Regional Energy Deployment System (ReEDS)

Walter Short, Patrick Sullivan, Trieu Mai, Matthew Mowers, Caroline Uriarte, Nate Blair, Donna Heimiller, and Andrew Martinez

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Technical Report
NREL/TP-6A20-46534
December 2011

Contract No. DE-AC36-08GO28308

NATIONAL RENEWABLE ENERGY LABORATORY

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Prepared under Task Nos. DOCC.1014, SS10.2210,
SS10.2250, SA10.1074

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List of Acronyms

AC	alternating current
AEO	Annual Energy Outlook
BA	balancing area
CAES	compressed air energy storage
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CCS	carbon capture and sequestration
CES	clean energy standard
CO_2	carbon dioxide
Coal-CCS	integrated gasification combined cycle coal with carbon capture and sequestration
Coal-IGCC	integrated gasification combined cycle coal
CoalNew	advanced super critical coal steam plant (with SO_2 and NO_x controls)
CoalOldScr	conventional pulverized coal steam plant (with SO_2 scrubber)
CoalOldUns	conventional pulverized coal steam plant (no SO_2 scrubber)
CofireNew	advanced super critical coal steam plant (with biomass co-firing)
CofireOld	conventional pulverized coal steam plant (with SO_2 scrubber and biomass co-firing)
CRF	capital recovery factor
CSP	concentrating solar power
DC	direct current
deep EGS	deep enhanced geothermal system
DNI	direct normal insolation
DSIRE	Database of State Incentives for Renewable Energy
EGS	enhanced geothermal system
EIA	U.S. Energy Information Administration
ELCC	effective load carrying capacity
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GAMS	General Algebraic Modeling System
Gas-CC	natural gas combined cycle gas turbine
Gas-CCS	natural gas combined cycle gas turbine with carbon capture sequestration
Gas-CT	natural gas combustion turbine
GIS	Geographic Information System
GW	gigawatt
Hg	mercury

Hydro	conventional hydropower, hydraulic turbine
IGCC	integrated gasification and combined cycle
ISO	independent system operator
ISO-NE	Independent System Operator New England
ITC	investment tax credit
LP	linear program
MACRS	Modified Accelerated Cost Recovery System
MISO	Midwest Independent System Operators
MMBtu	million British thermal units
MSW/LFG	municipal solid waste/landfill gas plant
MW	megawatt
NEMS	National Energy Modeling System
NERC	National Electric Reliability Council
NO_x	nitrogen dioxide
NP	non-deterministic polynomial-time
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Data Base
Nuclear	nuclear plant
O&M	operations and maintenance
OGS	oil/gas steam turbine
OPF	optimal power flow
PCA	power control area
PHEV	plug-in hybrid electric vehicle
PHS	pumped-hydro storage
PTC	production tax credit
PTDF	power transfer distribution factor
PV	photovoltaic
R&D	research and development
ReEDS	Regional Energy Deployment System
RPS	renewable portfolio standard
RROE	rate of return on equity
RTO	Regional Transmission Organization
SAM	System Advisor Model
SEAC	Strategic Energy Analysis Center
SERC	Southeast Reliability Council
SO_2	sulfur dioxide
SolarDS	Solar Deployment System
SPP	Southern Power Pool
T&D	transmission and distribution
TDY	typical direct normal insolation year
TES	thermal energy storage
UPV	utility-scale photovoltaic
VRRE	variable resource renewable energy
WACC	weighted average cost of capital
WECC	Western Electric Coordination Council

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1 Summary

The Regional Energy Deployment System (ReEDS) is a deterministic optimization model of the deployment of electric power generation technologies and transmission infrastructure throughout the contiguous United States into the future. The model, developed by the National Renewable Energy Laboratory's (NREL's) Strategic Energy Analysis Center (SEAC), is designed to analyze the critical energy issues in the electric sector, especially with respect to potential energy policies, such as clean energy and renewable energy standards or carbon restrictions.

ReEDS provides a detailed treatment of electricity-generating and electrical storage technologies and specifically addresses a variety of issues related to renewable energy technologies, including accessibility and cost of transmission, regional quality of renewable resources, seasonal and diurnal generation profiles, variability of wind and solar power, and the influence of variability on the reliability of the electrical grid. ReEDS addresses these issues through a highly discretized regional structure, explicit statistical treatment of the variability in wind and solar output over time, and consideration of ancillary services' requirements and costs.

1.1 Qualitative Model Description

To determine competition between the many electricity generation, storage, and transmission options throughout the contiguous United States, ReEDS chooses the cost-optimal mix of technologies that meet all regional electric power demand requirements, based on grid reliability (reserve) requirements, technology resource constraints, and policy constraints. This cost minimization routine is performed for each of 23 two-year periods from 2006 to 2050. The major outputs of ReEDS include the amount of generator capacity and annual generation from each technology, storage capacity expansion, transmission capacity expansion, total electric sector costs, electricity price, fuel prices, and carbon dioxide (CO_2) emissions.

Figure 1 shows an example of ReEDS's cumulative capacity estimates for the United States for different generation technologies over the 44-year evaluation period.

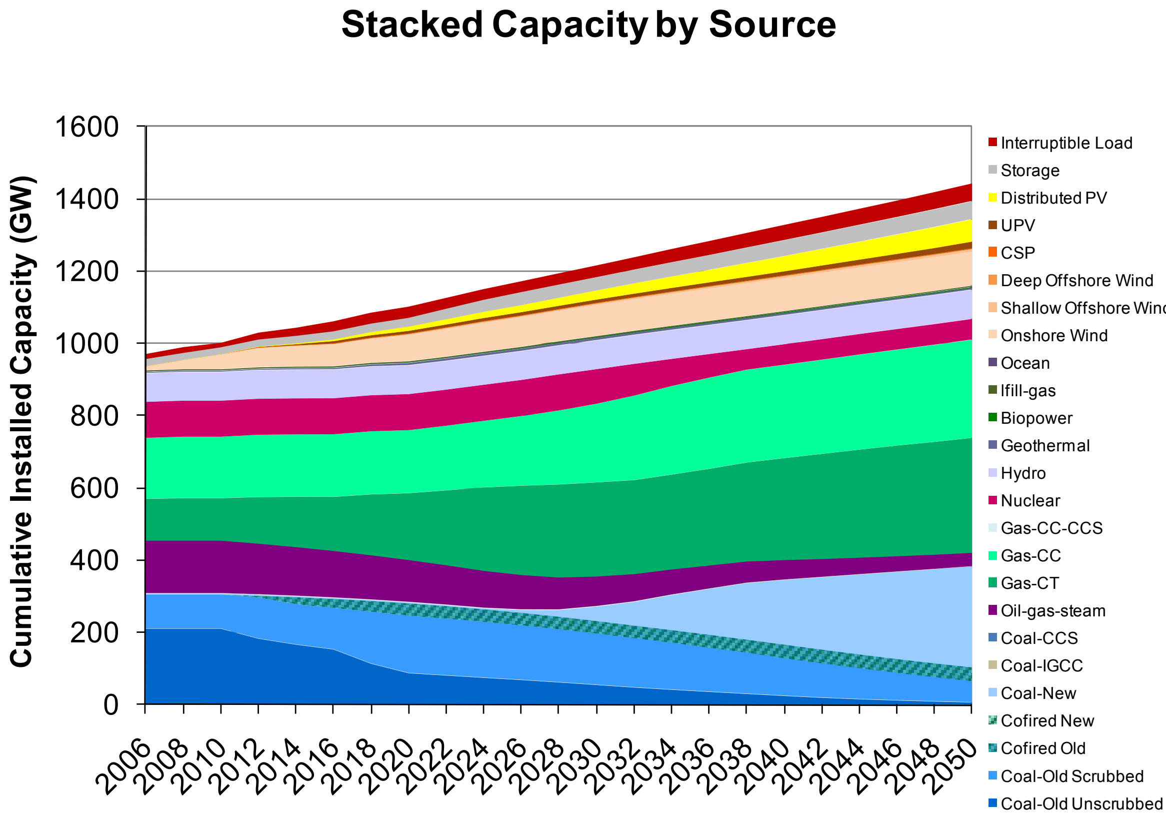

Figure 1. Business-as-usual case capacity build-out in ReEDS

Time in ReEDS is subdivided within each 2-year period, with each year divided into four seasons with a representative day for each season, which is further divided into four diurnal time-slices. Also, there is one additional summer-peak time-slice. These 17 annual time-slices enable ReEDS to capture the intricacies of meeting electric loads that vary throughout the day and year—with both conventional and renewable generators.

Although ReEDS includes all major generator types, it has been designed primarily to address the market issues that are of the greatest significance to renewable energy technologies. As a result, renewable and carbon-free energy technologies and barriers to their adoption are a focus. Diffuse resources, such as wind and solar power, come with concerns that conventional dispatchable power plants do not have, particularly regarding transmission and variability. The ReEDS model examines these issues primarily by using a much greater level of geographic disaggregation than do other long-term large-scale capacity expansion models. ReEDS uses 356 different resource regions in the continental United States. These 356 resource supply regions are grouped into four levels of larger regional groupings—balancing areas (BA), reserve-sharing groups, North American Electric Reliability Council (NERC) regions (NERC 2010), and interconnects. States are also represented for the inclusion of state policies.

Many of the data inputs in ReEDS are tied to these regions and derived from a detailed geographic information system (GIS) model/database of the wind and solar resource, transmission grid, and existing plant data. The geographic disaggregation of renewable resources enables ReEDS to calculate transmission distances as well as the benefits of dispersed wind farms, photovoltaic (PV) arrays, or concentrating solar power (CSP) plants supplying power to a demand region. Both the wind and CSP supply curves are subdivided into five resource classes based on the quality of the resource—strength and dependability of wind or solar insolation—that are further described in this report.

Regarding resource variability and grid reliability, ReEDS also allows electric and thermal storage systems to be built and used for load shifting, resource firming, and ancillary services. Four varieties of storage are supported: pumped hydropower, batteries, compressed air energy storage, and thermal storage in buildings.

Along with wind and solar power data, ReEDS provides supply curves for hydropower, biomass, and geothermal resources in each of the 134 balancing areas. The geothermal and hydropower supply curves are in megawatts (MW) of recoverable capacity, and the biomass supply curve is in million British thermal units (MMBtu) of annual feedstock production. In addition, other carbon-reducing options are considered. Nuclear power is an option, as is carbon capture and sequestration (CCS), on some coal and natural gas plants. CCS is treated simply, with only an additional capital cost for new coal and gas-fired power plants for the extra equipment and an efficiency penalty to account for the parasitic loads of the separation process. Also, a limited set of existing coal plants can choose to retrofit to CCS for an associated cost as well as a performance penalty. In the future, it is intended that ReEDS will integrate geographically varying costs for CCS and piping and sequestering constraints on the CO_2.

The major conventional electricity-generating technologies considered in ReEDS include hydropower, simple and combined cycle natural gas, several varieties of coal, oil/gas steam, and nuclear. These technologies are characterized in ReEDS by:

- Capital cost ($/MW)
- Fixed and variable operating costs ($/MWh)
- Fuel costs ($/MMBtu)
- Heat rate (MMBtu/MWh)
- Construction period (years)
- Equipment lifetime (years)
- Financing costs (such as nominal interest rate, loan period, debt fraction, and debt-service-coverage ratio)
- Tax credits (investment or production)
- Minimum turndown ratio (%)
- Quick-start capability and cost (%, $/MW)
- Spinning reserve capability
- Planned and unplanned outage rates (%).

Renewable and storage technologies are governed by similar parameters—accounting for fundamental differences. For instance, heat rate is replaced with round-trip efficiency in pure storage technologies, and the dispatchability parameters, such as fuel cost, heat rate, turndown ratio, and operating reserve capability, are not used for non-dispatchable wind and solar technologies.

The model includes consideration of distinguishing characteristics of each conventional-generating technology. There are several types of coal-fired power plants within ReEDS, including pulverized coal with and without sulfur dioxide (SO_2) scrubbers, advanced pulverized coal, integrated gasification combined cycle (IGCC), biomass co-firing, and IGCC with CCS options. Any of these plants can burn either high-sulfur coal or, for a cost premium, low-sulfur coal. Coal plant generation is discouraged from daily cycling via a cost penalty, which represents a combination of additional fuel burnt, heat rate drop off, and mechanical wear-and-tear. Natural gas plants represented in ReEDS include simple-cycle combustion turbines (gas-CT), combined cycle plants (gas-CC), and combined cycle with CCS plants.[1] Combined cycle natural gas plants can provide some spinning reserve and quick-start capability, and simple-cycle gas plants can be used cheaply and easily for quick-start power. Nuclear power is represented as one technology in ReEDS and is considered to be baseload.

Retirement of conventional generation and hydropower can be modeled through exogenous specification of planned retirements or based on usage characteristics of the plants. All retiring non-hydro renewable plants are assumed to be refurbished or replaced immediately because the site is already developed and has transmission access and other infrastructure.

ReEDS tracks emissions of carbon, SO_2, nitrogen oxides, and mercury from both generators and storage technologies. Caps can be imposed at the national level on any of these emissions, and constraints can also be applied to impose caps at state or regional levels. There is another option of applying a carbon tax instead of a cap; the tax level and ramp-in pattern can be defined exogenously.

Annual electric loads and fuel price supply curves are exogenously specified to define the system boundaries for each period of the optimization. To allow for the evaluation of scenarios that might depart significantly from the base scenario, price elasticity of demand is integrated into the model: the exogenously-defined demand projection can be adjusted up or down based on a comparison of an estimated business-as-usual electricity price path and a calculation of electricity price within the model for each of the 23 two-year periods. For coal and natural gas pricing, supply curves based on the *Annual Energy Outlook* (AEO) have been developed and used in ReEDS (EIA 2011a).

1.2 Linear Program Formulation

This section qualitatively describes the basic linear program (LP) formulation of ReEDS. Section 7 contains a more detailed description of the LP with the actual equations used in the model. ReEDS is recursive-dynamic in that it solves an LP for each of the 23 two-year time periods as it moves successively from 2006 to 2050.

The objective function in the ReEDS linear program is a minimization of both capital and operating costs for the U.S. electric sector including:

- The net present value of the cost of adding new generation, storage, and transmission capacity

[1] In addition, ReEDS represents existing oil-steam and gas-steam plants.

- The present value of 20 years of operating expenses (e.g., fuel and operation and maintenance) for all installed capacity
- The cost of several categories of ancillary services and storage.

By minimizing these costs and meeting the system constraints (discussed below), the LP determines the types of new capacity that are the most economical to add in each region during each period. Simultaneously, the linear program determines how generation and storage capacity should be dispatched to provide the necessary energy in each of the 17 annual time-slices at least cost to the system. The capacity factor for each dispatchable technology in each region therefore is an output of the model and not an input.

The constraints that govern how ReEDS builds and operates capacity fall into several main categories, including:

- **Load constraints.** There must be sufficient power generated in or imported to each of the 134 BAs in each of the 17 time-slices to meet the projected load. The annual and time-slice-specific electricity demand in future years are based on projections for each NERC region. Within each NERC region, the load distribution between BAs and the load shape in each BA is retained for all years.
- **Planning reserve constraints.** There must be sufficient firm-generating capacity available in each region to meet the forecasted peak demand plus an additional reserve (safety) margin (NERC 2010). For variable resource renewable energy (VRRE) technologies, ReEDS uses a statistical method to estimate the effective load-carrying capacity of both existing capacity and potential capacity additions to determine their contribution to meeting the reserve margin. Firm capacity is able to be contracted from one region to another as long as transmission is available to handle it.
- **Operating reserve constraints.** This constraint ensures that there is enough quick-start, spinning capacity, or interruptible load, to meet unexpected changes in generation and load in each reserve-sharing group (see Section 1.3) and time-slice. ReEDS accounts for the following operating reserve requirements: contingency reserve, frequency regulation, and VRRE forecast error reserve.
- **Transmission constraints.** Power transfers among regions are constrained by the nominal carrying capacity of transmission lines that connect the regions. Renewable energy contracts and firm power contracts for planning reserves are also subject to transmission limits. A more detailed description of the transmission constraint can be found in Section 3.
- **Resource constraints.** Many resources, including wind, solar, geothermal, biopower, and hydropower, are limited by where they can be built and, in some cases, the amount that can be built there. Several of the technologies include cost- and resource-quality considerations in resource supply curves to account for depletion, transmission, and competition effects. The resource assessments that seed the supply curves are from various sources and are discussed in detail below, along with further detail about the technologies.

- **Emissions constraints.** At the national level, ReEDS has the ability to cap the emissions from fossil-fueled generators for SO_2, nitrogen oxides, mercury, and CO_2. The annual national emission cap and the emission per megawatt-hour by fuel and plant type are inputs to the model. In carbon-constrained scenarios, CO_2 can be either capped or taxed, and either a cap or tax can be finely adjusted to match proposed legislation.
- **Renewable portfolio standards or clean electricity standards.** ReEDS allows users to input renewable portfolio standards (RPSs) or clean electricity standards constraints at the national and state levels. All renewable generation counts toward the national RPS requirement. The renewable generation sources include hydropower, wind, CSP, geothermal, PV, and biopower (including the biomass fraction of co-firing plants). Eligible technologies for state RPS requirements vary by state, depending on the specific requirements. The RPS targets over time are based on an externally defined profile. A penalty is imposed for each megawatt-hour shortfall occurring in the nation or state. In the same way, a clean energy standard constraint can be implemented to account for the crediting of clean energy resources, such as nuclear, CCS, or natural gas.

1.3 Spatial and Temporal Resolution

ReEDS represents the continental United States using five types of regions. Each region has various functions, and major examples of these functions are provided in the following list. This level of geographic detail enables the model to account for geospatial differences in resource quality, transmission needs, electrical (grid-related) boundaries, and political boundaries. See Figure 2 for a map of selected region types.

The five types of ReEDS regions include:

- **Wind/CSP resource regions.** There are 356 wind/CSP resource regions that are aggregated from U.S. counties. This is the level at which CSP and wind capacity expansion occurs and resource limitations for wind/CSP are considered. These resource regions are bounded by gray lines in Figure 2. The county aggregations were initially determined due to the wind and solar resource data available.
- **BAs.** There are 134 BAs. This is the regional level at which demand requirements must be satisfied and all non-wind/CSP technology capacity expansion occurs. Furthermore, the national transmission grid is represented in ReEDS as connections between the BAs. BA boundaries reflect electrical (grid-related) boundaries, political and jurisdictional boundaries, and demographic distributions.[2] The BAs are shown in Figure 2 as color-shaded groups of CSP/wind resource regions.[3]
- **Reserve-sharing groups.** There are 21 reserve-sharing groups. This is the regional level at which operating reserve requirements must be met[4] and the level at which curtailment of variable renewable power is calculated. The black boundaries in Figure 2 show the reserve-sharing group boundaries. Some of the reserve-sharing groups were designed based on existing Regional Transmission Organizations (RTOs) and independent system

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[2] It is noted that though existing BA boundaries are considered in the design of the BAs, the BA boundaries are generally not aligned with the boundaries of real BAs (NERC 2011).

[3] BAs are also referred to as power control areas (PCAs), as seen in Figure 2.

[4] Planning reserves requirements, on the other hand, are met at the BA regional level.

operators (ISOs),[5] while others (particularly those in the western states) are assumed based on current transmission plans.

- **NERC regions.** There are 13 NERC regions/subregions. Generally, inputs to the model from the U.S. Energy Information Administration (EIA) and the National Energy Modeling System (NEMS) model are provided at the NERC subregional level (DOE 2010). These inputs include fuel prices and demand profiles over time.
- **Interconnects.** There are three asynchronous interconnects in the United States: the Eastern Interconnection, the Western Electricity Coordinating Council (WECC), and the Electric Reliability Council of Texas (ERCOT). Due to the asynchronicity of the three interconnections, new transmission lines across interconnect boundaries require installations of new AC-DC-AC intertie capacity (and their associated costs). In Figure 2, interconnect boundaries are indicated by the solid red lines.

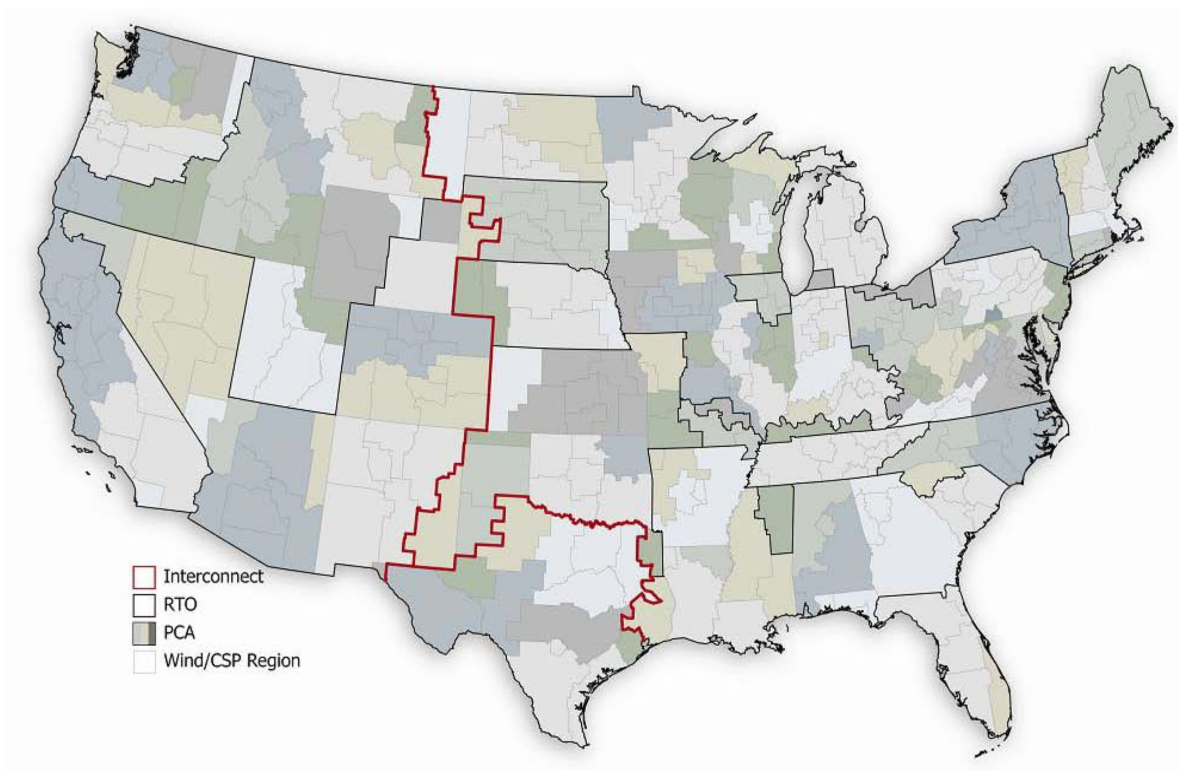

Figure 2. Regions in the ReEDS model

The optimal capacity expansion and dispatch routine in ReEDS occurs sequentially for every two-year period from 2006 to 2050. During the optimization routine, ReEDS considers the seasonal and diurnal variations in demand and resource profiles by using 17 time-slices, shown

[5] Examples of existing RTOs and ISOs include Midwest Independent Transmission System Operator (MISO), Independent System Operator New England (ISO-NE), PJM Interconnection, Southwest Power Pool (SPP), and California Independent System Operation (CAISO).

in Table 1. There are four time-slices in each of the four seasons,[6] as well as a peak time-slice in the summer. This level of temporal detail (though not as sophisticated as an hourly chronological dispatch model) enables ReEDS to consider seasonal and diurnal changes in demand and resource availability. In ReEDS, dispatch of generators is optimized to satisfy demand and operating reserve requirements in each of these 17 time-slices. Variability of electrical generation and demand is characterized in each time-slice as well as through the statistical representations described in other sections. Planning reserve requirements also must be satisfied in all time-slices.

Table 1. Time-Slice Definitions for ReEDS

Time-Slice	Number of Hours Per Year	Season	Time of Day	Time Period
H1	736	Summer	Night	10 p.m. to 6 a.m.
H2	644	Summer	Morning	6 a.m. to 1 p.m.
H3	328	Summer	Afternoon	1 p.m. to 5 p.m.
H4	460	Summer	Evening	5 p.m. to 10 p.m.
H5	488	Fall	Night	10 p.m. to 6 a.m.
H6	427	Fall	Morning	6 a.m. to 1 p.m.
H7	244	Fall	Afternoon	1 p.m. to 5 p.m.
H8	305	Fall	Evening	5 p.m. to 10 p.m.
H9	960	Winter	Night	10 p.m. to 6 a.m.
H10	840	Winter	Morning	6 a.m. to 1 p.m.
H11	480	Winter	Afternoon	1 p.m. to 5 p.m.
H12	600	Winter	Evening	5 p.m. to 10 p.m.
H13	736	Spring	Night	10 p.m. to 6 a.m.
H14	644	Spring	Morning	6 a.m. to 1 p.m.
H15	368	Spring	Afternoon	1 p.m. to 5 p.m.
H16	460	Spring	Evening	5 p.m. to 10 p.m.
H17	40	Summer	Peak	40 highest demand hours of summer 1 p.m.to 5 p.m.

1.4 Financial Calculations

To properly account for loans, contracts, and the time-value of money, ReEDS adjusts costs—both capital and operational—so that the model's costs are consistent and represent those that would be considered by a real-world actor as well as possible. Using a utility-owned project perspective, ReEDS discounts future transactions, accounts for tax benefits, and weighs risk where possible.

A discount rate represents the risk-adjusted time value of money. The discount rate is a function of the equity and debt fraction, cost of equity, and cost of debt. ReEDS uses a weighted average cost of capital (WACC) as the discount rate, calculated as follows:

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[6] The seasons are defined based on the following definitions: Summer = June, July, and August; Fall = September and October; Winter = November, December, January, and February; Spring = March, April, and May.

$$WACC_{nominal} = E \cdot R_e + D \cdot R_d \cdot (1 - T_c)$$

$$WACC_{real} = \frac{1 + WACC_{nominal}}{1 + i} - 1$$

where:

E = equity fraction
D = debt fraction

R_e = expected return on equity
R_d = expected return on debt
T_c = tax rate

i = inflation rate

The capital recovery factor (CRF) is computed using the WACC and represents the fraction of an investment that must be returned each year, including all interest. P is the evaluation period or investment lifetime in years.

$$CRF_{real} = \left(\sum_{t=1}^{P} (1 + WACC_{real})^{-t} \right)^{-1} = \frac{\text{WACC}_{real}}{1 - (1 + WACC_{real})^{-P}}$$

The investment decision making obviously only applies to those technologies in which new installations are allowed. However, dispatch decisions for new and existing plants are also based on net present values over the evaluation period, using the same discount rate.

ReEDS considers the interest incurred during construction when evaluating the cost of a new plant.[7] Total present costs also include interest during construction. Physical lifetimes play a role in the ReEDS model via retirements. Due to concerns about carbon regulation, a risk adjustment is applied to all coal-fired technologies.[8] This risk adjustment is added to both the cost of equity and that of debt (i.e. the interest rate of debt) for each applicable technology. CCS technologies are exempted from this regulatory risk.

In summary, when evaluating technology costs during the capacity expansion optimization routine, ReEDS considers debt/equity financing, taxes (and depreciation), interest during construction, risk adjustments, and any tax incentives on a state or national level [e.g., the wind production tax credit (PTC) or solar investment tax credit (ITC)]. An effective capital cost financial multiplier is calculated based on all of these considerations and applied to the overnight capital cost. These multipliers vary by technology and can vary over time (e.g., the multipliers can increase when an ITC expires).

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[7] Unless otherwise noted, capital costs referred to in this document represent overnight capital costs and do not include the interest during construction.
[8] The risk adjustment assumes that an investor would require a higher return on equity and debt. The actual value in ReEDS can be adjusted but the typical value used is an additional 3% return on equity and debt.

1.5 System Load

In ReEDS, electric power loads, or demands, are defined by region and time-slice. ReEDS is constrained to meet loads in all of the 134 BAs and in each of the 17 time-slices. The load forecast is exogenously fixed for each modeled year's solve but is not fixed through time: projections are adjusted between solves in ReEDS based on deviations between computed and expected electricity prices. Specifically, a regional electricity price is computed in ReEDS after each optimization and is used to adjust the load growth forecast for subsequent years based on deviations from expected electricity price. The load forecasts are adjusted from the previous year's forecast via short-term and long-term multipliers, which are exogenously defined for each NERC region. The demand elasticities have been determined based on differences between alternative Annual Energy Outlook (AEO) scenarios (e.g., reference case versus high and low economic growth) and therefore are consistent with the baseline demand trajectory.

1.6 Legislative Considerations

ReEDS has the capability to model federal and state emission standards, RPSs, and tax credits.

1.6.1 Renewable Portfolio Standard

An RPS requires that a certain fraction of a region's electricity be derived from renewable sources. ReEDS can accommodate national and state RPS policies with input values for an annual fraction of electricity to be provided by renewables, eligible technologies, and shortfall penalty (or alternative compliance payment).

1.6.2 Clean Energy Standard

A clean energy standard (CES) requires that a certain fraction of a region's electricity be derived from clean sources. In general, a credit fraction is provided for a clean technology's generation, such as a 0.5 credit for all natural gas combined cycles' generation or a 0.90 credit for all coal CCS technologies' generation. ReEDS also has the capability to accommodate CES policies with input values for annual fraction of electricity to be provided by clean sources, fractional credits given to eligible technologies, and shortfall penalty (or alternative compliance payment).

1.6.3 Federal Emissions Standard

ReEDS can track the following emissions: SO_2, CO_2, NO_x, and Hg. All emissions are point-source emissions from the plant only (not full life cycle emissions). ReEDS has the ability to impose a national cap on CO_2 emissions from electricity generation or a CO_2 emission tax. ReEDS does not account for the use of offsets, so any carbon cap input into ReEDS must reflect reductions attributed to offsets. ReEDS also offers the ability to impose a national cap on SO_2 emissions in a similar fashion. Although not currently fully defined in the U.S. legislation, ReEDS assumes a SO_2 cap, which was adopted from the U.S. Environmental Protection Agency's (EPA's) Clean Air Interstate Rule (CAIR) (EPA 2005a) for standard analysis.

2 Description of the Technologies

This section describes how each technology is treated in ReEDS and is divided into renewable, conventional, and electricity-storage systems.

2.1 Renewable Energy Resources and Technologies

All major renewable technologies are considered in ReEDS, including wind (onshore and offshore), PV (utility-scale and rooftop), CSP (with and without storage), geothermal (hydrothermal and enhanced geothermal systems), hydroelectric power, biopower (dedicated and co-fired with coal), and marine hydrokinetic (ocean wave and ocean current).

2.1.1 Wind

ReEDS considers five resource classes for wind based on wind power density and wind speed at 50 meters (m) above ground,[9] as seen in Table 2. Available land area of each wind class in each wind/CSP resource region is derived from state wind resource maps and modified for environmental and land-use exclusions. The available wind area is converted to available wind capacity using a constant multiplier of 5 MW/km^2. The available wind capacity by region for each of the wind power classes is shown in Figure 3 (3Tier 2010; NREL 2009). The colored stripes on the coastal and great lakes regions represent available (fixed-bottom and floating-platform) offshore wind capacity potential. Fixed-bottom and floating-platform wind resource was differentiated based on water depth, where fixed-bottom resources correspond to a shallow water depth of less than 30 m and floating-platform corresponds to regions deeper than 30 m.

Table 2. Classes of Wind Power Density

Wind Class	Wind Power Density (W/m^2)	Speed (m/s)
3	300-400	6.4-7.0
4	400-500	7.0-7.5
5	500-600	7.5-8.0
6	600-800	8.0-8.8
7	>800	>8.8

Notes: W/m^2 = watts per square meter; m/s = meters per second. Wind speed measured at 50 m above ground level.
Source: Elliott and Schwartz (1993)

[9] While the resource is characterized based on wind characteristics at 50 m above ground level, the capacity factors of the turbines are adjusted for higher turbine heights.

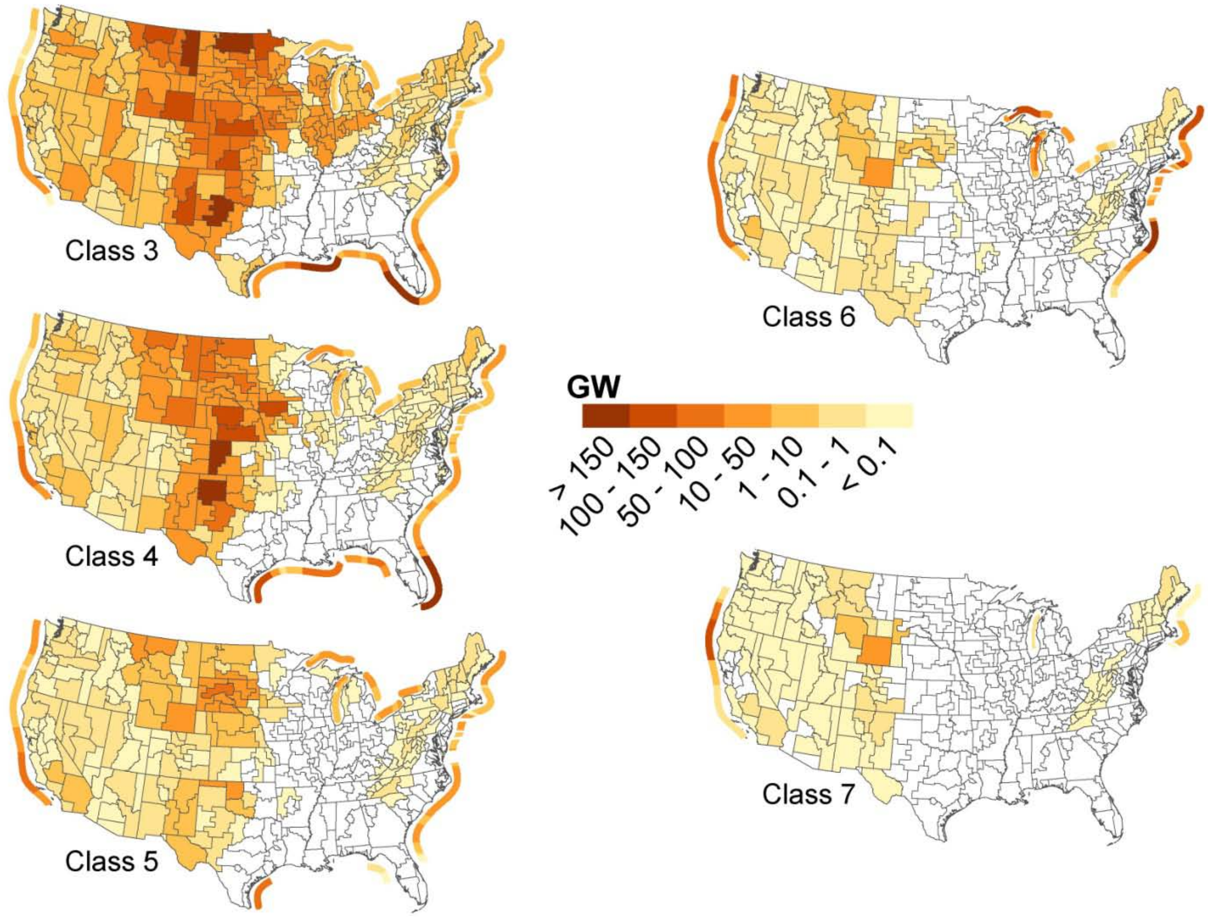

Figure 3. Available wind resource (onshore and offshore) by class

Sources: 3Tier (2010); NREL (2009)

Representative annual capacity factors by class and year are shown in Table 3.[10] Capacity factor adjustments by time-slice were made for each class of each region based on AWS TruePower text supplemental database files and the National Commission on Energy Policy (NCEP)/National Center for Atmospheric Research (NCAR) global reanalysis mean values.

[10] Annual projected capacity factors for wind and other non-dispatchable technologies are inputs to ReEDS and are frequently changed depending on the analysis. In general, technology costs and performance data are user-defined and are not fixed in the model.

Table 3. Annual Average Capacity Factor for Wind Energy Technologies

Technology	Wind Class	2010	2020	2030	2040	2050
Onshore	3	32%	33%	35%	35%	35%
	4	36%	37%	38%	38%	38%
	5	42%	42%	43%	43%	43%
	6	44%	44%	45%	45%	45%
	7	46%	46%	46%	46%	46%
(Fixed-bottom) offshore	3	36%	37%	38%	38%	38%
	4	39%	39%	40%	40%	40%
	5	45%	45%	45%	45%	45%
	6	48%	48%	48%	48%	48%
	7	50%	50%	50%	50%	50%
(Floating-platform) offshore	3	n/a	37%	38%	38%	38%
	4	n/a	39%	40%	40%	40%
	5	n/a	45%	45%	45%	45%
	6	n/a	48%	48%	48%	48%
	7	n/a	50%	50%	50%	50%

Source: Black and Veatch (2011)

To allow differentiation based on transmission and accessibility, a supply curve representing the cost of connecting individual wind sites to the existing grid as well as to local demand centers was developed based on a GIS database of the resource, existing grid, and loads. In constructing these supply curves, an assumption that the availability of the existing grid was limited to 10% of the total carrying capacity of each transmission line.[11]

2.1.2 Concentrating Solar Power

There are three representative CSP technologies in ReEDS: troughs without storage, troughs with at least five hours of storage, and towers with at least five hours of storage. All three technologies rely on the same resource (see Figure 4), which is divided into five resource classes based on direct normal insolation (DNI) (Table 4). All conventional and renewable technologies in ReEDS are considered at the BA level except for CSP and wind. CSP collection fields are installed at the wind/CSP resource region level.

[11] See Section 8.2 for a more detailed description of the wind supply curve formulation.

Table 4. Classes of CSP Power Density

CSP Class	Power Density $W/m^2/day$
1	5–6.25
2	6.25–7.25
3	7.25–7.5
4	7.5–7.75
5	>7.75

Table 5 shows the CSP resource available at each wind/CSP resource region assuming a solar multiple[12] of two. Since only regions with DNI greater than 5 $kWh/m^2/day$ are considered, CSP resource is predominantly found in the western states. In addition to DNI, available land area and slope also limit the available CSP resource. In particular, regions having a slope greater than 3% are excluded. The available land area for each CSP resource class is converted into gigawatts (GW) of available capacity assuming a plant density of 31 MW/km^2 for a system with a solar multiple of two. Plant density for systems with other solar multiples is assumed to scale inversely with solar multiple. For example, a CSP system with a solar multiple of one would be assumed to have a plant density of 62 MW/km^2, or twice that of a system with a solar multiple of two.

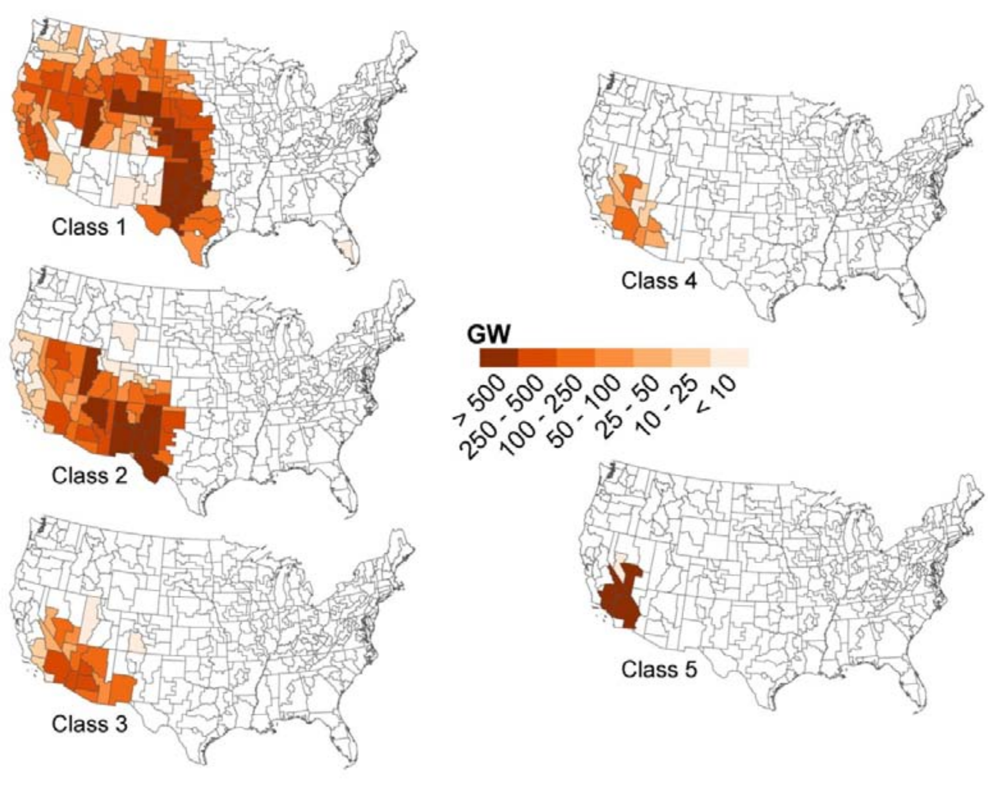

Figure 4. CSP resource

Source: NREL (2010b)

[12] A solar multiple is defined as the ratio of the power capacity of the collection field to the capacity of the power block. For CSP systems with storage, the number of hours of storage is based on the capacity of the power block.

Performance for each CSP resource class was developed using typical DNI year (TDY) hourly resource data (NREL 2010b) from representative sites of each wind/CSP resource region. The TDY weather files were processed through the CSP modules of the System Advisor Model (SAM) (NREL 2010a) for each type of CSP system considered in ReEDS. From this, performance characteristics for each CSP resource class were developed.

The representative CSP system without storage in ReEDS is a 100-MW trough system with a solar multiple of 1.4. As CSP systems without storage are non-dispatchable, capacity factors by time-slice were developed directly from SAM (NREL 2010a)[13] runs. The average annual capacity factors for these systems range from 20% (class 1) to 31% (class 5).

There are two CSP-with-storage systems represented in ReEDS—troughs and towers, both with at least five hours of thermal storage—for which ReEDS assumes full capacity credit valuations. In ReEDS, only a single technology type is used to represent new CSP-with-storage installations in a given year. Generally, those systems built before a user-defined year are troughs and those built after that are towers (in ReEDS, the default year for this transition is 2025); cost and performance of this technology type in ReEDS are adjusted accordingly.

In ReEDS, CSP-with-storage systems are allowed to have variable solar multiples and variable amounts of thermal storage. Greater solar multiples will result in higher capacity factors, and greater amounts of storage allow the systems to be more flexible, although both increase capital costs per kilowatt of installed turbine capacity. The CSP with storage systems are assumed to be fully dispatchable within the energy limitations imposed by solar multiple, hours of thermal storage, the time-profile of the solar insolation, and minimum loading constraints.

Although solar multiple and hours of storage are variable, the system configurations must abide by certain restrictions in ReEDS. First, to ensure that these systems are capable of providing firm capacity to the system during peak demand periods, they are restricted to an annual capacity factor of at least 40% in addition to the minimum five hours of storage. These systems are also restricted to capacity factors of less than 70% and solar multiples of less than 3.4 for troughs and 2.7 for towers to limit curtailment effects that become significant at these higher solar multiples. In addition, prescribed amounts of storage as a function of solar multiple were developed using SAM, as the broad time-slices and typical-day profiles in ReEDS prevent it from fully capturing the amount of storage required for a given plant performance.

Capacity factors by time-slice of CSP with storage systems in ReEDS are an output of the model, not an input, since ReEDS is allowed to dispatch CSP plants optimally. Instead, the profile of power input from the collectors (solar field) of the CSP plants are model inputs, based on SAM simulations from the TDY weather files.

In addition to capital and operation and maintenance (O&M) costs, and because CSP resource quality and land availability is highly variable within the wind/CSP resource regions, a supply curve was developed. This supply curve is based on a GIS database to represent the cost of building transmission from the CSP resource in each region of each class to the existing grid, as

[13] SAM has a specific CSP module and an hourly simulation engine, which was used, along with the appropriate solar resource data, to develop capacity factors by time-slice for the specific ReEDS resource regions. See https://www.nrel.gov/analysis/sam/.

well as to local demand centers. Furthermore, in these supply curves, the availability of the existing grid was limited to 10% of the total carrying capacity of each transmission line.

2.1.3 Solar Photovoltaic

Utility-scale PV and distributed rooftop PV are considered in ReEDS. Distributed rooftop PV deployment and performance are exogenously input into ReEDS from the Solar Deployment Systems (SolarDS) model.[14] The focus of this section is solely on utility-scale PV. In the ReEDS model, utility-scale PV represents both large central PV plants and distributed wholesale PV plants.

Central PV in ReEDS represents utility-scale single-axis-tracking PV systems with a representative size of 100 MW. Performance characteristics for central PV were developed by SAM's PV module (NREL 2010a) using annual hourly weather files from the National Solar Radiation Database (NSRDB) for 939 sites throughout the contiguous United States from 1998 to 2005.[15] For each site, generation profiles were averaged across the eight-year time period. The site with the highest average annual PV capacity factor in each BA was used to represent the performance (i.e., capacity factor in each time-slice) of central PV capacity installed in that BA. A map of the resulting annual capacity factors for central PV by BA is shown in Figure 5. The annual PV capacity factors shown represent the average AC capacity factor after taking into account the AC-DC conversion. Capacity factors for all other technologies are based on AC-ratings.

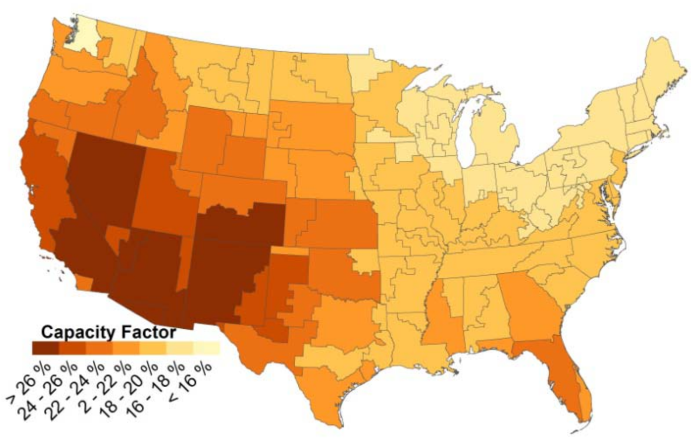

Figure 5. Regional capacity factor from central utility-scale PV

Source: NREL (2010a)

Distributed wholesale utility-scale PV in ReEDS represents utility-scale single-axis-tracking systems with a representative size of 1–20 MW and located within and directly connected to distribution networks. Capacity of these systems is limited to less than 15% of the distribution

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[14] The SolarDS model evaluates the market penetration of distributed rooftop solar PV technologies. See http://www.nrel.gov/docs/fy10osti/45832.pdf.

[15] See http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/.

network capacity.[16] Capital costs for distributed utility-scale PV are assumed to be 8.5% higher than central PV costs primarily due to the smaller system sizes.[17]

Similar to central PV, performance characteristics for distributed wholesale utility-scale PV were developed using SAM, except the performance in each BA was based on the average PV power output across all NSRDB sites within that BA. This methodology is different from central PV, which represented performance in each BA with the best performing NSRDB site in that BA. The reason for this difference in approach is that distributed wholesale PV is limited to distribution centers, and therefore, siting options are more limited than for central PV. Regional capacity factors for distributed wholesale PV are similar to central PV (Figure 5) but consequently reduced. ReEDS assumes all PV generated by distributed PV (both rooftop and distributed wholesale) systems is effectively consumed locally and without transmission and distribution (T&D) losses. For example, the power generated by distributed systems cannot be transmitted outside of the source BA.

2.1.4 Biopower

In ReEDS, there are two categories of power plants that rely at least in part on biomass fuel: dedicated biopower plants and plants that co-fire coal and biomass. Dedicated biopower plants are assumed to rely strictly on biomass feedstock for fuel. For biopower, ReEDS does not explicitly distinguish between direct combustion power plants and integrated gasification combined cycle plants. Instead, the cost and heat rate assumptions for new plants in a given year can be representative of a mix of plant types. ReEDS also includes the option to build new coal/biomass co-fired plants or to retrofit existing coal plants to co-fire biomass. In either case, a maximum of 15%, which can be adjusted by the user, of the electricity output is allowed to be derived from biomass fuel due to the boiler's engineering consideration. ReEDS does not include the option to completely "re-fuel" a coal plant or retrofit the pre-existing coal plant to fire 100% biomass fuel. Upon being retrofitted to co-fire biomass, a plant retains the same heat rate.

Figure 6 shows the annual supply curves for the biomass feedstock (Walsh et al. 2000) that has been disaggregated to the BA level (Milbrandt 2005). The available feedstock is divided into four cost bins with the following default prices: \$1.64/MMBtu, \$2.46/MMBtu, \$3.27/MMBtu, and \$4.09/MMBtu.[18] Though no price escalation is assumed by default, a user-defined annual price increase or decrease can be applied. The feedstock in the supply curve is comprised of urban and mill waste, forest and agriculture residues, and dedicated crops. Dedicated crops are predominantly in the two most costly bins of the supply curve. ReEDS does not currently treat competition for biomass feedstock between the electricity sector and other sectors (e.g., transportation), although the user-defined reduction in feedstock resource could be used to represent such competition.

[16] Distribution network capacity is tracked at the BA level in ReEDS.

[17] Distributed utility-scale PV does not incur grid interconnection costs.

[18] Unless otherwise noted, all dollars are in 2009 dollars.

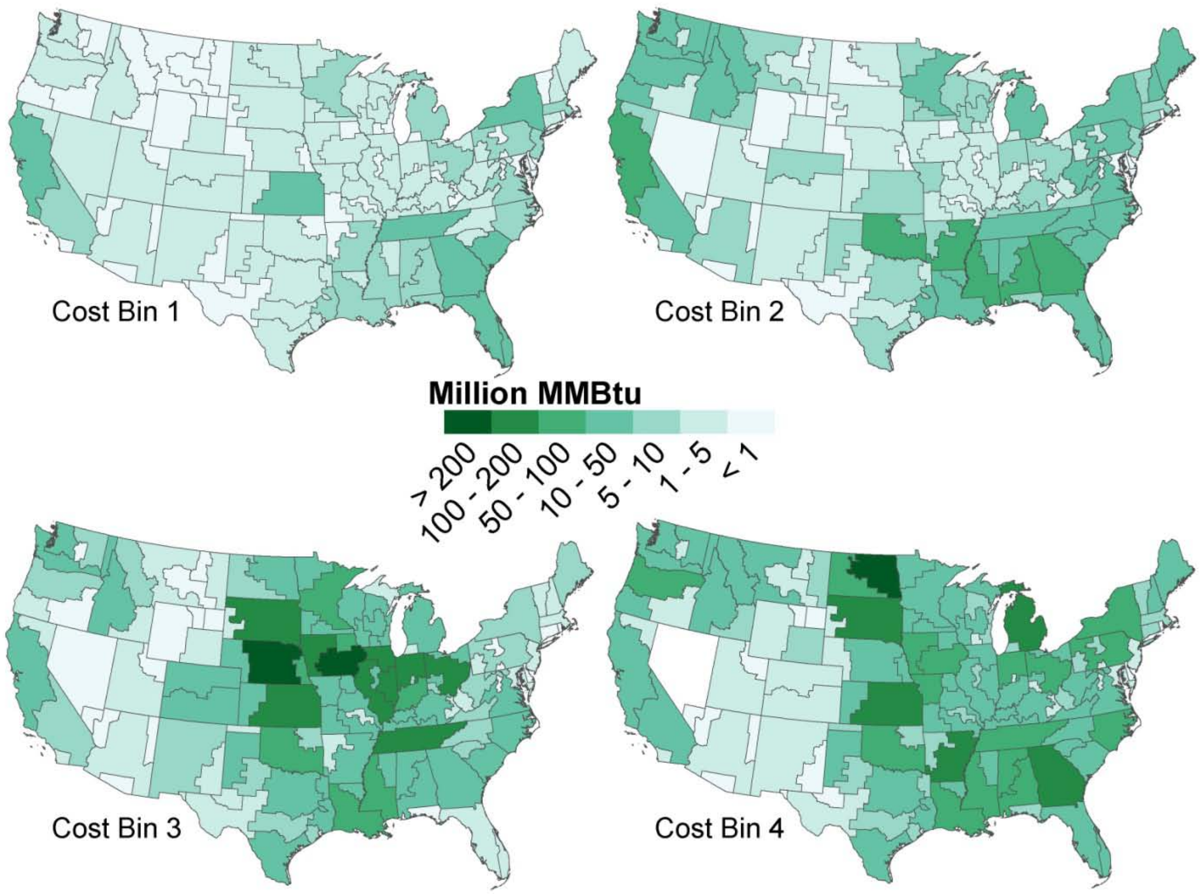

Figure 6. Biomass feedstock supply curve with default cost bins: $1.64/MMBtu, $2.46/MMBtu, $3.27/MMBtu, and $4.09/MMBtu

Source: Walsh et al. (2000)

2.1.5 Geothermal

ReEDS includes conventional geothermal power plants and enhanced geothermal system (EGS) power plants. The EGS category is further subdivided into near hydrothermal field EGS (near EGS) and deep hydrothermal field EGS (deep EGS). Figure 7 shows all geothermal resources represented in ReEDS, with most geothermal resources concentrated in the western part of the country (USGS 2008). In each BA, a capital cost supply curve is used to represent the available resource at a given cost. The BA-level supply curves were developed by aggregating site-specific resource assessments. Due to the wide range of geothermal resource quality between and within BAs, the range of capital costs for geothermal systems can be substantial. The total geothermal resource can also be adjusted to reflect estimates of "undiscovered" resource. The undiscovered resource is typically not included in normal ReEDS analysis.

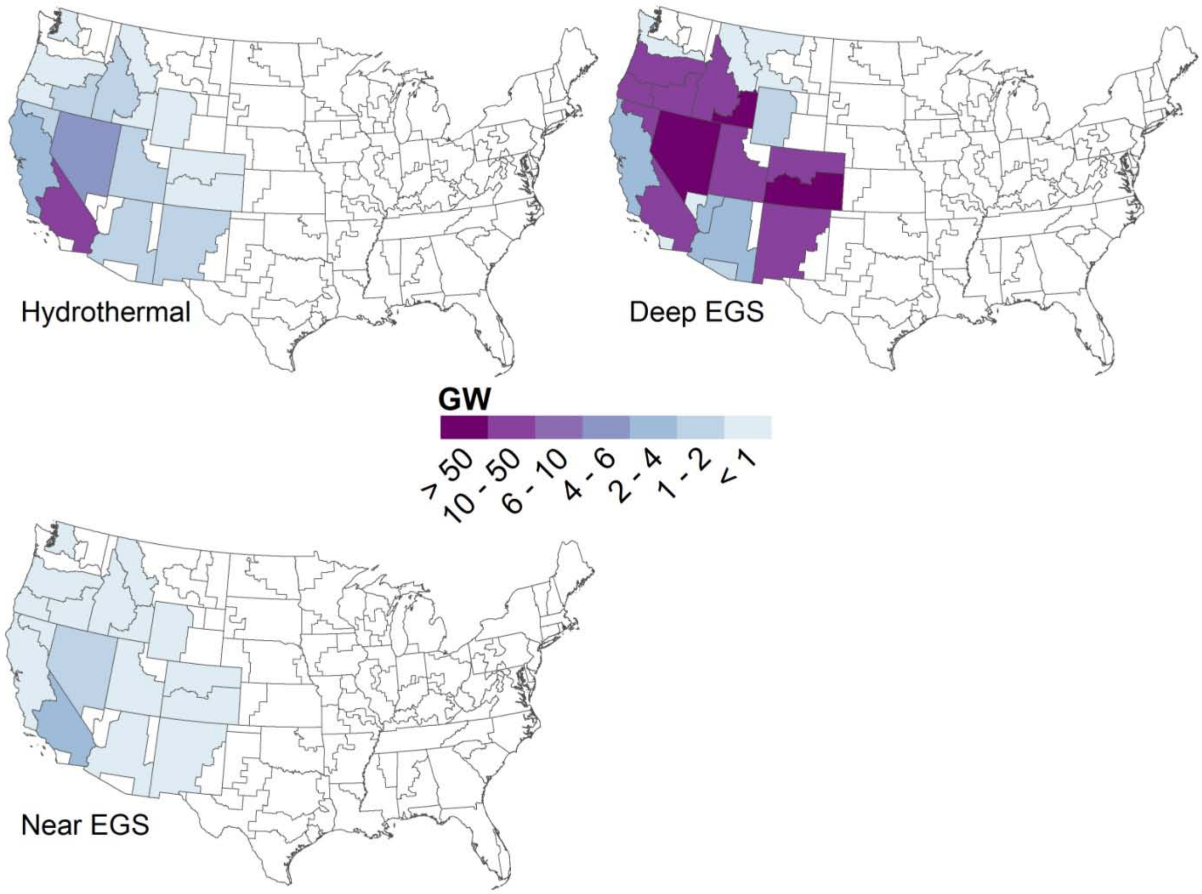

Figure 7. Hydrothermal and EGS geothermal resources

Source: USGS (2008)

2.1.6 Hydropower

Of all renewable resources, hydroelectric power currently comprises the largest share of the electricity sector in the continental United States with almost 80 GW of capacity online in 2010, excluding pumped hydropower storage. Figure 8 shows the distribution of this existing 80 GW among the ReEDS BAs and the annual capacity factor for the associated hydropower capacity in each BA. The BA-dependent annual capacity factors are estimated based on the average historical annual generation from 1990 to 2007 (Ventyx 2010). Existing hydropower capacity is modeled as reservoir hydropower, which can be optimally dispatched under seasonal energy constraints and minimum loading constraints. The associated annual capacity factor limitations are shown in Figure 9. Seasonal energy constraints in WECC are based on the GridView (Feng et al. 2002)[19] database, which was developed from WECC historical data of hydropower

[19] GridView is one of several commercially available utility simulation tools that combine security-constrained unit commitment, economic dispatch, and improved power flow to optimally dispatch a power plant fleet to provide reliable electricity at the lowest cost.

generation schedules. Seasonal energy constraints elsewhere are simply limited by the fractional amount of hours in a season relative to 8,760 hours in a year.

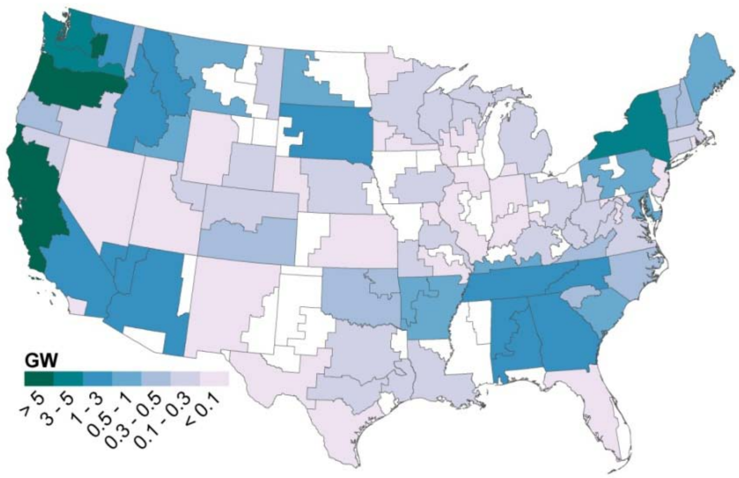

Figure 8. Hydropower capacity in 2010

Source: Ventyx (2010)

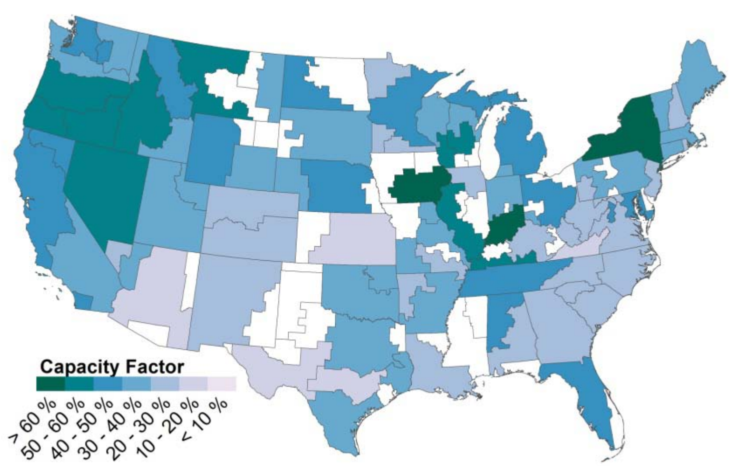

Figure 9. Average annual hydropower capacity factor for each BA

Source: Ventyx (2010)

Figure 10 shows the capital cost supply curve of potential new hydropower capacity based on a resource assessment study (INL 2006). Three cost bins of hydropower resource are considered. By default, hydropower resources in cost bins 1–3 have overnight capital costs of $3,500/kW,

$4,500/kW, and $5,500/kW, respectively, though other user-defined costs or changes in costs over time can be applied. The resource assessment only considered run-of-river resources, though due to unknown river flow conditions, new hydropower capacity is assumed to have constant output within a season. New hydropower capacity built in BAs with existing capacity abides by the same seasonal energy limitations as does the existing capacity. For example, new hydropower capacity in a BA with a capacity factor of 50% for the previously existing hydropower plants will also have the same capacity factor. For newly installed hydropower capacity located in BAs without any pre-existing capacity, the weighted average capacity factor of the neighboring BAs is used. As this new run-of-river hydropower capacity is modeled as non-dispatchable, new hydropower capacity cannot contribute to operating reserve requirements.

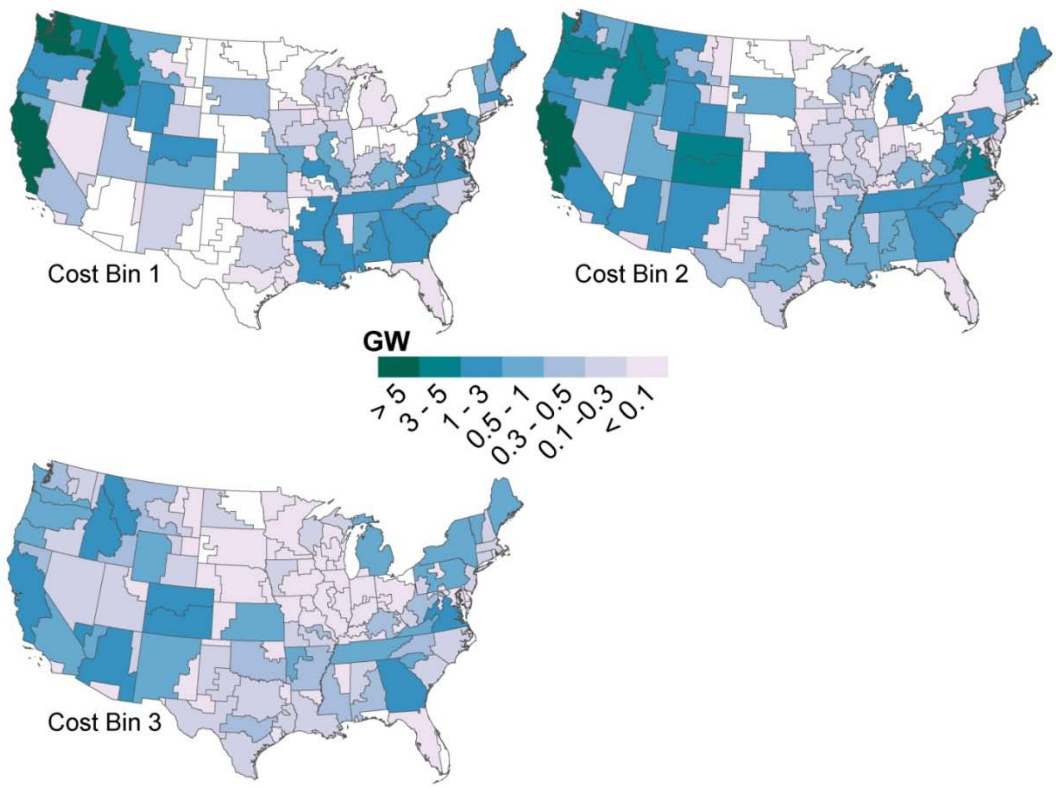

Figure 10. New hydropower supply curve with default cost bins of $3,500/kW, $4,500/kW, and $5,500/kW

Source: INL (2006)

Canadian electricity imports are also represented in the ReEDS model. Figure 11 shows the net import of electricity from each Canadian province and the continental United States projected over the next 10 years (NEB 2009). For all years after 2020, the imports are assumed fixed at the 2020 levels. The destination of the imported electricity is assumed to be the adjacent BA(s) of each province if existing transmission lines are present. Although the imported electricity from Canada is dominated by hydropower, other technologies, such as wind and nuclear, also contribute. The exact fraction of hydroelectric (or renewable) power is difficult to track, in part due to power exchanges between provinces. Therefore, all imported electricity is assumed to be renewable and counted under the hydropower category. The dispatch of the imported electricity is assumed to have a fixed schedule (EnerNex 2010).

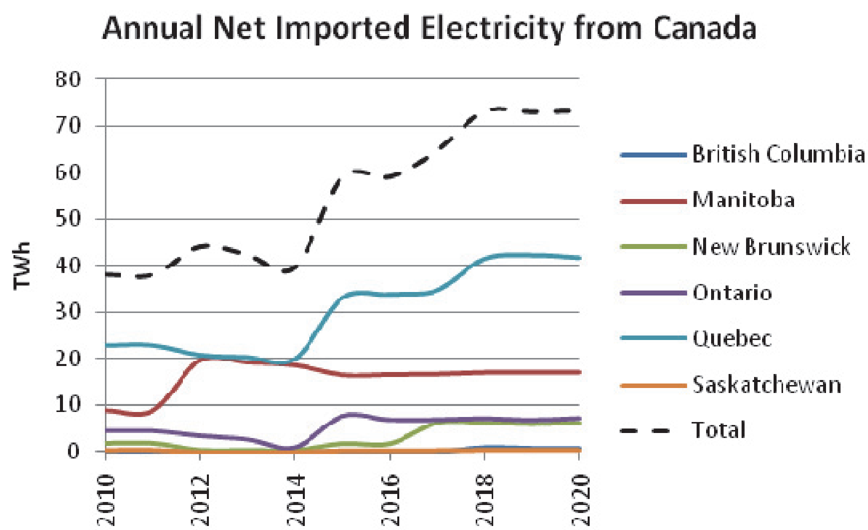

Figure 11. Net electricity imports from Canada

Source: NEB (2009)

2.1.7 Retirements for Renewable Energy Technologies

Renewable generation technologies are assumed to retire based on technology-specific lifetimes.[20] After retirement, the capacity is assumed to be automatically replaced with the appropriate capital cost incurred at that time.[21] Grid interconnection costs are not applied, as the previous interconnection is assumed to suffice.

2.2 Conventional Generation Technologies

Available generator types are based on the most predominant technology types as determined by the U.S. Department of Energy's EIA (EIA 2006). The generator types are as follows:

- **Hydro**. Conventional hydropower, hydraulic turbine
- **Gas-CT**. Natural gas combustion turbine
- **Gas-CC**. Combined cycle gas turbine
- **Gas-CCS**. Combined cycle gas turbine with CCS
- **CoalOldUns**. Conventional pulverized coal steam plant (no SO_2 scrubber)
- **CoalOldScr**. Conventional pulverized coal steam plant (with SO_2 scrubber)
- **CofireOld**. Conventional pulverized coal steam plant (with SO_2 scrubber and biomass co-firing)

[20] Table 12 in Section 6.2 lists assumed plant lifetimes.

[21] The retirement criteria for renewable generation technologies are conservative as it is unlikely that the entire plant will need to be rebuilt from scratch after the technical lifetime of the plant.

- **CoalNew**. Advanced super critical coal steam plant (with SO_2 and NO_x controls)
- **CofireNew**. Advanced super critical coal steam plant (with biomass co-firing)
- **Coal-IGCC**. IGCC coal
- **Coal-CCS**. IGCC with CCS
- **OGS**. Oil/gas steam turbine
- **Nuclear**. Nuclear plant
- **MSW/LFG**. Municipal solid waste/landfill gas plant.

2.2.1 Conventional Technology Performance Considerations

The fleet of existing power plants used to create the model for the 2006 start is identified based on the EIA database and the EIA 860 *Annual Electric Generator Report* (EIA 2006). Conventional generating capacity is aggregated by technology type within each BA, so individual-plant characteristics—such as start up, shutdown, and heat rate curves—cannot be included directly.

The existing pulverized coal fleet is divided based on age, with those plants that began operation after 1990 being considered "CoalNew." Older coal plants are treated separately from new plants due to their higher operating costs and heat rates and are further subdivided into those with a SO_2 scrubber and those without,[22] although unscrubbed plants have the option of being retrofitted with a scrubber. Coal plants also have the option of purchasing low-sulfur coal at a premium. In addition, coal plants have the option of upgrading to allow for the co-firing of biomass. The co-fired portion cannot exceed 15% of total generation. Finally, a select group of scrubbed coal plants are eligible to upgrade to CCS with a capacity reduction and heat rate penalty. The eligible capacity in each BA is exogenous: generators were selected based on plant size and heat rate (EIA 2011b).

There are some restrictions on future investments in generating capacity: new coal plants must be either supercritical or gasified, and carbon capture, nuclear, and storage technologies (coal or gas) may not be installed until 2020.[23] ReEDS does not allow new municipal solid waste/landfill gas plant or oil/gas steam turbine installations.

Many conventional technologies in ReEDS are dispatchable but must pay a penalty for ramping significantly and must abide by minimum plant-loading requirements, which specify the minimum level of output of plants that are operating in each season. Forced outage rates represent unplanned outage events and planned outage rates represent planned maintenance events, the latter of which are assumed to occur only during non-summer months. Together, the outage rates define a plant's availability, but capacity factor is an output of the model because the optimum solution may require a plant to operate below this maximum availability.

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[22] As indicated in Table 2, ReEDS ensures that SO_2 standards are enforced per current legislation. ReEDS also offers a retrofit option to install an SO_2 scrubber as well as to co-fire biomass for coal power plants.
[23] Planned additions of these technologies (e.g., nuclear) can be built before 2020, but these plants are exogenously inputted based on user references.

With a few exceptions, new conventional plants can be built in any BA. Regional cost multipliers are applied to the new capacity to account for the regional differences in labor rates, outdoor installations, seismic specifications, and other regional cost differences. Regional heat rate adjustments are also applied to all Brayton cycle conventional plants (e.g., combined cycle gas turbine and natural gas combustion turbine) to account for regional air density, humidity, and ambient temperature differences.

2.2.2 Retirements of Conventional Technologies

Assumptions about the retirement of conventional-generating units can have considerable cost implications. Considerations that go into the decision-making process on whether or not an individual plant should be retired involve a number of factors, specifically the economics of plant O&M. Projecting these economic considerations into the future given the uncertainties involved is beyond the scope of ReEDS, and instead ReEDS uses the following three retirement options that are not strictly economic:

- **Scheduled lifetimes for existing coal, gas, and oil**. These retirements are based on lifetime estimate data for power plants from Ventyx (2010). Near-term retirements are based on the officially reported retirement date as reported by EIA 860, EIA 411, or Ventyx unit research (Ventyx 2010). If there is no officially reported retirement date, a lifetime based retirement is estimated based on the unit's commercial online date and the following lifetimes:
    - Coal units (< 100 MW) = 65 years
    - Coal units (> 100 MW) = 75 years
    - Natural gas combined cycle unit = 55 years
    - Oil-gas-steam unit = 55 years
- **Usage-based retirements of coal**. In addition to scheduled retirements, coal technologies, including co-fired coal with biomass, can retire based on proxies for economic considerations. Any capacity that remains unused for energy generation or operating reserves for four consecutive years is assumed to retire. Coal capacity is also retired by requiring a minimum annual capacity factor; after every two-year investment period, if a coal unit has a capacity factor of less than this minimum capacity factor during the two-year period, an amount of coal capacity is retired such that the capacity factor increases to this minimum threshold. The threshold capacity factor is user-defined and can change over time. Coal plants are not retired under this algorithm until after 2020.
- **Scheduled nuclear license-based retirements**. Nuclear power plants are retired based on the age of the plant. Under default assumptions, older nuclear plants that are online before 1980 are assumed to retire after 60 years (one re-licensing renewal), whereas newer plants (online during or after 1980) are assumed to retire after 80 years (two re-licensing renewals). Other options can be implemented, such as assuming 60- or 80-year lifetimes for all nuclear plants.

2.3 Storage and Demand-Side Technologies

2.3.1 Electricity Storage Systems

ReEDS considers three utility-scale energy storage options: pumped-hydropower storage (PHS), batteries, and compressed air energy storage (CAES). All three storage options are capable of load shifting (arbitrage), providing planning and operating reserves, and reducing curtailment of VRRE. Load shifting capability is modeled in ReEDS as a balance in energy within each typical day of a season, which is represented by four time-slices per season. Installed storage capacity contributes fully to planning and operating reserves. For the latter, CAES can only contribute as quick-start (non-spinning) reserves (see Section 4 on how reserves are differentiated in ReEDS), whereas PHS and batteries can contribute to all operating reserves.

Although storage is not directly linked or co-located with renewable energy technologies in ReEDS, it plays an important role in reducing curtailed electricity from variable generation resources. In ReEDS, storage capacity is considered in the statistical calculation of curtailment. The contribution of storage in reducing curtailment in these statistical calculations was calibrated using the REFlex model (Denholm et al. 2010). ReEDS does not have sufficient temporal resolution to explicitly track the energy, or megawatt-hours, stored in a storage device across time. The curtailment calculation in ReEDS does, however, take into account the finite energy storage assumed (8 hours for PHS and batteries, 15 hours for CAES reservoirs).

PHS and CAES are location-restricted due to hydrology and topography (for PHS) and geology (for CAES). In contrast, utility-scale batteries are not restricted to any subset of regions. Figure 12 shows the existing pumped-storage hydropower capacity distribution across the contiguous United States as represented in ReEDS, while Figure 13 shows potential new PHS resource sites identified in the Federal Energy Regulatory Commission (FERC) licensing process (FERC 2010). The default assumption is that new PHS capacity overnight capital costs range from \$1,500/kW to \$2,000/kW. Figure 14 shows the new CAES resource supply curve represented in the model. The resource quality is estimated based on the underground geology, where domal salt is the least costly resource at \$900/kW, bedded salt is the next most costly resource at \$1,050/kW, and aquifers (porous rock) are the most costly resource at \$1,200/kW (Black and Veatch 2011). The cost values presented here are the default values used, although different user-defined costs can be applied.

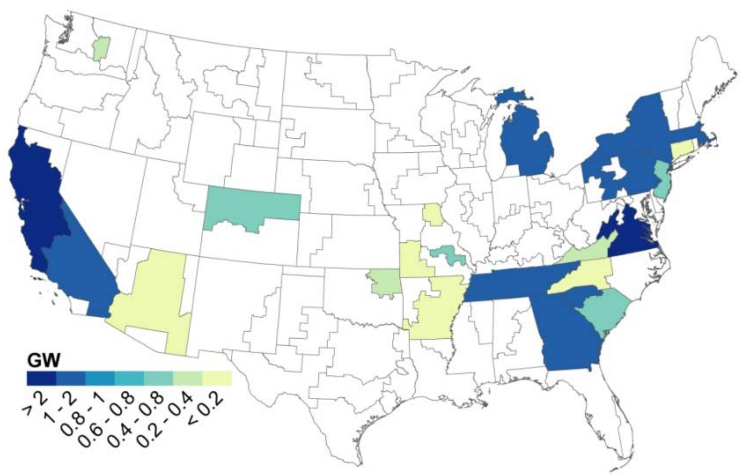

Figure 12. Storage capacity for existing pumped hydropower storage

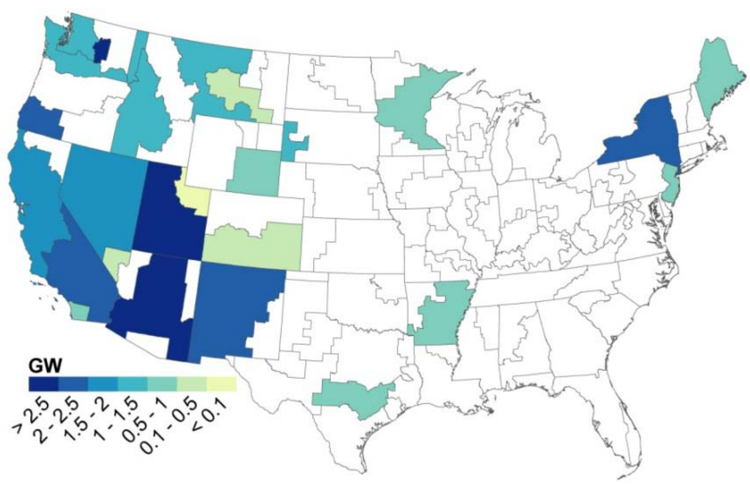

Figure 13. Potential resource for future pumped hydropower storage

Source: FERC (2010)

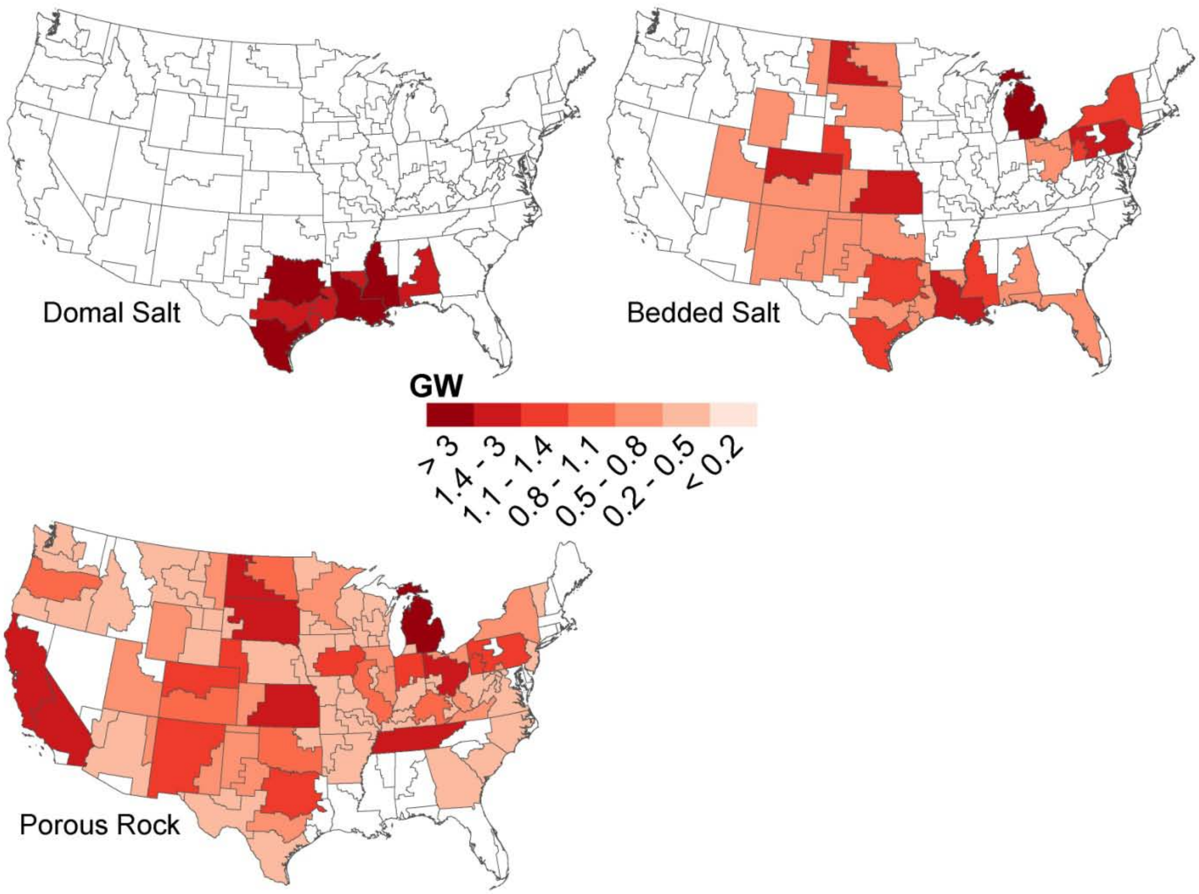

Figure 14. Resources for compressed air energy storage

2.3.2 Thermal Energy Storage in Buildings

Thermal energy storage (TES) represents chilled water and ice storage units in buildings, where cold water or ice is produced during cooler hours when loads are lower in the summer and used to replace or supplement the air conditioning during the warmer hours. Only units for commercial buildings are considered. A supply curve for TES units was developed at the NERC subregion level.

In the ReEDS model, use of TES devices is restricted by the regional cooling load profile. In particular, the power delivered by a TES device is assumed to be available only during times of high cooling load (e.g., summer afternoons). TES technologies can contribute to operating and planning reserves and reduce curtailment.

2.3.3 Interruptible Load

Interruptible load represents the load that utilities can control under conditions set forth by contracts between the utility and a demand entity. In ReEDS, interruptible load can only be used to satisfy operating reserve requirements and can only be counted towards contingency and forecast-error reserve requirements. Interruptible load is not counted toward frequency regulation reserve requirements. Due to the coarse time-slices of the ReEDS model, the frequency with which interruptible load (and any other reserve services) is called upon is unknown. For each

NERC subregion, interruptible load is represented by a supply curve that presents the annual cost of interruptible capacity as a function of the capacity used.

2.3.4 Plug-In Electric and Hybrid Vehicles

Because ReEDS does not include vehicle choice or transportation sector modeling, the deployment of plug-in electric vehicles (EVs) or plug-in hybrid electric vehicles (PHEVs) is input into ReEDS. The number of plug-in vehicles is simply translated in the model into additional annual demand for electricity. This annual demand can be met through a fixed charging profile over the 17 time-slices within a year in ReEDS, through an endogenously determined dynamic profile, or through some combination of the two. The endogenous profile is driven by the net load and dispatchable and non-dispatchable resources available within each time-slice of ReEDS.

The ReEDS model does not consider vehicle-to-grid or reserve services from vehicles. Plug-in vehicles cannot be used to meet the planning reserve requirements, and, in fact, generally increase the reserve requirements through increasing peak demand. Likewise, these vehicles cannot contribute to meeting operating reserve requirements. However, dynamically charged plug-in vehicles are allowed one operational benefit in ReEDS—adjusting load to better match generation profiles.

3 Transmission

3.1 General Treatment of Transmission

Transmission is an important component of the electric sector because transmission constraints and limitations influence where power plants are built and determine what power plants operate at what times. The interconnectedness and absence of flow control on the network makes the work of constantly balancing generation and load across large areas quite complicated. Since transmission constraints have substantial impacts on power-system economics for both investment and dispatch, it is important to represent those limitations in models of the electric sector.

ReEDS uses a reduced network with 134 nodes (center-to-center of ReEDS BAs) and roughly 300 aggregate lines that connect contiguous BAs, shown in Figure 15. Each line has a nominal carrying capacity limit determined for the start-year (2006) based on power-flow analysis using ABB's GridView model and NERC reported limits (NERC 2010). In later years, ReEDS is able to build additional capacity to increase these carrying capacities. Transmission expansion is limited before 2020 to lines for which new construction is already planned (Edison Electric Institute 2010). After 2020, that limitation is dropped. ReEDS considers transmission flow limits when dispatching generation in each of the 17 time-slices and in planning firm transmission capacity contracts between reserve-sharing groups. In all cases, the transmission capacity required to carry variable-resource generation from wind and PV is assumed to be the nameplate capacity of the wind and PV.

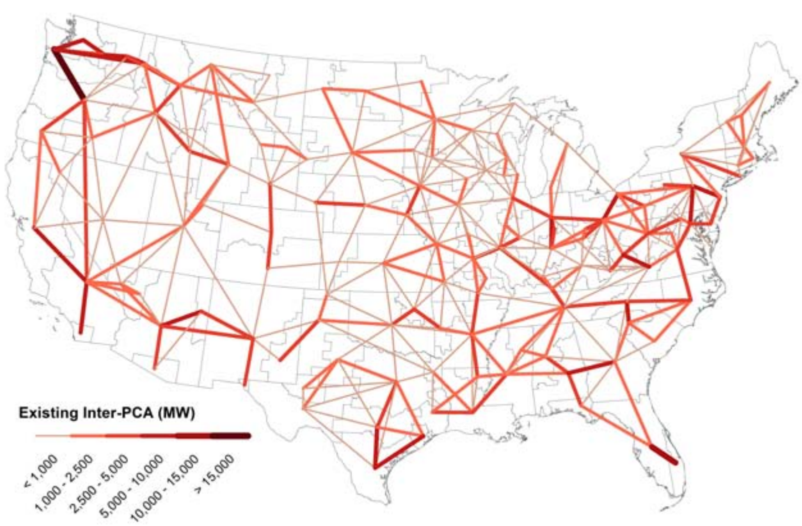

Figure 15. Existing long-distance transmission infrastructure as represented in ReEDS

ReEDS does not address AC-power-flow issues of voltage, frequency, or phase angle. Intra-BA transmission and distribution networks are similarly ignored, effectively assuming away transmission congestion within each region.

Transmission power losses are characterized by a factor of 1%/100 miles. Distribution losses are not considered endogenously in ReEDS; they are estimated at 5.3% of end-use demand and do not apply to distributed utility-scale and rooftop PV, as these technologies are assumed to be located within distribution networks.

Grid interconnection costs are applied to most generation and storage technologies upon construction. Since CSP and wind resource quality depends heavily on location, supply curves for each wind/CSP resource region (of which there are 356) in the United States were developed to account for the additional transmission line construction for connecting these resources to the grid as well as to local demand centers. These supply curves are explained in Sections 2.1.1 and 2.1.2.

ReEDS compromises between the complexity necessary to represent all aspects of transmission constraints and the effect of that complexity on the tractability of the model. ReEDS users can select between two transmission representations, truck-route and power-flow.

3.1.1 Truck Route

In the truck-route model, flow on each line in each time-slice is determined by a simple energy balance equation at each BA with net injections (generation minus load in the BA) balanced against net exports (exports minus imports). The flow along each line is a decision variable, and thus, exports and imports are determined by flow on each line connected to a BA. Flow on each aggregated line in each time-slice is only limited by the carrying capacity of the line. Through these flow limits, the method constrains the model's dispatch choices, but it ignores Kirchoff's voltage law that dictates that power will flow along the path of least impedance; that is, in reality, electricity injected at one node will slightly change the flow on even the most remote, but network-connected line, not simply on the line to the nearest node that could use the electricity. Thus, this model is, in general, less demanding of the transmission system and underestimates the requirement for new transmission capacity.

3.1.2 Power Flow

The power-flow version, on the other hand, does not assume that flow can be controlled to move directly from source to sink. The power-flow model is a linear approximation of DC power flow using a power-transfer distribution factor (PTDF) matrix to distribute flows across the network. It is more computationally complex than the truck-route model but also more realistic. The PTDF matrix approximates how transfers among regions are distributed. As in a real power system, the flows are all interdependent and determined by the topology of the network: the generators, loads, and lines. Changing the pattern of generation affects the flows on all lines in the interconnect.

Power flows are determined entirely by the net injections (generation minus load) at each node, or BA, and the PTDF matrix. If two BAs transfer power, the decision variables involved are the net injections/withdrawals at the two nodes. The flows are not decision variables but are simply calculated by multiplying the PTDF matrix (dimensions: lines x nodes) by the net-injection vector (nodes). As in the truck-route method, the flows must not exceed the carrying capacity of the lines. ReEDS can choose to build additional transmission capacity on the network to reduce congestion. Such additional capacity will modify the impedances in the network and, thus, change the PTDF matrix.[24]

The truck-route and power-flow versions both include AC-DC-AC interties that join the interconnects and the long-distance, high-voltage DC lines that connect, for example, the hydropower capacity of the Pacific Northwest to the loads of southern California. Such lines are always treated in the truck-route manner, with decision variables able to control flows on those lines independently of other lines. Therefore, they are indistinguishable from the rest of the network in the truck-route version but treated differently in the power-flow version. In the power-flow version, the net injections at BAs with AC-DC-AC interties are modified to subtract net exports across the intertie.

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[24] While an algorithm exists for modifying the PTDF matrix between each two-year linear program optimization of ReEDS, it has not yet been fully implemented. See Section 8.1 for more information on the formulation of the PTDF matrix.

4 Reserves

VRRE technologies, which include wind, CSP without storage, utility-scale PV, and distributed PV, produce power that is both variable and uncertain. Generally, greater penetrations of these technologies lead to greater levels of curtailment, required operating reserves, and a diminished contribution to planning reserve requirements per unit of VRRE capacity. The definitions of the reserve requirements and the statistical treatment of VRRE in relation to these requirements and curtailment are described in the following subsections.

In ReEDS, the variability of each VRRE technology is characterized using simulated hourly power output data, as described in Section 2.1. The hourly data was used to calculate the standard deviation of power output for each VRRE technology in each of the ReEDS time-slices. The standard deviation was used to characterize variability of individual technologies, but reserve-sharing entities (in ReEDS, the 21 reserve-sharing groups shown in Figure 2) are more concerned with the aggregate variability of all demand and generation on the system. To better capture aggregate variability, correlation statistics were also calculated between the power outputs of geographically separated wind, CSP, and PV plants. In general, greater geographic distance between two CSP, PV, or wind plants leads to a lower degree of correlation between power outputs, which decreases the variability of their combined generation. Because of this, and with all else being equal, ReEDS will choose to separate generators of a given type to reduce variability of the output.

The standard deviations and correlation statistics, along with the capacity factors for each VRRE technology in each time-slice, were used in calculations of curtailment, capacity value, and operating reserve requirements, as described in the following subsections.

4.1 Planning Reserves and Capacity Value

Planning reserve requirements ensure that adequate generating capacity is available at all times. In practice, this is enforced by requiring the system to have sufficient capacity to meet the forecasted peak demand plus a reserve margin. The capacity credit given to each technology to meet the reserve is calculated for each period in ReEDS before the linear program optimization is conducted for that period. This includes a marginal value, which applies to potential new installations in the period, and an old value, which applies to all the capacity built in previous periods.

All dispatchable generator types, including CSP systems with storage, count their full (nameplate) capacity toward the planning reserve requirement. For VRRE technologies—wind, PV, and CSP without storage—however, the contribution is less than nameplate due to the inability to control dispatch and the uncertainty of output. The fraction of capacity that can be reliably counted toward the planning reserve requirement is referred to as the capacity value of the plant. To determine the capacity value associated with a VRRE technology, a statistical effective load carrying capability (ELCC) calculation is performed in ReEDS between every two-year optimization period. The ELCC is calculated for both existing VRRE capacity and potential new capacity. The ELCC is defined as the amount of electrical demand that may be added in each time-slice for an incremental increase in capacity of a given VRRE technology without increasing the loss of load probability.[25] To perform the ELCC calculation, it is assumed that the annual capacity factors for variable renewable technologies (e.g., annual wind capacity factor) do not change from year to year.

4.2 Operating Reserves

In addition to ensuring adequate capacity to satisfy long-term planning reserve requirements, ReEDS requires adequate operating reserve capacity to meet daily operating reserve requirements. Operating reserve requirements ensure that there is sufficient flexibility from supply-side and demand-side technologies to balance generation and demand at all times. For ancillary services below the 4–8 hour resolution of ReEDS time-slices, ReEDS assumes statistically-computed operating reserve requirements for load and variable supply and requires that capacity with adequate flexibility is available to handle such events.[26] All operating reserves requirements must be satisfied in each reserve-sharing group in all time-slices.

The flexibility of generators and storage technologies depend on the ability of the plant to change its output and the time scales necessary to do so. Given start-up times and ramp rates, different technologies are classified to be able to offer varying amounts of spinning or quick-start reserves. Spinning reserves can be provided by generation and storage technologies that are currently operating below maximum capacity. The amount of capacity that may be counted toward the requirements depends on the amount that can be ramped up quickly (e.g., in less than 10 minutes). Quick-start reserves can be provided by technologies that can start generating power quickly (e.g., in less than 10 minutes) from a cold state. For example, natural gas combustion turbines can provide quick-start reserves. In addition, demand-side interruptible load can also contribute to reserve requirements.

The following operating reserve requirements are considered in ReEDS:

- **Contingency reserve requirements**. These requirements ensure that an unanticipated change to the operational status of generators or transmission lines, for example, due to unforeseen outages, will not cause an extended disruption to electricity end users. In ReEDS, the contingency reserve requirement is set at 6% of demand in each time-slice. At least half of this requirement must be met with spinning reserves or interruptible load whereas the other half can be met by quick-start units. The relevant time scale for contingency events is about 10 minutes.
- **Frequency regulation reserve requirements**. These requirements ensure that sub-minute deviations between demand and generation can be minimized. Due to the short time scales involved, only spinning reserves can satisfy the frequency regulation requirements. In ReEDS, this requirement is set at 1.5% of average demand in each time-slice.

[25] Additional information on the statistical calculations of the capacity value can be found in Section 7.6.

[26] Additional information on the statistical calculations of the operating reserve requirements can be found in Section 7.6.

- **VRRE forecast error reserve requirements**. These requirements ensure stability of the system despite uncertainties in forecasting for wind and PV.[27] Generally, forecast error reserve requirements increase as wind and PV penetration grows. The forecast error reserve requirements for wind and PV in ReEDS are assumed to be two standard deviations (Zavadil et al. 2004) of their respective aggregate forecast errors in each reserve-sharing group. The reserve requirements are held constant throughout the year. Forecasts for wind are assumed to be simple hourly persistence forecasts, based on simulated wind power output data (EnerNex 2010; GE 2010) for each wind resource class of each ReEDS region. In other words, wind forecast errors are simply the differences between simulated power output from one hour to the next. PV forecasts for a given hour are modified persistence forecasts, using the output from the previous hour as well as the average change between those two hours over the previous 15 days to account for the known apparent daily solar trajectory. Because forecast errors occur over longer timescales (roughly an hour) than contingency or frequency regulation events, ReEDS assumes that up to 5/6 of the requirement can be met by quick-start units, and the remainder must be met by a combination of spinning reserves and interruptible load.

4.3 Curtailment of Variable Generation

The major focus of planning and operating reserves is to ensure that there is adequate capacity to accommodate drops in generation or spikes in demand. On the other hand, there are times when generation, if not curtailed, could exceed demand. Generation must match load at all times, neither falling short nor surpassing. Demand is met through a combination of conventional power generators, dispatchable renewable generators, VRRE generators, storage, and power transfers among BAs. However, due to the inherent variability of certain renewables, variability of the load, transmission constraints, and the inflexibility of some generators (e.g., minimum loading requirements for conventional plants), generated power can sometimes exceed demand, and the excess must be non-economically curtailed to maintain reliability.

For each two-year time period, ReEDS estimates expected levels of curtailment associated with marginal additions of VRRE technologies from each resource region to each consuming reserve-sharing group for each time-slice through a statistical expected value calculation.[28] This calculation depends on the probability distributions of electrical demand and VRRE electrical output serving the reserve-sharing group, minimum loading requirements of other generators, and the amount of electrical storage.

[27] CSP without storage is considered to have enough thermal inertia (about 30 minutes) not to require additional operating reserves.

[28] Additional information on the statistical calculations of the curtailment of variable generation can be found in Section 7.6.

5 Cost Output

Two system-wide cost metrics are calculated from each ReEDS run: a present value of direct electric sector system costs and a national-average retail electricity price. These cost calculations are not part of the ReEDS optimization process; they are calculated after the ReEDS optimizations have been conducted. The direct electric sector costs, which are described in Section 5.1, represent the present value cost of building and operating the system over the scenario horizon (e.g., 2010–2050). The methodology to calculate electricity prices is described in Section 5.2.

5.1 Direct Electric Sector Costs

The following equations are used to calculate the present value cost of building and operating the system from 2010 to 2050. The cost in each future year is discounted by a social discount rate.[29] In the following equations, *a* represents the present value cost to operate the system during the entire 40-year analysis period. This cost includes fixed and variable O&M costs and fuel costs. The second term, *b*, represents the cost of new investments made before the last 20 years of the model horizon. The third term, *c*, represents the cost of new investments from the last 20 years of the model horizon. For investments that will clearly last beyond the end of the model horizon, the cost is reduced by the weighting factor at the end of the summation in *c*.

$$PVcosts_{2010-2050} = a + b + c\ ;$$

$$a = \sum_{t=2010}^{2050} (\text{Fixed O\&M} + \text{Var O\&M} + \text{Fuel})_t \cdot \frac{1}{(1+\mathrm{d})^{t-2010}}$$

$$b = \sum_{t=2010}^{2030} (\text{New Capacity} + \text{New Transmission})_t \cdot \frac{1}{(1+\mathrm{d})^{t-2010}}$$

$$\mathrm{c} = \sum_{\mathrm{t}=2031}^{2050} (\text{New Capacity} + \text{New Transmission})_{\mathrm{t}} \cdot \frac{1}{(1+\mathrm{d})^{\mathrm{t}-2010}} \cdot \frac{1 - \frac{1}{(1+\mathrm{d})^{2051-\mathrm{t}}}}{1 - \frac{1}{(1+\mathrm{d})^{20}}}$$

“New capacity” in *b* and *c* includes the capital cost[30] for new generation and storage capacity installed in each year. Grid interconnection costs for new generators are also included. New generation capacity includes “rebuilding” costs of renewable generation after the physical lifetime of the plants. ReEDS does not consider the replacement of existing or new transmission infrastructure.

[29] The discount rate (real) used here represents the social discount rate and is not the same as the discount rate used in the investment decisions within the optimization.

[30] The capital costs are not overnight capital costs; the costs accounted for by the financial multipliers described in Section 1.4 are considered here. ITCs are excluded from the direct electric sector costs as they are simply transfer payments.

5.2 Electricity Price Calculation

ReEDS also calculates a national average electricity price. The electricity price calculation assumes a regulated market structure with a 30-year rate base or amortization of all investments to 30 equal annual payments. Investments include investments for new and replacement of generation capacity and for new transmission lines.

$$Investment_t = (New\ Capacity + New\ Transmission)_t$$

$$\begin{aligned} RateBase_t = {} & RateBase_{t-1} \\ & - \frac{1}{30}\left(RateBase_{2006}(if\ t \leq 2036) + \sum_{s=max(2006,t-29)}^{t} Investment_s\right) \\ & + Investment_t \end{aligned}$$

The wholesale electricity price is based on costs associated with the rate base, O&M costs, fuel costs, and other annual costs (e.g., interruptible load contracts). The costs associated with the rate base include the annual payments owed and the "interest," which is based on the discount rate, *disc*, corresponding to the investment discount rate.

$$\begin{aligned} & Rate\ Base\ Costs_t \\ & = RateBase_t \cdot disc + \frac{1}{30}\left(RateBase_{2006} * \left(1 - \frac{t-2006}{30}\right)(if\ t \leq 2036)\right) \\ & + \frac{1}{30}\left(\sum_{s=\max(2006,t-29)}^{t} Investment_s\right) \end{aligned}$$

$$Wholesale\ Electricity\ Price_t = \frac{(Rate\ Base\ Costs + Fixed\ O\&M + Var\ O\&M + Fuel + Other\ Costs)_t}{Annual\ End\ Use\ Demand_t}$$

In addition to the wholesale cost of power, the retail price of electricity must cover distribution costs as well as general administrative costs for the utility (e.g., billing, facilities, and management). These additional costs are not estimated directly in ReEDS. Instead the markup from wholesale to retail electricity price is based on calibration with historical 2006 prices. More specifically, ReEDS calculates the wholesale electricity price in 2006 (the start year of the model), and the difference between this model-calculated wholesale price and the historical retail price is used to markup the wholesale electricity price in all subsequent years.[31]

There is also another methodology within ReEDS to calculate the "competitive" instead of the regulated (i.e., "cost of service") wholesale electricity price. The calculation takes advantage of the linear programming formulation of the model. The constraints within ReEDS are written

[31] Since all prices are in real dollars, this assumption of a constant markup implicitly assumes that all costs beyond generation and transmission will grow at the same rate as inflation.

such that the marginal off of the load constraint can be used as a proxy for the competitive electricity price. The load constraint is linked though generation variables to the capacity constraints and operating reserve constraints. Taking the marginal off the linked load constraint we can find the marginal value of an additional unit of load (e.g., MWh) to the system taking into account the additional energy, capacity, and operating reserves required. It is assumed that this methodology mimics a competitive electricity market's behavior better than the regulated electricity price discussed above. The user has the choice to use the competitive, regulated, or a blending of the two prices to calculate the national or regional electricity prices.

6 ReEDS Standard Inputs and Assumptions

There are a number of assumptions and inputs used in the ReEDS model. Included are technology cost and performance projections, financial assumptions, baseline policy inputs, and load and fuel price projections.

6.1 Technology Cost and Performance Projections

Many organizations and companies, such as Black & Veatch and RW Beck, develop technology costs and performance values for the generating and storage technologies modeled in ReEDS (Black and Veatch 2011; EIA 2010). The results are sensitive to these technology cost assumptions. Each technology cost and performance set is different and presents an alternative view on the expected performance improvements due to research and development (R&D), learning, normal evolutionary development, and other considerations. ReEDS has the ability to improve the cost and performance values of a technology endogenously through "learning by doing."

6.1.1 Renewable Technologies

The technology cost and performance assumptions for renewable technologies include the following information if applicable to the technology[32]:

- Year
- Base overnight capital cost ($/kW)
- Variable O&M cost ($/MWh)
- Fixed O&M cost ($/kW-Yr)
- Heat rate (Btu/kWh)

6.1.2 Conventional Generating Technologies

The technology cost and performance assumption for conventional generating technologies include the following information if applicable to the technology[33]:

- Year
- Base overnight capital cost ($/kW)
- Variable O&M cost ($/MWh)
- Fixed O&M cost ($/kW-Yr)
- Heat rate (Btu/kWh)

[32] For examples of specific cost and performance values, see the cost specific reports from Black & Veatch (Black and Veatch 2011) and RW Beck (EIA 2010).

[33] For examples of specific cost and performance values, see the cost specific reports from Black and Veatch (Black and Veatch 2011) and RW Beck (EIA 2010).

6.1.3 Electricity Storage and Demand-Side Systems

The technology cost and performance assumption for electricity storage technologies include the following information, if applicable to the technology[34]:

- Year
- Base overnight capital cost ($/kW)
- Variable O&M cost ($/MWh)
- Fixed O&M cost ($/kW-Yr)
- Round-trip efficiency (%)
- Heat rate (Btu/kWh)

Interruptible load is represented by supply curves, as shown in Table 5. Variations in availability of interruptible load for a given year reflect the ranges between NERC subregions. In addition, for each NERC subregion, a supply curve is developed to represent the range in costs. For example, in 2030 the first megawatt costs $3.36/kW in the NERC subregion with the most abundant interruptible load resource (e.g., 17% of peak demand), whereas the last megawatt of available interruptible load costs over 10 times as much. The interruptible supply curves are based on a resource assessment by FERC (2009) and cost data from EIA (2009).

Table 5. Supply Curve for Interruptible Load

Year	Costs ($/kW per year)	Availability (% of Peak Demand)
2010	$3.36–$37.10	1%–8%
2020	$3.36–$37.10	11%–17%
2030	$3.36–$37.10	11%–17%
2040	$3.36–$37.10	16%–24%
2050	$3.36–$37.10	16%–24%

Plug-in EVs, hybrid, or otherwise can impact electric loads. Their loads can be simply included with all other electric loads or endogenously calculated. The latter requires that EV penetration be specified in ReEDS. Vehicle charging-loads can be separated into utility-controlled (dynamic) and customer-controlled (fixed) portions. Utility-controlled means that the electric service provider (i.e., ReEDS) can control the charging schedule to best match its needs; fixed plug-in EV loads are set by the modeler in accordance with a predetermined schedule.

6.1.4 Operational Parameters and Emissions Rates

Table 6 lists operational parameters for generating technologies. Minimum plant load refers to a minimum turndown ratio for a given plant type in a given region, compared to that plant type's maximum output in that season. Outage rates restrict the availability of generators both for providing energy and for computations of system reliability.

[34] For examples of specific cost and performance values, see the cost specific reports from Black and Veatch (Black and Veatch 2011) and RW Beck (EIA 2010).

Table 6. Outage Rates and Emission Factors

Technology	Minimum Plant Load (%)	Outage Rates (%)		Emissions (lbs/MMBtu fuel)[a]			
		Forced	Planned	SO_2	NO_x	Hg	CO_2
Coal (pulverized)	40%	6%	10%	0.062	0.11	4.4e-6	205
Coal (IGCC)	50%	8%	12%	0.062	0.085	4.4e-6	205
Coal (IGCC-CCS)	50%	8%	12%	0.062	0.085	4.4e-6	20.5
Old pulverized coal (w/o SO_2 scrubber)	40%	6%	10%	1.245	0.11	5.3e-6	205
Old pulverized coal (with SO_2 scrubber)	40%	6%	10%	0.062	0.11	4.4e-6	205
Natural gas (CT)	0%	3%	5%	0.009	0.087	0	119
Natural gas (CC)	0%	4%	6%	0.003	0.035	0	119
Natural gas (CC-CCS)	0%	4%	6%	0.003	0.035	0	11.9
Oil/gas steam	40%	10%	12%	0.299	0.1	0	137
Nuclear	100%	4%	6%	0	0	0	0
Geothermal	90%	13%	2%	0	0	0	0
Dedicated biopower	40%	9%	8%	0.08	0	0	0
Landfill gas/MSW	0%	5%	5%	0	0	0	-250
New co-fire	40%	7%	9%	0.062	0.11	4.4e-6	205
Old co-fire	40%	7%	9%	0.062	0.11	4.4e-6	205
Hydropower	55%	5%	2%	0	0	0	0
PHS	n/a	4%	3%	0	0	0	0
Batteries	n/a	2%	1%	0	0	0	0
CAES	n/a	3%	4%	0.009	0.087	0	119
Thermal storage	n/a	1%	1%	0	0	0	0

[a] Emission rates shown for co-fire plants represent emissions from the coal portion only. In ReEDS, emissions are calculated based on the proportions of actual fuel sources used.

Sources and notes on emissions:

1. Sulfur dioxide (SO_2) emissions result from the oxidization of sulfur contained in the fuel. SO_2 input emissions rate for coal is based on the sulfur content of the fuel and the use of post-combustion controls. The base emissions rate for existing and new conventional coal plants is based on a national average sulfur content (EPA 2005b). ReEDS assumes that the national average for "low-sulfur" coal is 0.5 lbs SO_2/MMBtu from values based on national averages from AEO assumptions (EIA 2006, Table 73). Scrubber removal efficiency is assumed to put the SO_2 emissions of a new or retrofit on par with the national average (EPA 2005b).
2. Nitrogen oxide (NO_x) emissions result from the oxidization of nitrogen in the air. It is not a result of the type of fuel burned but rather the combustion characteristics of the generator. NO_x emissions can be reduced through a large variety of combustion controls or post-combustion controls. NO_x emissions are not restricted in the ReEDS base case. The emissions rates are national averages (EPA 2005b).
3. Mercury (Hg) is a trace constituent of coal. Mercury emissions are unrestricted in the ReEDS base case (see Section 1.6.3). Emissions rates are averages and do not consider control technologies (EPA 2005b).
4. Carbon dioxide (CO_2) emissions result from the oxidization of carbon in the fuel, and the emissions rate is based solely on fuel type and therefore is constant (per fuel input) for all plants burning the same fuel type. CO_2 content for natural gas and coal are based on the national average (EPA 2005b). Biofuels are assumed to be carbon neutral. Landfill gas is assumed to have negative effective carbon emissions because the gas would be flared otherwise. CSP plants burn a small amount of natural gas resulting in CO_2 emissions; however, these small emissions are ignored in ReEDS. CO_2 emissions are not constrained in the ReEDS base case.

6.2 Fuel Prices

Base coal, natural gas, and nuclear fuel prices used in ReEDS are taken from the most recent reference case of EIA's *Annual Energy Outlook* (EIA 2011a). Natural gas and coal fuel prices are represented by supply curves in ReEDS, where a fuel price is adjusted upward in ReEDS with respect to the AEO forecasted price if demand for that fuel is increased with respect to the AEO forecasted demand, and adjusted downward with respect to the AEO forecasted price if demand is decreased with respect to AEO forecasted demand. The adjustment is based on linear regressions on the fuel usages and prices between the AEO reference, low economic growth, and high economic growth cases.[35] Fuel price elasticity for uranium and biomass feedstock is not considered in ReEDS.

6.3 Transmission Assumptions

Costs of transmission were developed by NREL in conjunction with Black and Veatch (2011) and are shown in Table 7. Different regions have different costs of transmission due to the assumed prevalence of either 500 kilovolt (kV) or 765 kV lines, as well as regional cost multipliers (EnerNex 2010), which reflect additional sitting costs. The transmission line costs include a 25% contingency factor, which accounts for the fact that lines are overbuilt to accommodate greater power transfers only during contingency events. In addition to the cost of transmission lines, regional supply curves of costs for substation construction are included, which primarily includes cost of transformers to step between transmission line voltages and distribution network voltages. The substation supply curves were developed from the GridView database. An additional cost of $230/kW of transmission capacity is charged for building capacity across interconnects to account for the necessary AC-DC-AC intertie construction.

Table 7. Transmission Costs (2009$)

	Value	Applicable Regions
500 kV line costs ($/MW-mi)	1,500	WECC, ERCOT, Southwest Power Pool (SPP), Florida Reliability Coordinating Council (FRCC), Southeastern Reliability Council (SERC)
765 kV line costs ($/MW-mi)	1,200	Rest of the country
Line cost multiplier	3.56x	CA, NY, NE, East PJM
Line cost multiplier	1.58x	West PJM
Substation costs ($/kW)	10.7–24	All
AC-DC-AC intertie costs ($/kW)	230	Crossing interconnects

In addition to the transmission costs discussed above, grid interconnection costs (Table 8) are applied to most generation and storage technologies upon construction, with the exception of utility-scale PV and rooftop PV installations. For conventional technologies in which siting and transmission may be more significant issues (e.g., hydropower, nuclear, and coal), grid interconnection costs are twice as high as the standard cost.

[35] In assessing the elasticity of the fuel prices, fuel usage in non-electric sectors are assumed to follow the AEO reference scenario projections.

Table 8. Grid Connection Costs for Generating Technologies (2009$)

Technology	Grid Connection Cost ($/kW)
Hydro	227
Gas-CT	114
Gas-CC	114
Coal	227
Coal-IGCC	227
OGS	114
Nuclear	227
Geothermal	227
Biomass	114
Co-Fire	227
Wind	114
Central PV	114
Dist. Wholesale PV	0
CSP	114
Pumped Hydro	227
Batteries	0
CAES	227

6.4 Financial Assumptions

Because financial considerations vary widely between projects, technologies, and over time, general and simplifying financial assumptions are necessary for capacity expansion modeling over the long time horizon and large spatial scope of the ReEDS model. The major financial parameters used in ReEDS are shown in Table 9. Although project-specific financing can be considered, the default assumption in ReEDS uses the WACC as the discount rate. The WACC (introduced in Section 1.4) is used by default since it implicitly captures corporate financing and/or the ability to refinance for project-specific financing.

Table 9. Major Financial Parameters

Assumption	Value
Inflation rate	3%
Evaluation period	20 years
Rate of return on equity (RROE) (nominal)	13%
Debt interest rate (nominal)	8%
Interest rate during construction (nominal)	8%
Debt fraction	50%
WACC discount rate (nominal)	8.9%
WACC discount rate (real)	5.7%
Corporate tax rate (combined federal and state)	40%
Modified Accelerated Cost Recovery System (MACRS) (non-hydropower renewables)	5 years
MACRS (“conventionals" and hydropower)	15 years

Technology-specific financial parameters used in ReEDS are shown in Table 10. Technologies with the same construction time do not necessarily have the same construction cost multiplier because their construction schedules may differ. This is why the construction cost multipliers for wind, CSP, utility PV, and gas-combustion turbine are slightly less than that for gas-combined cycle, for instance. All technologies use the general interest rate and required RROE (shown in Table 9), except that 3% carbon risk premiums (real) on interest rate and required RROE are applied to coal technologies. Renewable technologies also have accelerated (MACRS) depreciation schedules. The capital cost financial multiplier encompasses the effects of the financial parameters on the capital cost and, when multiplied by overnight capital cost, represents the present value of revenue that a project must have to recover all costs over a 20-year evaluation period. This is the capital cost used by ReEDS for each technology as the technologies compete to minimize overall 20-year present value costs of the system.

Table 10. Technology-Specific Investment and Financial Assumptions

Technology	New Installations? (Y/N)	Construction Time (Years)	Risk Adjustment (%)	Capital Cost Financial Multiplier[a]
Coal (pulverized)	Y	6	3%	1.80
Coal (IGCC)	Y	6	3%	1.80
Coal (IGCC-CCS)	Y	6	0%	1.49
Natural gas (CT)	Y	3	0%	1.34
Natural gas (CC)	Y	3	0%	1.35
Natural gas (CC-CCS)	Y	3	0%	1.35
Nuclear	Y	6	0%	1.49
Geothermal	Y	4	0%	1.22
Dedicated biopower	Y	4	0%	1.22
New co-fire	new and retrofit	6	3%	1.80
Old co-fire	retrofit only	—	—	—
Hydropower	Y	3	0%	1.34
Wind	Y	3	0%	1.18
CSP	Y	3	0%	1.18
Utility-scale PV	Y	3	0%	1.16
PHS	Y	6	0%	1.34
Batteries	Y	3	0%	1.32
CAES	Y	6	0%	1.35
Thermal storage	Y	1	0%	1.32

[a] Capital cost multipliers shown do not include any tax credits.

6.5 Capacity Requirements

For each reserve-sharing group, ReEDS requires sufficient firm capacity to meet the expected peak instantaneous demand for the year, plus a reserve margin. Table 11 includes the reserve margin for each NERC subregion.[36]

[36] See http://www.nerc.com/page.php?cid=4|331|373.

Table 11. Reserve Margin by NERC Subregion

NERC Subregion	Reserve Margin
East Central Area Reliability Coordination Agreement (ECAR)	15%
California (CA)	17%
Electric Reliability Council of Texas (ERCOT)	12.5%
Florida (FL)	15.8%
Mid-Atlantic Area Council (MAAC)	15%
Mid-America Interconnected Network (MAIN)	15%
Mid-Continent Area Power Pool (MAPP)	15%
New England (NE)	15%
Northwest Power Pool (NWP)	17.2%
New York (NY)	15%
Rocky Mountain Power Area (RA)	17%
Southeastern Electric Reliability Council (SERC)	13%
Southwest Power Pool (SPP)	12%

6.6 Federal Emissions Standards

Emissions caps can be applied to criteria pollutants. For example, system-wide emissions of SO_2 are capped based on projections from the EPA's Integrated Planning Model analysis of the CAIR (EPA 2005). Although CAIR was remanded in 2008, the EPA is still in the process of developing and approving a new Transport Rule. Because the Transport Rule is still in flux, the ReEDS model uses the older projections as an SO_2 cap, as shown in Table 12. Once regulations are finalized, more up-to-date SO_2 caps will be applied.

Table 12. National SO_2 Emission Limit Schedule

	2003	2010	2015	2020	2030
SO_2 Cap (MTons)	10.6	6.1	5.0	4.3	3.5

Source: EPA (2006)

NO_x emissions currently are unconstrained in ReEDS. A NO_x cap can be added, but the net effect on the overall competitiveness of coal is expected to be relatively small. Also, adding such a cap is complicated by the wide array of options available for NO_x emission control.

Additionally, mercury emissions are currently unconstrained in ReEDS. As of December 2010, the Clean Air Mercury Rule, a cap-and-trade regulation,[37] is expected to be met largely via the requirements of the new Transport Rule, which is expected to be more stringent than the previous CAIR. Control technologies for SO_2 and NO_x that are required for the Transport Rule are expected to capture enough mercury to largely meet the cap goals. As a result, the incremental cost of mercury regulations is very low and is not modeled in ReEDS.

[37] See http://www.epa.gov/camr/index.htm.

Existing federal tax incentives for renewable energy are included in ReEDS and summarized in Table 13.

Table 13. Federal Renewable Energy Incentives

	Value	Notes and Source
Renewable energy production tax credit	$18.5/MWh	Applies to wind; no limit to the aggregated amount of incentive; value is adjusted for inflation to U.S. 2006$; expires at the end of 2012.
Renewable energy investment tax credit	30%	Applies to utility-PV and CSP; expires at the end of 2016.
	10%	Applies to utility-PV and CSP after 2016 and to geothermal until 2030.

Several states also have production and investment incentives for renewable energy sources. The values used in ReEDS are listed in Table 14.

Table 14. State Renewable Energy Incentives

State	PTC ($/MWh)	ITC (%)
Iowa	—	5.0
Idaho	—	5.0
Minnesota	—	6.5
New Jersey	—	6.0
New Mexico	10	—
Oklahoma	2.5	—
Utah	—	4.75
Washington	—	6.5
Wyoming	—	4.0

Source: IREC (2006)

6.7 State Renewable Portfolio Standards

Table 15 presents the RPS goals used in ReEDS as obtained from the Database of State Incentives for Renewables & Efficiency (DSIRE) (DSIRE 2010). The state RPS requires a utility to install or generate a certain fixed amount of renewable capacity or energy. Unless prohibited by law, a state might also meet the requirement by importing electricity. The states of Delaware, Illinois, Maryland, Missouri, North Carolina, New Hampshire, New Jersey, New Mexico, Nevada, Ohio, and Pennsylvania have chosen to encourage the widespread use of solar technologies by stipulating a solar set-aside, which requires that a certain fraction of the RPS be met specifically with solar resources.

Table 15. State RPS Requirements as of July 2010

State	RPS Start Year	RPS Full Implementation	RPS (%)
AZ	2006	2025	6.2
CA	2004	2020	32.4
CO	2007	2020	19.4
CT	2006	2020	21.5
DE	2008	2021	13.9
IL	2008	2025	22.1
KS	2011	2020	15.6
MA	2004	2020	19.5
MD	2006	2022	19.3
ME	2000	2017	39.3
MI	2012	2015	10.0
MN	2010	2020	27.4
MO	2011	2021	9.8
MT	2008	2015	10.0
NC	2010	2021	11.1
NH	2008	2025	23.4
NJ	2005	2021	24.9
NM	2006	2020	15.2
NV	2005	2025	22.0
NY	2003	2015	20.9
OH	2009	2024	11.0
OR	2011	2025	20.4
PA	2007	2021	17.5
RI	2007	2019	15.8
WA	2012	2020	12.7
WI	2006	2015	10.1

Source: DSIRE (2010)

7 Model Parameters, Variables, and Equations

This section describes the major parameters, variables, constraints, and other attributes in the linear program formulation of ReEDS. ReEDS was developed and written using the General Algebraic Modeling System (GAMS).[38] GAMS is a modeling system for large mathematical programming and optimization. It consists of a language compiler and relies on a separate solver engine to perform the optimization routines. ReEDS uses the CPLEX solver based on the Cplex Callable Library from IBM ILOG CPLEX.

The ReEDS model is constantly evolving and the following attributes represent the most current version of ReEDS as of May 2011. The following listed attributes are also not comprehensive of the actual modeling code but are intended to provide further clarity.

7.1 Subscripts

Variables, parameters, and constraints are subscripted to describe the space over which they apply. The various sets are listed below.

7.1.1 Geographical Sets

- ***i, j***. The 358 wind/CSP resource regions track where wind and solar power are generated and to where they are transmitted. Source regions are generally noted *i* and destinations *j*.
- ***n, p.*** The 136 BAs track all other generation capacity. Each contains one or more resource regions. Source regions are generally noted *n* and destinations *p*.
- ***states.*** There are 48 states included. Alaska and Hawaii are excluded.
- ***reg***. There are 32 reserve-sharing groups, each of which contains one or more BAs. Operating reserve requirements and wind curtailments are monitored at this level.
- ***r***. There are 13 NERC regions/subregions.
- ***in***. There are three interconnects: ERCOT, Eastern, and Western.

7.1.2 Temporal Sets

- ***year***. From 2006 to 2050.
- ***s***. There are four annual seasons.
- ***m***. There are 17 time-slices during each year, corresponding to four daily time-slices by season plus one super peak time-slice. The length (in hours) of each time-slice is represented by Hm_m.

7.1.3 Other Sets

- ***c***. There are five wind classes.
- ***cCSP***. There are five CSP classes.
- ***wscp, cspscp, escp***. Supply curve points for wind, CSP, and *inregion*, respectively.
- ***bioclass.*** Level of biomass supply curve.

[38] See http://gams.com/docs/intro.htm for more information about the GAMS software package.

- ***geoclass.*** Level of geothermal resource supply curve.
- ***fuelbin.*** Level of fuel (coal or natural gas) in national fuel supply curve.
- ***pol***. The four pollutants considered (SO_2, NO_x, Hg, and CO_2).
- ***q***. Conventional generating technologies, which has the following members:
    - ***hydro***. Hydropower.
    - ***gas-ct***. Natural gas – combustion turbine, ***gas-cc*** (combined cycle), ***gas-cc-ccs*** (combined cycle with CCS).
    - ***Coaloldun*s**. Coal (traditional pulverized coal, unscrubbed), ***coaloldscr***, (scrubbed), or ***cofireold*** (co-firing), ***coal-new*** (modern pulverized coal), ***cofirenew*** (with or without), ***coal-IGCC*** (integrated gasification combined cycle), ***coal-ccs*** (with or without CCS).
    - ***o-g-s***. Oil-gas-steam.
    - ***nuclear***. Nuclear.
    - ***biomass***. Dedicated biomass.
    - ***geothermal***. Geothermal (EGS, EHS).
    - ***lfill-gas***. Landfill gas.
    - ***other***. Distributed PV.
- ***st***. There are four storage technologies:
    - ***pumped-hydro***. Pumped-hydropower storage.
    - ***battery***. Batteries.
    - ***caes***. Compressed air energy storage.
    - ***ice storage***. Ice storage.

7.2 Major Decision Variables

The major decision variables include new capacity (built in the two-year period being optimized) builds of conventional generation, renewables, and storage along with transmission and dispatch of conventional capacity and storage. Unless otherwise noted, capacity variables are expressed in megawatts and energy variables are expressed as average power delivered during a time-slice (MW), which can be converted into an energy term by multiplying by a time parameter such as Hm_m (hours).

7.2.1 Variable Renewable Variables

Wind and CSP variables are separated into two groups, *inregion* and not-*inregion*, to reflect the structure of the wind supply curves. The *inregion* designation relates to capacity that is going to serve load in the same region. The following CSP variables are split to reflect CSP with and without storage technologies:

- $\mathbf{WturN}_{c,i,wscp}$. New class *c* wind turbines in region *i* from the *wscp* step on the accessibility supply curve (MW).

- $\mathbf{WN}_{c,i,j}$. Class *c* wind contracted from new turbines in region *i* to region *j* (MW).
- $\mathbf{WELEC\_inregion}_{c,i,escp}$. New class *c* wind produced and consumed in region *i* from the *escp* step of the inregion supply curve (MW).
- $\mathbf{CspturN}_{cCsp,i,cspscp}$. New class *cCSP* in region *i* from the *cspscp* step on the accessibility supply curve (MW).
- $\mathbf{CspN}_{cCSP,i,j}$. CSP contracted from new plants of class *cCSP* in region *i* to region *j* that must be accomodated on existing lines (MW).
- $\mathbf{CspELEC\_inregion}_{cCsp,i,escp}$. New class *cCSP* produced and consumed in region *i* from the *escp* step of the inregion supply curve (MW).

For CSP with storage, the following variables are separated to allow CSP cost and performance to reflect the cost of building the field, turbine, and storage separately:

- $\mathbf{CSPFieldN}_{cCsp,i}$. New class *cCSP* capacity on existing lines (MW) in region *i*.
- $\mathbf{CSPStorN}_{n}$. Capacity of new CSP storage assigned to existing lines (MW) in BA *n*.
- $\mathbf{CSPTurbN}_{n}$. Capacity of new CSP turbine (MW) in BA *n*.
- $\mathbf{CSPTurbPowN}_{n,m}$. Power output from CSP turbine in BA *n* in time-slice *m* on existing lines (MW).
- $\mathbf{CSPStorEnerN}_{n,m}$. Energy in CSP storage in BA *n* at beginning of time-slice *m* on existing lines (MWh).
- $\mathbf{UPVN}_{n,p}$. New UPV installations in BA *n* serving BA *p* (MW).
- $\mathbf{DUPVN}_{n}$. New distributed wholesale PV in BA *n* (MW).

7.2.2 Conventional Generator Variables

Conventional variables cover all technologies *q* that are not considered to be variable renewable technologies.

- $\mathbf{CONVqn}_{q,n}$. New capacity of technology *q* in BA *n* (MW).
- $\mathbf{UPGRADEqn}_{q,qq,n}$. Upgrades of conventional generators from technology *q* to *qq* (MW) in BA *n*.
- $\mathbf{CONVqmn}_{q,m,n}$. Average conventional capacity in use in time-slice *m* from technology *q* in BA *n* (MW).
- $\mathbf{CONVOLDqmn}_{q,m,n}$. Average conventional capacity in use in time-slice *m* from tech *q* in BA *n* from old plants (i.e., plants that existed before this time period) (MW).
- $\mathbf{SRqmn}_{q,n,m}$, $\mathbf{SRoldqmn}_{q,n,m}$. Spinning reserve capacity in time-slice *m* by technology *q* in BA *n* (MW). New and existing plants are differentiated.
- $\mathbf{QSqn}_{q,n}$, $\mathbf{QSoldqn}_{q,n}$. Available quick-start capacity of technology *q* in BA *n* (MW). New and existing plants are differentiated.
- $\mathbf{CofireGen}_{bioclass,n}$. Biomass-generated energy from coal-co-firing plants by biomass-supply-curve step *bioclass* on resource supply curve (MWh) in BA *n*.

- **Vgasbinq**$_{fuelbin}$, **Vcoalbinq**$_{fuelbin}$. Demanded quantity of gas/coal in supply-curve bin *fuelbin* (MMbtu).

7.2.3 Storage Variables

Storage variables cover all storage technologies ***st*** that are built and operated.

- **STOR**$_{n,st}$. Load-sited storage capacity of technology *st* in BA *n* (MW).
- **STORin**$_{m,n,st}$. Average charging level storage in time-slice *m* (MW) in BA *n* by storage technology *st*.
- **STORout**$_{n,m,st}$. Average discharging level for storage in time-slice *m* (MW) in BA *n* by storage technology *st*.
- **STOR_SR**$_{m,n,st}$. Storage capacity devoted to spinning reserve in time-slice *m* (MW) in BA *n* by storage technology *st*.
- **STOR_QS**$_{n,st}$. Storage capacity that will operate as quick-start (MW) in BA *n* by storage technology *st*.
- **ICEBIN**$_{iceclass,n}$. Ice storage capacity in each resource class *iceclass* (MW) in BA *n*.
- **CAESBIN**$_{caesclass,n}$. CAES capacity in each resource class *caesclass* (MW) in BA *n*.
- **IL**$_{n}$. Interruptible load at *n* (MW).

7.2.4 Transmission Variables

Transmission variables cover both the capacity of transmission lines between BAs and the flow on the particular lines.

- **AC_new**$_{n,p}$, **DC_new**$_{n,p}$. New transmission capacity on AC or DC lines between BAs *n* and *p* (MW).
- **Net_injection**$_{n,m}$. Generation less load at *n*, by time-slice *m* (MW).
- **AC_Flow**$_{m,n,p}$, **DC_Flow**$_{m,n,p}$. Power transferred directly from BA *n* to BA *p* in time-slice *m* (MW).
- **AC_loss**$_{\mathrm{m},n}$. Transmission losses on AC lines in time-slice *m* reducing the imported electricity at *n* (MW).
- **ReTnp**$_{\mathrm{n,p}}$. Contracted transmission capacity for VRRE between BAs *n* and *p* (MW).
- **CONTRACTcap**$_{n,p}$. Firm capacity contracted from BA *n* to *p* (MW).

7.2.5 Miscellaneous Variables

Miscellaneous variables cover the important variables that do not fall into one of the previous sections.

- **forerr_res_reqt**$_{reg,m}$. Estimation of the forecasting error reserve requirement in each time-slice *m* (MW) in reserve sharing region *reg*.
- **CoalLowSul**$_{q,n}$. Annual generation from low-sulfur coal by (coal-burning) technology *q* (MWh) in BA *n*.

- **emissions_excess**$_{pol.}$ Emissions over the cap, which have an associated penalty assessed in objective function (tons) by polutant *pol*.
- **RPS_shortfall, St_RPS_shortfall**$_{states.}$ Unmet portion of RPS requirement. A penalty is assessed on the shortfalls in the objective function (MWh) on a national and state level *states*.
- **RPSpen**, **St_RPSPen**$_{\mathbf{states}}$. Cost penalty associated with the shortfalls in meeting the national or state RPS requirement ($/MWh) on a national and state level *states*.
- **St_Invincent**$_{\mathbf{states}}$, **St_Prodincent**$_{\mathbf{states.}}$ Investment ($/MW) and production ($/MWh) tax-based incentives for a particular state *states*.

7.3 Important Parameters and Scalars

Parameters are inputs into the model and, unlike variables, are constant during the optimization process. The following list is not exhaustive but highlights some of the major parameters in the model. These parameters are either static inputs (set at the start year) or dynamic (updated from period to period between optimizations). In the definitions that follow, the word existing is used to describe the latter (e.g., existing capacity means that it was in place at the start of the two-year period being optimized).

7.3.1 Cost Parameters

The majority of the cost parameters are exogenously defined and are updated from period to period depending on future cost projections. For simplification purposes, only a subset of the technology cost parameters are discussed here. Similar parameters exist for all renewable and conventional technologies.

- **CWc**$_{c,i.}$ Capital cost of class *c* wind turbine ($/MW).
- **CWOM**$_{c.}$ 20-year present value cost of O&M cost of class *c* wind ($/MW).
- **WR2GPTS**$_{c,i,wscp.}$ Cost of step *wscp* on the class c wind accessibility supply curve in region *i* and in cost bin *wscp* ($/MW).
- **MW_inregion_dis**$_{\mathrm{c,i,}escp.}$ Cost of step *escp* on the inregion wind accessibility supply curve for region *i* ($/MW).
- **cpop**$_{c,i}$, **cslope**$_{c,i.}$ Slope- and population-based multipliers (fraction) on the capital cost of wind in region *i*.
- **CCspC**$_{cCsp,i.}$ Capital cost of class *cCSP* facility ($/MW).
- **CspOM**$_{cCSP.}$ O&M cost of class *cCSP* ($/MW).
- **CSP2GPTS**$_{cCsp,i,cspscp.}$ Cost of step *cspscp* on the class *cCSP* accessibility supply curve for region *i* ($/MW).
- **CSP_inregion_dis**$_{cCsp,i,escp.}$ Cost of step e*scp* on the inregion class *cCSP* accessibility supply curve for region *i* ($/MW).
- **CCspTurb**, **CCspStor**, **CCspField**. Capital costs for components of CSP with storage ($/MW).

- **CSPwStor_SolarMult** $_{i.}$ Estimated ratio of solar field to turbine size. Used to adjust transmission cost associated with new CSP field capacity built at *i* (fraction).
- **CCspTurbOM**. O&M cost of CSP with storage ($/MWh).
- **CUPV**$_{n.}$ Capital cost of utility-scale PV ($/MW) in BA *n*.
- **CDUPV**$_{n.}$ Capital cost of distributed utility-scale PV ($/MW) in BA *n*.
- **UPVOM**. 20-year present value cost of O&M cost for distributed and non-distributed utility-scale PV ($/MW).
- **CCC**$_{q,n.}$ Capital cost of conventional plant technology *q* ($/MW) in BA *n*.
- **CCONVF**$_{q.}$ Conventional fixed O&M cost for technology *q* ($/MW-year).
- **CCONVV**$_{q.}$ Conventional variable O&M cost for technology *q* ($/MWh).
- **Fuelprice**$_{\mathbf{fuel.}}$ Fuel price associated with a particular *fuel* ($/MMbtu).
- **CSTOR**$_{st,n.}$ Capital cost of electric storage systems of type *st* ($/MW) in BA *n*.
- **FSTOR**$_{\mathbf{st.}}$ Fixed O&M cost for electric storage systems of type *st* ($/MW-year).
- **VSTOR**$_{\mathbf{st.}}$ Variable O&M cost for electric storage systems of type *st* ($/MWh).
- **GridConCost**. Grid connection cost for all new utility-scale capacity connecting to the existing grid system ($/MW).
- **TNCOST**$_{n,p}$, **TsubstationCOST**$_{n,voltclass}$, **TinterCOST**. Capital cost for transmission lines ($/MW-mi), substations ($/MW), and AC-DC-AC interties ($/MW), respectively.
- **Ctranadder**$_{\mathbf{q.}}$ Additional transmission cost adder for conventional technology *q* ($/MW).
- **CRF**. Capital recovery factor.
- **Carbtax**, **Carbtax_disc**. Carbon tax: nominal and discounted 20-year present value ($/ton CO2). Zero unless specified otherwise.

7.3.2 Operational Parameters

Operational parameters describe the physical characteristics of the system and are either static or dynamic inputs.

- **Hm**$_{m.}$ Hours in time-slice *m*.
- **Lmn**$_{m,n.}$ Load in BA *n* and time-slice *m* (MW).
- **Pn**$_{n.}$ Peak load in BA *n* time-slice (MW).
- **reserve_marg**$_{n.}$ Required reserve margin fraction in BA *n*.
- **WO**$_{c,i,j}$, **CSPO**$_{cCsp,i,j}$, **UPVO**$_{n,p}$, **DUPVO**$_{n.}$ Existing wind/solar capacity at start of period (MW).
- **WRuc**$_{c,i.}$ Unconstrainted wind resource for class *c* wind in region *i* (MW). Analogs exist for solar.

- **$\mathbf{WR2G}_{c,i,wscp}$**, **$\mathbf{MW\_inregion}_{c,i,escp}$**. Wind supply curve bin sizes (MW). Analogs exist for solar.
- **$\mathbf{CFc}_{i,c,m}$**, **$\mathbf{CFCspc}_{i,cCsp,m}$**. Wind/CSP capacity factor for region *i*, class, and time-slice *m* (fraction).
- **$\mathbf{CFUPV}_{n,m}$**. UPV capacity factor for BA *n* and time-slice *m* (fraction).
- **$\mathbf{CONVOLDqn}_{q,n}$**. Existing conventional generator capacity of type *q* in BA *n* (MW).
- **$\mathbf{STOROLDst,}_{n}$**. Existing storage capacity of type *st* in BA *n* (MW).
- **$\mathbf{WGenOld}_{n}$**, **$\mathbf{CSPGenOld}_{n}$**, **$\mathbf{PVGenOld}_{n}$**. Output from existing wind/solar generators in BA *n* (MWh).
- **$\mathbf{Heatrate}_{q,n}$**. Heat rate applied to new conventional units of type *q* (MWh/MMbtu).
- **$\mathbf{HeatrateOld}_{q,n}$**. Generation-weighted average of all heat rates of the same technology in a region (MWh/MMbtu).
- **$\mathbf{StHeatrate}_{st}$**. Heat rate for electric storage units (only CAES; MWh/MMbtu).
- **$\mathbf{FO}_{q}$**, **$\mathbf{PO}_{q}$**. Forced and planned outage rates for generator type *q* (fraction).
- **$\mathbf{PTDF}_{n,p,n2}$**. PTDF matrix relating lines (*n*, *p*) to BAs (*n2*).
- **$\mathbf{AC\_routes}_{n,p}$**, **$\mathbf{DC\_routes}_{n,p}$**. Allowable AC and DC transmission corridors between BAs *n* and *p* (binary).
- **$\mathbf{AC\_old}_{n,p}$**, **$\mathbf{DC\_old}_{n,p}$**. Existing transmission capacity between BAs *n* and *p* (MW).
- **$\mathbf{Distance}_{i,j}$**. Distance from resource region *i* to resource region *j*. An analogous parameter exists for BA to BA distances (mi).
- **TLOSS**. Transmission loss metric (% loss/mi).
- **$\mathbf{LP}_{pol}$**. Emissions limits (e.g., tons/year).
- **$\mathbf{CONVpol}_{q,pol}$**, **$\mathbf{STORpol}_{st,pol}$**. Emissions rates by technology (tons/MMbtu fuel).
- **Coallowsulpolred**. SO_2 emission reduction from switching to low-sulfur coal (fraction).
- **$\mathbf{MTDF}_{q}$**. Minimum turndown fraction for technology *q* (fraction).
- **$\mathbf{MRprev}_{s,n}$**. Must-run thermal capacity in previous year for season *s* and BA *n* (MW).

7.3.3 Variability Parameters

The variability parameters describe how VRRE technologies interact with the larger electric system, especially with respect to reliability. The following list is not exhaustive but highlights the major input varability parameters that are used to calculate the mean and standard deviation for the load and renewable resource. For each of the wind parameters presented below, there exist similar parameters for other renewable resources.

- **$\mathbf{WCVold}_{m,n}$**. Capacity value of existing wind for BA *n* and time-slice *m* (MW).
- **$\mathbf{WCVmar}_{c,i,reg,m}$**. Marginal capacity value of class *c* wind from region *i*, used in BA *n* in time-slice *m* (fraction).

- **SurpOld**$_{m,reg}$. Quantity of VRRE expected to be curtailed for reserve sharing region *reg* and time-slice *m* (MW).
- **WSurplusMar**$_{c,i,reg,m}$. Marginal curtailment rate for class *c* wind from new turbines in region *i* supplied to reserve sharing region *reg* in time-slice *m* (fraction).
- **MRSurplusMar**$_{reg,m}$. Marginal curtailment rate associated with an incremental increase in must-run thermal capacity in time-slice *m* (fraction).
- **StSurpRecMar**$_{reg,m}$. Marginal curtailment recovery rate in time-slice *m* associated with an incremental increase in electric storage capacity in BA *n* (fraction).
- **WFERold**$_{reg,m}$. Forecast error reserve requirement for existing wind in time-slice *m* (MW).
- **WFERmar**$_{c,i,reg,m}$. Marginal forecast error reserve requirement for new class *c* wind from region *i* supplied to reserve sharing region *reg* in time-slice *m* (fraction).

7.4 Objective Function

The objective function is the equation over which the system is minimized. In the objective function, the variable *z*, which represents a 20-year present value cost of updating and operating the system, is minimized.

z = Capital and operating costs of new wind plants

+ Capital and operating costs of new CSP plants

+ Capital cost of new utility-scale PV and distributed utility-scale PV capacity

+ Capital cost of new and upgraded conventional generators

+ Fuel and operating costs of conventional generation

+ Capital cost for transmission expansion

+ Capital and operating cost of new storage capacity

+ Financial penalties (e.g., alternative compliance payments and carbon taxes)

The different portions of the objective function are developed below in equation form, along with explanatory notes in brackets. For clarity, the equation neglects some of the subtle nuances that are present in the actual cost function. Notes are provided below each equation to indicate the subtlety, where appropriate.

$$z = \sum_{c,i} \left[\begin{array}{l} (\sum_{j} \mathrm{WN}_{c,i,j} + \sum_{escp} \mathrm{WELEC\_inregion}_{c,i,escp}) \\ \cdot \left(\begin{array}{l} \mathrm{CWc}_{c,i} \cdot \mathrm{cpop}_{c,i} \cdot (1+\mathrm{cslope}_{c,i}) \cdot \sum_{i \in states} (1-\mathrm{st\_Invincent}_{states}) \\ +\mathrm{CWOM}_{c} + \sum_{i \in states} \mathrm{st\_Prodincent}_{states} \cdot \mathrm{CFc}_{c,i,m} \\ +\mathrm{GridConCost} \end{array} \right) \end{array} \right]$$

[Wind capital and O&M cost. Investment and production tax-based incentives are represented by *st_Invincent* and *st_Prodincent*, respectively].

$$+\sum_{c,i}\left[\sum_{wscp}(\mathrm{WturN}_{c,i,wscp}\cdot \mathrm{WR2GPTS}_{c,i,wscp})\right]$$
$$+\sum_{c,i}\left[\sum_{escp}(\mathrm{WELEC\_inregion}_{c,i,escp}\cdot \mathrm{MW\_inregion\_dis}_{c,i,escp})\right]$$

[Cost to connect wind to the grid; supply curve].

$$+\sum_{cCsp,i}\left[\begin{array}{l}\left(\sum_{j}\mathrm{CspN}_{cCSP,i,j}+\sum_{escp}\mathrm{CspELEC\_inregion}_{cCsp,i,escp}\right)\\ \cdot(\mathrm{CCspc}_{cCsp,i}+\mathrm{CspOM}_{cCsp}+\mathrm{GridConCost})\end{array}\right]$$

[CSP without storage capital and O&M cost. This sum only applies to building the capacity, not connecting the capacity to the grid].[39]

$$+\sum_{cCsp,i}\left[\sum_{cspscp}(\mathrm{CspturN}_{cCsp,i,cspscp}\cdot \mathrm{CSP2GPTS}_{cCsp,i,cspscp})\right]$$
$$+\sum_{cCsp,i}\left[\sum_{escp}(\mathrm{CspELEC\_inregion}_{cCsp,i,escp}\cdot \mathrm{CSP\_inregion\_dis}_{cCsp,i,escp})\right]$$

[Cost to connect CSP without storage to the grid; supply curve].

$$+\sum_{n}\mathrm{CspTurbN}_{n}\cdot(\mathrm{CCSPTurb}+\mathrm{CSPTurbOM}+\mathrm{GridConCost})$$
$$+\sum_{n}\mathrm{CspStorN}_{n}\cdot \mathrm{CCSPStor}$$
$$+\sum_{cCsp,cspscp,i}\mathrm{CspFieldN}_{cCsp,i,cspscp}\cdot\left(\mathrm{CCSPFieldc}_{cCsp,i}+\frac{\mathrm{CSP2GPTS}_{cCsp,i,cspscp}}{\mathrm{CSPwStor\_SolarMult}_{i}}\right)$$

[Cost of CSP with storage: turbine, storage unit, and oversize solar field. The costs associated with CSP with storage are broken into three variables to allow the model to decide the optimal size of storage and concentrator field. The *CspFieldN* variable is assessed at resource region *i* to be consistent with the resource supply curve].

$$+\sum_{q,n}\left[\mathrm{CONVqn}_{q,n}\cdot\left(\begin{array}{l}\mathrm{CCONVq}_{q,n}+\mathrm{CCONVFq}_{q}\\ +\mathrm{Ctranadder}_{q}+\mathrm{GridConCost}\end{array}\right)\right]$$

[39] There are two types of CSP technologies represented in ReEDS: CSP with and without storage. CSP with storage is assessed at the resource region *i,* whereas CSP with storage is assessed at the BA region *n*. CSP without storage is also assumed to be variable and is part of the variability calculations.

[Conventional capital and O&M cost].

$$+\sum_{q,n}\left[\begin{array}{l}\sum_{qq}(\mathrm{UPGRADEqn}_{q\;qq,n}-\mathrm{UPGRADEqn}_{q,q\;qn})\\ \cdot(\mathrm{CCONVq}_{q,n}+\mathrm{CCONVF}_{q,n}+\mathrm{GridConCost})\end{array}\right]$$

[Conventional upgrade capital and O&M cost].[40]

$$+\tfrac{1}{\mathrm{CRF}}\sum_{fuel}\left[\mathrm{Fuelprice}_{fuel}\cdot\sum_{q\in fuel,m,n}\begin{array}{l}\mathrm{CONVqmn}_{q,m,n}\cdot\mathrm{Hm}_m\cdot\mathrm{Heatrate}_{q,n}\\ +\;\mathrm{CONVOLDqmn}_{q,m,n}\cdot\mathrm{Hm}_m\cdot\mathrm{HeatrateOld}_{q,n}\end{array}\right]$$
$$+\tfrac{1}{\mathrm{CRF}}\sum_{fuelbin}\mathrm{Vgasbinq}_{fuelbin}\cdot\mathrm{gasbinp}_{fuelbin}$$
$$+\tfrac{1}{\mathrm{CRF}}\sum_{fuelbin}\mathrm{Vcoalbinq}_{fuelbin}\cdot\mathrm{coalbinp}_{fuelbin}$$

[Fuel cost: fixed cost component plus quantity-dependent bins].

$$+\sum_{n,p}\mathrm{AC\_new}_{n,p}\cdot\mathrm{TNCOST}_{n,p}\cdot\mathrm{Distance}_{n,p}$$
$$+\sum_{n,voltclass}\mathrm{TsubstationBin}_{n,voltclass}\cdot\mathrm{TsubstationCOST}_{n,voltclass}$$
$$+\sum_{n,p}\mathrm{DC\_new}_{n,p}\cdot\mathrm{TinterCOST}$$

[New transmission line and substation capital cost].

$$+\sum_{st,n}\mathrm{STOR}_{st,n}\cdot(\mathrm{CSTOR}_{st,n}+\mathrm{FSTOR}_{st}+2\cdot\mathrm{GridConCost})$$
$$+\sum_{st,m,n}\mathrm{STORout}_{m,n,st}\cdot\mathrm{Hm}_m\cdot\mathrm{VSTOR}_{st}$$

[Storage capital and O&M cost. A 2 multiplier is added to the grid connection cost to reflect the additional grid connection equipment required for storage technologies to both receive and distribute large amounts of electricity].

$$+\sum_{n,p}\mathrm{UPVN}_{n,p}\cdot(\mathrm{CUPV}_n+\mathrm{UPVOM}+\mathrm{GridConCost})$$
$$+\sum_{n}\mathrm{DUPVN}_{n}\cdot(\mathrm{CDUPV}_n+\mathrm{UPVOM})$$

[UPV and distributed PV capital and O&M cost].[41]

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[40] Old coal unscrubbed plants can upgrade to old coal scrubbed plants, and both old coal unscrubbed and scrubbed plants can upgrade to co-firing. Old coal scrubbed plants can upgrade to CCS with a capacity reduction and heat rate penalty (not shown explicitly here).

$$+ \text{RPS\_shortfall} \cdot \text{RPSpen}$$
$$+ \sum_{states} \text{St\_RPS\_shortfall}_{states} \cdot \text{St\_RPSpen}_{states}$$

[Alternative compliance payments for RPS requirements].

$$+ \sum_{q,m,n} \text{CONVOLDqmn}_{qmn} \cdot \text{Hm}_m \cdot \text{CONVpol}_{q,CO2} \cdot \text{HeatrateOld}_{q,n} \cdot \frac{\text{Carbtax}}{\text{CRF}}$$
$$+ \sum_{q,m,n} \text{CONVqmn}_{qmn} \cdot \text{Hm}_m \cdot \text{CONVpol}_{q,CO2} \cdot \text{Heatrate}_{q,n} \cdot \text{Carbtax\_disc}$$

[Carbon tax: existing plants dispatch seeing the present carbon price, new plants must consider a 20-year expected carbon price].

7.5 Key Constraints

The following section lists the key constraints that dictate the bounds in which the variables interact. Although only the key constraints are detailed in the following section, there are a number of supporting constraints that work in conjunction with these constraints. The constraints are formulated to model the operation and decision making of the current and future electric system.

Currently, there are two methods to model transmission constraints. The methods are detailed in the next two subsections. However, only one can be used during a model scenario run.

7.5.1 Truck-Route Representation: Load and Transmission Constraints

The following constraints describe the truck-route version of the transmission constraints. In this representation, power transfers (AC_Flow) are decision variables over which ReEDS has direct control and flows on different lines are independent of each other.

7.5.1.1 Load

The load (LOAD) constraint dictates that total generation plus imports have to be equal to load and exports in each time-slice. This constraint is held for each BA *n* and time-slice *m*.

$$\sum_{p} \text{AC\_Flow}_{m,p,n} \cdot (1 - \text{TLOSS}_{n,p} \cdot \text{Distance}_{\text{n,p}}) - \text{AC\_Flow}_{m,n,p}$$
$$+ \sum_{p} \text{DC\_flow}_{m,p,n} \cdot (1 - \text{TLOSS}_{n,p} \cdot \text{Distance}_{n,p}) - \text{DC\_flow}_{m,n,p}$$

[Net imported electricity].

$$+ \sum_{q} \text{CONVqmn}_{q,m,n} + \text{CONVOLDqmn}_{q,m,n}$$

[41] Distributed PV does not have any transmission cost associated with it, as it is assumed to be consumed inside the BA.

[New and existing conventional generation in the BA].

$$+\sum_{c,i,j\in n} \mathrm{WN}_{c,i,j} \cdot \mathrm{CFc}_{c,i,m} \cdot \mathrm{Hm}_m \cdot (1-\mathrm{TLOSS}_{i,j} \cdot \mathrm{Distance}_{i,j})$$
$$+\sum_{c,j\in n,escp} \mathrm{WELEC\_inregion}_{j,c,escp} \cdot \mathrm{CFc}_{c,j,m} \cdot \mathrm{Hm}_m$$
$$+\ \mathrm{WGenOld}_{m,n}$$
$$+\ \text{similar constraints for CSP and PV}$$

[New and existing renewable generation].

$$-\ \mathrm{Surplus}_{m,n}$$

[Minus curtailed VRRE].

$$+\sum_{st}\left(\mathrm{STORout}_{m,n,st} - \mathrm{STORin}_{m,n,st}\right)$$

[Plus net energy from storage].

$$= \mathrm{Lmn}_{n,m} + \mathrm{PHEVin}_{n,m}$$

[Equals load plus plug-in hybrid EV demand and energy being stored].

7.5.1.2 Transmission Limits and Contracts

Two contraints frame the truck-route transmission representation: one pertains to power transfers and the other to contract capacity. Power transfers (AC_Flow) can be used to meet load, as seen above, while capacity contracts are used toward planning reserves. The two transmission-limit constraints require that there be sufficient transmission on each transmission corridor to transmit the relevant contracted renewable capacity and conventional power. The constraint is held for each linked source-destination pair (*n*, *p*) in each time-slice *m*. An additional pair of constraints (not shown) limit flows and contracts along DC corridors.

$$\mathrm{ReTnp}_{n,p} + \mathrm{AC\_Flow}_{m,n,p} \ \leq\ \mathrm{AC\_new}_{n,p} + \mathrm{AC\_new}_{p,n} + \mathrm{AC\_old}_{n,p}$$

[Electricity flow on AC lines has to be less than transmission capacity (both new and old) of those lines].

$$\mathrm{ReTnp}_{n,p} + \mathrm{CONTRACTcap}_{n,p} \leq \mathrm{AC\_new}_{n,p} + \mathrm{AC\_new}_{p,n} + \mathrm{AC\_old}_{n,p}$$

[Contracted capacity between BAs has to be less than the transmission capacity (both new and old) of those lines].

7.5.2 Power Flow Representation: Load and Transmission Constraints

The following constraints describe the power-flow transmission representation in ReEDS. In this representation, electricity is distributed according to predefined distribution factors embodied in the exogenous PTDF matrix. As with the truck-route version, there are two layers to the PTDF representation: power and contracts. The power flow layer dictates the flow of power injected into the system whereas the contracts layer describes capacity contracts among BAs.

7.5.2.1 Load

The load (LOAD) constraint for the PTDF representation of transmission is very similar to the truck-route load constraint with the main difference being that, while the above version allows direct decisions about line flows, this version merely defines an intermediate variable—*Net_injections*. These net injections, defined as total generation minus load in that BA, are used later to determine the line flows along AC lines. The constraint is held for each BA *n* and each time-slice *m*.

$$\sum_{q} \text{CONVqmn}_{q,m,n} + \text{CONVOLDqmn}_{q,m,n}$$

[New and existing conventional generation].

$$+ \sum_{c,i,j \in n} \text{WN}_{c,i,j} \cdot \text{CFc}_{c,i,m} \cdot \text{Hm}_{m}$$
$$+ \sum_{c,j \in n,escp} \text{WELEC\_inregion}_{j,c,escp} \cdot \text{CFc}_{c,j,m} \cdot \text{Hm}_{m}$$
$$+ \text{ WGenOld}_{m,n}$$
$$+ \text{ similar constraints for CSP, and PV}$$

[New and existing renewable generation].

$$- \text{ Surplus}_{m,n}$$

[Minus curtailments].

$$+\sum_{st}\left(\text{STORout}_{m,n,st} - \text{STORin}_{m,n,st}\right)$$

[Plus net power from storage].

$$- \text{ (Lmn}_{n,m} + \text{PHEVin}_{n,m})$$

[Minus load and plug-in hybrid EV demand].

$$+\sum_{p} \text{DC\_flow}_{m,p,n} \cdot (1 - \text{TLOSS}_{n,p} \cdot \text{Distance}_{n,p}) - \text{DC\_flow}_{m,n,p}$$

[Plus net electricity imported via DC lines].

$$- \text{ AC\_loss}_{m,n}$$

[Minus losses associated with power transfer on the AC network].

$$= \text{Net\_injection}_{m,n}$$

[Net power injected into the AC network at n].

7.5.2.2 Flow Calculation

The flow calculation (FLOW_CALCULATION) constraint determines how the power injected into the system is distributed around the network, based on the distribution factors of the PTDF matrix. The constraint is held at each transmission corridor (n, p) and each time-slice m. There is a matched constraint for contracts—the second constraint below—that does not resolve time-slices. The "swap-subscripts-and-subtract" mechanism on the right-hand-side of these constraints is merely a way to allow bidirectional flows while using only positive variables.

$$\sum_{n2} \text{PTDF}_{n,p,n2} \cdot \text{net\_injection}_{m,n2} \;=\; \text{AC\_flow}_{m,n,p} - \text{AC\_flow}_{m,p,n}$$

$$\sum_{n2} \text{PTDF}_{n,p,n2} \cdot \text{net\_contracts}_{n2} \;=\; \text{AC\_cflow}_{n,p} - \text{AC\_cflow}_{p,n}$$

7.5.2.3 Transmission Limits

The transmission_limit (TRANSMISSION_LIMIT) constraint limits flow on the AC network by the transfer capacity of the transmission lines. The existing grid transfer capacities were developed in conjunction with the construction of the PTDF matrix. The constraint is held at each transmission corridor n to p and each time-slice m. An analogous constraint limits (second constraint below) contracts on AC lines, and an additional pair (not shown) limits flows and contracts on DC lines.

$$\text{AC\_flow}_{m,n,p} \;\leq\; \text{AC\_new}_{n,p} + \text{AC\_new}_{p,n} + \text{AC\_old}_{n,p}$$

$$\text{AC\_cflow}_{n,p} \;\leq\; \text{AC\_new}_{n,p} + \text{AC\_new}_{p,n} + \text{AC\_old}_{n,p}$$

7.5.2.4 Contracts

The contracts (CONTRACTS) constraint dictates that net flow of contracts out of a BA is the same as the contracts available in that BA. The constraint is held at each BA n.

$$\sum_{p}\left(\text{ReTnp}_{n,p} + \text{CONTRACTcap}_{n,p}\right) - \sum_{p}\left(\text{ReTnp}_{p,n} + \text{CONTRACTcap}_{p,n}\right)$$
$$-\sum_{p}\left(\text{DC\_cflow}_{n,p} - \text{DC\_cflow}_{p,n}\right)$$

[Net renewable and conventional contract capacity on both AC and DC lines].

$$= \text{net\_contracts}_{n}$$

[Equals net contracts at each node].

7.5.3 Planning Reserve Requirement

The reserve margin (RES_MARG) constraint dictates that total firm capacity available, both conventional and renewable, must exceed peak load in each time-slice plus a reserve margin.

Only a fraction, the capacity value, of variable resource capacity contributes to the firm capacity total.

$$\sum_{q} \mathrm{CONVqn}_{qn} + \mathrm{CONVOLDqn}_{qn}$$
$$+\sum_{q,qq} (\mathrm{UPGRADEqn}_{q\;qq,n} - \mathrm{UPGRADEqn}_{q,q\;qn})$$

[New and existing conventional capacity].

$$+\sum_{st} \mathrm{STOR}_{n,st} + \mathrm{STOROLD}_{n,st}$$

[New and existing storage capacity].

$$+\sum_{c,i,j\in n}\left[\mathrm{WN}_{c,i,j}\cdot\sum_{reg\in n}\mathrm{WCVmar}_{c,i,reg,m}\cdot(1-\mathrm{TLOSS}_{i,j}\cdot\mathrm{Distance}_{i,j})\right]$$
$$+\sum_{c,j\in n,escp}\left[\mathrm{WELEC\_inregion}_{c,j,escp}\cdot\sum_{reg\in j}\mathrm{WCVmar}_{c,j,reg,m}\right]$$
$$+ \text{ similar terms for other VRRE}$$

[New wind gets the marginal capacity value calculated for that particular region and class, calculated before the optimization period].[42]

$$+\mathrm{WCVold}_{n,m} + \mathrm{CSPCVold}_{n,m} + \mathrm{PVCVold}_{n,m}$$

[Capacity value for existing VRRE, calculated before the optimization period].[43]

$$+\mathrm{CONTRACTcap}_{p,n}\cdot(1 - \mathrm{TLOSS}_{n,p}\cdot\mathrm{Distance}_{n,p}) - \mathrm{CONTRACTcap}_{n,p}$$

[Net contracts for firm power from other BAs].

$$\geq\ (\mathrm{Pn}_{n} + \mathrm{PHEVin}_{n,m})\cdot(1+\mathrm{reserve\_marg}_{n})\cdot\frac{\mathrm{Lmn}_{n,m}}{\max_{mm}(\mathrm{Lmn}_{n,mm})}$$

[Peak load plus other demands times the reserve margin, moderated by the load curve].

7.5.4 Operating Reserve Requirements

The operating reserve requirement is broken up into four different constraints that try to capture some of the nuances of operating reserves. These four constraints are all held for each time-slice *m* at each reserve-sharing group *reg*.

[42] See Section 7.6 for more detailed discussion of how the marginal capacity values are calculated.

[43] See Section 7.6 for more detailed discussion of how the existing capacity values are calculated.

The first constraint dictates that total spinning plus quick-start plus interruptible load must exceed 7.5% of the load plus additional forecast error reserves required to balance variable resources. The second constraint caps the amount of operating reserves quick-start units can supply, and the third dictates a minimum level for spinning reserves. The first three constraints collectively impose an upper limit on the use of interruptible load to serve operating reserves. Finally, the fourth constraint defines the forecast error reserve tracking variable.[44]

7.5.4.1 OPER_RES

$$\sum_{n \in reg,q} \text{ILn}_n + \text{SRqmn}_{q,m,n} + \text{SROLDqmn}_{q,m,n} + \text{QSqn}_{q,n} + \text{QSOLDqn}_{q,n}$$

[Interruptible load plus spinning and quick start capacity in use in each time-slice].

$$+ \sum_{n \in reg,st} \text{STOR\_SR}_{st,m,n} + \text{STOR\_QS}_{st,n}$$

[Storage providing spinning and quick-start capacity].

$$\geq \ 0.075 \cdot \sum_{n \in reg} (\text{Lmn}_{n,m} + \text{PHEVin}_{n,m}) + \text{forerr\_res\_reqt}$$

[7.5% of load and demand requirements in each time-slice and forecast error reserves].

7.5.4.2 OPER_RES2

$$\sum_{n \in reg,q} (\text{QSqn}_{q,n} + \text{QSOLDqn}_{q,n}) + \sum_{n \in reg,st} \text{STOR\_QS}_{st,n}$$

[Conventional and storage technology capacity serving quick-start].

$$\leq \ 0.06 \cdot \sum_{n \in reg} (\text{Lmn}_{m,n} + \text{PHEVin}_{n,m}) + {}^{5}\!/_{6} \cdot \text{forerr\_res\_reqt}_{reg,m}$$

[6% of load and demand requirements plus 5/6 forecast error reserves].

7.5.4.3 OPER_RES3

$$\sum_{n \in reg,q} \text{SRqmn}_{q,m,n} + \text{SROLDqmn}_{q,m,n} \geq \ .015 \cdot \sum_{n \in reg} (\text{Lmn}_{m.n} + \text{PHEVin}_{n,m})$$

[Spinning reserves have to make up at least 1.5% of total demand in a reserve sharing region in all time-slices].

7.5.4.4 OPER_RES4

$$\text{forerr\_res\_reqt}_{reg,m}$$

[Forecast error reserve requirement per region and time-slice].

[44] See Section 7.6 for more information about how the forecast error is calculated.

$$= \sqrt{\mathrm{WFERold}_{reg}{}^{2} + \mathrm{UPVFERold}_{reg}{}^{2}}$$

[Forecast error reserve requirement for existing variable resource capacity].

$$+ \sum_{c,i,j \in reg} \mathrm{WN}_{c,i,j} \cdot \mathrm{WFERmar}_{c,i,reg,m}$$
$$+ \sum_{c,j \in reg,escp} \mathrm{WELEC\_inregion}_{c,j,escp} \cdot \mathrm{WFERmar}_{c,j,reg,m}$$
$$+ \sum_{n,p \in reg} \mathrm{UPVN}_{n,p} \cdot \mathrm{UPVFERmar}_{n,reg,m} + \sum_{n \in reg} \mathrm{DUPVN}_{n} \cdot \mathrm{UPVFERmar}_{n,reg,m}$$

[Forecast error reserve requirement for new variable resource capacity].

7.5.5 Emissions

The emissions (EMISSIONS) constraint limits the quantity of certain pollutants released through electricity generation. Tracked pollutants include CO_2, SO_2, NO_x, and Hg. ReEDS allows emissions to exceed pre-established caps with an additional penalty in the objective function.

$$\sum_{q,m,n} \left(\begin{array}{l} \mathrm{CONVqmn}_{q,m,n} \cdot \mathrm{Hm}_{m} \cdot \mathrm{CONVpol}_{q,pol} \cdot \mathrm{Heatrate}_{q,n} \\ +\mathrm{CONVOLDqmn}_{q,m,n} \cdot \mathrm{Hm}_{m} \cdot \mathrm{CONVpol}_{q,pol} \cdot \mathrm{HeatrateOld}_{q,n} \end{array} \right)$$

[Emissions from conventional units].

$$+ \sum_{st,m,n} \mathrm{STORout}_{m,n,st} \cdot \mathrm{Hm}_{m} \cdot \ \mathrm{STORpol}_{st,pol} \cdot \mathrm{StHeatrate}_{st,n}$$

[Emissions from storage units (i.e., CAES)].

$$-\mathrm{coallowsulpolred} \cdot \sum_{q,n,pol \in SO2} \mathrm{CoalLowSul}_{q,n} \cdot \mathrm{CONVpol}_{q,pol} \cdot \mathrm{Heatrate}_{q,n}$$

[Less SO_2 reductions from using low-sulfur coal].

$$- \sum_{bioclass,n} \mathrm{CofireGen}_{bioclass,n} \cdot (\mathrm{CONVpol}_{Cofire,pol} - \mathrm{CONVpol}_{biopower,pol}) \cdot \mathrm{Heatrate}_{Cofire,n}$$

[Less CO_2 savings from displacing coal with biomass in co-firing units].

$$\leq \ \mathrm{LPp}_{pol} + \mathrm{emissions\_excess}_{pol}$$

[Emissions cap plus excess emissions].

7.5.6 Renewable Portfolio Standards

ReEDS tracks renewable energy generation and is capable of enforcing renewable or clean energy standards through variations on the RPS constraint shown here. This constraint governs state-level requirements and is used in the base case to match current legislation. National-level

RPS as well as clean energy standard constraints are also available but disabled by default. These national level constraints have a similar form as the state RPS constraint shown below. For state-level requirements, ReEDS can distinguish between generated-in-state, delivered-to-state, and RECs; the constraint shown here assumes delivered-to-state.

$$\begin{aligned}
&\sum_{c,i,j\in states,m} \mathrm{WN}_{c,i,j}\cdot \mathrm{CFc}_{c,i,m}\cdot \mathrm{Hm}_m \cdot (1 - \mathrm{TLOSS}_{i,j}\cdot \mathrm{Distance}_{i,j})\\
&+\sum_{c,i\in states,m} \mathrm{WELEC_inregion}_{c,i,escp}\cdot \mathrm{CFc}_{c,i,m}\cdot \mathrm{Hm}_m\\
&-\sum_{m,n\in states} \mathrm{Surplus}_{m,n}\cdot \mathrm{Hm}_m\\
&+\text{ Similar for other VRRE}
\end{aligned}$$

[Net generation from renewables delivered-to-state].

$$+\mathrm{St\_RPSval}_{states,q}\cdot \sum_{\substack{q\in renewable,\\ n\in states}} (\mathrm{CONVqmn}_{q,m,n} + \mathrm{CONVOLDqmn}_{q,m,n})\cdot \mathrm{Hm}_m$$

[Generation from dispatchable renewables. *St_RPSval* is a binary that tracks what renewable energy technologies count toward each state's requirement].

$$\begin{aligned}
&-\mathrm{St_RPSfrac}_{states}\cdot \sum_{m,n\in states} \mathrm{AC_loss}_n \cdot \mathrm{Hm}_m\\
&-\mathrm{St_RPSfrac}_{states}\cdot \sum_{m,n\in states} \mathrm{DC_flow}_{m,p,n}\cdot \mathrm{TLOSS}_{n,p}\cdot \mathrm{Distance}_{n,p}\cdot \mathrm{Hm}_m
\end{aligned}$$

[Less transmission losses, prorated by renewable target].

$$+\mathrm{St\_RPSshortfall}_{states}$$

[Allow an alternative compliance payment].

$$\geq\ \mathrm{ST\_RPSFrac}_{states}\cdot \sum_{m,n\in states} (\mathrm{Lmn}_{n,m} + \mathrm{PHEVin}_{n,m})\cdot \mathrm{Hm}_m$$

[Must exceed a set fraction of load].

7.5.7 Resource Limits

The wind resource limit (WIND_RES_UC) constraint (first constraint below) dictates that the total amount of wind capacity built in a region in a certain class cannot be more than the actual available resource in that region. The component variables of the first constraint are separately constrained by individual supply curves. There are similar constraints for CSP and PV to characterize the solar resource in each region.

$$\sum_{wscp} \text{WturN}_{c,i,wscp} + \sum_{escp} \text{WELEC\_inregion}_{c,i,escp} \;\leq\; \text{WRuc}_{c,i} - \sum_{j} \text{WO}_{c,i,j}$$

$$\text{WturN}_{c,i,wscp} \;\leq\; \text{WR2G}_{c,i,wscp}$$

$$\text{WELEC\_inregion}_{c,i,escp} \;\leq\; \text{MW\_inregion}_{c,i,escp}$$

7.5.8 Fuel Supply Curves

Gas and coal supply curves are constructed of cost bins with a maximum amount of fuel available in each bin. The quantity consumed from each bin is embodied here in the variable *Vgasbinq*. Not shown here is a matching constraint for coal.

$$\sum_{q \in gastech,m,n} \text{CONVqmn}_{q,m,n} \cdot \text{Hm}_m \cdot \text{Heatrate}_{q,n} + \text{CONVOLDqmn}_{q,m,n} \cdot \text{Hm}_m \cdot \text{HeatrateOld}_{q,n}$$
$$\sum_{st \in CAES,m,n} \text{STORout}_{m,n,st} \cdot \text{Hm}_m \cdot \text{StHeatrate}_{st,n}$$

[Total annual gas usage (MMbtu)].

$$= \sum_{fuelbin} \text{Vgasbinq}_{fuelbin}$$

[Equals sum of quantity demanded by gas supply bins].

7.5.9 Dispatch of Thermal Units

The capacity forced and planned outage (CAP_FO_PO) constraint dictates that conventional capacity q in use in each time-slice m and each BA n has to be less than the statistically available conventional capacity, less forced, and planned outages. Similar constraints exist for existing conventional plants, electric storage units, and dispatchable CSP-with-storage facilities.

$$\text{CONVqmn}_{q,m,n} + \text{SRqmn}_{q,m,n} + \text{QSqn}_{q,n} \;\leq\; \text{CONVqn}_{q,n} \cdot (1 - \text{FO}_q) \cdot (1 - \text{PO}_q)$$

The minimum loading (MIN_LOADING) constraint sets a lower bound on the operation of certain thermal generator types based on peak seasonal output.

$$\text{CONVqmn}_{q,m,n} \;\geq\; \max_{mm \in s(m)} \text{CONVqmn}_{q,mm,n} \cdot \text{MTDF}_q$$

7.5.10 Renewable Contracts

The renewable contracts (RE_CONTRACTS) constraint defines the tracking variable, *ReTnp*, that is used elsewhere to ensure sufficient transmission. The constraint is held at each BA.

$$\sum_{c,i\in n,j}\left(\mathrm{WN}_{c,i,j}+\mathrm{WO}_{c,i,j}\right)-\sum_{c,i,j\in n}\left(\mathrm{WN}_{c,i,j}+\mathrm{WO}_{c,i,j}\right)$$
$$\sum_{cCsp,i\in n,j}\left(\mathrm{CspN}_{cCsp,i,j}+\mathrm{CspO}_{cCsp,i,j}\right)-\sum_{cCsp,i,j\in n}\left(\mathrm{CspN}_{cCsp,i,j}+\mathrm{CspO}_{cCsp,i,j}\right)$$
$$+\sum_{p}\left(\mathrm{UPVN}_{n,p}+\mathrm{UPVO}_{n,p}-\mathrm{UPVN}_{p,n}-\mathrm{UPVO}_{p,n}\right)$$

[Net imports of VRRE].

$$=\sum_{p}\left(\mathrm{ReTnp}_{n,p}-\mathrm{ReTnp}_{p,n}\right)$$

[Renewable contracted transmission between BAs].

7.5.11 Curtailments

To estimate the amount of VRRE curtailed, this constraint starts with the base level of curtailments computed in advance of the optimization. From that quantity, additional energy is added or subtracted based on additional VRRE capacity, changes to installations or behavior of must-run conventional units, and new electric storage system additions.

$$\mathrm{Surplus}_{m,n} \geq \mathrm{SurpOld}_{m,n}$$

[New tracking variable, computed base curtailments].

$$+\sum_{c,i\in n,j}\mathrm{WN}_{c,i,j}\cdot\mathrm{CFc}_{c,i,m}\cdot\mathrm{WSurplusMar}_{c,i,j,m}$$
$$+\text{ similar terms for other VRRE}$$

[Additional curtailments for new VRRE installations].

$$+\left(\max_{m\in s}\left((\mathrm{CONVqmn}_{q,m,n}+\mathrm{CONVOLDqmn}_{q,m,n})\cdot\mathrm{MTDF}_{q}\right)-\mathrm{MRprev}_{s,n}\right)$$
$$\cdot\mathrm{MRSurplusMar}_{m,n}$$

[Additional curtailments for increased must-run thermal generation].

$$-\mathrm{STOR}_{n,st}\cdot\mathrm{StSurpRecMar}_{n,st}$$

[Less generation recovered by storage].

7.6 Resource Variability Parameter Calculations

There are three basic resource variability parameters for renewables with variable resources (i.e., wind and solar) that are calculated for each period in ReEDS before the linear programming optimization is conducted for that period. These include capacity value, operating reserve requirements, and curtailments. For each, a marginal value is calculated, which applies to new installations in the period, and an old value is calculated, which represents the value for the existing system. This section describes the statistical assumptions and methodology used to calculate these values.

These variable-resource parameters are calculated for a source at which the VRRE is generated and a sink to which the energy is supplied. The source is always a supply region. The user must specify the regional level for the sink; it can be a BA, a reserve sharing group, a NERC region, or an entire interconnect. The old values for these variability parameters are calculated for each sink but not for each source because the old value is the same for all of the variable resource supplied to the sink.

7.6.1 Data Inputs for the Calculation of Resource Variability Parameters

The inputs required for calculating the resource variability parameters describe the probability distributions associated with loads, conventional generator availability, and VRRE generation. For each, an expected value and standard deviation are calculated. For loads, the expected value, μ_L, is the same as the values used in the LOAD constraint. The standard deviation of the load, σ_L, is calculated from the load duration curve of the sink region. For conventional generator availability, the expected value is the nameplate capacity times one, minus a fraction equal to the forced outage rate:

$$\mu_r = \sum_{q,n \in r} \mathrm{CONVOLDqn}_{q,n} \cdot (1 - \mathrm{FOq}_q)$$

Variance of conventional generator availability is calculated based on an average plant size:

$$\sigma^2{}_r = \sum_{q} \mathrm{numplants}_{q,r} \cdot \mathrm{plantsize}_{q,r}{}^2 \cdot \mathrm{FO}_q \cdot (1 - \mathrm{FO}_q)$$

where:

$\mathbf{FO}_q$ is the forced outage rate of a generator type q

$\mathbf{plantsize}_q$ is the input typical size of a generator of type q, and

$\mathbf{numplants}_{q,r} = \mathbf{CONVOLDqn}_{q,r}/\mathbf{plantsize}_q$.

The probability distribution associated with conventional generator availability is complex due to the fact that there can be many conventional generators and their availability is each a binomial random variable with probability $(1 - FO_q)$ of being one. This complexity is largely avoided by first combining the random variables for conventional generator availability, C, with loads, L, in the form of a random variable, X, as follows:

$$X = C - L$$

The expected value of X, μ_X, is the sum of the expected values of the other two random variables. We can also express its variance, σ^2_X, and standard deviation, σ_X, since C and L are statistically independent.

$$\sigma_X = \sqrt{\sigma_C^2 + \sigma_L^2}$$

Expected future improvements in the performance of wind and solar technologies are captured in ReEDS through increased capacity factors. These higher capacity factors translate directly into improvements in the mean of a VRRE plant's generation output. ReEDS also estimates a new standard deviation for a VRRE plant, based on regressions that estimate the new standard deviation as a function of the old standard deviation and the new capacity factor.

In the variable-resource parameters described below, the input distributions must represent the generation from all VRRE plants contributing to a sink region and not simply to a single plant. The mean value, μ_R, is calculated easily as the sum of the mean values of the output of the individual contributing VRRE plants. The standard deviation is complicated by the fact that the outputs of the VRRE plants are correlated. For each ReEDS time-slice, a 10-minute wind output time-series data created for the recent integration studies (NREL 2009; NREL 2010c) was used to develop a correlation matrix ($P_{k,l}$) of the Pearson correlation between pairs (k,l) of possible ordered sets (such as region, class, and VRRE). For example, there exists a correlation coefficient relating expected power output of class 5 wind in region 3 and class 2 PV generation in region 14. The variance of the VRRE arriving at a sink region r, $\sigma_{R_r}^2$, is then calculated from this correlation matrix P_{kl} through the following standard statistical formula:

$$\sigma_{R_r}^2 = \sum_{k \in R_r} \sum_{l \in R_r} P_{k,l} \cdot \sigma_k \cdot \sigma_l$$

where

σ_k and σ_l are the standard deviation of the particular VRRE site

P_{kl} is the Pearson correlation coefficient

R_r is the set of VRREs contributing to region r.

Given the mean and standard deviation of all VRREs contributing to a region r, the variable-resource parameters can be calculated—including capacity value, operating reserve requirement, and curtailment. In the current version of ReEDS, all combined random variables are approximated as normally distributed random variables. Other probability distributions, such as a beta distribution, could also be used.

7.6.2 Capacity Value

Capacity value is the fraction of VRRE capacity that can contribute to meet the reserve margin constraint in each sink region. It is a function of the amount and type of VRRE consumed in the sink region, the dispersion of the VRRE plants contributing the energy, the size and variability of the electric load in the sink region, and the amount and flexibility of conventional capacity contributing to the load in the sink region. Generally, as more VRREs are used by the sink region, the collective capacity value decreases. And, as more renewable energy from a particular source is used, the marginal capacity value from that source decreases.

7.6.2.1 $CVold_r$

The capacity value for the total VRRE generation that is to be consumed in sink region r, $CVold_r$, is the amount of load that must be removed in every hour to maintain system reliability if the VRRE were no longer available in sink region r (i.e., without changing the loss-of-load probability). This change in load is the ELCC associated with the VRRE contributed to the sink region. To estimate $CVold_r$, first equate the loss-of-load probabilities of the following random variables:

$$U = C + R_r - L$$

$$V = C - (L - \Delta_L)$$

where C, R_r, and L are as defined above and Δ_L is the ELCC for the VRRE in the system. Assuming C, R_r, and L are statistically independent, the variances of U and V are given by the following:

$$\sigma_U^2 = \sigma_C^2 + \sigma_{R_r}^2 + \sigma_L^2$$

$$\sigma_V^2 = \sigma_C^2 + \sigma_{L-\Delta_L}^2$$

The loss-of-load probability with VRRE in the system is the probability that U is less than zero or $P(U < 0)$. Define $U' = (U - \mu_U) / \sigma_U$ as a standard normal variable. The probability that U is less than zero is the probability that U' is less than $-\mu_U / \sigma_U$ or $N(-\mu_U / \sigma_U)$, where N is the cumulative standard normal distribution function. Similarly, $P(V < 0) = N(-\mu_V / \sigma_V)$ and the ELCC or Δ_L can be estimated by equating $P(U < 0) = P(V < 0)$.

With these definitions, $CVold_r = \Delta_L / TR_r$ where TR_r is the total installed VRRE nameplate capacity devoted to region r. The following shows the derivation for an expression for $CVold_r$:

$$P(V < 0) = P(U < 0)$$

$$N(-\mu_V/\sigma_V) = N(-\mu_U/\sigma_U)$$

$$\mu_V/\sigma_V = \mu_U/\sigma_U$$

$$(\mu_C - \mu_L + \mu_{\Delta_L})/\sigma_V = \mu_U/\sigma_U$$

$$\mu_{\Delta_L} = \mu_L - \mu_C + \mu_U \cdot \sigma_V/\sigma_U$$

$$\Delta_L = \mu_L - \mu_C + \mu_U \cdot \sigma_V/\sigma_U,$$

In the last equation, $\Delta_L = \mu_{\Delta_L}$ is set. Because μ_V is a function of $\sigma_{L-\Delta_L}^2$, which, in turn, depends on Δ_L. The above equation would be non-trivial to solve and would increase the run-time significantly. Instead of solving exactly, $\sigma_{L-\Delta_L}^2$ is estimated based on the ELCC or Δ_L of previous periods and the result is used to find:

$$CVold_r = \frac{\mu_{\Delta_L}}{\mathrm{TR_r}}$$

$$= \frac{\mu_L - \mu_C + (\mu_{R_r} - \mu_{R_r}) + \mu_U \cdot \frac{\sigma_V}{\sigma_U}}{TR_r}$$

$$= \frac{-\mu_U + CF_r \cdot TR_r + \mu_U \cdot \frac{\sigma_V}{\sigma_U}}{TR_r}$$

$$= CF_r - \mu_U \cdot \frac{1 - \frac{\sigma_V}{\sigma_U}}{TR_r}$$

where CF_r represents the VRRE generation capacity factor.

7.6.2.2 $CVmar_{c,i,r}$

This is the marginal capacity value associated with the addition of class c VRRE capacity in a source region i delivered to a sink region r. The calculation for $CVmar_{c,i,r}$ is very similar to the one for $CVold_r$. $CVmar_{c,i,r}$ is calculated using the random variable U above and the random variable W:

$$W = C + (R_r + \delta_{R_r,c,i}) - (L + \delta_L)$$

where W includes both $\delta_{R_r,c,i}$, which is an incremental amount of class c VRRE from region i that can serve region r, and δ_L, which is the ELCC for this increment of VRRE. δ_L is calculated similarly to the calculation for Δ_L above.

$$P(W < 0) = P(U < 0)$$

$$N(-\mu_W/\sigma_W) = N(-\mu_U/\sigma_U)$$

$$\mu_W/\sigma_W = \mu_U/\sigma_U$$

$$(\mu_C + \mu_{R_r} + \mu_{\delta_{R_r,c,i}} - \mu_L - \mu_{\delta_L})/\sigma_W = \mu_U/\sigma_U$$

$$\mu_{\delta_L} = \mu_C + \mu_{R_r} + \mu_{\delta_{R_r,c,i}} - \mu_L - \mu_U \cdot \sigma_W/\sigma_U$$

Finally, $CVmar_{c,i,r}$ is equal to $\delta_L/\delta_{R_r,c,i}$ or, equivalently,

$$CVmar_{c,i,r} = CF_{c,i} - (\frac{\sigma_W}{\sigma_U} - 1) \cdot \mu_U/\delta_{R_r,c,i}$$

7.6.3 Operating Reserve Requirement

Operating reserves include spinning reserves, quick-start capabilities, and interruptible loads that can be dispatched to meet unanticipated changes in loads and power availability. There is no standard way for estimating the level of operating reserves required. In ReEDS, it is assumed that the normal operating reserve required by a sink region *r* is 7.5% of the load ($Lmn_{r,m}$), plus the additional operating reserves induced by variable generation in the region.

ReEDS assumes that additional operating reserves are required to cover errors in forecasting VRRE generation. Forecasting errors are estimated based on a one-hour persistance forecast. The variance of a one-hour persistance forecast is simply the variance from hour to hour of a VRRE resource in a particular region, *i,* and class *c*.[45] The total one-hour persistance forecast variance from all VRREs contributing to a sink region *r* is the sum of the variances and covariances of those contributers.

$$\sigma^2_{r,\delta_{\text{hourly}}} = \sum_{c,i\in \text{r}} \sum_{c\prime,k\in \text{r}} DP_{c,c\prime,i,k} \cdot \sigma_{i,c} \cdot \sigma_{k,c\prime}$$

where $DP_{c,c',i,k}$ is the correlation between the forecast errors for class c wind from resource region *i* and class *c'* from region *k* contributing to sink region *r* ($k \in r$).

ReEDS assumes the total old forecast error reserve requirement, $TFERold_r$, is two standard deviations of the hourly delta variance.

$$TFERold_r = 2 \cdot \sqrt{\sigma^2_{r,\delta_{\text{hourly}}}}$$

The marginal value is calculated in a similar manner to capacity value marginals, by adding an incremental ($\Delta R_{c,i}$) amount of VRRE capacity in a particular resource region *i* and class *c* and calculating the forecast error requirement with and without the incremental amount of VRRE capacity added.

$$\sigma^2_{\Delta R_{hourly},\text{i}} = \sigma^2_{\Delta \text{R}_\text{c},\text{i}} + \sum_{\text{c}\prime,\text{k}\in\text{r}} DP_{c,c\prime,i,k} \cdot \sigma_{\Delta R_c,\text{i}} \cdot \sigma_{c\prime,k}$$

$$\text{FERmar}_{\text{c,i,r}} = \frac{2 \cdot \sqrt{\sigma^2_{\text{r},\delta_{\text{hourly}}} + \sigma^2_{\Delta R_{hourly},i}} - 2 \cdot \sqrt{\sigma^2_{\text{r},\delta_{\text{hourly}}}}}{\Delta R_{c,i}}$$

As with the old value, it is assumed that the marginal value is two standard deviations of the hourly delta variance. This marginal value per unit of VRRE capacity added is then applied to new VRRE capacity in the following optimization period and the result added to the normal operating reserve requirement.

7.6.4 Curtailment

At high levels of VRRE penetration, there are times when the VRRE generation could exceed that which can be used in the system. This "surplus" VRRE is not generated and does not contribute to meeting load. ReEDS calculates the existing VRRE generation ($TSurpOld_{n,m}$) that

[45] It is assumed that wind hourly delta variances do not change by season or time-slice. However, solar hourly delta variances do change by season and time-slice. It is also assumed that hourly delta forecasts are independent and not correlated with each other.

is curtailed as well as the fraction of generation from new VRRE plants (*Surplusmar*$_{c,i,reg,m}$). ReEDS uses these surplus values to reduce the useful energy contributed by VRREs, making them less cost-effective generators.

TSurpOld$_{n,m}$ is the expected generation from all the VRREs consumed in sink region *r* that cannot be used productively because the load is not large enough to absorb both the VRRE generation and the must-run generation from existing conventional sources. This situation occurs most frequently in the middle of the night when loads are small, baseload conventional plants are running at their minimum levels, and the wind is blowing. To calculate *TSurpOld*$_{m,n}$, use the random variable *Y* defined in the capacity value discussion above as the must-run conventional baseload generation *M* minus the load *L* plus the VRRE generation *R*.

$Y = M - L + R$

Next, define the surplus VRRE at any point in time, *S*, as follows.

If $Y < 0$, $S = 0$

If $Y > 0$, $S = Y$

Then, the expected surplus μ_s can be calculated from the density function of *Y*, $g(y)$ as follows.

$$\mu_S = \int_{-\infty}^{\infty} sf(s)ds$$

$$\mu_S = \int_{-\infty}^{0} sf(s)ds + \int_{0}^{\infty} sf(s)ds$$

$$\mu_S = 0 + \int_{0}^{\infty} yg(y)dy$$

The density function of *y* can be found by convolving the density function of *M–L* together with the density function of the VRRE. However, similar to what was done in the calculation of the VRRE capacity value above, normal distributions for both *M–L* and *R* are approximated. With the normal distribution assumption, the value of μ_s can be found quickly in ReEDS with the analytical formula derived below. Similar to the *CVmar* and *FERmar* calculations above, *Y* is assumed to be well-approximated by a normal distribution and the standard normal variable Y' can be defined as $Y' = (Y - \mu_Y) / \sigma_Y$, then:

$$Y = Y' \cdot \sigma_Y + \mu_Y$$

$$dY = \sigma_Y dY'$$

Thus, the variable change yields:

$$\mu_S = \int_{0}^{\infty} yg(y)dy$$

$$\mu_S = \int_{-\mu_Y/\sigma_Y}^{\infty} (y'\sigma_Y + \mu_Y) \cdot g(y'\sigma_Y + \mu_Y) \cdot \sigma_Y dy'$$

$$\mu_S = \int_{-\mu_Y/\sigma_Y}^{\infty} \sigma_Y^2 \cdot y' \cdot g(y'\sigma_Y + \mu_Y) dy' + \int_{-\mu_Y/\sigma_Y}^{\infty} \mu_Y \cdot \sigma_Y \cdot g(y'\sigma_Y + \mu_Y) dy'$$

Assuming that *Y* and *Y'* are normally distributed, as stated above, then:

$$\mu_S = \int_{-\mu_Y/\sigma_Y}^{\infty} \sigma_Y^2 \cdot y' \left(\frac{1}{\sigma_Y\sqrt{2\pi}}\right) \exp\left(\frac{(-y'\sigma_Y + \mu_Y - \mu_y)^2}{2\sigma_Y^2}\right) dy'$$

$$+ \int_{-\mu_Y/\sigma_Y}^{\infty} \mu_Y \cdot \sigma_Y \left(\frac{1}{\sigma_Y\sqrt{2\pi}}\right) \exp\left(\frac{(-y'\sigma_Y + \mu_Y - \mu_y)^2}{2\sigma_Y^2}\right) dy'$$

$$\mu_S = \int_{-\mu_Y/\sigma_Y}^{\infty} \frac{\sigma_Y \cdot y'}{\sqrt{2\pi}} \exp\left(\frac{-y'^2}{2}\right) dy' + \int_{-\mu_Y/\sigma_Y}^{\infty} \frac{\mu_Y}{\sqrt{2\pi}} \exp\left(\frac{-y'^2}{2}\right) dy'$$

$$\mu_S = \frac{\sigma_Y}{\sqrt{2\pi}} \exp\left(\frac{-\mu_Y^2}{2\sigma_Y^2}\right) + \mu_Y(1 - N_{0,1}(-\mu_Y/\sigma_Y))$$

where $N_{0,1}$ is the standard normal distribution with mean 0 and standard deviation 1. Then $TSurpOld_{m,n}$ is the difference between the expected surplus with VRRE, μ_s, and the expected surplus if there were no VRRE generation consumed in sink region *r*, μ_{SN}:

$$TSurpOld_{m,n} = (\mu_S - \mu_{SN})$$

Normally, μ_{SN} would be zero, as the conventional must-run units would not be constructed in excess of the minimum load. With the assumption of a normal distribution for *Y*, some non-zero probability is introduced that *Y* could be positive even if there were no VRREs (i.e., that the generation from must-run units could exceed load). Thus, it is important to calculate μ_{SN} and to subtract it from μ_S to remove the bulk of the error introduced by the normal distribution assumption; μ_{SN} is calculated exactly the same way but with no VRREs included.

Must-run conventional capacity is defined as existing available (i.e., not in a forced outage state) coal and nuclear capacity in sink region *r* times a minimum turn-down fraction, *MTDF*. The expected value of the must-run capacity of type *q* available at any given point in time, μ_{M_q}, thus is:

$$\mu_{M_q} = CONVOLD_{q,r} * (1 - FO_q) * MTDF_q$$

where:

> FO_q is the forced outage rate of the must-run capacity of type *q*,
>
> $CONVOLDqn_{q,r}$ is the existing conventional capacity in sink region *r* of type *q*

$MTDF_q$ is 0.45 for old (pre-2006) coal plants, 0.35 for new (post-2006) coal plants, and 1.0 for nuclear plants.

$SurplusMar_{c,i,r,m}$ is the fraction of generation from a small addition, $\Delta R_{c,i,r}$, of class c VRRE installed in supply region i destined for sink region r that cannot be productively used because the load is not large enough to absorb both the VRRE generation and the must-run generation from existing thermal sources. It is calculated as follows:

$$Surplusmar_{c,i,reg,m} = (\mu_{S+\Delta R_{c,i,r}} - \mu_S)/\Delta R_{c,i,r}$$

where $\mu_{SR+\Delta R_{c,i,r}}$ is calculated in exactly the same way as μ_S, but with $\Delta R_{c,i,r}$ megawatts of VRRE added in region i.

8 Appendix

8.1 Modeling Power Flow in ReEDS

ReEDS provides two options for modeling transmission. The more realistic but more computer-intensive option is a linear approximation to AC power flow. This section describes the derivation of the linear approximation to AC power flow as used in ReEDS. We begin with an overview of AC power flow and from that derive a linear approximation.

8.1.1 Describing AC Power Flow

With a handful of exceptions, all power lines in the United States transmit AC. The equations used to represent AC power flow are highly non-linear due to the sinusoidal nature of the voltage and current cycles of AC power.

The flow of power, F_{ik}, between a connection (bus) i and a second bus k is the product of the voltage at the bus i, E_i, and the current along the line connecting the two buses, I_{ik}:

$$F_{ik} = E_i \overline{I}_{ik} \tag{1}$$

where $\overline{I}$ denotes the complex conjugate of I. The current, I_{ik}, can be expressed as the ratio of the voltage at k to the impedance Z_{ik} of the line:

$$I_{ik} = \frac{E_k}{Z_{ik}} = \frac{E_k}{R_{ik}+jX_{ik}} \tag{2}$$

where R is the resistance of the line, X is the reactance and j is the imaginary unit, $\sqrt{-1}$. Alternatively,

$$I_{ik} = E_k \cdot \frac{R_{ik} - jX_{ik}}{R^2 + X^2} \tag{3}$$

Or, let $Y_{ik}=G_{ik}+jB_{ik}$ be defined as the admittance of the circuit, i.e., $Y_{ik}=1/Z_{ik}$:

$$I_{ik}=E_k \cdot (G_{ik}+jB_{ik}) \tag{4}$$

where $G_{ik}= \frac{R_{ik}}{R^2+X^2}$ and $B_{ik}= \frac{X_{ik}}{R^2+X^2}$.

Substituting (4) into (1) yields:

$$F_{ik} = E_i \overline{I}_{ik} = E_i \cdot \overline{(E_k(G_{ik} + jB_{ik}))} \ . \tag{5}$$

In polar coordinates, the voltage E_i can be expressed as

$$E_i = |E_i|e^{j\Theta_i} = |E_i|(\cos\Theta_i + j\sin\Theta_i), \tag{6}$$

which can be substituted into (5),

$$F_{ik} = \quad |E_i|(\cos\Theta_i + j\sin\Theta_i)\cdot \overline{(|E_k|(\cos\Theta_k + j\sin\Theta_k)(G_{ik} + jB_{ik}))} \tag{7}$$

$$= \quad |E_i||E_k|\cdot\begin{pmatrix} +j(G_{ik}\cos(\Theta_i - \Theta_k) + B_{ik}\sin(\Theta_i - \Theta_k)) \\ +j(G_{ik}\sin(\Theta_i - \Theta_k) - B_{ik}\cos(\Theta_i - \Theta_k)) \end{pmatrix}. \tag{8}$$

Clearly this power flow at *i* is a highly non-linear function. Therefore, AC Optimal Power Flow (OPF) is a non-linear optimization and is in fact classified as an NP-hard problem. There are several issues associated with such a problem: (1) there is no guarantee for the existence of a solution, (2) it is very difficult to find a solution if it exists, and (3) any solution found is most likely only a local solution.

8.1.2 DC Power Flow Linear Approximation

We seek a linear approximation to the above formulation that guarantees a single optima can be found. We begin by noting that for transmission lines of reasonable length the resistance of the line is considerably less than the reactance. Therefore, G_{ik} is relatively small and can be ignored:

$$F_{ik} \approx |E_i||E_k| \left(B_{ik}\cdot\sin(\Theta_i - \Theta_k) - jB_{ik}\cdot\cos(\Theta_i - \Theta_k)\right). \tag{9}$$

Secondly, we note that for small angles, $\sin(\Theta)\approx\Theta$ and $\cos(\Theta)\approx 1$, so that

$$F_{ik} \approx |E_i||E_k| \left(B_{ik}\cdot(\Theta_i - \Theta_k) - jB_{ik}\right). \tag{10}$$

Assuming we are concerned with only real power flows (hence the term "DC power flow"), we can eliminate the imaginary component:

$$F_{ik} \approx |E_i||E_k|B_{ik}\cdot(\Theta_i - \Theta_k). \tag{11}$$

If we differentiate (11) with respect to the voltage angle of the sending bus *i,* we arrive at

$$\frac{\delta F_{ik}}{\delta\Theta_i} \approx |E_i||E_k|B_{ik}, \tag{12}$$

and since $R \ll X$ we can simplify to this:

$$\frac{\delta F_{ik}}{\delta\Theta_i} \approx \frac{|E_i||E_k|X_{ik}}{(R^2 + X^2)} \approx \frac{|E_i||E_k|}{X_{ik}}. \tag{13}$$

Alternatively, we can differentiate (11) with respect to the voltage angle of the receiving bus k[46]

$$\frac{\delta F_{ik}}{\delta \Theta_k} \approx -\frac{|E_i||E_k|}{X_{ik}} \tag{14}$$

or with respect to the voltage magnitude

$$\frac{\delta F_{ik}}{\delta |E_i|} \approx |E_k| B_{ik} \cdot (\Theta_i - \Theta_k). \tag{15}$$

We can express a first order approximation to the change in flow around a point $F_{ik}{}^{\iota}$ by expanding a power series through the first derivative only. Using vector notation for all the flows from i, we have:

$$F_{ik}{}^{\iota+1} \approx F_{ik}{}^{\iota} + \frac{\delta F_{ik}}{\delta \Theta}^{T} \Delta\Theta + \frac{\delta F_{ik}}{\delta |E_i|}^{T} \Delta |E_i|. \tag{16}$$

We can eliminate the second term because voltage magnitudes are not allowed to vary significantly:

$$F_{ik}{}^{\iota+1} \approx F_{ik}{}^{\iota} + \frac{\delta F_{ik}}{\delta \Theta}^{T} \Delta\Theta. \tag{17}$$

Thus, the change in flow from bus i to bus k, ΔF_{ik}, can be approximated as

$$\Delta F_{ik} = F_{ik}{}^{\iota+1} - F_{ik}{}^{\iota} \approx \frac{\delta F_{ik}}{\delta \Theta}^{T} \Delta\Theta. \tag{18}$$

We can now build a matrix $\delta F/\delta\Theta$ whose rows are all the vectors $(\delta F_{ik}/\delta\Theta)^T$ for all the buses i in the system and all the links k from each of those buses. That is, the rows of $\delta F/\delta\Theta$ correspond to all the transmission lines in the system and the columns, to all the buses in the system. Thus $\delta F/\delta\Theta$ is of dimension LxN where L is the number of lines. The vector of flows ΔF over those lines is:

$$\Delta F \approx \frac{\delta F}{\delta \Theta} \Delta\Theta \tag{19}$$

The total real power, P_i, at a bus i can now be calculated using the same approximations. The total power, P_i, at a bus i is the sum of the power flows along all the lines connected to the bus, (i.e., P_i is the net power that must be injected at bus i to be consistent with the flows from i to all

[46] We can further simplify $\delta F_{ik}/\delta\Theta_k$ by assuming unit voltage magnitude so that $\delta F_{ik}/\delta\Theta_k = -1/X_{ik}$, and $\delta F_{ik}/\delta\Theta_i = 1/X_{ik}$.

connecting buses). A positive P_i implies that more power is generated at the bus than is consumed at the bus; negative P_i implies more power is consumed at the bus than is generated.

$$P_i = \sum_k F_{ik} \approx \sum_k |E_i||E_k|B_{ik} \cdot (\Theta_i - \Theta_k) \tag{20}$$

We can use the same approach and approximations[47] to compute the matrix of injections ΔP_i as we did ΔF_i

$$\Delta P_i \approx \frac{\delta P_i}{\delta \Theta}^T \Delta\Theta \tag{21}$$

where

$$\frac{\delta P_{ik}}{\delta \Theta_k} = |E_i||E_k|B_{ik} \qquad \text{for } k \neq i \tag{22}$$

and

$$\frac{\delta P_{ik}}{\delta \Theta_i} = -|E_i| \sum_k |E_k|B_{ik}. \tag{23}$$

Similarly we can construct the matrix $\delta P/\delta\Theta$ to compute ΔP as we did ΔF

$$\Delta P \approx \frac{\delta P}{\delta \Theta} \Delta\Theta \tag{24}$$

The matrix ΔP has one row and one column for each bus and is of dimension NxN.

Because a linear relationship is assumed in the DC power flow model and P and F both become zero if Θ equals zero, we will hereafter write $\Delta\Theta$, ΔF, and ΔP as simply Θ, F, and P, respectively.

We could use the relationships of equations (19) and (24) in a linear model of the grid to simulate the transmission flows. Such a formulation would require the addition of the voltage angles Θ as variables, essentially adding a new variable for each bus for each point in time at

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[47] We must also assume that:

- All shunt reactances to ground are ignored
- All shunts to ground that arise from autotransformers are eliminated
- Phase shift transformers are not employed.

which the flows are calculated. However, we can eliminate these additional variables by solving for Θ as shown below.

If we could invert the matrix $\delta P/\delta\Theta$, then

$$\Theta \approx t\,\frac{\delta P}{\delta\Theta}^{-1} P \tag{25}$$

And flows could be easily calculated as

$$F \approx \frac{\delta F}{\delta\Theta}\Theta \approx \frac{\delta F}{\delta\Theta}\cdot\frac{\delta P}{\delta\Theta}^{-1} P. \tag{26}$$

Unfortunately we cannot invert $\delta P/\delta\Theta$ because each of its rows sums to zero as shown by equations (22) and (23). Thus, $\delta P/\delta\Theta$ has rank N-1 where N is the number of buses. However if we remove one column and one row from $\delta P/\delta\Theta$, it will have full rank (N-1) and be invertible. We will call this new matrix B_{bus}. Unlike $\delta P/\delta\Theta$, B_{bus} has full rank of N-1 and is invertible. We also need to remove the column in the $\delta F/\delta\Theta$ matrix corresponding to the same "angle reference" bus (i.e., the same column as the column removed in the $\delta P/\delta\Theta$ matrix) yielding a matrix of size Lx(N-1); we refer to this new matrix as B_{branch}. Now we can solve as in equation (26) for the flow from the N-1 buses:

$$F \approx B_{branch}\cdot B_{bus}^{-1}\cdot P_{non-ref} = H_0\cdot P_{non-ref}. \tag{27}$$

Typically, to obtain a full complement of N buses, a zero vector corresponding to the column for the "reference" bus is added back into the Lx(N-1) matrix H_0 and to the vector of injections $P_{non-ref}$ so that equation (27) becomes

$$F \approx \begin{pmatrix} 0 & H_0 \end{pmatrix} \begin{pmatrix} P_{ref} \\ P_{non-ref} \end{pmatrix} = HP \quad \text{where } H = \begin{pmatrix} 0 & H_0 \end{pmatrix}. \tag{28}$$

P_{ref} is the injection required at the reference bus to meet the system power balance equation, and H is the matrix of PTDFs, also called shift factors.

8.1.3 Determining the Values for H *for the Three Interconnects of the U.S. Grid*

Before the above approximations were used to represent the interconnects in ReEDS, the number of buses and lines in the interconnects were reduced by aggregating buses and lines together consistent with the BAs of ReEDS and the single line connection between any two contiguous BAs. A detailed description of the process used to generate H based on these aggregated buses and lines is presented in Oh (2010). An improved methodology for grouping buses together has been identified and documented by Oh (2011) but has not been implemented in ReEDS.

8.2 Geographic Information System Calculations

Using GIS, a preliminary optimization is performed outside and prior to the first period's linear programming optimization to construct a supply curve for onshore wind, shallow offshore wind, and deep offshore wind, for each region i and wind class c as well as CSP for each region i and CSP class $cCsp$. The following example describes the process for wind, but a similar process is done for CSP. The pre-optimization minimizes the following.

$$\sum_{c,i,l,h,k} (GC_{c,l} + TC_{c,i,l,h,k}) \cdot W_{c,i,l,h,k} + \sum_{k} M \cdot D_k$$

Subject to:

$$\sum_{c,i,l,h,k} W_{c,i,l,h,k} + D_k = a_k \cdot T_k$$

$$W > 0$$

$$D > 0$$

where:

$GC_{c,l}$ is the levelized cost of generation from a type l wind plant at a class c wind resource site

$TC_{c,i,l,h,k}$ is the levelized cost of building a transmission spur for class c wind of type l from grid square h in region i to transmission line k

$W_{c,i,l,h,k}$ is class c wind of type l transported from grid square h in region i on transmission line k

M is a large number (very high cost)

D_k is a dummy variable to ensure feasibility in the constraint below

a_k is the fraction of the capacity (T_k) of line k available.

Using the results of this pre-optimization, supply curves are constructed for each region i, for each type of wind resource l (such as onshore, shallow offshore, and deep offshore), and for each class of wind resource within that type. Each supply curve is made up of four wind resource-cost pairs identified by the subscript *wscp*, where *wscp* takes on values 1 through 4. The amount of wind resource in each step initially is set so that for each type of wind l,

$$WR2G_{c,i,l,wscp} = f_{wscp} \cdot \sum_{h,k} W_{c,i,l,h,k}$$

where $f_i = 0.1 \cdot i$.

Thus, the first step on the supply curve is comprised of the 10% of all the class c wind grid squares in region i having the lowest cost to build transmission spurs to the grid. The next step consists of the 20% with the next lowest set of costs. The cost, $WR2GPTS_{c,i,l,wscp}$, associated with each point or step on the supply curve, is the mean levelized transmission spur cost for that step.

The supply curve quantity/price pairs ($WR2G_{c,i,l,wscp}$ and $WR2GPTS_{c,i,l,wscp}$) from this pre-linear programming optimization are input to the linear programming ReEDS model within the wind supply curve constraints. In each period, the quantities, $WR2G_{c,i,l,wscp}$, are decremented by the amount of wind resource in that step deployed in previous periods.

Ideally, this preoptimization should be performed for each period of the ReEDS run with the costs of wind generation specific to that period. Wind generation costs generally decrease from one period to the next because of exogenously specified R&D-driven reductions in capital and operating costs and also because of learning through industrial experience. This is not possible because of the time and computer resources required to conduct this optimization in GIS for the great number of wind grid squares considered. Currently, the optimization is conducted once using the wind cost/performance characteristics for the first period.

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