# Economic Studies Technical Guide



Economic Studies and Environmental Outlook

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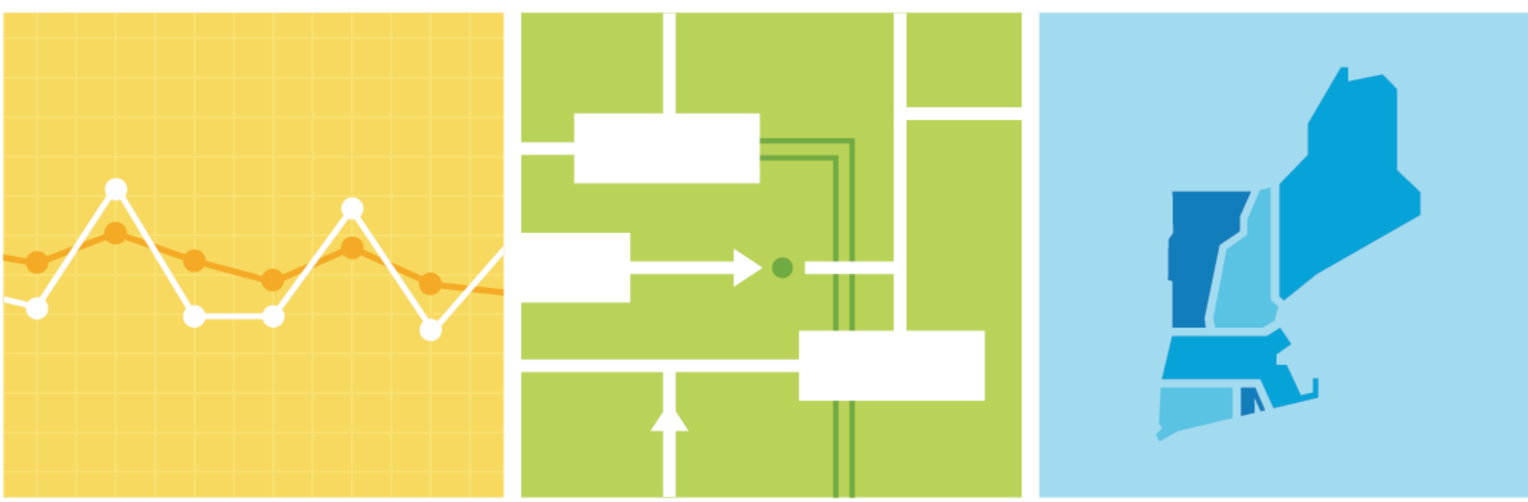

# Disclaimer

The provisions in this document are intended to be consistent with ISO New England's Tariff. If the provisions in this planning document conflict with the Tariff in any way, the Tariff takes precedence, as the ISO is bound to operate in accordance with the ISO New England Tariff.

# Contents

# Figures



# Tables

# Section 1
# Introduction

This Economic Study Technical Guide (the Guide) describes the current assumptions, methodology and outputs used in ISO New England's Economic Study process, which is governed by Section 17 of Attachment K of the ISO New England Open Access Transmission Tariff - *Procedures for the Conduct of Economic Studies*.[1] This Guide is not intended to address every assumption used in system planning studies, but to provide additional detail on certain assumptions relevant to the Economic Study process.

The Guide has been organized into three main sections. Section 1 describes the history of Economic Studies, the process through which these studies are performed, and the types of scenarios examined through the Economic Study process. Section 2 details the base modeling assumptions used to simulate the New England power system in both near-term and future scenarios, and describes how these base assumptions can be altered to suit different study purposes and sensitivity requests. Section 3 describes common output metrics of Economic Studies, and explains how these metrics can be compared to the New England wholesale electricity market of today.

Appendices to the Guide are also included. Appendix A – Terms and Definitions provides a glossary of commonly used terms, Appendix B – Data Sources Spreadsheet details the data inputs used for Economic Studies, the level of confidentiality/market sensitivity of that data, and links to the data source itself wherever feasible, and Appendix C – Market Efficiency Needs Scenario Assumptions describes the assumptions used for the Market Efficiency Needs Scenario. Section 5 provides a history of revisions to this document.

## 1.1 History of Economic Studies

Since 2008, the ISO has performed a variety of Economic Studies. These studies have considered a wide range of topics, but often focus on potential changes to the power grid related to the region's changing fuel mixes and environmental goals. In conducting Economic Studies, the ISO provides the region with information and data on possible evolutionary changes to the power grid. Changes to the grid impact the wider public, and the implications of these changes must be explored and shared in order to educate and inform. Since the ISO is a regional transmission operator, it possesses market sensitive information about power system resources and critical energy infrastructure information (CEII) about the power system that cannot be shared broadly. However, the ISO can use this unique access to data to produce publicly available studies to inform future development. These simulations can assist stakeholders in their decision-making by identifying key regional issues. Please note that the hypothetical alternative power systems explored in Economic Studies like the Policy Scenario, or the Stakeholder Requested Scenario, should not be assumed to be actual plans or as the ISO's vision of realistic future development and preferences.

All Economic Studies conducted on or before the 2021 Economic Study were conducted according to Section 4.1(b) of Attachment K. In 2021, ISO began using the modeling software PLEXOS, which has simulation capabilities that help capture the changing nature of the power grid through the use of its capacity expansion modeling. This presented an opportunity to revise the Economic Study process to better-incorporate PLEXOS. The capabilities of PLEXOS are detailed further in Section

[1] From this point onward, any references to Attachment K of the Open Access Transmission Tariff (OATT) shall be referred as "Attachment K". https://www.iso-ne.com/participate/rules-procedures/tariff/oatt

2.1. In 2023, FERC accept revisions to the ISO Tariff for the procedures relevant to Economic Studies. This new section of Attachment K (Section 17) describes the procedures for the ISO's conduct of Economic Studies. To prepare for these changes, in 2023 the ISO performed a pilot study outside of the Economic Study framework known as the Economic Study for the Clean Energy Transition (EPCET) using PLEXOS. Starting with the 2024 Economic Study, all Economic Studies will be conducted under the guidance of Section 17 of the Attachment K.

Generally, Economic Studies explore hypothetical future power systems that deviate from today's electrical grid in large and small ways. These deviations can include changes to how the power system operates, new transmission lines, new technologies, and the retirement of existing resources. To date, the ISO's Economic Studies have focused heavily on the integration of wind power, solar power, and battery storage, or increased transfers with neighboring power systems. Several Market Efficiency Transmission Upgrades (METU) were also investigated in previous Economic Studies (Keene Road was identified in the 2015 Economic Study and Orrington South upgrades were identified as part of the 2019 Economic Studies).[2,3,4]

#### 1.1.1 Previous Economic Studies

The table below lists all previous Economic Studies. As mentioned in Section 1.1 of this guide, revisions to the ISO's Attachment K pertaining to the conduct of Economic Studies were made by the ISO and accepted by FERC in early 2023. Accordingly, all prior Economic Study listed in Table 1-1 were conducted under the old language of Section 4.1(b) of Attachment K. Please refer to Section 1.3 for an overview of the scenarios studied under the new language for the conduct of Economic Studies dictated by Section 17 of Attachment K.

[2] https://www.iso-ne.com/system-planning/transmission-planning/met

[3] https://www.iso-ne.com/static-assets/documents/2016/09/2015_economic_study_keene_road_increased_export_limits_fina.docx

[4] https://www.iso-ne.com/static-assets/documents/2020/10/2019-renew-es-report-final.docx

| REQUEST YEAR | REQUEST |
|---|---|
| 2022 | No study requested under Section 4.1(b) of Attachment K. The ISO proposed a 'pilot' study of Economic Planning for the Clean Energy Transition (EPCET) to achieve a better understanding of the effect of on-going industry trends on economic planning analyses. The 'pilot' study is intended to achieve three main objectives: perform a dry-run for a new study framework for Economic Studies now under Section 17; review and test input assumptions in economic planning analyses; gain experience in the features and capabilities of the ISO's economic planning software. |
| 2021 | One economic study was received. NEPOOL submitted their Future Grid Reliability Study – Phase I that examined potential reliability gaps in operating the New England system in the year 2040 with more variable energy resources and increased electrification of the overall economy. The final 2021 Economic Study: Future Grid Reliability Study Phase 1 report and a two-page summary was been posted.<br><br>This report has three technical appendices on Production Cost, Ancillary Services, and Resource Adequacy. Data from the Production Cost and Ancillary Services work are also available. |
| 2020 | One economic study was received. The study examines how utilizing existing and new ties to neighboring regions in a bi-directional fashion could optimize the use of renewables across several regions, minimizing spillage, and reducing the reliance on fossil units during peak hours. |
| 2019 | Three separate study requests. The first examined offshore wind expansion scenarios in southern New England up to 8,000 MW. The second examined offshore wind expansion in southern New England between 8,000 MW and 12,000 MW. The third evaluated the effectiveness of transmission upgrades to Orrington South to increase production from constrained onshore renewables in Maine. |
| 2018 | None |
| 2017 | Exploration of Least-Cost Emissions-Compliant Scenarios examines several low-carbon-emitting resource-expansion scenarios of the regional power system and the potential effects of these different future changes on resource adequacy, operating and capital costs, and options for meeting environmental policy goals. |
| 2016 | Performed in two phases. Phase I: Implications of Public Policy on ISO New England Market Design, System Reliability and Operability, Resource Costs and Revenues, and Emissions, examines resource-expansion scenarios of the regional power system and the potential effects of these different future changes on resource adequacy, operating and capital costs, and options for meeting environmental policy goals. Phase II: two presentations were made in lieu of a report, Regulation, Ramping, and Reserves Scenario Results Introduction and Ramping, Regulation, and Reserves. |
| 2015 | Three wind-expansion scenarios: Keene Road (Evaluation of Increasing the Keene Road Export Limit), Northern New England (Strategic Transmission Analysis—Onshore Wind Integration), and off the shore of Rhode Island and Massachusetts (Evaluation of Offshore Wind Deployment). |
| 2014 | None |
| 2013 | One request that examined the economic impacts of different megawatt levels of imports across the Hydro-Québec Phase II interface. |
| 2012 | Three study requests with one report, which examined various resource-expansion and retirement scenarios. |
| 2011 | Wind-integration study examined onshore wind development for five different subareas. |

**Table 1-1: Previous Economic Studies**

## 1.2 Timeline of Studies

Under Section 17 of "Attachment K," Economic Studies are to be conducted at least once every three years and at most once every two years. Typically, these studies are initiated at the January Planning Advisory Committee (PAC) meeting, with the ISO providing notice that the Economic Study cycle is beginning. Within three months of initiating the cycle, the ISO provides a schedule to the PAC that includes dates for the ISO's collection, and stakeholders' submission, of data to be used in the studies, and dates for the preparation of models, the completion of studies, and the issuance of study results. The schedule includes a one-month period for stakeholders to submit proposals for the Stakeholder-Requested Scenario (described further in Section 1.3.4). These studies may result in competitive requests for proposals for identified transmission upgrades.

If the Economic Study cycle cannot be completed within the initial timeline, the ISO notifies stakeholders, provides a revised estimated completion date, and explains the reason(s) why additional time is required.

Assumptions, preliminary results, and final results are presented to the PAC for the ISO to solicit stakeholder input and feedback. If a final report is published, the ISO provides the PAC a draft copy and opens a one-month comment period for stakeholders to provide feedback before final publication.

## 1.3 Study Scenarios

The following section describes the four scenarios outlined in section 17.2 of Attachment K - *Economic Study Reference Scenarios*. The first three scenarios are representations of the New England System at three predetermined moments in time: as it looks in the present, as it might look in ten years, and as it might look at the end of the New England States' current decarbonization legislation timeline, around 2050 (for further details on this legislative timeline see Section 2.5). The fourth, the Stakeholder-Requested Scenario, allows stakeholders to propose a set of assumptions that does not fit in the framework of the first three scenarios. In addition to the Stakeholder-Requested Scenario, stakeholders may request sensitivities of any scenario. While these sensitivities are for informational purposes only, they allow the ISO to test the effect of a specific, targeted change to input assumptions. These sensitivities are limited to a single theme or category of changes to allow for better understanding of the causal relationship between the change in input assumptions and downstream study results.

### 1.3.1 Benchmark Scenario

The purpose of the Benchmark Scenario is to improve the study's model by using input assumptions from the previous year and comparing the model's results to actual power system performance from that same year. Any differences between model results and actual power system performance can then be used to pinpoint issues and to adjust study assumptions and model design accordingly. Historical power system performance includes recorded observations from the beginning of the prior year up to the beginning of the study cycle year. For example, if a particular economic study cycle began in 2022, its Benchmark Scenario year would be 2021. The study year of the Benchmark Scenario is known as year N-1.

Results from the Benchmark Scenario are used for informational purposes only. Any identified market efficiency issues resulting from a Benchmark Scenario will not be evaluated as market efficiency needs against the factors and metrics in ISO New England OATT Attachment N, which describes the standards used by the ISO to identify Reliability Transmission Upgrades, Market Efficiency Transmission Upgrades and Public Policy Transmission Upgrades.[5]

### 1.3.2 Market Efficiency Needs Scenario

The purpose of the Market Efficiency Needs Scenario (MENS) is to identify potential market efficiency issues on the Pool Transmission Facilities (PTF) portion of the New England Transmission System through the end of the ten-year planning horizon pursuant to Section 17.5 - *Market Efficiency Needs Assessment*. This MENS is the updated base case, fine-tuned using results from the Benchmark Scenario, forecasted out to the ten-year planning horizon year using

[5] From this point onward, any references to Attachment N of the Open Access Transmission Tariff (OATT) shall be referred as "Attachment N". https://www.iso-ne.com/participate/rules-procedures/tariff/oatt

assumptions and criteria provided in Section 4.1(f) of Attachment K - *Treatment of Market Responses in Needs Assessments*. The study year for the MENS is known as year N+10, and the simulation length is one year.

The underlying assumptions, input data and evaluation process for the MENS are defined in greater detail in Appendix C – Market Efficiency Needs Scenario Assumptions.

#### 1.3.3 Policy Scenario

The purpose of the Policy Scenario is to identify potential market efficiency issues resulting from the New England states' energy policies and goals, and other relevant policies and goals (e.g., federal legislation, state legislation, or utility renewable portfolio standard targets). The model Policy Scenario is the updated base case, fine-tuned using results from the Benchmark Scenario, forecasted out to a year when New England's and other relevant applicable energy policies and goals are in full effect. The ISO uses a capacity expansion model that simulates the power system over a multi-year or multi-decade horizon to examine the possible composition of resources in this future power system.

The final study year for the Policy Scenario is dependent on legislatively determined deadlines for achieving the relevant energy policies and goals. However, the final study year is always at least ten years into the future and covers deadlines for achieving all applicable policies and goals. The study simulation length for the production cost analysis is one year. Results from the Policy Scenario are used for informational purposes only. Any identified market efficiency issues resulting from a Policy Scenario will not be evaluated as market efficiency needs against the factors and metrics in Attachment N, which describes the standards used by the ISO to identify Reliability Transmission Upgrades, Market Efficiency Transmission Upgrades and Public Policy Transmission Upgrades.

#### 1.3.4 Stakeholder-Requested Scenario

The purpose of the Stakeholder-Requested Scenario is to study any scenario with a region-wide scope that is informative to stakeholders and is not covered by the other scenarios. The model used for the Stakeholder-Requested Scenario is the updated base case, fine-tuned using results from the Benchmark Scenario, forecasted out to a requested year, with assumptions requested by the stakeholders and agreed upon by the ISO. The study year is dependent on the requested scenario, and the simulation length is one year. The results of the Stakeholder-Requested Scenario are used for informational purposes only. Any identified market efficiency issues resulting from a Stakeholder-Requested Scenario will not be evaluated as market efficiency needs against the factors and metrics in Attachment N, which describes the standards used by the ISO to identify Reliability Transmission Upgrades, Market Efficiency Transmission Upgrades and Public Policy Transmission Upgrades.

# Section 2
# Modeling Assumptions

The following section provides an overview of the tools used to perform Economic Studies, as well as the underlying data assumptions used in the Economic Studies model. A more detailed list of input data can be found in Appendix B – Data Sources Spreadsheet of this guide.

## 2.1 PLEXOS Modeling Tool

Economic Studies rely on PLEXOS to model the New England power system. PLEXOS is a software application developed by Energy Exemplar to simulate the market operations of an electric power system that considers the effect of constraints on the transmission system. PLEXOS is typically used by entities participating in electricity markets to study common operational and planning issues, including those related to the restructuring of an evolving electric industry. It helps investigate the effect of changing types and quantities of energy transfers over the transmission system, in ways that may be different from the originally designed intent or ways that may stress the transmission system. PLEXOS was first used by the ISO in 2021, and in 2022 was used in EPCET pilot study.

### 2.1.1 Capabilities of PLEXOS

PLEXOS integrates a detailed supply model, demand model, and transmission system model in order to simulate the market dynamics of a large-scale transmission grid. The software performs transmission and security-constrained optimization of the system resources against spatially distributed loads to produce a realistic forecast of the utilization of power system components and flow patterns in the transmission grid. A key output series, Locational Marginal Pricing (LMP), provides investment signals to energy providers with regard to the locations of resources and loads given regional import and export constraints. Congestion conditions and the cost of increasing transmission load (shadow prices) for constrained transmission lines or interfaces provide valuable insight into what pathways in the power system are stressed, and the magnitude of that stress for a given set of assumptions.

PLEXOS also has the ability to model and optimize the integration of battery storage systems within a network, which is critical to accurately model the evolving electric grid. The software's simulation of battery storage includes characteristics such as state of charge, charging & discharging rates, and charging efficiency.

The solution algorithm for PLEXOS simulations is designed to minimize production costs for a given set of demand and supply-side resources, while considering the transmission system that links them together. Within a system, the program has the capability to model the full transmission network (nodal modeling), no transmission (unconstrained modeling), or a proxy in-between the two, where only major interface or flowgate constraints are simulated (zonal modeling). In Economic Studies, the generators selected to serve load by the program's optimization engine (unit commitment) typically is performed over only the New England region while taking in considerations of constraints within the transmission network. Some scenarios and sensitivities examine the effects of nodal, unconstrained or zonal transmission networks to quantify the benefit of eliminating transmission constraints on the system.

#### 2.1.2 Timeline of Applicability

PLEXOS relies on four modeling horizons to address various planning concerns: short-term, medium term, projected assessment of system adequacy, and long-term. Short-term (ST) modeling optimizes over timeframes that range from hours to days. It focuses on real-time energy dispatch and pricing to meet current demand. Medium-term (MT) modeling covers timeframes that range from a few days to months. It assesses resource allocation related to inter-temporal issues such as battery state-of-charge, hydro storage, fuel supply, and emission constraints, among others. The results of the MT simulation feed into the ST simulation to better optimize dispatch of resources over the simulation horizon. Projected assessment of system adequacy (PASA) optimizes energy distribution among regions and can be used to schedule distributed maintenance. The ISO does not currently utilize the PASA phase of PLEXOS.

Long-term (LT) modeling, which handles capacity expansion, covers timeframes that range from months to years, and is intended to look decades into the future. LT modeling focuses on generation and transmission buildouts and is useful for illustrating the long-term impact of policies and investments. All four modeling horizons can be integrated. When modeling multiple horizons, simulations are run in order from longest to shortest timeframe.

#### 2.1.3 Typical Economic Studies

PLEXOS has been the ISO's primary tool for production cost modeling and capacity expansion modeling since 2022. The production cost models in PLEXOS incorporate a full network model and constraints to optimize generation dispatch and meet demand at the lowest possible cost. The ISO has used PLEXOS to evaluate the economic effects of transmission upgrades, increased penetration of onshore wind, offshore wind, and the other changes to supply-side and demand-side resources. Metrics for evaluating production costs, costs to load-serving entities to obtain energy, and congestion across specific transmission paths have been developed, and these are detailed further in Section 3. These studies typically include an analysis of total power system emissions, often with a comparison to a baseline model and an emission-constrained model.

PLEXOS is also used for capacity expansion modeling, which can help evaluate the need for new generating capacity and transmission buildouts to meet future demand reliably and cost-effectively. Capacity expansion modeling relies on the LT schedule that optimizes, at a high level, both production cost and capital costs, including costs of new generator builds, transmission expansion, and generator retirements. Since capital cost increases as more assets are built, but production cost may tend to decrease, the capacity expansion model can help find a least expensive reliable future power system, although more detailed analysis may identify areas where the simplifications involved have produced a sub-optimal solution.

*Reliability Modeling*

In PLEXOS, reliability modeling refers to the ability of the power system to meet demand reliably under various conditions. When using LT in capacity expansion modeling, the software encounters some limitations in effectively addressing reliability concerns, since the model has difficulty representing intricate details of the power system over different timeframes, and inputs to the LT schedule are necessarily simplified.

*Reliability Metrics and Resource Adequacy Modeling*

The policy scenario will often evaluate far-reaching (10+ years in the future) scenarios with significant penetrations of intermittent resources. To evaluate the reliability of power systems built in the capacity expansion model, the ISO has developed a proxy analysis that will generate a target dispatchable resource requirement.

In this proxy analysis, the capacity expansion model must be run first, typically building towards a target decarbonization goal. The model will not retire any resources during the expansion phase. After a set of new resources has been determined, a net load analysis is run. This may only be run for the terminal year, or it may be run at intermittent steps (for example, the model may be stopped every 5 years for the reliability analysis.) The model uses hourly loads from the ISO New England load forecasting team for a 20-year period. Then, the net load is calculated for the determined buildout of intermittent resources. Each intermittent resource has a 20-year rating profile from the advisory firm DNV's dataset. The net load is calculated by subtracting intermittent resource generation from the gross load for each hour. The remaining net load is the load that must be met by dispatchable resources. To account for forced outages of resources, the maximum net load is increased by 10%. To set an upper limit on dispatchable capacity for a retirement threshold, the maximum net load is increased by 20%. If the model's build out results in more than 120% of the maximum net load in dispatchable resources, units are retired based on age. For example, if a 50 GW gross load is reduced to a 40 GW net load with a given set of resources, the required dispatchable amount is equal to 40 GW × 1.1 = 44 GW. If the model has more than 40 GW × 1.2 = 48 GW of dispatchable resources, units are retired based on age.

For the purpose of the analysis, intermittent resources refers to photovoltaic (PV) and wind units, while dispatchable resources refers to all fossil, nuclear, and hydro generation as well as all energy storage.

### 2.1.4 Model Settings

Production cost and capacity expansion modeling have different objectives. Though they perform similar functions (i.e., the capacity expansion model contains a simplified production cost model), different levels of detail are required for both models. Capacity expansion models must analyze details at an abstract level of detail over long periods (10 to 30 years), which can become resource intensive. Chronological abstractions are therefore made to reduce runtime. Production cost models, on the other hand, are typically run at one-hour time steps for one year at a time. This shorter period allows for more detailed transmission and dispatch modeling. Production cost models also do not require chronological simplification, and can rely on an hourly model.

*LT Specific Settings*

Capacity expansion modeling utilizes the long term (LT) phase. This phase shares many settings with the MT and ST phases, but has more detailed settings regarding time resolution and expansion accounting.

PLEXOS's chronology setting determines how large timeseries profiles are simplified within the LT. The ISO is currently using sampled chronology. Sampled chronology selects a number of representative periods per larger period (i.e., four days per month, two weeks per quarter, etc.) These representative periods are designed to capture the possible variation in conditions within a larger period. The model then selects which generators dispatch for each hour of those representative periods. A rescaling method built into the model then modifies the dispatch between these bookend samples, such that wind, solar, and load energies match the original input profiles. This sampling methodology was selected for two reasons: it represents energy storage operation more accurately than the other options, and it generates production cost and emission metrics that are closer to the hourly models than other methods. The other settings available, sampled and fitted chronology, use load duration curves to estimate unit dispatches. Although these settings allow the model to run faster, they represent energy storage poorly, and do not always respect unit characteristics such as ramp rates or minimum up times.

Other LT settings capture the economics and optimality of expansion decisions. Certain settings enable discount rates, tax rates, and inflation rates. The ISO is currently using only a discount rate in Economic Studies. The optimality of expansion decisions can be linear or integer. Integer decisions require that whole hypothetical generating units be built in order to solve issues in the grid, while linear decisions allow partial generating units to be built. For example, under the integer setting, a 200 MW candidate generator would require that the entire 200 MW of generation be built, or not be built at all. Under the linear setting, the model allows for a fraction of the candidate 200 MW to be built, i.e., a 150 MW generator. The ISO has elected to use the linear setting to avoid distortions caused by disjointed additions in calculating marginal costs.

*MT and ST Specific Settings*

Production cost simulations utilize both the medium term (MT) and short-term (ST) phases of PLEXOS. During simulations, the MT phase runs before the ST phase. The purpose of the MT phase is to optimize the dispatch of resources, especially hydro and energy storage resources, across the entire horizon of the simulation, and subsequently use this information in the ST phase. The ISO currently utilizes the partial chronology of the MT phase for time slicing. The MT phase of the model generates weekly duration curves for both load and resource hourly profiles. These curves are then divided into seven blocks, and each hourly profile is applied approximately to one of those seven blocks. This time slicing approximation allows the MT to determine a reasonably optimal dispatch of resources with much less computing power. The MT schedule dispatch helps the ST schedule to better optimize the dispatch of hydro resources, and coordinates the charge and discharge of energy storage.

The ST schedule runs as chronological 8,760-hour simulations for each year, with one-hour “interval length” and one-day “time steps.” This schedule optimizes unit dispatch of generators for a 24-hour window for each of the 365 days of the year. Since input profiles in the ST schedule are hourly, no time slicing is needed.

*Transmission Settings*

The ST phase and the LT phase of PLEXOS use high level transmission and heat rate detail settings. Transmission settings are categorized as regional, zonal, and nodal (see Section 2.2 for further detail). The ISO uses either regional or nodal settings, depending on the type of model. In an unconstrained model where transmission is not being studied, using the regional setting speeds up runtimes. Conversely, the nodal setting takes longer, but allows for more detailed transmission analysis.

*Generator Heat Rates*

In PLEXOS, heat rate settings are categorized as detailed, simple, and simplest. The detailed setting utilizes full quadratic heat rates, while the simple setting uses only no-load and linear rates. The simplest setting uses only linear heat rates. The ISO has elected to use the detailed heat rate setting in the hourly production cost models to fully model heat rate detail. Capacity expansion models use the simplest setting, as it reduces runtime while appropriately simplifying fuel consumption.

*Production Settings*

The production module in PLEXOS determines how detailed the unit commitment will be for a given model. In addition to the three heat rate settings listed above, additional settings control unit commitment optimality, simultaneous storage charging/discharging, and other unit commitment formulation settings.

The unit commitment optimality setting determines how the unit commitment variables are treated in the optimization. This setting's options include linear relaxation, rounded relaxation, and integer optimal. Linear relaxation is the simplest, while integer optimal is the most complex, with a correlated tradeoff between runtime and optimality of dispatch. The ISO has elected to use rounded relaxation in the hourly production cost models to convert the optimization problem from an equation with decimals, to one with integers with a rounding up threshold of 0.25, as this setting generates an appropriate dispatch at reduced run times. Capacity expansion models use the linear relaxation setting, as the chronology simplifications of these models reduce the importance of optimal dispatch. It is important to note that buildouts in the capacity expansion model are subsequently run in follow-up hourly production cost models, which ensures analysis using a more detailed hourly model.

The simultaneous storage charging/discharging setting determines if storage should be allowed to charge and discharge (or pump and generate, in the case of pumped storage) at the same time. During extended periods of negative LMPs, this setting would allow storage to LMPs by allowing one battery to charge while a second battery discharges. By doing so, some energy is lost through inefficiencies in the battery charge/discharge cycle, thereby reducing the total production cost on the power system. Though the ISO does not currently use this setting, the future operation of energy storage may make this behavior worth investigating, and the assumption can be revisited.

Certain settings formulate unit commitment and ramping constraints upfront. These settings determine if min up/min down times and ramp rates should be verified after the unit commitment is created or if they should be considered as the unit commitment is being created. In the ISO's experience, verifying the rates after unit commitment creation reduces runtime without violating any constraints.

*Custom Constraints*

By default, the primary objective of both production cost and capacity expansion models is cost minimization. However, custom constraints can be applied to enforce additional rules and limits on the model. If applied, these custom constraints are included in the model's formulation, with the result that cost is minimized subject to the custom constraint. For example, a capacity expansion model without a custom constraint will build a power system for least cost given a set of loads, fuel prices, starting resources and candidate resources. If a carbon constraint is added to the capacity expansion model, PLEXOS will try to reduce emissions to meet the given set of loads, prices, starting resource, candidate resources *and* carbon constraint for the least cost.

## 2.2 Transmission Topology

Economic Studies include an analysis of transmission system constraints, which are enforced limits on the power system that prevent thermal overloads. Thermal overloads on the transmission system occur when transmission lines, transformers, or certain substation equipment carries more than its rated amount of current or power flow. This condition can lead to overheating, equipment disconnection, or, in some cases, permanent damage.

To quantify the impacts of transmission constraints, two versions of a power system must be modeled: a constrained topology and an unconstrained topology. The unconstrained topology allows for unlimited transfer across the New England power system, while the constrained topology will enforce line, transformer, and interface limits on the power system. The total costs (in dollars and emissions) generated by resulting congestion are then calculated based on the results from the two models.

To quantify the impact of a single transmission element or interface on the model, limits associated with that element can be increased, and the production cost metrics subsequently compared.

The Benchmark Scenario is modeled using a fully nodal model for production cost simulations. The topology of the system is reflective of the N-1 simulation year.

The Market Efficiency Needs Scenario models a nodal production cost system. The topology of the system is reflective of N+10 year. Further details on the transmission topology of the MENS scenario is discussed in greater detail within Appendix C – Market Efficiency Needs Scenario Assumptions.

The Policy Scenario is modeled without any transmission constraints for the New England power system in the capacity expansion runs and is typically modeled as a zonal system using the major interfaces of the New England power system for the production cost simulations. While it is possible to model both nodal and zonal topologies within capacity expansion, the simplifications made of time slicing made by capacity expansion modeling remove the inter-temporal complexities that would be of interest. Therefore, an iterative approach between capacity expansion modeling without internal transmission constraints and production cost modeling with zonal transmission constraints is necessary.

### 2.2.1 Transmission Modeling Sources

The transmission topology in Economic Studies is drawn from the transmission planning base case library (TPBCL),[6,7] specifically, a model representing the power system 10 years into the future. This case aligns with transmission planning studies that examine the same time period and include all planned additions of transmission. Since the transmission system faces different constraints in

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[6] https://www.iso-ne.com/system-planning/planning-models-and-data/transmission-planning-models

[7] The Transmission Planning Base Case Library (TPBCL) requires CEII clearance. Stakeholders may request access to CEII clearance on the ISO's Website. https://www.iso-ne.com/participate/support/request-ceii-access

summer and winter, the summer peak load case is used for standard ratings, while the winter peak load case is used to determine winter ratings.

Interface definitions are drawn from the associated Base Case Database (BCDB)[6,7] file. These interfaces are imported into the model and lines/transformers are matched with existing transmission objects. Interface limits are provided by the ISO Transmission Planning team. Some thermally limited interfaces may not have interface limits applied, allowing for individual elements within the interface to become binding. Since the thermal interface limits used in Economic Studies are based on the peak load conditions of today's power system, these same limits may not be binding in alternate future conditions with different peak load conditions, including time of day and seasonality.

Contingency definitions are drawn from the associated BCDB file, and include only OP-19 generator, line, and transformer contingencies, and only contingencies at 115kV and above. These contingencies are imported into the model and matched with existing generation and transmission elements. Only contingencies of 115kV lines and above are modeled to identify Pool Transmission Facilities (PTF), which reduces model runtime.

#### 2.2.2 Transmission Definitions

The following section describes various transmission elements and how they are defined within the modeling framework of PLEXOS and Economic Studies.

*Line*

A line connects two buses of the same voltage and allows energy to flow bidirectionally. Lines are modeled with a resistance and a reactance. Lines also have two associated limits, one for N-0 conditions and one for post-contingency N-1 conditions. Some lines may also have a set of winter ratings applied for only the winter months; these are higher than their summer ratings, since the transmission lines can withstand higher thermal loads in colder weather. Line limits are enforced at 115 kV and above. Additionally, because electrification will require significant upgrades to the sub-transmission and distribution power systems the 115 kV limit avoids representing overloads that are outside the purview of the ISO.

*Transformer*

A transformer acts similarly to a line and shares most of its properties, but can connect two buses of different voltage levels. Transformers are also modeled with a resistance, reactance, N-0 and N-1 limit. Transformer limits are enforced at 115 kV and above for the same reasons as for lines.

*Interface*

Interfaces represent a certain set of lines and transformers. Since PLEXOS cannot model voltage or stability issues, interfaces are used to enforce voltage & stability limitations on the power system. Interfaces are modeled with a limit. For each line and transformer in the interface, a directionality coefficient must be defined, which specifies whether the line or transformer path between particular buses is flowing into the interface or out of the interface. N-1 limits on the interfaces are used from the BCDB.

*Flow Control*

Flow control objects represent phase shifting transformers. These are modeled as a line with variable impedance. In addition to the typical line properties, a maximum and minimum angle is defined. During the course of a simulation, the impedance is adjusted such that production cost is minimized subject to the allowed angle limits.

*Contingencies*

Contingencies exist as monitored element/contingency pairs (mon/con pairs) within the model. Each contingency has both affected elements (elements directly impacted by the contingency) and monitored elements (elements that may possibly be affected by the contingency). Affected and monitored elements are generators, transformers, or lines. Prior to running the model, the network around each affected element is searched to five buses away to identify mon/con pairs. Any line or transformer at or above 115 kV is added to the monitored element list for a given contingency object. If an affected object is part of an interface, all other interface elements are also added to the monitored element list.

*Slack Bus*

For contingencies that result in a loss of generation, a slack bus must be defined to satisfy the post contingency power flow.

### 2.2.3 Transmission Methodology

During the course of a simulation, network injections and withdrawals are used to calculate optimal power flow (OPF). After calculating network flows, the flows on each interface, line, and transformer at or above 115kV are compared to their N-0 limits. If a flow exceeds the limit, the dispatch is altered to alleviate the violation. The element with the violated limit is reported as a binding element for that period.

Following the OPF formulation, the security constrained unit commitment (SCUC) calculates a new power flow for each contingency object. For each contingency, the affected elements are removed, and new line and transformer flows are calculated and compared against their N-1 limits. If generation or load is lost as a result of the removal of affected elements, an equivalent amount of energy is provided by the slack bus. If a limit is violated, the mon/con pair is reported as binding for that period.

The model is configured to report nodal prices, generation, unserved energy, and dump energy. Lines, transformers, and interfaces report hourly flows, and hours binding/shadow prices if they are constrained. Contingency objects also report hours binding/shadow prices.

### 2.2.4 Load and Distributed Generation Distribution

Both load and distributed generation are modeled zonally, and a load profile is assigned to each load zone. For behind-the-meter photovoltaics (BTM-PV) and active demand response units (ADR), one aggregated generator is modeled per dispatch zone with its output distributed among the loads busses in the zone. This aggregation is explained further in the following paragraph. For energy efficiency resources (EE), a similar approach using one aggregated generator is modeled per load zone.

The load and generation for each aggregated load zone or generator are mapped out to each participating node via load participation factors (LPF) and generation participation factors (GPF). These represent the fraction of the load or generation that is affected. For example, aggregated BTM-PV generation may have a 10% GPF with a certain node. If that BTM-PV zonal generator is producing 100 MW in a given hour, the node will receive 10 MW of BTM-PV generation for that hour. These distributions are based on data from the BCDB.

## 2.3 Power System Load

The following section describes how power system load is modeled in the Benchmark, MENS, and Policy Scenarios.

*Benchmark Scenario*

The power system load in the Benchmark Scenario is taken from historical SMD load data[8] published on the ISO New England website. The profiles include the effect of EE and BTM-PV (Class III PV) generation. The distribution factors of load across New England nodes are based on models from the BCDB. The historical load profiles are assigned to the load zone, and a fraction of the total zonal load is injected into each node.

*Market Efficiency Needs Scenario*

The load for the MENS is consistent with the horizon year of the most recent Forecast Report of Capacity, Energy, Loads, and Transmission (CELT)[9]. The ISO's Load Forecasting team provides the monthly 50/50 gross model output peak loads for the given time period. The gross load is an increase above observed loads due to adding back energy that was conserved through energy efficiency programs compensated in the ISO markets. A scaling factor is calculated for each month to scale the historical monthly peak to the N+10 monthly peak. This scaling factor is then interpolated from month-to-month and applied to all other hours. The load profile is distributed to each load zone based on the forecasted zonal 50/50 gross model output energies.

EE is modeled as a distinct resource, since the CELT includes an EE peak reduction and energy reduction value. The EE profile is applied to the 50/50 gross model. On the peak gross load day, EE is assumed to provide the maximum amount of energy possible. Once a preliminary profile is created, monthly scaling factors are applied to ensure that the total energy reduced matches the CELT forecast. This EE profile is distributed to each load zone based off of the CELT zonal peak reduction amounts.

Load profiles for heating and transportation electrification are supplied by the ISO Load Forecasting team, and are distributed by zone based on CELT zonal distributions using the load participation factors (LPF).

The load and BTM-PV distribution methodologies are similar to those in the Benchmark Scenario, with the only difference relating to the magnitude of the energy to be distributed. One load profile exists per load zone and one aggregated BTM-PV generator exists per dispatch zone, and both are

[8] SMD Hourly Loads by Load Zone https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info

[9] The CELT provides detailed 10-year forecasts of the demand for electricity in New England https://www.iso-ne.com/system-planning/system-plans-studies/celt

injected into multiple nodes via LPFs and GPFs. EE is also distributed on a nodal level based on BCDB distributions.

Further details on the load assumptions for the MENS scenario can be found in Appendix C – Market Efficiency Needs Scenario Assumptions.

*Policy Scenario*

The load in the Policy Scenario is taken from the ISO's long-term load forecast for 2040 and 2050. Due to the nature of the modeling, extrapolation is performed from the Benchmark load profile (previous year) to the MENS load profile (10 years out), then between the MENS load profile and a 2040 profile. The 2040 and 2050 profiles include reductions reflecting EE, so EE does not need to be explicitly modeled in the load. Beyond the horizon of the CELT, the BTM-PV nameplate value is scaled up based on the difference between the last two years of the forecast (for example, if there is a 500 MW difference in BTM-PV nameplate between the last two years, each year beyond the CELT horizon includes an additional 500 MW of BTM-PV).

While load and BTM-PV distributions are based on the load distributions in the MENS, the Policy Scenario is not run at a nodal level, and is instead run using zonal (pipe and bubble) transmission detail. As a result, the LPF distributions from the MENS are aggregated into RSP zones for BTM-PV as well as electrification loads.

## 2.4 Power System Resources

Unless otherwise requested, all resources participating in the New England markets are included in an Economic Study regardless of whether they are capacity resources or energy-only resources. The net nameplate (MW)[10] values for the following resources are used for the nameplate values of generators and are taken from the most recent transmission BCDB:

- Natural gas
- Oil
- Coal
- Biomass
- Battery energy storage system (BESS)
- Nuclear
- Hydro
- Wind
- Solar
- Pumped storage

The CELT provides BTM-PV nameplate values.

PLEXOS is an object-oriented modelling tool, wherein each generator is classified as an object with user-defined generator properties and multiple objects are grouped under a specific class. There are four main types of generator classes in the model: thermal, hydro, storage, and profiled (i.e. wind and solar). Relationships between objects can be defined by creating memberships. These memberships are the linkage between two objects within PLEXOS such as the membership between a generator and a fuel type. PLEXOS also includes a variety of built in constraints that can be imposed on transmission, generation, or emissions. Additionally, PLEXOS's ability to add user-defined custom constraints to the unit commitment algorithm allows for additional features to be

[10] *Net nameplate* refers to the gross output of a generator minus the station service load

modelled such as generator fuel-switching due to fuel constraints, energy storage, and distributed generation.

#### 2.4.1 Thermal Generation

Thermal generating resources include natural gas, oil, coal, biomass, and hypothetical future clean resources with similar generating capabilities. Typically, these thermal generators are characterized by the following generator attributes:

- Net Nameplate (MW)
- Heat rate base (MMBtu/h)
- Heat rate increment (Btu/kWh)
- Heat rate increment 2 (Btu/kWh$^2$)
- Minimum stable level (MW)
- Minimum up and down times (h)
- Max ramp up and down rates (MW/min)
- Start costs ($)
- Emission rates (lbs/MWh)
- Fuel prices ($)
- Other identifiers (e.g., Asset IDs or Resource IDs)

There are three different types of heat rates represented in the model: heat rate base, heat rate increment, and heat rate increment 2. The heat rate base represents the time period when the generator is beginning to run, and is the least efficient stage in the startup process. As the generator continues to run, the heat rate will change as the generator increases its output, which is represented in a quadratic formula containing the two heat rate increments. Thermal generators, such as coal, have data for all three types of heat rates. Oil generators that only have data for average heat rates are represented in the model using the heat rate increment.

Thermal generating resources and their attributes are obtained from a combination of public sources and the ISO's confidential information. Generator-specific attributes like heat rates, start costs, minimum up and down times, and max ramp up and down rates are sourced from internal ISO databases and are considered market sensitive data. Publicly available data provided by the Environmental Protection Agency (EPA) and the Energy Information Administration (EIA) can offer estimations of these values, but modelling results will differ from the results of the Economic Studies. See Appendix B – Data Sources Spreadsheet for further detail on the source of input data.

Emission rates for $CO_2$ are calculated using the heat rates and the generator emission factors (lbs/MMBtu) sourced from the EIA. Additional generator emission constraints (i.e., emission limits) can be enforced to assess various Policy Scenarios. Section 2.5 contains additional information on emissions. The New England region fuel prices used in the model are also obtained from the EIA. Since the EIA assumes all coal units in New England as retired in the near future, the model uses the prior year's price forecast relative to the modelled future year for coal instead. Lastly, the net nameplate, minimum stable level, min/max stable levels, min up/down times, and Asset IDs are taken from the BCDB.

*Natural Gas*

Natural gas resources are divided into two categories: combined cycle generators (CC) and gas turbine generators (GT). CC generators are modeled as one generator injecting into multiple nodes on the transmission system, since the ISO has heartrates only at the asset level, not the machine level. GT generators are able to be modeled closer to the machine level since there is no steam recycler being shared with the turbines as there is in CC generators. The fraction of each generator's actual output MW into each node is represented by the generation participation factor, which is obtained from the BCDB.

Both natural gas and oil resources include dual-fuel generators that are capable of burning more than one type of fuel. Typically, these generators will have a primary fuel (i.e. natural gas or oil) and a secondary fuel to allow for fuel-switching during periods of fuel constraints. Daily gas constraints can be enforced in the model using a custom constraint:

$$\sum(Generator\ Gas\ Consumption)\ \leq\ Temperature\ Dependant\ Daily\ Gas\ Allotment$$

If the sum of all gas generation requires more gas than the allotment, the model will optimize some units to switch to their backup fuel to minimize production cost. The daily gas allotment, or specifically the natural gas and liquefied natural gas (LNG) availability, is estimated from gas curves provided by an ISO vendor. The gas curves are temperature dependent, therefore, changing the weather year can significantly alter fuel consumption, and consequently, emissions. Generally, a colder weather year would place a higher demand on natural gas and LNG for heating, resulting in less natural gas available for electric generation. Under a constrained natural gas and LNG system, the price of constrained gas would rise, thus making dispatchable resources like oil and coal economic to operate.

*Biomass*

Biomass sources for energy include municipal solid waste (MSW), landfill gas (LFG), and wood. The primary function of biomass resources is waste disposal; electric generation is only a byproduct of this service. Therefore, these generators are considered must-run regardless of the current LMP. However, they are allowed to operate between their economic minimum and maximum, which is the amount of energy (MW) available for economic dispatch.

Economic Studies do not assess the life cycle emissions of energy resources, only the emissions associated with electric generation. As such, biomass generators are not considered carbon neutral in the model and are assigned positive emission rates.

*Nuclear*

Nuclear generators share many of the same attributes as thermal generators, with the exception that operating parameters such as start costs, ramping capability, and emissions are ignored. Similar to biomass generators, nuclear generators are also considered must-run.

*Active Demand Response*

Active Demand Response (ADR) resources are measures installed on end-use consumer facilities that allow the grid operator to curtail the electrical usage of that facility upon dispatch. Similar to BTM-PV, ADR nameplate distributions are provided by the BCDB. ADR resources are modelled similarly to BTM-PV except that, rather than producing according to a profile, each ADR generator is given a fuel cost ($/MWh) and will not run unless LMPs reach this threshold. In scenarios that investigate an energy constrained power grid, ADR is represented similarly to batteries, due to the need to perform the service that was temporarily foregone during the ADR activation period.

### 2.4.2 Profiled Resources

A profiled resource is a unit whose output is defined by an input profile (typically hourly) and magnitude of generation. This generator class typically covers wind, solar, and imports, but can also be used for modeling novel generating resources, provided an input profile is available. Profiled resources are useful for illustrating the effect of weather on a resource (typically wind or solar) during a particular year, since the input profile can be adjusted to reflect a particular weather year. By modeling more than one weather year, the variability in these resources can be reduced as more atmospheric conditions and anomalies are accounted for. In the Policy Scenario, many different weather years are used in order to build out a power system that can withstand these different weather conditions.

Dispatch of these resources is typically performed using a profile and a nameplate capacity rating, and a variable Operational and Maintenance (VO&M) cost that is commonly referred to as a threshold price. The threshold price is used to determine when to allow generation from a profiled resource to serve load, or when there is too much generation online and the units output is cut – known as curtailment. The use of energy storage systems or production of synthetic fuels may help reduce curtailment, but the threshold price is still necessary to regulate profiled generating resources during times of oversupply.

Figure 2-1 below illustrates a hypothetical situation in which a 2 MW solar plant is overproducing energy in comparison to current demand. The plant's production is curtailed due to a drop in the locational marginal price (LMP) and an assumed threshold price of -$10/MWh. Provided the LMP is above this threshold price, this unit will dispatch in accordance with its input profile and magnitude. In this example, this dispatch occurs between hours 1 through 9 and hours 17 through 24. The generation is not curtailed since the LMP is at $5/MWh. For some of these hours, e.g. hour 1, there is no generation, since the input profile for this unit calls for zero solar generation at this time of day.

Once the LMP reaches the threshold price, the resource begins to curtail. In this example, the curtailment occurs between hours 10 and 11, where the LMP is equal to the threshold price. A portion of the solar generation is curtailed while a portion of the generation still serves load.

When the LMP is equal to the threshold price, a portion of the solar generation may be curtailed. Threshold price resources of the same value are treated as a fleet, thus LMPs will not drop below this threshold price until every MWh output is curtailed in that fleet.

Finally, when the LMPs falls below the threshold price, all output from a profiled resource is fully curtailed. The LMP drops to -$15/MWh, and thus the entirety of the plant's output is curtailed.

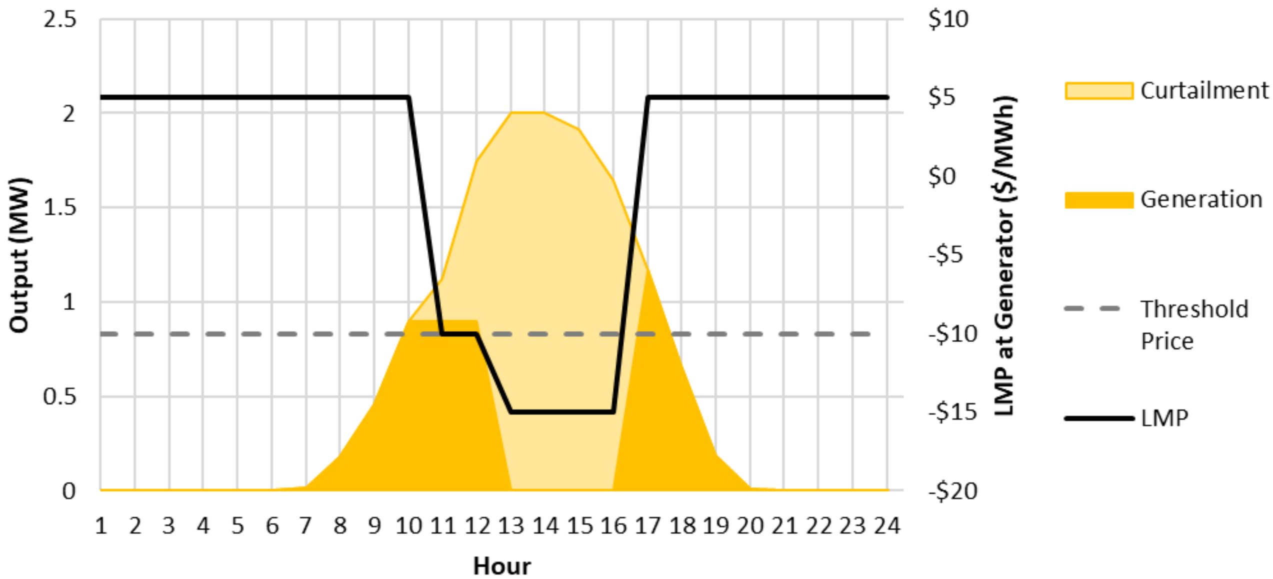


**Figure 2-1: Example of Solar Curtailment due to Threshold Price**

Profiled resources are sometimes used to model load reduction and increases such as BTM-PV, electrification, and EE resources. In these cases, resources are assigned either a very negative curtailment price to ensure they are the last unit curtailed, or they are defined as a must-run resource.

*Utility Scale Solar and Wind*

Solar and wind generators in the PLEXOS model share the same attributes. The nameplate (MW), min stable level (MW), and generation participation factor for both resources are provided by the BCDB. Any grid connected solar generators (i.e. non-BTM PV) with nameplate greater than 10 MW are classified as Class 1 solar. A nameplate value is also assigned to each generator, which the model uses to apply hourly generating profiles. These production profiles are gathered from a historical dataset of hourly time series data for solar and wind resources. The dataset currently used was created by advisory firm DNV using NASA satellite information and modeling software to construct production profiles based on New England weather.[11]

An assumed VO&M charge of negative $10/MWh is assigned to solar and wind generators. As shown in the example above, this is also known as the threshold price, and it allows the model to curtail these resources if LMPs reach the specified price. Setting the same VO&M charge for solar and wind allows the PLEXOS model to decide which resource to curtail based on the location of transmission congestion. Changing the VO&M charge changes how frequently certain resources are dispatched or curtailed.

[11] The results of the DNV analysis were presented to the Planning Advisory Committee on February 17, 2021. https://www.iso-ne.com/static-assets/documents/2021/03/a9_stochastic_time_series_modeling_for_isone_rev_2.pdf

*Behind-the-Meter Solar*

The BCDB shows distributions of BTM-PV nameplate based on dispatch zones.[12] Each dispatch zone is assigned an aggregated generator with a nameplate capacity equal to the sum of all BTM-PV in that zone. The nameplates are scaled to match the nameplate by zone in the most recent CELT. BTM-PV shares the same attributes as the grid-connected solar generators, except BTM-PV does not have a defined min stable level. In addition, the assumed threshold price for BTM-PV, - $99/MWh, is much lower than the assumed price for grid connected solar and wind (- $10/MWh), since BTM-PV is considered the last resource to be curtailed.

*Imports*

Hourly import profiles for Québec, New York, and New Brunswick are based on a monthly diurnal average profile developed from the previous three years for future Scenarios. The profile is based on the average import for each hour of the day for a specific month using historical data from the past three years. This profile is used to simulate each day in that month for a future year. [13] As with other generators, imports are assigned a nameplate (MW), rating factor, max energy, VO&M charge, and generation participation factor. Imports are given an assumed positive VO&M charge so that they are the first resources to be curtailed.

Further information on how imports are handled for the MENS scenario can be found in Appendix C – Market Efficiency Needs Scenario Assumptions. The Benchmark Scenario uses historical import profiles for the year being modeled.

*Distributed Resources*

Distributed resources are typically smaller-sized resources that use load-reduction technologies or on-site generation. These resources are directly connected to the distribution system, not the ISO regional power system, however, they effectively reduce the amount of energy the region consumes. Distributed resources include aggregated Class 2 PV, small hydro generation, and ADR. EE resources are not modelled because their load reduction is already accounted for in the system load profiles. It is important to include distributed resources in Economic Studies in order to account for their impact on the power system load.

### 2.4.3 Energy Storage

All existing and planned energy storage objects, which include pumped storage and BESS, are taken from the BCDB. The attributes associated with each generator are assumed values under Economic Studies, except for the load and max capacity associated with pumped storage, which are sourced from the market participants.

Energy storage systems operate to maximize price arbitrage by charging from the grid when LMPs are lower and discharging their stored energy when LMPs have risen. Scheduling this charge and discharge cycle is handled by PLEXOS's look-ahead logic. In production cost modeling, the entire year is first analyzed in the MT phase to determine the best times of year for batteries to charge and

[12] Behind-the-Meter PV (BTM-PV) is defined as PV units that operate behind the retail meter. This excludes PV units that have obtained a CSO or that participate in the Energy Markets.

[13] Historical import data is available on the ISO website. https://www.iso-ne.com/isoexpress/web/reports/grid/-/tree/external-interface-metered-data

discharge. This determines a general pattern that the dispatch will follow as the hourly dispatch is then handled in the 24-hour windows of the ST phase. Again, the objective of the batteries is to maximize profits to the storage resource based on the differences in LMPs.

*Pumped Storage*

Pumped storage generators take advantage of the gravitational potential energy of water to store energy. During low demand periods, water is pumped from a lower elevation reservoir to a higher elevation and is later released through turbines to produce electric power when the value of the energy is relatively high. Within the model, each pumped storage facility is represented as a storage object and is assigned a VO&M charge, pump efficiency, pump load, and max capacity. There is no limit enforced on the number times energy storage resources can charge or discharge (i.e. cycle), but pumped storage typically cycles twice per day under an assumed pump efficiency of 74%.

*Battery Energy Storage Systems*

Similar to pumped storage generators, BESS units charge when net demand is low and discharge to supply energy when net demand is high. Existing and planned BESS units are derived from the BCDB for the Benchmark and MENS Scenarios. BESS has an assumed initial state of charge of 50% and unlimited charging range, since it is assumed that batteries bidding into the market are set at a safe charge level to avoid significant degradation. Since the model has perfect foresight as a result of the MT phase, the cycling of energy storage resources is optimized. A sufficient price separation must exist for the model to charge or discharge the BESS. The cycling frequency can vary depending on how the VO&M charge and charging efficiency are set. In the current model, the assumed charge efficiency is 86% and the assumed capacity (MWh) varies across the BESS object. BESS is assumed to have a higher efficiency than pumped storage to reflect presumed advancement of battery technology in the future.

### 2.4.4 Hydro-Electric Resources

There are three broad classifications of hydro generation in the ISO New England markets:

- Hydro daily run-of-river (HDR)
- Hydro daily pondage (HDP)
- Hydro weekly pondage (HW)

HDR generators only run when there is river flow, therefore, generation is variable and uncontrollable. In contrast, HDP and HW generators have water reservoirs that store water on a daily or weekly basis during low-demand periods and are dispatched when demand is high. Hydro generators are assigned nameplate (MW), minimum stable level (MW), and monthly max energy in the PLEXOS model. The hydro model assigns hydro generators monthly maximum capacities and minimum stable levels. Some smaller hydro generators are aggregated and connected to 345kV buses.

## 2.5 Air Emissions

The power sector is one of the primary sources of greenhouse gas emissions, alongside the transportation and industry sectors. Greenhouse gas emissions are primarily comprised of carbon dioxide ($CO_2$) with smaller amounts of methane ($CH_4$) and nitrous oxide ($N_2O$). These gases effectively trap heat in the atmosphere and contribute to climate change. In order to curb $CO_2$ emissions, five New England states have adopted economy-wide greenhouse gas requirements with varying levels of reduction mandated over the next several decades.[14] Modelling $CO_2$ emissions and evaluating those estimated emissions against decarbonization initiatives such as the Regional Greenhouse Gas Initiative (RGGI) and renewable portfolio standards can help illustrate what the power system might look like in a decarbonized future.

### 2.5.1 $CO_2$ Emissions

PLEXOS uses the following inputs to quantify the total amount of $CO_2$ emissions (tons) from each source and/or by state:

- Generator Emission Factors (lbs/MMBtu)
- Generator Heat Rates (MMBtu/MWh)

The generator emission factors for $CO_2$ are taken from the latest Annual Energy Outlook (AEO) report published by the Energy Information Administration (EIA). The AEO explores long-term energy trends in the United States and accounts for current laws and regulations impacting the power sector. The emission factors reported in the AEO are aggregated by fuel type and are expressed in units of lbs/MMBtu.

The generator heat rates used in Economic Studies are sourced internally and are considered market sensitive data. However, the EPA's Clean Air Markets database is publicly available and provides detailed generator attributes data, including heat rates that can be used for this analysis.

Generator emissions of $NO_x$ and $SO_2$ can be quantified using the historical unit specific emission rates (lbs/MWh) taken from the ISO New England Electric Generator Air Emissions[15] analysis. Interest in $NO_x$ and $SO_2$ emissions have waned in recent years, primarily due to the significant reduction in coal and oil resources, which were the primary source of these pollutants.

### 2.5.2 Regional Emission Targets

The majority of the New England states have established greenhouse gas emission reduction targets of at least 80% below 1990 levels by 2050, with some states setting a more stringent target of net zero by 2050. Net zero could be achieved by balancing $CO_2$ emissions with removal of $CO_2$ from the atmosphere via sequestration, or by reducing carbon emissions to zero through changing energy sources. Table 2-1 below shows the New England states' economy-wide goals for reducing emissions over the next 20 to 30 years.

[14] The New England states that have adopted greenhouse gas reduction mandates are Connecticut, Maine, Massachusetts, Rhode Island, and Vermont.

[15] https://www.iso-ne.com/system-planning/system-plans-studies/emissions

| State | 2020 Interim Target/Goal | Interim Target/Goal | 2050 Target/Goal |
|---|---|---|---|
| **Connecticut** [16] | 10% below 1990 levels | 2040: 0% from electric sector<br>2030: 45% below 2001 levels | 2050: 80% below 2001 levels |
| **Maine** [17] | 10% below 1990 levels | 2045: Carbon neutral<br>2030: 45% below 1990 levels | 2050: 80% below 1990 levels |
| **Massachusetts** [18] | 25% below 1990 levels | 2040: 75% below 1990 levels<br>2030: 50% below 1990 levels<br>2025: 33% below 1990s level[19] | 2050: achieve at least net zero but do not exceed 85% below 1990 levels |
| **New Hampshire** | N/A | N/A | N/A |
| **Rhode Island** [20] | 10% below 1990 levels | 2040: 80% below 1990 levels<br>2030: 45% below 1990 levels | 2050: net zero |
| **Vermont** [21] | N/A | 2030: 40% below 1990 levels<br>2025: 26% below 2005 levels | 2050: 80% below 1990 levels |

**Table 2-1: New England State Emission Targets**

The Economic Study Policy Scenarios are focused on analyzing emissions from the New England region as a whole, therefore, the general $CO_2$ emission constraint of 80% below 1990 levels by 2050 is applied to the PLEXOS model rather than an accounting of each state's varying emission reduction targets.

Based on historical emissions data, the New England $CO_2$ emissions from 1990 was approximately 54.1 million short tons. An 80% reduction below 1990 levels therefore equates to an emission constraint of 11.2 million short tons. It is important to note that emissions from wood, biomass, municipal solid waste (MSW), and landfill gas (LFG) units are not counted in state emission reduction goals and are therefore excluded from the model's emissions constraint. However, they are separately tracked and reported.

[16] Conn. Gen. Stat. Sec. 22a-200a

[17] 38MRS§576-A

[18] *"An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy"*, State of Massachusetts, accessed June 7, 2023.

[19] "Massachusetts Clean Energy and Climate Plan for 2025 and 2030", State of Massachusetts, accessed March 13, 2023.

[20] R.I. Gen. Laws § 42-6.2-9

[21] *"Vermont Global Warming Solutions Act of 2020"*, State of Vermont, accessed June 7, 2023.

#### 2.5.3 Emission Prices

Emission price or “carbon price” is the cost of emitting one ton of $CO_2$ ($/ton) and is a useful metric for evaluating the costs of a future decarbonized power system. The New England states currently participate in two carbon reducing cap-and-trade programs that impose a price on carbon emissions:

1. The Regional Greenhouse Gas Initiative (RGGI), covering generators in all New England states; and
2. The Massachusetts Global Warming Solutions Act (GWSA), covering only generators in Massachusetts.

The objective of these programs is to quantify the environmental cost of emitting one ton of $CO_2$ in dollar terms so that it can be accounted for in the generation cost for most fossil-fuel resources. Currently, carbon allowance prices under the cap-and-trade programs affect the total energy costs of the affected fossil fuel-fired generators. It is therefore useful to incorporate these emission costs into Economic Studies to assess how expensive fossil fuel generation will be in the future compared to renewable resources as carbon allowance prices increase over time.

The projected $CO_2$ emission prices are taken from NYISO’s RGGI and the Massachusetts GWSA price forecast, which extrapolates $CO_2$ allowance prices from 2023-2040.[22] The price forecast also includes emission prices for $SO_2$ and $NO_x$, however, the effect of these emission prices is not the focus of Economic Studies.

The MENS includes emission prices from both RGGI and GWSA. However, the GWSA emission price is not included in the Policy Scenario due to uncertainty that the program will continue into 2050.

#### 2.5.4 Renewable Resource Energy Production vs. Renewable Portfolio Standards (RPS) Targets or Goals

To support the development of renewable resources and decarbonization efforts, the New England states have established Renewable Portfolio Standards (RPS) that require electricity providers to serve a minimum percentage of their retail load using renewable energy. RPS requirements and definitions of renewable resources vary from state to state.

Due to the complexities of RPS standards, which assign energy from similar resources in one category versus another based on attributes like “new” versus “existing as of a specified date,” accounting of these standards has proven daunting, and only examinable at a conceptual level. The MWh of renewable energy generated can be compared to the MWh required to satisfy a state or regional mandate, and the remaining MWh needed to meet the RPS targets can give a sense of the number of renewable resources that might be needed in a future year. More fine-grained analysis related to RPS standards is not currently possible.

[22] https://www.nyiso.com/documents/20142/40757605/04a_10242023_ESPWG_2023-2042_Outlook_Update.pdf/fec50258-b289-bfcc-5de7-35377929d5f5

# Section 3
# Economic and System Performance Metrics

The results of Economic Studies can be compiled to produce various metrics depicting different aspects of power system-expansion scenarios. These metrics can then be used by stakeholders to evaluate the pros and cons associated with a given scenario, and to assess simulated power system performance for future scenarios that include changes like additional imports from Canada, more offshore wind, fewer resource retirements, etc.

Key metrics include estimates of production costs, transmission congestion, electric-energy costs for New England consumers, environmental emissions, and a number of other aspects of power system operations. These metrics may suggest beneficial economic locations for resource development, as well as the least economical locations for resource additions or retirements. Economic Studies provide a common framework for NEPOOL participants, regional electricity market stakeholders, policymakers, and consumers to identify and discuss reliability, economic, and environmental issues along with possible solutions. Metrics are an important part of this collaborative process. The commonly reported metrics are discussed below, as well as the limitations for each metric.

## 3.1 Economic Metrics

Many economic metrics are associated with both production-cost modeling as well as capacity expansion modeling. The following section describes some frequently used economic metrics in detail.

### 3.1.1 Production Cost

Production cost is the generator's variable cost of producing energy to serve customer loads. Changes to production cost due to a project or improvement provide an indicator of the change in cost to be borne by the customers in the region. All changes that improve the efficiency of the power system operation or markets will reduce production costs.

Production cost is calculated by summing all of the costs associated with fuel, VO&M, and/or if applicable, costs of emission allowances, and renewable energy credits (RECs).

$$Production\ Cost = Fuel\ Cost + VO\&M\ Cost + Emission\ Costs + RECs\ Cost$$

The production cost concept does not distinguish between costs that provide benefits to the local economy versus costs that provide benefits to an external economy. For example, production cost metrics consider it cheaper to spend $10 million on fuel from Saudi Arabia than spend $11 million on locally-harvested biomass using local labor, where the related economic activity would recirculate throughout the regional economy. This aspect is particularly important to consider when studying future changes in infrastructure, where differences in capital spending versus operational expense become important. For example, part of the economic benefits of wind and PV are that these technologies provide "green", local jobs during the construction phase. Conversely, the ongoing purchase of non-New England-sourced fuel benefits the economies of other, gas-producing regions. While economy-wide regional economic modeling can help to better understand the downstream impacts of inside-the-region costs versus outside-the-region costs, this topic is not part of Economic Studies performed by ISO New England.

Accounting for the production cost of interchange with areas outside of ISO's jurisdiction is challenging, since the actual costs of fuel and emissions are outside ISO's purview and are thus unknown and subject to supply and demand in a larger interregional marketplace. Models used in Economic Studies assume interchange profiles that represent the flows into New England and, in some cases, out of New England. Past practices include assigning a relatively low price that ensures the external energy is high priority, and all available energy could be imported. If the same price is used between all studied cases, the production cost of imports in every case would be the same, which allows for a "canceling out" effect. However, in actual simulations, transmission constraints can create unequal amounts of imported energy between cases, and the cost of imported energy between cases may not cancel out completely. There is no defined adjustment to the production-cost metric for this unequal imported energy situation.

#### 3.1.2 Location Marginal Prices

The purpose of this metric is to provide a yardstick for the cost of energy at various locations throughout the network. LMPs are comprised of three components – energy cost, congestion costs, and losses. In a hypothetical lossless, unconstrained power system, the latter two components would be zero.

The LMP is calculated from the incremental cost of energy production from the most expensive marginal cost resource that is needed to serve customer loads within a constrained area (if constraints exist). Whenever a transmission constraint is reached, there are marginal resources on either side of the constraint.

There are nuances to the exact method of calculation for LMPs between aggregate areas that create subtle LMP differences. LMP metrics are based on one of the following three formulas:

1. A simple average of all LMPs at each bus in a year ($LMP_{avg}$)
2. An LMP weighted based on the load at each load bus ($LMP_{load}$)
3. An LMP weighted based on the generated MWh at each generator ($LMP_{gen}$)

For Economic Studies, ISO New England uses the $LMP_{load}$ and a fourth metric based on the RSP subarea's LSE Energy Expense divided by RSP subarea's load to calculate a load weighted LMP that would be consistent with LSE Energy Expense. The average calculated $LMP_{load}$ can be influenced by subtle effects, like whether load served by BTM-PV is included as load in the calculation, and how it is valued.

#### 3.1.3 Load-Servicing Entity Energy Expense

Load-Servicing Entity (LSE) Energy Expense is a metric that represents the cost of energy to customers. This metric excludes non-energy charges such as capacity, transmission and distribution network demand charges, user fees and other legislated or tariff charges. It is calculated by totaling, at each location, the load multiplied by the corresponding LMP in each hour to give the cost in millions of dollars per year.

$$LSE\ Energy\ Expense_{Node} = \sum_{i=1}^{Hours\ in\ Year} Load_i \times LMP_i$$

Under the current framework for the Benchmark and MENS Scenarios, EE and energy served by BTM-PV are included in the MWh of load within the RSP subareas and, therefore, included in the aggregate LSE Energy Expense.

LSE Energy Expense can be a challenging metric for use in economic analysis for the following reasons:

1. Transmission constraints may create pockets of high or low LMPs that distort the LSE Energy Expense metric.
2. Depending on the relative size of the load in the areas affected by the high and low LMPs, an improvement that increases efficiency can either increase or decrease the total New England LSE Energy Expense metric.
3. Production-cost simulation models develop a simulated dispatch based on a production-cost minimization algorithm, and create a dispatch that would be different from the results of a simulation based on an LSE Energy Expense minimization algorithm.

In a production-cost model, a small change in assumptions may change how the model optimizes dispatch of resources to minimize production costs. For example, the model may choose to dispatch a high-variable cost-peaking unit instead of a base-load unit with high start-up costs because it would result in lower production costs even as it increases the LSE Energy Expense affecting all load in that hour. Since an annual analysis consists of 8,760 dispatch periods (total hours in a year), the different optimizations may settle out into a "reasonable" and explainable pattern, where LSE energy expense exhibits the same trend as production-cost. However, this settling is not guaranteed, since results can vary depending on the type of optimization solution engine.

Transmission constraints can create "pockets" with bottled-in, low-cost generation. LMPs within these "pockets" may become so low that any change to the assumptions about the transmission constraint may dominate the LSE Energy Expense metric for both the pocketed area and the rest of the power system. For example, past studies have shown that relieving an export constraint helped to reduce production cost, but consequently increased total New England LSE Energy Expense. This outcome arises because the LMPs associated with the small amount of load in bottled-in areas increased significantly from their depressed levels, while the change in the rest of New England's prevailing LMPs were very small. Therefore, total New England LSE Energy expense increased.

Complexities also arise related to whether EE and BTM-PV should be included in the amount (MWh) of load within the RSP subareas, and subsequently included in the LSE Energy Expense. Furthermore, the LSE energy expense metric is limited in that it does not accurately represent what customers actually pay. In reality, customer rates are based on a risk-adjusted rate set by an energy service provider, which may deviate from expected LMPs.

### 3.1.4 Uplift

Uplift is metric that represents the revenue stream paid to a generator when the generator is dispatched by the simulation model, but does not recover all of its start-up and production costs from energy revenues within a 24-hour period. Uplift is tracked for each resource in each hour. If the revenues from LMP-based energy are not sufficient to cover the start-up and no-load cost of a generator in a 24-hour calendar day, the shortfall is recorded and accumulated as uplift. Uplift accounts are assumed to be settled on a daily basis, and the metric is typically expressed in millions of dollars per year.

$$Uplift_{Generator} = \sum_{i=1}^{Hours\ in\ Day} Generator\ Costs_i - Generator\ Revenue_i$$

This metric represents a revenue stream to generators and a cost to the customer that may be considered when looking at the total profitability of resources or a more complete estimate of the total LSE Energy Expense.

Since the incremental costs of energy production from the marginal resource is what sets the LMP (and the incremental costs of energy from the marginal unit is lower than the average cost to produce the power from that resource), the marginal generator will not recover its operating costs from the LMP-based revenue stream. Uplift is a relatively small component of actual ISO New England markets, and typically results from out-of-market dispatch. In ISO energy markets, bidding and LMP price formation is intended to cover most, if not all, of the energy costs without the inclusion of an out-of-market revenue stream (e.g., uplift). Since production cost simulations exclude market bidding strategies, uplift is generally higher in simulations than actual historical charges.

### 3.1.5 Financial Transmission Rights / Auction Revenue Rights

This metric can be considered as an adjustment to LSE Energy Expense, and is based on the distribution of Auction Revenue Rights (ARRs) received from the sale of Financial Transmission Rights (FTRs) in an ISO/RTO administered market. These FTRs have a value since LSEs have a right to a portion of any lower-cost energy produced in export-constrained areas.

The economics of energy introduced into an import-constrained area or delivered from an export-constrained area can be accounted for using a mechanism that allows the imported energy into the receiving area ("sink") to be valued at the producing area's ("source") LMP. This mechanism is based on the concept of FTRs, where LSEs have a right to a portion of any lower-cost energy produced in other areas. The value of these FTRs is monetized in an FTR auction and the proceeds of the auction flow back to the LSEs as their share of the ARRs. Thus, this adjustment to the LSE Energy Expense metric is referred to as "FTR/ARR" congestion. FTR/ARR congestion values are equal to the product of the constrained interface flow (MW) and the price differential across the constrained interface.

$$FTR/ARR\ Value = MW \times (LMP_{Sink} - LMP_{Source})$$

The effect of compensating LSEs indirectly via ARRs for energy produced within a constrained area is a reduction in the net LSE Energy Expense metric. Under this reallocation, the LSE Energy Expense equals the sum of the supplier/generator revenues. This FTR/ARR process assumes that 100 percent of the ultimate value of the FTRs is returned to the LSEs via their share of ARRs.

However, this is not necessarily the case under New England's current market structure since the FTRs are sold via auctions, where participants value them based on their estimates of future on- and off-peak transmission constraints.

#### 3.1.6 Gross Revenues to Resources

The purpose of the gross revenue metric is to show the magnitude of revenues that resources will receive. This metric does not explicitly take into account uplift revenue, which may be an important revenue stream for some resources. The sum of Gross Revenues earned by all resources (internal and external) should equal the cost paid by load as measured by LSE Energy Expense. If there is a difference between these two values, it can be used to evaluate the effect of congestion as calculated by the FTR/ARR metric.

Gross revenues equal the sum of each MWh of energy produced by a resource in an hour multiplied by the LMP applicable to the resource's location in that hour. Typically, this metric is expressed in $/kW-year or Millions of Dollars per year for a specific resource in the model that is intended to be representative of a type of resource.

$$Gross\ Revenue_{Generator} = \sum_{i=1}^{Hours\ in\ Year} MWh_i \times LMP_i$$

#### 3.1.7 Net Revenues to Resources and Contributions to Fixed Costs (CTFC)

The purpose of this metric is to show the magnitude of net revenues that resources will receive from operations. Ideally, this net revenue is applied to recover the fixed costs of the resources. This value represents the profit a generator earns from operations by selling energy into the power system at their hourly LMP, and is typically compared to the costs of ownership. The Net Revenues to Resources is expressed in $/kW-year or Millions of Dollars per year for a specific resource and should equal the Gross Revenues minus fuel, VO&M and emission-allowance costs.

$$Net\ Revenue_{Generator} = Gross\ Revenue_{Generator} - Fuel\ Costs - VO\&M\ Costs - Emission\ Allowance\ Cost$$

This metric does not explicitly consider uplift revenue, which may be an important revenue stream for some resources. An additional limitation for this metric is that there are many fixed costs borne by an owner that are not included in the production-cost simulations.

The net revenues from operations are also described as Contributions to Fixed Costs (CTFCs). This is typically calculated for a single "representative" resource for each technology/fuel type. This metric can be negative if the energy production sold at the LMPs is not sufficient to cover start-up and no-load costs of operations, which can occur when the incremental heat rate that determined LMPs is lower than the average cost for the marginal unit. Uplift accounts for these revenue shortages and prevents a negative CTFC. A negative CTFC would mean that the there is no money for fixed O&M, property tax, depreciation expense, return on capital investment, etc.

#### 3.1.8 Relative Annual Resource Cost (RARC)

This metric is used to compare different visions of the future using a snapshot that illustrates the key cost components in a single metric. The RARC accounts for the annual power system-wide production costs (which can be thought of as operating costs), plus the annual costs of capital additions by including the annualized carrying costs for new resources and high-order-of-magnitude, transmission-development costs. RARC is thus a measure of the relative total costs for a scenario. It does not include all consumer costs that would ultimately be determined by distribution rates, which may include a variety of factors outside the scope of this metric, but should be equal in the other scenarios that are compared using this metric. RARC is expressed in either billions of dollars per year or cents per kilowatt-hour (kWh).

Capital costs for new resources and/or transmission upgrades must be converted to a levelized annual-cost perspective using an assumption such as Annual Carrying Charges (e.g., assuming 12% to 15% of capital cost per year) that can be used in the comparison.

- Levelized annual cost of transmission upgrades/additions
- Levelized annual capital cost of new resources (which can be presented by new scenario-based technology types)

These capital costs are typically uncertain, and ISO/RTOs have developed markets and procedures to allow participants to compete based on their expertise and familiarity with these costs. Participants can compete to provide supply resources in the Forward Capacity Market and develop transmission solutions through competitive solicitations.

## 3.2 Operational Metrics

Many of the metrics extracted from the simulation describe physical quantities related to operations. Some of the most frequently used metrics for describing physical quantities are described below.

### 3.2.1 Energy Production

The energy production metric by technology or fuel type allows for a comparison of energy sources in various scenarios. For example, there are differences in behavior between scenarios where coal units operate and scenarios where they are retired, and these metrics can be used to explain the resultant behavior of other metrics such as production costs, emissions and LMPs.

This metric is the summation of energy from each resource type and/or fuel type category and is expressed in GWh per year or TWh per year. The metric can also be represented as a percentage of total requirements.

### 3.2.2 Capacity Factor

The rate of utilization of specific resource types as characterized by capacity factor can be useful in understanding their contribution to market operations. Capacity factor is defined as the amount of energy produced by a particular resource type divided by the nameplate capacity of the group of resources, and then divided by the number of hours within the study period (8760 hours to represent a year).

$$Capacity\ Factor = \frac{Actual\ Energy\ \mathrm{Pr}o\ duced}{Nameplate\ Capacity \times Hours\ Within\ Study\ Period}$$

This metric is expressed as a percentage. If there is a wide range of capacity factors within a group of resources, then distributions of the capacity factors versus unit count (or cumulative MW) can be developed, which would help evaluate how various resource types perform and identify noticeable trends or distinctions among the resources.

This metric is useful for many classes of generators, with some exceptions. For example, within a broad "unit class" for the gas turbine technology "GT," resources may utilize different fuels that range from "zero-cost" landfill gas (which would result in a high-capacity factor), to high cost, intra-day natural gas (which may provide a low-capacity factor) or distillate oil (which would result in a very low-capacity factor). In order to be informative, a unit class may need to be subdivided into smaller distinctive sub-classes. This could make the classes potentially small and therefore not particularly useful for high-level analysis.

A large-unit class, such as the 10,000+ MW of combined cycle generators, may have a very wide continuous range that cannot be easily subdivided. Reasons for variations within the class could result from relatively small cost differences due to heat-rate, chiller-operations, or even different characteristics of no-load and start-up costs. Additionally, operation of a generator within either an import- or export-constrained area could affect capacity factors and provide outliers that would need supplemental information to explain.

#### 3.2.3 Curtailment

Curtailment, sometimes referred to as spillage, is the amount of energy generation from profiled resources that is unable to serve load due to oversupply. Section 2.4.2 of this Guide provides a detailed example of how curtailment may occur within the system.

The levels of curtailment on a system is a key metric when evaluating the addition of new resources or changes to the transmission topology. Since profiled resources are considered 'non-price-taking' resources by the optimization engine, it can be difficult to evaluate the cost associated with this excess generation. Typically, adding more profiled resources (of equal or lesser threshold price value) to a system or increasing transmission constraints will tend to increase curtailment.

Energy storage provides one avenue to reduce curtailment under certain circumstances. Short-term energy storage such as 2-hour or 4-hour batteries can be effective at moving oversupply of resources from one part of the day to later part of the day. Co-location of a battery and a profiled resource, such as solar, can help even out the net generation of a facility. However, it can become difficult to store all curtailment via energy storage when looking at the seasonal production of profiled resources and oversupply issues. Wind resources often generate most during the spring season when load is relatively low in comparison to the summer and winter. Seasonal storage, such as energy bank with Hydro-Québec or synthetic fuel production, may provide reductions in the large curtailment patterns seen over the course of a year.

#### 3.2.4 Marginal Fuel

Knowing which fuel(s) set the marginal LMP in an Economic Study can help illuminate some of the potential simulation results. An estimate of the marginal unit can be made for each hour. Typically, this metric is expressed in hours or fraction of total hours in the study period.

This metric has limitations related to transmission constraints, energy-storage resources and hydro units. For example, there are multiple "marginal" units whenever a transmission constraint is binding. When there is a binding transmission constraint, an incremental change in load on one side of the constraint cannot be compensated for by a change in generation (e.g., from the marginal resource) on the other side of the constraint. Consequently, multiple marginal units must be accounted for on each side of a constraint.

Additionally, due to their bidding behavior in actual operations, hydro generators and pumped storage resources frequently set the LMP in real-time energy markets. However, in the model, hydro generation and pumped storage are treated as load modifiers that are not be able to be "marginal" based on their bidding behavior. In studies with significant penetrations of wind, PV and batteries, those types of resources may also be marginal in actual operations, but cost minimization models typically cannot reflect such behavior. While marginal resources in Day-Ahead markets typically include virtual offers, these are outside of the purview of Economic Studies.

#### 3.2.5 Net Load Ramp

Net load ramp is defined as the change in load that power system operators must match using adjustments from dispatchable resources, after taking into account output from renewable resources. Ramping flexibility will be increasingly important in futures with high penetrations of renewable resources, since generally fewer dispatchable resources will be kept on-line to serve the lower net load.

Net load ramp is typically calculated after subtracting BTM and market-facing wind and solar generation from customer loads. This metric provides a numerical or graphical comparison of the changes in net loads over a specific time-step (or interval), which helps identify the quantity of load-following reserves needed to balance supply from resources versus demand from load.

As the output of renewable resources used to serve load becomes a larger fraction of the dispatched resources, these net load ramps may become more difficult to forecast accurately. The difference in net loads for a given time-step is calculated and sorted as a distribution over the study period. The given time-step could be net-load ramps in one minute, five minutes, thirty minutes, one hour, two hours, four hours, or any other time-step desired. Typically, this metric is expressed in "Change in MW per time-step."

Typically, this metric assumes that the absorption of the renewable energy has a very high priority, and that renewable resources do not participate in automatic generation control (AGC) or load following because some amount of energy would be foregone (e.g., "spilled"). As the penetration of renewables increases, renewable resources may need to be "dispatchable" to accommodate the potential limitations or shortfalls of other dispatchable resources. In current ISO studies, renewable resources operate for maximum output, which increases overall ramping needs.

#### 3.2.6 Transmission Outputs

To evaluate the effects of transmission constraints on a modeled power system, two models must be run: one constrained, one unconstrained. The total impacts of congestion can be evaluated by comparing production cost, carbon emissions, curtailment, and generation by fuel type between the two models.

To understand which transmission constraints are most impactful, the model provides certain outputs. For N-0 analysis, a transformer, line, or interface can be reported as being binding and having a shadow price. For N-1 analysis, a contingency object is reported as being binding and having a shadow price, while the binding element is also reported. The hours binding metric signals that the element is creating a constraint which causes a deviation from the optimal least cost dispatch. The shadow price is the difference in locational marginal prices across the interface. When determining which transmission constraints are most binding, both metrics must be considered. For example, a constraint can be frequently binding but at a low shadow price, or it can have a high shadow price but only be binding for a handful of hours. Multiplying the two metrics together can give a high-level estimation of how to rank binding elements.

To know exactly what impact a single binding element is having on production cost and other metrics, a new production cost model must be run where the limit on the binding element is removed. Then, the production cost, emissions, curtailment, and other metrics can be compared between the original constrained model and the new model. It is possible that relieving a constrained element can shift some of the congestion from one element onto a new element.

#### 3.2.7 Reserves

Reserve capacity is the amount of energy a power system can supply and is greater than what is required to meet demand. Ensuring that adequate reserves are available to manage deviations from expected conditions is an essential role for a NERC Balancing Authority like ISO New England.

In production cost modelling, the operating reserve margin must meet 120% of ISO New England's largest asset. The number of reserves can be derived from the resource mix being modeled and is expressed as the number of hours with deficient reserves.

#### 3.2.8 Environmental Metrics

The ISO tracks the hourly emissions of $CO_2$, $NO_X$, and $SO_2$ for each generator in the regional system. The ISO does not report individual operational metrics for these generators, but instead reports these emissions in aggregate (i.e. by resource type or by RSP zone)

In the capacity expansion mode, the LT phase buildout of generators can include an emissions target as a constraint. Emission levels reported for certain resource buildouts can differ slightly between the MT/ST phases and and the LT phase. This difference is due to the simplification of load and generation profiles used in the time slicing of the LT phase. Any difference in emissions between the LT phase and MT/ST phase should be negligible.

# Section 4
# Appendices

## 4.1 Appendix A – Terms and Definitions

**ADEQUACY (as defined in NERC Glossary of Terms)**
The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

**ANCILLARY SERVICE (as defined in NERC Glossary of Terms)**
Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice.

**BULK POWER SYSTEM (as defined in NPCC Glossary of Terms)**
The interconnected electrical systems within northeastern North America comprised of system elements on which faults or disturbances can have a significant adverse impact outside of the local area.

**CONTINGENCY (as defined in NPCC Glossary of Terms)**
An event, usually involving the loss of one or more Elements, which affects the power system at least momentarily.

**DISTRIBUTION FACTOR (as defined in NERC Glossary of Terms)**
The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (flowgate).

**DUMP ENERGY**
The amount of over-generation at the node due to a lack of transmission capacity out of the node and constraints on generation at the node that are forcing certain levels of generation.

**ECONOMIC DISPATCH (as defined in NERC Glossary of Terms)**
The allocation of demand to individual generating units on line to affect the most economical production of electricity.

**ELEMENT (as defined in NERC Glossary of Terms)**
Any electric device with terminals which may be connected to other electric devices such as a generator, transformer, circuit, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components

**FACILITY (as defined in NERC Glossary of Terms)**
A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

**FIRM LOAD (as defined in NERC Glossary of Terms)**
That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.

**FORCED OUTAGE (as defined in NERC Glossary of Terms)**

1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons.
2. The condition in which the equipment is unavailable due to unanticipated failure.

**HEAT RATE**

A measure of a thermal power plant's efficiency in converting fuel (British thermal units; Btus) to electric energy (kilowatt-hours; kWh); the amount of heat, measured in Btus, required to produce a kilowatt-hour of electrical output. The lower the heat rate, the more efficient the facility.

**LOAD SHEDDING (as defined in NPCC Glossary of Terms)**

The process of deliberately removing (either manually or automatically) preselected customers' load from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

**LOCATIONAL MARGINAL PRICE (LMP)**

The calculated price of electric energy at a pricing node, load zone, reliability region, or the Hub based on the patterns of load, generation, and the physical limits of the transmission system.

**POOLED TRANSMISSION FACILITY (PTF)**

The transmission facilities owned by Participating Transmission Owners (PTO), over which the ISO exercises Operating Authority in accordance with the terms set forth in the Transmission Operating Agreement[23], rated at 69 kV and above, except for lines and associated facilities that contribute little or no parallel capability to the PTF. The scope of PTF facilities is defined in Section II.49 of the OATT.

**PROPOSED TRANSMISSION SOLUTION (as defined in Attachment K of the OATT)**

A regulated transmission solution that (1) has been proposed in response to a specific identified need in a transmission Needs Assessment or the Regional System Plan (RSP) and (2) has been evaluated or further defined and developed in a Solutions Study, as specified in the OATT, Attachment K, Section 4.2(b) but has not received ISO approval under Section I.3.9 of the Tariff. The regulated transmission solution must include analysis sufficient to support a determination by the ISO, as communicated to the PAC, that it would likely meet the identified need included in the transmission Needs Assessment or the RSP, but has not received approval by the ISO under Section I.3.9 of the Tariff.

**PLANNED (as defined in Attachment K of the OATT)**

A transmission upgrade the ISO has approved under Section I.3.9 of the Tariff (Both a transmission Needs Assessment and a Solutions Study have been completed for planned projects).

**PEAK DEMAND (as defined in NPCC Glossary of Terms)**

The highest electric power requirement occurring in a given period (e.g., an hour, a day, month, season, or year). For an electric system, it is equal to the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system.

[23] https://www.iso-ne.com/participate/governing-agreements/transmission-operating-agreements

**RESOURCE (as defined in Section I of the Tariff)**
Resource means a generating unit, a Dispatchable Asset Related Demand, an External Resource, or an External Transaction. For Capacity Commitment Periods commencing on or after June 1, 2018, it also means to include a Demand Response Resource.

**SHADOW PRICE**
A term used in optimization programming that quantifies the incremental cost associated with increasing the utilization of a resource by one unit. This term is used for many different aspects of optimization programs, but is most commonly referenced in Economic Studies when quantifying the cost of increasing load on a transmission line/interface to calculate LMP.

**TRANSMISSION CONTSTRAINT (as defined in NERC Glossary of Terms)**
A limitation on one or more transmission elements that may be reached during normal or contingency system operations.

**WEATHER YEAR**
The use of a single year of weather data in building energy load, solar, and wind profiles that is generated with the intention of representing long-term average energy performance as well as conditions due to atmospheric events.

**WHEELING (as defined in NERC Glossary of Terms)**
The contracted use of electrical facilities of one or more entities to transmit electricity for another entity.

## 4.2 Appendix B – Data Sources Spreadsheet

This spreadsheet provides a breakdown of each source of data input used in the Economic Study process and links to the data for publicly available sources. It is listed separately on the ISO website at:

https://www.iso-ne.com/system-planning/system-plans-studies/economic-studies/

## 4.3 Appendix C – Market Efficiency Needs Scenario Assumptions

**This appendix is under development and will be released at a later date.** It provides a detailed breakdown of the Market Efficiency Needs Scenario and how market efficiency issues are identified on the PTF portion of the New England Transmission System at the end of the ten-year planning horizon pursuant to Section 17.5 - *Market Efficiency Needs Assessment* of Attachment K.

# Section 5
# Revision History

| Rev. No. | Date | Changes Made |
|---|---|---|
| **1.0** | 03/25/2024 | • Preliminary Release of the Technical Guide |