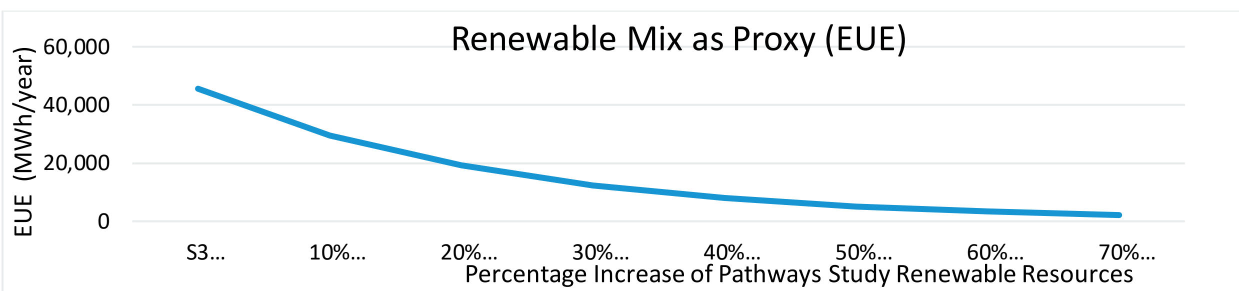

Figure 4-26: EUE Curve of Renewables Mix as Proxy Units Proxy Scenario

4.7.9 Scenario 3 P8: P7 + 3000 MW Dispatchable Resource: Scaled PV/Wind/BESS Resources Mix from Pathways Study

This proxy Scenario was similar to the base Scenario 3, P7 proxy Scenario, but replaced ~20.8 GW of the Scenario 3 P7 renewable and BESS resource capacity mix with 3,000 MW of dispatchable resource capacity. These dispatchable resource proxy units were modeled using a similar outage rate as combustion turbines. The results of this proxy Scenario illustrate the significant impact that small amounts of targeted dispatchable resources might have on the future grid, as a comparatively small quantity of resources (only ~68 GW compared to ~89 GW) was required to meet reliability criteria compared to the renewable/BESS mix of the base P7 proxy Scenario. The resource types and quantities from Scenario 3 P7 and the +3000 MW dispatchable version of P7 are shown in Table 4-10.

Table 4-10: Resource Mixes for Proxy Scenarios S3 P7 and S3 P7 +3000MW Dispatchable

Resource Type	***S3_P7***	***S3_P7 + 3000 MW Dispatchable Resource***
ONSW	*7,400*	*5,800*
OFSW	*27,000*	*21,100*
BESS	*22,000*	*17,200*
PV	*33,000*	*25,800*
New Dispatchable Resource	*0*	*3,000*
Total	*89,400*	*72,900*

4.8 Summary of Additional PRAA Proxy Mix Findings

Several key takeaways were produced by the PRAA simulations of proxy Scenarios. Results showed that neither a majority battery energy storage or majority solar system could produce a reliable system. Substantial offshore or onshore wind solutions did produce a reliable system, however the amount of nameplate capacity required in these proxy Scenarios rendered these options impractical.

In general, geographically diverse installations of onshore wind proved to be more reliable than offshore wind, due to the geographically concentrated nature of offshore wind installations and the highly correlated nature of the offshore wind production. Offshore wind droughts caused larger common-mode outages on the system than onshore due to offshore wind resources' closer geographical proximity to other similar resources. As a result, more offshore wind was needed to make the system secure than was needed in the onshore proxy Scenarios.

Additionally, the reserve margin results of many of these proxy simulations (~300%) were significantly larger than the reserve margin of today's system (~15%). More resources were therefore required in these Scenarios to ensure a reliable system.

Proxy mixes containing dispatchable resources with unconstrained fuel substantially lowered the MWs needed to achieve reliability criteria. Provided they can be developed, dispatchable emissions-free resources could therefore be a crucial part of future resource mixes to achieve the regional environmental guidelines.

Section 5: Conclusion

5.1 Relation to Takeaways

The Future Grid Reliability Study was the first economic study that included a resource adequacy analysis. This analysis revealed vital information not only regarding the challenges of a future renewable-dominant grid, but also a more beneficial sequence for economic studies. Resource adequacy analysis in the FGRS, both RAA and PRAA, revealed an insufficiency of resources to meet reliability criteria in several main Scenarios. Conducting this analysis *before* production cost and ancillary services analysis will help future economic studies identify and solve for fundamental issues in resource adequacy before performing complex analysis like production cost. In future studies, resource adequacy, in particular PRAA, should be performed before other types of analysis.

The resource adequacy analysis showed that the diversity and makeup of resources in the power grid has a significant effect on the number of new resources required to meet reliability criteria. More accurate reflections of hourly load reduction capability of the weather-dependent intermittent resources would help to improve investment decisions, and help to better achieve identified resource adequacy and reliability targets.

In the large quantities assumed in many of this study's Scenarios, solar and wind had diminishing returns in their ability to help a Scenario meet reliability criteria. The periods of highest risk in each Scenario generally occurred at times when the output of these resources was low. Therefore, simply adding more and more solar and wind resources was less and less beneficial, and the needed quantities of these resources increased.

Proxy analysis revealed storage's crucial role in maintaining reliability in those Scenarios with large penetrations of renewables. The key difference between FGRS Scenario 3's assumptions and Pathways Status Quo's assumptions was Pathways Status Quo's more balanced mix of BESS and solar and wind. As a result, fewer resources were needed to meet reliability criteria in the proxy addition analysis of Pathways Status Quo.

As both demand and supply become more weather-dependent, the times of day when the system is most at risk will shift. Risks will increase particularly on winter mornings before sunrise when large quantities of air-source heat pumps are turned on simultaneously. Across the simulated Scenarios of this analysis, solar had a very limited impact on a Scenario's ability to meet reliability criteria, since these risks occurred primarily before sunrise. As the system evolves toward a clean energy transition, we will need to continuously re-evaluate when periods of risk occur, as they will likely shift from their traditional seasons and times of day.