Documentation of Code solveGEN.R, for the Energy Infrastructure of the Future study, September 2020 (paper 2020.5)

ENERGY FUTURES DASHBOARD

Description of solveGEN.R Code that Solves for Power Plant Capacity and Dispatch given Desired User Electricity Mix

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Abstract

The code solveGEN.R solves for (1) the necessary amount of power plant capacity and (2) the hourly generation from each type of power plant in the future year 2050. The inputs into this code are (1) the Energy Infrastructure of the Future website user's desired 2050 mix of electricity generation as the percent of annual electricity generated, G_{annual}, by each technology type, i, (2) the electricity generation needed each hour in 2050 (i.e., an 8760 hourly generation profile), and (3) hourly generation profiles from non-dispatchable generation technologies of wind, solar photovoltaics, and concentrating solar power, and (4) assumed amortized capital costs and variable operating costs for natural gas combined cycle and natural gas combustion turbines (to determine the ratio of natural gas generation from each type of natural gas power plant).

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Introduction

The Energy Infrastructure of the Future (EIoF) study seeks to provide a robust understanding of the state of the cost and other impacts of energy infrastructure and consumption in the United States. The flagship product of the EIoF project is the Energy Futures Dashboard, a user interactive web-based tool that allows users to see the impacts of their choices for three major categories of energy production and use for the year 2050: electricity generation mix, the percentage of light-duty vehicles driven on electricity versus liquid fuels, and the percentage of homes heated by electricity and natural gas. For the purposes of this study, the country is divided into geographic regions established by the EIoF project (see Figure 1). The regional definitions enable us to investigate broad geographical differences in energy infrastructure quantities, costs, regulations, and customers that can be compared to trends for the continental United States. In total, there are 13 regions comprised of one or more states.

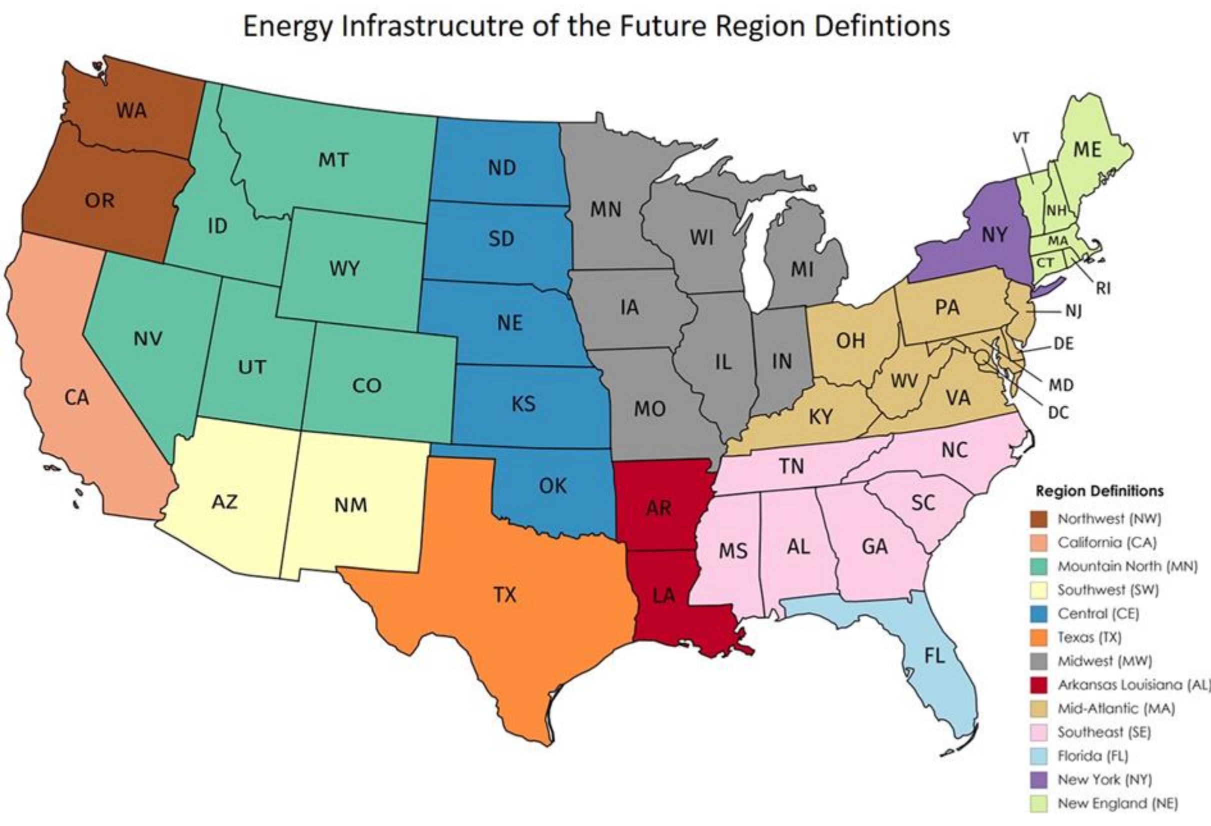

Figure 1. Regional definitions used for analysis in the Energy Infrastructure of the Future (EIoF) study.

This white paper summarizes the methodology within the code "solveGEN.R" that solves for (1) the necessary amount of power plant capacity and (2) the hourly generation from each type of power plant in the future year 2050. The inputs into this code are (1) the Energy Infrastructure of the Future website user's desired 2050 mix of electricity generation (the percent of annual electricity generated by each technology type), (2) the electricity generation needed each hour in 2050 (i.e., an 8760 hourly generation profile), and (3) hourly generation profiles from non-dispatchable generation technologies of wind, solar photovoltaics, and concentrating solar power, and (4) assumed amortized capital costs and variable operating costs for natural gas combined cycle and natural gas combustion turbines (to determine the ratio of natural gas generation from each type of natural gas power plant).

Method to Solve for Power Plant Capacity and Dispatch (no electricity storage)

The code solveGEN.R solves for (1) the necessary amount of power plant capacity and (2) the hourly generation from each type of power plant in the future year 2050. The inputs into this code are (1) user's desired 2050 mix of electricity generation expressed as the percent of annual electricity generated by each technology type *i*, labeled as $GFracDesired_i$, as input into the Energy Infrastructure of the Future (EIoF) Energy Futures Dashboard (EFD) website, (2) the assumed electricity generation each hour in 2050 (i.e., an 8760 hourly generation profile of constant MW output over the hour), and (3) hourly generation profiles from non-dispatchable generation technologies of wind, solar photovoltaics, and concentrating solar power, and (4) assumed amortized capital costs and variable operating costs for natural gas combined cycle and natural gas combustion turbines (to determine the ratio of natural gas generation from each type of natural gas power plant).

<u>Simplifying Assumptions</u>

There are many simplifying assumptions within solveGEN.R. These assumptions are driven by the nature of the EIoF EFD that is meant to

1. perform calculations in less than a few minutes such that online users can obtain rapid feedback on their inputs, and
2. give an approximate, but realistic estimate, of the amount of energy infrastructure investment (in units of money and physical items such as power plants and miles of transmission) required to meet the user's desired future conditions.

The program solveGEN.R is ***not a least cost dispatch***, or security constrained economic dispatch (SCED), algorithm. Because the user specifies the desired mix of future electricity into the EFD, there is no need to refer to costs to determine the mix of electricity by lowest cost or any other criteria. There are several overarching assumptions that affect the dispatch of power plants, and that are very different than real-world SCED:

1. there is no explicit modeling of ramp rate limits (either up or down) for any type of power plant,
2. there is no explicit modeling of start-up and shut-down times for any type of power plant, and
3. there is no explicit modeling of specific ancillary services, setting aside capacity within capacity markets, or other functions that power plants provide in addition to providing

real power (or selling energy only). Future versions might assume some capacity for ancillary services.

4. Currently there is no assumed reserve margin of power plants. Future versions might assume extra capacity for a summer and/or winter reserve margin.

Definitions of Generation and Load

For the purposes of this EIoF project, the total electricity generation requirement at each hour, G_t, is the total end use load, L_t, plus additional generation that accounts for resistive losses in transmission and distribution, $TDloss_t$. We assume that residential, commercial, and transportation loads incur both transmission and distribution loss, $TDloss_t$, but that industrial loads only losses in transmission, $Tloss_t$. This is specified in Equation (1). We assume *Tloss* = 2% and *TDloss* = 7% of their respective end use loads.

$$G_t = \left(L_{residential,t} + L_{commercial,t} + L_{transport,t}\right)(1 + TDloss_t) + \left(L_{industrial,t}\right)(1 + Tloss_t) \quad (1)$$

solveGEN Inputs and Order for solving Power Plant Capacity and Dispatch

The model solves for generation capacity and dispatch for each type of power plant in the following order of technology category or subcategory:

1. Nuclear
2. Hydropower (non-dispatchable)
3. Non-dispatchable variable renewable technologies (all simultaneously)
    a. Solar photovoltaic (PV)
    b. concentrating solar power (CSP), and
    c. wind power
4. Dispatchable fuel-based power plants where the order in which they are solved is from least to highest total variable cost (both variable O&M cost + fuel cost). The programmed order, per Table 1, is:
    a. Geothermal
    b. Coal
    c. Biomass
    d. PetroleumCC (petroleum combined cycle)
5. Dispatchable hydropower
6. Natural gas combined cycle (NGCC) and natural gas single-cycle combustion turbine (NGCT) are solved simultaneously where the proportion of each is based upon the screening curve method [Phillips *et al.* (1969), Zhang *et al.* (2015), Zhang and

Baldick (2017)] that uses information from Table 1 for amortized capital costs, fixed O&M costs, and variable O&M costs.

Table 1. The assumed operating and variable costs in solveGEN.R that are ONLY used for the purposes of determining an order of solving for dispatchable generators biomass, coal, geothermal, petroleum combined cycle (CC), natural gas combined cycle (NGCC), and natural gas combustion turbines (NGCT).

Technology	Annualized Capital Cost (k$/MW-year)	Fixed O&M Cost (k$/MW-year)	Variable O&M Cost ($/MWh)	Variable Fuel Cost ($/MWh)
Nuclear	224	89.88	2.05	6.5
Coal	174	30.04	4.31	19.05
NGCC	60	14.58	3.45	39.8
NGCT	39	14.88	7.07	53.78
Wind	154	39	0	0
PV	94	23.6	0	0
HydroDispatch	0	40.05	1.33	0
HydroNonDispatch	0	40.05	1.33	0
Biomass	309	112.15	5.58	80
Geothermal	199	119.87	0	0
CSP	339	71.41	0	0
PetroleumCC	79.14	11.11	3.45	100

We now describe the solution for capacity from each type of power plant in order of solution via the solvGEN algorithm.

Nuclear

Nuclear power is assumed to operate at 95% capacity factor, CF_{Nuc}, at a constant power output for each hour of the year. While we assume nuclear capacity operates at constant power output for all 8760 hours of the year, the capacity factor value at 95% (< 100%) inherently assumes that 5% of the nuclear fleet is not operating, due to refueling and other maintenance, at every given hour.

We assume that the maximum level of nuclear power capacity, $C_{Nuc,max}$, cannot be greater than the minimum generation requirement, $G_{t,min}$, across all hours, t, divided by the capacity factor, during the year within the assumed 2050 hourly generation profile.

$$C_{Nuc,max} = \min\{G_t\}/CF_{Nuc} \; \forall \; t \tag{2}$$

Given the assumption for maximum nuclear capacity, the maximum fraction of total annual generation, G_{annual} (defined in Equation (3)), allowed from nuclear power, $GFrac_{Nuc,max}$ is as in Equation (3), where 8760 represents the number of hours per year.

$$GFrac_{Nuc,max} = \frac{8760 C_{Nuc,max} CF_{Nuc}}{G_{annual}} = \frac{8760 C_{Nuc,max} CF_{Nuc}}{\sum_{t=1}^{8760} G_t} \quad (3)$$

<u>Hydropower (non-dispatchable portion)</u>

The major assumption that is unique for hydropower is that no new hydropower capacity can be built. This is not strictly true since as of 2020 there are river reaches with no conventional dams or run-of-river hydropower designs, and some existing dams can be upgraded to produce more power. However, given the historical data that shows very little addition of U.S. hydropower capacity over the last forty years, and a relatively constant level of total annual hydropower generation, the assumption of no additional hydropower serves the purposes of the EIoF EFD.

The EIoF EFD utilizes hydropower resource data and assumptions from the National Renewable Energy Laboratory (NREL) Regional Energy Deployment System (ReEDS) model (Cohen *et al.*, 2019). ReEDS distributes *existing* hydropower capacity into two types: dispatchable (hydED) and non-dispatchable (hydEND). Thus, both hydED and hydEND are characterized by a maximum capacity in MW. In addition, ReEDS associates a maximum total amount of energy, in MWh, associated with each type of hydropower capacity each season of the year, and this relates to the amount of water assumed available to flow through the facility. Existing non-dispatchable hydro represents water that is assumed must flow through the dam at a constant rate for each season. Existing dispatchable hydro represents water that can flow through the dam for the purposes of best addressing peak generation, or peak net generation (to be described later). The capacity and energy limits assumed for hydropower for each EIoF region are listed in Table 2.

We set a maximum power output of non-dispatchable hydropower equal the seasonal energy limit in MWh divided by the hours in the season. For example, using data in Table 2 for the Northwest (NW) region, there is 1.12e7 MWh of available generation during the spring months that constitute 2208 hours during the months of March, April, and May. Thus, the maximum hourly power output in spring for the NW region is 1.12e7 MWh/2208 hours = 5,072 MW.

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Table 2. The maximum capacity (power output, MW) and energy production (MWh) per season assumed for both existing dispatchable hydropower (hyED) and existing non-dispatchable hydro (hyEND).

Technology	EIoF region	Existing Capacity = Maximum Capacity (MW)	Maximum Energy, *Winter (Jan-Feb)* (MWh)	Maximum Energy, *Spring (Mar-May)* (MWh)	Maximum Energy, *Summer (Jun-Aug)* (MWh)	Maximum Energy, *Fall (Sep-Oct)* (MWh	Maximum Energy, *Winter (Nov-Dec)* (MWh)
Dispatchable Hydro	NW	1.89E+04	1.17E+07	2.16E+07	2.19E+07	8.65E+06	1.21E+07
	CA	5.12E+03	1.84E+06	4.80E+06	5.47E+06	2.14E+06	1.90E+06
	MN	3.11E+03	1.21E+06	2.96E+06	3.14E+06	1.20E+06	1.25E+06
	SW	9.28E+02	2.43E+05	6.01E+05	4.87E+05	2.16E+05	2.51E+05
	CE	2.49E+03	9.19E+05	1.57E+06	2.07E+06	1.24E+06	9.50E+05
	TX	1.61E+02	3.14E+04	6.86E+04	8.19E+04	3.21E+04	3.25E+04
	MW	5.53E+02	2.73E+05	6.32E+05	5.67E+05	2.58E+05	2.82E+05
	AL	7.48E+02	2.18E+05	3.54E+05	4.14E+05	1.58E+05	2.25E+05
	MA	1.02E+03	3.70E+05	5.57E+05	5.08E+05	2.96E+05	3.83E+05
	SE	6.11E+03	2.91E+06	3.51E+06	3.42E+06	2.22E+06	3.01E+06
	FL	4.26E+01	3.28E+04	5.25E+04	4.22E+04	2.29E+04	3.39E+04
	NY	3.66E+03	3.84E+06	5.96E+06	5.58E+06	3.48E+06	3.97E+06
	NE	4.54E+02	4.01E+05	6.60E+05	5.55E+05	3.19E+05	4.15E+05
Non-Dispatchable Hydro	NW	9.28E+03	6.19E+06	1.12E+07	9.10E+06	4.43E+06	6.40E+06
	CA	5.09E+03	1.75E+06	4.57E+06	5.30E+06	2.04E+06	1.81E+06
	MN	4.38E+03	1.96E+06	4.53E+06	5.57E+06	1.86E+06	2.03E+06
	SW	1.32E+03	8.02E+05	1.25E+06	1.54E+06	7.34E+05	8.29E+05
	CE	7.53E+02	3.24E+05	8.08E+05	7.93E+05	3.92E+05	3.35E+05
	TX	5.24E+02	8.04E+04	1.97E+05	2.00E+05	7.94E+04	8.31E+04
	MW	1.04E+03	6.86E+05	1.39E+06	1.24E+06	6.63E+05	7.09E+05
	AL	7.99E+02	4.01E+05	7.99E+05	7.25E+05	3.12E+05	4.15E+05
	MA	2.35E+03	1.51E+06	2.69E+06	1.46E+06	8.76E+05	1.56E+06
	SE	4.91E+03	2.30E+06	3.13E+06	2.26E+06	1.38E+06	2.38E+06
	FL	1.19E+01	2.75E+03	4.25E+03	3.51E+03	1.87E+03	2.84E+03
	NY	7.77E+02	5.66E+05	8.88E+05	8.46E+05	4.95E+05	5.85E+05
	NE	1.31E+03	9.90E+05	1.82E+06	1.32E+06	7.37E+05	1.02E+06

The amount of non-dispatchable hydropower generation used in the EIoF EFD is determined by the user inputs for nuclear and hydropower generation percentages. We perform the following steps to adjustment non-dispatchable hydropower if and as needed.

- Step 1: assume 100% of non-dispatchable hydro is used each hour per data in

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- Table 2, $G_{hyEND,t,max}$
- Step 2: Calculate net generation each hour, $GNet_t$: $G_t – G_{nuc,t}$ - $GNet_t$ - $G_{hyEND,t,max}$
- Step 3: For any hour t where $GNet_t < 0$, reduce $G_{hyEND,t}$ below $G_{hyEND,t,max}$ such that $GNet_t = 0$ (i.e., net generation must be greater than or equal to zero).
- Step 4: Calculate the fraction of generation from non-dispatchable hydropower as $Gfrac_{hyEND} = \Sigma G_{hyEND,t} / G_{annual}$ (Σ where represents the sum over all hours). If $Gfrac_{hyEND}$ is greater than the user's desired fraction of electricity served by hydropower, then at this point the algorithm has assumed too much hydropower, and we reduce each hour of the series $G_{hyEND,t}$ by the same fraction to ensure that the users' desired fraction of hydropower generation is equal to that provided by non-dispatchable hydro, or such that $Gfrac_{hyEND} = GFracDesired_{hyEND} = \Sigma G_{hyEND,t} / G_{annual}$.

Hourly Generation Profiles (8760 hours per year) for Solar PV and CSP

We used the National Renewable Energy Laboratory (NREL) System Advisor Model (SAM), **Version 2020.1.6**, to develop solar photovoltaic (PV) and concentrating solar power (CSP) hourly generation profiles ("profiles") for all EIoF regions of interest. We developed these profiles for 2016 and 2017 by using actual meteorological year (AMY) weather files for multiple locations within each region. The AMY data represent 216 locations total for each year, purchased from White Box Technologies[1]. These weather files were all used in the SAM to calculate what the hourly net electricity generation output from each type of technology would have been in each location given those input data.

Output from each model were (capacity-factor weighted) averaged by EIoF region and a final, single profile for each region was used as the expected output for that type of technology in each year. We assumed that more capacity would be deployed in locations with more favorable resources. Thus, the averaging for each region was weighted towards regions with higher capacity factor. For example, in each region, if an individual location had a capacity factor that was greater than the (unweighted) average capacity factor for all locations in a region, that profile was given a double weighting in the final profile generated for each region. Figure 2 shows the locations of the weather files used in the regional profile generation.

[1] http://weather.whiteboxtechnologies.com/

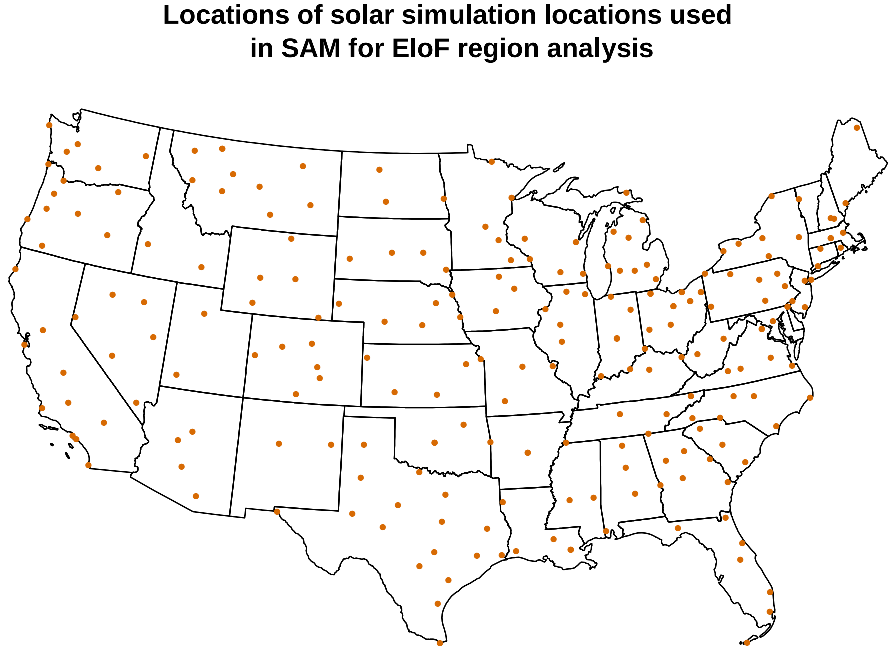

Figure 2: Weather file locations used in SAM to generate solar (PV and CSP) profiles for EIoF regions.

Solar CSP (System Advisor Model)

The NREL SAM solar CSP model is based on a 100 MW net (electric) power tower that utilizes a molten nitrate salt heat transfer fluid[2]. The system can be configured with a thermal energy storage system, but that component was not used in this analysis, thus the CSP output profile was just the plant output profile based on the available solar resource. It is common to model CSP systems with thermal energy storage, such that electricity can be dispatched in evenings when there is little to no direct solar insolation. The reason we did not model CSP with storage is that the online EIoF tool calculates values for electricity storage based upon any excess (or otherwise curtailed) renewable electricity generation relative to demand. Thus, there is no electricity or heat storage assumed associated with any specific technology in the EIoF tool.

Solar PV (System Advisor Model)

SAM's photovoltaic performance model combines module and inverter submodels with supplementary code to calculate a photovoltaic power system's hourly AC output given a weather file and data describing the physical characteristics of the module, inverter, and array[3]. The model used for this analysis is similar to the model used in NREL's popular PVWatts tool

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[2] https://www.nrel.gov/docs/fy13osti/57625.pdf
[3] https://www.nrel.gov/docs/fy15osti/64102.pdf

and is based on a 1 MW (DC) single-axis tracking solar PV farm with a 1.2 DC to AC inverter loading ratio and a 96% efficient inverter.

Hourly Generation Profiles (8760 hours per year) for Wind

The hourly wind profiles are derived from actual wind generation data for the year 2016. It is important to note that there was no wind generation within three of the EIoF regions in 2016: Arkansas-Louisiana, Southeast, and Florida. Thus, for the user's specified wind generation for these three regions, all generation is assumed to come from other regions (e.g., imported from wind farms in other regions). See subsection of this report "Interregional Transfer of CSP and wind." Future updates to the EFD can incorporate simulated or real data for wind generation within these three regions.

We generation hourly wind generation profiles on a "per MW installed" basis by using actual reported wind generation data from Independent System Operators (ISOs) and scale those generation data relative to the installed wind capacity at the time generation.

Table 3. Data sources used to create hourly wind generation profiles per EIoF region.

ISO	Applicable EIoF Region(s)	Web link and/or Data filename from ISO
Bonneville Power Administration (BPA)	Northwest	https://transmission.bpa.gov/business/operations/wind/ Item 5 contains data on MW every five minutes. We used the following item-five-datasets corresponding to the years 2015-2018: • 2015: WindGenTotalLoadYTD_2015.xls • 2016: WindGenTotalLoadYTD_2016.xls • 2017: WindGenTotalLoadYTD_2017.xls • 2018: WindGenTotalLoadYTD_2018.xls Moreover, item 7 contains information on MW capacity by date installed. We used data from the pdf-file which contains information on "WIND GENERATION NAMEPLATE CAPACITY IN THE BPA BALANCING AUTHORITY AREA": *WIND_InstalledCapacity_LIST.pdf* The BPA datasets contain the following variables: • Date/Time, • TOTAL WIND GENERATION BASEPOINT (FORECAST) IN BPA CONTROL AREA (MW; SCADA 103349), • TOTAL WIND GENERATION IN BPA CONTROL AREA (MW; SCADA 79687),

		• TOTAL BPA CONTROL AREA LOAD (MW; SCADA 45583), • TOTAL HYDRO GENERATION (MW; SCADA 79682), • TOTAL THERMAL GENERATION (MW; SCADA 79685), • NET INTERCHANGE (MW; SCADA 45581)
California Independent System Operator (CAISO)	California	http://www.caiso.com/market/Pages/ReportsBulletins/DailyRenewablesWatch.aspx We downloaded the text files from CAISO´s website containing the daily hourly generation data for different types of power generation including wind and renewables. The CAISO dataset contain the following variables: • Hour, • GEOTHERMAL, • BIOMASS, • BIOGAS, • SMALL.HYDRO, • WIND.TOTAL, • SOLAR.PV, • SOLAR.THERMAL, • RENEWABLES, • NUCLEAR, • THERMAL, • IMPORTS, • HYDRO, • Date, • Time, • UTC
Western Electricity Coordinating Council (WECC)	Mountain North, Southwest, California, Northwest	We obtained data from Colby Johnson, and employee of WECC. He kindly shared with us three datasets for the years 2015-2017: • 2015: *2015 Hourly Renewable Data.csv* • 2016: *2016 Hourly Renewable Data.csv* • 2017: *2017 Hourly Renewable Data.csv* These data contain output and capacity information for the following list of balancing authorities: AESO, AESO, AVA, AVA, AZPS, AZPS, BCHA, BCHA, BPAT, BPAT, CFE, CFE, CISO, CISO, DOPD, DOPD, EPE, EPE, GWA, GWA, IPCO, IPCO, LDWP, LDWP, NEVP, NEVP, NWMT, NWMT, PACE, PACE, PACW, PACW, PGE, PGE, PNM, PNM, PSCO, PSCO, PSEI, PSEI, SRP, SRP, TEPC, TEPC, WACM, WACM, WWA, WWA.

Electric Reliability Council of Texas (ERCOT)	Texas	http://www.ercot.com/gridinfo/generation We downloaded the following wind generation data from ERCOT: • *rpt.00013424.0000000000000000.ERCOT_2015_Hourly_Wind_Output.xlsx* • *rpt.00013424.0000000000000000.20170112.104938392.ERCOT_2016_Hourly_Wind_Output.xlsx* • *rpt.00013424.0000000000000000.20180131.170245804.ERCOT_2017_Hourly_Wind_Output.xlsx*
Independent System Operator New England (ISONE)	New England	https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/daily-gen-fuel-type • 2015: hourly_wind_gen_2015.xlsx • 2016: hourly_wind_gen_2016.xlsx • 2017: hourly_wind_gen_2017.xlsx\
Midcontinent Independent System Operator (MISO)	Midwest, Central, Arkansas-Louisiana	https://www.misoenergy.org/markets-and-operations/RTDataAPIs/ • 2015: 20151231_hwd_hist.csv • 2016: 20161231_hwd_hist.csv • 2017: 20171231_hwd_hist.csv The MISO datasets contain the following variables: • Market.Day, • Hour.Ending, • MWh
New York Independent System Operator (NYISO)	New York	• NYISO Gen Mix.csv
PJM Interconnection LLC (PJM	Mid-Atlantic, Midwest	https://dataminer2.pjm.com/feed/wind_gen/definition • gen_by_fuel_20150101_20171231.csv
Southwest Power Pool (SPP)	Central, Texas, Mountain North, Midwest, Arkansas-Louisiana	https://marketplace.spp.org/pages/generation-mix-historical We downloaded the following SPP data sets: • 2014: GenMix_2014.csv • 2015: GenMix_2015.csv • 2016: GenMix_2016.csv • 2017: GenMix_2017.csv

		• 2018: GenMix_2018.csv Each file has generation per hour by the following fuel types: • Coal Market • Coal Self • Diesel Fuel Oil • Hydro • Natural Gas • Nuclear • Solar • Waste Disposal Services • Wind • Waste Heat • Other

For installed generation capacity (by month) we used data set EIA-860M. Form EIA-860 contains monthly generator-level information about installed capacity by location and type of generator.

Aggregating at the EIoF Region Level

To create EIoF region level wind output profiles we aggregate hourly wind generation data per EIoF region.

We use the map in Figure 3. Map of the 38 Western Balancing AreasFigure 3 with the 38 Western Balancing Areas (BAs) to aggregate the columns contained in the WECC data up to the EIoF region level. We also use the wind turbine map available at the United States Geological Survey's website to make decisions for those cases in which the resolution of Figure 3 is not enough. The link to the U.S. Wind Turbine Database (USWTDB) map is the following: https://eerscmap.usgs.gov/uswtdb.

The aggregation of wind generation data per BA is as follows:

- **California** = CISO + BANC + TIDC + LDWP + some PACW + some BPAT
  - After checking the USWTDB, there was no wind generation originating in the PACW and BPAT regions within California
  - In the WECC data there are no columns for wind generation within BANC and TIDC

- **Mountain North** = NEVP + PACE + IPCO + NWMT + GWA + WWA + WAUW + WACM + PSCO + some BPAT
  - In our WECC data there are no data for WAUW
  - Data in the USWTDB imply no turbines within BPAT that are in our Mountain North states

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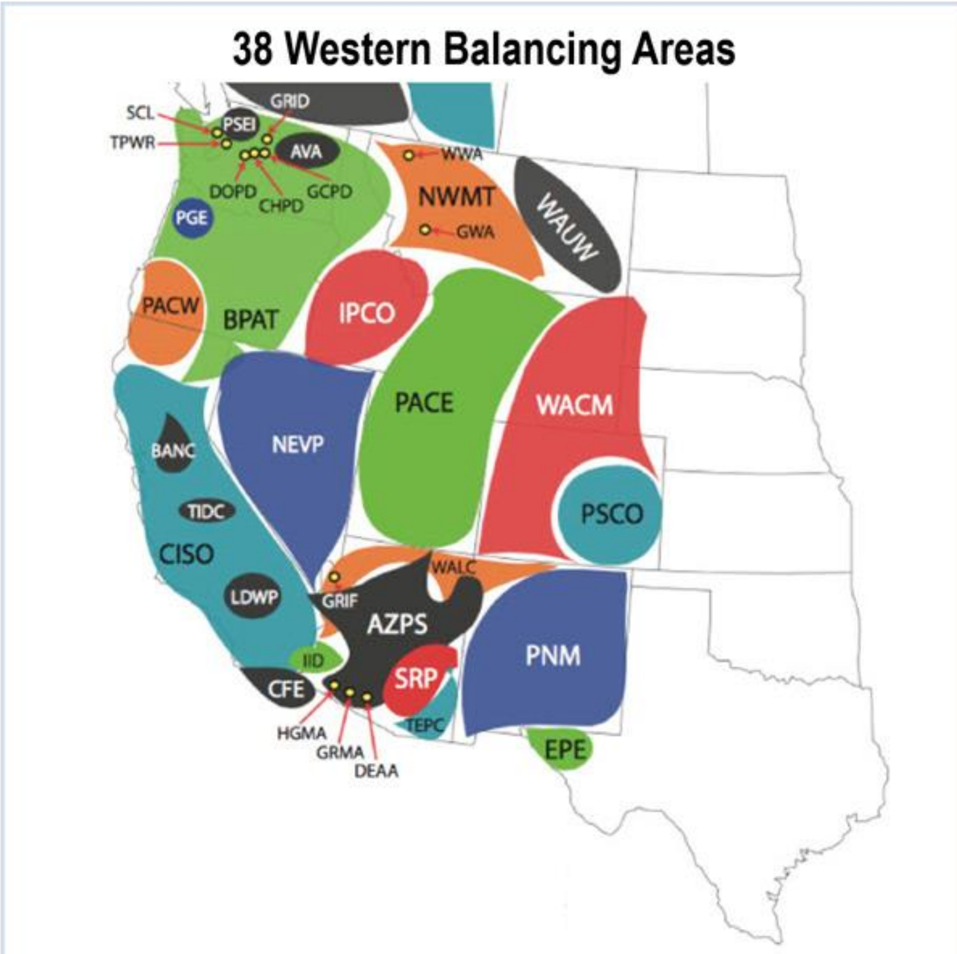
Figure 3. Map of the 38 Western Balancing Areas of WECC.



Source: https://www.rtoinsider.com/wecc-western-interconnection-44464/

- **Southwest** = AZPS + GRIF + HGMA + GRMA + DEAA + SRP + IID + WALC + TEPC + PNM + some EPE
    - In the WECC data, there are no columns for GRIF, HGMA, GRMA, DEAA, IID, and WALC
    - Per data in the USWTDB, there seems to be no wind generation within the EPE area that would not otherwise be aggregated into the Texas region

- **Northwest** = PSEI + SCL + TPWR + AVA + DOPD + CHPD + GCPD + PGE + PACW + BPAT
    - In our WECC data there are no columns for SCL, TPWR, CHPD, and GCPD

Per the location of the wind turbines within each region (in reference to the USWTDB, we assume the following output profiles from ISOs are the same as the EIoF regions as indicated:

- **Texas** wind profile is that of ERCOT
- **New England** wind profile is that of ISONE
- **New York** wind profile is that of NYISO
- **Mid-Atlantic** wind profile is that of PJM
- **Midwest** wind profile is that of MISO
- **Central** wind profile is that of SPP

Resource Limits for Non-dispatchable variable renewable technologies (solar PV, CSP, wind)

The non-dispatchable variable renewable technologies are solar photovoltaics (PV), concentrating solar power (CSP), and wind power. For each EIoF region we define one generation profile of MW output for each of the 8760 hours of the year. This hourly profile, $GenPerCapacity_{i,t}$ is in units of MW output per MW of installed capacity. These profiles are described in the white paper describing the code "generate8760.R".

The user specifies the desired percentage of G_{annual} to be served by PV, CSP, and wind, or $GFracDesired_i$. An optimization is performed to simultaneously solve for the three unknown variables, the capacity of each type of generation, C_{PV}, C_{CSP}, and C_{wind}. The optimization uses the R package "optimr" and the "optim" function via the L-BFGS-B algorithm option (a limited-memory quasi-Newton code for bound-constrained optimization).

The calculated actual fraction of annual generation for generator type *i* (*i* = PV, CSP, wind), $GFrac_i$, is as in Equation (4) where $G_{i,no\ curtailment}$ is the annual generation from type *i* without considering curtailment, and $G_{i,curtailment}$ is the amount of annual generation from type *i* that must be curtailed. $G_{i,no\ curtailment}$ is the sum of the power plant capacity, C_i, multiplied by the hourly generation profile expressed in MW output per installed MW, or $GenPerCapacity_{i,t}$ (Equation (5)). Here, total annual curtailed generation, $G_{curtailment,annual}$, is the sum of the curtailed generation each hour, $G_{t,curtailment}$, which is equal to the generation from PV, CSP, and wind each hour that is greater than the remaining *net generation*, $GNet_t$, that needs to be served that hour after already accounting for nuclear and nondispatchable hydro (Equation (6)). In this case, the net generation each hour *t* is $GNet_t = G_t – G_{nuc,t} - G_{hyEND,t}$.

$$GFrac_i = \frac{GFrac_{i,no\ curtailment} - G_{i,curtailment}}{G_{annual}} \quad (4)$$

$$G_{i,no\ curtailment} = C_i \times \sum_{t=1}^{8760} GenPerCapacity_{i,t} \tag{5}$$

$$\begin{aligned} G_{curtailment,annual} &= \sum_{t=1}^{8760} G_{t,curtailment} \\ &= \left(\sum_{t=1}^{8760} G_{PV,t} + G_{CSP,t} + G_{wind,t} \right. \\ &\quad \left. - \left(G_t - G_{nuc,t} - G_{hyEND,t} \right) \right) \\ &\forall\ t\ where\ G_{t,curtailment} > 0 \end{aligned} \tag{6}$$

For any hour t in which the right hand side of Equation (6) is less than zero, curtailment of PV, CSP, and wind is zero, or $G_{t,curtailment} = 0$. For any hour t in which the right hand side of Equation (6) is greater than zero, or $G_{t,curtailment} > 0$ (i.e., there is curtailment for that hour), we calculate the proportion of total PV, CSP, and wind generation that was coming from each technology, $FracCurtailed_{i,t}$. We assume that there is no preference given to any one of these three technologies in the sense that if there is any curtailment of their generation in any hour, each of them is curtailed in proportion to their contribution at that hour as in Equation (7). Thus, if there is curtailed PV, CSP, and wind generation in an hour equal to $G_{t,curtailment}$ = 100 MW, with 100 MW of PV, 60 MW of CSP, and 40 MW of wind generation, then the curtailed generation is 50 MW of PV (50% of curtailment), 30 MW of CSP (30% of curtailment), and 20 MW of wind (20% of curtailment).

$$FracCurtailed_{i,t} = \frac{G_{i,t}}{G_{PV,t} + G_{CSP,t} + G_{wind,t}} \text{ where i=PV, CSP, wind} \tag{7}$$

Thus, annual curtailment of technology i, $G_{i,curtailment}$ in Equation (4), is calculated as in Equation (8).

$$G_{i,curtailment} = \sum_{t=1}^{8760} FracCurtailed_{i,t} \times G_{i,t} \tag{8}$$

Now with all components defined to calculate $GFrac_i$, we can compare this to the user's desired fraction of annual electricity from technology *i*, $GFracDesired_i$, and minimize the square of the differences. We minimize the objective function of Equation (9) given the lower bound and upper bound constraints as in Equations (10) and (11), respectively.

$$min \sum_{t=}^{8760} (GFrac_i - GFracDesired_i)^2, \qquad i = PV, CSP, wind \tag{9}$$

with constraints:

$$C_i \geq 0 \tag{10}$$

$$C_i \leq max\left(G_t - G_{t,nuclear} - G_{t,nondispatchable\ hydro}\right) \forall\, t \tag{11}$$

Limits in Total Installed Capacity for PV, CSP, and wind

We use data from NREL's ReEDS model to set upper bounds on the amount of total installed capacity of PV, CSP, and wind that can be placed in any given EIoF region. ReEDS defines 134 balancing areas (BAs) that are county aggregates. Renewable resources are defined for each BA, and the BAs are further subdivided into 356 resource regions that describe **wind and CSP resource supply and quantity** to provide more spatial granularity. Thus, we are able to aggregate the BAs resource regions into states and our EIoF regions. ReEDS designates 5 designations of PV, CSP, and wind resources (these are different than the resource "classes"), and the total potential capacity within each of these, as well as their total sum, are listed in Table 4-Table 7.

Table 4. The maximum utility photovoltaic (UPV) installed capacity (MW) available per EIoF region as defined by five separate resource designations ("upvsc") within the NREL ReEDS model, and summed into a total of all five resource designations.

EIoF Region	UPV1	UPV2	UPV3	UPV4	UPV5	UPV Total
NW	220,326	531,717	712,366	697,056	581,191	2,742,657
CA	188,748	350,954	527,365	674,268	560,030	2,301,364
MN	2,293,721	3,901,793	4,138,460	4,252,285	3,639,808	18,226,066
SW	1,447,998	1,915,982	2,021,066	1,979,224	1,804,815	9,169,084
CE	4,285,847	4,862,972	4,884,147	4,955,901	4,820,864	23,809,731
TX	2,724,770	3,500,874	3,533,579	3,458,997	3,124,912	16,343,132
MW	3,380,361	4,456,159	4,597,846	4,566,867	4,043,308	21,044,541
AL	616,056	857,053	876,647	854,905	857,246	4,061,907
MA	567,228	1,089,440	1,196,778	1,184,168	1,026,686	5,064,300
SE	1,560,887	2,229,492	2,324,551	2,325,124	2,176,901	10,616,955
FL	169,910	393,834	453,440	458,434	366,039	1,841,657
NY	39,160	136,371	218,947	265,710	266,759	926,946
NE	148,641	253,694	274,145	278,138	181,180	1,135,798

Table 5. The maximum utility concentrating solar power (CSP) installed capacity (MW) available per EIoF region as defined by five separate resource designations ("cspsc") within the NREL ReEDS model, and summed into a total of all five resource designations.

EIoF Region	CSP1	CSP2	CSP3	CSP4	CSP5	CSP Total
NW	22,988	58,620	100,299	145,881	138,279	466,068
CA	28,655	45,940	102,162	142,547	187,873	507,177
MN	120,875	556,336	938,984	1,101,787	793,489	3,511,471
SW	157,846	472,729	680,199	695,741	468,466	2,474,982
CE	192,053	888,289	1,303,002	1,348,361	965,360	4,697,064
TX	228,137	916,342	1,171,298	1,098,499	747,855	4,162,131
MW	3,299	13,251	20,579	22,344	19,135	78,608
AL	25,387	52,136	99,284	104,829	89,990	371,626
MA	18	0	0	0	0	18
SE	24,353	26,471	46,349	77,522	86,450	261,145
FL	7,547	19,901	39,325	46,194	48,003	160,971
NY	0	0	0	0	0	0
NE	0	0	0	0	0	0

Table 6. The maximum onshore wind installed capacity (MW) available per EIoF region as defined by five separate resource designations ("wsc") within the NREL ReEDS model, and summed into a total of all five resource designations.

EIoF Region	Wind1 (onshore)	Wind2 (onshore)	Wind3 (onshore)	Wind4 (onshore)	Wind5 (onshore)	Wind Total (onshore)
NW	45,627	93,220	109,510	127,757	116,268	492,383
CA	26,773	48,037	63,045	69,297	73,180	280,332
MN	185,327	514,766	646,983	669,236	542,844	2,559,156
SW	93,400	236,559	320,478	298,614	197,964	1,147,015
CE	193,810	460,469	545,775	554,523	460,597	2,215,175
TX	169,484	299,621	377,135	364,932	251,212	1,462,383
MW	176,785	280,768	393,223	423,361	341,768	1,615,905
AL	26,154	37,057	63,889	70,246	56,841	254,186
MA	76,932	119,258	154,246	158,148	138,735	647,318
SE	84,300	120,108	176,430	176,519	137,396	694,753
FL	12,074	8,552	12,563	12,712	14,335	60,235
NY	11,623	17,647	22,475	27,083	28,020	106,848
NE	11,153	18,259	19,740	21,432	20,474	91,057

Table 7. The maximum offshore wind installed capacity (MW) available per EIoF region as defined by five separate resource designations ("wsc") within the NREL ReEDS model, and summed into a total of all five resource designations.

EIoF Region	Wind1 (offshore)	Wind2 (offshore)	Wind3 (offshore)	Wind4 (offshore)	Wind5 (offshore)	Wind Total (offshore)
NW	19,523	21,632	23,785	22,648	19,804	107,392
CA	13,741	20,750	27,173	27,702	20,628	109,994
MN	0	0	0	0	0	0
SW	0	0	0	0	0	0
CE	0	0	0	0	0	0
TX	24,556	42,271	48,218	49,086	33,707	197,838
MW	18,698	17,194	14,371	13,255	9,619	73,138
AL	36,500	49,057	59,238	53,888	46,451	245,135
MA	26,518	33,721	32,882	32,868	28,393	154,382
SE	60,970	96,736	94,057	92,502	82,897	427,162
FL	37,937	53,132	68,825	67,554	62,474	289,922
NY	12,096	16,772	19,825	16,438	8,608	73,739
NE	49,298	72,436	87,775	82,242	59,245	350,996

Note, that since Regions NY and NE have 0 MW of possible CSP capacity, and because we assume 0% of CSP electricity can be imported from other regions into either NY or NE, these two regions can only have 0% (or 0 MWh) of electricity generation from CSP to serve customers in those regions.

Interregional Transfer of CSP and wind

For wind and concentrating solar power (CSP) renewable electricity technology, the EFD assumes that some of a user's desired renewable electricity consumption within one region (e.g., California) can be generated in neighboring regions (e.g., Northwest, Mountain North, and Southwest). As an example to understand how the EFD calculates total installed capacity of wind and CSP when considering region-to-region transfers, consider an example where Region A obtains 30% of its CSP from its own Region A and 70% from neighboring Region B. For simplicity solveGEN creates a single CSP generation profile (8760 hour per year) that is a weighted combination (30% and 70%) of each region's profile. Then, an optimization algorithm simultaneously solves for the amount of capacity for this single CSP profile that is needed to reach the user's targeted annual generation from each. The solveGEN algorithm next checks to see if there is enough resource capacity to meet the user's target by checking to see which Region is binding the limit of installed capacity:

1) Assume Region A has a maximum capacity of 100 MW, Region B has a maximum capacity of 500 MW, and the optimization has initially solved for requiring 1000 MW of the CSP weighted profile. This is more capacity than in both regions, so we must reduce the installed capacity to within the resource limit. The solveGEN algorithm calculates which region is the constraining region. For example, if Region A is binding and it contributes 30% of the electricity at its maximum capacity of 100 MW (of the weighted profile), then Region B can contribute 70% of the electricity at 70%/30% × 100 MW = 2.33 × 100 MW = 233 MW (of the weighted profile). Thus, the total MW of installed CSP capacity across both Regions A and B is 333 MW.
2) Conversely, if Region B is binding and it contributes 70% of the electricity at its maximum capacity of 500 MW, then Region A would need to contribute 30%/70% × 500 MW = 0.43 × 500 MW = 214 MW, for a total capacity of 714 MW. However, the required 214 MW from Region A is larger than the available capacity in Region A, so this solution is not viable.

Thus, because Region A is the constraining region, we assume the total capacity of CSP is 333 MW from bullet 1) above. Further, we calculate the corresponding energy generation (e.g., in megawatt-hours) based on the capacity of 333 MW, and this will be less than the user's desired percentage of total regional generation. When the EFD cannot supply the user's targeted percentage of electricity from a type of generation, a pop-up window indicates this to the user.

The EFD assumptions for wind power and CSP region-to-region transfers are as follows:

- Wind
  - The EFD assumes that some percentage of wind generation for consumption in the user's chosen EIoF region can come from neighboring EIoF regions. These percentages are fixed as shown in Figure 4.

TO / FROM

FROM		NW Northwest	CA California	MN Mountain North	SW Southwest	CE Central	TX Texas	MW Midwest	AL Arkansas-Louisiana	MA Mid-Atlantic	SE Southeast	FL Florida	NY New York	NE New England
NW	Northwest	70%	40%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
CA	California	5%	10%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MN	Mountain North	25%	50%	100%	30%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SW	Southwest	0%	0%	0%	40%	0%	0%	0%	0%	0%	0%	0%	0%	0%
CE	Central	0%	0%	0%	30%	100%	0%	50%	80%	40%	60%	75%	0%	0%
TX	Texas	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%
MW	Midwest	0%	0%	0%	0%	0%	0%	50%	20%	40%	30%	0%	0%	0%
AL	Arkansas-Louisiana	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MA	Mid-Atlantic	0%	0%	0%	0%	0%	0%	0%	0%	20%	10%	0%	30%	0%
SE	Southeast	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
FL	Florida	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	25%	0%	0%
NY	New York	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	60%	20%
NE	New England	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	10%	80%

Figure 4. The matrix indicating what percentage of wind electricity consumed in the "TO" EIoF region is assumed to be generated by power plants located in the "FROM" EIoF region. When the "TO" and "FROM" regions are the same, this means that wind electricity originates within the EIoF region itself.

- Concentrating Solar Power (CSP)
  - The EFD assumes that some percentage of CSP generation for consumption in the user's chosen EIoF region can come from neighboring EIoF regions. These percentages are fixed as shown in Figure 5.

TO / FROM

FROM		NW Northwest	CA California	MN Mountain North	SW Southwest	CE Central	TX Texas	MW Midwest	AL Arkansas-Louisiana	MA Mid-Atlantic	SE Southeast	FL Florida	NY New York	NE New England
NW	Northwest	50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
CA	California	25%	80%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MN	Mountain North	25%	10%	100%	0%	20%	0%	0%	0%	0%	0%	0%	0%	0%
SW	Southwest	0%	10%	0%	100%	20%	0%	0%	0%	0%	0%	0%	0%	0%
CE	Central	0%	0%	0%	0%	60%	0%	50%	30%	0%	0%	0%	0%	0%
TX	Texas	0%	0%	0%	0%	0%	100%	0%	30%	0%	0%	0%	0%	0%
MW	Midwest	0%	0%	0%	0%	0%	0%	30%	0%	30%	0%	0%	0%	0%
AL	Arkansas-Louisiana	0%	0%	0%	0%	0%	0%	20%	40%	0%	0%	0%	0%	0%
MA	Mid-Atlantic	0%	0%	0%	0%	0%	0%	0%	0%	10%	0%	0%	0%	0%
SE	Southeast	0%	0%	0%	0%	0%	0%	0%	0%	60%	100%	0%	0%	0%
FL	Florida	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%	0%
NY	New York	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%	0%
NE	New England	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	100%

Figure 5. The matrix indicating what percentage of concentrating solar power (CSP) electricity consumed in the "TO" EIoF region is assumed to be generated by power plants located in the "FROM" EIoF region. When the "TO" and "FROM" regions are the same, this means that CSP electricity originates within the EIoF region itself.

Land use for PV, CSP, and wind

Another important note on the use of data in Table 4-Table 7 is that we assume 100% of the wind, solar PV, and CSP in any given EIoF region call all be simultaneously installed. This is to say that we do not estimate any potential overlap in land area that would be covered with the power plant infrastructure of each technology. In reality, there would likely be the choice to install, for example, solar PV ***or*** CSP on a given area of land, but not both, and since the EFD does not estimate specific geographic locations for power plant installations, it does consider any practical land-based social, legal, or regulatory restrictions (e.g., setback distance requirements for wind turbines from homes) for installation of one type of power plant on another.

To further describe how to interpret land use, consider both the "direct area" and the "total area" footprint of wind and solar farms. The direct area includes only the physical footprint of infrastructure. The total area includes all area of a project that might be fenced in and includes all of the land area between and among infrastructure on a project site. For example, total area includes all area circumscribed within all of the wind turbines in a wind farm. Thus, from a strict physical layout, a solar PV and wind farm can overlap in total project areas since solar panels can be installed between wind turbines.

Table 8 shows land-use calculations for each EIoF region that indicate both the direct and total land use if the entire capacities of wind, solar PV, and CSP (from – Table 7) are installed within each region. The sum of maximum direct land areas (for wind+PV+CSP) stays below 100% of each region's total land area, but the sum of maximum total project land area coverage for all three technologies is greater than 100% for the Central and Texas regions.

It is important to note that the deployment of the maximum capacity of power plants in Table 8 involves a magnitude of energy infrastructure across each region of the U.S. that would in all likelihood never be achieved. Thus, this is one good case in which by not arbitrarily restricting options, the EFD decision support tool enables users to explore and contemplate various issues and feedbacks that might arise if pursuing certain energy mixes, such as high percentages of wind and solar power.

Table 8. The land use (direct area and total project area) for each EIoF region if 100% of assumed wind (onshore), solar PV, and CSP capacity are installed in that region.

	Maximum capacity in region (MW)				Direct Area (% of land)			Total Area (% of land)		
Region	PV	CSP	Wind (onshore)	Land Area (acres)	PV	CSP	Wind (onshore)	PV	CSP	Wind (onshore)
Northwest (NW)	2,742,657	466,068	492,383	103,964,160	13.0%	3.6%	0.4%	14%	4%	23%
California (CA)	2,301,364	507,177	280,332	99,698,560	11.4%	4.1%	0.2%	13%	5%	14%
Mountain North (MN)	18,226,066	3,511,471	2,559,156	397,360,000	22.7%	7.1%	0.5%	25%	8%	32%
Southwest (SW)	9,169,084	2,474,982	1,147,015	150,330,880	30.1%	13.2%	0.6%	33%	15%	38%
Central (CE)	23,809,731	4,697,064	2,215,175	238,073,600	49.4%	15.8%	0.7%	54%	18%	46%
Texas (TX)	16,343,132	4,162,131	1,462,383	167,188,480	48.3%	19.9%	0.7%	53%	22%	43%
Midwest (MW)	21,044,541	78,608	1,615,905	260,011,520	40.0%	0.2%	0.5%	44%	0%	31%
Arkansas-Louisiana (AL)	4,061,907	371,626	254,186	60,952,960	32.9%	4.9%	0.3%	36%	5%	21%
Mid-Atlantic (MA)	5,064,300	18	647,318	132,920,960	18.8%	0.0%	0.4%	21%	0%	24%
Southeast (SE)	10,616,955	261,145	694,753	175,996,800	29.8%	1.2%	0.3%	33%	1%	20%
Florida (FL)	1,841,657	160,971	60,235	34,320,000	26.5%	3.8%	0.1%	29%	4%	9%
New York (NY)	926,946	0	106,848	30,160,640	15.2%	0.0%	0.3%	17%	0%	18%
New England (NE)	1,135,798	0	91,057	40,120,960	14.0%	0.0%	0.2%	15%	0%	11%

Table 8 footnote: Data for land area per installed MW are from the following sources:
Wind (permanent direct area)**:** 0.74 acre/MW Denholm et al. (2009)
Wind (total area): 49.4 acre/MW Table A-10 of Hand et al. (2012) (= 1/5 km^2/MW × 247.105 acre/km^2)
solar PV (direct area): 4.9 acre/MW Table A-10 of Hand et al. (2012)
solar PV (total area): 5.4 acre/MW per ratio of 1.10 for total:direct area from Denholm et al. (2009)
solar CSP (direct area): 8 acre/MW
solar CSP (total area): 9 acre/MW per ratio of 1.12 for total:direct area from Denholm et al. (2009)

Because the EFD assumes renewable electricity can be imported from neighboring regions for consumption in the user's chosen region, land use for wind and solar CSP can occur in more than one region at a time. The EFD displays a value for total acres of land used for power plants (as of this document ONLY land for wind, solar PV, and CSP) and percentage of land total land area that is used via power plant footprints. The land area occupied by power plants is simply the sum of all installed capacity multiplied by the acre/MW factor assumed in Table 8. The percentage of land calculation is a weighted average of the percentage of land occupied in each region that is assumed to have power plants serving the user's chosen region (see Equation (12)).

Assume, for example, that the Central region wants some amount of electricity from CSP, but none from wind and PV, and that these power plants would take 1,000,000 acres. Figure 5 indicates that for CSP electricity delivered to the Central region, 20% comes from Mountain North, 20% from Southwest, and 60% from the Central region itself. Thus, 200,000 acres of CSP plants would be in the Mountain North and Southwest regions, and 600,000 acres of CSP plants would be in the Central region. This is 0.05%, 0.13%, and 0.25% of each region's land, respectively. Using Equation (12) the EFD displays the percentage of land used as = (200,000·0.05% + 200,000·0.13% + 600,000·0.25%)/(1,000,000) = 0.19%.

$$PercentLandUsed_{wind,PV,CSP} = \frac{\sum_{r=1}^{13} Land\ Used_{r,wind+PV+CSP} \cdot PercentLandUsed_{r,wind+PV+CSP}}{\sum_{r=1}^{13} Land\ Used_{r,wind+PV+CSP}} \tag{12}$$

Dispatchable generation technologies (coal, biomass, geothermal, petroleum)

Once nuclear, non-dispatchable hydro, solar PV, CSP, and wind generation has been determined, we now approximate the dispatch coal, biomass, geothermal, and petroleum combined cycle generation technologies. The algorithm is the same for each of these four technologies, and it is used in sequence from one to the next. The dispatch for each technology is solved for in the order from least to highest total variable operating cost (both variable O&M and fuel costs from Table 1) in the following steps.

- Step 1: Select electricity generation technology i.
- Step 2: Calculate, $GNet_t$ that accounts for all generation for every technology solved to this point in the algorithm.
- Step 3: Sort $GNet_t$ from the highest to lowest values to create a net generation duration curve, $GNet_h$ (where h refers to sorted hours, not the actual sequence in time t) as shown in Figure 6.
- Step 4: Using the net generation duration curve, we increase the capacity of generation technology i, C_i, until the shared area of Figure 6 equals the user's desired quantity of generation from that technology, equal to $GFracDesired_i \times G_{annual}$.

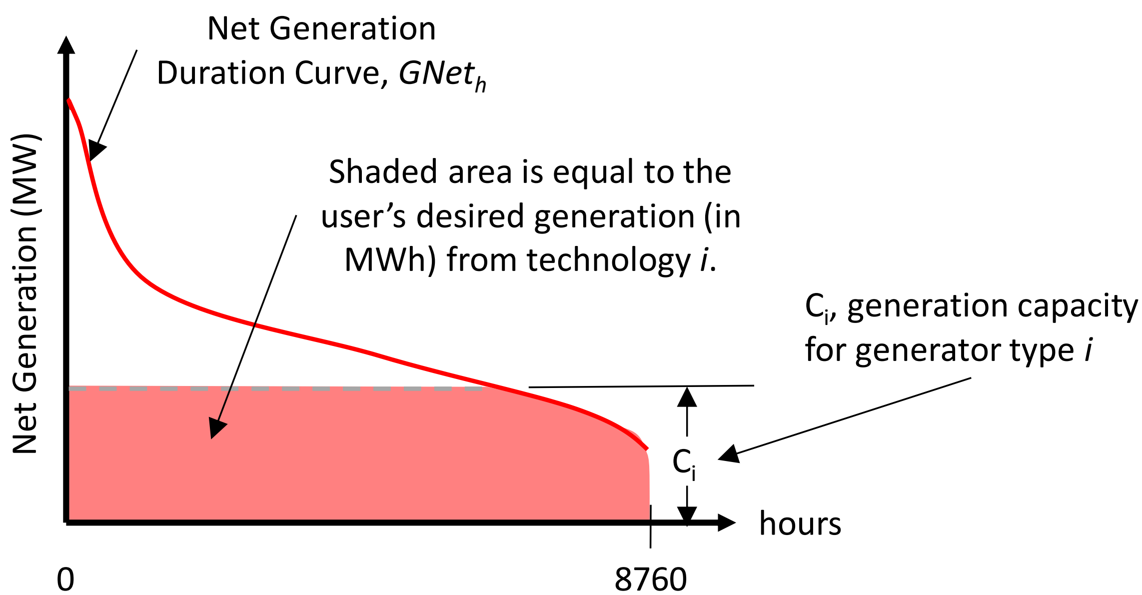


Figure 6. Net generation duration curve, $GNet_h$, and shaded area indicating how solveGEN solves for the necessary generation capacity, C_i, for electricity generation technologies of coal, biomass, geothermal, and petroleum.

We repeat Steps 1-4 until we solve for each of the four types of generation listed for this section. Because we assume no ramping rates restrictions or start-up and shut-down costs, each generator is assumed to be able to meet any temporal sequence of generation necessitated by the method of this section. While this is an unrealistic assumption that must always be kept in mind in interpreting the results of the EIoF EFD, this online tool is meant to perform calculations in less than a few minutes to provide feedback to the user, and these simplifications facilitate this intention.

We assume no limits in capacity or annual generation for coal and petroleum electricity generation. We use data on resource quantities as listed in the NREL ReEDS model to limit the maximum power capacity and/or annual electricity generation from geothermal and biomass.

Limits in Total Electricity Generation for Biomass

We use data from NREL's ReEDS model to set upper bounds on the amount of annual biomass electricity that can be generated within any given region. Thus, the limit in the EFD is on energy, or the megawatt-hours of electricity generated from biomass, and not a direct limit on the installed capacity for biomass power plants. While ReEDS states that "ReEDS can generate electricity from biomass either in dedicated biomass integrated gasification combined cycle (IGCC) plants or cofired with coal in facilities that have been retrofitted with an auxiliary fuel feed.", the present EIoF EFD assumes only dedicated biomass power plants.

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ReEDS defines 134 balancing areas (BAs) within the U.S. that are county aggregates. We further aggregate these regions into the 13 EIoF regions. Table 9 displays to the total biomass energy supply per EIoF region. This supply is in units of heat energy caused by burning the biomass, and we translate this to a maximum quantity of electricity generation for the year 2050, $G_{max,biomass}$, by using a biomass power plant heat rate of 7,845 Btu/kWh as assumed in EIA AEO 2019.

Table 9. The assumed maximum annual biomass fuel (billion Btu) supply and power generation (TWh) from biomass within each EIoF region ass summed form data inputs into the NREL ReEDS model, and summed into a total of all five resource designations (bioclass1 to bioclass5).

EIoF Region	Annual Biomass Supply (Trillion Btu)	Maximum Electricity from Biomass @ 7,845 Btu/kWh (TWh/yr)
NW	183	23.3
CA	125	15.9
MN	182	23.1
SW	38	4.9
CE	699	89.1
TX	239	30.5
MW	1,626	207.2
AL	468	59.6
MA	499	63.6
SE	1,400	178.4
FL	158	20.2
NY	73	9.3
NE	315	40.2

The algorithm for solving biomass generation dispatch follows as described above for Figure 6 except for an additional step that limits total electricity generation to the limits in Table 9. If the initial algorithm solves for a quantity of annual generation that is greater than the limit for that region, then both the (i) hourly generation profile (all 8760 hours) and (ii) solved biomass power plant capacity are multiplied by the following fraction (where the sum is across all hours, t): $\Sigma G_{t,biomass}/G_{max,biomass}$. This reduces the generation each hour, peak generation, and capacity from biomass by the fraction ($1 - \Sigma G_{t,biomass}/G_{max,biomass}$).

Limits in Total Installed Capacity and Cost for Geothermal Electricity

We use data from the NREL ReEDS model to create installed capital cost vs supply curves for geothermal electricity as shown in Figure 7 (Brown *et al.*, 2020). Figure 7 includes all types of geothermal resources as considered in the ReEDS model for both binary cycle and flash steam cycle[4] geothermal plant designs: hydrothermal, undiscovered hydrothermal, near-field enhanced geothermal systems (EGS), and deep EGS. We also calculate fixed operating and maintenance (FOM) costs using the data in the ReEDS model. As the user specifies inputs that dictate necessary capacity in 2050 (representing a value on the x-axis of Figure 7), we estimate the 2050 installed cost of geothermal power plants as the capacity-weighted cost from the curves in Figure 7. We assume the 2020 cost of geothermal is the lowest value on each supply curve. Finally, we assume (for simplicity) a linear change in cost from 2020 to 5050 that inherently additionally assumes that geothermal capacity at each point on the supply curve is built at the same rate from 2020 to 2050.

[4] Flash steam plants take high-pressure hot water from deep inside the earth and convert it to steam to drive generator turbines. When the steam cools, it condenses to water and is injected back into the ground to be used again. Most geothermal power plants are flash steam plants.

Binary cycle power plants transfer the heat from geothermal hot water to another liquid. The heat causes the second liquid to turn to steam, which is used to drive a generator turbine. (https://www.eia.gov/energyexplained/geothermal/geothermal-power-plants.php)

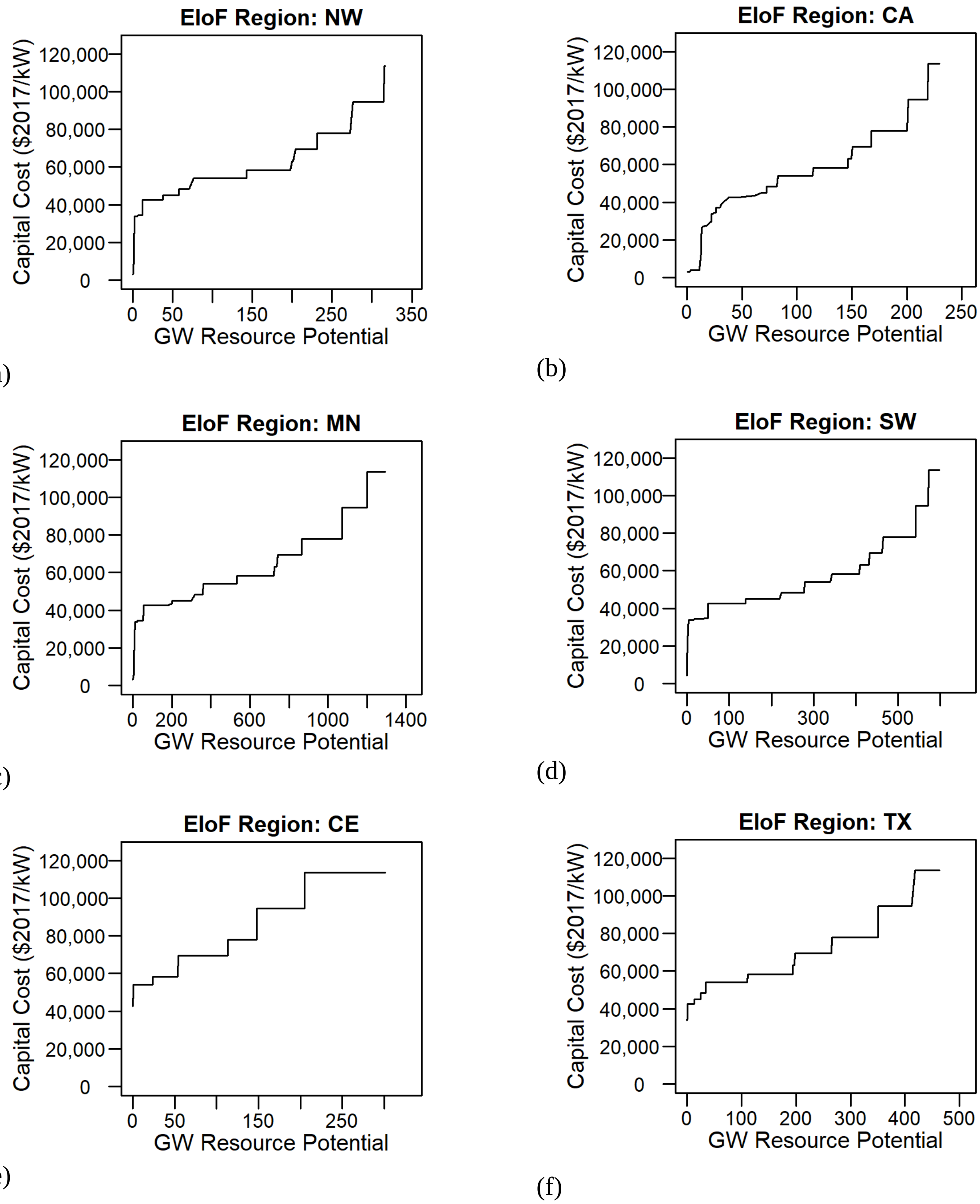


Figure 7. Capital cost versus resource supply curves, per EIoF region, for geothermal power plants.

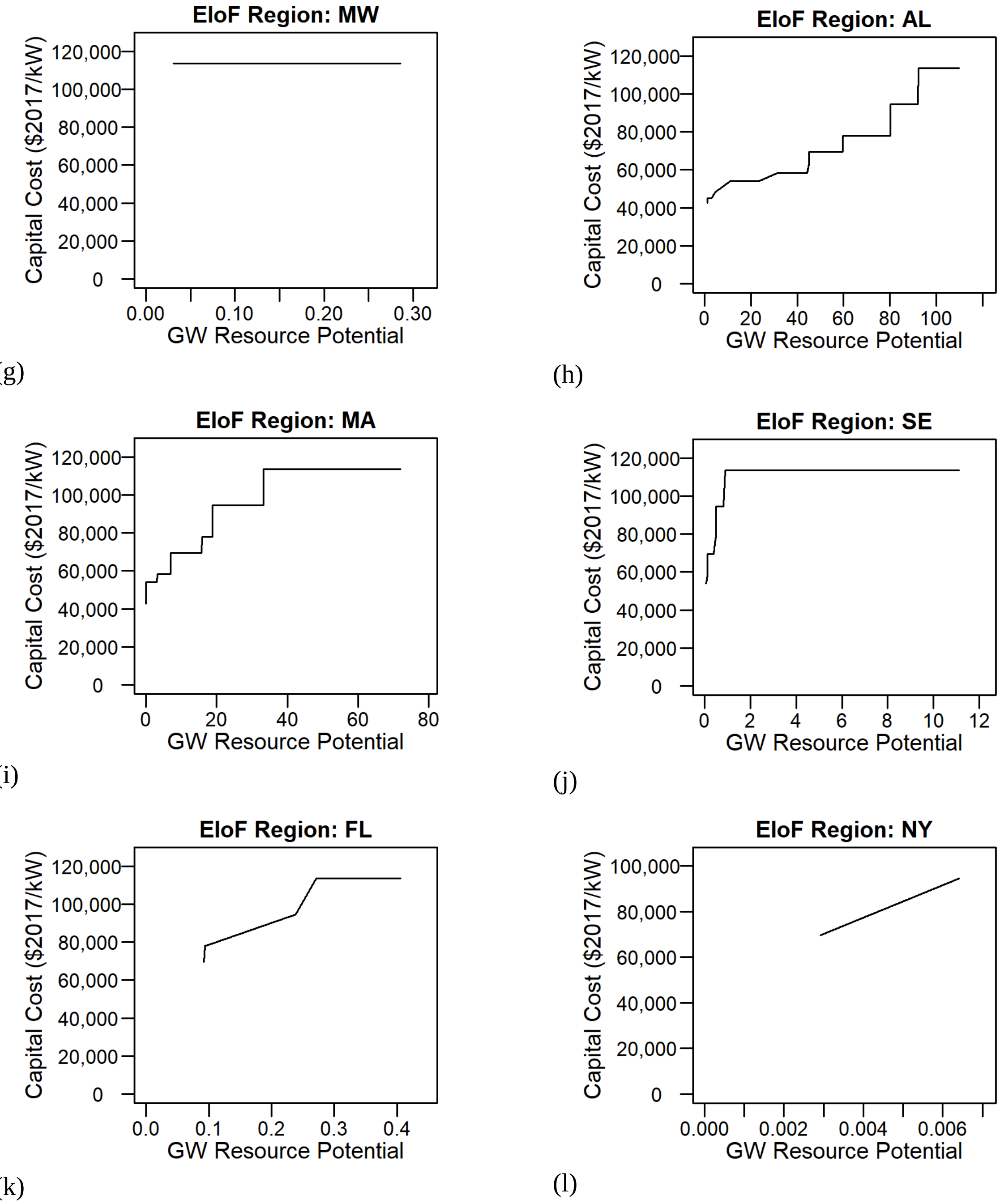
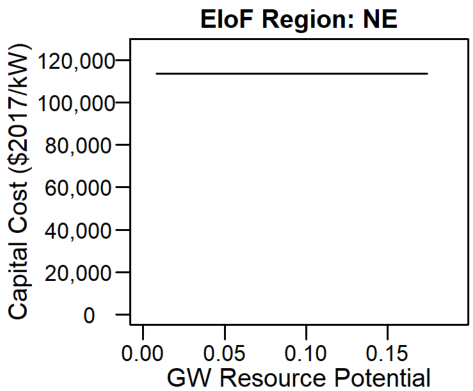


Figure 7. (continued) Capital cost versus resource supply curves, per EIoF region, for geothermal power plants.



(m)

Figure 7. (continued) Capital cost versus resource supply curves, per EIoF region, for geothermal power plants.

Dispatchable hydropower generation

We next solve for the dispatchable hydropower generation each hour, $G_{hyED,t}$, using the following steps that are repeated for each season (Winter, Spring, Summer, Fall). Figure 8 illustrates the factors described in the steps. The goal is to determine the factors $C_{max,hydED}$, $t_{transition}$, and t_2 that define Area1 and Area2 such that the remaining amount of the user's desired generation from hydropower (that remaining after already solving for non-dispatchable hydropower generation) is equal to Area1 + Area2.

- Step 1: Determine the remaining generation budget for each season as required from dispatchable hydropower, $GDesired_{hyED}$, after accounting for the non-dispatchable hydropower, equal to $GDesired_{hyED} = (GFracDesired_{hy} - Gfrac_{hyEND}) \times G_{annual}$.
- Step 2: Calculate the *seasonal* net generation duration curve, $GNet_h$, composed only of generation during a single season. One must keep track of which hour of $GNet_h$ (the duration curve) relates to the actual hour of generation during the year, $GNet_t$.
- Step 3: Determine the maximum capacity possible for dispatchable hydropower $C_{max,hydED}$ (as depicted in Figure 8) which is equal to the maximum of either the maximum capacity listed in

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- Table 2 or the maximum of the net generation duration curve, $GNet_{max.}$ This ensures that the power output of dispatchable hydro generation in any given hour cannot exceed the capability of the facility and doesn't exceed the required net generation.
- <u>Step 4:</u> Start with $h_{transition}$ begins at the maximum number hours in the season, calculate Area1. If $GNet_h[h_{transition}] \geq GNet_{max}$, then Area1 = $GNet_{max} \times h_{transition}$, otherwise the bottom portion of Area1 resides on the x-axis of Figure 8, and it equals the area under the curve $GNet_h$ from 0 to $h_{transition}$. If this is not the first calculation using $h_{transition}$, move $h_{transition}$ one hour to the left.
- <u>Step 5:</u> With $h_{transition}$ known, h_2 is the hour where $G_{transition}$ is equal to the net generation duration curve, $GNet_h$. Now calculate Area2 based on the geometry of Figure 8.
- <u>Step 6:</u> Now calculate Area1+Area2. Initially (when $h_{transition}$ equals the maximum number of hours in the season) this quantity will generally be larger than the required seasonal dispatchable hydro generation, $GDesired_{hyED}$. If it is not, then the dispatchable hydro generation is known by associating each $GNet_h$ with its corresponding $GNet_t$. If (Area1+Area2) > $GDesired_{hyED}$, then reduce $h_{transition}$ sequentially from right to left one hour at a time, calculating Area1+Area2 until that quantity becomes just less than the required seasonal dispatchable hydro generation, $GDesired_{hyED}$. At that time, then match each $GNet_h$ with its corresponding $GNet_t$.

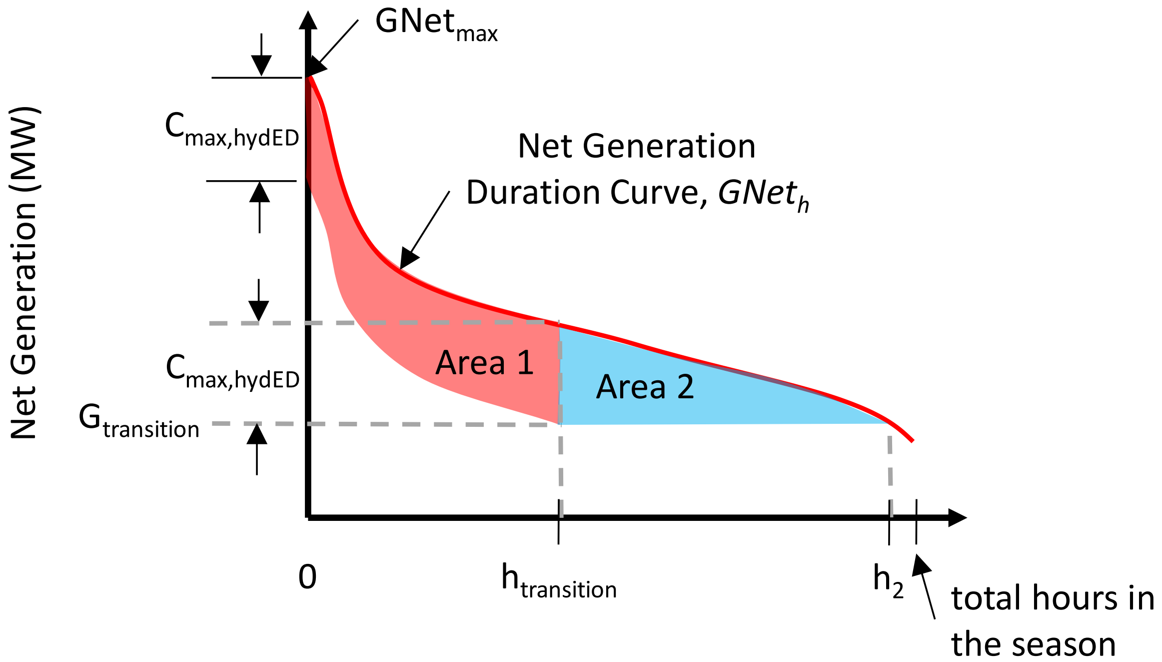

Figure 8. Net generation duration curve and shaded areas, Area1 and Area2, indicating how solveGEN solves for the hourly generation and generation capacity for existing dispatchable hydropower generation (hydED) while assuming constraints on both power (capacity) and energy (MWh related to water flow).

<u>Dispatchable generation technologies (natural gas)</u>

At this point in the algorithm, there is no generation left to dispatch except for that from natural gas. Thus, the net generation $GNet_t$ is calculated as generation G_t minus all dispatched generation except from natural gas. Thus, the dispatch of total natural gas generation is known, but we split this natural gas generation between a mix of natural gas combined cycle (NGCC) and natural gas single-cycle combustion turbine (NGCT) power generation. We use the screening curve method to calculate the dispatch and required capacity for a mix of NGCC and NGCT. We do not summarize the screening curve method that is described in the literature [Phillips *et al.* (1969), Zhang *et al.* (2015), Zhang and Baldick (2017)]. However, the screening curve method solves for the least cost mix of dispatchable generation technologies given (i) an annual net generation duration curve, (ii) the generation technologies' annualized fixed capital cost, and (iii) the generation technologies' variable costs. NGCC has a higher capital cost but lower operating cost than NGCT, and thus total NGCC generation is generally more than total NGCT generation that serves the last remaining required peak net generation.

Method to Solve for Power Plant Capacity and Dispatch (with annual electricity storage)

In addition to solving for the capacity C_i and dispatch of each generation technology as described in the previous section without any assumed electricity storage technologies, we also calculate capacity and dispatch when assuming an electricity storage technology. To reiterate, the purpose of the EIoF EFD is to calculate solutions in 10s of seconds, and thus we do not solve for a minimum cost capacity and dispatch of electricity storage. We calculate the capacity and dispatch of a very general "annual storage" technology. We label this as "annual storage" to specify that its power and energy capacity is determined by using data for all 8760 hours of the year, not assuming only a 24-hour duty cycle (e.g., operating for daily charging and discharging).

We solve for the generation capacities in the same order as in the case for no storage. In this case for storage, the storage technology capacity and discharge is solved simultaneously with the PV, CSP, and wind capacities.

The storage technology is assumed to operate using a simplified set of rules as follows:

- Rule 1: Store all curtailed solar PV, CSP, and wind generation.
    - This rule determines the power capacity of storage, $C_{AnnualStorage}$ in units of MW, where its value equals the maximum hourly curtailed generation, or $C_{AnnualStorage} = \max\{G_{t,curtailment}\}$.
    - Because storage discharge cannot occur during charging hours, this rule also determines which hours are available for discharge.
- Rule 2: The available stored energy for discharge is equal to the stored electricity times a round trip charge/discharge efficiency. We assume charging efficiency equals discharging efficiency such that they are both equal to a one-way efficiency and the round trip efficiency is $(\eta_{1way})^2$. We set $(\eta_{1way})^2 = 0.85$ such that $\eta_{1way} = 0.922$ following Cole and Frazier (2019) assumptions for a lithium ion battery with 4 hours of energy storage capacity at full power capacity.
- Rule 3: To solve for the dispatch of stored electricity each hour, $GStoredToGrid_t$, we use the same algorithm as for the dispatch of dispatchable hydropower generation. Both technologies have a maximum power capacity, a maximum energy budget (or energy storage capacity).
- Rule 4: For accounting purposes, the hourly dispatch of technology i (i = PV, CSP, wind) is the sum of generation fed directly to the grid, $GDirectToGrid_{t,i}$, and generation dispatched from storage to the grid $GStoredToGrid_{t,i}$. $GDirectToGrid_{t,i}$ is equal to any generation that is not curtailed for the given hour. $GStoredToGrid_{t,i}$ is equal to the fraction of generation from PV, CSP, and wind served from technology i served during hour t, multiplied by the total power dispatched from storage that hour (see Equation (13)). For example, if 100 MW of electricity were dispatched from storage for a given hour, and during that hour generation from each of PV, CSP, and wind was 2000 MW, 500 MW, and 1500 MW, then 50 MW of storage dispatch is associated with PV

(2000/4000 = 50%), 12.5 MW is associated with CSP (500/4000 = 12.5%), and 37.5 MW is associated with wind (1500/4000 = 37.5%).

- For the purposes of Equation (13), $GDirectToGrid_{t,i} = G_{t,i}$, because for storage dispatch to occur in any given hour, per Rule 1, there is no curtailment of PV, CSP, or wind power.

$$GStoredToGrid_{t,i} = GStoredToGrid_t \times \frac{G_{t,i}}{G_{t,PV} + G_{t,CSP} + G_{t,wind}} \tag{13}$$

To solve for the necessary PV, CSP, and wind capacity we use the above Rules 1-3 inside of an optimization routine to minimize the objective function of Equation (9) given the lower bound and upper bound constraints as in Equations (10) and (11), respectively, in the same way we solved for PV, CSP, and wind capacity without annual storage. This method necessarily solves for a lower PV, CSP, and wind capacity because the otherwise-curtailed generation now contributes to the user's desired fractions of generation from PV, CSP and wind.

For the purposes of displaying data to the user on the EIoF EFD, one can show individually display the hourly dispatch of $GStoredToGrid_{t,PV}$, $GStoredToGrid_{t,CSP}$, and $GStoredToGrid_{t,wind}$.

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