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NUREG-2242

Replacement Energy Cost Estimates for Nuclear Power Plants: 2020–2030

Final Report

Office of Nuclear Material Safety and Safeguards

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United States Nuclear Regulatory Commission

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Replacement Energy Cost Estimates for Nuclear Power Plants: 2020–2030

Final Report

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ABSTRACT

Replacement energy costs are estimated for the United States wholesale electricity market regions with nuclear electricity-generating units over the 2020–2030 report period. These estimates were developed to assist the U.S. Nuclear Regulatory Commission (NRC) in evaluating proposed regulatory actions that (1) require safety modifications that might necessitate temporary reactor outages and (2) reduce the potential for the loss of generation associated with a possible severe reactor accident. Estimates were calculated using ASEA Brown Boveri's (ABB's) PROMOD model and ICF's Integrated Planning Model (IPM) for North America.

The models simulate dispatching a collection of generating units in merit order (i.e., lowest to highest incremental cost of dispatch) until the regional power demand is met. Each generating unit is characterized by the technology and fuel it uses to generate electricity, the unit's heat rate, and the variable and fixed costs incurred in owning and operating the unit. To estimate the replacement energy cost, the report models a Reference Case, in which all operational nuclear power plants are generating, and an Alternative Case, in which a nuclear generating unit is taken offline so that the next unit in merit order is dispatched to replace the lost generation. The difference in market clearing prices between the two cases is the replacement energy cost.

FOREWORD

This report presents updated estimates of replacement energy costs for nuclear electricity-generating units in the United States. The information was developed principally for the U.S. Nuclear Regulatory Commission (NRC) to use in its regulatory analyses. The NRC conducts these analyses to examine the impacts of proposed regulations that require retrofitting or safety modifications to nuclear power plants and to estimate the value of replacement energy costs for regulatory actions that reduce the likelihood of severe reactor accidents. These replacement energy cost estimates also could be used in NRC licensing actions and other regulatory decisions.

The replacement energy cost estimates in this report were developed to update replacement energy cost estimates for both short- and long-term outages provided in NUREG/CR-4012, Volume 4, “Replacement Energy Costs for Nuclear Electricity-Generating Units in the United States: 1997–2001,” published in September 1997, and NUREG/CR-6080, “Replacement Energy, Capacity, and Reliability Costs for Permanent Nuclear Reactor Shutdowns,” published in October 1993. This report provides replacement energy cost estimates between the beginning of 2020 and the end of 2030. Given the length of time since these values had been updated and the many market changes that have occurred in the electrical generation and transmission industries due in part to deregulation, the NRC decided to develop a new approach and new values.

The NRC contracted with ICF Incorporated, LLC, to assist in the replacement energy cost analysis. The project identified key modeling parameters to be used in the replacement energy cost analysis, as well as specific market areas and representative nuclear electricity-generating units. Once the modeling parameters, market areas, and representative units were finalized, replacement energy cost estimates were calculated to estimate the impacts of unit outages on wholesale power prices in each region.

This analysis uses the North American Electric Reliability Corporation (NERC) areas, which consist of eight regional entities used to improve the reliability of the bulk electric power system. The members of the regional entities come from all segments of the electrical industry. Overlaid on the NERC regional entities are regional electricity “market areas,” in which buyers and sellers have traditionally bought and sold power and for which the transmission system operator (TSO) can accommodate such transactions.

To estimate the impact of a nuclear unit outage on the wholesale power price and, consequently, the cost of replacing the lost electrical production from the unit, simulations were performed to model the operation of specific power markets, with the selected first nuclear unit included and then excluded from the market area’s stock of operable generators.

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ABBREVIATIONS AND ACRONYMS

ABB	ASEA Brown Boveri
ADS	Anchor Data Set
AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
BFB	biomass-bubbling fluidized bed
Btu	British thermal unit
CAGR	compound annual growth rate
CAISO	California Independent System Operator
CAMX	WECC California/Mexico
CCS	carbon capture and storage
CEC	California Energy Commission
CPUC	California Public Utility Commission
CRR	congestion revenue right
CSP	concentrated solar power
CSAPR	Cross-State Air Pollution Rule
CO_2	carbon dioxide
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
EIM	Energy Imbalance Market
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ES&D	Electricity Supply and Demand
FERC	U.S. Federal Energy Regulatory Commission
FOM	fixed operation and maintenance
FPL	Florida Power and Light
FRCC	Florida Reliability Coordinating Council
FTR	financial transmission right
GMM	Gas Market Model
GWh	gigawatt-hour
HCL	hydrochloric acid
IEPR	Integrated Energy Policy Report
IPM®	Integrated Planning Model
IRP	integrated resource plan
ISO	independent system operator
ISO-NE	ISO New England
kW	kilowatt
kWh	kilowatt-hour
Lb	pound
LDC	load duration curve

LMP	locational marginal prices
MATS	Mercury and Air Toxics Standards
MISO	Midcontinent Independent System Operator
MMBtu	one million British thermal units
MRO	Midwest Reliability Organization
MTEP	MISO Transmission Expansion Plan
MTons	million tons
MW	megawatt
MWe	megawatts electric
MWh	megawatt-hour
NA	not applicable
NAMGas	North American market gas
NEMA	Northeast Massachusetts/Boston
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Corporation
NO_x	nitrous oxide
NPCC	Northeast Power Coordinating Council
NRC	U.S. Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NTTG	Northern Tier Transmission Group
NWPP	Northwest Power Pool
NWPP-US	Northwest Power Pool-United States
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
O&M	operation and maintenance
OASIS	Open-Access Same-Time Information System
OATT	open-access transmission tariff
PCM	production cost model
PROMOD®	PROMOD model
PJM	PJM Interconnection
PV	photovoltaic
RF	ReliabilityFirst Corporation
RGGI	Regional Greenhouse Gas Initiative
RMRG	Rocky Mountain Reserve Group
RPS	renewable portfolio standard
RTO	regional transmission organization
SAE	Statistically Adjusted End-use model
SCRTP	South Carolina Regional Transmission Planning
SERC	SERC Reliability Corporation
SERTP	Southeastern Regional Transmission Planning
SO_2	sulfur dioxide

SPP	Southwest Power Pool
SRSG	Southwest Reserve Sharing Group
STP	South Texas Project
TCC	transmission congestion contract
TRE	Texas Reliability Entity, Inc.
TSO	transmission system operator
TVA	Tennessee Valley Authority
VOM	variable operation and maintenance
WECC	Western Electricity Coordinating Council
Yr	year
ZEC	zero-emission credit

1 INTRODUCTION AND OBJECTIVE

The U.S. Nuclear Regulatory Commission (NRC) performs analyses to support a variety of regulatory actions that affect nuclear power plant licensees. These include actions that reduce risks or enhance the safety of nuclear power plants. Some of these regulatory actions may require that a nuclear generating unit be taken out of service for a period of time to implement the required change; other regulatory actions may result in reduced outages for the unit. The change in energy cost represents one factor that the NRC considers when deciding to require a regulatory change. This report updates previous estimates of long-term and short-term, plant-specific replacement energy costs contained in NUREG/CR-6080, “Replacement Energy, Capacity, and Reliability Costs for Permanent Nuclear Reactor Shutdowns,” (NRC, 1993) and NUREG/CR-4012, “Replacement Energy Costs for Nuclear Electricity-Generating Units in the United States: 1997–2001,” (NRC, 1997). As described below, this report modeled the operation of the U.S. electricity markets over the 2020-2030 report period and calculated the replacement energy costs for regions with nuclear power plants.

This report estimates the replacement energy costs for a range of regions, years, and scenarios. It presents the inputs and generation cost outlook used as the basis for assumptions for the replacement energy cost analysis 2020–2030 period. The assumptions are based on information from the U.S. Energy Information Administration’s (EIA) 2019 Annual Energy Outlook (AEO), and many other publicly available resources from regional market operators, interconnection planning collaboratives, and public utility commissions. The report provides context and a more detailed understanding of the use of these assumptions, their potential impact on the replacement energy cost estimates, and information on the overall approach and the modeling methodology.

This report covers the following items:

- A discussion of the approach, including the methodology, input assumptions, the basis for estimating replacement energy costs (an approach for methods capturing a range of replacement cost estimates), and the differences in approach in comparison with the previous NRC method (Section 2).

- A discussion of the results of the analysis and a demonstration of the use of the results to calculate replacement energy costs for power plants in different regions (Section 3).

- A summary of the structure and capabilities of the two models— ICF’s Integrated Planning Model (IPM®)[1] and ABB’s PROMOD model (PROMOD®)[2] (Appendices A and B).

- Additional detail on the methodology, assumptions, and results (Appendices C to G), including the basis for selecting nuclear power plants to analyze for the replacement energy cost calculation (Appendix C), existing and committed nuclear units (Appendix D), regional definitions (Appendix E), detailed input assumptions (Appendix F), detailed results (Appendix G), and summary of studies (Appendix H).

All cost values in this report are in nominal dollars unless otherwise specified.

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[1] The IPM is an ICF model used in support of ICF’s public and private sector clients. IPM® is a registered trademark of ICF Resources, L.L.C.

[2] PROMOD® is a product of ABB licensed by ICF. The version used is PROMOD IV.

2 APPROACH

2.1 Introduction

The NRC's regulatory analyses can examine actions that reduce risks or enhance the safety of nuclear power plants and that may require that a nuclear generating unit be taken out of service for some time period to implement the required change; alternatively, some regulatory actions may result in reduced outages for the unit. These actions would result in changes in energy generation from these units. The NRC's regulatory analyses therefore require estimates of the costs of replacement energy to support cost-benefit analyses. The goal of this update is to develop replacement energy costs to be used in support of regulatory analyses. This report simulated the operation of the U.S. electricity markets over the 2020–2030 analysis period and calculated the wholesale market prices for regions with nuclear power plants. Market clearing prices represent the price at which supply equals demand for the forecasted period and the specified power market.

In the context of this report, the term "replacement energy cost" refers to the difference in forecasted market clearing prices between a Reference Case with the nuclear power plant operating and an Alternative Case with the plant taken out of service. In this Alternative Case, additional energy generation will be dispatched to replace the generation that is no longer provided by the nuclear unit. This report provides projections of replacement energy costs (in dollars per megawatt-hour [$/MWh]) for regions within the U.S. electricity system over the 2020 to 2030 analysis horizon. This report summarizes the analysis that is used to develop the replacement energy cost estimates.

Replacement energy costs are based on the average electricity price for the duration of the outage. This report provides both annual and seasonal replacement energy costs because of seasonal variations in electricity prices in the electricity markets. Factors that affect seasonal variations include fuel price, demand, generator unit availability, generator maintenance scheduling, and renewable resource availability. For example, electricity prices are typically higher during the summer due to higher demand. The appropriate replacement energy cost can be applied depending on the period of the outage.

The remainder of this chapter describes the modeling approach, including the models applied (Section 2.2); the calculations of the replacement energy costs (Section 2.3); the approach used to identify the nuclear units to be taken out of service in each Alternative Case (Section 2.4); and discussion of the key assumptions underlying the modeling (Section 2.5). Chapter 3 presents the results for the analysis.

2.2 Modeling Methodology

To determine the clearing price in the Reference and Alternative Cases, the report simulated the operation of the U.S. electricity market using PROMOD, a production cost model (PCM) that determines the price of electricity in each location based on the economic dispatch of generation plants subject to operational constraints and limitations of the transmission system. The report divided the U.S. electricity markets into eight regions as described in Section 2.5. The report assessed the impact of the loss of a nuclear generating unit on energy prices in the power market region in which it is located. To determine the impact, the report modeled a Reference Case and up to two Alternative Cases for each region. Market clearing prices for a selected number of years within the report period were modeled for each of these cases and in each region.

Because the impact of a nuclear power plant outage within a region could vary—depending on the unit's size, its location relative to load, or significant transmission constraints—the report modeled two Alternative Cases for regions where significant variations in the impact on market clearing prices as a result of these factors was expected, to estimate a range for the replacement cost. Where the effect was expected to be similar, regardless of which nuclear generation unit was taken out of service, only one Alternative Case was used. The nuclear generation units assessed in the Alternative Cases are shown in Table 2-1 in Section 2.4.2.

Because PROMOD, a PCM, does not incorporate capacity expansion investment decision-making capability, entry and exit (investment) decisions for future years were determined exogenously using IPM. IPM is a long-term investment planning and production costing model that considers fuel, emission allowance, and renewable electricity credit prices. The new investments and retirements decisions from the IPM analysis were incorporated into PROMOD and are reflected in the analysis to determine the replacement energy costs.

Figure 2-1 provides a conceptual overview of the modeling methodology.

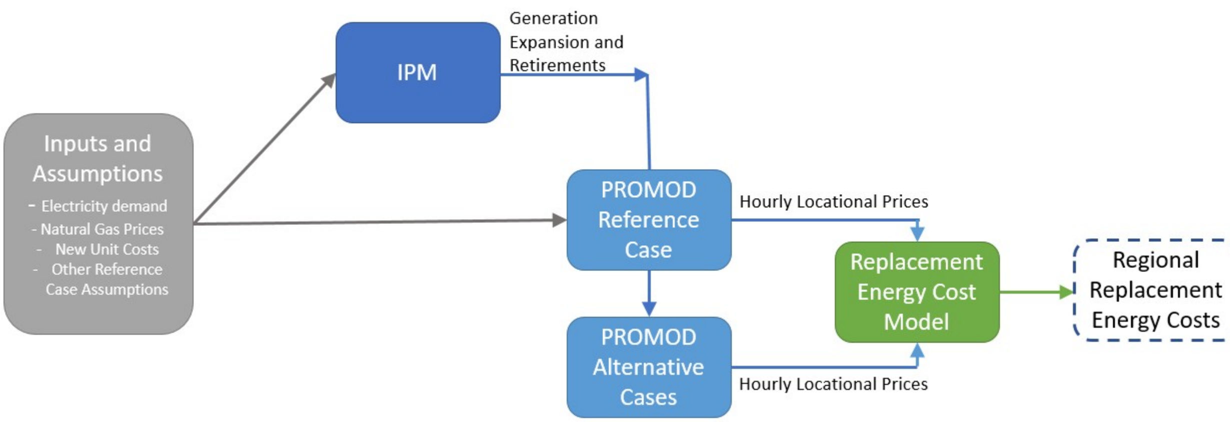

Figure 2-1 Overview of Modeling Methodology

The analysis accounted for legislation enacted in recent years in Illinois, New York, and New Jersey[3]. These states provide price support for specific nuclear generating units that were at risk of being retired early due to economic factors. The report modeled the zero-emission credit (ZEC) programs in IPM by explicitly requiring affected nuclear generation units to remain in the market and continue to operate for the duration of the applicable ZEC program. AEO 2019 (DOE, 2019) uses a similar approach. In PROMOD, the report ensured that units under ZEC programs dispatched fully.

The report developed replacement energy costs for the 2020–2030 period; however, in the interest of computational tractability, not all years were modeled explicitly. The report modeled five run years in PROMOD: 2020, 2021, 2023, 2025, and 2030. Results for intermediate years were linearly interpolated.

Summaries of the structure and capabilities of the two models— IPM and ABB's PROMOD—are provided in Appendix A and Appendix B.

[3] In the next revision of this NUREG, the analysis will also account for recent legislation enacted in Virginia (i.e., Virginia Clean Economy Act).

2.3 Replacement Energy Cost Calculations

The report modeled the cases depending on the expected impact of the outage of different nuclear generating units in the region. In the first case, the report selected the unit likely to have the least impact on energy prices, referred to as the Least Critical Unit. In the second case, the report selected the unit expected to have the largest impact, referred to as the Most Critical Unit. The basis for selecting these units is described in Section 2.4.

The report calculated the replacement energy cost for a region as the change in annual average energy price between the Reference Case and each Alternative Case. For regions with two Alternative Cases, the report developed a replacement energy cost range with a minimum value based on the impact of the Least Critical Unit and a maximum value based on the impact of the Most Critical Unit. The report provided annual and seasonal replacement energy cost values for each region. For each region and year, the report developed hourly energy prices and calculated annual average energy prices as a simple average of hourly prices. By comparing energy prices from the Reference Cases to those of the Alternative Cases, the report determined the impact of the loss of nuclear generating units on electricity market prices and calculated the replacement energy cost for each region.

To account for seasonal variations in energy prices, the report provided seasonal replacement energy costs. Average seasonal prices were calculated by averaging the appropriate hourly prices. The impact of a nuclear generation outage that is concentrated in a particular season might be higher or even lower than the annual average, depending on the season. The impact of such outages can be assessed using seasonal replacement energy costs.

The seasonal values were calculated as the change in average energy price between the Reference Case and each Alternative Case for the months within the season. The seasons were defined as:

- Winter: December (of prior year), January, February
- Spring: March, April, May
- Summer: June, July, August
- Fall: September, October, November

The impact of an outage of a specific nuclear generation unit on energy costs within its region can be assessed by multiplying the replacement energy cost (in $/MWh) by the unit's loss of generation (MWh). For long duration outages of several months to years, the impact can be assessed using the annual replacement energy costs. For shorter duration outages of a few months to a couple of seasons, the seasonal replacement energy costs can be used to derive a replacement cost impact that is more reflective of the particular season in which the nuclear generation unit is expected to be out of service. Section 3.2 describes how to apply the replacement energy costs.

2.4 Selection of Nuclear Generating Units to Be Taken Out of Service in Alternative Cases

A list of the nuclear generating units modeled is shown in Table D-1 in Appendix D. The report assumes that a unit is retired based on the announced plans by their owners. The remaining nuclear units were considered as candidates for being taken out of service in the Alternative Cases. This section describes the approach used to select nuclear outages for the Alternative Cases and shows the unit(s) selected for each region.

2.4.1 Approach to Selecting Nuclear Outage Units

The units for the Alternative Cases were selected according to the key criteria that determine how the impact of unit outages on electricity market prices would vary. These criteria include the location of the unit relative to congestion in the region, the size of the nuclear generating unit, and proximity to load centers.

- **Location relative to congestion in the region**. Congestion occurs on the transmission system when restrictions prevent the use of the most economic power plants to serve load. When congestion occurs, less economic generation is dispatched out of economic merit to serve load. This results in prices being higher in the areas limited by congestion compared with areas with little or no congestion. Within a region, generators in congested areas would therefore have higher replacement energy costs than would those in less congested locations.

- **Size of the generating unit**. Older nuclear units typically are smaller than 1,000 megawatts electric (MWe), whereas newer units are greater than 1,000 MWe in size.[4] A smaller nuclear unit would require less replacement energy than would a larger unit and could have a lower impact on the generation stack. The replacement cost could therefore be lower for a smaller unit, all else being equal.

- **Proximity to load centers.** Wholesale electricity prices are usually higher in load centers because they have higher demand than other locations and they are relatively far from generation centers. Transmission capability limitations and transmission losses in delivering power over long distances generally result in relatively higher prices in load centers. It is likely that generators closer to load centers would have higher replacement energy costs than would those farther away.

The modeling approach covered the entire contiguous U.S. electricity markets in the lower 48 states but focused on regions with nuclear power plants to produce the replacement cost estimates. A detailed description of the selection approach along with an example is provided in Appendix C. In general, the report applied expertise and judgment that leverages past and ongoing power sector modeling and analysis work to assess how each unit fit the criteria and to identify the appropriate unit(s) to model.

2.4.2 Selected Units to be Taken Out of Service for Alternative Cases

Table 2-1 shows the nuclear generation units assessed in the Alternative Cases. Because the impact of the outage of a nuclear generating unit in the Electric Reliability Council of Texas (ERCOT) is expected to be similar regardless of the unit that is out of service, only one generation unit, the South Texas Project (STP) Unit 1, was selected for the Alternative Case. In

[4] NUREG-1350, vol. 31, Information Digest 2019-2020 (NRC, 2019).

other regions the impact could vary significantly due to factors such as size and location of the unit, therefore, two generation units were selected. For example, in New England, Millstone Unit 2 was expected to have the least impact, due to its relatively smaller size. The relatively larger Millstone Unit 3 represented units that would have the most impact on replacement energy costs. The assessment of regional conditions suggests that the impact of the Seabrook Unit would be similar to that of Millstone Unit 3 (see Appendix C), therefore it was sufficient to analyze Millstone Unit 2 and Millstone Unit 3 to determine the range of replacement energy costs for the region.

Appendix D provides the complete list of existing and committed nuclear generation plants modeled in the report.

Table 2-1 Nuclear Power Plants Selected for Analysis in Nuclear Outage Alternative Cases

Region	Nuclear Power Plant, Unit Name	Capacity (MWe)	Expected Impact on Market Prices	Primary Driver of Impact
ISO-NE	Millstone Power Station, Unit 2	868	Least Impact	Unit size
ISO-NE	Millstone Power Station, Unit 3	1,220	Most Impact	Unit size
WECC	Palo Verde Nuclear Generating Station, Unit 2	1,314	Most Impact	Location, proximity to load center
WECC	Columbia Generating Station	1,180	Least Impact	Proximity to load center
ERCOT	South Texas Project, Unit 1	1,280	N/A	N/A
NYISO	Nine Mile Point Nuclear Station, Unit 2	1,287	Most Impact	Unit size
NYISO	R E Ginna Nuclear Power Plant	582	Least Impact	Unit size
SPP	Wolf Creek Generating Station, Unit 1	1,175	Most Impact	Unit size
SPP	Cooper Nuclear Station	772	Least Impact	Unit size
PJM	Limerick Generating Station, Unit 2	1,122	Most Impact	Unit size, location
PJM	Quad Cities Nuclear Power Station, Unit 1	908	Least Impact	Unit size, location
MISO	Clinton Power Station, Unit 1	1,065	Most Impact	Unit size, location
MISO	Prairie Island Nuclear Generating Plant, Unit 2	519	Least Impact	Unit size
Southeast	Vogtle Electric Generating Plant, Unit 2	1,152	Most Impact	Unit size, location
Southeast	Joseph M Farley Nuclear Plant, Unit 1	874	Least Impact	Unit size, location

2.5 Summary of Key Input Assumptions

A broad range of input assumptions is required for the modeling used to support a report of this kind. This includes information on the generating equipment (e.g., capacity, fixed and variable operating and maintenance costs, operating constraints and regulatory limits), electric energy and peak demand, fuel prices, the cost and performance characteristics of new technologies, and national and state-level laws and regulations that affect operations (e.g., emissions limits, and renewable portfolio standards [RPSs][5]), among other inputs.

The report collected data and developed assumptions to represent conditions in the Reference Cases and Alternative Cases, which included:

- Regional definitions for replacement cost calculations
- Peak demand and energy demand
- Natural gas prices
- Energy and environmental policies
- Recent and firm generation builds
- Recent and firm generation retirements
- New unit costs

All assumptions affect the results of the modeling and analysis; however, not all factors have a significant impact on the replacement energy costs. To determine the most appropriate sources to use to develop assumptions, the report focused on three parameters that are important for the determination of replacement energy costs. The parameters included natural gas prices, electricity demand, and technology cost and performance as discussed below.

- **Natural gas prices.** Over the past few years, natural gas has become the fuel of the marginal unit of generation in most electricity markets and, thus, a major determinant of electricity prices. In addition, most conventional generation plants that are currently planned or under development are natural gas-fired units. In some markets, natural gas-fueled plants are virtually the only non-renewable power plants currently under active development. This indicates that the correlation between natural gas prices and electricity prices, as well as the role of natural gas prices in setting electricity prices, is likely to continue.

- **Electricity demand.** In addition to natural gas prices, the level of demand also affects marginal energy prices. For a given hourly demand level, the market operator will dispatch a subset of available generating units that will minimize the total cost of meeting that load. The variable cost (fuel cost, emission allowance cost, and variable operation

[5] Renewable portfolio standards are policies designed to increase the use of renewable energy sources for electricity generation. These policies require or encourage electricity suppliers to provide their customers with a stated minimum share of electricity from eligible renewable resources.

and maintenance [VOM] cost) of operating the marginal unit (most expensive unit) sets the marginal energy price in that region in that hour. As the marginal unit will change as the level of demand changes, electricity demand assumptions are a critical input for estimating the replacement costs of energy.

- **Technology cost and performance.** The cost and performance of new units are also an important input for calculating the replacement energy costs. However, unlike natural gas prices and electricity demand assumptions that directly impact the price setting for energy prices as discussed above, the cost and performance of new technologies have an indirect impact on the marginal energy price calculation. This is because these assumptions affect the generating capacity that will be built and the generating units that will retire in the future. These entry and exit decisions will change the mix of resources available in a region and thus the marginal unit and its associated cost as well.

The assumptions were derived primarily from public sources, including:

- U.S. Department of Energy (DOE) Energy Information Administration (EIA) AEO 2019 Reference Case (DOE, 2019)

- North American Electric Reliability Corporation (NERC) Electricity Supply and Demand (ES&D), December 2018 release (NERC, 2018)

- Environmental Protection Agency (EPA) Power Sector Modeling Platform v6 (EPA, 2019)

- National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB), 2018 (NREL, 2018)

- EIA Form 860M (February 2019 version) (EIA, 2019)

In addition to these sources, national, interconnection-wide, inter-regional, and regional studies were reviewed. Because the replacement cost report calculates costs at the regional level, studies that were at least regional in scope were preferred. In addition, because replacement energy costs are based on electricity prices derived from a production cost analysis, the report focused on studies that included production cost or related economic assessments that would have the relevant economic input parameters required to implement the replacement cost simulations. Appendix H provides a summary of the studies reviewed.

The EIA's AEO 2019 Reference Case (DOE, 2019) was selected as the basis for development of natural gas price assumptions because the AEO is national in scope and has all the data elements needed for this report. Furthermore, the AEO is publicly available and readily accessible; and its assumptions are used for regional, inter-regional, and national energy policy studies. Also, the AEO natural gas price projections are used as the basis for gas prices in several regional and inter-regional studies.

The NERC ES&D 2018 was selected as the source for electricity demand assumptions because NERC and other operators use these assumptions in their analyses, and their regional structure is consistent with the regions in PROMOD and IPM (NERC, 2018).

The AEO 2019 was used for capital cost assumptions for fossil and nuclear technologies, and the NREL ATB 2018 was used for solar and wind technologies (DOE, 2019; NREL, 2018). Most studies reviewed use the NREL ATB 2018 for new technology costs, and of the studies examined, the NREL ATB was the only report, other than the AEO, that provided a full dataset of new technology costs (NREL, 2018).

For other assumptions, EPA Platform v6 (EPA, 2019) was used. The firm builds and firm retirements were based on the February 2019 version of EIA Form 860M (EIA, 2019).

The remainder of this section provides a summary of the key assumptions. Additional details are provided in Appendix F.

The report divided the U.S. electricity markets into eight regions and determined the replacement energy cost for each region. The regional definitions used for the replacement cost calculations were based on the U.S. Federal Energy Regulatory Commission (FERC) Order No. 1000 (FERC, 2012) planning regions shown in Figure 2-2. In most areas with competitive markets, the report used regional definitions that were coincident with the existing competitive markets.[6] For example, the New York Independent System Operator (NYISO) market was considered as a single region. Therefore, the replacement energy costs determined for NYISO would apply to all nuclear power plants located in that market. The exception was the California Independent System Operator (CAISO) market. CAISO operates the Western Energy Imbalance Market (Western EIM), a real-time energy market, which includes eight non-CAISO utilities or balancing authorities, with seven entities planning to participate by 2022. The Western EIM covers portions of almost all the states in the Western Interconnection. Because of the scope of the Western EIM, the report considered the U.S. portion of the Western Interconnection as a single region for the purposes of the calculation of replacement energy cost.

The remaining area is the southeastern United States, which is served by vertically integrated utilities in regulated markets. Although utilities serve most of their demand with generation located within their service territories, there are frameworks under which utilities in regulated markets can source power from locations outside their service territories in the event of shortages. Further, regional transmission planning processes established under FERC Order No. 1000 (FERC, 2012) include economic transmission planning studies that allow market participants to request studies for the feasibility of long-term economic power transactions. The three entities responsible for regional transmission planning in the southeastern U.S. under FERC Order No. 1000 (FERC, 2012) are Florida Reliability Coordinating Council (FRCC), South Carolina Regional Transmission Planning (SCRTP), and Southeastern Regional Transmission Planning (SERTP). Because of the potential for interactions between the regions, the report considered the regulated markets in the southeastern United States as a single region for the purposes of the calculation of replacement energy cost.

[6] The competitive markets are the seven regional transmission organizations (RTO) or independent system operator (ISO) markets: CAISO, ERCOT, ISO New England, Midcontinent Independent System Operator, New York Independent System Operator, PJM Interconnection, and Southwest Power Pool.

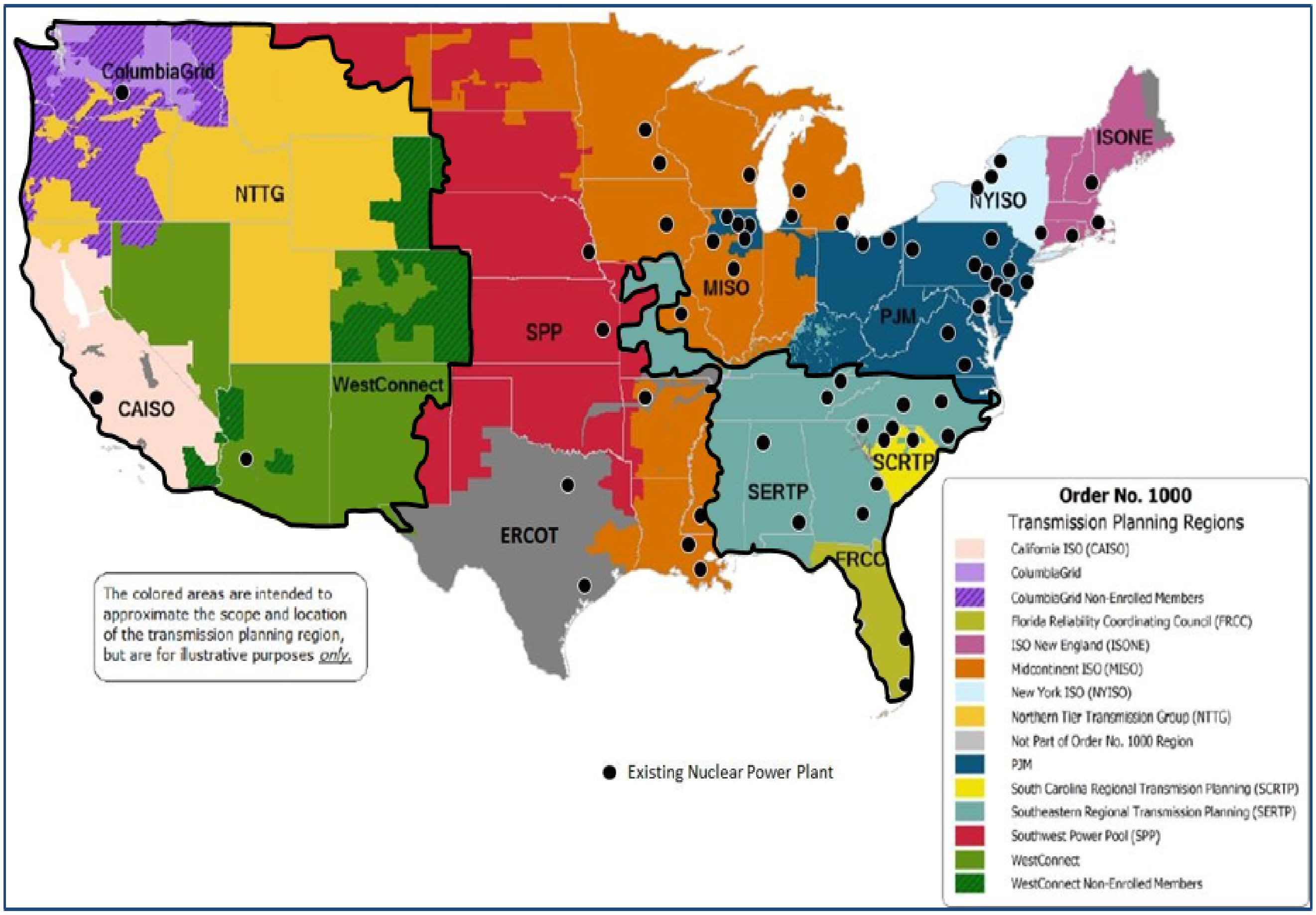

Figure 2-2 FERC Order No. 1000 Transmission Planning Regions

Note: The map was annotated with black dots to show the approximate locations of existing nuclear power plants. Heavy black lines have been added to distinguish the planning regions that have been combined for the purpose of this analysis.

Source: (FERC, 2020)

The eight regions specified for the replacement energy cost report were defined as:

1. ERCOT
2. ISO New England (ISO-NE) (ISO, 2018)
3. Midcontinent Independent System Operator (MISO)
4. NYISO
5. PJM Interconnection (PJM)
6. Southwest Power Pool (SPP)
7. Southeast, comprising FRCC, SCRTP, and SERTP

8. Western Electricity Coordinating Council (WECC), comprising CAISO, ColumbiaGrid, Northern Tier Transmission Group (NTTG) and WestConnect

The report modeling reflected the current operation of the electricity markets. Regions in PROMOD were defined consistent with the current representation in the markets. Market prices from PROMOD analysis were aggregated up to the eight regions for the calculation of the replacement energy costs. For example, in WECC, the report modeled utility areas in CAISO as a single market administered by the system operator, with appropriate financial hurdles between the region and its neighbors. Other utility areas were modeled similarly. This captured the actual operation of the electricity markets. However, the replacement energy cost was calculated for the entire WECC region. Prices at all nodes in WECC, including in CAISO, were aggregated to determine the replacement energy cost for WECC.

A more detailed description of the report approach is provided in Appendix E.

2.5.1 Peak and Energy Demand Assumptions

The net internal peak demand assumptions for selected years and compound annual growth rate (CAGR) are shown in Table 2-2. The net internal demand is the maximum hourly demand within a given year after removing interruptible demand[7]. Peak demand assumptions for all years is provided in Section F.1 of Appendix F.

Table 2-2 Net Internal Peak Demand (MW)

Region (Assessment Area)	Year			
	2020	2025	2030	CAGR (Percent)
FRCC (FRCC)	45,608	48,290	50,534	1.03
Midwest Reliability Organization [MRO] (MISO)	119,303	121,289	122,842	0.29
Northeast Power Coordinating Council [NPCC] (New England)	24,878	24,239	24,190	-0.28
NPCC (New York)	31,759	31,429	31,559	-0.06
ReliabilityFirst Corporation [RF] (PJM)	144,287	147,118	151,070	0.46
SERC Reliability Corporation (SERC-East)	42,907	44,930	47,361	0.99
SERC (SERC-North)	39,935	40,477	41,121	0.29
SERC (SERC-Southeast)	45,983	47,201	46,764	0.17
SPP (SPP)	52,044	53,965	55,603	0.66
Texas Reliability Entity, Inc. [TRE] (ERCOT)	73,706	80,677	87,666	1.75
WECC (Northwest Power Pool-United States [NWPP]-US)	49,075	50,767	52,343	0.65
WECC (Rocky Mountain Reserve Group [RMRG])	12,637	13,549	14,394	1.31

[7] Interruptible demand is demand that the end-use customer agrees with its Load-Serving Entity via contract or agreement can be curtailed.

Table 2-2 Net Internal Peak Demand (MW) (continued)

Region (Assessment Area)	Year 2020	2025	2030	CAGR (Percent)
WECC (Southwest Reserve Sharing Group [SRSG])	24,298	26,650	28,788	1.71
WECC (WECC California/Mexico [CAMX])	50,132	51,584	52,031	0.37

Source: (NERC, 2018)

The net energy for load demand assumptions for selected years and CAGR between years 2020 and 2030 are shown in Table 2-3. Net energy for load is the projected annual electric grid demand, prior to accounting for intra-regional transmission and distribution losses. Section F.1 of Appendix F shows the energy demand assumptions for all years of the report period.

Table 2-3 Net Energy for Load (GWh)

Region (Assessment Area)	Year 2020	2025	2030	CAGR (Percent)
FRCC (FRCC)	236,779	245,769	253,486	0.68
MRO (MISO)	669,881	681,949	694,663	0.36
NPCC (New England)	120,395	115,594	113,400	-0.60
NPCC (New York)	155,567	153,454	153,518	-0.13
RF (PJM)	808,638	824,140	849,551	0.49
SERC (SERC-East)	214,026	221,904	233,819	0.89
SERC (SERC-North)	214,064	214,084	215,733	0.08
SERC (SERC-Southeast)	247,542	253,679	253,860	0.25
SPP (SPP)	259,341	274,090	281,854	0.84
TRE (ERCOT)	392,609	439,094	487,269	2.18
WECC (NWPP-US)	294,092	301,503	308,586	0.48
WECC (RMRG)	69,671	74,874	80,099	1.40
WECC (SRSG)	111,351	121,139	129,981	1.56
WECC (CAMX)	267,722	271,314	272,334	0.17

Source: (NERC, 2018)

2.5.2 Natural Gas Price Assumptions

Natural gas price assumptions are based on the AEO 2019 Reference Case (DOE, 2019) price projections. The Henry Hub natural gas price projections for the run years are shown in Table 2-4. The Henry Hub natural gas price projections remain below $4/MMBtu through the report period, although growing demand in domestic and export markets led to increasing prices. The Henry Hub price is projected to be $3.00/MMBtu in 2021, increasing to

$3.76/MMBtu in 2030. EIA also provides delivered natural gas prices for the regions modeled for the AEO. The report used the EIA's delivered natural gas price projections and its energy markets expertise to develop price projections for the regions. Section F.2 of Appendix F shows the delivered natural gas price projections for the AEO regions.

Table 2-4 Henry Hub Natural Gas Price Projections

Year	Henry Hub Natural Gas Price (2018$/MMBtu)
2020	3.08
2021	3.00
2023	3.13
2025	3.53
2030	3.76

Source: (DOE, 2019)

2.5.3 Energy and Environmental Policies

The power sector is subjected to a variety of clean energy policies that include RPSs, tax credits for new solar and wind units, and ZECs for selected existing nuclear units. The report modeled the RPSs and tax credits for new solar and wind units explicitly in IPM. These policies affect the generating technologies chosen during the 2020–2030 period. The renewable energy credit prices were an output of IPM.

In addition, the analysis accounted for clean energy legislation that recently passed in Illinois, New York, and New Jersey, which provides price support in the form of ZECs for nuclear units that are at risk of early closure because of declining profitability. The revenue a nuclear generation plant receives from a ZEC program is assumed to enable the plant to continue to operate for the duration of the program. The following ZEC programs are modeled:

- The New York Clean Energy Standard, established in 2016, creates ZECs that apply to Fitzpatrick, Ginna, and Nine Mile Point nuclear units. The New York load-serving entities are responsible for purchasing ZECs equal to their share of the statewide load, providing an additional revenue source to the nuclear units holding the ZECs. The program is set to cover a 12-year term.

- Illinois Future Energy Jobs Bill, passed in 2017, also creates a ZEC program covering a 10-year term for Clinton and Quad Cities Units 1 and 2.

- New Jersey has established a ZEC program. Salem Nuclear Generating Station Units 1 and 2 and Hope Creek Generating Station are eligible to receive payments during the year of implementation and in the three following years and may be considered for additional three-year renewal periods thereafter. Only the first three years of the program are modeled in the report.

The analysis accounted for environmental regulations that were approved and enacted as of 2018. These include the Regional Greenhouse Gas Initiative (RGGI), the Cross-State Air

Pollution Rule (CSAPR), and the Mercury and Air Toxics Rule (MATS). Policies under discussion but not enacted (e.g., Pennsylvania nuclear subsidies) were not modeled.

In PROMOD, generation units bid their marginal cost. The report explicitly modeled environmental compliance costs and subsidies that affect the variable costs of the generation units. Emission allowance prices were modeled as adders to the variable cost of units. Production tax credits for wind generators were modeled as discounts to the variable cost where applicable, enabling them to bid low to negative marginal costs. Nuclear power plants covered under a ZEC program were modeled in PROMOD so that these plants were connected to the grid in accordance with their availability.

Section F.3 of Appendix F provides input assumptions on renewable policies and environmental regulations.

2.5.4 Recent and Firm Builds and Retirement Assumptions

The report incorporates the generating unit inventory including the operating as well as firm build units as of February 2019. The analysis modeled projections of firm generation builds and retirements based on Form EIA-860 (EIA, 2019),[8] generator-level specific information about existing and planned units.

Generation addition and retirement assumptions based on Form EIA-860 data are shown in Table 2-5 and Table 2-6, respectively. Table 2-5 is a summary of generation capacity that was placed in service recently, or capacity that developers expect will be placed in service over the next few years. For planned units not yet in service, the report identified these units as likely to come online based on whether it is under construction in Form EIA-860. Projections are shown through 2024, with more than half of the approximately 56 GW of capacity being in service by 2018. More than 90 percent were expected to be in operation by 2020. Additional detail on generation capacity additions is provided in Section F.4 of Appendix F.

Table 2-5 Recent and Firm Builds Assumptions for the Period 2018 through 2024 (MWe)

Technology	ERCOT	ISO-NE	MISO	NYISO	PJM	Southeast	SPP	WECC	Total
Combined Cycle	232	1,230	4,725	1,721	13,065	5,480		1,235	27,689
Combustion Turbine	329	629	729	124	371	155	409	1,425	4,171
Nuclear						2,200			2,200
Onshore Wind	5,166	33	2,858	158	959		3,423	2,531	15,128
Other	11	16		21		215	1	373	637
Solar Photovoltaic (PV)	1,032	7	109	10	437	2,109	15	2,554	6,273
Totals	6,770	1,915	8,421	2,034	14,832	10,159	3,848	8,118	56,097

Note: No new coal fired generation is projected to be built through year 2024.

Source: (EIA, 2019)

[8] The survey Form EIA-860 (EIA, 2019) collects generator-level specific information about existing and planned generators and associated environmental equipment at electric power plants with 1 megawatt or greater of combined nameplate capacity.

Table 2-6 is a summary of the assumed planned capacity retirements based on Form EIA 860 (EIA, 2019). The table shows generation capacity that was retired recently or that is scheduled to retire by 2030. The EIA data show that about 82 percent of the approximately 96 GW capacity retirements are scheduled to occur by 2025. Additional detail on generation capacity retirements is provided in Section F.4 of Appendix F.

Table 2-6 Recent and Firm Generation Retirements through 2030 (MWe)

Technology	ERCOT	ISO-NE	MISO	NYISO	PJM	Southeast	SPP	WECC	Total
Coal	5,583	383	12,906		11,417	8,529	1,546	9,416	49,780
Combined Cycle		34	424		430	121		2,268	3,277
Combustion Turbine	26	25	1,798	99	777	371	237	737	4,069
Nuclear	1,205	1,928	5,181	3,260	5,361			2,240	19,174
Oil/Gas Steam	1,692		2,098		1,394	364	3,241	9,090	17,879
Other	1,010	2	183	2	242	255	169	437	2,301
Totals	9,516	2,372	22,590	3,361	19,621	9,640	5,193	24,187	96,480

Note: No solar photovoltaic generation is projected to be retired through year 2030.

Source: Form EIA-860 (EIA, 2019)

In addition to the firm generation additions and retirements, the report modeled unplanned economic generation additions and retirements projected to occur over the report period. These are generation capacity decisions expected to occur as a result of market conditions and are based on the IPM model projections. A summary of IPM's generation capacity additions and retirements are shown in Table 2-7 and Table 2-8, respectively. Additional details on IPM economic builds and retirements are provided in Section F.5 of Appendix F.

Table 2-7 IPM Economic Builds through 2030 in Addition to Firm Generation Builds (MW)

Technology	ERCOT	ISO-NE	MISO	NYISO	PJM	Southeast	SPP	WECC	Total
Combined Cycle	13,242		7,974	519	6,123	12,117		11,250	51,225
Combustion Turbine					673			1,409	2,082
Onshore Wind		3,692	3,589	5,173	8,341	330	229	25,835	47,189
Other		43	4,026	1,507	3,224	2,428	680	2,985	14,893
Solar PV	14,895		5,430	2,828	36,963	15,767	4,694	21,105	101,682
Total	28,137	3,735	21,019	10,027	55,324	30,642	5,603	62,584	217,071

Table 2-8 IPM Economic Retirements through 2030 in Addition to Firm Generation Retirements (MW)

Technology	ERCOT	ISO-NE	MISO	NYISO	PJM	Southeast	SPP	WECC	Total
Coal	815	534	9,505	723	12,514	22,860		1,193	48,144
Combined Cycle		1,576		1,519		110		2,975	6,180
Combustion Turbine		148		54	40	8		1,424	1,674
Nuclear			5,456	853	1,590	5,526	1,947	1,180	16,552
Oil/Gas		1,723	202	2,297	2,236	130	536	34	7,158
Other	118	547	724	74	210	1,558		949	4,180
Totals	933	4,528	15,887	5,520	16,590	30,192	2,483	7,755	83,888

2.5.5 New Unit Cost Assumptions

For its capacity expansion and retirement assessment, the staff and ICF developed assumptions for new unit technologies that could potentially be placed in service during the report period.

Selected technologies are shown in Table 2-9. Because the cost and performance characteristics of new units evolve over time, Table 2-9 provides the cost assumptions for new units that were used in the IPM run years shown. Additional detail on other technologies is provided in Section F.6. of Appendix F.

Table 2-9 Performance and Unit Cost Assumptions for New Technologies

Parameter	Advanced Combined Cycle	Advanced Combustion Turbine	Nuclear	Battery Storage	Solar Photovoltaic	Solar Thermal	Onshore Wind
Size (MWe)	1,100	237	2,234	30	150	100	100
First Year Available	2022	2021	2025	2020	2020	2022	2022
Lead Time (Years)	3	2	6	1	1	3	3
Generation Capability	Economic Dispatch	Economic Dispatch	Economic Dispatch	Economic Dispatch	Generation Profile	Economic Dispatch	Generation Profile
2021							
Heat Rate (Btu/kWh)	6,300	9,550	10,461	NA	0	0	0
Capital (2018$/kW)	768	667	5,813	1,796	939	6,675	1,460
Fixed O&M (2018$/kW-yr)	10.30	7.01	103.31	36.32	7.84	67.80	51.48

Table 2-9 Performance and Unit Cost Assumptions for New Technologies (continued)

Parameter	Advanced Combined Cycle	Advanced Combustion Turbine	Nuclear	Battery Storage	Solar Photovoltaic	Solar Thermal	Onshore Wind
Variable O&M (2018$/MWh)	2.06	11.02	2.37	7.26	0.00	3.69	0.00
2023							
Heat Rate (Btu/kWh)	6,250	9,050	10,461	NA	0	0	0
Capital (2018$/kW)	732	625	5,651	1,673	918	6,505	1,426
Fixed O&M (2018$/kW-yr)	10.30	7.01	103.31	36.32	7.67	64.32	50.71
Variable O&M (2018$/MWh)	2.06	11.02	2.37	7.26	0.00	3.69	0.00
2025							
Heat Rate (Btu/kWh)	6,200	8,550	10,461	NA	0	0	0
Capital (2018$/kW)	711	600	5,550	1,573	897	6,334	1,395
Fixed O&M (2018$/kW-yr)	10.30	7.01	103.31	36.32	7.50	60.85	49.94
Variable O&M (2018$/MWh)	2.06	11.02	2.37	7.26	0.00	3.69	0.00
2030							
Heat Rate (Btu/kWh)	6,200	8,550	10,461	NA	0	0	0
Capital (2018$/kW)	658	545	5,195	1,385	844	5,909	1,329
Fixed O&M (2018$/kW-yr)	10.30	7.01	103.31	36.32	7.07	52.15	48.02
Variable O&M (2018$/MWh)	2.06	11.02	2.37	7.26	0.00	3.69	0.00

Btu – British thermal units; kW – Kilowatt; kWh – Kilowatt-hour; kW-yr – Kilowatt-year; MW – Megawatt; MWh – Megawatt-hour; NA – not applicable; O&M – operation and maintenance.

Source: (DOE, 2019; NREL, 2018

2.6 Limitations of Model and Methodology

Actual market outcomes will be different from the replacement energy costs calculated in this report due to limitations of the model and methodology used. The PCM used for the analysis is deterministic and most contingencies are predefined. It therefore might not fully capture spikes in prices and volatility that could occur as a result of unexpected outages or errors in forecasts. The modeling would also not account for the effect of extreme events such as the polar vortex or hurricanes. The impact of future regulations and the effect of economic and other disruptions due to events such as pandemics are not captured in the projections of the replacement energy costs.

In addition, the model assumes generation units in each region are dispatched in economic order subject to transmission and other constraints, and electricity market prices are based on the variable cost of the marginal unit. Prices could vary in regulated markets where unit commitment and dispatch decisions are conducted at the utility level, rather than at a centralized utility level. Similarly, some power transactions take place under contract terms that could affect commitment decisions and the order in which units are dispatched.

Another factor is that the replacement energy costs are based on average prices calculated for an entire region. The actual market outcome within a region would depend on the location of the nuclear plant that goes out of service and the location where the replacement power is sourced. For example, the replacement power could be sourced from a hub that is not representative of the average for the entire market or from a specific resource within the region.

Further, the replacement energy costs are calculated as a range using up to two nuclear generation units within a region. The actual outcome could vary if a unit not included in the selection goes out of service. The report also uses interpolation to determine values for intermediate years (between the selected run years). Market dynamics such as fuel price variations, resource builds and retirements, or demand fluctuations that occur in the intermediate years could result in costs that are different from the interpolated values.

Finally, this report uses modeling assumptions from a multitude of sources beyond DOE 2019 and also differs in the modeling framework used. Therefore, the results obtained in this report are expected to differ from the projections from DOE 2019.

3 RESULTS

The report simulated the operation of the U.S. electricity markets and calculated the incremental replacement energy cost for each of the regions specified in the report. This chapter discusses the results and demonstrates how to use the incremental replacement energy costs to calculate the replacement energy cost for specific projected generation outages.

3.1 Market Price Impact and Replacement Energy Costs

As described in Section 2.3, PROMOD runs for the Reference and Alternative Cases produce a series of hourly market energy prices ($/MWh) for each run year. Replacement energy costs are defined as the difference in these energy prices between the Reference and the Alternative Cases. The report calculated annual and seasonal replacement energy costs for each of the eight identified regions. Annual replacement energy costs are the simple average of the hourly replacement energy costs.

Seasonal variations in factors such as gas prices, demand, and unit availabilities result in corresponding seasonal variations in replacement energy costs. An outage that is concentrated in a particular season might have a replacement energy cost that is lower or higher than the annual value depending on the season. Seasonal replacement energy costs have been provided to account for the seasonal variations. Seasonal replacement energy costs are calculated as the average of the hourly replacement energy cost values in each season.

The impact of long duration outages (several months to years) can be assessed using the annual replacement energy costs. Shorter duration outages (up to several months) can be assessed using the seasonal replacement energy cost that is more reflective of the particular season in which the nuclear generation unit is expected to be out of service.

The annual replacement energy costs for the run years are shown in Table 3-1. Detailed results for the entire report period, 2020 to 2030, are shown in Appendix G. Because ERCOT has only one Alternative Case, the Most Impact and Least Impact values are the same. A single replacement energy cost is provided in each year in Table 3-1. In some regions some of the units selected for the market price impact assessment are forecasted not to be dispatched due to economic reasons or when their operating licenses expire. In NYISO, the unit assessed to develop the Least Impact value is the R E Ginna Nuclear Power Plant (Ginna). The Ginna plant is assumed to cease commercial operation when its current operating license expires in 2030. Therefore, in 2030 only a single replacement energy cost is calculated for the region. In SPP, there are no replacement energy cost values in 2023 and later because both units in the region are projected to not be dispatched beginning in 2023 for economic reasons. In WECC, the operating license for the unit assessed to develop the Least Impact value, Columbia Generating Station, expires in January 2023. Therefore, in 2023 and beyond there is a single replacement energy cost in each year.

Table 3-1 shows a jump in replacement energy cost in 2030 in ERCOT and ISO-NE. This is because the operating licenses for Comanche Peak Nuclear Power Plant Unit 1 in ERCOT and Seabrook Station in ISO-NE expire in 2030. Replacing the lost energy from these large, relatively lower cost units in addition to the unit modeled offline for the replacement energy cost calculation results in a higher difference in prices between the Reference Case and the

Alternative Case in 2030 relative to the other run years. The operating license for Nine Mile Point Nuclear Station Unit 1 also expires in 2030, but the impact on the NYISO region annual replacement energy cost is less pronounced because it is a relatively smaller unit (approximately half the capacity of the Comanche Peak and Seabrook units).

Table 3-1 Annual Replacement Energy Costs

Region	Annual Replacement Energy Costs ($/MWh)[a]									
	2020		2021		2023		2025		2030	
	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact
ERCOT[b]	1.01	1.01	0.85	0.85	1.48	1.48	1.22	1.22	2.8	2.8
ISO-NE	2.36	1.68	3.00	2.13	2.96	2.13	3.42	2.38	6.12	4.35
MISO	0.13	0.01	0.23	0.03	0.30	0.03	0.37	0.09	0.17	0.00
NYISO[c]	2.04	0.92	2.14	0.98	1.73	0.72	2.19	0.80	3.77	0.00
PJM	1.02	0.08	0.67	0.09	0.74	0.19	0.79	0.16	1.16	0.17
Southeast	0.18	0.11	0.18	0.07	0.17	0.13	0.16	0.10	0.26	0.15
SPP[d]	0.92	0.46	0.86	0.47	0.00	0.00	0.00	0.00	0.00	0.00
WECC[e]	1.12	0.68	1.15	0.91	1.07	0.00	0.94	0.00	1.76	0.00

[a] *Values are in nominal dollars.*

[b] *ERCOT has only one Alternative Case, so a single replacement energy cost is used for the region in all years.*

[c] *The operating license for the unit assessed for Least Impact in NYISO, R E Ginna Nuclear Power Plant, expires in 2030. Therefore, in 2030 this report calculates a single replacement energy cost for the region.*

[d] *In 2023, the report assumes that the Wolf Creek Generating Station and Cooper Nuclear Station in SPP will not be dispatched for economic reasons.*

[e] *The report assumes that beginning in 2023, the unit assessed for Least Impact, Columbia Generating Station, will not be dispatched for economic reasons. Therefore, beginning in 2023 a single replacement energy cost for the WECC region is modeled.*

The seasonal incremental energy costs for the spring season are shown in Table 3-2. Spring season replacement energy costs are based on values for the months of March, April, and May. Results for all years are shown in Appendix G. The swings in seasonal replacement energy costs are due to differences in the scheduled maintenance outage dates modeled in the Reference Cases and the Alternative Cases. Modeling a large nuclear unit out of service in an Alternative Case affects the maintenance decisions of other units in the region. Some scheduled maintenance outage dates shift relative to the Reference Case. For example, a power plant in one of the regions might have its scheduled maintenance outage in April in the Reference Case and in May in the Alternative Case. Because maintenance outages are typically scheduled in the spring and fall, the swings are pronounced in spring and fall and muted in summer, when virtually no maintenance outages occur.

Table 3-2 Spring Season Replacement Energy Costs

Region	Spring Season Incremental Replacement Energy Costs ($/MWh)[a]									
	2020		2021		2023		2025		2030	
	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact
ERCOT[b]	0.65	0.65	0.51	0.51	0.58	0.58	0.43	0.43	0.62	0.62
ISO-NE	1.78	1.12	3.35	2.38	1.46	1.27	2.25	1.58	4.41	3.19
MISO	0.00	0.03	0.33	0.10	0.27	0.09	0.32	0.04	0.04	0.00
NYISO[c]	1.79	0.92	2.67	1.22	0.85	0.46	1.20	0.45	1.57	0.00
PJM	0.70	0.10	0.49	0.03	0.55	0.12	0.59	0.11	0.85	0.11
Southeast	0.14	0.11	0.22	0.11	0.23	0.21	0.14	0.09	0.31	0.18
SPP[d]	1.09	0.52	0.96	0.47	0.00	0.00	0.00	0.00	0.00	0.00
WECC[e]	1.53	1.16	1.35	1.11	1.09	N/A	0.9	N/A	1.74	N/A

[a] *Values are in nominal dollars.*

[b] *ERCOT has only one Alternative Case, so a single replacement energy cost is used for the region in all years.*

[c] *The operating license for the unit assessed for Least Impact in NYISO, R E Ginna Nuclear Power Plant, expires in 2030. Therefore, in 2030 this report calculates a single replacement energy cost for the region.*

[d] *In 2023, the report assumes that the Wolf Creek Generating Station and Cooper Nuclear Station in SPP will not be dispatched for economic reasons.*

[e] *The report assumes that beginning in 2023, the unit assessed for Least Impact, Columbia Generating Station will not be dispatched for economic reasons. Therefore, beginning in 2023 a single replacement energy cost for the WECC region is modeled.*

The seasonal incremental energy costs for the summer season are shown in Table 3-3. Summer season replacement energy costs are based on values for the months of June, July, and August. Results for all years are shown in Appendix G. As discussed above for the spring season costs, the swings in seasonal replacement energy costs are due to differences in the scheduled maintenance outage dates modeled in the Reference Cases and the Alternative Cases. In addition, as discussed above for the annual values, the jump in replacement energy cost in 2030 in ERCOT, ISO-NE, and NYISO are partly due to the operating licenses of Comanche Peak Nuclear Power Plant Unit 1 in ERCOT, Seabrook Station in ISO-NE, and Nine Mile Point Nuclear Station Unit 1 in NYISO expiring.

Table 3-3 Summer Season Replacement Energy Costs

Region	Summer Season Replacement Energy Costs ($/MWh)[a]									
	2020		2021		2023		2025		2030	
	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact
ERCOT[b]	2.07	2.07	1.62	1.62	3.03	3.03	2.91	2.91	8.32	8.32
ISO-NE	2.86	1.97	3.19	2.23	5.75	4.10	6.20	4.22	11.73	8.19
MISO	0.36	0.07	0.30	0.01	0.34	0.00	0.44	0.02	0.07	0.01
NYISO[c]	2.38	1.18	2.05	0.99	2.15	0.95	3.35	1.15	6.23	0.00
PJM	1.18	0.10	0.69	0.14	0.87	0.22	1.02	0.29	1.65	0.20
Southeast	0.10	0.07	0.15	0.06	0.15	0.08	0.23	0.18	0.33	0.18
SPP[d]	0.91	0.55	1.27	0.73	0.00	0.00	0.00	0.00	0.00	0.00
WECC[e]	0.96	0.56	1.19	0.63	1.27	0.00	1.19	0.00	2.01	0.00

[a] *Values are in nominal dollars.*

[b] *ERCOT has only one Alternative Case, so a single replacement energy cost is used for the region in all years.*

[c] *The operating license for the unit assessed for Least Impact in NYISO, R E Ginna Nuclear Power Plant, expires in 2030. Therefore, in 2030 this report calculates a single replacement energy cost for the region.*

[d] *In 2023, the report assumes that the Wolf Creek Generating Station and Cooper Nuclear Station in SPP will not be dispatched for economic reasons.*

[e] *The report assumes that beginning in 2023, the unit assessed for Least Impact, Columbia Generating Station will not be dispatched for economic reasons. Therefore, beginning in 2023 a single replacement energy cost for the WECC region is modeled.*

The seasonal incremental energy costs for the fall season are shown in Table 3-4. Fall season replacement energy costs are based on values for the months of September, October, and November. Results for all years are shown in Appendix G. As discussed above for the spring season costs, the swings in seasonal replacement energy costs are due to differences in the scheduled maintenance outage dates modeled in the Reference Cases and the Alternative Cases.

Table 3-4 Fall Season Replacement Energy Costs

Region	Fall Season Replacement Energy Costs ($/MWh) [a]									
	2020		2021		2023		2025		2030	
	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact
ERCOT[b]	0.89	0.89	0.74	0.74	1.68	1.68	1.03	1.03	1.76	1.76
ISO-NE	1.97	1.44	2.51	1.83	1.40	1.00	1.90	1.49	4.63	3.40
MISO	0.05	0.00	0.15	0.00	0.43	0.16	0.64	0.23	0.47	0.14
NYISO[c]	1.42	0.70	1.77	0.91	1.31	0.50	1.26	0.65	2.82	0.00
PJM	0.80	0.14	0.60	0.13	0.69	0.19	0.68	0.17	0.99	0.14
Southeast	0.17	0.14	0.16	0.07	0.15	0.16	0.13	0.05	0.22	0.15
SPP[d]	0.99	0.51	0.70	0.38	0.00	0.00	0.00	0.00	0.00	0.00
WECC[e]	0.88	0.41	0.97	0.65	0.99	0.00	0.87	0.00	1.96	0.00

[a] *Values are in nominal dollars.*

[b] *ERCOT has only one Alternative Case, so a single replacement energy cost is used for the region in all years.*

[c] *The operating license for the unit assessed for Least Impact in NYISO, R E Ginna Nuclear Power Plant, expires in 2030. Therefore, in 2030 this report calculates a single replacement energy cost for the region.*

[d] *In 2023, the report assumes that the Wolf Creek Generating Station and Cooper Nuclear Station in SPP will not be dispatched for economic reasons.*

[e] *The report assumes that beginning in 2023, the unit assessed for Least Impact, Columbia Generating Station will not be dispatched for economic reasons. Therefore, beginning in 2023 a single replacement energy cost for the WECC region is modeled.*

The seasonal incremental energy costs for the winter season are shown in Table 3-5. Winter season replacement energy costs are based on values for the months of December in the previous year, and January and February in the prevailing year. Results for all years are shown in Appendix G. As discussed above for the spring season costs, the swings in seasonal replacement energy costs are due to differences in the scheduled maintenance outage dates modeled in the Reference Cases and the Alternative Cases.

Table 3-5 Winter Season Replacement Energy Costs

Region	Winter Season Incremental Replacement Energy Costs ($/MWh)[a]									
	2020		2021		2023		2025		2030	
	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact
ERCOT[b]	0.41	0.41	0.47	0.47	0.57	0.57	0.54	0.54	0.44	0.44
ISO-NE	2.91	2.25	3.00	2.25	3.38	2.24	3.22	2.17	3.55	2.52
MISO	0.10	0.00	0.18	0.00	0.17	0.00	0.01	0.01	0.14	0.18
NYISO[c]	2.76	0.99	2.17	0.81	2.72	0.98	2.92	0.96	4.34	0.00
PJM	1.28	0.01	1.10	0.03	0.87	0.17	0.86	0.11	1.16	0.22
Southeast	0.29	0.11	0.20	0.10	0.16	0.07	0.11	0.07	0.19	0.10
SPP[d]	0.73	0.29	0.56	0.27	0.00	0.00	0.00	0.00	0.00	0.00
WECC[e]	1.33	0.67	1.16	1.22	0.88	0.00	0.78	0.00	1.29	0.00

[a] *Values are in nominal dollars.*

[b] *ERCOT has only one Alternative Case, so a single replacement energy cost is used for the region in all years.*

[c] *The operating license for the unit assessed for Least Impact in NYISO, R E Ginna Nuclear Power Plant, expires in 2030. Therefore, in 2030 this report calculates a single replacement energy cost for the region.*

[d] *In 2023, the report assumes that the Wolf Creek Generating Station and Cooper Nuclear Station in SPP will not be dispatched for economic reasons.*

[e] *The report assumes that beginning in 2023, the unit assessed for Least Impact, Columbia Generating Station, will not be dispatched for economic reasons. Therefore, beginning in 2023 a single replacement energy cost for the WECC region is modeled.*

3.2 Use of Replacement Cost Estimates

Wholesale power prices are higher during the on-peak hours (daytime hours) of the day than the off-peak hours (nighttime hours) because average hourly loads are lower during the off-peak hours and on weekends and holidays. Because generators are dispatched in merit order (from low-cost to high-cost alternatives), the lower the average load the lower the incremental cost of dispatched power. Typically, power is more expensive during the summer cooling season and the winter heating season compared with the cost of power during the spring and fall (i.e., shoulder periods).

Given that it is not possible to predict when an outage might occur or how long it might last, the average annual 24-hour prices projected for each of the postulated nuclear unit outages are a good representation of what the price of replacement power would be for each hour of the postulated outage. The increase in the wholesale power price would affect any market participant that had to purchase power in the spot market during the postulated outage periods. However, most power transactions take place under the terms of a contract rather than in the spot market, and the contract prices are not typically tied (or indexed to) the spot market price. It is difficult to determine what fraction of any hour's power transactions for delivery at a given price hub might be affected by the postulated nuclear unit outages. Therefore, no attempt was made to calculate any other costs that could result from the impact on the outage beyond the direct cost to purchase replacement power.

This section discusses the use of the replacement energy cost estimates to assess the impact of the outage of a nuclear generation unit on energy prices in a region. The report demonstrates the calculation using four examples to illustrate variations in approach depending on the number of Alternative Cases developed for the region and the duration of the outage. The report uses the following illustrations:

- Example 1: Annual energy cost calculation for a region with only one Alternative Case
- Example 2: Annual energy cost calculation for a region with two Alternative Cases
- Example 3: Seasonal energy cost calculation for a region with only one Alternative Case
- Example 4: Seasonal energy cost calculation for a region with two Alternative Cases

3.2.1 Example 1: Annual Energy Cost Calculation for a Region with Only One Alternative Case

The ERCOT region has only one Alternative Case. This illustrates the annual replacement energy cost calculation for ERCOT using STP Unit 1 in 2020.

Capacity of STP Unit 1= 1,280 MW (from Table D-1)

Representative capacity factor of STP Unit 1 = 90 percent[9]

Estimated annual power production from STP Unit 1 in 2020

= 1,280 MW × 0.9 × 8,784 hours per year[10]

= 10,119,168 MWh

Annual replacement energy cost in 2020 for the ERCOT region = $1.01/MWh (from Table 3-1)

Annual replacement energy cost for STP Unit 1 in 2020

= 10,119,168 MWh × $1.01/MWh

= $10,192,435

[9] Historical capacity factors for individual nuclear power plant units are available in NUREG-1350 (NRC, 2019a). The 10-year capacity factor for South Texas Project Unit 1 ranges from 78 percent to 101 percent over the 11 year period of 2008 to 2018 with an average capacity factor of 90 percent. https://www.nrc.gov/reading-rm/doc-collections/datasets/ (NRC, 2019b).

[10] The number of hours in year 2020 is 8,784 because 2020 is a leap year. For a standard year, the number of hours in a year is 8,760.

3.2.2 Example 2: Annual Energy Cost Calculation for a Region with Two Alternative Cases

Two Alternative Cases were modeled for the WECC region, which produce a low and high estimate of replacement energy costs. When determining the replacement energy cost for a specific facility the user would need to determine where the value for that facility is likely to fall given factors such as location, size, and proximity to load centers. The report illustrates the annual replacement energy cost calculation for WECC using Diablo Canyon Unit 1 in 2020.

Diablo Canyon Unit 1 has a capacity of 1,122 MW. This is lower than the capacities of Columbia Generating Station (1,180 MW), used to develop the Least Impact values, and Palo Verde Unit 2 (1,314 MW), used to develop the Most Impact values. In terms of location on the grid and the impact of factors such as transmission congestion on market prices, Diablo Canyon is likely to be more similar to Palo Verde. The impact of the proximity to load centers will likely be similar to the other two. The report will therefore assume that the replacement energy cost will be the average of the Most Impact and Least Impact values.

The calculation of the energy cost is shown below:

Capacity of Diablo Canyon Unit 1= 1,122 MW (from Table D-1)

Representative capacity factor of Diablo Canyon Unit 1 = 91 percent

Estimated annual power production from Diablo Canyon Unit 1 in 2020

= 1,122 MW × 0.91 × 8,784 hours per year

= 8,968,640 MWh

Annual replacement energy cost in 2020, calculated from WECC Most Impact and Least Impact values

= $(1.12 + 0.68)/2/MWh

= $0.90/MWh (from Table 3-1)

Annual replacement energy cost for Diablo Canyon Unit 1 in 2020

= 8,968,640 MWh × $0.90/MWh

= $8,071,776

3.2.3 Example 3: Seasonal Energy Cost Calculation for a Region with Only One Alternative Case

The ERCOT region has only one Alternative Case. The report illustrates the seasonal replacement energy cost calculation for ERCOT using STP Unit 1 in summer 2020.

Capacity of STP Unit 1 = 1,280 MW (from Table D-1)

Representative capacity factor of STP Unit 1 during the three summer months = 100 percent

Estimated power production from STP Unit 1 during the three 2020 summer months

= 1,280 MW × 1 x 2,208 hours per summer season

= 2,826,240 MWh

Incremental replacement energy cost in summer 2020 = $2.07/MWh (from Table 3-3)

Replacement energy cost for STP Unit 1 in summer 2020

= 2,667,264 MWh × $2.07/MWh

= $5,850,317

3.2.4 Example 4: Seasonal Energy Cost Calculation for a Region with Two Alternative Cases

Two Alternative Cases were modeled for the WECC region, which produce a low and high estimate of replacement energy costs. When determining the replacement energy cost for a specific facility the user would need to determine where the value for that facility is likely to fall given factors such as location, size, and proximity to load centers. The report illustrates the annual replacement energy cost calculation for WECC using Diablo Canyon Unit 1 in summer 2020.

As discussed in Section 3.2.2, the report assumed the replacement energy cost will be the average of the Most Impact and Least Impact values for the WECC region. The calculation of the energy cost is shown below:

Capacity of Diablo Canyon Unit 1= 1,122 MW (from Table D-1)

Representative capacity factor of Diablo Canyon Unit 1 during the three summer months = 100 percent

Estimated power production from Diablo Canyon Unit 1 in summer 2020

= 1,122 MW × 1 × 2,208 hours per summer season

= 2,477,376 MWh

Incremental replacement energy cost in summer 2020

= $(0.96 + 0.56)/2/MWh

= $0.76/MWh (from Table 3-3)

Replacement energy cost for Diablo Canyon Unit 1 in summer 2020

= 2,477,376 MWh × $0.76/MWh

= $1,882,806

Table 3-6 shows the range of prices for replacement power in 2020 for a postulated outage lasting a day and a year for each of the units modeled in this report using a 100 percent capacity factor.

Table 3-6 Estimated Replacement Energy Costs for Postulated Nuclear Outages

Nuclear Unit	Unit Size (MWe)	2020 Unit Output (MWh)[a,b]	Market Region	2020 Incremental Replacement Energy Cost ($/MWh)	2020 Annual Incremental Outage Cost per Day ($ thousands)	2020 Annual Incremental Outage Cost ($ millions)
South Texas Project, Unit 1	1,280	11,243,520	ERCOT	$1.01	$31.027	$11.356
Millstone Power Station, Unit 2	868	7,624,512	ISO-NE	$1.68	$34.998	$12.809
Millstone Power Station, Unit 3	1,220	10,716,480	ISO-NE	$2.36	$69.101	$25.291
Prairie Island Nuclear Generating Plant, Unit 2	519	4,558,896	MISO	$0.01	$0.125	$0.046
Clinton Power Station, Unit 1	1,065	9,354,960	MISO	$0.13	$3.323	$1.216
R E Ginna Nuclear Power Plant	582	5,112,288	NYISO	$0.92	$12.851	$4.703
Nine Mile Point Nuclear Station, Unit 2	1,287	11,305,008	NYISO	$2.04	$63.012	$23.062
Quad Cities Nuclear Power Station, Unit 1	908	7,975,872	PJM	$0.08	$1.743	$0.638
Limerick Generating Station, Unit 2	1,122	9,855,648	PJM	$1.02	$27.467	$10.053
Joseph M Farley Nuclear Plant, Unit 1	874	7,677,216	Southeast	$0.11	$2.307	$0.844
Vogtle Electric Generating Plant, Unit 2	1,152	10,119,168	Southeast	$0.18	$4.977	$1.821
Cooper Nuclear Station	772	6,781,248	SPP	$0.46	$8.523	$3.119
Wolf Creek Generating Station, Unit 1	1,175	10,321,200	SPP	$0.92	$25.944	$9.496
Columbia Generating Station	1,180	10,365,120	WECC	$0.68	$19.258	$7.048
Palo Verde Nuclear Generating Station, Unit 2	1,314	11,542,176	WECC	$1.12	$35.320	$12.927

[a] *Unit output = unit size x number of hours per year = unit size by 8,784 (accounts for leap year with 366 days). For a standard year, the number of hours is 8,760.*

[b] *The calculations in this table assumes a 100 percent capacity factor for this example*.

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APPENDIX A
OVERVIEW OF IPM

This appendix provides an overview of IPM, the software that is used to project economic generation capacity additions or retirements over the report period.

The report used IPM to support analysis of the electric power sector. The EPA, in addition to state air regulatory agencies, utilities, and public and private sector entities, has used IPM extensively for various air regulatory analyses, market studies, strategy planning, and economic impact assessments.

IPM is a well-established model of the electric power sector designed to help government and industry analyze a wide range of issues related to this sector. The model represents economic activities in key components of energy markets—fuel markets, emissions markets, and electricity markets. Because the model captures the linkages in electricity markets, it is well suited for developing integrated analyses of the impacts of alternative regulatory policies on the power sector. In the past, applications of IPM have included capacity planning, environmental policy analysis and compliance planning, wholesale price forecasting, and power plant asset valuation.

A.1 Purpose and Capabilities

IPM is a dynamic linear programming model that generates optimal decisions under the assumption of perfect foresight. It determines the least-cost method of meeting energy and peak demand requirements over a specified period. In its solution, the model considers several key operating or regulatory constraints that are placed on the power, emissions, and fuel markets. The constraints include but are not limited to emissions limits, transmission capabilities, renewable generation requirements, and fuel market constraints. The model is designed to accommodate complex treatment of emissions regulations involving trading, banking, and special provisions affecting emissions allowances, as well as traditional command-and-control emissions policies.

IPM represents power markets through model regions that are geographical entities with distinct operational characteristics. The model regions are largely consistent with the North American Electric Reliability Corporation (NERC) assessment regions, and with the organizational structures of the Regional Transmission Organizations (RTOs) and the Independent System Operators (ISOs) that handle dispatch on most of the U.S. bulk power grid. IPM calculates the least-cost arrangement of electricity supply (capacity and generation) within each model region to meet assumed future load (electricity demand) while constrained by a transmission network of bulk transfer limitations on inter-regional power flows. All utility-owned existing electric generating units, including renewable resources, as well as independent power producers and cogeneration facilities selling electricity to the grid, are modeled.

IPM provides a detailed representation of new and existing resource options. These include fossil, nuclear, renewable, and non-conventional options. Fossil options include coal steam, oil/gas steam, combined cycles, and gas-fired simple cycle combustion turbines. Renewable options include wind, landfill gas, geothermal, solar thermal, solar PV, and biomass. Non-conventional options include fuel cell, pump storage, and battery storage.

IPM can incorporate a detailed representation of fuel markets and can endogenously forecast fuel prices for coal, natural gas, and biomass by balancing fuel demand and supply for electric generation. The model also includes detailed fuel quality parameters to estimate emissions from electric generation.

IPM provides estimates of air emissions changes, regional wholesale energy and capacity prices, incremental electric power system costs, changes in fuel use, and capacity and dispatch projections.

A.2 Applications

IPM's structure, formulation, and setup make it adaptable and flexible. The necessary level of data, modeling capabilities exercised, and computational requirements can be tailored to the strategies and policy options being analyzed. This adaptability has made IPM suitable for a variety of applications. These include:

Air Regulatory Assessment: Because IPM contains extensive air regulatory modeling features, state and federal air regulatory agencies have used the model extensively in support of air regulatory assessment.

Integrated Resource Planning: IPM can be used to perform least-cost planning studies that simultaneously optimize demand-side options (load management and efficiency), renewable options, and traditional supply-side options.

Options Assessment: IPM allows industry and regulatory planners to "screen" alternative resource options and option combinations based on their relative costs and contributions to meeting customer demands.

Cost and Price Estimation: IPM produces estimates of energy prices, capacity prices, fuel prices, and allowance prices. Industry and regulatory agencies have used these cost reports for due diligence, planning, litigation, and economic impact assessment.

A.3 Model Structure and Formulation

IPM employs a linear programming structure that is particularly well suited for analysis of the electric sector to help decision makers plan system capacity and model the dispatch of electricity from individual units or plants. The model consists of three key structural components:

- A linear "objective function"
- A series of "decision variables"
- A set of linear "constraints"

The sections below describe the objective function, key decision variables, and key constraints included in IPM.

A.3.1 Objective Function

IPM's objective function is to minimize the total, discounted net present value of the costs of meeting demand, power operation constraints, and environmental regulations over the entire planning horizon. The objective function represents the summation of all the costs incurred by the electricity sector on a net present value basis. These costs, which the linear programming formulation attempts to minimize, include the cost of new plant and pollution control construction, fixed and variable operating and maintenance costs, and fuel costs. Many of these cost components are captured in the objective function by multiplying the decision variables by a cost coefficient. Cost escalation factors are used in the objective function to reflect changes in cost over time. The applicable discount rates are applied to derive the net present value for the entire planning horizon from the costs obtained for all years in the planning horizon.

A.3.2 Decision Variables

Decision variables represent the values for which the IPM model is solving, given the cost-minimizing objective function and the set of electricity system constraints. The model determines values for these decision variables that represent the optimal least-cost solution for meeting the assumed constraints. Key decision variables represented in IPM are described in detail below.

<u>Generation Dispatch Decision Variables</u>: IPM includes decision variables that represent the generation from each model power plant.[11] For each model plant, a separate generation decision variable is defined for each possible combination of fuel, season, model run year, and segment of the seasonal load duration curve (LDC) applicable to the model plant. In the objective function, each plant's generation decision variable is multiplied by the relevant heat rate and fuel price (differentiated by the appropriate step of the fuel supply curve) to obtain a fuel cost. It is also multiplied by the applicable VOM cost rate to obtain the VOM cost for the plant.

<u>Capacity Decision Variables</u>: IPM includes decision variables that represent the capacity of each existing model plant and capacity additions associated with potential (new) units in each model run year. In the objective function, the decision variables that represent existing capacity and capacity additions are multiplied by the relevant fixed operation and maintenance (FOM) cost rates to obtain the total FOM cost for a plant. The capacity addition decision variables are also multiplied by the investment cost and capital charge rates to obtain the capital cost associated with the capacity addition.

<u>Transmission Decision Variables</u>: IPM includes decision variables that represent the electricity transmission along each transmission link between model regions in each run year. In the objective function, these variables are multiplied by variable transmission cost rates to obtain the total cost of transmission across each link.

<u>Emission Allowance Decision Variables</u>: For emissions policies where allowance trading applies, IPM includes decision variables that represent the total number of emission allowances for a given model run year that are bought and sold in that or subsequent run years. In the objective function, these year-differentiated allowance decision variables are multiplied by the

[11] Model plants are aggregate representations of real-life electric generating units. They are used by IPM to model the electric power sector.

market price for allowances prevailing in each run year. This formulation allows IPM to capture the inter-temporal trading and banking of allowances.

Fuel Decision Variables: For each type of fuel and each model run year, IPM defines decision variables that represent the quantity of fuel delivered from each fuel supply region to model plants in each demand region.

A.3.3 Constraints

Model constraints are implemented in IPM to accurately reflect the characteristics of and the conditions faced by the electric sector. Among the key constraints included are:

Reserve Margin Constraints: Regional reserve margin constraints capture system reliability requirements by defining a minimum margin of reserve capacity (in megawatts) per year beyond the total capacity needed to meet future peak demand that must remain in service to that region. These reserve capacity constraints are derived from reserve margin targets that are assumed for each region based on information from NERC, RTOs, or ISOs. If existing plus planned capacity is not sufficient to satisfy the annual regional reserve margin requirement, the model will “build” the required level of new capacity.

Demand Constraints: The model categorizes regional annual electricity demand into seasonal load curves that are used to form winter (December 1–February 28), winter shoulder (March 1-April 30, October 1–November 30), and summer (May 1–September 30) LDC[12]. The seasonal load segments, when taken together, represent all the hourly electricity load levels that must be satisfied in a region in the particular season for a particular model run year. As such, the LDC defines the minimum amount of generation required to meet the region’s electrical demand during the specific season. These requirements are incorporated in the model’s demand constraints.

Capacity Factor Constraints: These constraints specify how much electricity each plant can generate (a maximum generation level), given its capacity and seasonal availability.

Turn Down Constraints: The model uses these constraints to take into account the cycling capabilities of the units, i.e., whether or not they can be shut down at night or on weekends, or whether they must operate at all times, or at least at some minimum capacity level. These constraints ensure that the model reflects the distinct operating characteristics of peaking, cycling, and base load units.

Emissions Constraints: IPM can endogenously consider an array of emissions constraints for sulfur dioxide (SO_2), nitrous oxide (NO_x), hydrochloric acid (HCL), mercury, and carbon dioxide (CO_2). Emissions constraints can be implemented on a plant-by-plant, regional, or system-wide basis. The constraints can be defined in terms of a total tonnage cap (e.g., tons of SO_2) or a maximum emission rate (e.g., lb/MMBtu of NO_x). The scope, timing, and definition of the emissions constraints depend on the required analysis.

[12] The seasonal definitions of the IPM and PROMOD models are different. While IPM models three seasons, PROMOD is modeled at an hourly level and Section 2.3 and Table 3-5 summarize the hourly results from PROMOD run into four seasons.

Transmission Constraints: IPM can simultaneously model any number of regions linked by transmission lines. The constraints define either a maximum capacity on each link, or a maximum level of transmission on two or more links (i.e., joint limits) to different regions.

Fuel Supply Constraints: These constraints define the types of fuel that each model plant is eligible to use and the supply regions that are eligible to provide fuel to each specific model plant. A separate constraint is defined for each model plant.

A.4 Key Methodological Features of IPM

IPM is a flexible modeling tool for obtaining short-and long-term projections of production activity in the electric generation sector. The projections obtained using IPM are not statements of what will happen, but they are estimates of what might happen given the assumptions and methodologies used. This section provides an overview of the essential methodological and structural features of IPM.

A.4.1 Model Plants

Model plants are a central structural component that IPM uses in three ways: (1) to represent aggregations of existing generating units, (2) to represent retrofit and retirement options that are available to existing units, and (3) to represent potential (new) units that the model can build.

Existing Units: Theoretically, there is no predefined limit on the number of units that can be included in IPM. However, to keep model size and solution time within acceptable limits, IPM utilizes model plants to represent aggregations of actual individual generating units. The aggregation algorithm groups units with similar characteristics for representation by model plants with a combined capacity and weighted-average characteristics that are representative of all the units comprising the model plant. Model plants are defined to maximize the accuracy of the model's cost and emissions estimates by capturing variations in key features of those units that are critical to the analysis.

Retrofit and Retirement Options: IPM also utilizes model plants to represent the retrofit and retirement options that are available to existing units. Existing model plants are provided with a wide range of options for retrofitting with emissions control equipment as well as with an option to retire.

The options available to each model plant are predefined at the model's setup. The retrofit and retirement options are themselves represented in IPM by model plants, which, if actuated in a model run, take on all or a portion of the capacity initially assigned to a model plant, which represents existing generating units.[13] In setting up IPM, parent-child-grandchild relationships are predefined between each existing model plant (parent) and the specific retrofit and retirement model plants (children and grandchildren) that may replace the parent model plant during a model run. The child and grandchild model plants are inactive in IPM unless the model finds it economical to engage one of the options provided, e.g., retrofit with particular emissions controls or retire.

[13] IPM has a linear programming structure whose decision variables can assume any value within the specified bounds subject to the constraints. Therefore, IPM can generate solutions where model plants retrofit or retire a portion of the model plants' capacity. IPM's standard model plant outputs explicitly present these partial investment decisions.

Theoretically, there are no limits on the number of child, grandchild, and even great-grandchild model plants (i.e., retrofit and retirement options) that can be associated with each existing model plant. However, model size and computational considerations dictate that the number of successive retrofits be limited.

Potential (New) Units: IPM also uses model plants to represent new generation capacity that may be built during a model run. All the model plants representing new capacity are predefined at setup, differentiated by type of technology, regional location, and years available. When it is economically advantageous to do so (or otherwise required by reserve margin constraints to maintain electric reliability), IPM "builds" one or more of these predefined model plants by raising its generation capacity from zero during a model run. In determining whether it is economically advantageous to "build" new plants, IPM takes into account cost differentials between technologies, expected technology cost improvements, and regional variations in capital costs that are expected to occur over time.

A.4.2 Model Run Years

Another important structural feature of IPM is the use of model "run years" to represent the full planning horizon being modeled. Although IPM can represent an individual year in an analysis time horizon, mapping each year in the planning horizon into a representative model run year enables IPM to perform multiple year analyses while keeping the model size manageable. IPM takes into account the costs in all years in the planning horizon but reports results only for model run years.

Often models like IPM include a final model run year that is not included in the analysis of results. This technique reduces the likelihood that modeling results in the last represented year will be skewed due to the modeling artifact of having to specify an end point in the planning horizon, whereas economic decision-making will continue to take information into account from years beyond the model's time horizon. This should be considered when assessing model projections from the last output year.

A.4.3 Cost Accounting

As noted earlier in this appendix, IPM is a dynamic linear programming model that solves for the least-cost investment and electricity dispatch strategy for meeting electricity demand subject to resource availability and other operating and environmental constraints. The cost components that IPM considers in deriving an optimal solution include the costs of investing in new capacity options, the cost of installing and operating pollution control technology, fuel costs, and the operation and maintenance costs associated with unit operations. Several cost accounting assumptions are built into IPM's objective function that ensures a technically sound and unbiased treatment of the cost of all investment options offered in the model. These features include:

- All costs (in real dollars) in IPM's single multi-year objective function are discounted to a base year. Because the model solves for all run years simultaneously, discounting to a common base year ensures that IPM properly captures complex inter-temporal cost relationships.

- Capital costs in IPM's objective function are represented as the net present value of levelized stream of annual capital outlays, not as a one-time total investment cost. The payment period used in calculating the levelized annual outlays never extends beyond the model's planning horizon. It is either the book life of the investment or the years remaining in the planning horizon, whichever is shorter. This approach avoids presenting artificially lower capital costs for investment decisions taken closer to the model's time horizon boundary simply because some of that cost would typically be serviced in years beyond the model's view. This treatment of capital costs ensures both realism and consistency in accounting for the full cost of each of the investment options in the model.

- The cost components informing IPM's objective function represent the composite cost over all years in the planning horizon rather than just the cost in the individual model run years. This permits the model to capture more accurately the escalation of the cost components over time.

A.4.4 Modeling Wholesale Electricity Markets

IPM is designed to simulate electricity production activity in a manner that would minimize production costs, as is the intended outcome in wholesale electricity markets. For this purpose, the model captures transmission costs and losses between IPM model regions, but it is not designed to capture retail distribution costs. However, the model implicitly includes distribution losses because net energy for load,[14] rather than delivered sales, is used to represent electricity demand in the model. Additionally, the production costs calculated by IPM are the wholesale production costs. In reporting costs, the model does not include embedded costs, such as carrying charges of existing units, which may ultimately be part of the retail cost incurred by end-use consumers.

A.4.5 Load Duration Curves

IPM uses LDCs to provide realism to the dispatching of electric generating units. Unlike a chronological electric load curve, which is an hourly record of electricity demand, the LDCs are created by rearranging the hourly chronological electric load data from the highest to lowest (MW) value. To aggregate such load detail into a format enabling this scale of power sector modeling, EPA applications of IPM use a 24-step piecewise linear representation of the LDC.

IPM can include any number of user-defined seasons. A season can be a single month or several months. Use of seasonal LDCs rather than annual LDCs allows IPM to capture seasonal differences in the level and patterns of customer demand for electricity. For example, in most regions air conditioner cycling only impacts customer demand patterns during the summer season. The use of seasonal LDCs also allows IPM to capture seasonal variations in the generation resources available to respond to the customer demand depicted in an LDC. For example, power exchanges between utility systems may be seasonal in nature. Some air regulations affecting power plants are also seasonal in nature. This can impact the type of generating resources that are dispatched during a particular season. Further, because of maintenance scheduling for individual generating units, the capacity and utilization for these supply resources also vary between seasons.

[14] Net energy for load is the electrical energy requirements of an electrical system, defined as system net generation, plus energy received from others, less energy delivered to others through interchange. It includes distribution losses.

Within IPM, LDCs are represented by a discrete number of load segments, or generation blocks, as illustrated in Figure A-1.

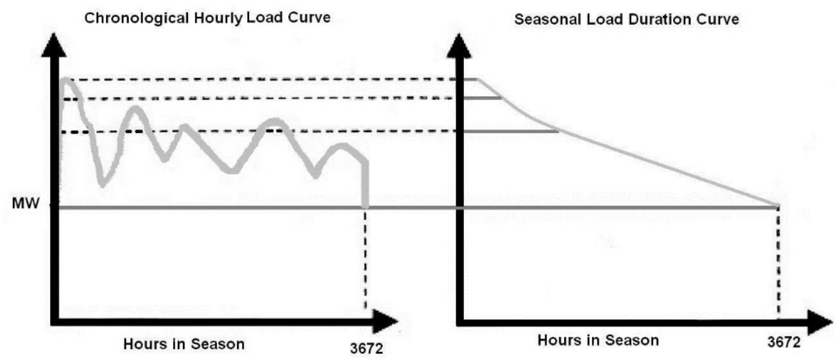

Figure A-1 Hypothetical Chronological Hourly Load Curve and Seasonal Load Duration Curve

Hourly load curves from FERC Form 714 and ISO/RTOs are used to derive future seasonal LDCs for each IPM run year in each IPM region. The results of this process are individualized seasonal LDCs that capture the unique hourly electricity demand profile of each region. The LDCs change over time to reflect projected changes in load factors because of future variations in electricity consumption patterns.

The EPA Platform v6 (EPA, 2019) uses 24 load segments in its seasonal LDCs. Figure A-2 illustrates and the following text describes the 24-segment LDCs used in EPA Platform v6 (EPA, 2019). Length of time and system demand are the two parameters, which define each segment of the LDC. The load segment represents the amount of time (along the x-axis) and the capacity that the electric dispatch mix must be producing (represented along the y-axis) to meet system load. In EPA Platform v6 (EPA, 2019), the hours in the LDC are initially clustered into six segments. Segment 1 incorporates 1 percent of all hours in the season with the highest load. Segments 2 to 6 have 4 percent, 10 percent, 30 percent, 30 percent, and 25 percent of the hours, respectively, with progressively lower levels of demand. Each of these segments is further separated into four time-of-day categories to result in a possible maximum of 24 load segments. This approach better accounts for the impact of solar generation during periods of high demand. The four time-of-day categories are 8 PM–6 AM, 6 AM–9 AM, 9 AM–5 PM and 5 PM–8 PM. Plants are dispatched to meet this load based on economic considerations and operating constraints. The most cost-effective plants are assigned to meet load in all 24 segments of the LDC.

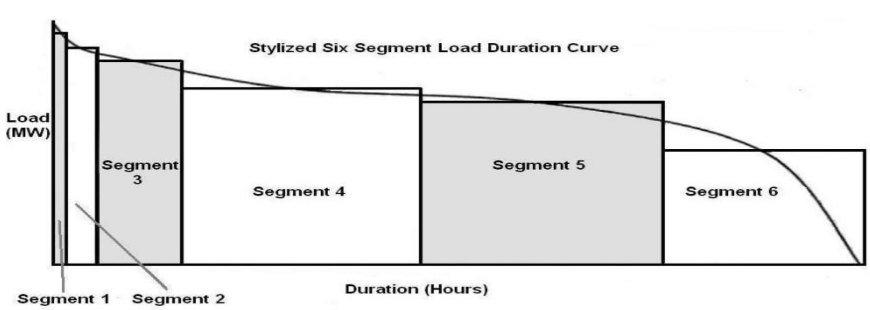

Figure A-2 Stylized Depiction of a Six Segment Load Duration Curve Used in EPA Platform v6 (EPA, 2019)

Each segment is further divided into four time-of-day categories resulting in 24-segment LDCs.

A.4.6 Dispatch Modeling

In IPM, the dispatching of electricity is based on the variable cost of generation. In the absence of any operating constraints, units with the lowest variable cost generate first. The marginal generating unit, i.e., the power plant that generates the last unit of electricity, sets the energy price. Physical operating constraints also influence the dispatch order. For example, IPM uses turn down constraints to prevent base load units from cycling, i.e., switching on and off. Turn down constraints often override the dispatch order that would result based purely on the variable cost of generation. Variable costs in combination with turn down constraints enable IPM to dispatch generation resources in a technically realistic fashion.

Figure A-3, below, depicts a stylized dispatch order based on the variable cost of generation of resource options. In this figure, two hypothetical load segments are subdivided according to the type of generation resource that responds to the load requirements represented in that segment. Notice that the generation resources with the lowest operating cost (i.e., hydro and nuclear) respond first to the demand represented in the LDC and are accordingly at the bottom of the "dispatch stack." They are dispatched for the maximum possible number of hours represented in the LDC because of their low operating costs.

Generation resources with the highest operating cost (e.g., peaking turbines) are at the top of the "dispatch stack," because they are dispatched last and for the minimum possible number of hours. In the load segment with non-dispatchable generating capacity such as solar, the conventional power plants are dispatched to the residual load level where residual load is defined as the difference between the total load and the load met by non-dispatchable resources.

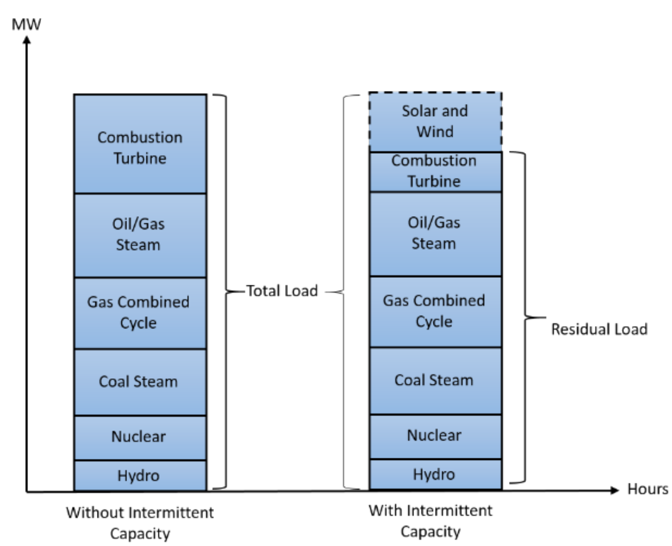

Figure A-3 Stylized Dispatch Order in Illustrative Load Segments

Note: This figure does not include all the plant types that are modeled in EPA Platform v6 (EPA, 2019). Intermittent renewable technologies, such as wind and solar, are considered non-dispatchable and are assigned a specific hourly generation profile.

A.4.7 Fuel Modeling

Another key methodological feature of IPM is its capability to model the full range of fuels used for electric power generation. The cost, supply, and (if applicable) quality of each fuel included in the model are defined during model setup. Fuel price and supply are represented in EPA Platform v6 (EPA, 2019) in one of two alternative ways: (1) through a set of supply curves (coal, natural gas, and biomass) or (2) through an exogenous price stream (fuel oil and nuclear fuel). With the first approach, the model endogenously determines the price for that fuel by balancing the supply and demand. IPM uses fuel quality information (e.g., the sulfur, chlorine, or mercury content of different types of coal from different supply regions) to determine the emissions resulting from combustion of that fuel.

A.4.8 Transmission Modeling

IPM includes a detailed representation of existing transmission capabilities between model regions. The maximum transmission capabilities between regions are specified in IPM's transmission constraints. Due to uncertainty surrounding the building of new transmission lines in the United States, IPM's capability to model the building of new transmission lines is not exercised. However, that capacity of the model is described in case it is applied in future analyses. Additions to transmission lines are represented by decision variables defined for each eligible link and model run year. In IPM's objective function, the decision variables representing transmission additions are multiplied by new transmission line investment cost and capital charge rates to obtain the capital cost associated with the transmission addition.

A.4.9 Perfect Competition and Perfect Foresight

Two key methodological features of IPM are its assumptions of perfect competition and perfect foresight. The former means that IPM models production activity in wholesale electric markets on the premise that these markets operate within a market structure of perfect competition. The model does not explicitly capture any market imperfections such as market power, transaction costs, informational asymmetry, or uncertainty. However, if desired, appropriately designed sensitivity analyses or redefined model parameters can be used to gauge the impact of market imperfections on the wholesale electric markets.

IPM's assumption of perfect foresight implies that agents know precisely the nature and timing of conditions in future years that affect the ultimate costs of decisions along the way. For example, under IPM there is complete foreknowledge of future electricity demand, fuel supplies, and other variables (including regulatory requirements) that are subject to uncertainty and limited foresight. Modelers frequently assume perfect foresight to establish a decision-making framework that can estimate cost-minimizing courses of action given the best-guess expectations of these future variables that can be constructed at the time the projections are made.

A.4.10 Scenario Analysis and Regulatory Modeling

One of the most notable features of IPM is its detailed and flexible modeling features enabling for scenario analysis involving different outlooks of key drivers of the power sector and environmental regulations. Treatment of environmental regulations is endogenous in IPM. That is, by providing a comprehensive representation of compliance options, IPM enables environmental decisions to be made within the model based on least-cost considerations, rather than exogenously imposing environmental choices on model results. For example, unlike other models that enter allowance prices as an exogenous input during model setup, IPM obtains allowance prices as an output of the endogenous optimization process of finding the least-cost compliance options in response to air regulations. In linear programming terminology, the "shadow prices"[15] of the respective emissions constraints are the standard output produced in solving a linear programming problem.

A.5 Model Inputs and Outputs

A.5.1 Data Parameters for Model Inputs

IPM requires input parameters that characterize the U.S. electricity system, economic outlook, fuel supply, and air regulatory framework.

Table A-1 lists the key input parameters required by IPM.

Table A-1 IPM Input

Category	Key Input Parameters
Existing Generating Resources	Plant Capacities Heat Rates Fuels Used Availability Fixed and Variable O&M Costs Minimum Generation Requirements (Turn Down Constraint) Output Profile for Non-Dispatchable Resources Emissions Limits or Emission Rates for NO_x, SO_2, HCl, CO_2, and Mercury Existing Pollution Control Equipment and Retrofit Options
New Generating Resources	Cost and Operating Characteristics Resource Limits and Generation Profiles
Other System Requirements	Regional Specification Inter-regional Transmission Capabilities Reserve Margin Requirements for Reliability System Specific Generation Requirements
Electricity Demand	Electricity Demand Peak Load Load Curves
Financial Outlook	Capital Charge Rates
Fuel Supply	Fuel Supply Curves for Coal, Gas, and Biomass Fuel Price Fuel Quality Transportation Costs for Coal, Natural Gas, and Biomass
Regulatory Outlook	Air Regulations for NO_x, SO_2, HCl, CO_2, and Mercury Other Air Regulations Nuclear Unit Zero-Emission Credit Programs Non-air Regulations (Affecting Electric Generating Unit Operations)

[15] Shadow pricing is the practice of assigning a monetary value to an item, commodity, or service that is not ordinarily bought and sold in any marketplace. The shadow price is an estimate of the monetary value of a good or input in the absence of market distortions.

A.5.2 Model Outputs

IPM can produce a variety of output reports. These range from extremely detailed reports, which describe the results for each model plant and run year, to summary reports, which present results for regional and national aggregates. Individual topic areas can be included or excluded at the user's discretion. Standard IPM reports cover the following topics:

- Generation and capacity mix
- Capacity additions and retirements
- Capacity and energy prices
- Power production costs
- Fuel consumption
- Fuel supply and demand
- Fuel prices for coal, natural gas, and biomass
- Emissions (NO_x, SO_2, HCl, CO_2, and mercury)
- Emission allowance prices

A.6 Appendix A References

U.S. Environmental Protection Agency (EPA), "Power Sector Modeling Platform v6," 2019. (EPA, 2019).

APPENDIX B
OVERVIEW OF PROMOD

This appendix provides an overview of PROMOD, the software that was used to simulate electricity market operations and derive electricity price projections for replacement energy cost calculations.[16]

For over 40 years, energy firms have been using PROMOD for a variety of applications that include locational marginal price (LMP) forecasting, financial transmission right (FTR) valuation, environmental analysis, asset valuations (generation and transmission), transmission congestion analysis, and purchased power agreement evaluations.

PROMOD provides valuable information on the dynamics of the marketplace by determining the effects of transmission congestion, fuel costs, generator availability, bidding behavior, and load growth on market prices. PROMOD performs a daily or weekly commitment and hourly or sub-hourly dispatch, recognizing both generation and transmission impacts at the nodal and zonal level.

PROMOD forecasts hourly and sub-hourly energy prices, unit generation, revenues and fuel consumption, external market transactions, transmission flows, and congestion and loss prices.

PROMOD is built on robust data structures. This includes the ability to enter time-based data changes at the hourly and sub-hourly granular level and detailed generator data inputs. In addition to unit capacity changes, users can enter data describing future changes to generator data.

B.1 Price Forecasting

PROMOD performs a security-constrained unit commitment and economic dispatch that is co-optimized with operating reserve requirements, similar to how transmission/independent system operators (TSOs/ISOs) set schedules and determine prices, to provide forecasts of LMPs. LMP may be reported for selected nodes, user-defined hubs, or load-weighted or generator-weighted hubs; this may be further broken down into a reference price, a congestion price (showing individual flowgate contributions to congestion), and a marginal loss price.

B.2 Transmission and Congestion Valuation

PROMOD performs valuation of transmission, congestion and associated financial instruments—such as FTRs, congestion revenue rights (CRRs), and transmission congestion contracts (TCCs)—by providing all market participants and energy companies with the powerful tools needed to quantify market prices, identify binding constraints, and evaluate economic impacts of the specific constraints that have strategic significance to specific portfolios and business needs.

B.3 Renewable Energy Valuation

PROMOD simulates the effects of intermittent energy schedules from wind, solar, and other renewable projects on transmission congestion, and forecasts the amount of energy that may

[16] ABB is the source of information for this appendix, unless otherwise stated.

be curtailed considering the opportunity costs from production tax and renewable energy credits. This information enables the user to evaluate renewable projects and their impacts on the wider generation and transmission system.

B.4 Economic Transmission Analysis

PROMOD provides market participants and energy companies with the ability to evaluate the economic benefit, changes in transmission congestion, and impact to generation assets associated with transmission expansion and outage scheduling. By simulating the energy market in detail, users can see the LMP and its components, transmission flows, and the behavior of the generating units.

B.5 Zonal Power Market Analysis

PROMOD simulates, on an hourly and sub-hourly basis, the applicable region under a variety of conditions. This information is then used to quantify the operating risks associated with each facility and develop a detailed forecast of zonal market clearing prices and system operation under these conditions. PROMOD is also used to perform long-term, transportation-based simulations of regions with robust hourly unit commitment and sub-hourly dispatch decisions, using the capacity expansion determined by ABB's Reference Case, Capacity Expansion or Market Power solutions. Figure B-1 summarizes PROMOD inputs and outputs.

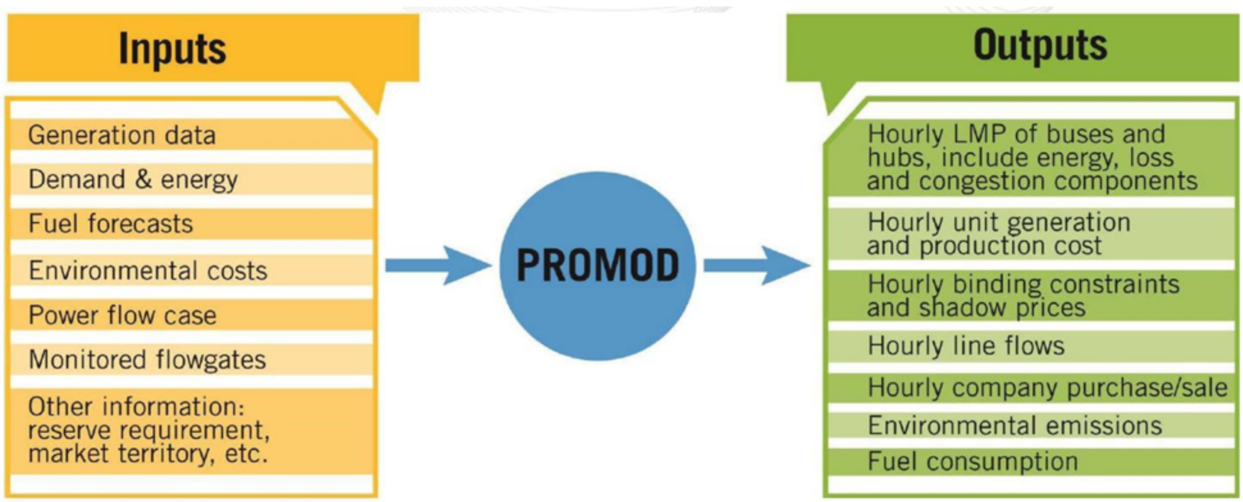

Figure B-1: PROMOD Data Inputs and Outputs

Source: PJM

B.6 Appendix B References

ABB, "ABB Ability™ PROMOD®–Generation and transmission modeling system with nodal and zonal price forecasting," 2018. Brochure available for download at: https://www.hitachiabb-powergrids.com/offering/product-and-system/enterprise/energy-portfolio-management/market-analysis/promod.

PJM Interconnection LLC, "PJM PROMOD Overview," 2017. Available at: https://www.pjm.com/-/media/committees-groups/subcommittees/cs/20170811/20170811-item-02-pjm-promod-overview.ashx.

APPENDIX C
SELECTION OF NUCLEAR PLANTS FOR ALTERNATIVE CASES (NEW ENGLAND)

This appendix illustrates the use of the criteria to determine the Alternative Case(s) for the calculation of replacement energy costs for ISO-NE (ISO, 2018).

The nuclear power plants currently in operation in the ISO-NE (ISO, 2018) market are:

- Millstone Power Station, Unit 2 and Unit 3
- Seabrook Station

The Pilgrim Nuclear Power Station was shut down permanently on May 31, 2019, so it is not considered in the determination of replacement energy costs. The report considers only Millstone Power Station and Seabrook Station.

Regarding location relative to congestion in the region, there is no significant difference between Millstone and Seabrook. Historically, ISO-NE had congestion that created relatively high electricity prices in locations such as southwest Connecticut and the Greater Boston area. Over the past few years, however, transmission providers in the region have implemented large transmission projects that have significantly reduced congestion and led to relatively flat prices in the market, with variations due to losses. To illustrate, Figure C-1 shows pricing zones in ISO-NE. In addition to providing prices for specific locations or nodes on the system, ISO-NE provides prices for the eight load zones. The zonal prices are aggregations of the nodal prices and are calculated as load-weighted-average prices of all the nodes within a load zone. In addition, ISO-NE provides prices for a central Hub. The Hub is "a collection of internal nodes intended to represent an uncongested price for electric energy, facilitate energy trading, and enhance transparency and liquidity in the marketplace."[17] The Hub price is calculated as a simple average of price at 32 nodes in central New England where little congestion is evident.

[17] ISO New England, 2017 Annual Markets Report, May 17, 2018, page 48, available at : https://www.iso-ne.com/staticassets/documents/2018/05/2017-annual-markets-report.pdf (ISO, 2018).

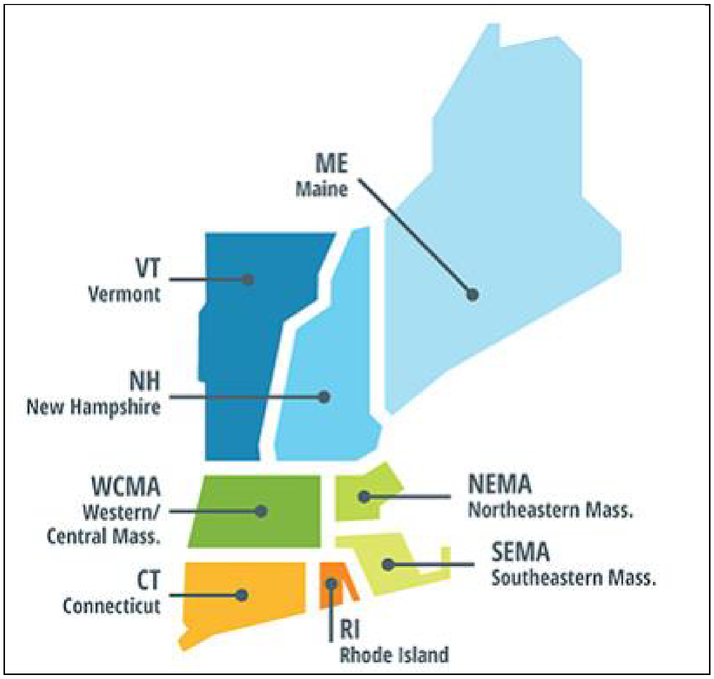

Figure C-1 ISO New England Pricing Zones

Source: ISO New England (ISO, 2018)

Figure C-2 shows the simple average zonal and hub prices in 2017. The differences between zonal prices and between zonal and hub prices were relatively small. ISO-NE's 2017 Annual Markets Report (ISO, 2018) states that the "Maine load zone had the lowest average prices in the region in 2017. Maine's prices averaged \$0.86 per MWh and \$2.55 per MWh lower than the Hub's prices for the day-ahead and real-time markets, respectively."[18] The report also adds that "NEMA [Northeast Massachusetts/Boston] had the highest average prices in both the day-ahead and real-time markets. NEMA average prices were slightly higher than the Hub's prices, by \$0.10 per MWh and \$0.83 per MWh, respectively."[19]

[18] Ibid, page 52.

[19] Ibid.

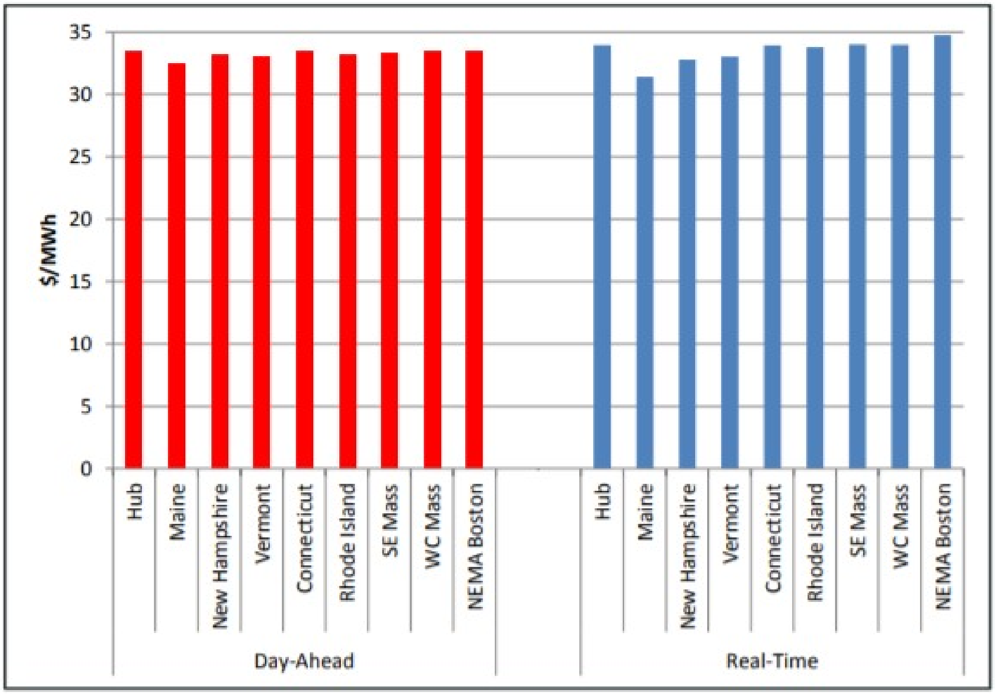

Figure C-2 Simple Average Hub and Load Zone Prices, 2017

Source: (ISO, 2018)

Figure C-3 shows load-weighted monthly average prices for the ISO-NE (ISO, 2018) over the 5-year span from 2013 to 2017. As indicated in the ISO-NE (ISO, 2018) report, "load-weighted energy prices by load zone from 2013 to 2017 indicate a pattern that varies considerably by year and month, but typically not by load zone."[20] Extreme prices occurred in periods such as the months of January and February in 2013 to 2015 due to high natural gas prices.

The foregoing shows that there will be relatively small difference in the impact of an outage of a unit at Millstone or Seabrook based on congestion at the unit's location.

[20] Ibid, page 53.

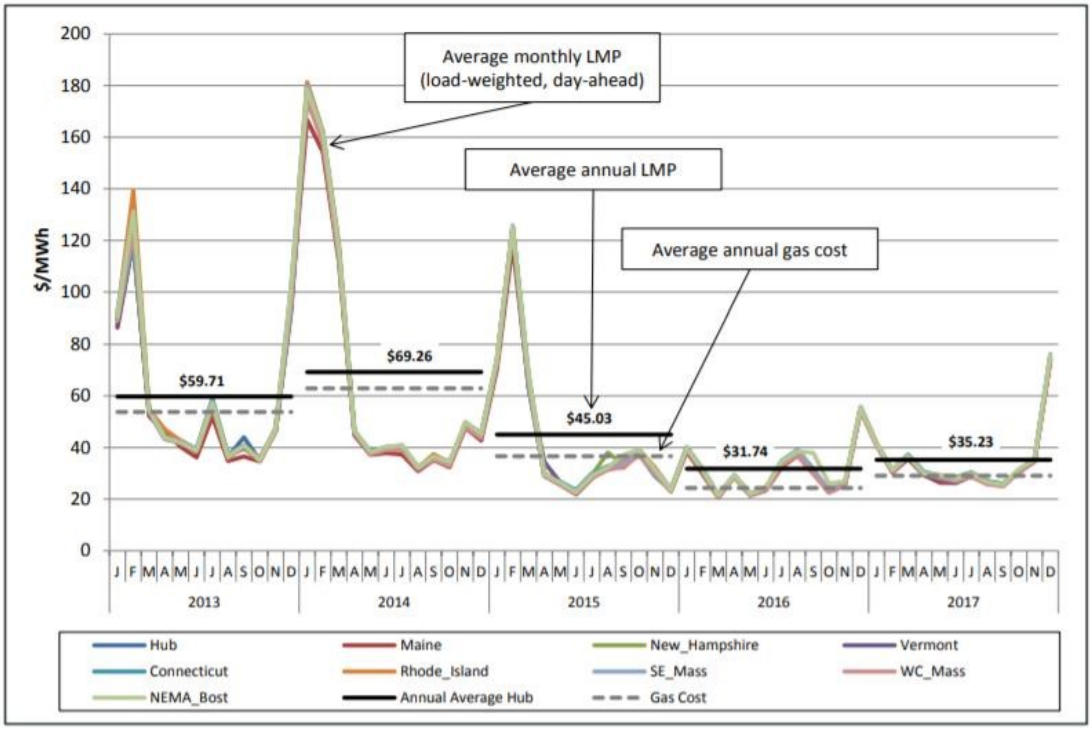

Figure C-3 Day-Ahead Load-Weighted Prices

Source: (ISO, 2018)

There is some variation in the sizes of the units. Millstone Power Station Unit 2 and Unit 3 are 868 MW and 1,220 MW, respectively. Seabrook Station is 1,251 MW. Because there isn't a significant difference in unit capacities between Millstone Unit 3 and Seabrook Station, the report expects that there will be a relatively small difference in the impact of an outage at either unit. The replacement energy cost impact of an outage at Millstone Unit 2 might be different from an outage at either of the other two units.

Regarding proximity to load centers both power plants are relatively close to the ISO-NE's major load centers, which are in southern New England. In New England, power generally flows from generation centers in the north and east to load centers in the south and west. Because Millstone is more embedded in the south and west of the market it will be downstream of flows, relative to Seabrook. Therefore, to the extent proximity to load centers is a factor, the impact will be stronger for Millstone than Seabrook; however, the effect is likely to be relatively small. The report therefore expects that there will be relatively small difference in the impact of an outage of a unit at Millstone or Seabrook based on the unit's proximity to load centers.

To summarize, considering the criteria for selection of nuclear power plants to analyze to determine replacement energy cost for ISO-NE:

- Location relative to congestion in the region: Relatively small difference in impact on market if either Millstone Unit or the Seabrook Unit is selected. The outage of any unit will be sufficient to determine replacement energy costs for the region.

- Size of power plant: Relatively small difference in impact on the market if either Millstone Unit 3 or Seabrook Station is selected, but the impact of Millstone Unit 2 might be different, and likely lower. Millstone Unit 2 should be selected for least impact and either Millstone Unit 3 or Seabrook Station should be selected for most impact.

- Proximity to load centers: Relatively small difference in pricing based on the unit's proximity to load centers if either Millstone Unit or Seabrook Unit is selected. The outage of any unit will be sufficient to determine replacement energy costs for the region.

C.1 Appendix C References

ISO New England, "2017 Annual Markets Report," May 2018. Available at: https://www.iso-ne.com/static-assets/documents/2018/05/2017-annual-markets-report.pdf. (ISO, 2018).

APPENDIX D
EXISTING AND COMMITTED NUCLEAR UNITS

Table D-1 is a list of existing and committed nuclear generation units modeled in service in the replacement energy cost report. The Planned Retirement Year is the year the unit is expected to be taken out of service based on the owner's announced plan or the units' operating license expiration date. IPM simulates electricity production activity in a manner that would minimize production costs, by dispatching generation in the market in economic merit order, subject to transmission and other system limitations, to determine prices. For modeling purposes, the IPM Economic Dispatch Curtailment column identifies when a unit may not be economically dispatched for the purposes of calculating replacement energy costs.

Table D-1 Existing and Committed Nuclear Generation Units

Plant Name	Unit ID	State Name	Capacity (MW)	On Line Year	Planned Retirement Year	IPM Economic Dispatch Curtailment Year[a]	Model Region
Arkansas Nuclear One	1	Arkansas	833	1974	2034	2023	MISO
Arkansas Nuclear One	2	Arkansas	985	1980	2039	2039	MISO
Beaver Valley Power Station[b]	1	Pennsylvania	907	1976	2021	2021	PJM
Beaver Valley Power Station[b]	2	Pennsylvania	901	1987	2022	2022	PJM
Braidwood Station	1	Illinois	1,183	1988	2047	2047	PJM
Braidwood Station	2	Illinois	1,154	1988	2048	2048	PJM
Browns Ferry Nuclear Plant	1	Alabama	1,266	1974	2034	2034	Southeast
Browns Ferry Nuclear Plant	2	Alabama	1,268	1975	2034	2034	Southeast
Browns Ferry Nuclear Plant	3	Alabama	1,270	1977	2037	2037	Southeast
Brunswick Steam Electric Plant	1	North Carolina	938	1977	2037	2037	Southeast
Brunswick Steam Electric Plant	2	North Carolina	932	1975	2035	2035	Southeast
Byron Station	1	Illinois	1,164	1985	2021[c]	2045	PJM
Byron Station	2	Illinois	1,136	1987	2021[c]	2047	PJM
Callaway Plant	1	Missouri	1,190	1984	2045	2023	MISO

Table D-1 Existing and Committed Nuclear Generation Units (continued)

Plant Name	Unit ID	State Name	Capacity (MW)	On Line Year	Planned Retirement Year	IPM Economic Dispatch Curtailment Year[a]	Model Region
Calvert Cliffs Nuclear Power Plant	1	Maryland	866	1975	2035	2035	PJM
Calvert Cliffs Nuclear Power Plant	2	Maryland	842	1977	2037	2037	PJM
Catawba Nuclear Station	1	South Carolina	1,160	1985	2044	2044	Southeast
Catawba Nuclear Station	2	South Carolina	1,150	1986	2044	2044	Southeast
Clinton Power Station	1	Illinois	1,065	1987	2027	2027	MISO
Columbia Generating Station	2	Washington	1,180	1984	2044	2023	WECC
Comanche Peak Nuclear Power Plant	1	Texas	1,205	1990	2030	2030	ERCOT
Comanche Peak Nuclear Power Plant	2	Texas	1,195	1993	2033	2033	ERCOT
Cooper Nuclear Station	1	Nebraska	772	1974	2034	2023	SPP
Davis Besse Nuclear Power Station	1	Ohio	894	1977	2037	2037	PJM
Diablo Canyon Nuclear Power Plant	1	California	1,122	1985	2025	2025	WECC
Diablo Canyon Nuclear Power Plant	2	California	1,118	1986	2026	2026	WECC
Donald C Cook Nuclear Plant	1	Michigan	1,009	1975	2035	2035	PJM
Donald C Cook Nuclear Plant	2	Michigan	1,060	1978	2038	2038	PJM
Dresden Nuclear Power Station	2	Illinois	902	1970	2021[c]	2030	PJM
Dresden Nuclear Power Station	3	Illinois	895	1971	2021[c]	2031	PJM
Duane Arnold Energy Center	1	Iowa	601	1975	2020	2020	MISO

Table D-1 Existing and Committed Nuclear Generation Units (continued)

Plant Name	Unit ID	State Name	Capacity (MW)	On Line Year	Planned Retirement Year	IPM Economic Dispatch Curtailment Year[a]	Model Region
Edwin I Hatch Nuclear Plant	1	Georgia	876	1975	2035	2023	Southeast
Edwin I Hatch Nuclear Plant	2	Georgia	883	1979	2038	2023	Southeast
Enrico Fermi Nuclear Plant	2	Michigan	1,141	1988	2045	2023	MISO
Grand Gulf Nuclear Station	1	Mississippi	1,401	1985	2045	2023	MISO
H B Robinson Steam Electric Plant	2	South Carolina	741	1971	2031	2023	Southeast
Hope Creek Generating Station	1	New Jersey	1,190	1986	2046	2023	PJM
Indian Point Nuclear Generating	2	New York	1,012	1973	2020	2020	NYISO
Indian Point Nuclear Generating	3	New York	1,039	1976	2021	2021	NYISO
James A Fitzpatrick Nuclear Power Plant	1	New York	853	1976	2035	2030	NYISO
Joseph M Farley Nuclear Plant	1	Alabama	874	1977	2037	2037	Southeast
Joseph M Farley Nuclear Plant	2	Alabama	883	1981	2041	2041	Southeast
LaSalle County Station	1	Illinois	1,135	1984	2042	2042	PJM
LaSalle County Station	2	Illinois	1,134	1984	2044	2044	PJM
Limerick Generating Station	1	Pennsylvania	1,120	1986	2045	2045	PJM
Limerick Generating Station	2	Pennsylvania	1,122	1990	2049	2049	PJM
McGuire Nuclear Station	1	North Carolina	1,158	1981	2041	2041	Southeast
McGuire Nuclear Station	2	North Carolina	1,158	1984	2043	2043	Southeast

Table D-1 Existing and Committed Nuclear Generation Units (continued)

Plant Name	Unit ID	State Name	Capacity (MW)	On Line Year	Planned Retirement Year	IPM Economic Dispatch Curtailment Year[a]	Model Region
Millstone Power Station	2	Connecticut	868	1975	2036	2036	ISO-NE
Millstone Power Station	3	Connecticut	1,220	1986	2046	2046	ISO-NE
Monticello Nuclear Generating Plant	1	Minnesota	617	1971	2031	2023	MISO
Nine Mile Point Nuclear Station	1	New York	626	1969	2030	2030	NYISO
Nine Mile Point Nuclear Station	2	New York	1,287	1987	2047	2047	NYISO
North Anna Power Station	1	Virginia	948	1978	2038	2038	PJM
North Anna Power Station	2	Virginia	944	1980	2041	2041	PJM
Oconee Nuclear Station	1	South Carolina	847	1973	2033	2033	Southeast
Oconee Nuclear Station	2	South Carolina	848	1974	2034	2034	Southeast
Oconee Nuclear Station	3	South Carolina	859	1974	2035	2035	Southeast
Palisades Nuclear Plant	1	Michigan	784	1972	2022	2022	MISO
Palo Verde Nuclear Generating Station	1	Arizona	1,311	1986	2045	2045	WECC
Palo Verde Nuclear Generating Station	2	Arizona	1,314	1986	2046	2046	WECC
Palo Verde Nuclear Generating Station	3	Arizona	1,312	1988	2048	2048	WECC
Peach Bottom Atomic Power Station	2	Pennsylvania	1,245	1974	2034	2034	PJM
Peach Bottom Atomic Power Station	3	Pennsylvania	1,248	1974	2035	2035	PJM
Perry Nuclear Power Plant	1	Ohio	1,240	1987	2026	2026	PJM

Table D-1 Existing and Committed Nuclear Generation Units (continued)

Plant Name	Unit ID	State Name	Capacity (MW)	On Line Year	Planned Retirement Year	IPM Economic Dispatch Curtailment Year[a]	Model Region
Point Beach Nuclear Plant	1	Wisconsin	598.1	1970	2031	2031	MISO
Point Beach Nuclear Plant	2	Wisconsin	598	1972	2033	2033	MISO
Prairie Island Nuclear Generating Plant	1	Minnesota	521	1974	2034	2034	MISO
Prairie Island Nuclear Generating Plant	2	Minnesota	519	1974	2035	2035	MISO
Quad Cities Nuclear Power Station	1	Illinois	908	1972	2033	2033	PJM
Quad Cities Nuclear Power Station	2	Illinois	911	1972	2033	2033	PJM
R E Ginna Nuclear Power Plant	1	New York	582	1970	2030	2030	NYISO
River Bend Station	1	Louisiana	968	1986	2026	2023	MISO
Salem Nuclear Generating Station	1	New Jersey	1,170	1977	2037	2037	PJM
Salem Nuclear Generating Station	2	New Jersey	1,158	1981	2040	2040	PJM
Seabrook Station	1	New Hampshire	1,251	1990	2030	2030	ISO-NE
Sequoyah Nuclear Plant	1	Tennessee	1,152	1981	2041	2041	Southeast
Sequoyah Nuclear Plant	2	Tennessee	1,126	1982	2042	2042	Southeast
Shearon Harris Nuclear Power Plant	1	North Carolina	932	1987	2047	2030	Southeast
South Texas Project	1	Texas	1,280	1988	2048	2048	ERCOT
South Texas Project	2	Texas	1,280	1989	2049	2049	ERCOT
St Lucie Plant	1	Florida	981	1976	2036	2036	Southeast
St Lucie Plant	2	Florida	987	1983	2043	2043	Southeast

Table D-1 Existing and Committed Nuclear Generation Units (continued)

Plant Name	Unit ID	State Name	Capacity (MW)	On Line Year	Planned Retirement Year	IPM Economic Dispatch Curtailment Year[a]	Model Region
Surry Power Station	1	Virginia	838	1972	2032	2032	PJM
Surry Power Station	2	Virginia	838	1973	2033	2033	PJM
Susquehanna Steam Electric Station	1	Pennsylvania	1,247	1983	2043	2043	PJM
Susquehanna Steam Electric Station	2	Pennsylvania	1,247	1985	2044	2044	PJM
Turkey Point Nuclear Generating	3	Florida	802	1972	2033	2033	Southeast
Turkey Point Nuclear Generating	4	Florida	802	1973	2033	2033	Southeast
Virgil C Summer Nuclear Station	1	South Carolina	971	1984	2043	2023	Southeast
Vogtle Electric Generating Plant	1	Georgia	1,150	1987	2047	2047	Southeast
Vogtle Electric Generating Plant	2	Georgia	1,152	1989	2049	2049	Southeast
Vogtle Electric Generating Plant	3	Georgia	1,100	2022	2062	NA	Southeast
Vogtle Electric Generating Plant	4	Georgia	1,100	2023	2063	NA	Southeast
Waterford Steam Electric Station	3	Louisiana	1,165	1985	2025	2023	MISO
Watts Bar Nuclear Plant	1	Tennessee	1,123	1996	2036	2023	Southeast
Watts Bar Nuclear Plant	2	Tennessee	1,122	2016	2056	NA	Southeast
Wolf Creek Generating Station	1	Kansas	1,175	1985	2045	2023	SPP

[a] The IPM Economic Dispatch Curtailment Year is a calculated value and represents when a unit is projected not to be economically dispatched for the purposes of calculating replacement energy costs based on modeling performed in this report.
[b] Beaver Valley Units 1&2 are assumed to be curtailed in the model beginning after 2021 and 2022 based on a March 2018 announcement by the owner that was rescinded in March 2020.

[c] *The IPM Economic Dispatch model calculates the Byron Units 1&2 and Dresden Units 2&3 units will continue to operate for the entire 2020 to 2030 period, even though on August 27, 2020, Exelon Corporation announced plans to take these units out of service on or before September 30, 2021 and November 30, 2021, respectively.*

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APPENDIX E
DETERMINATION OF REGIONAL DEFINITIONS FOR REPLACEMENT COST CALCULATIONS

As shown in Figure E-1, the U.S. electricity system covering the lower 48 states and the District of Columbia is divided into three major interconnections:[21]

- The Eastern Interconnection covers the area east of the Rocky Mountains.
- The Western Interconnection covers the Rocky Mountains and areas to the west.
- The ERCOT covers most, but not all, of Texas.

The interconnections operate largely independently from each other except for a few direct current connections that allow for limited transfers of power between them. Utilities within each are interconnected and synchronized. Because of the electrical connections or network, a problem in one part of an interconnection can propagate to other parts of the interconnection if the appropriate safeguards are not in place. The network also allows generation to be sited in one part of the interconnection and serve load in other parts. The interconnections are also subdivided into electricity markets, with generators in a market generally serving load in that market, although imports and exports of power are allowed.[22]

[21] The Eastern Interconnection includes parts of Canada, and the Western Interconnection includes parts of Canada and Mexico.

[22] U.S. electricity markets have wholesale and retail components. Wholesale electricity involves the sale of electricity between generators, utilities, and load-serving entities. Retail electricity involves the sale to consumers. The NRC is focused on wholesale electricity impacts; therefore, this report focuses on wholesale electricity markets.

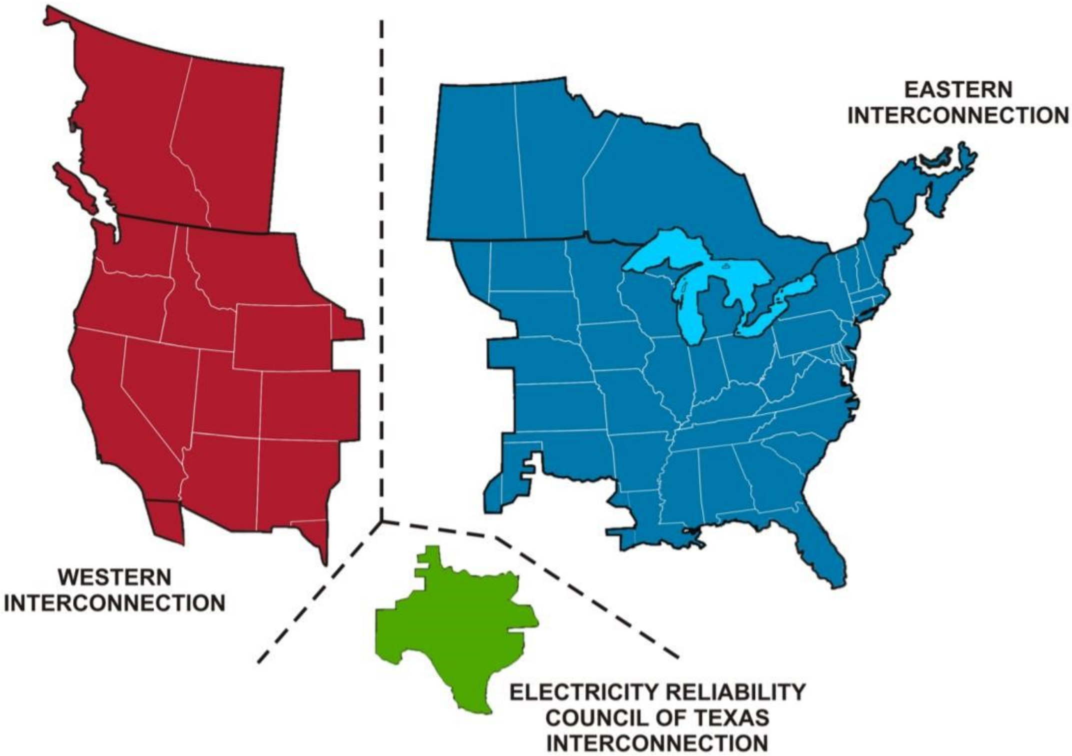

Figure E-1 North American Electric Interconnections

Source: (NERC, 2018). The Canadian province of Quebec is a separate interconnection, which is not shown on the map.

Some U.S. wholesale electricity markets are regulated, whereas others are restructured competitive markets. In regulated electricity markets, vertically integrated utilities own generation, transmission, and distributions systems and are responsible for serving consumers in the market. In restructured markets the generation, transmission, and distribution functions are unbundled, generation is competitive, and operation of the transmission system is transferred to an independent, not-for-profit market operator. As shown in Figure E-2, the seven restructured, competitive markets in the United States are:

- CAISO
- ERCOT
- ISO-NE
- Midcontinent ISO (MISO)
- New York ISO (NYISO)
- PJM
- SPP

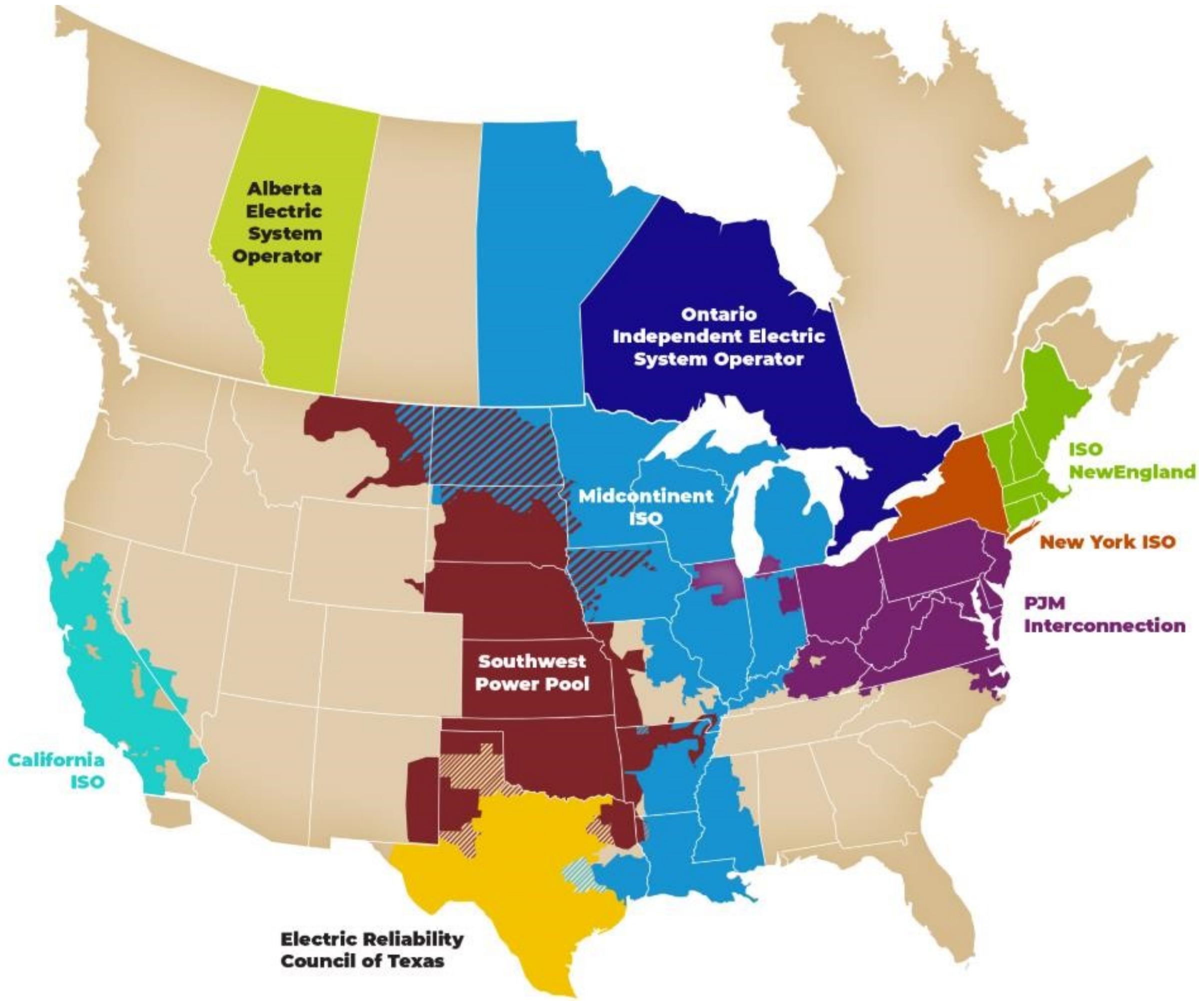

Figure E-2 Restructured Markets in North America

Source: (IRC, 2020) Available at http://isorto.org.

The competitive markets are characterized by a relatively high level of price transparency. The market operators publish electricity prices for hundreds of locations as frequently as every 5 minutes, and these are aggregated to determine hourly prices. The markets also have liquid trading hubs that are used for transactions by market participants. In general, market operators dispatch generation in the market in economic merit order, subject to transmission and other system limitations, to determine prices. The marginal unit sets prices as determined by the economic merit order of the supply offers (the generation stack). If a nuclear power plant that is part of the generation stack is taken out of service, the operator would redispatch generation and rebuild the stack. Prices would change if a generator with a different cost profile becomes the new marginal unit. Therefore, the loss of a nuclear power generating unit could affect prices in the market, and units of different sizes could affect prices differently. For example, the larger a nuclear plant, the more likely it is to affect power prices and the larger the impact is likely to be. Further, if a nuclear power plant goes out of service in a competitive market, replacement power can be purchased from the spot market. Purchases could also be based on futures or structures, such as long-term contracts built on underlying market prices.

Consistent with the foregoing, in areas with competitive markets the report uses regional definitions that are coincident with the existing competitive markets. For example, NYISO was considered as a single region for the purposes of the report. Therefore, the report determines replacement energy costs for NYISO that apply to all nuclear power plants located in that market.

The exception is CAISO. CAISO operates the Western EIM, which currently includes eight non-CAISO utilities or balancing authorities, with seven entities planning to participate by 2022. As shown in Figure E-3, the EIM covers portions of almost all the states in the Western Interconnection. The EIM is a real-time energy market. In other competitive markets, participants commit to sell or purchase power usually a day ahead of the time when the power would be used.

This is referred to as the day-ahead market. Shortly before the actual time for the power to be consumed, the operator makes adjustments, if necessary, to balance fluctuations (imbalances) in demand and supply caused by unexpected events, such as load forecast errors, generation outages, or transmission line limitations. These adjustments are made in the real-time market. Because the EIM is only a real-time market, participants do not make prior commitments for sales or purchases, such as the commitments in a day-ahead market. Rather, participants buy and sell power close to the time electricity is consumed. The EIM gives system operators real-time visibility across neighboring grids, and it helps balance supply and demand at relatively lower cost (CAISO, 2020).[23]

Two nuclear power plants in the Western Interconnection are included in the report—Columbia Generating Station in Washington State and Palo Verde Nuclear Generating Station in Arizona. Diablo Canyon Nuclear Power Plant units in California are scheduled to retire by 2026 and therefore were not assessed explicitly for replacement energy costs. Because of the scope of the Western EIM, it is likely that the outage of any of the nuclear power plants would affect prices in several parts of the Western Interconnection. Therefore, Western Interconnection is treated as a single region for the purposes of calculating replacement energy cost.

[23] See www.westerneim.com for additional information.

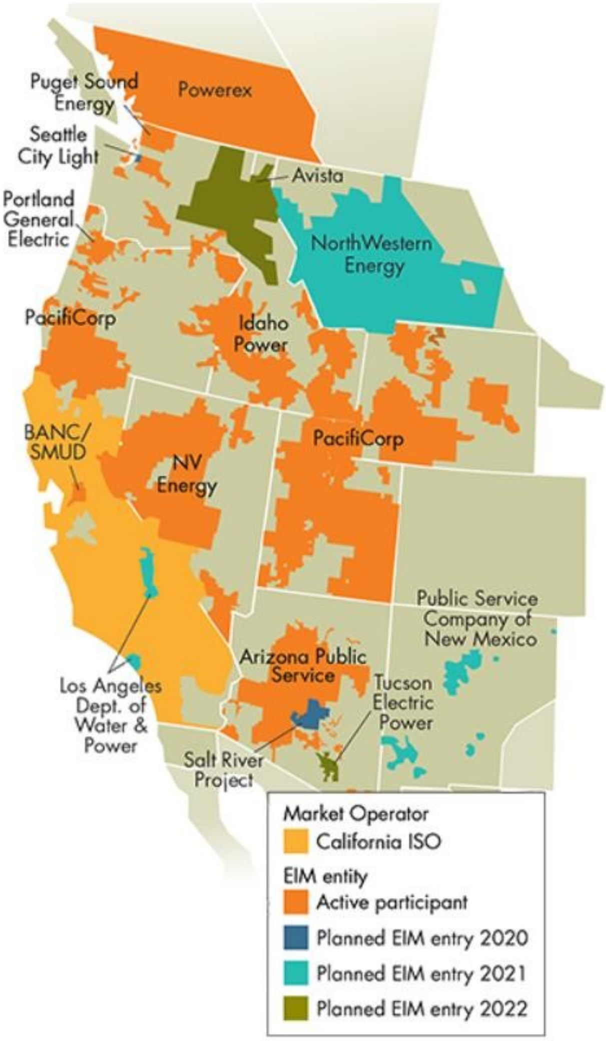

Figure E-3 Western EIM

Source: (CAISO, 2020)

The remaining area is the southeastern United States, which is served by vertically integrated utilities in regulated markets. Although utilities serve most of their demand with generation located within their service territories, some own or contract for generation capacity outside of their service territories and reserve transmission capacity to transport the power to serve their customers (FPL, 2019; GPC, 2019).[24]

In addition, under FERC Order No. 888 (FERC, 2006), public utilities are required to provide open-access transmission service on a comparable basis to the transmission service they provide themselves. Each public utility is required to file an open-access non-discriminatory transmission tariff that contains minimum terms and conditions of non-discriminatory service.

[24] For example, Florida Power and Light (FPL) owns generation capacity in central Georgia, and Gulf Power owns generation capacity in central Georgia and Mississippi. See FPL Ten Year Power Plant Site Plan, 2019-2028, April 2019 (http://newhampshiretransmission.com/company/pdf/10-year-site-plan.pdf) (FPL, 2019) and Gulf Power Ten Year Site Plan, 2019-2028, April 1, 2019 (http://www.psc.state.fl.us/Files/PDF/Utilities/Electricgas/TenYearSitePlans/2019/Gulf%20Power.pdf). (GPC, 2019).

Further, Order No. 889 established rules governing Open-Access Same-Time Information System (OASIS), an information sharing system that is used to provide or request transmission services. Each utility has an OASIS site, which among other things, provides information about available transmission capability and a process for requesting transmission service on a non-discriminatory basis.[25] Therefore, there are frameworks under which utilities in regulated markets can source power from locations outside their service territories in the event of shortages. The outage of a nuclear power plant in one utilities service territory could therefore impact power flows and electricity prices in neighboring service territories.

Under FERC Order No. 1000 (FERC, 2012), public utility transmission providers are required to participate in a regional transmission planning process that satisfies the transmission planning principles of Order No. 890 (FERC, 2007) and produces a regional transmission plan.[26] Figure E-4 shows the transmission planning regions formed in compliance with Order No. 1000 (FERC, 2012). Three entities are responsible for regional transmission planning in the southeastern U.S.

- FRCC
- SCRTP
- SERTP

The regional transmission planning processes include economic transmission planning studies that allow market participants to request studies for the feasibility of long-term economic power transactions. For example, in 2018 SERTP evaluated economic planning studies for the transfer of 1,000 MW of power between Santee Cooper and neighboring transmission systems (Duke Energy Carolinas, Duke Energy Progress, and Southern Balancing Authority Area).[27]

Because of the potential for interactions between the regions, the report considers the regulated markets in the southeastern United States as a single region for the purposes of the calculation of replacement energy cost.

[25] For additional information, see FERC, 2006.

[26] For additional information on Order No. 1000 see FERC, 2012. FERC Order No. 890 (FERC, 2007) was designed to: (1) strengthen the pro forma open-access transmission tariff (OATT), to ensure that it achieves its original purpose of remedying undue discrimination; (2) provide greater specificity to reduce opportunities for undue discrimination and facilitate the Commission's enforcement; and (3) increase transparency in the rules applicable to planning and use of the transmission system.

[27] SERTP 2018 Economic Planning Studies, November 29, 2018, available at http://www.southeasternrtp.com/docs/general/2018/2018-SERTP-Economic-Study-Results-FINAL.pdf. (SERTP, 2018).

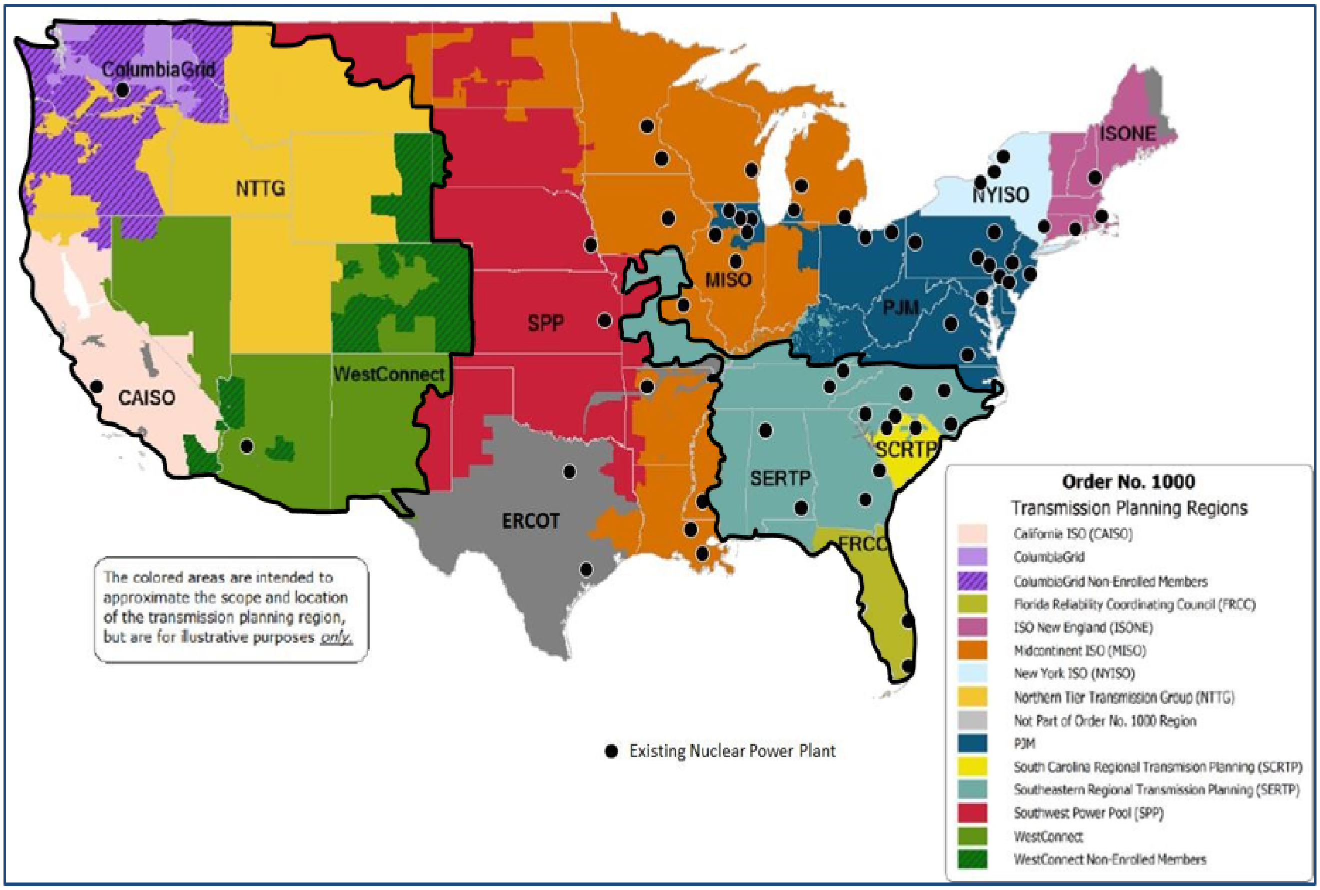

Figure E-4 FERC Order No. 1000 Transmission Planning Regions

Source: (FERC, 2012). The map was annotated with black dots to show the approximate locations of existing nuclear power plants. Heavy black lines have been added to distinguish the planning regions that have been combined for the purpose of this analysis.

The following eight regional definitions are used for the replacement cost analysis:

1. ERCOT
2. ISO-NE
3. MISO
4. NYISO
5. PJM
6. SPP
7. Southeast, comprising FRCC, SCRTP, and SERTP
8. WECC, comprising CAISO, ColumbiaGrid, NTTG and WestConnect

E.1 Appendix E References

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U.S. Federal Energy Regulatory Commission, "Order No. 890 Preventing Undue Discrimination and Preference in Transmission Service," 2007. (FERC, 2007).

U.S. Federal Energy Regulatory Commission, "Order No. 1000 Transmission Planning and Cost Allocation by Transmission Owning and Operating Utilities," 2012. (FERC, 2012).

APPENDIX F
SUMMARY OF ASSUMPTIONS

This appendix provides additional details on the assumptions used for the replacement energy cost report. It includes:

- Peak and energy demand assumptions
- Delivered natural gas prices
- Environmental assumptions, including state RPS requirements, RGGI assumptions, CSAPR rules
- Recent and firm generation builds and retirements
- IPM economic builds and retirements

F.1 Peak and Energy Demand Assumptions

The report developed electricity peak and energy assumptions for the 2020 to 2030 report period from NERC Electricity Supply & Demand (ES&D) information (Table F-1). Net internal demand (peak demand) is the maximum hourly demand within a given year after removing interruptible demand. Net energy for load is the projected annual electric grid demand, prior to accounting for intra-regional transmission and distribution losses (Table F-2).

Table F-1 Peak Demand Assumptions: 2020–2030

Net Internal Demand (MW)														
Region	**FRCC**	**MRO**	**NPCC**	**NPCC**	**RF**	**SERC**	**SERC**	**SERC**	**SPP**	**TRE**	**WECC**	**WECC**	**WECC**	**WECC**
Assessment Area	**FRCC**	**MISO**	**New England**	**New York**	**PJM**	**SERC-E**	**SERC-N**	**SERC-SE**	**SPP**	**ERCOT**	**NWPP-US**	**RMRG**	**SRSG**	**CAMX**
2020	45,608	119,303	24,878	31,759	144,287	42,907	39,935	45,983	52,044	73,706	49,075	12,637	24,298	50,132
2021	46,170	119,646	24,511	31,581	144,672	43,257	39,982	46,158	52,410	75,422	49,495	12,806	24,668	50,275
2022	46,653	120,003	24,396	31,469	145,166	43,598	40,092	46,406	53,194	76,854	49,682	12,952	25,222	50,550
2023	47,144	120,424	24,317	31,414	145,885	44,100	40,296	46,662	53,485	78,258	50,141	13,202	25,712	50,201
2024	47,753	120,788	24,264	31,406	146,459	44,490	40,354	46,936	53,694	79,500	50,456	13,369	26,158	51,447
2025	48,290	121,289	24,239	31,429	147,118	44,930	40,477	47,201	53,965	80,677	50,767	13,549	26,650	51,584
2026	48,897	121,629	24,249	31,473	147,862	45,432	40,748	47,876	54,238	82,006	51,046	13,695	27,021	51,380
2027	49,508	122,227	24,288	31,533	148,706	45,928	40,820	46,976	54,528	83,338	51,409	13,844	27,473	51,471
2028	49,508	122,126	24,326	31,599	149,688	46,435	40,881	46,607	54,873	84,677	51,672	14,024	27,828	51,645
2029	50,018	122,483	24,258	31,579	150,377	46,896	41,001	46,686	55,237	86,158	52,007	14,208	28,304	51,838
2030	50,534	122,842	24,190	31,559	151,070	47,361	41,121	46,764	55,603	87,666	52,343	14,394	28,788	52,031

Source: (NERC, 2018)

Table F-2 Energy Demand Assumptions: 2020–2030

Net Energy for Load (GWh)														
Region	**FRCC**	**MRO**	**NPCC**	**NPCC**	**RF**	**SERC**	**SERC**	**SERC**	**SPP**	**TRE**	**WECC**	**WECC**	**WECC**	**WECC**
Assessment Area	**FRCC**	**MISO**	**New England**	**New York**	**PJM**	**SERC-E**	**SERC-N**	**SERC-SE**	**SPP**	**ERCOT**	**NWPP-US**	**RMRG**	**SRSG**	**CAMX**
2020	236,779	669,881	120,395	155,567	808,638	214,026	214,064	247,542	259,341	392,609	294,092	69,671	111,351	267,722
2021	238,483	672,266	118,949	154,567	808,882	215,557	213,647	248,432	265,942	401,983	295,659	70,869	113,463	268,124
2022	240,380	675,220	117,870	153,898	812,908	216,856	213,691	249,788	267,318	412,593	297,547	71,392	116,076	269,637
2023	241,710	679,319	117,039	153,593	816,817	218,138	213,861	251,006	271,312	422,216	298,914	72,987	117,962	270,617
2024	244,035	680,250	116,249	153,476	822,364	220,369	214,277	252,444	272,734	431,139	300,409	73,974	119,851	270,940
2025	245,769	681,949	115,594	153,454	824,140	221,904	214,084	253,679	274,090	439,094	301,503	74,874	121,139	271,314
2026	247,849	684,148	115,196	153,504	828,788	224,309	214,223	256,182	275,174	448,093	302,145	75,761	122,817	271,302
2027	250,053	687,133	114,981	153,691	833,712	226,671	214,622	253,400	276,116	457,273	303,565	76,793	124,326	271,324
2028	250,053	689,634	114,766	153,926	841,206	229,719	215,398	252,584	277,200	466,667	305,631	77,896	126,021	271,405
2029	251,764	692,144	114,081	153,722	845,368	231,760	215,565	253,221	279,518	476,856	307,105	78,990	127,986	271,869
2030	253,486	694,663	113,400	153,518	849,551	233,819	215,733	253,860	281,854	487,269	308,586	80,099	129,981	272,334

Source: (NERC, 2018)

F.2 Delivered Natural Gas Price Assumptions

The EIA AEO (DOE, 2019) provides delivered natural gas prices by state within the U.S. electricity market. The report used the delivered natural gas prices shown in Table F-3 as the basis for the natural gas price projections for the modeling and replacement cost calculations.

Table F-3 AEO Delivered Natural Gas Prices (2018$/MMBtu)

Year	Season	CT, MA, ME, NH, RI, VT	NY, PA, NJ	OH	IN, IL, MI, WI	MN, IA, ND SD, NE, MO, KS	WV, MD, DC, DE, VA, NC, SC	GA	FL	KY, TN	AL, MS	TX, LA, OK, AR	MT, WY, ID	CO, UT, NV	AZ, NM	OR, WA	CA
2020	Winter	5.02	3.47	2.98	3.44	3.59	3.75	3.41	4.14	3.46	3.36	2.92	2.95	3.36	3.72	3.38	3.52
2020	Summer	3.79	3.42	3.09	3.51	3.44	3.41	3.65	3.90	3.37	3.16	3.22	2.90	3.49	3.75	3.27	3.81
2020	Spring/Fall	3.71	3.31	2.89	3.25	3.29	3.59	3.40	3.97	3.34	3.13	2.90	4.95	3.49	3.57	3.19	3.44
2021	Winter	4.82	3.42	2.98	3.39	3.50	3.77	3.35	4.02	3.34	3.30	2.91	2.92	3.31	3.58	3.32	3.49
2021	Summer	3.67	3.34	3.09	3.51	3.38	3.37	3.54	3.83	3.27	3.09	3.17	2.83	3.44	3.73	3.23	3.82
2021	Spring/Fall	3.64	3.22	2.87	3.19	3.18	3.50	3.30	3.83	3.26	3.02	2.86	5.04	3.38	3.47	3.19	3.40
2022	Winter	4.88	3.49	3.09	3.46	3.59	3.85	3.40	4.03	3.38	3.34	2.98	2.95	3.36	3.60	3.36	3.54
2022	Summer	3.77	3.41	3.21	3.61	3.49	3.42	3.58	3.86	3.34	3.13	3.25	2.89	3.49	3.85	3.29	3.93
2022	Spring/Fall	3.61	3.25	2.96	3.27	3.26	3.53	3.32	3.84	3.30	3.05	2.91	5.13	3.43	3.54	3.26	3.44
2023	Winter	5.03	3.62	3.30	3.59	3.76	3.94	3.48	4.15	3.53	3.46	3.09	2.98	3.48	3.76	3.47	3.67
2023	Summer	3.92	3.61	3.52	3.85	3.76	3.62	3.82	4.08	3.57	3.34	3.49	3.09	3.73	4.10	3.51	4.12
2023	Spring/Fall	3.69	3.38	3.19	3.39	3.45	3.66	3.46	3.97	3.44	3.21	3.08	5.32	3.58	3.71	3.42	3.58
2024	Winter	5.28	3.77	3.54	3.80	3.97	4.12	3.67	4.35	3.71	3.64	3.29	3.25	3.69	3.99	3.70	3.74
2024	Summer	4.19	3.89	3.92	4.20	4.12	3.96	4.19	4.46	3.92	3.69	3.83	3.49	4.08	4.45	3.86	4.28
2024	Spring/Fall	3.76	3.53	3.40	3.58	3.62	3.81	3.60	4.14	3.60	3.37	3.22	5.52	3.77	3.86	3.59	3.49
2025	Winter	5.40	3.91	3.77	3.98	4.16	4.31	3.81	4.53	3.91	3.82	3.46	3.38	3.87	4.22	3.84	3.93
2025	Summer	4.35	4.11	4.20	4.45	4.39	4.20	4.49	4.75	4.18	3.97	4.11	3.75	4.37	4.75	4.15	4.64
2025	Spring/Fall	3.86	3.67	3.61	3.79	3.83	4.02	3.82	4.35	3.81	3.59	3.45	5.69	3.97	4.07	3.80	3.74
2026	Winter	5.44	3.96	3.86	4.05	4.26	4.39	3.89	4.62	3.99	3.92	3.56	3.53	3.99	4.36	3.99	4.05
2026	Summer	4.37	4.13	4.27	4.52	4.49	4.25	4.53	4.81	4.23	4.04	4.19	3.84	4.48	4.89	4.26	4.76
2026	Spring/Fall	3.82	3.71	3.72	3.88	3.89	4.07	3.88	4.44	3.91	3.69	3.55	6.11	4.11	4.18	3.92	3.79

Table F-3 AEO Delivered Natural Gas Prices (2018$/MMBtu) (continued)

Year	Season	CT, MA, ME, NH, RI, VT	NY, PA, NJ	OH	IN, IL, MI, WI	MN, IA, ND SD, NE, MO, KS	WV, MD, DC, DE, VA, NC, SC	GA	FL	KY, TN	AL, MS	TX, LA, OK, AR	MT, WY, ID	CO, UT, NV	AZ, NM	OR, WA	CA
2027	Winter	5.44	3.97	3.91	4.08	4.31	4.41	3.92	4.66	4.00	3.96	3.61	3.53	4.03	4.41	4.02	3.97
2027	Summer	4.35	4.11	4.30	4.56	4.52	4.24	4.53	4.82	4.26	4.06	4.22	3.85	4.51	4.88	4.31	4.69
2027	Spring/Fall	3.81	3.71	3.75	3.91	3.88	4.09	3.91	4.47	3.93	3.71	3.59	5.72	4.13	4.21	3.81	3.79
2028	Winter	5.43	3.98	3.94	4.11	4.35	4.44	3.95	4.68	4.03	3.99	3.65	3.54	4.06	4.47	4.10	3.98
2028	Summer	4.42	4.20	4.42	4.67	4.63	4.33	4.65	4.96	4.41	4.20	4.35	3.91	4.63	5.03	4.44	4.81
2028	Spring/Fall	3.81	3.75	3.81	3.96	3.94	4.14	3.96	4.52	4.00	3.76	3.66	5.77	4.17	4.29	3.81	3.86
2029	Winter	5.49	3.93	3.96	4.12	4.37	4.30	3.95	4.71	4.05	4.02	3.66	3.42	4.03	4.49	4.03	3.97
2029	Summer	4.38	4.16	4.42	4.67	4.63	4.32	4.65	4.96	4.41	4.22	4.35	3.88	4.60	5.00	4.39	4.76
2029	Spring/Fall	3.76	3.76	3.83	3.97	3.94	4.13	3.96	4.54	4.00	3.80	3.67	5.55	4.17	4.30	3.90	3.69
2030	Winter	5.51	3.93	3.98	4.12	4.39	4.31	3.95	4.72	4.03	4.03	3.68	3.43	3.99	4.51	3.99	3.99
2030	Summer	4.45	4.23	4.50	4.73	4.70	4.39	4.67	5.03	4.50	4.28	4.42	3.91	4.65	5.04	4.45	4.74
2030	Spring/Fall	3.74	3.68	3.82	3.95	3.93	4.05	3.94	4.53	3.99	3.79	3.68	5.53	4.17	4.31	3.86	3.60

Note: Winter-Dec/Jan/Feb/Mar, summer-June/July/Aug/Sep, and spring/fall-Apr/May/Oct/Nov.

Source: (DOE, 2019).

F.3 Environmental Assumptions

Renewable portfolio standards (RPS) are policies designed to increase generation of electricity from renewable resources. These policies require or encourage electricity producers within a given jurisdiction to supply a certain minimum share of their electricity from designated renewable resources. Generally, these resources include wind, solar, geothermal, biomass, and some types of hydroelectricity, but may include other resources such as landfill gas, municipal solid waste, and tidal energy. Twenty-nine States and the District of Columbia in the U.S. have enforceable RPS or other mandated renewable capacity policies. Table F-4 shows the RPS percentages applied to modeled electricity sale projections by state for each year between 2020 and 2030. The RPS in Hawaii is not modeled and is outside the scope of this report.

Table F-4 State Renewable Portfolio Standards

State	Renewable Portfolio Standards (Percent)										
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Arizona	5.69	6.25	6.82	7.39	7.96	8.53	8.53	8.53	8.53	8.53	8.53
California	33.00	35.75	38.50	41.25	44.00	46.67	49.33	52.00	54.67	57.33	60.00
Colorado	21.25	21.25	21.25	21.25	21.25	21.25	21.25	21.25	21.25	21.25	21.25
Connecticut	25.00	26.50	28.00	30.00	32.00	34.00	36.00	38.00	40.00	42.00	44.00
District of Columbia	20.00	20.00	20.00	20.00	23.00	26.00	29.00	32.00	35.00	38.00	42.00
Delaware	14.46	15.18	15.90	16.62	17.35	18.07	18.07	18.07	18.07	18.07	18.07
Iowa	0.64	0.64	0.63	0.63	0.62	0.62	0.62	0.61	0.61	0.60	0.60
Illinois	8.95	9.79	10.63	11.47	12.31	13.15	13.99	13.99	13.99	13.99	13.99
Massachusetts	20.50	21.50	22.50	23.50	24.50	25.50	26.50	27.50	28.50	29.50	30.50
Maryland	28.00	30.50	31.85	34.65	37.45	40.00	42.50	45.50	47.50	49.50	50.00
Maine	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00
Michigan	12.50	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Minnesota	25.66	25.66	25.66	25.66	25.66	28.43	28.43	28.43	28.43	28.43	28.43
Missouri	7.09	10.63	10.63	10.63	10.63	10.63	10.63	10.63	10.63	10.63	10.63
Montana	10.39	10.39	10.39	10.39	10.39	10.39	10.39	10.39	10.39	10.39	10.39
North Carolina	5.56	6.95	6.95	6.95	6.95	6.95	6.95	6.95	6.95	6.95	6.95
New Hampshire	19.10	19.80	20.50	21.20	22.10	23.00	23.00	23.00	23.00	23.00	23.00
New Jersey	23.43	28.60	32.10	35.60	38.90	42.30	45.00	47.85	50.24	52.57	54.71
New Mexico	15.84	19.87	23.91	27.94	31.98	36.02	37.82	39.62	41.42	43.22	45.02
Nevada	17.35	17.35	17.35	17.35	17.35	21.90	27.38	32.85	38.33	43.81	43.81
New York	24.10	25.31	27.10	28.89	30.69	32.48	34.27	36.06	37.85	39.64	41.44
Ohio	5.79	6.68	7.57	8.46	9.35	10.24	11.13	11.13	11.13	11.13	11.13
Oregon	14.08	14.08	14.08	14.08	14.08	21.05	21.23	21.42	21.60	21.78	27.59
Pennsylvania	7.50	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
Rhode Island	16.00	17.50	19.00	20.50	22.00	23.50	25.00	26.50	28.00	29.50	31.00
Texas	4.26	4.22	4.18	4.15	4.11	4.07	4.03	3.99	3.96	3.92	3.88
Vermont	61.80	62.40	63.00	67.60	68.20	68.80	73.40	74.00	74.60	79.20	79.80
Washington	11.80	11.80	11.80	11.80	11.80	11.80	11.80	11.80	11.80	11.80	11.80
Wisconsin	9.65	9.65	9.65	9.65	9.65	9.65	9.65	9.65	9.65	9.65	9.65

Source: (EPA, 2019; DSIRE, 2020)

States often drive renewable energy projects to a particular technology by providing carve-out provisions that mandate that a certain percentage of electricity generated come from a particular technology. A solar carve-out requires a specific share of electricity generation is met by solar photovoltaics. Table F-5 shows the RPS solar carve-out percentages applied to modeled electricity sale projections for each year between 2020 and 2030 for applicable states.

Table F-5 State Renewable Portfolio Standard Solar Carve-Outs

State	RPS Solar Carve-Outs (Percent)										
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
District of Columbia	1.58	1.85	2.18	2.50	2.60	2.85	3.15	3.45	3.75	4.10	4.50
Delaware	1.63	1.81	1.99	2.17	2.35	2.53	2.53	2.53	2.53	2.53	2.53
Illinois	0.96	1.05	1.14	1.23	1.32	1.41	1.50	1.50	1.50	1.50	1.50
Massachusetts	0.16	0.17	0.18	0.18	0.19	0.20	0.21	0.22	0.22	0.23	0.24
Maryland	6.00	6.75	7.25	8.75	10.25	11.50	12.50	13.50	14.50	14.50	14.50
Minnesota	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19
Missouri	0.14	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
North Carolina	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
New Hampshire	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
New Jersey	4.90	5.10	5.10	5.10	4.90	4.80	4.50	4.35	3.74	3.07	2.21
New Mexico	3.17	3.17	3.17	3.17	3.17	3.17	3.17	3.17	3.17	3.17	3.17
Nevada	1.04	1.04	1.04	1.04	1.04	1.31	1.31	1.31	1.31	1.31	1.31
Ohio	0.23	0.27	0.30	0.34	0.37	0.41	0.45	0.45	0.45	0.45	0.45
Pennsylvania	0.44	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50

Source: (EPA, 2019; DSIRE, 2020)

The report implemented applicable environmental regulations in the Reference Case that were approved and enacted as of 2018.

The Regional Greenhouse Gas Initiative (RGGI) was the first mandatory cap-and-trade program in the United States to limit carbon dioxide from the power sector. The states currently participating are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. New Jersey will rejoin in 2020. The RGGI requires fossil fuel power plants with capacity greater than 25 MW to obtain an allowance for each ton of carbon dioxide emitted annually. Power plants within the region may comply by purchasing allowances from quarterly auctions, other generators within the region, or offset projects. Table F-6 shows the RGGI assumptions that are modeled in the report.

Table F-6 Regional Greenhouse Gas Initiative Cap and Trade Assumptions

Item	RGGI
Coverage[a]	All fossil units > 25 MW
Timing	Annual
Size of Initial Bank (MTons)	2021: 49,442
Total Allowances (MTons)	2021: 75,148
	2022: 72,873
	2023: 70,598
	2024: 68,323 2025: 66,048
	2026: 63,773
	2027: 61,498
	2028: 59,223
	2029: 56,948
	2030–2054: 54,673

[a] RGGI states are Connecticut, Delaware, Maine, New Hampshire, New York, Vermont, Rhode Island, Massachusetts, and Maryland.

The Cross-State Air Pollution Rule (CSAPR) is a U.S. Environmental Protection Agency (EPA) regulation that addresses air pollution from upwind states that crosses state lines and affects air quality in downwind states. The rule regulates sulfur dioxide and oxide of nitrogen power plant emissions, which contribute to smog and soot pollution in downwind states. Table F-7 shows the CSAPR assumptions that are modeled in IPM.

Table F-7 CSAPR-Trading and Banking Rules

Item	CSAPR-SO_2 – Region 1	CSAPR-SO_2 – Region 2	CSAPR – Annual NO_x	CSAPR Update Rule – Ozone Season NO_x – Region 1	CSAPR Update Rule Ozone Season NO_x – Region 2
Coverage	All fossil units > 25 MW[a]	All fossil units > 25 MW[b]	All fossil units > 25 MW[c]	All fossil units > 25 MW[d]	All fossil units > 25 MW[e]
Timing	Annual	Annual	Annual	Ozone Season (May–September)	Ozone Season (May–September)
Size of Initial Bank (MTons)	The bank starting in 2021 is assumed to be zero	The bank starting in 2021 is assumed to be zero	The bank starting in 2021 is assumed to be zero	The cap in 2021 includes 21% of banking	The bank starting in 2021 is assumed to be zero
Total Allowances (MTons)	2021-2054: 1372.631	2021–2054: 597.579	2021–2054: 1069.256	2021: 411.9106 2022–2054: 313.24	2021–2054: 24.041

Notes:

[a] *Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, Wisconsin*

[b] *Alabama, Georgia, Kansas, Minnesota, Nebraska, South Carolina*

[c] *Alabama, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, Wisconsin*

[d] *Alabama, Arkansas, Iowa, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maryland, Michigan, Missouri, Mississippi, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia, Wisconsin, West Virginia*

[e] *Georgia*

Source: (EPA, 2019)

The Mercury and Air Toxics Standards (MATS) for Power Plants Rule is an EPA regulation to reduce emissions of heavy metals, including mercury, arsenic, chromium, and nickel; and acid gases, including hydrochloric acid and hydrofluoric acid. The rule applies to electric generating units larger than 25 MW that burn coal or oil to generate electricity for sale and distribution through the national electric grid to the public. This report incorporates the impact of this rule.

F.4 Recent and Firm Builds and Retirements Assumptions

The IPM and PROMOD modeling for NRC's replacement energy cost report requires current projections of firm generation builds and retirements. These were based on the EIA Form 860 (EIA, 2019), generator-level specific information about existing and planned units. The recent and firm builds include those units that have been recently installed or are currently under construction. Generation capacity addition and retirement assumptions are shown in Table F-8 and Table F-9, respectively. Table F-10 shows the net change in capacity due to expected builds and retirements.

Table F-8 Recent and Firm Builds (MW)

Technology	2018	2019	2020	2021	2022	2023	2024	Total
ERCOT								
Combined Cycle		232						232
Combustion Turbine	226	103						329
Onshore Wind	1,971	2,553	643					5,167
Other	2	10						12
Solar PV	442	590						1,032
ISO-NE								
Combined Cycle	745	485						1,230
Combustion Turbine	90	539						629
Onshore Wind		33						33
Other	8	8						16
Solar PV	7							7
MISO								
Combined Cycle	644	1,235	1,700		1,146			4,725
Combustion Turbine	262	250		218				730
Onshore Wind	1,595	1,192	70					2,857
Solar PV	109							109
NYISO								
Combined Cycle	705		1,016					1,721
Combustion Turbine	123	2						125
Onshore Wind	158							158
Other	2			19				21
Solar PV	10							10
PJM								
Combined Cycle	8,850	1,783	1,373	1,060				13,066
Combustion Turbine	337	33						370
Onshore Wind	415	543						958
Solar PV	170	169	98					437
Southeast								
Combined Cycle	3,170	2,310						5,480
Combustion Turbine	25	130						155
Nuclear					1,100	1,100		2,200
Other	14	189		12				215
Solar PV	919	1,190						2,109

Table F-8 Recent and Firm Builds (MW) (continued)

Technology	2018	2019	2020	2021	2022	2023	2024	Total
SPP								
Combustion Turbine	409							409
Onshore Wind	1,297	1,730	396					3,423
Other	1							1
Solar PV	15							15
WECC								
Combined Cycle		29	1,206					1,235
Combustion Turbine	547	524	274		80			1,425
Onshore Wind	917	393	480	240			500	2,530
Other	306	44	23					373
Solar PV	1,266	1,288						2,554

Source: EIA Form 860 (EIA, 2019).

Table F-9 Recent and Firm Retirement Assumptions (MW)

Technology	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
ERCOT														
Coal	4,273					470	840							5,583
Combustion Turbine	22								4					26
Oil/Gas Steam							862		420		410			1,692
Nuclear													1,205	1,205
Other	92		518	23	302							75		1,010
ISO-NE														
Coal				383										383
Combined Cycle	34													34
Combustion Turbine		6	19											25
Nuclear		677											1,251	1,928
Other		1	1											2
MISO														
Coal	2,667	671	313	245	1,556	1,302	2,688	154		1,632			1,678	12,906
Combined Cycle	360	44		20										424
Combustion Turbine	336	54	195	4	122	153	52	535	59				288	1,798
Nuclear			601		784		1,165	968	1,065				598	5,181
Oil/Gas Steam	1,505	337			239		18							2,098
Other	64	36	42		20	17	1	3						183
NYISO														
Combustion Turbine	88	2	2		4	3								99
Nuclear			1,012	1,039								1,208		3,260
Other	2													2
PJM														
Coal	3,166	3,655	1,948	850	1,288		510							11,417
Combustion Turbine	115	386	233	30	13									777
Nuclear	608	803		1,808					1,240			902		5,361
Oil/Gas Steam	1,001	393												1,394

Table F-9 Recent and Firm Retirement Assumptions (MW) (continued)

Other	129	29	65	1		5			1	4	8			242
Southeast														
Coal	2,791	1,821	593	1,356			870	582				516		8,529
Combined Cycle		121												121
Combustion Turbine	196	29	135					12						371
Oil/Gas Steam	278		11		75									364
Other	119	128	8											255
SPP														
Coal	436		650							460				1,546
Combustion Turbine	2					82		71	82					237
Oil/Gas Steam	1,159	239	243	78	107	593	93	183		190	112		244	3,241
Other	109												60	169
WECC														
Coal		2,250	670	585	1,039			1,955		2,560		357		9,416
Combined Cycle	624	535	703			179			227					2,268
Combustion Turbine	165	86	142		165	6			172					737
Nuclear							1,122	1,118						2,240
Oil/Gas Steam	1,914	1,933	2,208	1,629	241		268	113	102	352		330		9,090
Other	168	139	125	3		1				1				437

Source: (EIA, 2019)

Based on the Form EIA-860 data contained in Table F-8 and Table F-9, the net generation additions and retirements for years 2018 through 2030 are summarized in Table F-10.

Table F-10 Form EIA-860 Projected Net Generation Additions and Retirements

Parameter	Megawatts by Year													Total Net Additions (Retirements) (MW)
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	
Annual Net Additions (Retirements)	2,904	3,212	(3,158)	(6,505)	(3,629)	(1,711)	(7,989)	(5,694)	(3,372)	(5,199)	(530)	(3,388)	(5,324)	(40,383)

F.5 IPM Economic Builds and Retirement Details

Projections of IPM economic builds and retirements are detailed in Table F-11 and Table F-12, respectively.

Table F-11 IPM Economic Builds through 2030 (MW)

Technology	2021	2023	2025	2030	Total
ERCOT					
Combined Cycle	302		4,455	8,486	13,242
Solar PV	5,475	5,822		3,598	14,895
ISO-NE					
Onshore Wind	2,141			1,551	3,692
Other	43				43
MISO					
Combined Cycle		3,331	1,510	3,133	7,974
Onshore Wind	2,336	55	462	736	3,589
Other	1,914	2,089	23		4,026
Solar PV	794	2,209	54	2,372	5,430
NYISO					
Combined Cycle				519	519
Onshore Wind	3,680			1,493	5,173
Other			1,479	28	1,507
Solar PV	24			2,804	2,828
PJM					
Combined Cycle		1,157	2,471	2,495	6,123
Combustion Turbine	397		77	198	673
Onshore Wind	5,533	2,314		494	8,341
Other	1,091	733		1,400	3,224
Solar PV	5,278	7,110	10,980	13,596	36,963
Southeast					
Combined Cycle		5,976	3,085	3,056	12,117
Onshore Wind	318			12	330
Other	1,826	312	289		2,428

Table F-11 IPM Economic Builds through 2030 (MW) (continued)

Technology	2021	2023	2025	2030	Total
Solar PV	1,861	2,378	96	11,432	15,767
			SPP		
Onshore Wind				229	229
Other		467	214		680
Solar PV				4,694	4,694
			WECC		
Combined Cycle		4,859	2,712	3,679	11,250
Combustion Turbine		1,393	17		1,409
Onshore Wind	6,277	4,518	263	14,777	25,835
Other	2,320	257	103	304	2,985
Solar PV	5,424	888	7,276	7,518	21,105

Table F-12 IPM Economic Retirements through 2030 (MW)

Technology	2023	2025	2030	Total
		ERCOT		
Coal	815			815
Other	118			118
		ISO-NE		
Coal	534			534
Combined Cycle	1,576			1,576
Combustion Turbine	148			148
Oil/Gas	1,723			1,723
Other	547			547
		MISO		
Coal	9,436	35	34	9,505
Nuclear	5,456			5,456
Oil/Gas	202			202
Other	724			724
		NYISO		
Coal	686	37		723

Table F-12 IPM Economic Retirements through 2030 (MW) (continued)

Technology	2023	2025	2030	Total
Combined Cycle	1,519			1,519
Combustion Turbine	54			54
Nuclear			853	853
Oil/Gas	1,728	569		2,297
Other	74			74
PJM				
Coal	9,643	2,600	271	12,514
Combustion Turbine	40			40
Nuclear	1,590			1,590
Oil/Gas	2,236			2,236
Other	210			210
Southeast				
Coal	20,528	570	1,761	22,860
Combined Cycle			110	110
Combustion Turbine			8	8
Nuclear	4,594		932	5,526
Oil/Gas			130	130
Other	1,558			1,558
SPP				
Nuclear	1,947			1,947
Oil/Gas	536			536
WECC				
Coal	1,193			1,193
Combined Cycle	2,975			2,975
Combustion Turbine	1,424			1,424
Nuclear	1,180			1,180
Oil/Gas	34			34
Other	836		113	949

Based on the IPM projections contained in Table F-11 and Table F-12, the net generation additions and retirements for years up to 2030 are summarized in Table F-13.

Table F-13 IPM Projected Net Generation Additions and Retirements

Parameter	Megawatts by Year 2021	2023	2025	2030	Total (MW)
Additions	47,034	45,868	35,566	88,604	217,071
Retirements	0	(75,864)	(3,811)	(4,212)	(83,888)
Net	47,034	(29,996)	31,755	84,392	133,183

F.6 Performance and Unit Cost Assumptions for Other Electric Generation Technologies

For its capacity expansion and retirement assessment, the report developed assumptions for new unit technologies that could potentially be placed in service during the report period. Table F-14 provides details on other electric generation technologies assessed for the modeling and analysis. The first year a technology is available is based on the year the analysis was performed (2019) and the lead time for the technology. The year specific capital cost and heat rate estimates were obtained from EIA.

Table F-14 Performance and Unit Cost Assumptions for Other New Technologies

Parameter	Ultrasupercritical Coal with 30% CCS	Ultrasupercritical Coal with 90% CCS	Biomass-Bubbling Fluidized Bed (BFB)	Landfill Gas
Size (MW)	650	650	50	50
First Year Available	2023	2023	2023	2022
Lead Time (Years)	4	4	4	3
2023				
Heat Rate (Btu/kWh)	9,574	10,852	13,500	18,000
Capital (2018$/kW)	4,853	5,367	3,660	8,417
Fixed O&M (2018$/kW-yr)	72.12	83.75	114.39	425.38
Variable O&M (2018$/MWh)	7.31	9.89	5.70	9.47
2025				
Heat Rate (Btu/kWh)	9,221	9,257	13,500	18,000
Capital (2018$/kW)	4,773	5,278	3,604	8,311
Fixed O&M (2018$/kW-yr)	72.12	83.75	114.39	425.38
Variable O&M (2018$/MWh)	7.31	9.89	5.70	9.47
2030				
Heat Rate (Btu/kWh)	9,221	9,257	13,500	18,000

Table F-14 Performance and Unit Cost Assumptions for Other New Technologies (continued)

Fixed O&M (2018$/kW-yr)	72.12	83.75	114.39	425.38
Variable O&M (2018$/MWh)	7.31	9.89	5.70	9.47

Btu – British thermal units; CCS – carbon capture and storage; kW – Kilowatt; kWh – Kilowatt-hour; kW-yr – Kilowatt-year; MW – Megawatts; MWh – Megawatt-hour; O&M – operation and maintenance
Source: DOE 2019. (DOE, 2019)

F.7 Appendix F References

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APPENDIX G
DETAILED REPLACEMENT ENERGY COSTS: 2020–2030

Table G-1 ERCOT Annual and Seasonal[a] Replacement Energy Costs ($/MWh)

Year	Annual	Winter	Spring	Summer	Fall
2020	1.01	0.41	0.65	2.07	0.89
2021	0.85	0.47	0.51	1.62	0.74
2022	1.17	0.54	0.55	2.33	1.21
2023	1.48	0.57	0.58	3.03	1.68
2024	1.35	0.59	0.52	2.97	1.36
2025	1.22	0.54	0.43	2.91	1.03
2026	1.54	0.49	0.47	3.99	1.18
2027	1.85	0.48	0.5	5.07	1.33
2028	2.17	0.47	0.54	6.15	1.47
2029	2.49	0.45	0.58	7.23	1.62
2030	2.8	0.44	0.62	8.32	1.76

[a] *Winter: Dec/Jan/Feb/, spring: Mar/April/May, summer: June/July/Aug, and fall: Sep/Oct/Nov.*

Table G-2 ISO-NE Annual and Seasonal Replacement Energy Costs ($/MWh)

Year	Annual		Winter		Spring		Summer		Fall	
	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact
2020	2.36	1.68	2.91	2.25	1.78	1.12	2.86	1.97	1.97	1.44
2021	3.00	2.13	3.00	2.25	3.35	2.38	3.19	2.23	2.51	1.83
2022	2.98	2.13	3.26	2.21	2.40	1.82	4.47	3.17	1.95	1.42
2023	2.96	2.13	3.38	2.24	1.46	1.27	5.75	4.10	1.40	1.00
2024	3.19	2.26	3.19	2.15	1.86	1.42	5.98	4.16	1.65	1.25
2025	3.42	2.38	3.22	2.17	2.25	1.58	6.20	4.22	1.90	1.49
2026	3.96	2.77	3.27	2.23	2.68	1.90	7.30	5.02	2.45	1.87
2027	4.50	3.17	3.34	2.30	3.11	2.22	8.41	5.81	2.99	2.26
2028	5.04	3.56	3.41	2.37	3.55	2.54	9.52	6.60	3.54	2.64
2029	5.58	3.95	3.48	2.45	3.98	2.86	10.62	7.40	4.09	3.02
2030	6.12	4.35	3.55	2.52	4.41	3.19	11.73	8.19	4.63	3.40

Table G-3 MISO Annual and Seasonal Replacement Energy Costs ($/MWh)

Year	Annual		Winter		Spring		Summer		Fall	
	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact
2020	0.13	0.01	0.10	0.00	0.00	0.03	0.36	0.07	0.05	0.00
2021	0.23	0.03	0.18	0.00	0.33	0.10	0.30	0.01	0.15	0.00
2022	0.26	0.03	0.17	0.00	0.30	0.10	0.32	0.00	0.29	0.08
2023	0.30	0.03	0.17	0.00	0.27	0.09	0.34	0.00	0.43	0.16
2024	0.33	0.06	0.05	0.00	0.29	0.06	0.39	0.00	0.54	0.19
2025	0.37	0.09	0.01	0.01	0.32	0.04	0.44	0.02	0.64	0.23
2026	0.23	0.07	0.00	0.11	0.33	0.00	0.13	0.02	0.46	0.21
2027	0.21	0.05	0.03	0.13	0.26	0.00	0.12	0.02	0.46	0.19
2028	0.20	0.04	0.07	0.15	0.19	0.00	0.10	0.02	0.47	0.18
2029	0.19	0.02	0.10	0.16	0.11	0.00	0.09	0.01	0.47	0.16
2030	0.17	0.00	0.14	0.18	0.04	0.00	0.07	0.01	0.47	0.14

Table G-4 NYISO Annual and Seasonal Replacement Energy Costs ($/MWh)

Year	Annual		Winter		Spring		Summer		Fall	
	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact
2020	2.04	0.92	2.76	0.99	1.79	0.92	2.38	1.18	1.42	0.70
2021	2.14	0.98	2.17	0.81	2.67	1.22	2.05	0.99	1.77	0.91
2022	1.93	0.85	2.43	0.91	1.76	0.84	2.10	0.97	1.54	0.70
2023	1.73	0.72	2.72	0.98	0.85	0.46	2.15	0.95	1.31	0.50
2024	1.96	0.76	2.74	0.96	1.02	0.45	2.75	1.05	1.29	0.57
2025	2.19	0.80	2.92	0.96	1.20	0.45	3.35	1.15	1.26	0.65
2026	2.51	0.93	3.18	1.07	1.27	0.51	3.93	1.37	1.57	0.72
2027	2.83	1.05	3.47	1.22	1.35	0.58	4.51	1.60	1.88	0.79
2028	3.14	1.18	3.76	1.36	1.42	0.65	5.08	1.82	2.20	0.86
2029	3.46	1.30	4.05	1.50	1.50	0.72	5.66	2.05	2.51	0.92
2030[28]	3.77	N/A	4.34	N/A	1.57	N/A	6.23	N/A	2.82	N/A

[28] The current operating license for the R E Ginna Nuclear Power Plant expires in 2030.

Table G-5 PJM Annual and Seasonal Replacement Energy Costs ($/MWh)

Year	Annual		Winter		Spring		Summer		Fall	
	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact
2020	1.02	0.08	1.28	0.01	0.70	0.10	1.18	0.10	0.80	0.14
2021	0.67	0.09	1.10	0.03	0.49	0.03	0.69	0.14	0.60	0.13
2022	0.70	0.14	0.89	0.08	0.52	0.07	0.78	0.18	0.64	0.16
2023	0.74	0.19	0.87	0.17	0.55	0.12	0.87	0.22	0.69	0.19
2024	0.77	0.17	0.85	0.20	0.57	0.12	0.95	0.25	0.69	0.18
2025	0.79	0.16	0.86	0.11	0.59	0.11	1.02	0.29	0.68	0.17
2026	0.87	0.16	0.93	0.07	0.64	0.11	1.15	0.27	0.74	0.17
2027	0.94	0.16	0.99	0.11	0.69	0.11	1.27	0.25	0.81	0.16
2028	1.01	0.16	1.05	0.15	0.74	0.11	1.40	0.23	0.87	0.15
2029	1.09	0.17	1.10	0.18	0.80	0.11	1.52	0.21	0.93	0.15
2030	1.16	0.17	1.16	0.22	0.85	0.11	1.65	0.20	0.99	0.14

Table G-6 Southeast Annual and Seasonal Replacement Energy Costs ($/MWh)

Year	Annual		Winter		Spring		Summer		Fall	
	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact
2020	0.18	0.11	0.29	0.11	0.14	0.11	0.10	0.07	0.17	0.14
2021	0.18	0.07	0.20	0.10	0.22	0.11	0.15	0.06	0.16	0.07
2022	0.17	0.10	0.16	0.06	0.23	0.16	0.15	0.07	0.16	0.11
2023	0.17	0.13	0.16	0.07	0.23	0.21	0.15	0.08	0.15	0.16
2024	0.16	0.12	0.13	0.07	0.19	0.15	0.19	0.13	0.14	0.10
2025	0.16	0.10	0.11	0.07	0.14	0.09	0.23	0.18	0.13	0.05
2026	0.18	0.11	0.15	0.09	0.18	0.11	0.25	0.18	0.15	0.07
2027	0.20	0.12	0.16	0.09	0.21	0.13	0.27	0.18	0.17	0.09
2028	0.22	0.13	0.17	0.09	0.24	0.14	0.29	0.18	0.19	0.11
2029	0.24	0.14	0.18	0.09	0.27	0.16	0.31	0.18	0.20	0.13
2030	0.26	0.15	0.19	0.10	0.31	0.18	0.33	0.18	0.22	0.15

Table G-7 SPP Annual and Seasonal Replacement Energy Costs ($/MWh)

Year	Annual		Winter		Spring		Summer		Fall	
	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact
2020	0.92	0.46	0.73	0.29	1.09	0.52	0.91	0.55	0.99	0.51
2021	0.86	0.47	0.56	0.27	0.96	0.47	1.27	0.73	0.70	0.38
2022	0.90	0.49	0.53	0.31	0.91	0.48	1.34	0.77	0.76	0.39
2023[a]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

[a] *The IPM model forecasts that the Wolf Creek Generating Station and the Cooper Nuclear Station in SPP would not be economically dispatched beginning in 2023.*

Table G-8 WECC Annual and Seasonal Replacement Energy Costs ($/MWh)

Year	Annual		Winter		Spring		Summer		Fall	
	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact	Most Impact	Least Impact
2020	1.12	0.68	1.33	0.67	1.53	1.16	0.96	0.56	0.88	0.41
2021	1.15	0.91	1.16	1.22	1.35	1.11	1.19	0.63	0.97	0.65
2022	1.11	1.13	0.96	1.20	1.22	1.20	1.23	0.96	0.98	0.83
2023[a]	1.07	0.00	0.88	0.00	1.09	0.00	1.27	0.00	0.99	0.00
2024	1.01	0.00	0.86	0.00	0.99	0.00	1.23	0.00	0.93	0.00
2025	0.94	0.00	0.78	0.00	0.90	0.00	1.19	0.00	0.87	0.00
2026	1.11	0.00	0.88	0.00	1.07	0.00	1.35	0.00	1.09	0.00
2027	1.27	0.00	0.98	0.00	1.23	0.00	1.52	0.00	1.30	0.00
2028	1.44	0.00	1.09	0.00	1.40	0.00	1.68	0.00	1.52	0.00
2029	1.60	0.00	1.19	0.00	1.57	0.00	1.85	0.00	1.74	0.00
2030	1.76	0.00	1.29	0.00	1.74	0.00	2.01	0.00	1.96	0.00

[a] *The IPM model forecasts that the Columbia Generating Station in WECC would not be economically dispatched beginning in 2023.*

APPENDIX H
STUDIES AND SOURCES OF DATA REVIEWED FOR ASSUMPTIONS DEVELOPMENT

Table H-1 Summary of Studies and Sources of Data Compared with AEO 2018

Study/Report	Vintage	Scope	Modeling Method	Natural Gas Prices	Electricity Demand	New Build Costs	Legend
AEO 2018	2018	National	Long-term Capacity Expansion and Production Cost Modeling	AEO 2018 National Energy Modeling System (NEMS Endogenous)	AEO 2018 (NEMS Endogenous)	AEO 2018 (NEMS Endogenous)	AEO 2018
EPA Platform v6 November 2018 Reference Case	2018	National	Long-term Capacity Expansion and Production Cost Modeling	IPM and ICF's Gas Market Model (GMM)	AEO 2018 for Energy, and NERC ES&D and AEO 2018 for Peak Load	AEO 2018 for fossil and nuclear, and NREL ATB for renewables	EPA
MISO Transmission Expansion Plan (MTEP) 2018	2018	Regional	Production Cost	NYMEX, Wood Mackenzie No Carbon, and EIA forecasts	MISO Internal (Module E 50/50 load forecast growth rate)	NREL ATB for solar and wind	MISO
PJM Market Efficiency Analysis 2018	2018	Regional	Production Cost	Combination of NYMEX forward prices and a fundamental forecasting model	January 2018 PJM Load Forecast Report	–	AEO 2018
ERCOT 2018 Regional Transmission Plan	2018	Texas Interconnect	–	EIA 2018 AEO High Oil and Gas Resource and Technology Case	ERCOT 2018Regional Transmission Plan	–	ERCOT
NYISO Congestion Assessment and Resource Integration Studies 2017 and 2018	2018	Regional	Production Cost	AEO as the starting point	2018 Gold Book Forecast	–	NYISO

Table H-1 Summary of Studies and Sources of Data Compared with AEO 2018 (continued)

Study/Report	Vintage	Scope	Modeling Method	Natural Gas Prices	Electricity Demand	New Build Costs	Legend
California Public Utility Commission (CPUC)–RESOLVE	2018	Regional	–	WECC burner tip price estimate using California Energy Commission's (CEC's) 2017 Integrated Energy Policy Report (IEPR) Demand Forecast	CEC's 2017 IEPR	Natural Gas Units: E3's 2014 review of capital costs for WECC, Capital Cost Review of Generation Technologies. Renewable Resources: Developed by Black & Veatch for the CPUC's RPS Calculator v.6.3.For the 2019-2020 IRP CPUC plans to use NREL ATB	North American Market Gas (NAMGas)
WECC Anchor Dataset	–	Western Interconnect	Production Cost	California Energy Commission's NAMGas-Trade Model projections	–	–	NAMGas
WestConnect Regional Transmission Planning 2018-2019	2019	Western Interconnect	Production Cost	WECC 2028 Anchor Data Set (ADS) PCM Version 1.0 (2028 ADS PCM V1.0)	WECC 2028Anchor Data Set (ADS) PCM Version 1.0 (2028 ADS PCM V1.0)	–	NAMGas
NREL 2018 ATB	2018	National	Long-term Capacity Expansion and Production Cost Modeling	AEO 2018	–	Fossil and Nuclear- AEO 2018; Wind - Forecasting Wind Energy Costs and Cost Drivers: The Views of the World's Leading Experts- Wiser et al. (2016); Enabling the SMART Wind Power Plant of the Future Through Science-Based Innovation (Technical Report) - Dykes et al. (2017); Solar photovoltaic (PV) and CSP - Internal NREL analysis; Hydro - DOE 2016, Geothermal - EIA NEMS	AEO 2018

Table H-1 Summary of Studies and Sources of Data Compared with AEO 2018 (continued)

Study/Report	Vintage	Scope	Modeling Method	Natural Gas Prices	Electricity Demand	New Build Costs	Legend
Southwest Power Pool 2019 ITP Benchmarking	2018	Regional	Production Cost	ABB Projection	–	–	SPP
FPL's 2017 Ten-Year Site Plan: Key Forecasts and Resource Plan	2017	Utility	Production Cost	Forward + Proprietary PIRA Energy Group Projection	FPL's econometric model with projections for the national and Florida economies obtained from IHS Global Insight	–	FPL
Tennessee Valley Authority (TVA) 2019 Integrated Resource Plan (IRP)	2019	Regional	Long-term Capacity Expansion and Production Cost Modeling	–	TVA's Statistically Adjusted End-use model (SAE)	–	TVA

CSP–concentrated solar power; NYMEX – New York Mercantile Exchange

H.1 Appendix H References

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NRC FORM 335 (12-2010) NRCMD 3.7 U.S. NUCLEAR REGULATORY COMMISSION **BIBLIOGRAPHIC DATA SHEET** *(See instructions on the reverse)*	1. REPORT NUMBER (Assigned by NRC, Add Vol., Supp., Rev., and Addendum Numbers, if any.) NUREG-2242
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11. ABSTRACT (200 words or less)

Replacement energy costs are estimated for the United States wholesale electricity market regions with nuclear electricity-generating units over the 2020–2030 report period. These estimates were developed to assist the U.S. Nuclear Regulatory Commission (NRC) in evaluating proposed regulatory actions that (1) require safety modifications that might necessitate temporary reactor outages and (2) reduce the potential for the loss of generation associated with a possible severe reactor accident. Estimates were calculated using ASEA Brown Boveri's (ABB's) PROMOD model and ICF's Integrated Planning Model for North America.

The models simulate dispatching a collection of generating units in merit order (i.e., lowest to highest incremental cost of dispatch) until the regional power demand is met. Each generating unit is characterized by the technology and fuel it uses to generate electricity, the unit's heat rate, and the variable and fixed costs incurred in owning and operating the unit. To estimate the replacement energy cost, the report models a Reference Case, in which all operational nuclear power plants are generating, and an Alternative Case, in which a nuclear generating unit is taken offline so that the next unit in merit order is dispatched to replace the lost generation. The difference in market clearing prices between the two cases is the replacement energy cost.

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