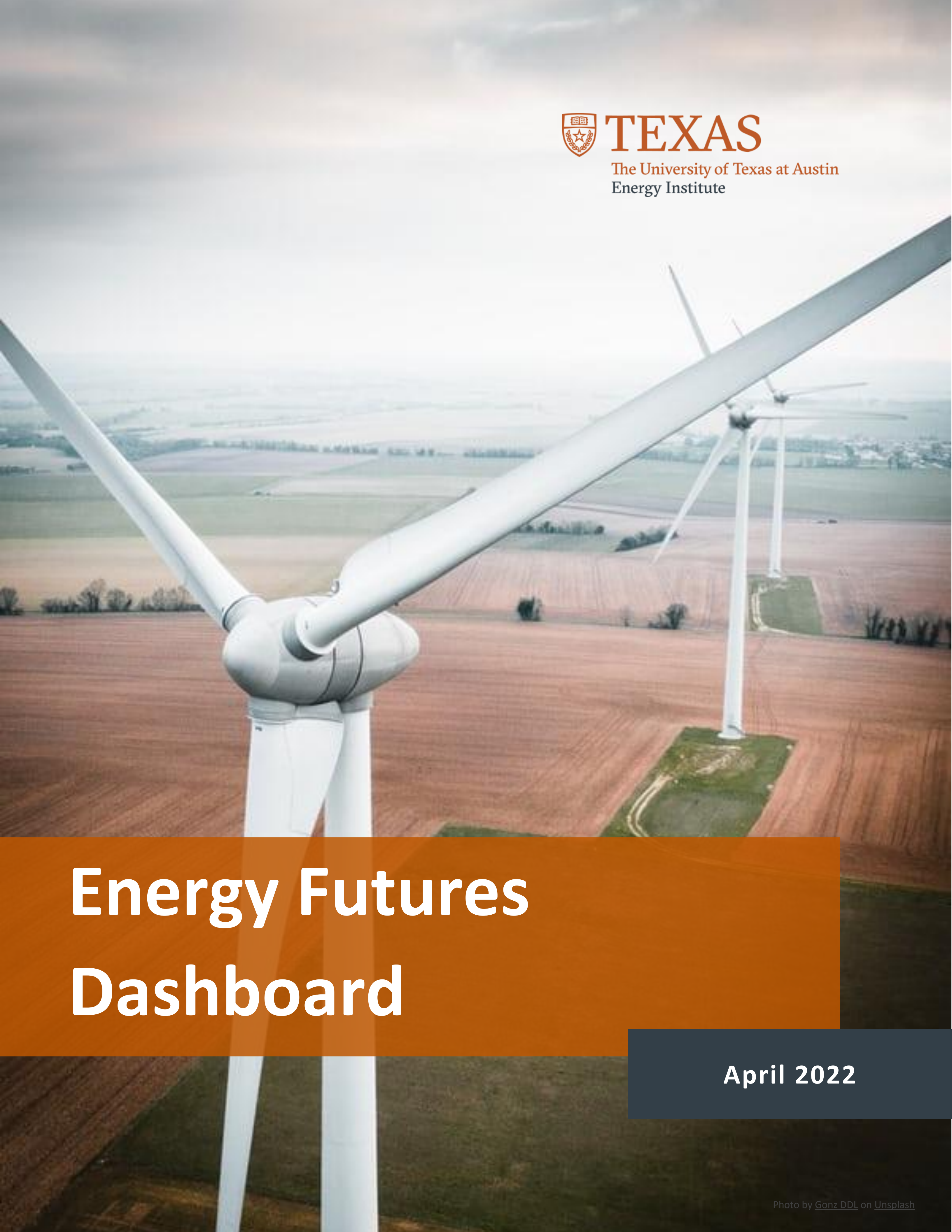

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Energy Futures Dashboard

April 2022

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The impact of renewable electricity mixes on residential electricity costs, land-use, and carbon emissions via the Energy Futures Dashboard

A report by a committee of faculty and staff at
The University of Texas at Austin

April 2022

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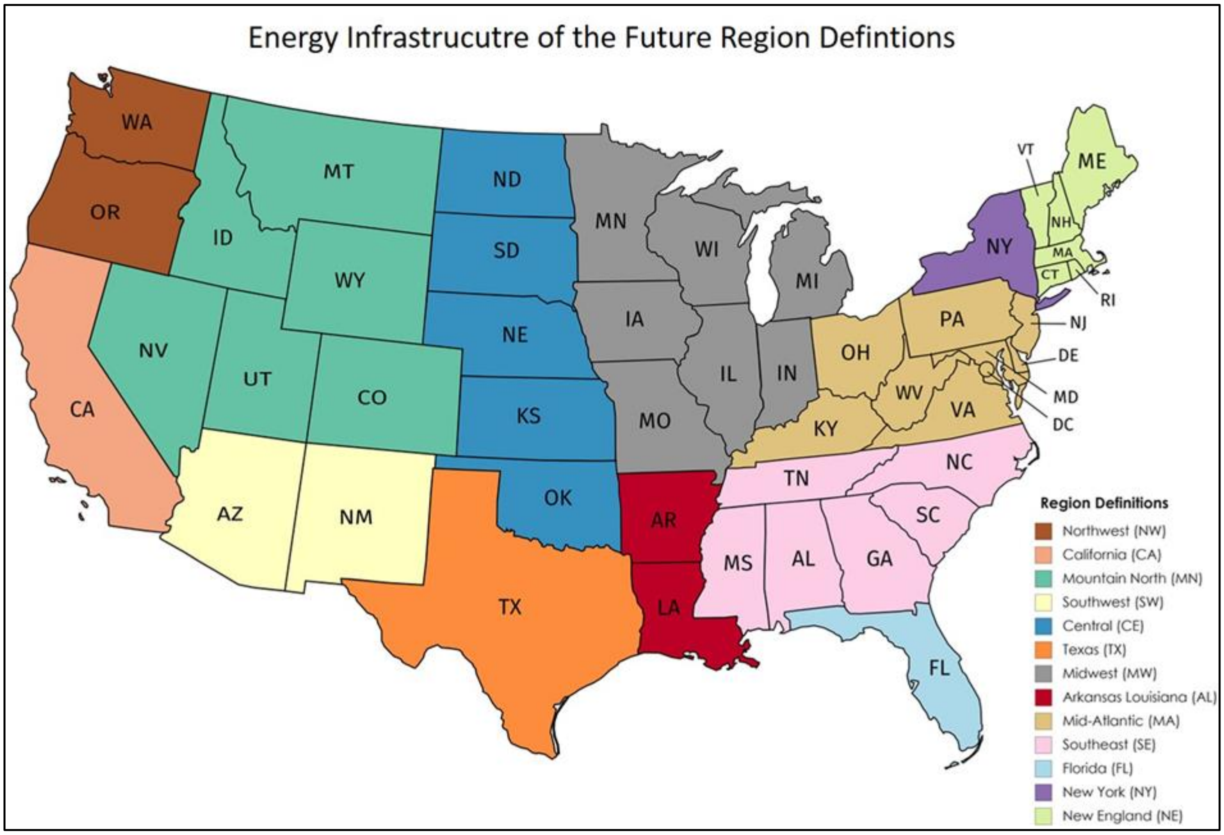
Executive Summary

The [Energy Futures Dashboard]() (EFD) is a user-friendly online and open-source energy modeling tool that provides non-energy professionals with a way to explore their own energy future in minutes. Because the EFD is easy to use for those with minimal knowledge of energy system issues, it serves as a complement, not a replacement, to models that have more detail and resolution, but take specialized knowledge and hours to run each simulation.

The main purpose of this paper is to use the EFD to provide insights into how future energy choices reveal tradeoffs in electricity costs, land use of wind and solar farms, and carbon emissions by summarizing results of thousands of simulations for each of thirteen regions of the continental U.S.

Figure ES 1 Regional definitions used in the Energy Futures Dashboard



Northwest (NW), California (CA), Mountain North (MN), Southwest (SW), Central (CE), Texas (TX), Midwest (MW), Arkansas Louisiana (AL) Mid-Atlantic (MA), Southeast (SE), Florida (FL), New York (NY), New England (NE)

To facilitate a fast simulation time for online users, the EFD makes many simplifying assumptions. These assumptions include, among others, a simplified use of electricity storage, specifications for what fraction of wind power can be generated in one region to serve load in another via transmission lines, no use of carbon capture and storage, and a linear change from the existing power plant mix in 2020 until the targeted end date of 2050.

We find that in all regions, electricity mixes in 2050 up to 75% wind, solar, and hydropower are achievable at historical costs, moderately more land use, and low carbon emissions. However, reaching very high penetrations (> 75-98%, depending on region) of wind, solar, and hydro can have a significant impact on all three metrics. Without electricity storage, very high penetrations of wind and solar technologies require large amounts of new capacity, land use, and high carbon emissions embodied in power plants, but electricity storage reduces these requirements at additional costs, demonstrating land-carbon-cost tradeoffs that a user can explore. To check our results, we compare the EFD to the National Renewable Energy Laboratory's Regional Energy Deployment System (ReEDS) model and demonstrate sufficiently compatible outcomes for all but very high (> 80-90%) penetrations of renewable electricity. Given that much of the data, such as cost assumptions, behind the EFD are from ReEDS, this similarity in outcomes provides confidence that the EFD demonstrates realistic results for non-extreme cases.

Assessing Tradeoffs of cost, land use, and CO_2 emissions with high renewables

With some variation over the last three decades and across the U.S., each household has typically spent between $1000 and $2000 per year on electricity. Land use for wind and solar plants has historically been minimal, but their installed capacity is expanding. Further, land use of electricity infrastructure has historically covered less than 1 percent of land. While electricity-related carbon dioxide (CO_2) emissions increased with industrialization, and have declined over the past 15 years, many climate mitigation goals seek to reduce CO_2 emissions to near zero by 2050. Thus, we use this historical cost range, 0.5% (direct) and 1% (total) land use criteria (for wind and solar farms), and electricity-related CO_2 emissions as context for comparing thousands of scenarios of electricity mixes for the year 2050.

We summarize findings from two particular scenarios, J and K, that have further description within the paper. Scenarios J and K are defined to find electricity grid mixes in 2050 that have *a "tradeoff" among the competing goals* of lower CO_2 emissions, low land use, and low cost.

Scenario J sought a solution that minimizes the annual cost to a residential customer in 2050 (in $2017 per household) but that is constrained in by the following criteria (per region):

- electricity-related CO_2 emissions in 2050 are ≤ 20% of emissions in 2005,
- direct land use (covered by the footprint of infrastructure at wind and solar farms) < 0.5% of total land, and
- total land use (includes land between infrastructure at wind and solar farms) < 1%.

Scenario K sought a solution that minimizes CO_2 emissions but that is constrained in by the following criteria (per region):

- annual cost to a residential customer in 2050 (in $2017 per household) must be no more than that which customers have paid over the last 30 years, and
- direct land use (covered by the footprint of infrastructure at wind and solar farms) < 0.5% of total land.

Table ES 1 summarizes either a J or K scenario for each region that has the highest hydro, wind, and solar generation and meets the scenario criteria. In addition to those listed below, several regions could meet the criteria with high (> 40%) use of nuclear power (regions FL, MW, NE, NW, NY, SW, TX are listed as such in the report), but since our main goal was to explore tradeoffs with renewable electricity, we've listed the compatible results with the highest renewable percentages.

Table ES 1 Scenarios that highlight tradeoffs to minimize costs with low land use and CO_2 emissions

Region	Scenario	Storage Assumed?	Hydro	Wind	PV	Nuclear	NG & Coal	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	CO_2 Emissons from 2020-2050 (Mmt)	CO_2 Emissons in 2020 (Mmt)	CO_2 Emissons in 2050 (Mmt)	CO_2 Emissons in 2050 as % of 2020 (Mmt)
AL	K	Y or N	1	17	3	14	65	$2,000	< 0.1%	0.1%	2,180(19.4)	73	67	91%
CA	J	N	5	21	7	66	1	$1,900	0%	0.8%	515(118)	23	8	33%
CE	J	N	3	58	24	0	15	$1,900	0.1%	1.0%	1,970(12.4)	78	27	35%
FL	K	N	0	78	14	1	7	$2,200	0.5%	4.0%	1,530(190)	67	21	32%
MA	K	N	0	48	4	12	36	$1,700	0.1%	1.3%	8,230(178)	281	229	81%
MN	K	N	7	20	2	69	2	$1,200	< 0.1%	0.4%	1,930(39.1)	84	3	4%
MW	K	Y	1	35	6	12	46	$1,450	< 0.1%	0.7%	8,210(104)	291	189	65%
NE	K	N	5	61	11	10	13	$1,600	0.2%	5.9%	403(69.3)	17	10	62%
NW	K	N	36	0	0	63	1	$1,200	0.0%	0.0%	256(7.11)	11	1	9%
NY	K	N	8	22	2	63	5	$1,600	0.1%	2.3%	360(33.8)	15	6	37%
SE	K	Y	3	28	4	25	40	$2,000	< 0.1%	0.7%	5,940(98.5)	199	170	85%
SW	J	N	6	42	13	12	27	$910	< 0.1%	0.1%	1,130(23.8)	43	16	37%
TX	K	N	0	78	15	1	6	$2,200	0.4%	9.5%	3,270(349)	144	41	28%
										Totals	**37,166**	**1,326**	**788**	**59%**

Storage Assumed? (Y = excess wind and solar are stored in batteries, N = no battery storage for excess wind and solar) The numbers below the electricity technologies are the percent of total generation in 2050. CO2 emissions are only those associated with power generation. “CO2 Emissions from 2020-2050” in million metric tonnes (Mmt) are those summed from 2020-2050 from burning fossil fuels for power generation (not in parentheses) and embodied in building power plants (within parentheses).

Even when attempting to maximize use of wind, solar, and hydropower electricity, the cost, CO_2, and/or land constraint did not allow some regions to reach more than 20-40% electricity from renewables and necessitated the use of high levels of nuclear power (CA, MN, NW, NY) or imports of electricity from very long distances (i.e., FL assumes high use of wind power from the Central, CE, region of the country). Different assumptions for how much wind power can be transmitted among regions can dramatically change the results, but we did not fully explore this aspect (see the supplemental material for assumptions of wind importation from one region to another).

The selected tradeoff scenarios of Table ES 1 show that it is difficult (under the assumptions of the EFD) to reach low levels of CO_2 emissions. The J scenarios (by definition) reach lower emissions in 2050, but not every region had a cost-feasible J scenario that met the land and CO_2 constraints. Thus, the K scenario is shown as one with balanced tradeoffs. Considering all 13 regions of the continental U.S., the 2050 scenarios in Table ES 1 reach 59% of the 2020 electricity-related CO_2 emissions. This result demonstrates both the challenge of reducing greenhouse gases, and potential limitations of the EFD as an educational tool.

We did not generally explore the full range of use of nuclear power to achieve the low CO_2 threshold constraint even though nuclear power will very likely provide very-high penetrations of low-carbon power at or near historical costs in every region. Three scenarios in the report (G, H, and I) posit a maximum penetration of nuclear power, between 55-70% depending on the region, and three different concepts for the rest of the mix of electricity from renewables and natural gas. These scenarios again demonstrate cost and CO_2 tradeoffs: a pure nuclear-natural gas mix might minimize cost at the expense of higher emissions, while a mostly-nuclear plus hydro/wind/solar mix has higher cost but lower emissions.

Readers can use the Energy Futures Dashboard online tool for themselves to explore different mixes, including those with nuclear power. For more information beyond this report, visit the Energy Futures Dashboard tool itself, and see the Energy Infrastructure of the Future website for three example reports for scenarios that explore more future 2050 energy changes than we do in this document:

- California's Renewable Vision
- Mid-Atlantic Nuclear Renaissance
- Central U.S. Wind Power

1. Introduction

Many computational models exist to analyze the costs and benefits of different energy supplies, including those available for transitioning to a low-carbon energy system. This paper describes one such tool, the Energy Futures Dashboard (EFD). Existing computational energy system tools provide researchers with a robust array of analyses for a variety of research topics focused on the energy sector. The motivation, however, for the EFD is not to add new functionality for the research and modeling community, but rather to engage non-experts into a broader discussion of the impacts of a changing energy system via a model that has enough resolution to inform realistic tradeoffs among future energy choices. Thus, the purpose of the EFD is to provide access to a non-expert audience that has interest in environmental and economic energy-related tradeoffs but might lack the training, experience, or time to utilize more complex modeling tools.

With this purpose in mind, there are several limitations that constrained the design of the EFD to enable greater accessibility. First, we designed it to work via a web-based interface. Thus, we designed the EFD to perform calculations and return results in minutes rather than the hours required by some optimization-based models. In this way the user can obtain rapid feedback on their inputs. Second, the EFD uses approximate, but realistic, inputs and constraints to guide 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 conditions in 2050. Third, while the EFD reports total energy consumption, it provides only a small subset of possible user inputs by which users can create future scenarios.

This paper explains the EFD inputs and outputs, its major assumptions and algorithms that govern its results, and a comparison of thousands of future electricity mix scenarios across the EFD's thirteen regions within the continental United States. Via these scenarios we discuss differences in cost and environmental impacts that are affected by the region-specific patterns of electricity load, renewable electricity generation, and renewable resource availability. We also present results from running the EFD over 60,000 times to indicate the trends in ***costs, land use, and carbon dioxide emissions*** as the electricity mix shifts to higher penetrations of renewable electricity. In order to demonstrate the robustness of our tool, we also compare similar scenario results from the EFD to results from the National Renewable Energy Laboratory Regional Energy Deployment System (ReEDS) model.

The underlying EFD model source code is open source and publicly available through the Energy Institute's GitHub site with detailed instructions on how to set up and operate the tool.

1.1 Comparison to Existing Energy or Electricity System Models

As previously mentioned, there are numerous models that exist for studying the electricity sector and its operations, each with its own set of tradeoffs which are heavily influenced by the general purpose of the model (Ringkjøb et al., 2018). We identify several specific models (ReEDS (Cole et. al., 2020); NEMS (EIA, 2019); SWITCH (Johnston et. al., 2019); WIS:dom (Clack et. al.,2020)) and compare them to the EFD as shown inTable 1. The first key difference between these models is their methodology. Other than the EFD, each model in this table uses cost optimization (to some degree) with a scenarios approach to produce results under various sets of parameters and constraints. Conversely, the EFD performs no cost optimization. Instead, it solves for future electricity capacities to match a user's input for a desired mix of electricity supplies in 2050. This difference contributes significantly to the run-time. Complex optimization at the scale of the U.S. power system requires significant computing power and run-times of multiple hours for ReEDS, NEMS, SWITCH, and WIS:dom. By not performing cost optimization, the EFD is able to provide outputs rapidly enough for a web-based tool.

High spatial and temporal resolutions increase computational requirements and run-times, as well as accuracy of results. The EFD uses hourly resolution for electricity generation and load, however it sacrifices spatial resolution. ReEDS and NEMS have made the opposite tradeoff, sacrificing temporal resolution for high spatial resolution, and SWITCH and WIS:dom allow for both high temporal and spatial resolution. The EFD maps total primary energy flows (although the user cannot change every aspect of energy use) through multiple sectors and estimates economic and environmental impacts. The high complexity of NEMS allows it to provide a more in-depth analysis of all energy activities within all major economic sectors as well as energy interactions within the entire U.S. economy and other markets. ReEDS, WIS:dom, and SWITCH provide a more in-depth analysis than the EFD but cover only the electricity sector. To summarize, there is a tradeoff between model complexity and computational needs, i.e., run-time. There are significantly more differences than we are able to cover in this paper that should be considered when considering tradeoffs in modeling approaches, including the treatment of energy storage, demand response, and accessibility (open sourced vs. proprietary). Throughout this paper, we will cover these factors for the EFD in greater detail.

Table 1 Comparison of EFD with other energy modeling tools

Model	Developer	Methodology	Run Time	Temporal Resolution	Time Horizon	Spatial Resolution	Scope
EFD	**Unversity of Texas Energy Institute**	Linear modeling of energy flows and power system operation	Minutes	hourly; annual	30 years	Contiguous U.S.; 13 regions	Energy flows for industrial, commercial, residential, and transportation sectors
ReEDS	**National Renewable Energy Laboratory**	Capacity expansion and dispatch optimization	Hours	17 timeslices; biannual	40 years	Contiguous U.S.; 134 regions	Electricicty sector growth and operation
NEMS	**Energy Information Administration**	Modular optimization of energy activities by economic sector and fuel market	Hours/Days	annual	30 years	Contiguous U.S.; 25 regions for electricity market; 12 regions for oil and gas supply; 9 regions for demand	Energy supply and demand for power,industrial, commercial, residential, and transportation sectors
WIS:dom	**Vibrant Clean Energy**	Capacity expansion and production cost optimization	Hours/Days	5 minutes	Indefinite	3 km	Electricicty sector growth and operation
SWITCH	**Various**	Capacity expansion and simplified economic dispatch optimization	Hours/Days	Hourly	Indefinite	User-determined	Electricicty sector growth and operation

2. Methods

2.1 EFD Algorithm and Assumptions

Given the purpose of the EFD, there are many simplifying assumptions, and we summarize them in this section. For a full discussion of data inputs and assumptions for algorithms, see the series of EFD white papers (2020.1 – 2020.6) listed in the references.[1]

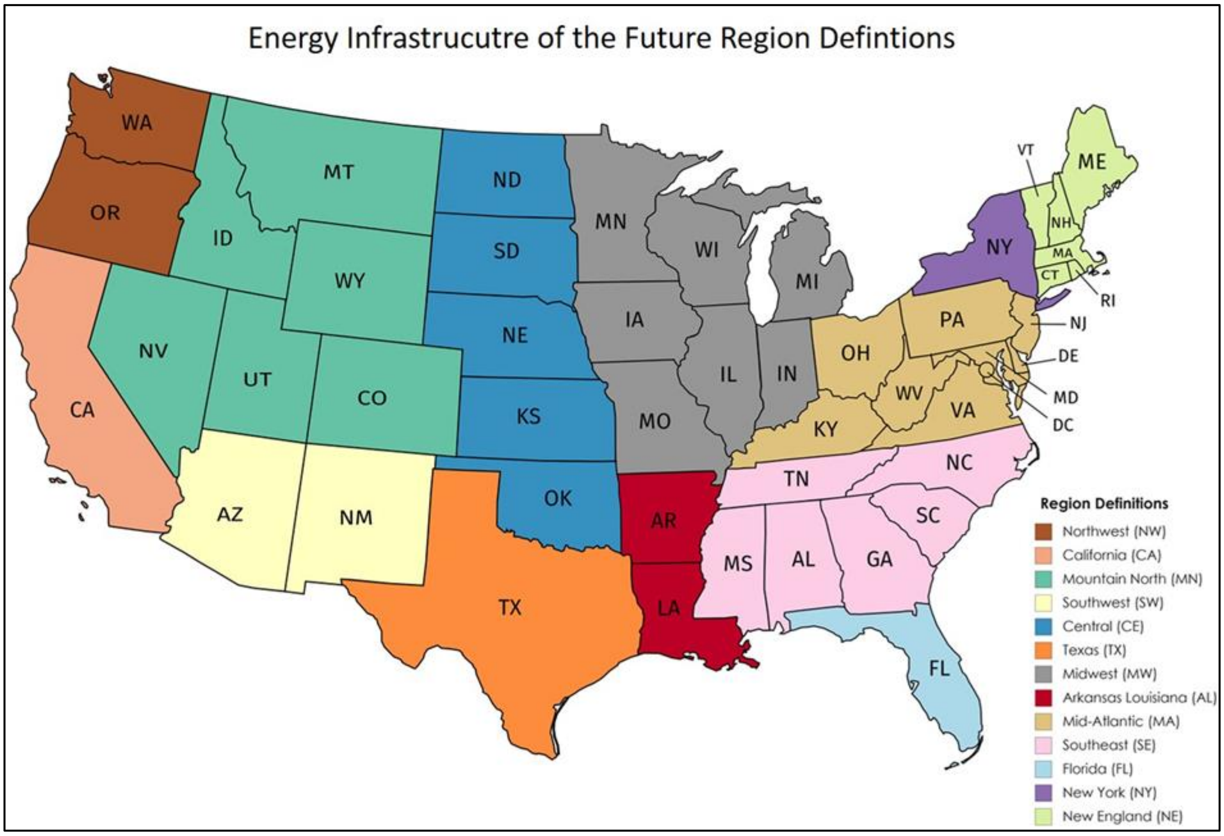
The EFD is a user interactive web-based tool that allows users to explore regional economic and environmental impacts from their choices for three major categories of energy production and use for the year 2050 (starting from the year 2020). *When using the EFD, a user is able to select the electricity generation technology mix as a percentage of generation, the percentage of light-duty vehicles driven on electricity versus liquid fuels, and the percentage of homes heated by electricity and natural gas*. The user can then see the impact of their selections on metrics such as land use, carbon dioxide emissions, consumer costs, annual spending, and capacity buildout. To achieve the user's desired inputs, the EFD assumes linear changes in electric grid investment from 2020 to 2050.

2.1.1 Definitions of Regions

The EFD divides the continental United States into 13 geographic regions (see Figure 1). The regional definitions enable us to investigate broad geographical differences in energy infrastructure capacities, supply costs, electricity demand and climate profiles, and number of customers (or population). We aggregate each region by state boundary to facilitate ease of combining data sets to inform regional energy use and population (see EFD white paper (2020.3) for assumptions for future population and electricity customers).

[1] http://energyfuturesdashboard.energy.utexas.edu Also accessible via the Energy Institute website https://energy.utexas.edu/policy/eiof.

Figure 1 Regional definitions used in the Energy Futures Dashboard



Northwest (NW), California (CA), Mountain North (MN), Southwest (SW), Central (CE), Texas (TX), Midwest (MW), Arkansas Louisiana (AL) Mid-Atlantic (MA), Southeast (SE), Florida (FL), New York (NY), New England (NE)

2.1.2 Hourly Demand and Dispatch

The EFD uses hourly resolution in defining electricity demand and generation. All generation, load, and weather data are based on hourly data of 2016[2], incorporating seasonal weather differences. We aggregate all data and simulation outputs into a single hourly profile for each of the 13 EFD regions. The EIA Hourly Electric Grid Monitor data serves as source data for hourly load profiles. See documentation, EFD white papers (2020.2), for details on scaling hourly load data to 2050 and constructing hourly profiles.

The allowable electricity generation technologies or fuel sources are onshore wind, utility-scale photovoltaics (PV), concentrating solar power (CSP), conventional hydropower, conventional nuclear, biomass, coal, geothermal, and natural gas. To maintain simplicity in the model, the EFD does not consider carbon capture and sequestration technology on any combustion-based power generation, distributed technologies (such as rooftop solar), or non-commercial nuclear power technologies (e.g., small modular reactors).

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[2] Leap year data were removed.

We couple the load data with wind generation data from Independent System Operators, and simulations of solar generation, both PV and CSP, using 2016 weather files as inputs into NREL's System Advisor Model (SAM) (EFD white paper 2020.5; Blair, 2014). Due to the concentration of wind and CSP resource in certain areas, the EFD assumes wind and CSP generation can be generated in one region for consumption in another by connecting via long-distance transmission. This is required if a user wants to make use of these resources in a region where they are lacking (see EFD White Paper (2020.5) for details on inter-regional import assumptions). Supplemental Table S 3 and Table S 4 report the percentage of generation from wind and CSP, respectively, that is assumed imported from one region to another. We assume intraregional transmission investment is a function of peak power demand, and the cost is region specific based on Federal Energy Regulatory Commission (FERC) Form 1 data (see EFD White Paper (2020.6)).

If a user specifies a percentage of generation from solar PV, biomass, or geothermal power plants, the EFD assumes 100% of the capacity serving each type of that generation resides within that region. We aggregate data from NREL's ReEDS model to calculate the maximum size of renewable resources for electricity generation for biomass, hydropower (separated into dispatchable and non-dispatchable quantities by season), geothermal, wind, and solar generation. We assume no long-term fuel quantity constraints for natural gas, coal, or petroleum generation, as we consider such constraints possible but given the wide expanse of the existing infrastructure, this consideration is beyond the scope of the EFD.

For household energy demand by fuel (electricity, natural gas, and "other" current mix of fuel oil, propane, and biomass), which is affected by user inputs for heating fuel, we use NREL's ResStock (Wilson, 2017) model to approximate hourly electricity and natural gas demands for the current stock of residential housing using (i) the current mix of heating technologies, (ii) only natural gas heating, and (iii) using only electric heat pumps with electrical resistance heating when heat pumps are unable to meet heating demand. See EFD White Paper (2020.4) for more complete discussion of simulations of hourly household energy demand using NREL's ResStock model.

The EFD uses a simplified algorithm to approximate power plant dispatch. The EFD does not use a least-cost dispatch or security constrained economic dispatch (SCED), algorithm, but it approximates least-cost dispatch. Thus, there are several overarching assumptions that affect the dispatch of power plants: there is no explicit modeling of ramp rate limits (either up or down) for any type of dispatchable power plant, there is no explicit modeling of start-up and shut-down times or costs for any type of power plant, there is no explicit modeling of specific ancillary services, capacity markets, or other functions that power plants provide in addition to selling energy only, and we assume no reserve margin for the system. We justify these simplifications on three counts. First, the level and timing of electricity demand 30 years into the future is uncertain enough as to overwhelm adding about 10% generation capacity for peak hours as reserve margin or to be supported by capacity markets. Second, the approximate nature of the EFD algorithm does not have sufficient resolution to meaningfully distinguish which type of power plants provide which ancillary services, benefit from capacity markets at what rate or provide reserve margins. Third, the EFD assumes no demand response. One implication of this demand response assumption is that the estimated hourly electricity demand in 2050 (that is influenced by hard-coded data and user inputs for household heating types) does not change no matter what the annual cost or calculated hourly marginal costs of electricity generation. In all likelihood, demand response technologies will significantly impact peak loads in 2050, offer some ancillary services to enhance grid reliability and, hence, alter the need for capacity mechanisms and reserve margins, compared to our baseline profiles from 2016.

Because the user specifies the desired 2050 generation mix, costs do not determine the mix of electricity. However, given the user's criteria, the EFD does approximate hourly dispatch based on marginal cost of generation. The process is as follows. First, nuclear power is assumed to run at a constant rate (at 95% capacity factor), and the EFD limits nuclear maximum capacity to be equal to the lowest hourly load in a region. Next, the EFD schedules non-dispatchable hydropower that generates at constant levels per each of four seasons. Next the EFD solves for wind, solar PV, and CSP generation and capacity. When electricity storage is assumed to exist, it also simultaneously solves for storage charging and discharging. Next, the EFD dispatches the "dispatchable" thermoelectric technologies in the following order based approximately on increasing marginal cost: geothermal, coal, biomass, and petroleum combined cycle. Next "dispatchable" hydropower is scheduled. For all hours in which electricity storage is not occurring, storage is dispatched to reduce the hours with highest net load. Finally, all remaining load is served by natural gas power as a least cost mix of natural gas combined cycle (NGCC) and natural gas combustion turbine (NGCT) capacity solved via a screening curve. See EFD White Paper (2020.5) for a complete description of the dispatch algorithm.

The EFD produces outputs for two different solutions from each simulation: one assumes *no curtailment* of wind, PV, or CSP, and one assumes *full curtailment* of excess wind, PV, and CSP. For the rest of this paper, we refer to these as the *no curtailment* (or with storage) and *full curtailment* (or no storage) solutions. In all likelihood, the future electric grid will operate both with some curtailment and some electricity storage. Thus, the two EFD solutions should be viewed as bounding cases. However, if we solved for solutions with partial storage and partial curtailment, there would almost assuredly be some solutions with lower cost than our two cases, particularly for high penetrations of wind and solar generation.

The *no curtailment* solution serves as an extreme case of the use of electricity storage. For any hour (of 8760 hours of the year) when aggregate wind and solar generation exceed total electricity demand, the *no curtailment* solution assumes batteries store 100% of the excess generation. Thus, the solution considers the impacts for installing the required amount of storage capacity to achieve *zero curtailment*. Any wind and solar generation larger than hourly demand is sent to battery storage to determine the required storage capacity in both power (MW) and energy (MWh) units. All electricity storage is assumed to be in Li-ion batteries with a round-trip efficiency of 85%. Fundamentally, the EFD could be programmed with characteristics for any energy storage technology. However, multiple storage technologies hinder the purpose of the EFD to be accessible to non-experts since modeling more than one storage technology forces the user to determine the use of each storage technology or the EFD algorithm itself must assume how to operate each storage technology independently of the user.

The *full curtailment* solution serves as an extreme case where absolutely no wind or solar power is stored. Thus, this solution demonstrates the motivation for electricity storage with high percentages of wind and solar generation that are required to meet peak demand but are otherwise greater than hourly demand during many hours of the year.

2.1.3 EFD Outputs

In this paper, we will discuss outputs from the EFD for the cost of the energy system, energy-related carbon dioxide emissions associated with the life cycle of constructing and operating electric power plants and batteries, and land use only for wind, PV, and CSP. For simplicity, we do not include land use, during any part of the life cycle, for any other power plants. In addition, the EFD reports power plant capacity, storage energy capacity, and energy flows from technology sources to economic sectors. The EFD will produce a solution based on the generation mix, percentage of electric light-duty vehicles, and percentage of household heating from electricity and natural gas input by the user. However, the tool is subject to certain constraints, and it is possible that a solution matching the user's inputs for an electricity mix cannot be found. For example, the EFD's assumptions do not allow for a mix of 100% nuclear or solar with no storage. If a user's desired electricity mix cannot be solved, the EFD seeks a solution as close as possible to user inputs and substitutes natural gas generation as necessary to meet all electricity demand.

2.2 Scenario Definitions

We discuss results from EFD simulations in two different ways. First, we simulate several thousand electricity generation mix scenarios for the year 2050 for each EIoF region. We chose these simulations to provide insight into the rate of change of output metrics as the electricity mix increases to a larger fraction of renewable electricity generation from wind, solar PV, and hydroelectric power plants. The electricity mix scenarios do not fully explore mixes including coal, nuclear, geothermal, biomass, and CSP. The scenarios neither include petroleum in the electric mix, nor explore the full suite of options for the EFD user for light duty vehicles and home heating. They hold the percentage of light-duty vehicles as electric vehicles constant at 20% for each region, and they keep the default mix of technologies for household heating (see Supplemental Table S 2). Thus, for a given region the total annual required generation, in megawatt-hours, is constant across all scenarios. See the Energy Infrastructure of the Future website for three example reports on scenarios that change more parameters (California's Renewable Vision, Mid-Atlantic Nuclear Renaissance, Central U.S. Wind Power).

Each EIoF region has a default input generation mix for 2050 (see Table S 1 and EFD White Paper (2020.4) for description of method for creation of default generation mixes). Our scenario definitions for a specific region adjust from the default mix. We first adjust the default mix to maximize the utilization of hydropower resources across all scenarios. We then reduce the default values of wind and PV to 0%. The difference of the maximum available hydro and default wind and PV is then applied to the percentage of generation from natural gas to ensure total generation from all technologies equals 100%. Once these values are fixed, we create new scenarios by separately incrementing wind and PV by 1% while reducing all other technologies (excluding hydro) in proportion to their default value (e.g., all non-wind, PV, and hydro technologies hit 0% at the same time). We increment wind and solar PV in this way to see the incremental impact of increasing the penetration of these technologies on our output metrics. Our scenarios thus explore all possible combinations of wind and PV that fill all remaining generation after maximizing use of hydropower, as possible given other EFD constraints.

In addition to the thousands of scenarios generated using the aforementioned methodology, we select a small subset of these scenarios to highlight results of interest to researchers and policy makers who are interested in the regional differences from similar electricity mixes (see Table 2). We also discuss scenarios with high penetrations of nuclear and natural gas to provide a more comprehensive set of low-carbon and flexible generation scenarios. In addition, we simulate one scenario for each region that matches, as close as possible, to the Mid-Case scenario from the NREL Standard Scenarios report (2020 edition) that uses the open-source ReEDS capacity expansion model. This provides comparison of EFD results to those from similar tools used for researching the power system, and because many of the underlying data of the EFD come directly from those of the ReEDS model, we can explore the impact of other differences in the EFD algorithm versus the ReEDS model.

With this methodology, we end up with some number of simulations per region that is largely based on the maximum available hydro. This ranges from 877 (Northwest) to 5,723 (Midwest). See Supplemental Table S 6 for the number of simulations per region.

Table 2 presents twelve scenarios (A-L) that we highlight for each EIoF region, and the wording refers to the calculated situation for the year 2050. We highlight these scenarios to reflect tradeoffs from various technologies and metrics. Scenarios J and K are designed to explore realistic threshold criteria for each of our measured outputs for CO_2 emissions and land use.

Table 2 Selected 2050 scenarios defined for further analysis

Scenario	Label
Maximize hydro generation with remaining generation from a 1 to 1 ratio of wind and solar.	A
Maximize hydro generation with remaining generation from a 3 to 1 ratio of wind and solar.	B
Maximize hydro generation with remaining generation from a 1 to 3 ratio of wind and solar.	C
Maximize hydro generation with remaining generation from wind and solar, in a ratio that minimizes costs per customer.	D
Maximize hydro generation with remaining generation from wind and solar, in a ratio that minimizes direct land use.	E
Maximize hydro generation with remaining generation from wind and solar, in a ratio that minimizes CO_2 emissions.	F
Maximize nuclear generation, with remaining generation from natural gas.	G
Maximize nuclear generation with remaining generation from wind and solar, in a ratio that minimizes cost per customer.	H
Maximize nuclear generation, then maximize hydro generation, with remaining generation from wind and solar, in a ratio that minimizes cost per customer.	I
Threshold Scenario: CO_2 emissions must be less than 80% of 2005 levels, direct land use must be less than .5%, total land use must be less than 1%, minimize cost per customer.	J
Threshold Scenario: Cost per customer must be less than 30-year max, direct land use must be less than .5%, minimize CO_2 emissions.	K
EFD scenario that matches the NREL Mid Case scenario.	L

3. Results

Our analysis focuses on three output metrics from the EFD: (1) annual cost per residential customer (in real $2017), (2) cumulative CO_2 emissions from 2020 - 2050, and (3) land use from wind and PV development. The annual cost per customer, or residential meter, is the approximated cost of service in a regulated utility (see EFD White Paper (2020.6)). There are two land use metrics presented: direct land use, which refers to the direct land covered by the footprint of a wind turbine or solar PV panel, and total land use, which refers to the total area covered by a wind or solar generation facility (e.g., including area between wind turbines). We present results in two ways. First, we show figures that detail how the three aforementioned metrics change with each scenario that presents a different electricity mix. These figures order each scenario along the x-axis by one of the three metrics. Second, we discuss the highlighted scenarios in Table 2, defined the same for each region, to provide insights for interpreting the more detailed figures and comparing differences across regions.

Our results indicate that common scenarios impact each region differently, and even more so when considering the impacts of energy storage. Because of the large amount of data for each of the 13 regions, this main manuscript only presents results from the thousands of EFD scenarios for two regions: Texas (TX) and Northwest (NW). The Supplemental Information presents equivalent figures for the other eleven regions. We highlight Texas because it has practically no hydropower resources, but abundant wind and solar resources. We highlight Northwest because it has very high hydropower resources to complement variable wind and solar generation.

Figure 2 and Figure 3 show results for Texas, Figure 4 and Figure 5 show results for the Northwest. Figure 2 (TX) Figure 4 (NW) show results for the full curtailment (no storage) solutions, and Figure 3 (TX) Figure 5 (NW) show results for the no curtailment (with storage) solutions. The letter labels (A-L) refer to the scenarios in Table 2. Each of Figures 2-5 show the full suite of scenarios that demonstrate the variation in cost, CO_2 emissions, and land use metrics in relation to the chosen electricity mix. The electricity mix is represented by the color bars, and each figure orders the scenarios from the highest (left) to lowest (right) value of a given metric as indicated by the black line on each subfigure (values on right y-axis that indicates the value of the metric being presented for each scenario. Because electricity storage dominates capital investment at high wind and solar penetrations in the *no curtailment* solutions, we present two cost calculations. A dotted black line on Figure 3(a) and Figure 5(a), for example, indicates costs per customer when assuming storage costs at 50% of the default assumption of battery costs of 300 $2017/kWh in 2020 declining to 126 $2017/kWh in 2050 (per Cole and Frazier (2019) and as discussed in EFD White Paper (2020.6)).

3.1 Results Summary: Texas (TX)

3.1.1 Texas (TX): *full curtailment* (no storage)

Figure 2(a) shows that while increasing percentages of wind and PV generation are associated with higher costs, for Texas the costs (all reported in $2017/customer/year) can remain below $2,200 until reaching near 75% renewable penetration, such as in Scenario L (34% wind, 40% PV) with a cost of 2,050 $2017/customer/year. This annual cost for electricity is within recent historical records for Texas, and Supplemental Figure S 34 shows that $2,200 is near the maximum average annual cost paid by residential customers in Texas since (Figure S 34 also shows historical spending on electricity for all EIoF regions). All but Scenarios G, K, and L show costs higher than the historical maximum for Texas, indicating that these three generation mixes can be achieved at reasonable costs to the customer with no electricity storage.

Costs are particularly high for high wind and solar scenarios with maximum nuclear (62% for Texas, Scenarios H and I at $6,000), near 100% wind and solar (Scenarios A-F, with minimum cost at $7,400), or over 50% PV since PV capacity increases to over 15 TW to meet such high solar needs with no storage (Scenario A at > $40,000). Each subfigure of Figure 2 exhibits a steep rise in metric toward a plateau (far left scenarios) defined by scenarios with more than 50% PV as the costs, CO_2 emissions, and land use are dominated by the high quantities of PV capacity.

For a wide range of scenarios from near 0% to 100% wind and solar PV, thirty-year cumulative power sector emissions range from 3,000 to 7,000 million metric tonnes of CO_2 ($MtCO_2$), or about 100 to 200 $MtCO_2$/year (see Figure 2(b)). The lower range represents scenarios with high wind and solar generation, but with less than 50% solar. A sharp increase in CO_2 emissions occurs once solar generation increases to 50% (to its maximum achievable level of 54% in Texas, as in Scenario A) since the embodied emissions associated with such high solar manufacturing and installation increase total emissions to over 30,000 $MtCO_2$. Thus, to reduce annual power sector CO_2 emissions in Texas, one must stay below 50% PV and/or use electricity storage (see next section).

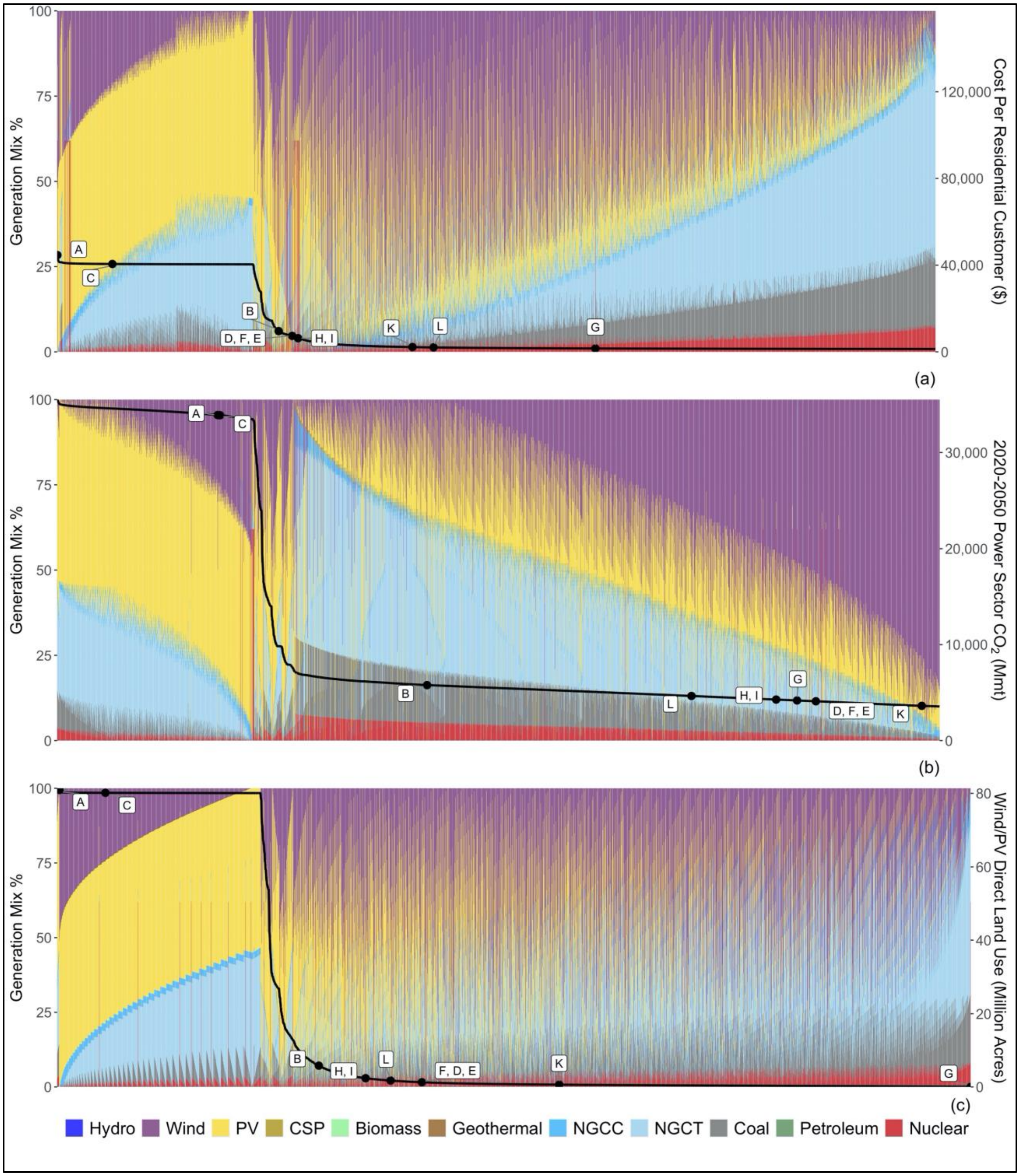
The EFD assumes all wind (and PV, as in all regions) in Texas is generated within the region. The direct land use from wind and solar PV is less than 1% of Texas' land area for scenarios with less than approximately 47% PV and low use of nuclear (Figure 2(c)). The highest land-use scenarios require greater than 40% of all the land in Texas to build the required capacity for large penetrations of solar, such as 48% of direct land for 50% PV in Scenario A. Since the EFD assumes a constant dispatch priority for nuclear, a higher percentage of nuclear translates to higher land use for a given percentage of PV and wind (e.g., compare scenarios H and I to scenario L).

Table 3 Texas: 2050 *full curtailment* (no storage)

Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use (%)	Total Land Use (%)	Carbon Emissions[2] (Mmt)
A	0M/50/50/0/0	$45,000	48.0%	87.0%	2,960(30,900)
B	0M/75/25/0/0	$9,600	3.5%	52.0%	2,960(2,820)
C	0M/25/54/0/21	$41,000	48.0%	55.0%	3,630(30,300)
D	0M/99/1/0/0	$7,400	0.8%	49.0%	2,980(1,110)
E	0M/99/1/0/0	$7,400	0.8%	49.0%	2,980(1,110)
F	0M/99/1/0/0	$7,400	0.8%	49.0%	2,980(1,110)
G	0M/0/0/62/38	$1,500	-	-	4,150(25.1)
H	0M/30/8/62/0	$6,300	1.4%	32.0%	2,950(1,310)
I	0M/30/8/62/0	$6,300	1.4%	32.0%	2,950(1,310)
J	No Solution	-	-	-	-(-)
K	0M/78/15/1/6	$2,200	0.4%	9.5%	3,270(349)
L	0M/34/40/5/21	$2,000	1.0%	3.7%	3,950(694)
NREL Mid	0/34/40/5/21	NA	NA	NA	3,500(-)

[1] "Disp." refers to dispatchable technologies: coal, natural gas, geothermal, CSP, and biomass. This will mostly consist of coal and natural gas in many regions.
[2] We report carbon emissions from generation as well as emissions embodied in power plants. This is indicated in the final column as "emission from generation (embodied emissions)".
Green cells highlight the lowest value per column. Minimum emissions is based on summing emissions from power generation and embodied in power plants.

Figure 2 Texas scenarios for the *full curtailment (no storage)* solution



Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

3.1.2 Texas (TX): *no curtailment* (with storage)

Figure 3(a) shows the cost trend for the *no curtailment* solution, and the trend is similar to the no storage solution (Figure 2(a)) but magnified by the addition of energy storage. We also show the costs per customer assuming storage costs at 50% of the default assumption, indicated by the dashed line. Again, the cost per customer is greatest with high penetrations of wind and PV as more storage capacity is required to capture the generation when those technologies generate more than demand. Here, Scenarios G and K (0% wind and PV) show costs lower than the historical maximum for Texas. Scenario L however, now shows costs of $33,000 per customer due to the addition of energy storage to capture generation from 74% wind and solar PV. Also, scenarios pairing maximum nuclear penetration (62%) with renewables (Scenario H, I, and J) show costs in the $30,000 - $40,000 per customer range.

The addition of energy storage offers a reduction in carbon emissions for the high penetration solar PV scenarios by reducing the capacity of PV needed and the associated embodied emissions. Under this *no curtailment* solution, Scenario A now shows only 3,300 $MtCO_2$ in total emissions. Additionally, scenarios with high nuclear penetration paired with renewables (Scenarios H, I, and J) are among the lowest emission levels of the chosen scenarios.

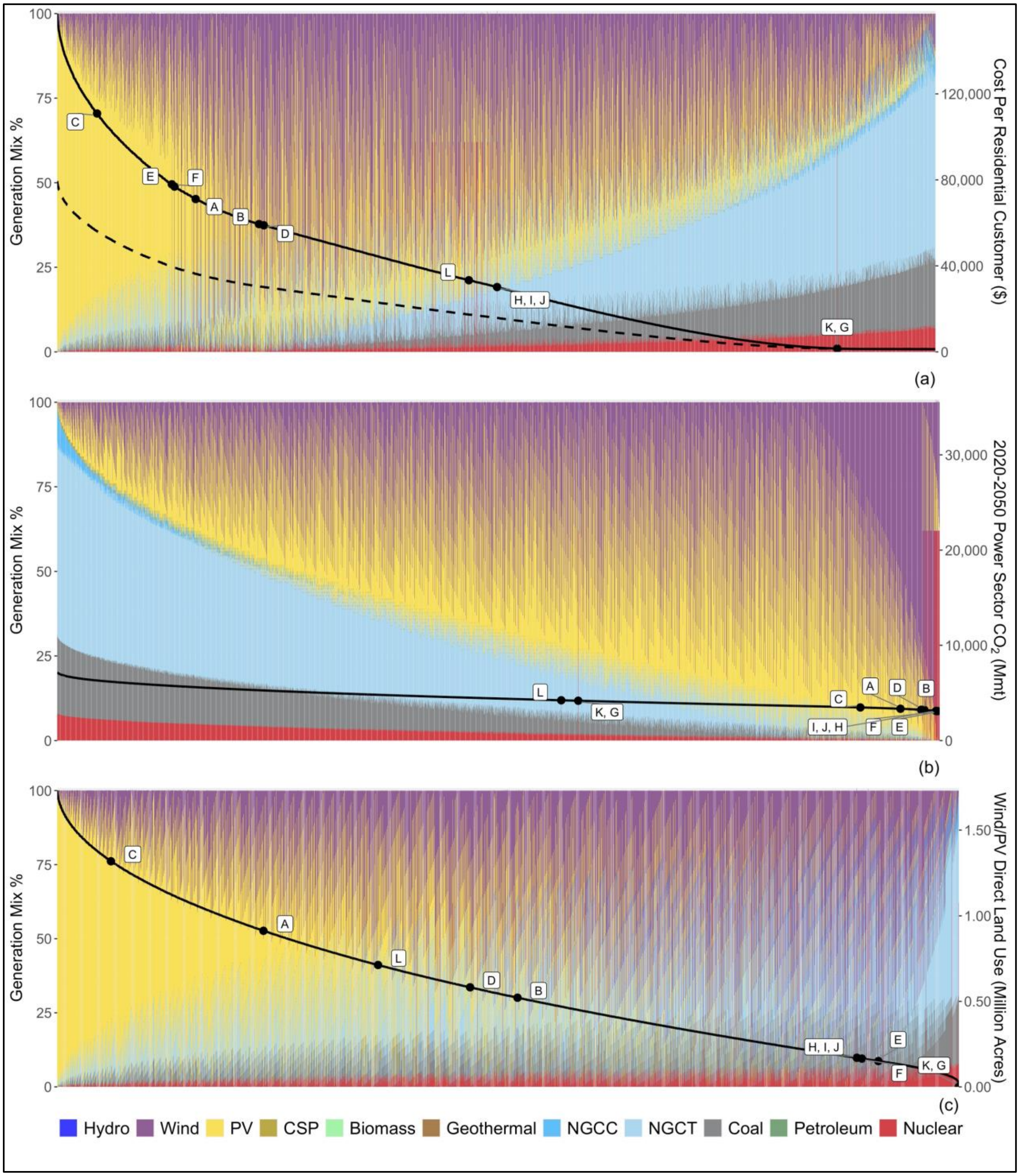
Figure 3(c) shows the large impact of energy storage on reducing land-use needs. Now all scenarios, including Scenario A with 50% PV, directly cover less than 1% of Texas land. Indirect land use that includes the land between wind turbines, is 1-6% for several high renewable scenarios. It is important to note, that using our assumed value of 0.74 and 49.4 acres/MW for direct and indirect land use, respectively, the EFD would estimate 0.02 and 1.1 % of Texas land for the 2020 installed wind capacity of 36,000 MW.

Table 4 Texas: 2050 *no curtailment* (with storage)

Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use (%)	Total Land Use (%)	Carbon Emissions[2] (Mmt)
A	0M/50/50/0/0	$71,100	0.5%	3.5%	2,950(381)
B	0M/75/25/0/0	$59,500	0.3%	4.7%	2,950(253)
C	0M/25/75/0/0	$111,000	0.8%	2.3%	2,960(515)
D	0M/71/29/0/0	$58,900	0.3%	4.5%	2,960(273)
E	0M/100/0/0/0	$78,000	0.1%	6.0%	2,950(135)
F	0M/99/1/0/0	$76,900	0.1%	6.0%	2,950(138)
G	0M/0/0/62/38	$1,550	-	-	4,150(25.1)
H	0M/30/8/62/2	$30,200	0.1%	1.9%	3,000(102)
I	0M/30/8/62/2	$30,200	0.1%	1.9%	3,000(102)
J	0M/12/26/62/0	$38,700	0.3%	1.0%	2,950(160)
K	0M/0/0/62/38	$1,550	-	-	4,150(25.1)
L	0M/34/40/5/21	$33,300	0.4%	2.4%	3,930(296)
NREL Mid	0/34/40/5/21	NA	NA	NA	3,500(-)

[1] "Disp." refers to dispatchable technologies: coal, natural gas, geothermal, CSP, and biomass. This will mostly consist of coal and natural gas in many regions.
[2] We report carbon emissions from generation as well as emissions embodied in power plants. This is indicated in the final column as "emission from generation (embodied emissions)".
Green cells highlight the lowest value per column. Minimum emissions is based on summing emissions from power generation and embodied in power plants.

Figure 3 Texas scenarios for the *no curtailment (with storage)* solution



Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year) (solid line: normal battery capital costs assumptions, dashed line: 50% of normal battery capital cost assumptions), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

3.1.3 Texas (TX): Insights comparing *full curtailment* (no storage) and *no curtailment* (with storage) solutions

For a given region, the highlighted cells in Table 3 and Table 4 indicate the lowest value for that metric across all summary scenarios. We chose the scenarios to demonstrate tradeoffs among cost, CO_2 emissions, and land use. The fuel, operating, and capital cost assumptions lead to the lowest cost scenarios being those based on nuclear and dispatchable (coal and natural gas) generation that also have the highest CO_2 emissions. The *no curtailment* scenarios with lowest carbon emissions (A – J except for G) have very high costs to the customer. When you look at the same scenarios (except for A, C, and J) under the *full curtailment* solution, there are much more reasonable costs, but the lack of storage results in an order of magnitude more land use required by wind and PV to build the capacity needed to achieve the generation levels required by those scenarios.

We define Scenarios J and K to act as examples that seek a balance among the three metrics. Scenario J minimizes customer costs subject to 2050 carbon emissions maintained at 20% of 2005 levels with a maximum direct and indirect land use of 0.5% and 1%, respectively. There is no *full curtailment* (no storage) solution that fits the scenario J threshold because the EFD cannot meet the land use and CO_2 emissions constraints without electricity storage (see Figure 3). Scenario K minimizes CO_2 emissions while restricting costs to less than the maximum experienced in the past 30 years with direct land use less than 0.5%. The *full curtailment* solution achieves 3,270 $MtCO_2$ using 78% wind and 15% solar power, and the *no curtailment* solution achieves 4,150 $MtCO_2$ by maximizing use of nuclear power.

3.2 Results Summary: Northwest (NW)

This section reviews the results for the Northwest region. A unique characteristic of this region is the large amount of available hydro resources. Hydropower is composed of dispatchable and non-dispatchable quantities. Because the EFD dispatches hydropower after wind and solar, the maximum percentage of hydropower generation might not occur at high penetrations of variable generation technologies. For this reason, we set the maximum hydro percentage to be 47% which is the highest amount achievable when the rest of generation comes from PV. However, hydro potential can be significantly higher (up to 57%) when there is a greater share of dispatchable technologies in the generation mix.

3.2.1 Northwest (NW): *full curtailment* (no storage)

Hydro capacity in the Northwest region allows for high penetration of renewables with little increase in costs. Figure 4(a) shows that, while increasing percentages of renewable (hydro, wind and PV) generation are associated with higher costs, the costs do not appreciably rise until reaching near 98% penetration, such as in Scenarios A, B, D, E, and F. These range from 95% to 98% renewables with costs below the maximum average annual cost of $1,408 paid by residential customers since 1990 (see Supplemental Figure S 34). All but Scenarios C and H show costs lower than the historical maximum customer for the Northwest. Costs escalate quickly for scenarios with maximum penetration of nuclear (63%) if paired only with wind and solar (Scenario H at $4,700) and with more than 40% PV since PV capacity must increase to over 2.7 TW to meet such high solar needs with no storage (Scenario C at $3,900). This is not the case, however, for nuclear paired with the Northwest's substantial hydropower resources, such as in Scenarios I, J, and K with annual costs per customer at $1,220.

For a wide range of scenarios from near 0% to 100% wind, solar PV, and hydro, thirty-year cumulative power sector emissions range from 250 to 650 $MtCO_2$, or about 8 to 22 $MtCO_2$/yr (see Figure 4(b)). The lower range represents scenarios with high wind and solar generation, but with less than 43% solar. A sharp increase in CO_2 emissions is evident once solar generation increases above 39% (to its maximum achievable level of 43%) since the embodied emissions associated with such high solar manufacturing and installation increase total emissions to over 1,000 $MtCO_2$. Thus, in order to reduce annual power sector CO_2 emissions in the Northwest, including embodied emissions, one must stay below 39% PV and/or use electricity storage.

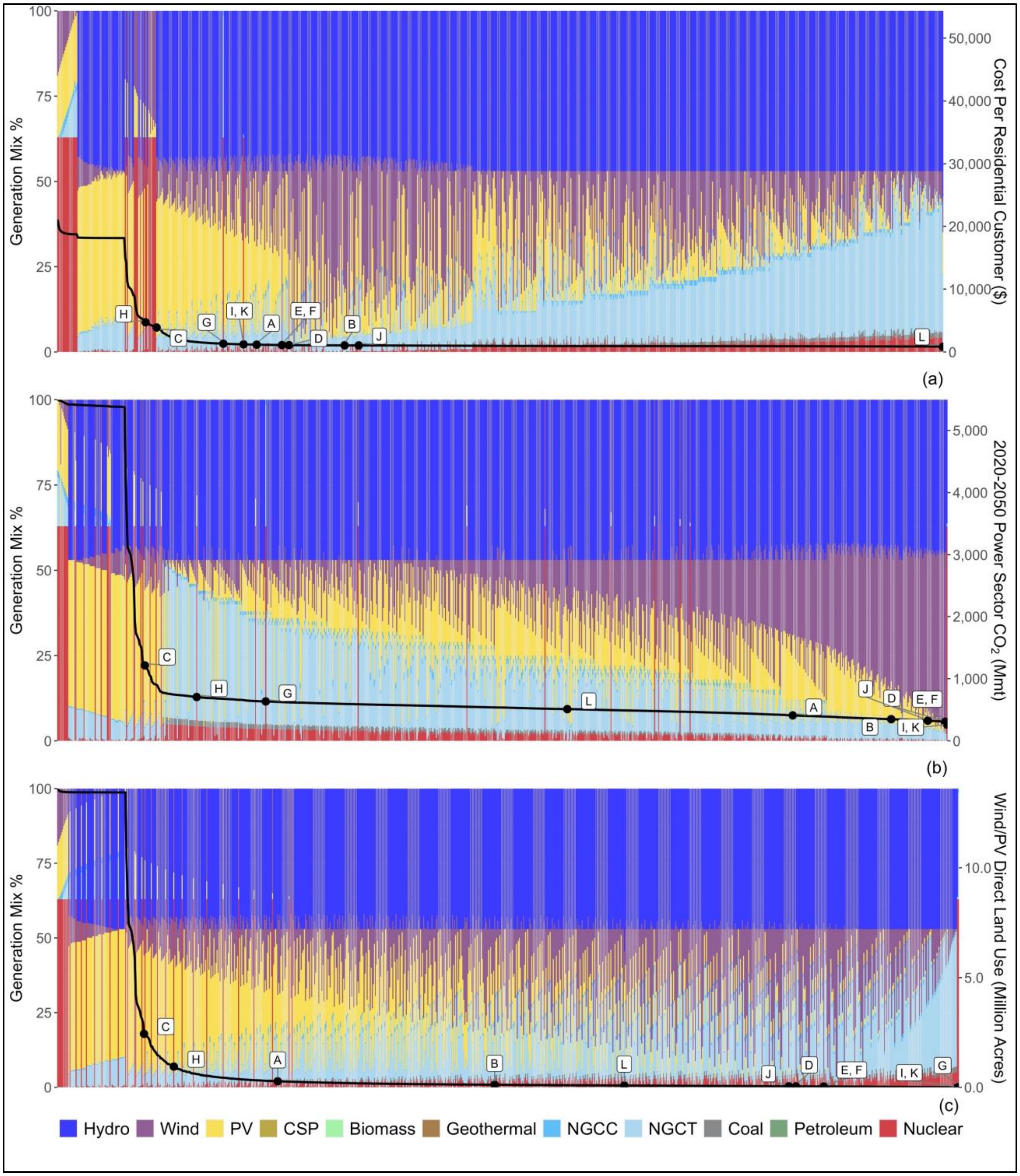
Direct land use for wind and PV installations remains less than 1%, except for Scenario C with a high percentage (40%) of PV. Indirect land use is less than 2% except in Scenario C (driven by PV) and H. Indirect land use of Scenario H is driven by high wind capacity assumed to reside in the Northwest, as well as in California and Mountain North regions from which the EFD assumes wind power is imported to the Northwest (see Supplemental Table S 3).

Table 5 Northwest: 2050 full curtailment (no storage)

Scenario	Hyd/Wind/PV/Nuc/Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use (%)	Total Land Use (%)	Carbon Emissions[2] (Mmt)
A	42M/27/26/0/5	$1,200	0.3%	0.8%	295(114)
B	43M/40/13/0/4	$1,100	0.1%	0.9%	290(57.9)
C	43M/13/40/0/4	$3,900	2.3%	2.9%	288(926)
D	45M/52/1/0/2	$1,100	< 0.1%	1.2%	271(36.3)
E	45M/53/0/0/2	$1,100	< 0.1%	1.3%	269(35)
F	45M/53/0/0/2	$1,100	< 0.1%	1.3%	269(35)
G	0M/0/0/63/37	$1,300	-	-	625(8.97)
H	0M/28/9/63/0	$4,700	0.8%	6.9%	246(459)
I	36M/0/0/63/1	$1,200	-	-	256(7.11)
J	36M/0/0/63/1	$1,200	-	-	256(7.11)
K	36M/0/0/63/1	$1,200	-	-	256(7.11)
L	55M/10/12/0/23	$830	0.1%	0.3%	475(35.6)
NREL Mid	74/10/12/0/4	NA	NA	NA	199(-)

[1] "Disp." refers to dispatchable technologies: coal, natural gas, geothermal, CSP, and biomass. This will mostly consist of coal and natural gas in many regions.
[2] We report carbon emissions from generation as well as emissions embodied in power plants. This is indicated in the final column as "emission from generation (embodied emissions)".
Green cells highlight the lowest value per column. Minimum emissions is based on summing emissions from power generation and embodied in power plants.

Figure 4 Northwest scenarios for the *full curtailment (no storage)* solution



Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

3.2.2 Northwest (NW): *no curtailment* (with storage)

When including electricity storage to prevent any wind and solar curtailment (Figure 5(a)), the costs increase gradually but to much higher levels than with *full curtailment*, or no storage. The cost per customer is greatest with high penetrations of wind and PV as more storage capacity is required to capture the generation when those technologies generate more than demand. Scenarios G, I, J, K and L show costs lower than the historical max of $1,408 per customer for the Northwest. Each of these scenarios, except for L, uses the maximum assumed allowable generation from nuclear paired with either hydro or natural gas. Scenario L however, has the lowest annual cost per customer at $841, with a mix of hydro, wind, solar, and natural gas.

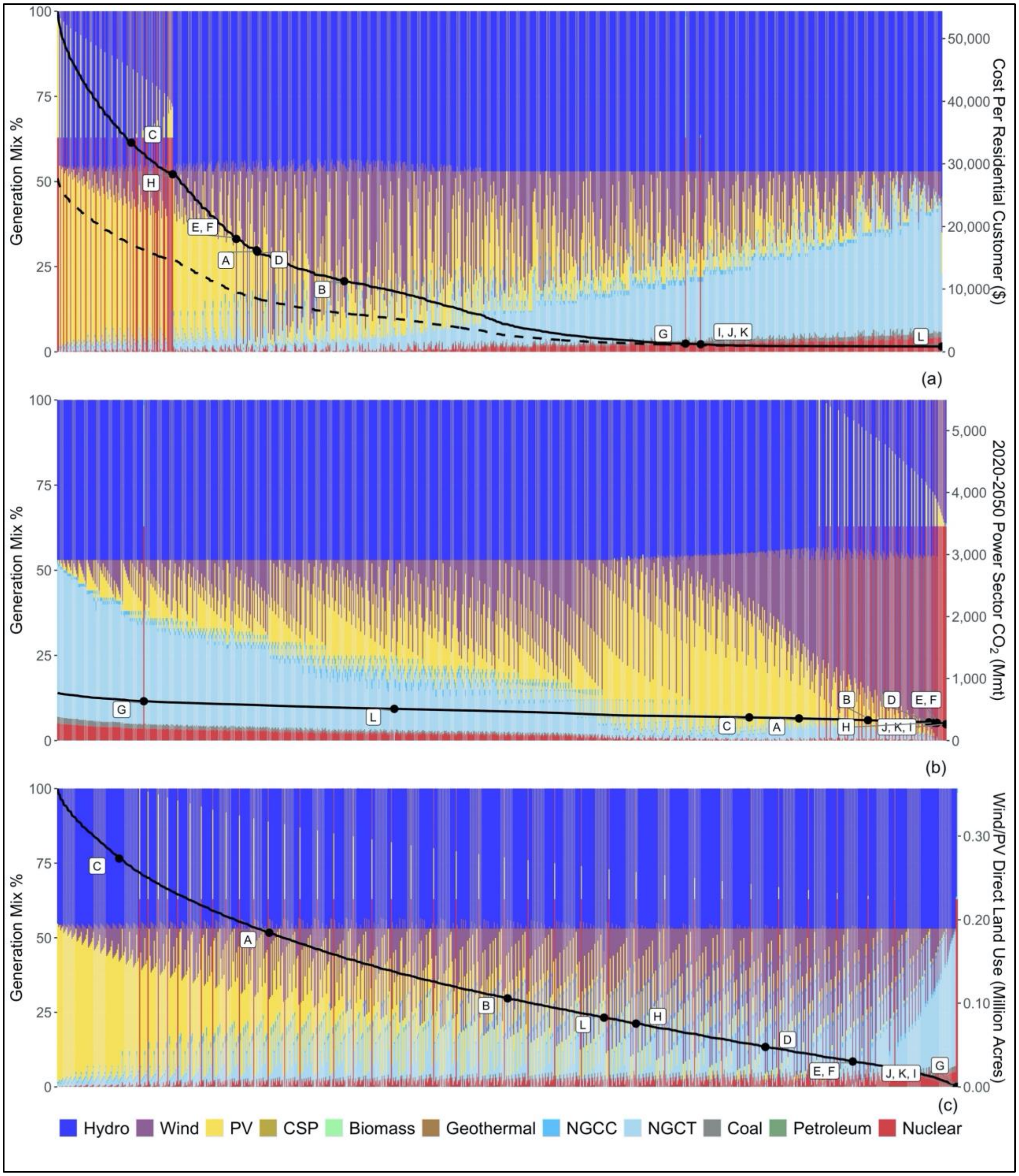
The addition of energy storage offers a reduction in carbon emissions for the high penetration solar PV scenarios by reducing the necessary PV capacity and the associated embodied emissions. Under this solution, Scenario A now shows 357 $MtCO_2$ in total emissions. Additionally, scenarios with high nuclear penetration paired with renewables (Scenarios H, I, J and K) are among the lowest emission levels of the chosen scenarios. Both direct and indirect land use for PV and wind (includes land in California and Mountain North regions due to assumed imported wind power from those regions) installations remains less than or equal to 1% for all scenarios.

Table 6 Northwest: 2050 *no curtailment* (*with storage*)

Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use (%)	Total Land Use (%)	Carbon Emissions[2] (Mmt)
A	44M/27/26/0/3	$16,200	0.2%	0.7%	279(77.7)
B	44M/40/13/0/3	$11,300	0.1%	0.8%	276(51.9)
C	45M/13/40/0/2	$33,400	0.3%	0.5%	266(107)
D	46M/50/3/0/1	$16,000	< 0.1%	1.0%	261(32.8)
E	46M/53/0/0/1	$18,000	< 0.1%	1.0%	258(27.4)
F	46M/53/0/0/1	$18,000	< 0.1%	1.0%	258(27.4)
G	0M/0/0/63/37	$1,320	-	-	625(8.97)
H	0M/28/9/63/0	$28,300	0.1%	0.6%	246(42.5)
I	36M/0/0/63/1	$1,220	-	-	256(7.11)
J	36M/0/0/63/1	$1,220	-	-	256(7.11)
K	36M/0/0/63/1	$1,220	-	-	256(7.11)
L	55M/10/12/0/23	$841	0.1%	0.3%	475(35.6)
NREL Mid	74/10/12/0/4	NA	NA	NA	199(-)

[1] "Disp." refers to dispatchable technologies: coal, natural gas, geothermal, CSP, and biomass. This will mostly consist of coal and natural gas in many regions.
[2] We report carbon emissions from generation as well as emissions embodied in power plants. This is indicated in the final column as "emission from generation (embodied emissions)".
Green cells highlight the lowest value per column. Minimum emissions is based on summing emissions from power generation and embodied in power plants.

Figure 5 Northwest scenarios for the *no curtailment* (with storage) solution



Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year) (solid line: normal battery capital costs assumptions, dashed line: 50% of normal battery capital cost assumptions), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

3.2.3 Northwest (NW): Insights comparing *full curtailment* and *no curtailment* solutions

The availability of hydro resources makes it much easier to balance costs, emissions, and land use. Effectively, hydropower dams provide the energy storage that prevents the need for significant battery investment. Almost all highlighted scenarios of the *full curtailment* (no storage) solution have customer costs below the 30-year maximum average annual cost of $1,408 per customer. When adding electricity storage, costs increase significantly in scenarios with high penetrations of wind and solar PV, but in turn, land use goes down. The high amount of dispatchable hydro results in electricity storage having little to no impact on CO_2 other than in Scenarios C and H, which have high penetrations of solar PV and no dispatchable generation, respectively.

3.3 Comparing Trends Across All EIoF Regions

Despite differences among the 13 EIoF regions, we highlight four common trends in each of them. The Supplemental Information presents figures and data for each region, other than Texas and the Northwest. The first common trend is rapidly increasing cost and land use with high penetrations (> 60%) of wind and solar PV in the *full curtailment* (no storage) solutions. This result derives from high amount of required installed capacity. Recall the EFD only calculates land use for wind and solar, so logically this metric increases with increasing use of these technologies. In the *no curtailment* (with storage) solution, because of the strict assumption to save all excess wind and solar PV generation, battery costs begin to dominate and increase costs even at moderate wind, solar, and hydro penetrations (<40-50%).

The second common trend refers only to the *full curtailment* (no storage) solution. Depending on the region, and thus available solar resource, there is a clear increase in each metric when solar PV penetration reaches a threshold of about 50% ± 5%. These increases are due to the high-capacity requirements needed to meet this level of solar PV penetration with no storage. The magnitude of this jump varies by the available solar resource in the region, but is largely driven by physical inability to meet much larger penetrations without assuming use of storage.

Third, in all regions, energy storage plays a significant role in reducing land use and embodied emissions by reducing the capacity required to reach high penetrations of wind and solar PV. This shows the importance of lowering battery (or other) storage costs to keep land use and total embodied emissions low. Battery manufacturing is improving rapidly, and thus the CO_2 emissions embodied in battery supply chain could decline considerably from that assumed in our study.

Lastly, we see the max nuclear penetration scenarios (at over 50% nuclear), combined with high wind and solar, contribute to high costs to the customer but with lower overall emissions. There are many scenarios with penetrations of nuclear power below 50%, but above that of the current nuclear fleet, that have feasible values for all three metrics explored in this paper. However, to keep the present scope feasible, we did not explore all combinations of moderate to high nuclear penetration (e.g., with low use of wind and solar). Because the EFD is an online tool, readers can explore their own electricity generation mixes of nuclear power with increasing wind and solar.

3.4 Comparing Results from EFD (Scenario L) to NREL 2020 Standard Scenarios Mid Case

In an effort to corroborate our results, we defined Scenario L for comparison with the NREL ReEDS model. For each EIoF region, Scenario L matches, as closely as possible, the 2050 electricity generation mix of the Mid Case scenario from the ReEDS 2020 Standard Scenarios (Cole et. al., 2020). In other words, we set the EFD fraction of generation from each technology, relative to the total generation, to be as similar as possible to the NREL Mid Case scenario. The metrics we compare are (1) 2050 MW capacity (total and by technology) (2) 2050 MWh generation (total and by technology), and (3) cumulative CO_2 emissions from combustion (2020-2050). The generation metrics are slightly different in that ReEDS identifies generation that *occurs within a region* and the EFD reports generation as power that is *consumed within a region*. We do not compare any cost metrics, because these are not directly comparable between models, or land use since ReEDS does not calculate land use estimates. Given that ReEDS considers a wider array of electricity generation technologies than the EFD, we make the following assumptions:

1. We aggregate all distinct PV technologies in ReEDS to compare to the single-axis tracking utility PV modeled in the EFD.
2. We aggregate Oil-Gas-Steam generators in ReEDS into the category of natural gas generation for comparison to natural gas generation in the EFD.
3. We aggregate off-shore wind and on-shore wind in ReEDS to compare to (on-shore) wind in the EFD.
4. ReEDS assumes imported electricity from Canada, and we count 100% of this imported electricity as hydropower for comparison to hydropower generation in the EFD. The EFD assumes no electricity imports into the U.S.-48 from Mexico or Canada.

Table 7 compares 2050 generation, 2050 capacity, and cumulative 2020 to 2050 CO_2 emissions for both the *no curtailment* (with storage) and *full curtailment* (no storage) solutions in all EFD regions, to the NREL ReEDS Mid Case scenario. Overall the EFD results compare rather well to those from ReEDS.

Table 7 2050 NREL Mid Case Generation, Capacity, and CO_2 Emissions as compared to EFD

Region	Case	Total Generation (TWh)	Total Capacity (GW)	2020-2050 Cumulative CO2 Emissions (Mmt)
AL	NREL Mid Case	235	58	1,840
	EFD No Curtailment	229	47	2,170
	EFD Full Curtailment	229	47	2,170
CA	NREL Mid Case	334	133	865
	EFD No Curtailment	433	167	911
	EFD Full Curtailment	433	2,400	1,090
CE	NREL Mid Case	277	92	1,630
	EFD No Curtailment	247	77	1,830
	EFD Full Curtailment	247	120	1,840
FL	NREL Mid Case	302	124	2,190
	EFD No Curtailment	312	114	2,030
	EFD Full Curtailment	312	1,900	2,080
MA	NREL Mid Case	915	282	8,450
	EFD No Curtailment	1,070	332	8,170
	EFD Full Curtailment	1,070	391	8,180
MN	NREL Mid Case	346	103	3,400
	EFD No Curtailment	263	83	2,730
	EFD Full Curtailment	263	100	2,730
MW	NREL Mid Case	726	240	9,150
	EFD No Curtailment	662	207	7,800
	EFD Full Curtailment	662	240	7,810
NE	NREL Mid Case	145	50	472
	EFD No Curtailment	148	53	591
	EFD Full Curtailment	148	68	597
NW	NREL Mid Case	174	52	199
	EFD No Curtailment	207	59	475
	EFD Full Curtailment	207	60	475
NY	NREL Mid Case	196	74	487
	EFD No Curtailment	195	79	568
	EFD Full Curtailment	195	103	579
SE	NREL Mid Case	774	271	5,570
	EFD No Curtailment	861	255	5,080
	EFD Full Curtailment	861	390	5,110
SW	NREL Mid Case	197	66	1,460
	EFD No Curtailment	105	31	1,130
	EFD Full Curtailment	105	56	1,130
TX	NREL Mid Case	624	240	3,500
	EFD No Curtailment	631	233	3,930
	EFD Full Curtailment	631	519	3,950

Fossil fuel combustion for NREL Mid Case and equivalent EFD Scenario L with both *no curtailment* and *full curtailment* solutions. Total generation for NREL represents generation from power plants within a region, and for the EFD it represents consumption by consumers within a region.

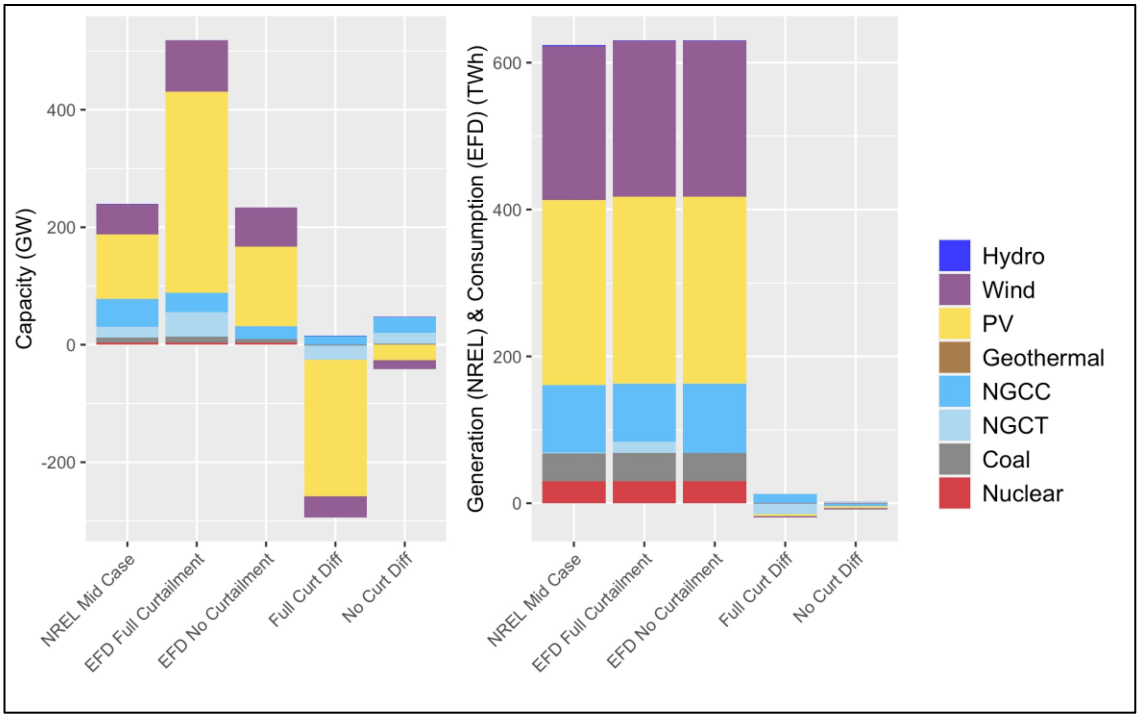
The most dramatic difference we see in the generation metric is in the Southwest which has about 47% less in the EFD compared to the NREL solution. This is due to the difference in generation metrics between the tools indicating that the Southwest exports much of the power it generates to other regions. Other than the Southwest, in all regional comparisons, each EFD scenario assumes total 2050 generation within ±25 % of the respective NREL scenario. The closest match is in New York (EFD consumption is 0.5% lower) and furthest match is in the Mountain North (EFD consumption is 24% lower). Supplemental Section S 3 contains figures comparing EFD and NREL capacity and generation for each power plant fuel and technology. Supplemental Table S 3 states what percentage of wind generation is imported into any region from another.

The next section compares these metrics broken down by technology, for the TX and NW regions. We identify when a specific technology has a 10% difference in a metric from the total of that metric in the NREL Mid Case. Generation and capacity from CSP and biomass are either 0 or negligible (<.0001 TWh and <.0005 GW), thus they are not included.

3.4.1 Comparing EFD (Scenario L) to NREL Mid Case Scenario: Texas (TX)

Here we compare generation and capacity (Figure 6) as well as emissions by technology from the NREL Mid Case to the EFD equivalent scenario (L) for the Texas region. All generation differences by technology are within the 10% margin for both the *full curtailment* and *no curtailment* solutions. The *no curtailment* solution has 11% more capacity from PV and 11% less capacity from NGCC when compared to the ReEDS Mid Case total capacity. Alternatively, in the *full curtailment* solution, the EFD has 15% more capacity from wind, 97% more from PV, and 10% more from NGCT. All other capacity differences by technology are less than 10% of the total ReEDS Mid Case capacity.

Figure 6 Texas (TX) Region: Comparisons of results for the year 2050



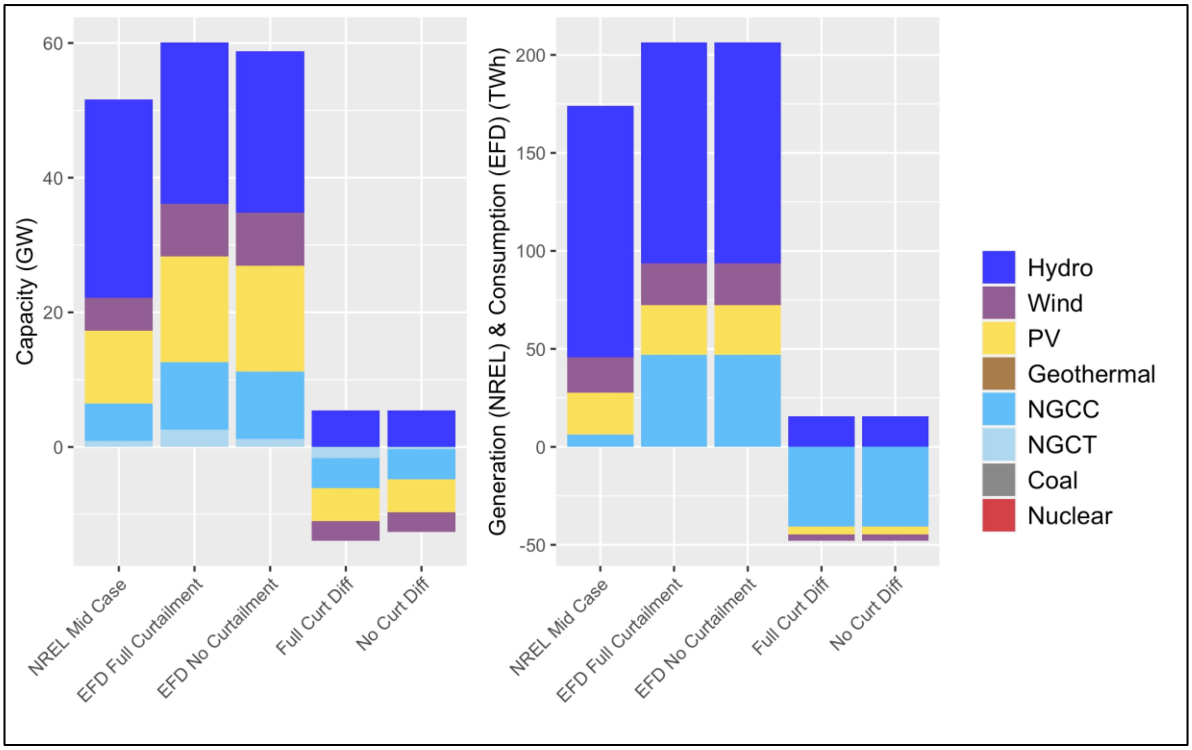
From the NREL 2020 Standard Scenario Mid Case to the counterpart Scenario L of the EFD, per generation technology, for (left) operating capacity (GW) and (right) generation (NREL) & consumption (EFD) (TWh). Differences are NREL data minus EFD data.

The EFD *no curtailment* solution reports 430 $MtCO_2$ more cumulative emissions (from 2020 to 2050) than the ReEDS Mid Case (Table 7). This discrepancy in emissions derives from the EFD calculating 866 TWh more cumulative coal generation, and 54 TWh less natural gas generation. The higher coal generation in the EFD explains the full difference in cumulative CO_2 emissions. Similarly, the EFD *full curtailment* solution reports 450 $MtCO_2$ higher cumulative emissions than the NREL Mid Case Scenario, primarily due to 239 TWh and 279 TWh more natural gas and coal generation, respectively.

3.4.2 Comparing EFD (Scenario L) to NREL Mid Case Scenario: Northwest (NW)

This section compares generation and capacity (Figure 7) as well as emissions by technology from the NREL Mid Case to the EFD equivalent scenario (L) for the Northwest region. Both the no curtailment and full curtailment solutions show 23% more generation from NGCC compared to the ReEDS Mid Case. All other generation differences by technology are less than 10% of the total ReEDS Mid Case generation. Additionally, both the no curtailment and the full curtailment solutions report 11% less hydro capacity than the ReEDS Mid Case. All other capacity differences by technology are less than 10% of the total ReEDS Mid Case capacity.

Figure 7 Northwest (NW) Region: Comparisons of results for the year 2050



From the NREL 2020 Standard Scenario Mid Case to the counterpart Scenario L of the EFD, per generation technology, for (left) operating capacity (GW) and (right) generation (TWh).

The ReEDS Mid Case reports 276 $MtCO_2$ less cumulative emissions (from 2020-2050) than the EFD no curtailment solution (Table 7). This discrepancy in emissions is fully explained from the EFD calculating 690 and 100 TWh more cumulative natural gas and coal generation, respectively. The difference and justification for 2020-2050 CO_2 emissions remain the same for the full curtailment solution.

3.5 Comparing Results from EFD to NREL ReEDS 100% Renewable

A recent paper from NREL authors expanded the use of the ReEDS model to explore 100% renewable electricity for the entire contiguous U.S. (Cole, et al., 2021). The results of Cole et al. (2021) present 100% renewable electricity at much lower costs than presented by the EFD. They show the net present value (NPV) (in year 2020) cost of building a 100% renewable grid to 2050 to be approximately $3.4 trillion, and this compares to costs for the reference case (57% renewable), current generation mix, and 80% renewable scenarios of $2.6, $3.0, and $2.8 trillion, respectively. A comparable calculation of NPV of 100% wind, solar, and hydro EFD scenarios for the U.S.-48 is near 100 trillion $2017, or approximately 30 times larger. Thus, while for some regions the EFD shows costs of 100% wind, solar, and hydropower grids as an order of magnitude higher customer cost than present grid costs, Cole et al. (2021) show a 100% renewable grid to be only 13% higher than maintaining the existing mix and 30% higher than their baseline. Further, when we calculate a similar NPV cost for the US-48 states (all 13 of our EFD regions) for our Scenario L that mimics the NREL "2020 Standard Scenario Mid Case", we obtain approximately $8 trillion—still 2-3 times higher cost than all reported grid mix scenarios of Cole et al. (2021).

The main reasons that the EFD calculates significantly higher costs at higher than 50-70% wind, solar, and hydropower are associated with the simplifications that enable short computation times for EFD web accessibility: strict full and no curtailment scenarios, an assumed constant (linear) rate of capital investment to reach 2050 targets, and an assumed limited set of technologies for 100% renewable scenarios (specifically no renewable fuel combustion turbines that increase in capacity at > 95% renewable in Cole et al. (2021)). The first assumption, for example, dictates about twice as much PV and wind capacity in the Texas full curtailment (no storage) Scenario L as in the NREL "2020 Standard Scenario Mid Case (see Figure 6). The last assumption is also highly influential. Consider the cost of the Texas 50% wind and 50% PV full curtailment (no storage) solution is $45,000/customer-year. However, when adding 5% natural gas with 50% wind and 45% PV under full curtailment, to mimic the Cole et al. (2021) 100% U.S. renewable scenario with 5% renewable gas use in combustion turbines, the cost is approximately $4,900/customer-year or $2.1 trillion in NPV, or only 2-3 times higher cost, not an order of magnitude, compared to those of the last three decades of $1,500-$2,000/customer-year in Texas (Supplemental Figure S 34).

Thus, while the EFD and NREL ReEDS results are quite different at very high (>90%) penetrations of renewable generation, the reasons directly relate to the EFD assumptions to simplify the calculations to facilitate a rapid web-based operation. When specifying relatively low percentages of dispatchable generation (up to 10%) from coal or natural gas, the costs calculated in the EFD are quite similar to that of ReEDS.

3.6 Summary of Scenarios Exploring Tradeoffs of Cost, Land use, and CO_2 Emissions

Here we summarize findings from the J and K scenarios that we defined to focus on tradeoffs of achieving low CO_2 emissions, land use, and cost while using increasing levels of wind and solar electricity.

Table 8 summarizes either a J or K scenario for each region that has the highest hydro, wind, and solar generation and meets the scenario criteria. In addition to those listed below, several regions could meet the criteria with high (> 40%) use of nuclear power (regions FL, MW, NE, NW, NY, SW, TX are listed as such in the report), but since our main goal was to explore tradeoffs with renewable electricity, we've listed the compatible results with the highest renewable percentages.

Table 8 Scenarios that highlight tradeoffs to minimize costs with low land use and CO_2 emissions

Region	Scenario	Storage Assumed?	Hydro	Wind	PV	Nuclear	NG & Coal	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	CO_2 Emissons from 2020-2050 (Mmt)	CO_2 Emissons in 2020 (Mmt)	CO_2 Emissons in 2050 (Mmt)	CO_2 Emissons in 2050 as % of 2020 (Mmt)
AL	K	Y or N	1	17	3	14	65	$2,000	< 0.1%	0.1%	2,180(19.4)	73	67	91%
CA	J	N	5	21	7	66	1	$1,900	0%	0.8%	515(118)	23	8	33%
CE	J	N	3	58	24	0	15	$1,900	0.1%	1.0%	1,970(12.4)	78	27	35%
FL	K	N	0	78	14	1	7	$2,200	0.5%	4.0%	1,530(190)	67	21	32%
MA	K	N	0	48	4	12	36	$1,700	0.1%	1.3%	8,230(178)	281	229	81%
MN	K	N	7	20	2	69	2	$1,200	< 0.1%	0.4%	1,930(39.1)	84	3	4%
MW	K	Y	1	35	6	12	46	$1,450	< 0.1%	0.7%	8,210(104)	291	189	65%
NE	K	N	5	61	11	10	13	$1,600	0.2%	5.9%	403(69.3)	17	10	62%
NW	K	N	36	0	0	63	1	$1,200	0.0%	0.0%	256(7.11)	11	1	9%
NY	K	N	8	22	2	63	5	$1,600	0.1%	2.3%	360(33.8)	15	6	37%
SE	K	Y	3	28	4	25	40	$2,000	< 0.1%	0.7%	5,940(98.5)	199	170	85%
SW	J	N	6	42	13	12	27	$910	< 0.1%	0.1%	1,130(23.8)	43	16	37%
TX	K	N	0	78	15	1	6	$2,200	0.4%	9.5%	3,270(349)	144	41	28%
										Totals	**37,166**	**1,326**	**788**	**59%**

Storage Assumed? (Y = excess wind and solar are stored in batteries, N = no battery storage for excess wind and solar) The numbers below the electricity technologies are the percent of total generation in 2050. CO_2 emissions are only those associated with power generation. “CO_2 Emissions from 2020-2050” in million metric tonnes (Mmt) are those summed from 2020-2050 from burning fossil fuels for power generation (not in parentheses) and embodied in building power plants (within parentheses).

Even when attempting to maximize use of wind, solar, and hydropower electricity, the cost, CO_2, and/or land constraint did not allow some regions to reach more than 20-40% electricity from renewables and necessitated the use of high levels of nuclear power (CA, MN, NW, NY) or imports of electricity from very long distances (i.e., FL assumes high use of wind power from the Central, CE, region of the country). Different assumptions for how much wind power can be transmitted among regions can dramatically change the results, but we did not fully explore this aspect (see the supplemental material for assumptions of wind importation from one region to another).

The selected tradeoff scenarios of Table 8 show that it is difficult (under the assumptions of the EFD) to reach low levels of CO_2 emissions. The J scenarios (by definition) reach lower emissions in 2050, but not every region had a cost-feasible J scenario that met the land and CO_2 constraints. Thus, the K scenario is shown as one with balanced tradeoffs. Considering all 13 regions of the continental U.S., the 2050 scenarios in Table 8 reach 59% of the 2020 electricity-related CO_2 emissions. This result demonstrates both the challenge of reducing greenhouse gases, and potential limitations of the EFD as an educational tool.

We did not generally explore the full range of use of nuclear power to achieve the low CO_2 threshold constraint even though nuclear power will very likely provide very-high penetrations of low-carbon power at or near historical costs in every region. Three scenarios in the report (G, H, and I) posit a maximum penetration of nuclear power, between 55-70% depending on the region, and three different concepts for the rest of the mix of electricity from renewables and natural gas. These scenarios again demonstrate cost and CO_2 tradeoffs: a pure nuclear-natural gas mix might minimize cost at the expense of higher emissions, while a mostly-nuclear plus hydro/wind/solar mix has higher cost but lower emissions.

4. Conclusion and Policy Implications

The focus of the EFD is to provide the general public with a tool that can investigate tradeoffs in energy-related environmental and economic impacts. The EFD is designed to be a user-friendly tool that provide rapid and reasonable results based on the user's desired electricity generation mix, vehicle electrification share, and share of household heating from different energy sources.

In this paper, we demonstrate the EFD by exploring the tradeoffs between residential electricity costs, carbon emissions, and land use with increasing penetrations of wind and solar across thousands of possible generation mixes. The EFD assumes two types of solutions: (*full curtailment*) curtail 100% of any “excess” (greater than demand at any hour) wind and solar generation while storing none, and (*no curtailment*) store 100% of wind and solar electricity that would otherwise have been curtailed. While the future energy system will assuredly have some balance of curtailment and storage of renewable electricity, as well as demand response which the EFD does not explore, the EFD provides many important takeaways.

Our *full curtailment* solutions indicate that extremely high penetrations of solar PV (approximately 50% or more) translate to significant increases in costs, oftentimes many multiples over historic annual costs, as well as land use and carbon emissions. However, for wind, solar, and hydropower penetrations between 75-98% (depending on the region), costs can be comparable to historical costs. Energy storage can reduce land use and keep carbon emissions low even up to 100% renewable electricity, however, under the assumptions of the EFD, including no demand response, this translates to costs (> $10,000 per customer per year) that would in all likelihood not be tolerable for the vast majority of consumers. We also demonstrate the robustness of the EFD by comparing outputs to those of the NREL ReEDS model. We believe this comparison indicates that, even with more simplified assumptions, the EFD provides realistic results that are useful for non-experts to explore future energy scenarios. This paper by no means explores the full capabilities of the EFD, but we hope it provides the reader with an introduction to its usefulness in exploring questions related to the broader energy system.

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Supplemental Information

S.1 Code for Energy Futures Dashboard

The underlying R codes used to run the Energy Futures Dashboard calculations, but not produce the website, are available on the University of Texas at Austin Energy Institute's GitHub site: https://github.com/ut-energy-institute.

S.2 EFD Assumptions

Table S 1 Default EFD generation mix for each EIoF region

Region	Nuclear	Coal	Natural Gas	Geothermal	Biomass	Hydro	CSP	PV	Wind
NW	5%	2%	20%	0%	1%	53%	0%	0%	19%
CA	5%	0%	39%	4%	1%	8%	3%	30%	10%
MN	0%	48%	36%	1%	0%	5%	0%	3%	7%
SW	29%	26%	36%	0%	0%	2%	1%	4%	2%
CE	2%	50%	22%	0%	0%	2%	0%	1%	23%
TX	8%	23%	53%	0%	0%	0%	1%	5%	10%
MW	21%	44%	27%	0%	0%	0%	0%	2%	6%
AL	18%	20%	59%	0%	1%	1%	0%	1%	0%
MA	24%	35%	35%	0%	0%	1%	0%	2%	3%
SE	37%	19%	29%	0%	1%	1%	0%	11%	2%
FL	18%	15%	66%	0%	0%	0%	0%	1%	0%
NY	29%	2%	57%	0%	0%	9%	0%	1%	2%
NE	40%	0%	47%	0%	3%	3%	0%	2%	5%

Table S 2 Default percentage of residential household heating by source for each EIoF region

Region	Electric Heating	Gas Heating	Other Heating
NW	14%	48%	38%
CA	2%	71%	27%
MN	3%	75%	22%
SW	22%	53%	25%
CE	9%	63%	28%
TX	13%	58%	29%
MW	4%	72%	24%
AL	13%	47%	40%
MA	12%	50%	38%
SE	18%	41%	41%
FL	29%	8%	63%
NY	2%	61%	37%
NE	1%	22%	77%

Table S 3 Assumptions for Where Wind Power is Installed to meet Demand in Each Region

FROM \ TO		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%

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 region itself.

Table S 4 Assumptions for Where CSP Plants are Installed to meet Demand in Each Region

FROM \ TO		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%

The matrix indicating what percentage of 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 wind electricity originates within the region itself.

S.3 Scenario Specifications

Table S 5 ReEDS Mid Case generation mix for each EIoF region

Region	Nuclear	Coal	NGCT	NGCC	Geothermal	Biomass	CSP	PV	Wind	Hydro
NW	0%	0%	0%	4%	0%	0%	0%	12%	10%	74%
CA	0%	0%	0%	17%	7%	0%	0%	58%	8%	10%
MN	0%	18%	0%	16%	1%	0%	0%	18%	40%	8%
SW	16%	14%	0%	6%	0%	0%	0%	29%	30%	4%
CE	0%	7%	0%	1%	0%	0%	0%	17%	68%	7%
TX	5%	6%	0%	15%	0%	0%	0%	40%	34%	0%
MW	4%	17%	0%	30%	0%	0%	0%	22%	25%	3%
AL	6%	5%	0%	77%	0%	0%	0%	11%	0%	2%
MA	5%	5%	0%	50%	0%	0%	0%	25%	12%	1%
SE	24%	3%	0%	34%	0%	0%	0%	33%	2%	4%
FL	10%	3%	0%	36%	0%	0%	0%	52%	0%	0%
NY	0%	0%	0%	21%	0%	0%	0%	27%	31%	20%
NE	7%	0%	0%	25%	0%	0%	0%	20%	27%	20%

Table S 6 Number of simulations run for each EIoF region

Region	Number of Simulations Run
NW	877
CA	4,625
MN	4,335
SW	4,642
CE	4,920
TX	5,192
MW	5,723
AL	5,119
MA	5,200
SE	4,990
FL	5,194
NE	4,729
NY	3,981

S.4 Results by EIoF Region

S.4.1: Results Summary: California (CA)

Table S 7 California: 2050 *full curtailment* (no storage)

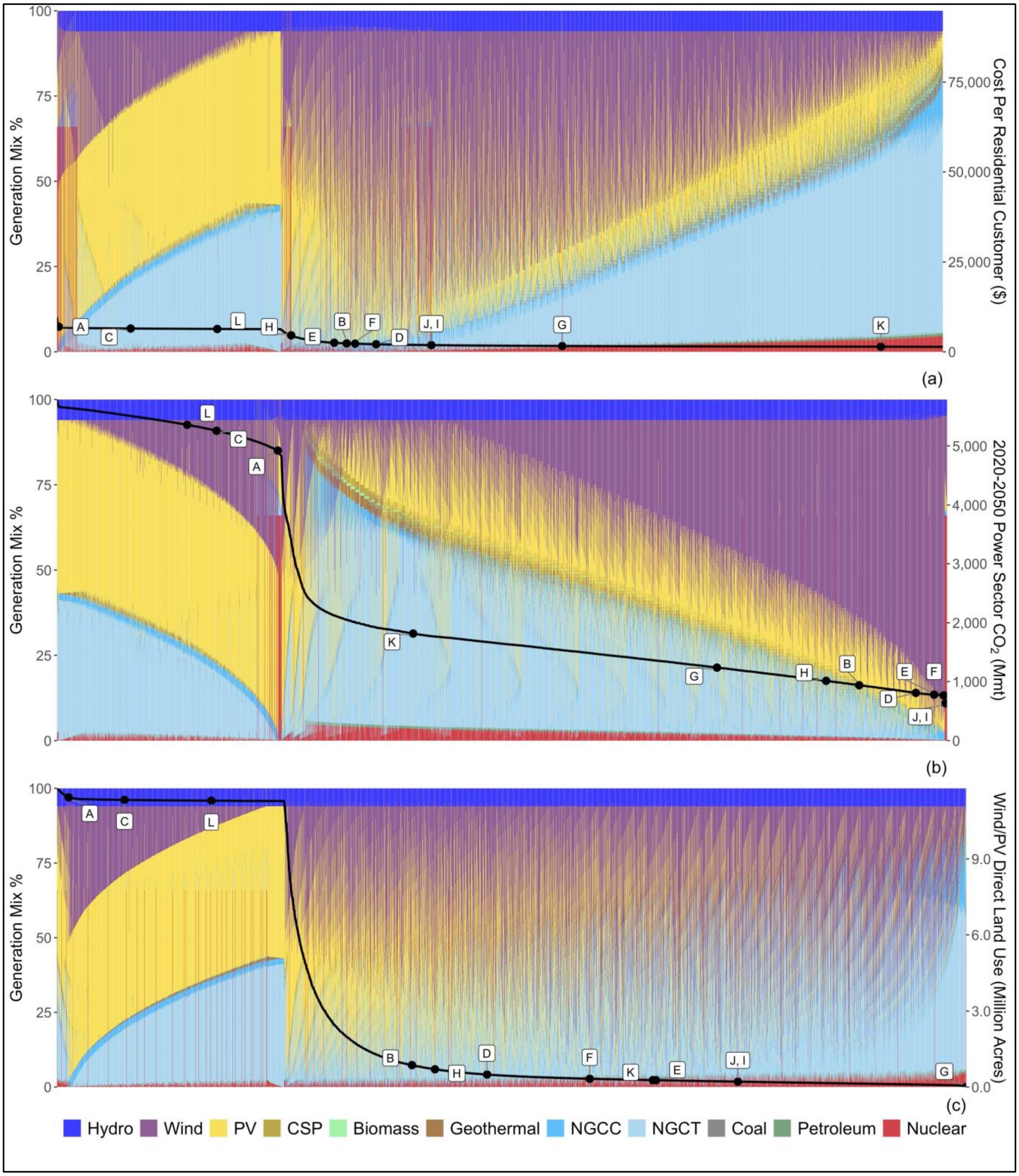
Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
A	5M/47/46/0/2	$7,000	11.0%	9.1%	543(4,380)
B	4M/70/24/0/2	$2,300	0.6%	2.6%	526(413)
C	6M/23/49/0/22	$6,500	11.0%	11.0%	965(4,290)
D	5M/76/17/0/2	$2,100	0.3%	2.4%	543(266)
E	5M/92/1/0/2	$2,500	0.1%	3.8%	546(234)
F	5M/86/7/0/2	$2,300	0.1%	3.1%	542(226)
G	0M/0/0/66/34	$1,600	-	-	1,220(21)
H	0M/32/2/66/0	$4,600	0.2%	7.7%	477(537)
I	5M/21/7/66/1	$1,900	0.1%	0.8%	515(118)
J	5M/21/7/66/1	$1,900	0.1%	0.8%	515(118)
K	6M/6/23/3/62	$1,400	0.2%	0.2%	1,710(108)
L	7M/7/50/0/35	$6,300	11.0%	12.0%	1,090(4,270)
NREL Mid	10/8/57/0/25	NA	NA	NA	865(-)

Table S 8 California: 2050 *no curtailment* (with storage)

Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
A	6M/47/47/0/0	$44,400	0.5%	0.8%	477(233)
B	6M/70/24/0/0	$30,600	0.2%	1.2%	477(161)
C	6M/24/70/0/0	$68,000	0.7%	0.7%	480(307)
D	6M/76/18/0/0	$30,200	0.1%	1.3%	477(143)
E	6M/94/0/0/0	$35,200	< 0.1%	1.6%	477(97.2)
F	6M/89/5/0/0	$33,000	< 0.1%	1.5%	477(106)
G	0M/0/0/66/34	$1,610	-	-	1,220(21)
H	0M/23/11/66/1	$18,100	0.1%	0.4%	487(76.5)
I	6M/20/8/66/0	$15,000	0.1%	0.3%	478(61.6)
J	6M/20/8/66/0	$15,000	0.1%	0.3%	478(61.6)
K	6M/11/14/4/65	$1,410	< 0.1%	0.2%	1,780(78.5)
L	7M/8/58/0/28	$35,400	0.6%	0.5%	911(241)
NREL Mid	10/8/57/0/25	NA	NA	NA	865(-)

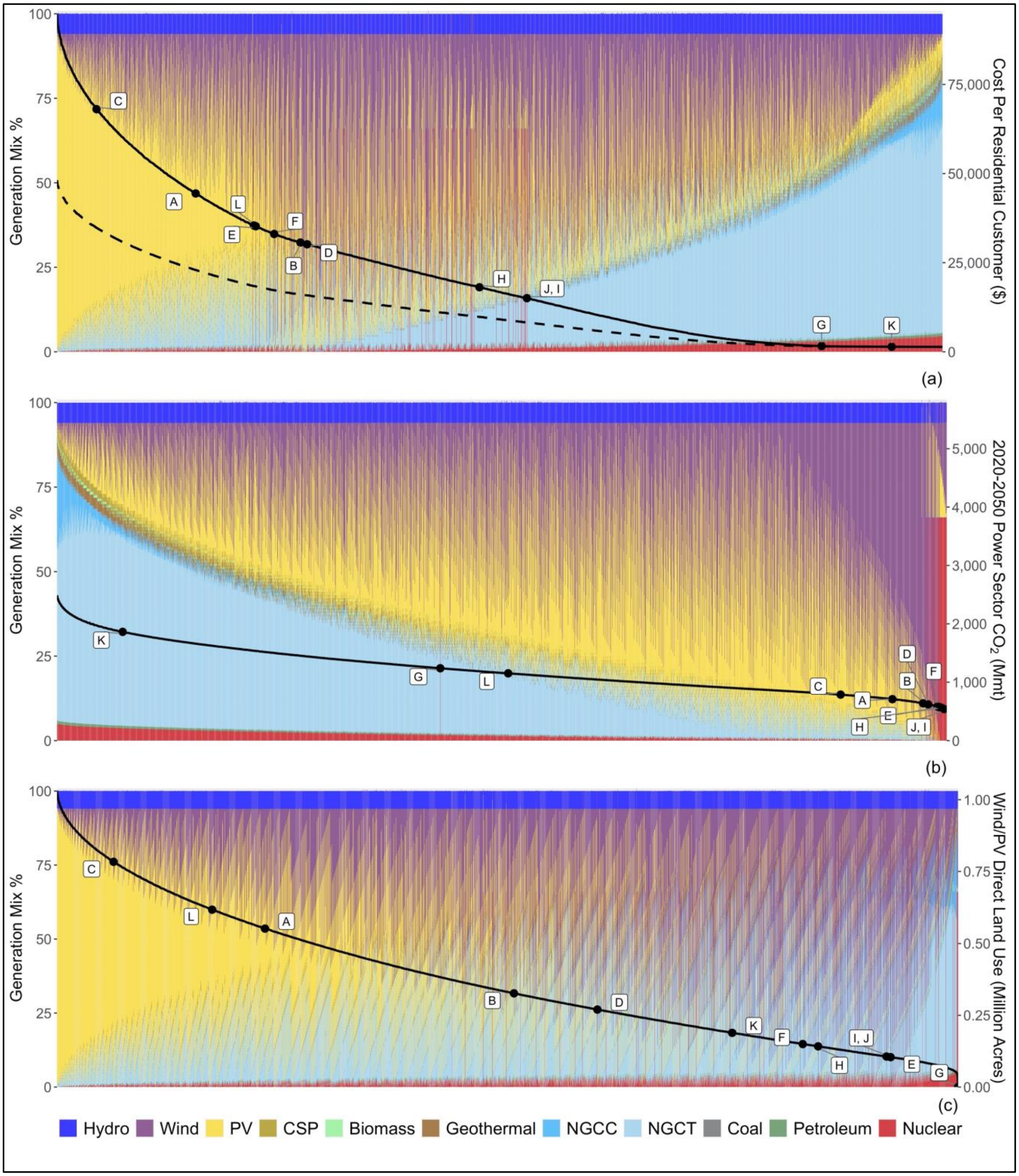
[1] "Disp." refers to dispatchable technologies: coal, natural gas, geothermal, CSP, and biomass. This will mostly consist of coal and natural gas in many regions.
[2] We report carbon emissions from generation as well as emissions embodied in power plants. This is indicated in the final column as "emission from generation (embodied emissions)".
Green cells highlight the lowest value per column. Minimum emissions is based on summing emissions from power generation and embodied in power plants.

Figure S 1 California scenarios for the *full curtailment (no storage)* solution



Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

Figure S 2 California scenarios for the *no curtailment (with storage)* solution



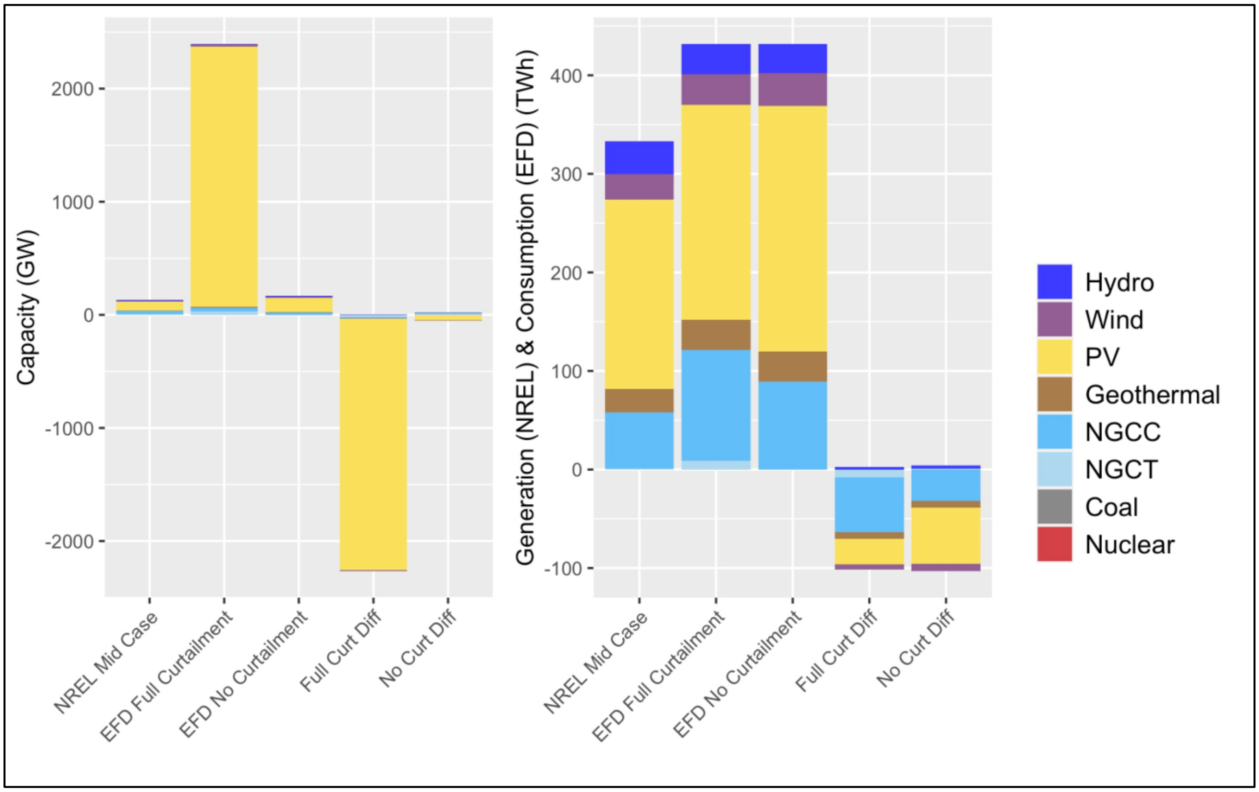
Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

All generation differences by technology are within the 10% margin for both the *full curtailment* and *no curtailment* solutions. The *no curtailment* solution has 34% more capacity from PV when compared to the ReEDS Mid Case total capacity. Additionally, in the *full curtailment* solution, the EFD has 1,674% more capacity from PV and 17% more from NGCT. All other capacity differences by technology are less than 10% of the total ReEDS Mid Case capacity.

CO_2 emissions, 2020-2050 (*no curtailment/with storage*): The ReEDS Mid Case reports 46 $MtCO_2$ less cumulative emissions than the EFD solution (Table 7). This discrepancy in emissions derives from the EFD calculating 545 and 4 TWh more cumulative natural gas and coal generation respectively.

CO_2 emissions, 2020-2050 (*full curtailment/no storage*): The EFD *full curtailment* solution reports 225 $MtCO_2$ higher cumulative emissions than the NREL Mid Case Scenario, primarily due to 1,500 TWh and 4 TWh more natural gas and coal generation, respectively.

Figure S 3 California (CA) Region: Comparisons of results for the year 2050



From the NREL 2020 Standard Scenario Mid Case to the counterpart Scenario L of the EFD, per generation technology, for (left) operating capacity (GW) and (right) generation (TWh).

S.4.2: Results Summary: Mountain North (MN)

Table S 9 Mountain North: 2050 *full curtailment* (no storage)

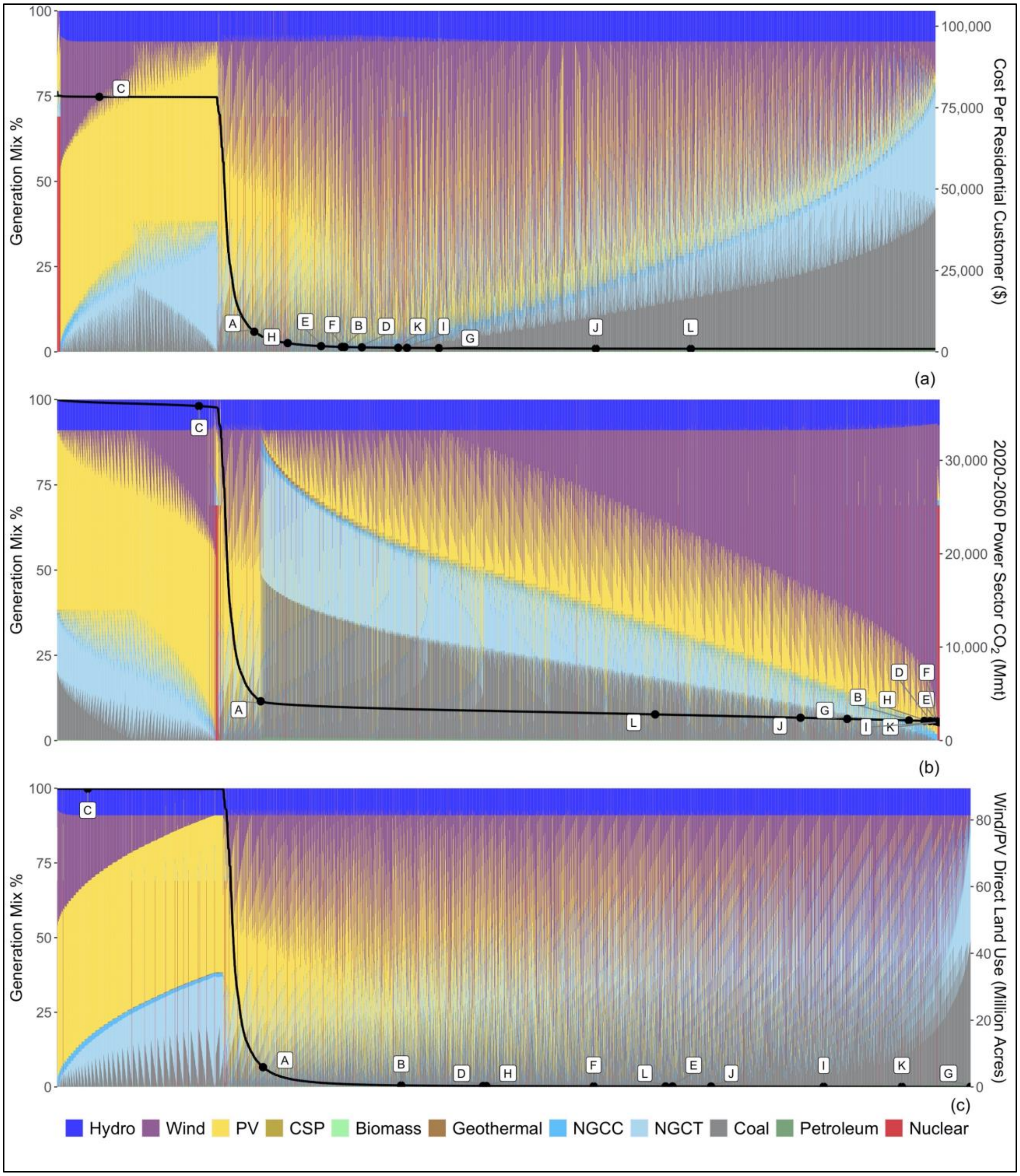
Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
A	7M/46/45/0/2	$6,200	1.5%	2.8%	1,940(2,270)
B	7M/68/23/0/2	$1,500	0.1%	1.4%	1,940(217)
C	9M/23/52/0/16	$78,000	23.0%	25.0%	2,120(33,700)
D	7M/76/15/0/2	$1,400	0.1%	1.5%	1,930(148)
E	7M/91/0/0/2	$1,800	< 0.1%	2.4%	1,940(131)
F	7M/85/6/0/2	$1,500	< 0.1%	1.9%	1,930(127)
G	0M/0/0/69/31	$1,100	-	-	2,310(12.8)
H	0M/29/2/69/0	$2,700	0.1%	3.1%	1,900(204)
I	8M/17/5/69/1	$1,200	< 0.1%	0.3%	1,930(48.1)
J	9M/60/12/0/19	$970	< 0.1%	0.7%	2,370(69.3)
K	7M/20/2/69/2	$1,200	< 0.1%	0.4%	1,930(39.1)
L	8M/40/18/0/34	$940	< 0.1%	0.4%	2,730(70.4)
NREL Mid	8/40/18/0/34	NA	NA	NA	3,400(-)

Table S 10 Mountain North: 2050 *no curtailment* (with storage)

Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
A	9M/46/45/0/0	$45,700	0.1%	0.5%	1,900(146)
B	9M/68/23/0/0	$30,200	0.1%	0.7%	1,900(95.7)
C	9M/23/68/0/0	$74,300	0.1%	0.4%	1,910(200)
D	9M/71/20/0/0	$29,900	< 0.1%	0.7%	1,900(89.2)
E	9M/91/0/0/0	$38,300	< 0.1%	0.9%	1,900(49)
F	9M/89/2/0/0	$37,000	< 0.1%	0.9%	1,900(51.6)
G	0M/0/0/69/31	$1,140	-	-	2,310(12.8)
H	0M/14/15/69/3	$14,200	< 0.1%	0.2%	1,940(56.3)
I	9M/16/6/69/0	$12,200	< 0.1%	0.2%	1,900(32)
J	0M/0/0/69/31	$1,140	-	-	2,310(12.8)
K	0M/0/0/69/31	$1,140	-	-	2,310(12.8)
L	8M/40/18/0/34	$3,270	< 0.1%	0.4%	2,730(68.6)
NREL Mid	8/40/18/0/34	NA	NA	NA	3,400(-)

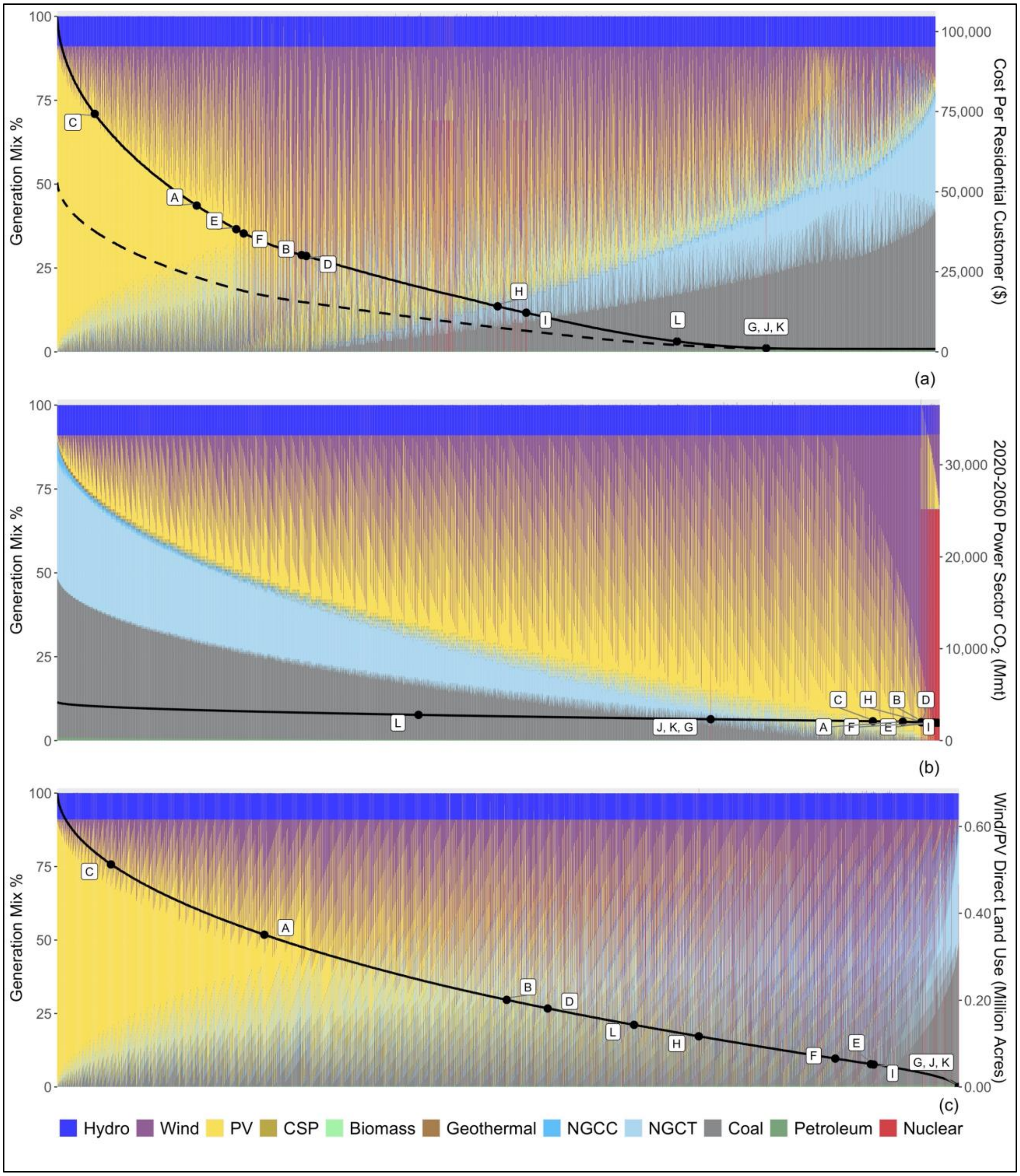
[1] "Disp." refers to dispatchable technologies: coal, natural gas, geothermal, CSP, and biomass. This will mostly consist of coal and natural gas in many regions.
[2] We report carbon emissions from generation as well as emissions embodied in power plants. This is indicated in the final column as "emission from generation (embodied emissions)".
Green cells highlight the lowest value per column. Minimum emissions is based on summing emissions from power generation and embodied in power plants.

Figure S 4 Mountain North scenarios for the *full curtailment (no storage)* solution



Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

Figure S 5 Mountain North scenarios for the *no curtailment (with storage)* solution



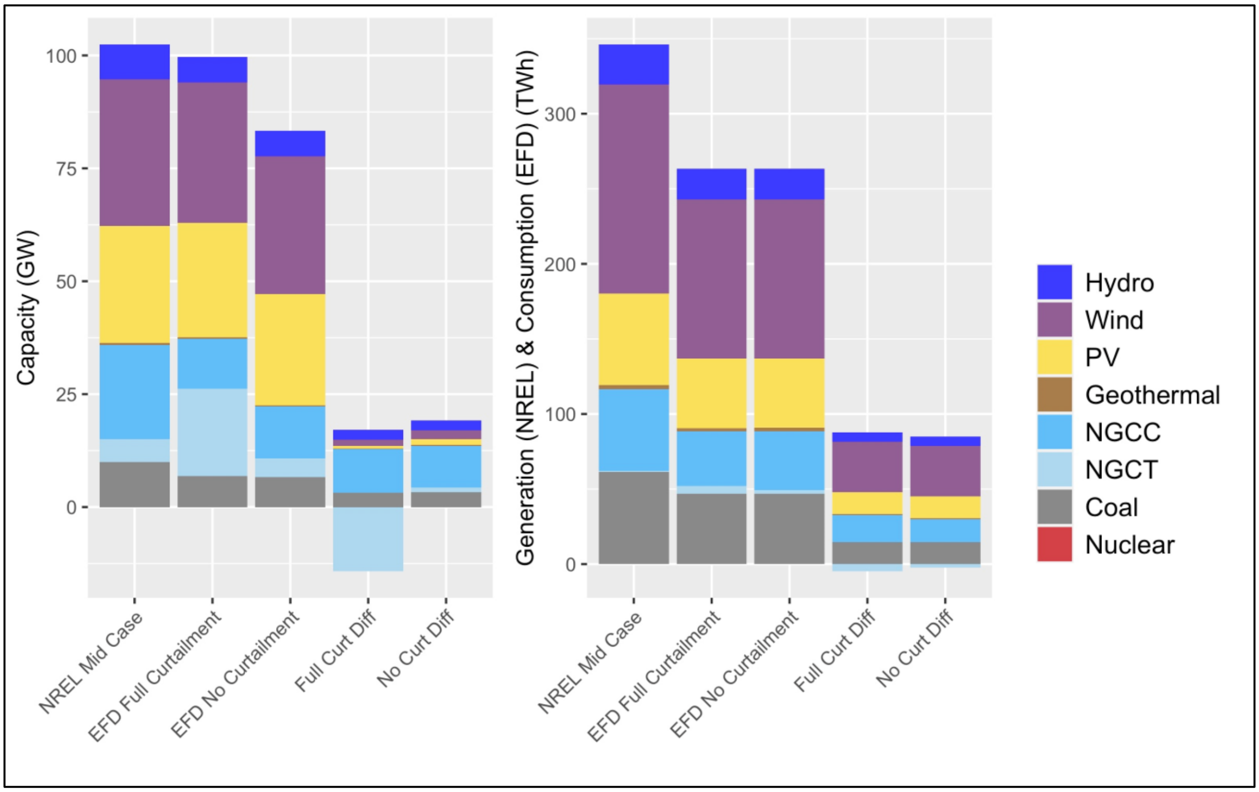
Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

Both the *no curtailment* and *full curtailment* solutions show 10% less generation from wind compared to the ReEDS Mid Case. All other generation differences by technology are less than 10% of the total ReEDS Mid Case generation. Additionally, the *full curtailment* solution reports 14% more NGCT capacity than the ReEDS Mid Case. All other capacity differences by technology are less than 10% of the total ReEDS Mid Case capacity.

CO_2 emissions, 2020-2050 (*no curtailment*/*with storage*): The ReEDS Mid Case reports 670 $MtCO_2$ more cumulative emissions than the EFD solution (Table 7). This discrepancy in emissions derives from the EFD calculating 203 and 207 TWh less cumulative natural gas and coal generation respectively.

CO_2 emissions, 2020-2050 (*full curtailment*/*no storage*): The difference for 2020-2050 CO_2 emissions remain the same for the *full curtailment*/*no storage* solution.

Figure S 6 Mountain North (MN) Region: Comparisons of results for the year 2050



From the NREL 2020 Standard Scenario Mid Case to the counterpart Scenario L of the EFD, per generation technology, for (left) operating capacity (GW) and (right) generation (TWh).

S.4.3: Results Summary: Southwest (SW)

Table S 11 Southwest: 2050 *full curtailment* (no storage)

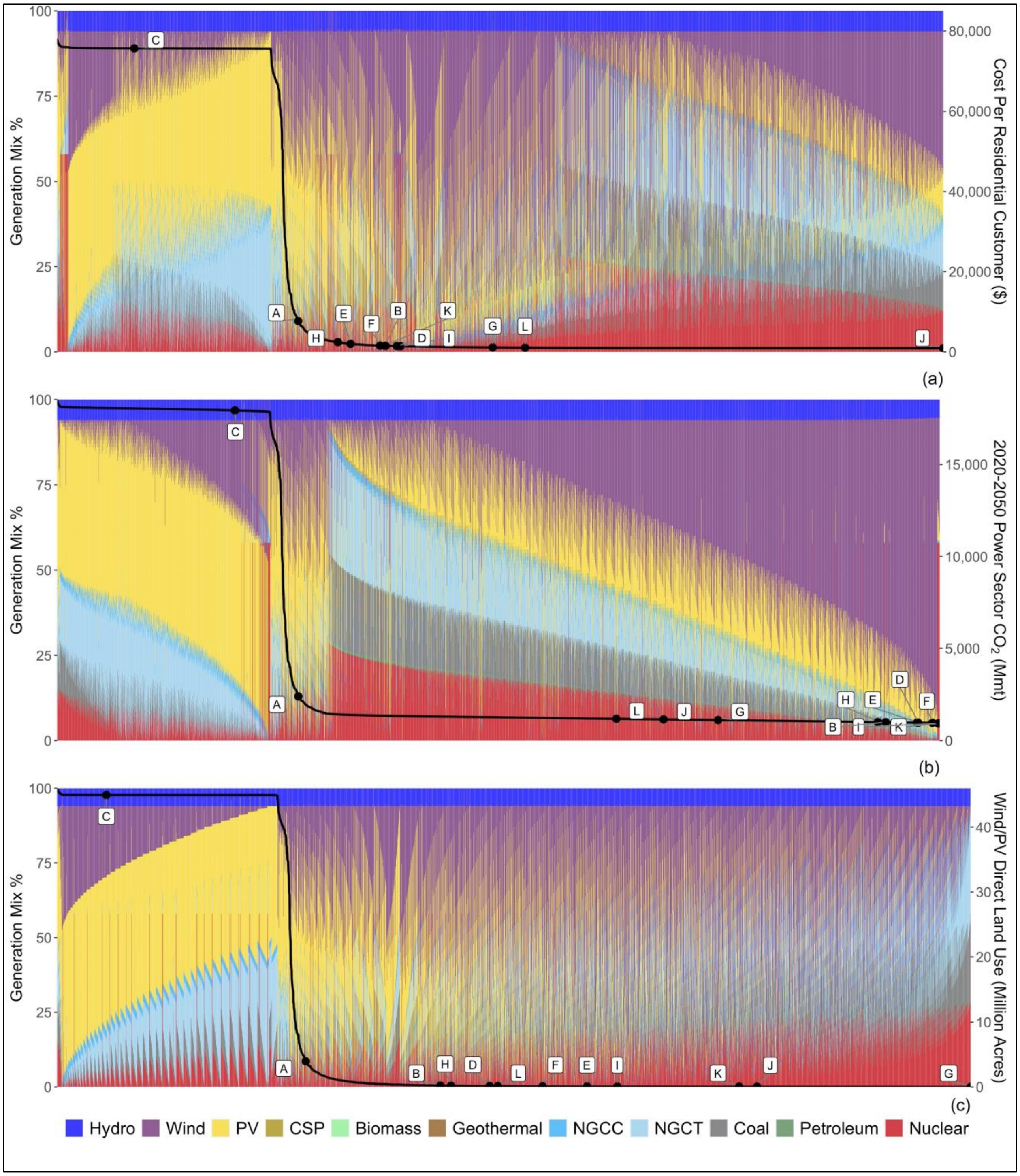
Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
A	5M/47/47/0/1	$7,700	2.6%	2.8%	896(1,510)
B	5M/70/24/0/1	$1,500	0.1%	0.6%	896(103)
C	6M/24/51/0/19	$76,000	30.0%	33.0%	991(16,900)
D	5M/77/17/0/1	$1,400	0.1%	0.6%	896(77.5)
E	5M/94/0/0/1	$2,000	< 0.1%	1.0%	896(78.2)
F	5M/85/9/0/1	$1,600	< 0.1%	0.7%	896(69.1)
G	0M/0/0/58/42	$1,100	-	-	1,110(5.57)
H	0M/35/7/58/0	$2,400	0.1%	0.9%	891(114)
I	5M/28/8/58/1	$1,400	< 0.1%	0.3%	895(42.8)
J	6M/42/13/12/27	$910	< 0.1%	0.1%	1,130(23.8)
K	5M/33/3/58/1	$1,500	< 0.1%	0.3%	895(36.7)
L	4M/30/29/16/21	$1,100	0.1%	0.2%	1,130(56.6)
NREL Mid	4/30/29/16/21	NA	NA	NA	1,460(-)

Table S 12 Southwest: 2050 *no curtailment* (with storage)

Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
A	6M/47/47/0/0	$39,600	0.1%	0.2%	891(52.8)
B	6M/70/24/0/0	$29,800	< 0.1%	0.2%	891(36.6)
C	6M/24/70/0/0	$60,500	0.1%	0.2%	891(69.7)
D	6M/74/20/0/0	$29,500	< 0.1%	0.2%	891(33.9)
E	6M/94/0/0/0	$34,300	< 0.1%	0.3%	891(22.1)
F	6M/89/5/0/0	$32,300	< 0.1%	0.2%	891(24.1)
G	0M/0/0/58/42	$1,110	-	-	1,110(5.57)
H	0M/32/10/58/0	$20,900	< 0.1%	0.1%	892(18.8)
I	6M/25/11/58/0	$19,000	< 0.1%	0.1%	892(18.3)
J	0M/0/0/58/42	$1,110	-	-	1,110(5.57)
K	0M/0/0/58/42	$1,110	-	-	1,110(5.57)
L	4M/29/29/16/22	$13,700	< 0.1%	0.1%	1,130(33.5)
NREL Mid	4/30/29/16/21	NA	NA	NA	1,460(-)

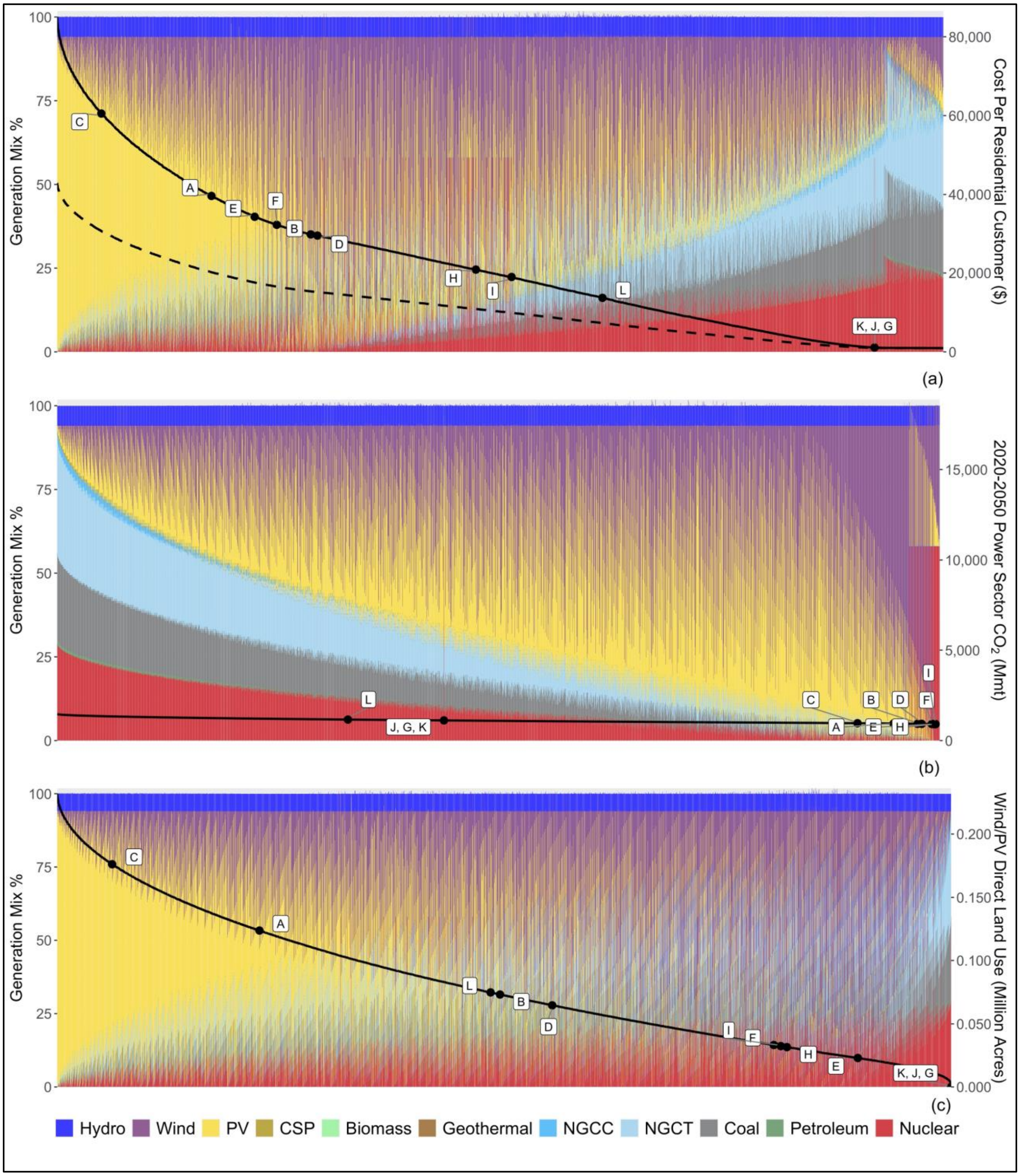
[1] "Disp." refers to dispatchable technologies: coal, natural gas, geothermal, CSP, and biomass. This will mostly consist of coal and natural gas in many regions.
[2] We report carbon emissions from generation as well as emissions embodied in power plants. This is indicated in the final column as "emission from generation (embodied emissions)".
Green cells highlight the lowest value per column. Minimum emissions is based on summing emissions from power generation and embodied in power plants.

Figure S 7 Southwest scenarios for the *full curtailment (no storage)* solution



Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

Figure S 8 Southwest scenarios for the *no curtailment (with storage)* solution



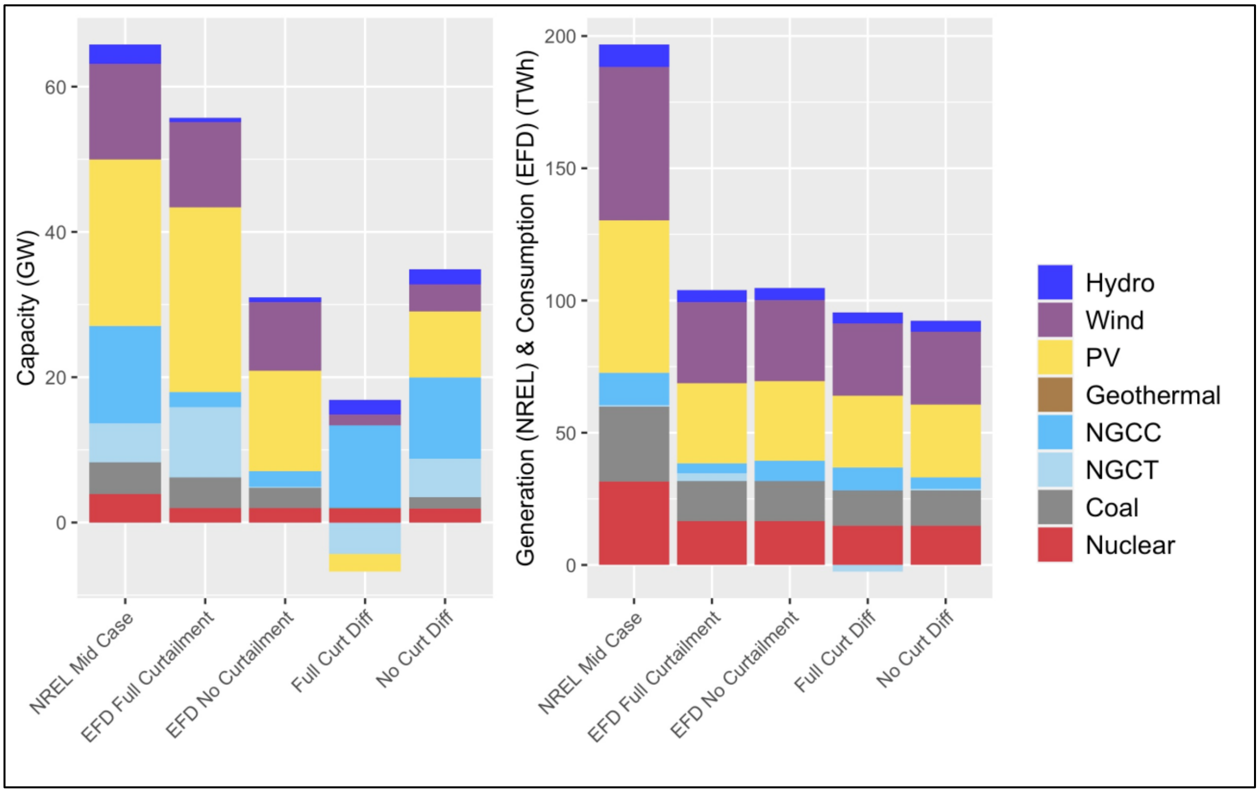
Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

Both the *no curtailment* and *full curtailment* solutions show 14% less generation from PV and wind compared to the ReEDS Mid Case. All other generation differences by technology are less than 10% of the total ReEDS Mid Case generation. Additionally, the *no curtailment* solution reports 14% less PV capacity, and both the *no curtailment* and the *full curtailment* solutions report 17% less NGCC capacity than the ReEDS Mid Case. All other capacity differences by technology are less than 10% of the total ReEDS Mid Case capacity.

CO_2 emissions, 2020-2050 (*no curtailment*/*with storage*): The ReEDS Mid Case reports 330 $MtCO_2$ more cumulative emissions than the EFD solution (Table 7). This discrepancy in emissions derives from the EFD calculating 300 TWh more cumulative natural gas and 236 TWh less cumulative coal generation.

CO_2 emissions, 2020-2050 (*full curtailment*/*no storage*): The difference for 2020-2050 CO_2 emissions remain the same for the *full curtailment*/*no storage* solution.

Figure S 9 Southwest (SW) Region: Comparisons of results for the year 2050



From the NREL 2020 Standard Scenario Mid Case to the counterpart Scenario L of the EFD, per generation technology, for (left) operating capacity (GW) and (right) generation (TWh).

S.4.4: Results Summary: Central (CE)

Table S 13 Central: 2050 *full curtailment* (no storage)

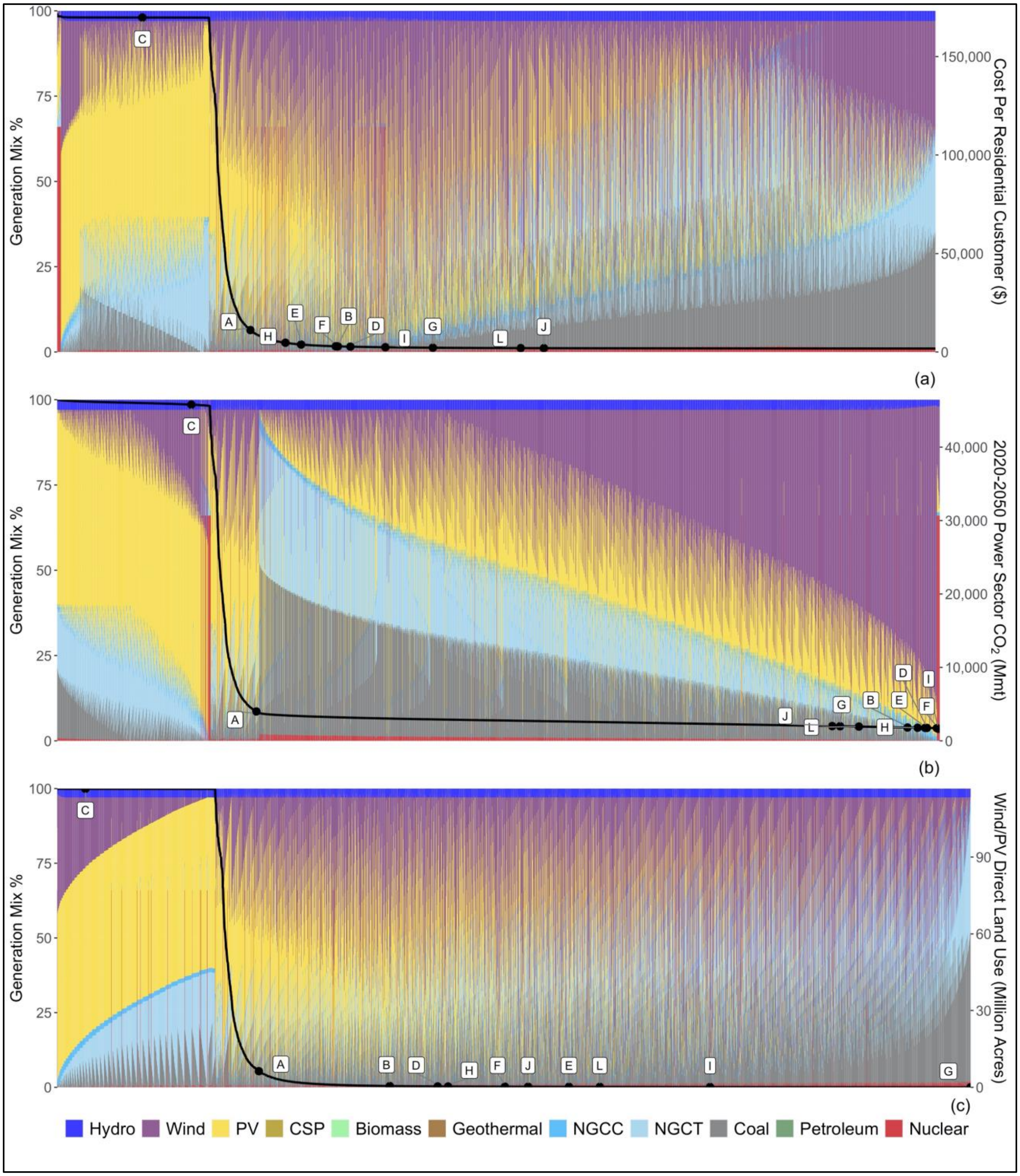
Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
NREL Mid	74/10/12/0/4	NA	NA	NA	199(-)
A	3M/49/48/0/0	$73,900	0.1%	0.8%	1,550(144)
B	3M/73/24/0/0	$57,300	0.1%	1.1%	1,550(92.1)
C	3M/24/73/0/0	$121,000	0.2%	0.6%	1,560(201)
D	3M/71/26/0/0	$57,200	0.1%	1.0%	1,550(96.3)
E	3M/97/0/0/0	$76,400	< 0.1%	1.3%	1,550(43.6)
F	3M/97/0/0/0	$76,400	< 0.1%	1.3%	1,550(43.6)
G	0M/0/0/66/34	$2,160	-	-	1,970(12.4)
H	0M/22/12/66/1	$29,600	< 0.1%	0.3%	1,560(47.7)
I	3M/16/14/66/2	$24,100	< 0.1%	0.3%	1,580(52.4)
J	0M/0/0/66/34	$2,160	-	-	1,970(12.4)
K	No Solution	-	-	-	-(-)
L	4M/68/17/0/11	$35,700	0.1%	1.0%	1,830(73.5)
NREL Mid	7/68/17/0/8	NA	NA	NA	1,630(-)

Table S 14 Central: 2050 *no curtailment* (with storage)

Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
NREL Mid	74/10/12/0/4	NA	NA	NA	199(-)
A	2M/49/48/0/1	$11,000	2.7%	5.1%	1,570(2,420)
B	2M/73/24/0/1	$2,800	0.2%	2.7%	1,570(237)
C	3M/24/57/0/17	$170,000	49.0%	55.0%	1,760(44,000)
D	2M/79/18/0/1	$2,700	0.1%	2.8%	1,570(182)
E	2M/97/0/0/1	$3,800	0.1%	5.7%	1,580(182)
F	2M/87/10/0/1	$2,900	0.1%	3.5%	1,570(160)
G	0M/0/0/66/34	$2,200	-	-	1,970(12.4)
H	0M/31/3/66/0	$4,700	0.1%	5.5%	1,550(231)
I	2M/23/8/66/1	$2,400	0.1%	0.8%	1,570(70)
J	3M/58/24/0/15	$1,900	0.1%	1.0%	1,970(12.4)
K	No Solution	-	-	-	-(-)
L	3M/68/17/0/12	$2,000	0.1%	1.3%	1,840(94.5)
NREL Mid	7/68/17/0/8	NA	NA	NA	1,630(-)

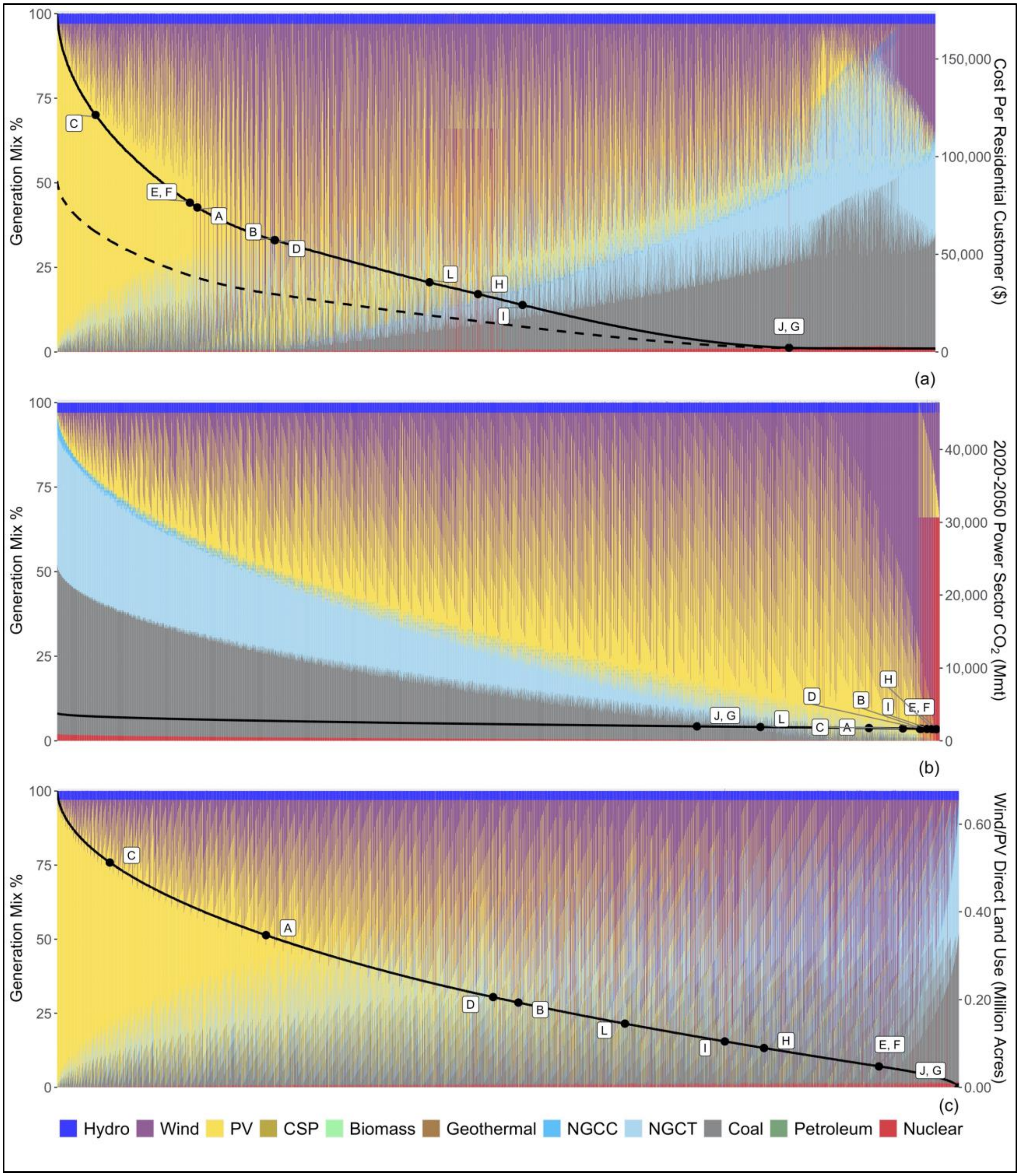
[1] "Disp." refers to dispatchable technologies: coal, natural gas, geothermal, CSP, and biomass. This will mostly consist of coal and natural gas in many regions.
[2] We report carbon emissions from generation as well as emissions embodied in power plants. This is indicated in the final column as "emission from generation (embodied emissions)".
Green cells highlight the lowest value per column. Minimum emissions is based on summing emissions from power generation and embodied in power plants.

Figure S 10 Central scenarios for the *full curtailment (no storage)* solution



Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

Figure S 11 Central scenarios for the *no curtailment (with storage)* solution



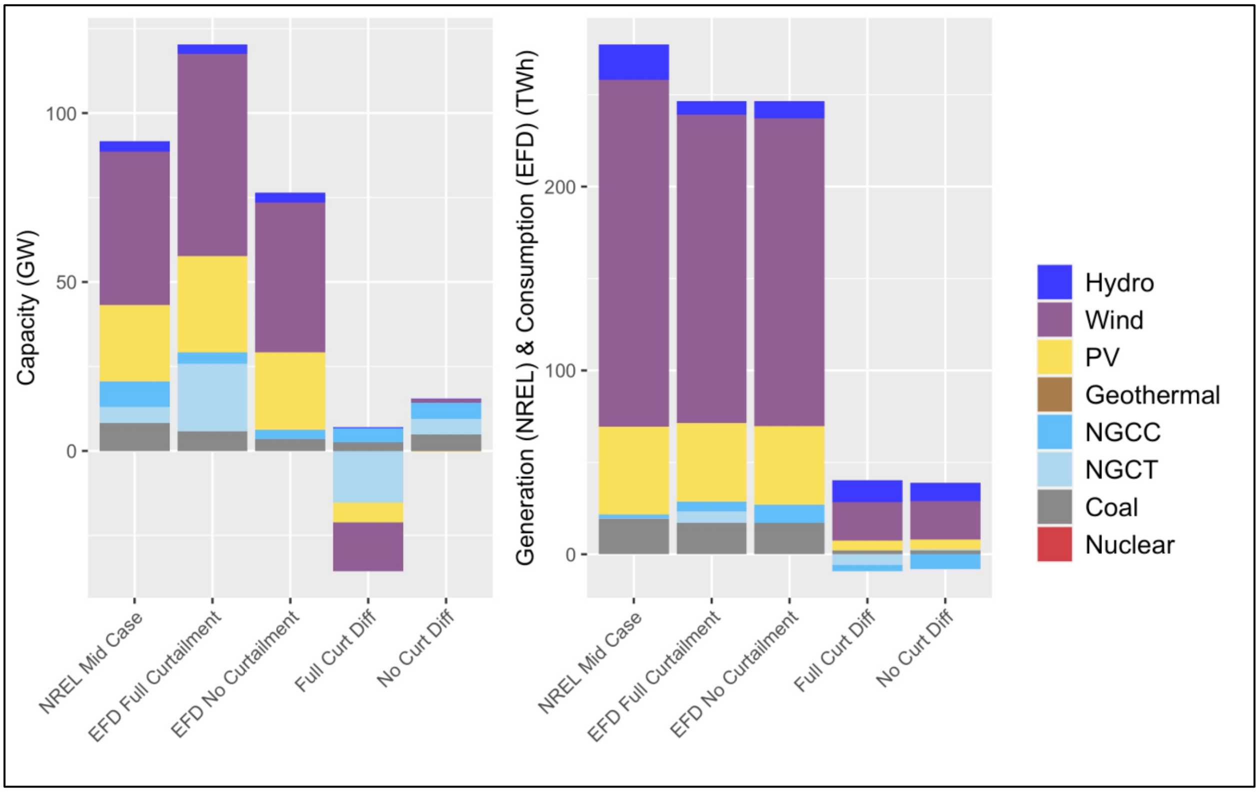
Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

All generation differences by technology are within the 10% margin for both the *full curtailment* and *no curtailment* solutions. The *full curtailment* solution reports 16% more capacity from wind and 17% more from NGCT when compared to the ReEDS Mid Case total capacity. All other capacity differences by technology are less than 10% of the total ReEDS Mid Case capacity.

<u>CO_2 emissions, 2020-2050 (*no curtailment*/*with storage*):</u> The ReEDS Mid Case reports 200 $MtCO_2$ less cumulative emissions than the EFD solution (Table 7). This discrepancy in emissions derives from the EFD calculating 363 and 350 TWh more cumulative natural gas and coal generation respectively.

<u>CO_2 emissions, 2020-2050 (*full curtailment*/*no storage*):</u> The EFD *full curtailment* solution reports 210 $MtCO_2$ higher cumulative emissions than the NREL Mid Case Scenario, primarily due to 390 TWh and 350 TWh more natural gas and coal generation, respectively.

Figure S 12 Central (CE) Region: Comparisons of results for the year 2050



From the NREL 2020 Standard Scenario Mid Case to the counterpart Scenario L of the EFD, per generation technology, for (left) operating capacity (GW) and (right) generation (TWh).

S.4.5: Results Summary: Midwest (MW)

Table S 15 Midwest: 2050 *full curtailment* (no storage)

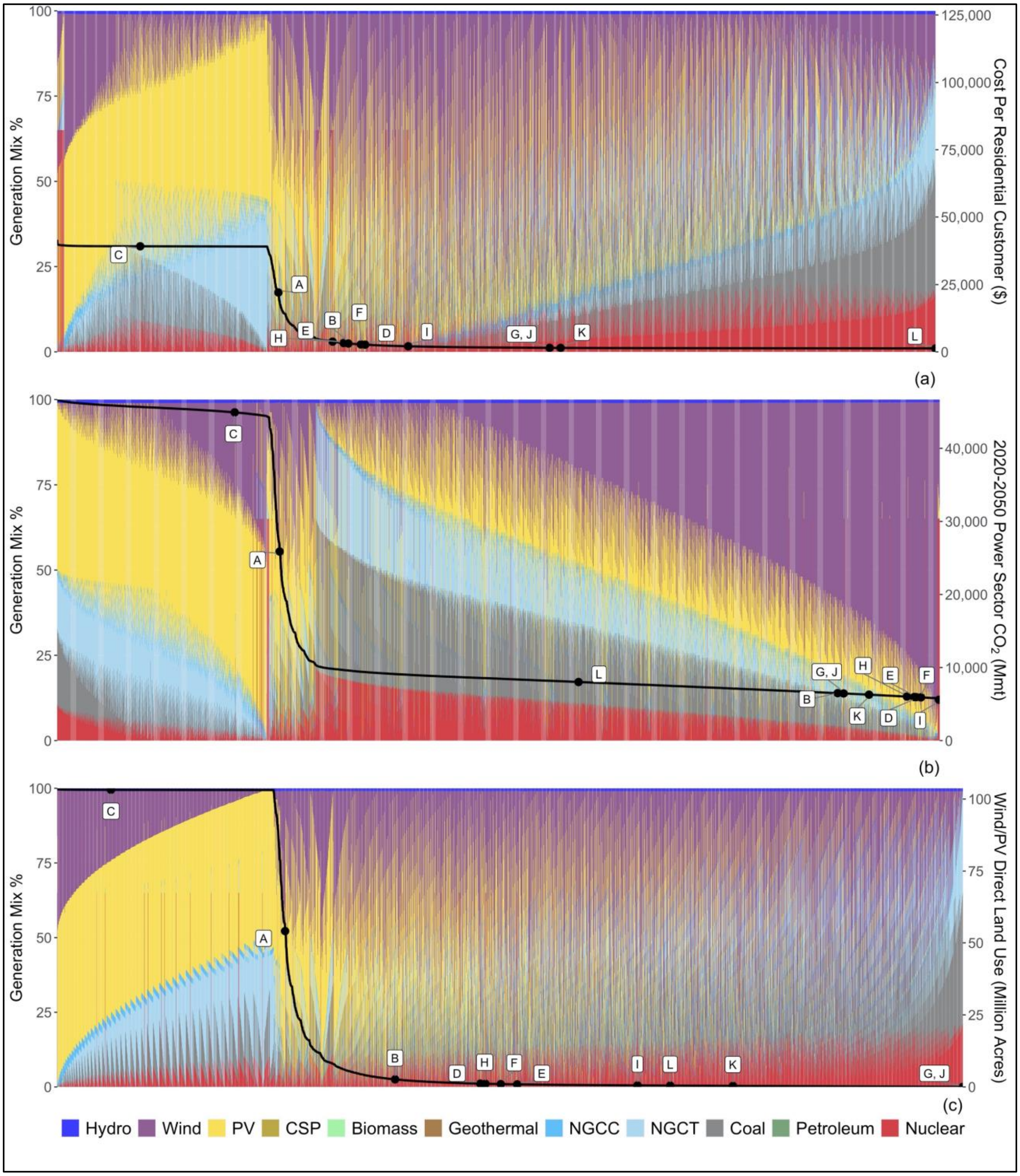
Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
A	1M/50/49/0/0	$22,000	21.0%	24.0%	5,280(20,600)
B	1M/75/24/0/0	$3,100	0.9%	6.1%	5,280(1,210)
C	1M/23/54/0/22	$39,000	40.0%	44.0%	6,010(38,900)
D	1M/87/12/0/0	$2,700	0.3%	6.3%	5,280(673)
E	1M/95/4/0/0	$3,300	0.2%	9.0%	5,280(689)
F	1M/90/9/0/0	$2,800	0.2%	6.8%	5,280(639)
G	0M/0/0/65/35	$1,500	-	-	6,420(31.6)
H	0M/32/3/65/0	$3,800	0.3%	8.5%	5,270(759)
I	1M/28/6/65/0	$2,100	0.2%	2.3%	5,280(310)
J	0M/0/0/65/35	$1,500	-	1.5%	6,420(31.6)
K	1M/75/9/3/12	$1,500	0.1%	2.1%	6,060(229)
L	1M/25/22/4/49	$1,200	0.2%	0.6%	7,810(211)
NREL Mid	3/25/22/3/47	NA	NA	NA	9,150(-)

Table S 16 Midwest: 2050 *no curtailment* (with storage)

Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
A	1M/50/49/0/0	$57,400	0.4%	1.2%	5,270(454)
B	1M/75/24/0/0	$41,200	0.2%	1.6%	5,270(286)
C	1M/24/75/0/0	$92,200	0.6%	0.9%	5,270(637)
D	1M/77/22/0/0	$41,100	0.2%	1.6%	5,270(273)
E	1M/99/0/0/0	$50,400	< 0.1%	2.0%	5,270(135)
F	1M/99/0/0/0	$50,400	< 0.1%	2.0%	5,270(135)
G	0M/0/0/65/35	$1,480	-	-	6,420(31.6)
H	0M/25/10/65/0	$21,200	0.1%	0.5%	5,270(132)
I	1M/24/10/65/0	$20,300	0.1%	0.5%	5,280(131)
J	0M/0/0/65/35	$1,480	-	-	6,420(31.6)
K	1M/35/6/12/46	$1,450	< 0.1%	0.7%	8,210(104)
L	1M/25/22/4/49	$3,110	0.2%	0.6%	7,800(206)
NREL Mid	3/25/22/3/47	NA	NA	NA	9,150(-)

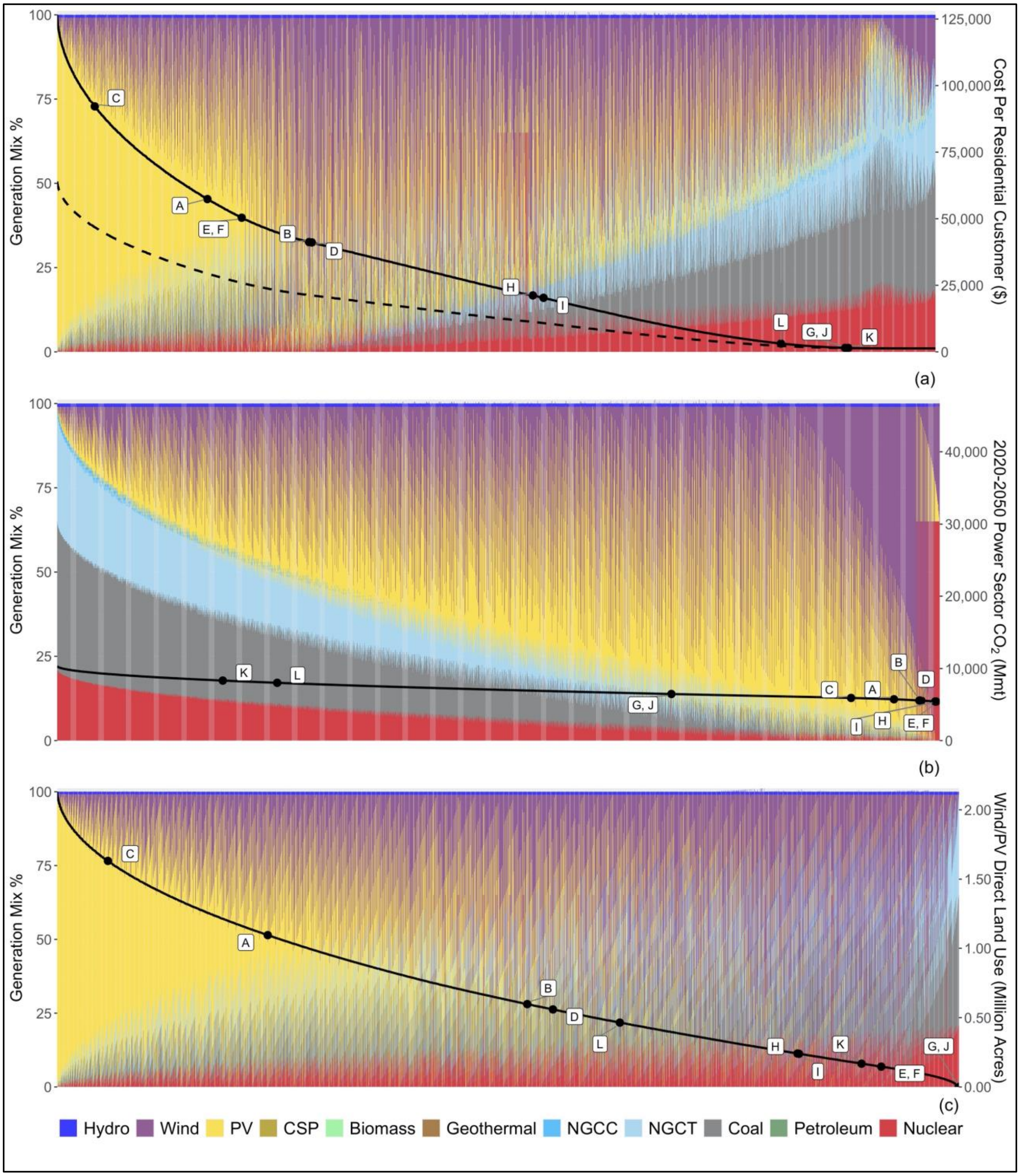
[1] "Disp." refers to dispatchable technologies: coal, natural gas, geothermal, CSP, and biomass. This will mostly consist of coal and natural gas in many regions.
[2] We report carbon emissions from generation as well as emissions embodied in power plants. This is indicated in the final column as "emission from generation (embodied emissions)".
Green cells highlight the lowest value per column. Minimum emissions is based on summing emissions from power generation and embodied in power plants.

Figure S 13 Midwest scenarios for the *full curtailment (no storage)* solution



Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

Figure S 14 Midwest scenarios for the *no curtailment (with storage)* solution



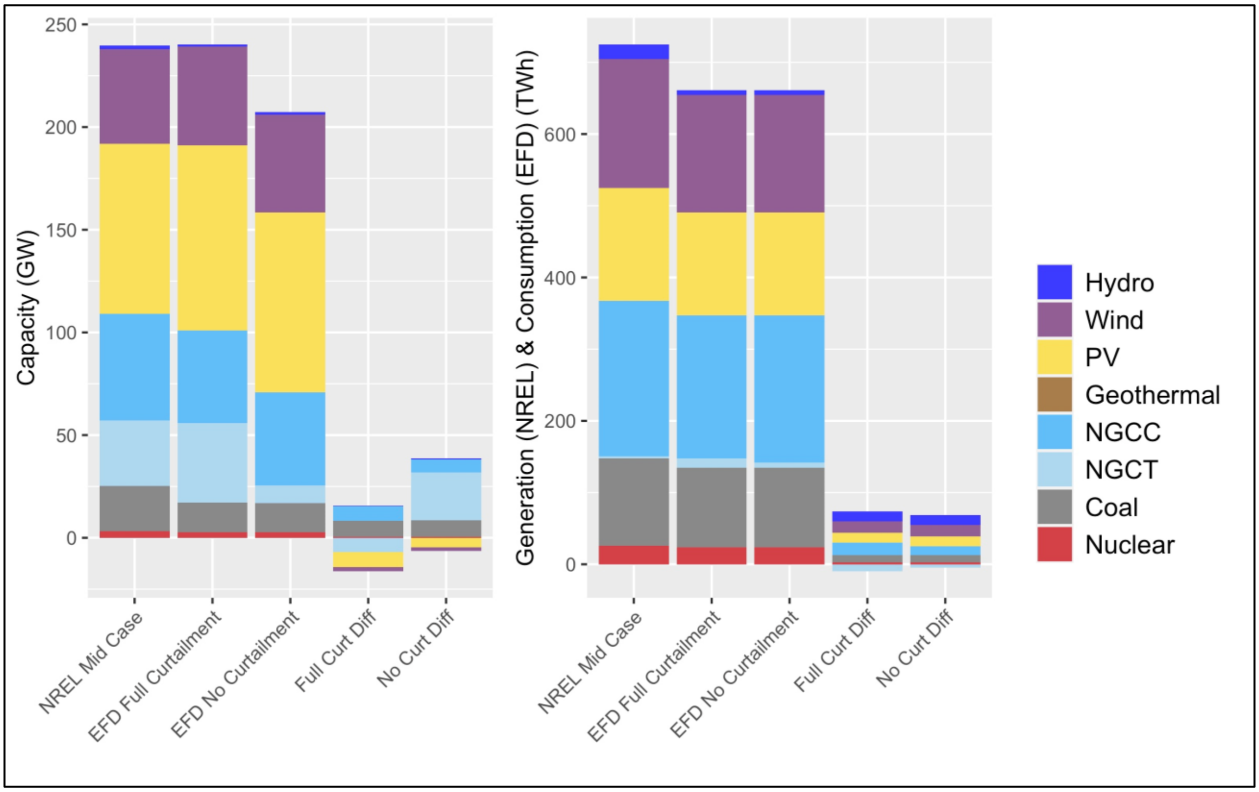
Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

All generation differences by technology are within the 10% margin for both the *full curtailment* and *no curtailment* solutions. The *no curtailment* solution has 10% less capacity from NGCT when compared to the total ReEDS Mid Case capacity. All other capacity differences by technology are less than 10% of the total ReEDS Mid Case capacity.

CO_2 emissions, 2020-2050 (*no curtailment*/*with storage*): The ReEDS Mid Case reports 1,350 $MtCO_2$ more cumulative emissions than the EFD solution (Table 7**Error! Reference source not found.**). This discrepancy in emissions derives from the EFD calculating 390 TWh more cumulative natural gas generation and 317 TWh less cumulative coal generation.

CO_2 emissions, 2020-2050 (*full curtailment*/*no storage*): The difference for 2020-2050 CO_2 emissions remains roughly the same for the *full curtailment*/*no storage* solution.

Figure S 15 Midwest (MW) Region: Comparisons of results for the year 2050



From the NREL 2020 Standard Scenario Mid Case to the counterpart Scenario L of the EFD, per generation technology, for (left) operating capacity (GW) and (right) generation (TWh).

S.4.6: Results Summary: Arkansas Louisiana (AL)

Table S 17 Arkansas Louisiana: 2050 *full curtailment* (no storage)

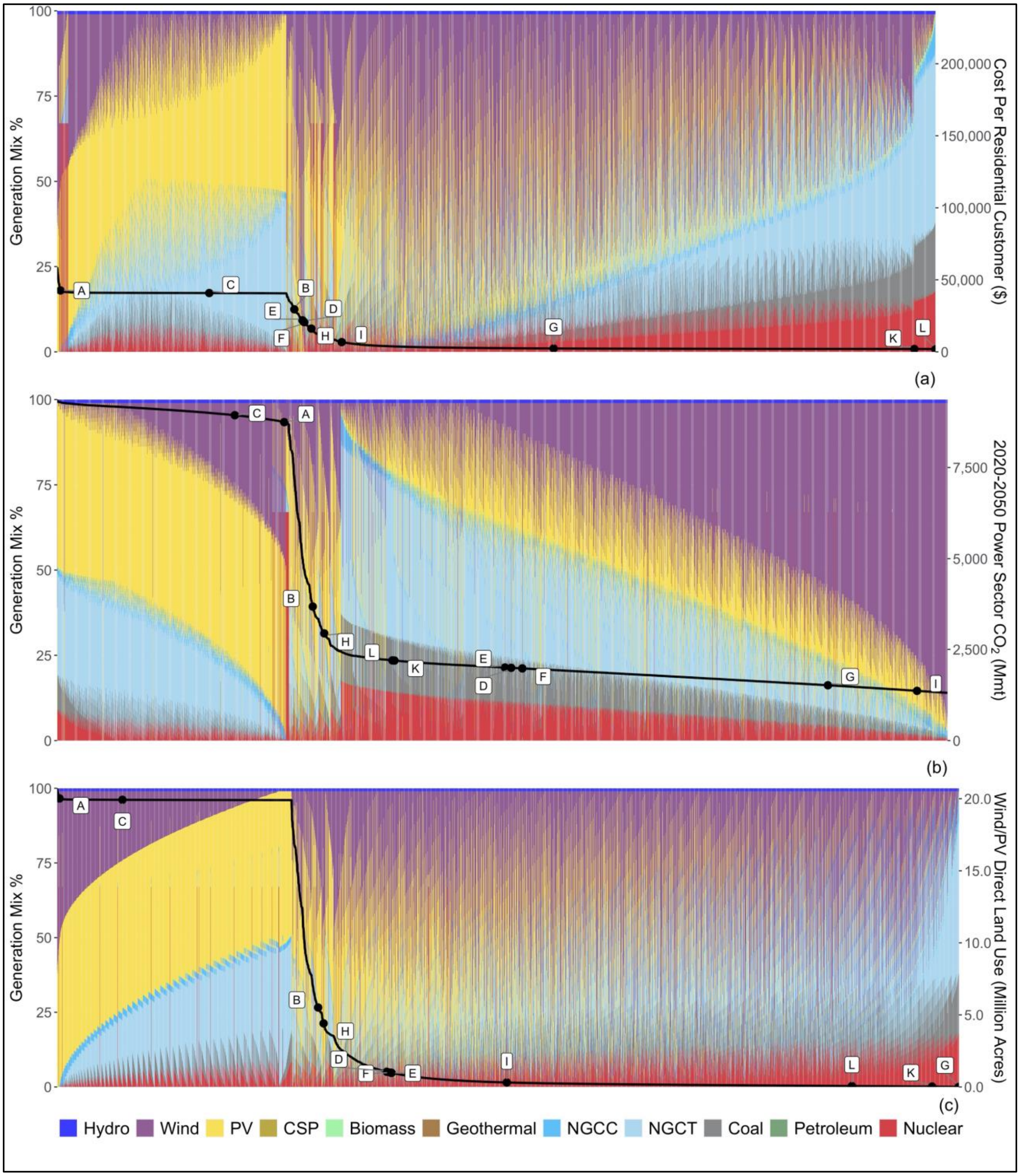
Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
A	1M/50/49/0/1	$43,000	33.0%	27.0%	1,140(7,610)
B	1M/75/24/0/0	$29,000	6.3%	17.0%	1,130(2,550)
C	1M/23/51/0/24	$41,000	33.0%	34.0%	1,410(7,520)
D	1M/97/2/0/0	$21,000	0.3%	17.0%	1,130(865)
E	1M/99/0/0/0	$22,000	0.3%	19.0%	1,130(874)
F	1M/98/1/0/0	$21,000	0.3%	18.0%	1,130(849)
G	0M/0/0/67/33	$2,300	-	-	1,510(9.39)
H	0M/20/13/67/0	$16,000	6.4%	5.7%	1,130(1,810)
I	1M/30/2/67/0	$6,700	0.1%	3.9%	1,130(232)
J	No Solution	-	-	-	-(-)
K	1M/17/3/14/65	$2,000	-	0.1%	2,180(19.4)
L	2M/0/11/6/81	$1,700	0.1%	0.1%	2,170(29.1)
NREL Mid	2/0/11/6/81	NA	NA	NA	1,840(-)

Table S 18 Arkansas Louisiana: 2050 *no curtailment* (with storage)

Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
A	1M/50/49/0/0	$108,000	0.5%	0.5%	1,130(143)
B	1M/75/24/0/0	$81,700	0.2%	0.6%	1,130(90.6)
C	1M/24/75/0/0	$172,000	0.8%	0.5%	1,130(201)
D	1M/77/22/0/0	$81,700	0.2%	0.7%	1,130(86.5)
E	1M/99/0/0/0	$97,700	< 0.1%	0.9%	1,130(43.1)
F	1M/99/0/0/0	$97,700	< 0.1%	0.9%	1,130(43.1)
G	0M/0/0/67/33	$2,330	-	-	1,510(9.39)
H	0M/19/13/67/2	$36,900	0.1%	0.2%	1,150(46.8)
I	1M/19/13/67/1	$38,800	0.1%	0.2%	1,140(46.9)
J	0M/19/13/67/2	$36,900	0.1%	0.2%	1,150(46.8)
K	1M/17/3/14/65	$2,000	< 0.1%	0.1%	2,180(19.4)
L	2M/0/11/6/81	$1,750	0.1%	0.1%	2,170(29.1)
NREL Mid	2/0/11/6/81	NA	NA	NA	1,840(-)

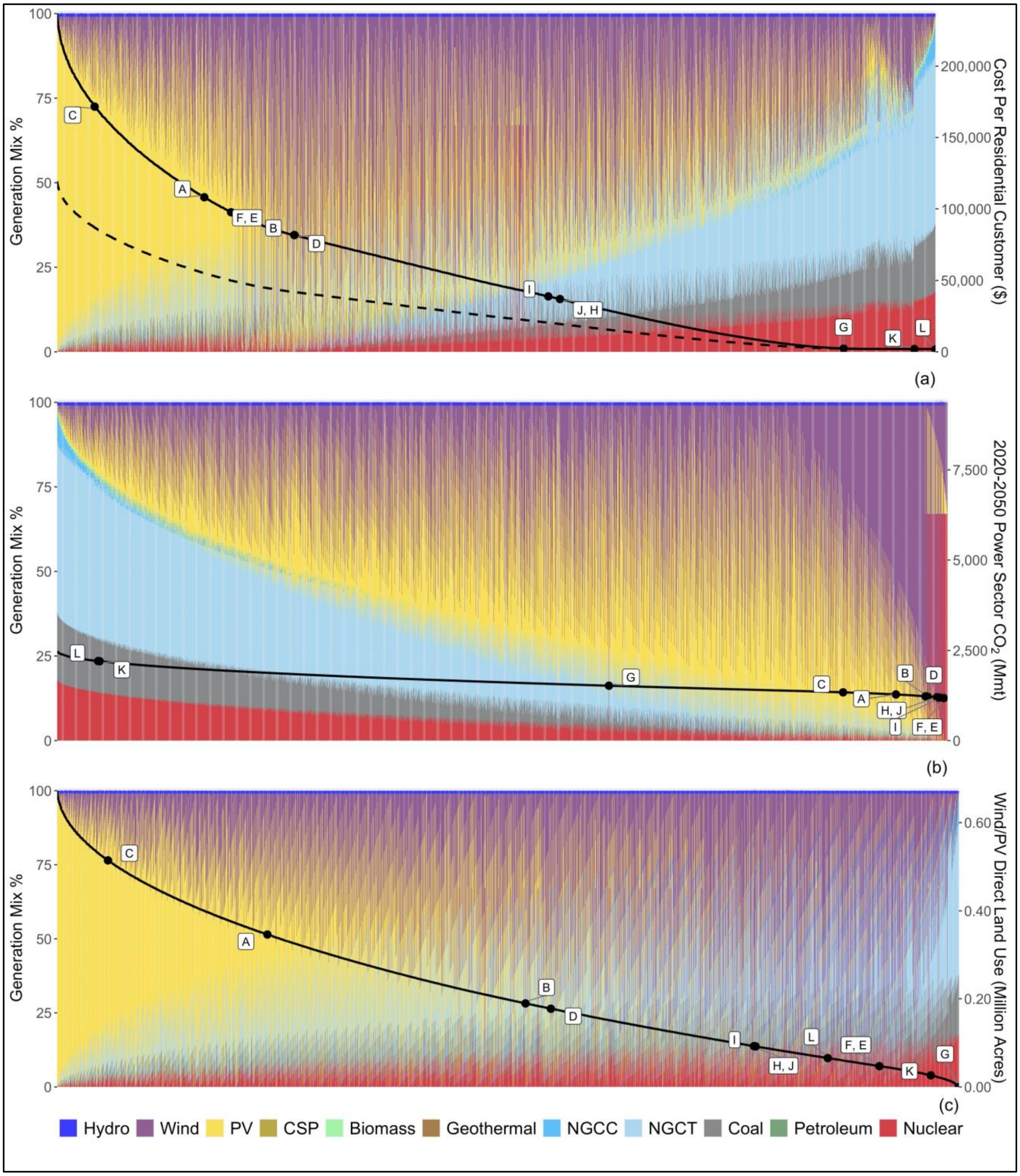
[1] "Disp." refers to dispatchable technologies: coal, natural gas, geothermal, CSP, and biomass. This will mostly consist of coal and natural gas in many regions.
[2] We report carbon emissions from generation as well as emissions embodied in power plants. This is indicated in the final column as "emission from generation (embodied emissions)".
Green cells highlight the lowest value per column. Minimum emissions is based on summing emissions from power generation and embodied in power plants.

Figure S 16 Arkansas Louisiana scenarios for the *full curtailment (no storage)* solution



Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

Figure S 17 Arkansas Louisiana scenarios for the *no curtailment (with storage)* solution



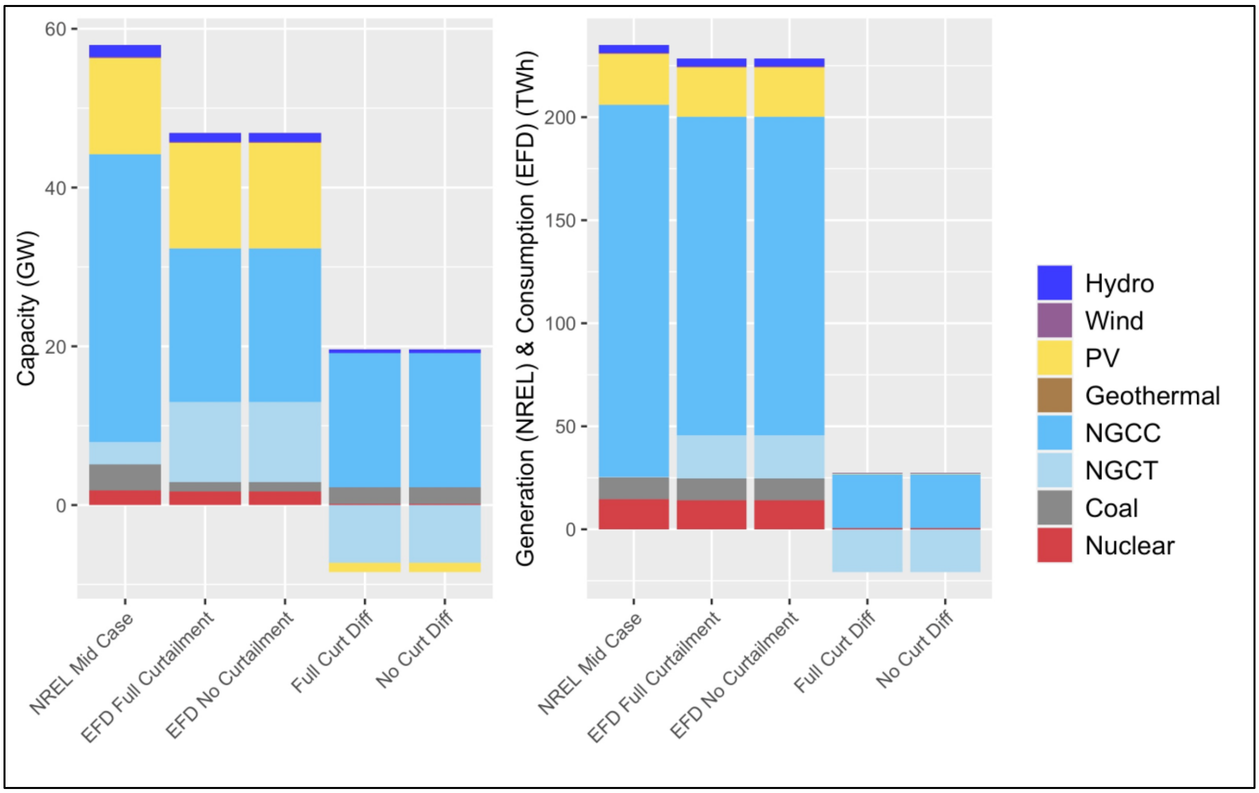
Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

Both the *no curtailment* and *full curtailment* solutions show 11% less generation from NGCC compared to the total ReEDS Mid Case generation. All other generation differences by technology are less than 10% of the total ReEDS Mid Case generation. Additionally, both the *no curtailment* and the *full curtailment* solutions report 29% less capacity from NGCC and 13% more from NGCT than the ReEDS Mid Case. All other capacity differences by technology are less than 10% of the total ReEDS Mid Case capacity.

CO_2 emissions, 2020-2050 (*no curtailment*/*with storage*): The ReEDS Mid Case reports 330 $MtCO_2$ less cumulative emissions than the EFD solution (Table 7). This discrepancy in emissions derives from the EFD calculating 16 TWh less cumulative natural gas generation and 438 TWh more cumulative coal generation.

CO_2 emissions, 2020-2050 (*full curtailment*/*no storage*): The difference for 2020-2050 CO_2 emissions remain the same for the *full curtailment*/*no storage* solution.

Figure S 18 Arkansas Louisiana (AL) Region: Comparisons of results for the year 2050



From the NREL 2020 Standard Scenario Mid Case to the counterpart Scenario L of the EFD, per generation technology, for (left) operating capacity (GW) and (right) generation (TWh).

S.4.7: Results Summary: Mid Atlantic (MA)

Table S 19 Mid Atlantic: 2050 *full curtailment* (no storage)

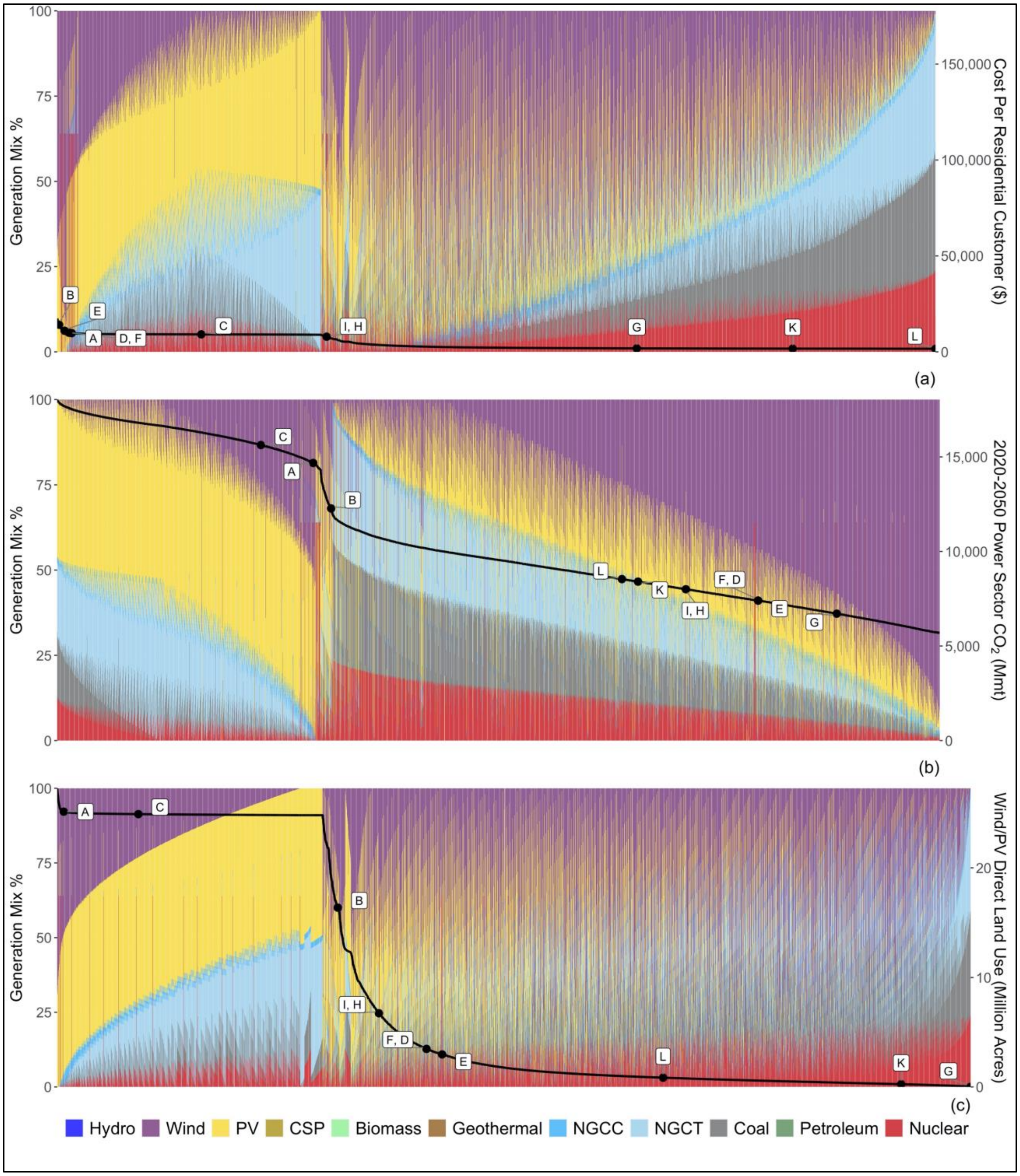
Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
A	0M/49/47/0/4	$9,800	19.0%	17.0%	5,040(9,650)
B	0M/75/25/0/0	$14,000	9.4%	31.0%	4,750(7,530)
C	0M/23/51/0/26	$9,100	19.0%	18.0%	6,180(9,460)
D	0M/96/4/0/0	$10,000	0.7%	28.0%	4,750(2,660)
E	0M/100/0/0/0	$11,000	0.5%	32.0%	4,750(2,650)
F	0M/96/4/0/0	$10,000	0.7%	28.0%	4,750(2,660)
G	0M/0/0/64/36	$1,800	-	-	6,670(43.2)
H	0M/27/9/64/0	$7,900	3.6%	15.0%	4,750(3,260)
I	0M/27/9/64/0	$7,900	3.6%	15.0%	4,750(3,260)
J	No Solution	-	-	-	-(-)
K	0M/48/4/12/36	$1,700	0.1%	1.3%	8,230(178)
L	1M/12/25/5/56	$1,500	0.6%	0.6%	8,180(357)
NREL Mid	1/13/25/5/56	NA	NA	NA	8,450(-)

Table S 20 Mid Atlantic: 2050 *no curtailment* (with storage)

Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
A	0M/50/50/0/0	$82,800	1.2%	1.8%	4,750(743)
B	0M/75/25/0/0	$60,800	0.5%	2.2%	4,750(481)
C	0M/25/75/0/0	$127,000	1.9%	1.7%	4,770(1010)
D	0M/78/22/0/0	$60,500	0.5%	2.3%	4,750(451)
E	0M/100/0/0/0	$70,900	< 0.1%	2.7%	4,750(237)
F	0M/100/0/0/0	$70,900	< 0.1%	2.7%	4,750(237)
G	0M/0/0/64/36	$1,800	-	-	6,670(43.2)
H	0M/28/12/64/0	$28,300	0.3%	0.9%	4,750(249)
I	0M/28/12/64/0	$28,300	0.3%	0.9%	4,750(249)
J	0M/28/12/64/0	$28,300	0.3%	0.9%	4,750(249)
K	0M/32/2/16/50	$1,660	< 0.1%	0.9%	9,510(117)
L	1M/12/25/5/56	$4,650	0.6%	0.6%	8,170(344)
NREL Mid	1/13/25/5/56	NA	NA	NA	8,450(-)

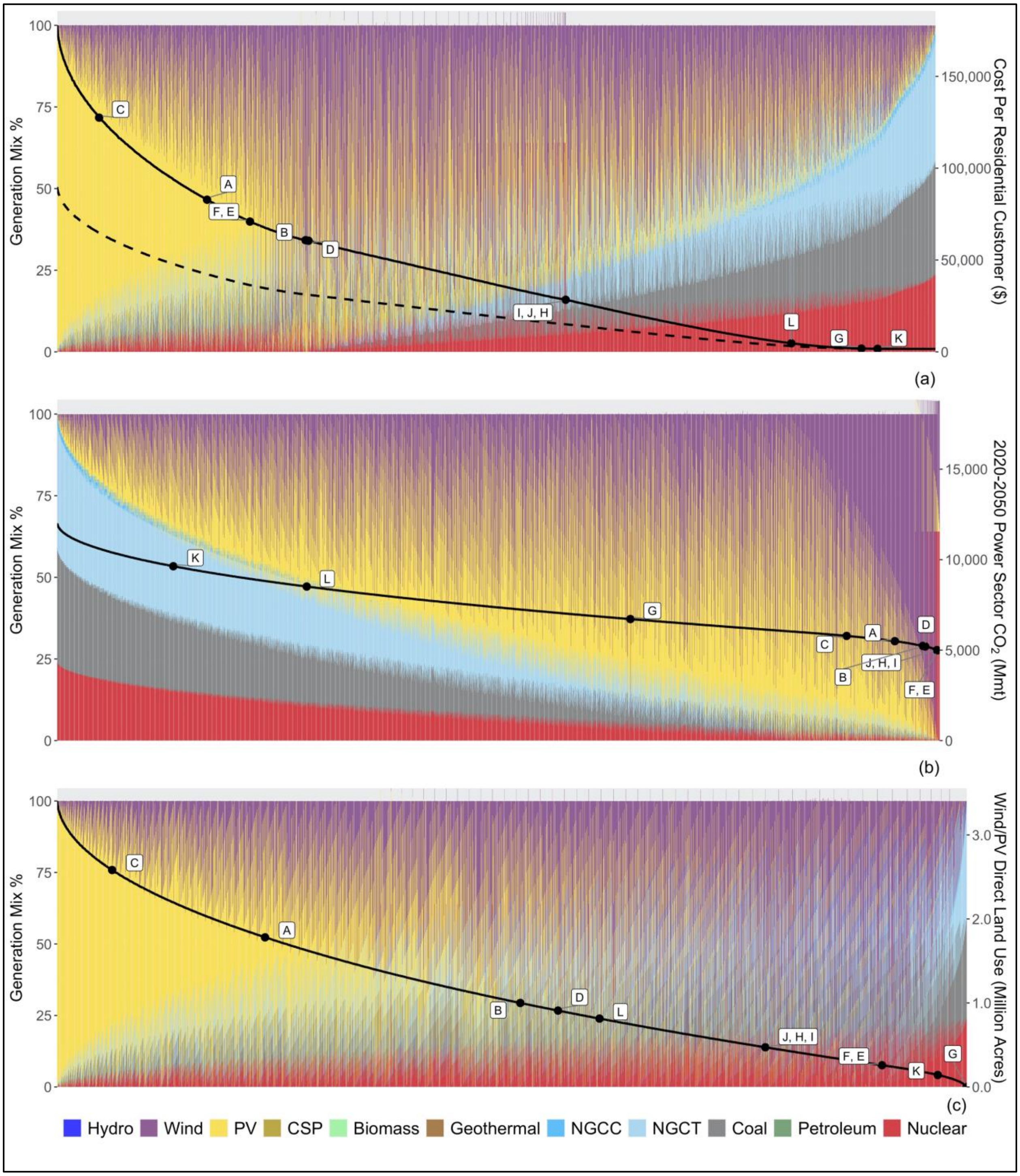
[1] "Disp." refers to dispatchable technologies: coal, natural gas, geothermal, CSP, and biomass. This will mostly consist of coal and natural gas in many regions.
[2] We report carbon emissions from generation as well as emissions embodied in power plants. This is indicated in the final column as "emission from generation (embodied emissions)".
Green cells highlight the lowest value per column. Minimum emissions is based on summing emissions from power generation and embodied in power plants.

Figure S 19 Mid Atlantic scenarios for the *full curtailment (no storage)* solution



Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

Figure S 20 Mid Atlantic scenarios for the *no curtailment (with storage)* solution



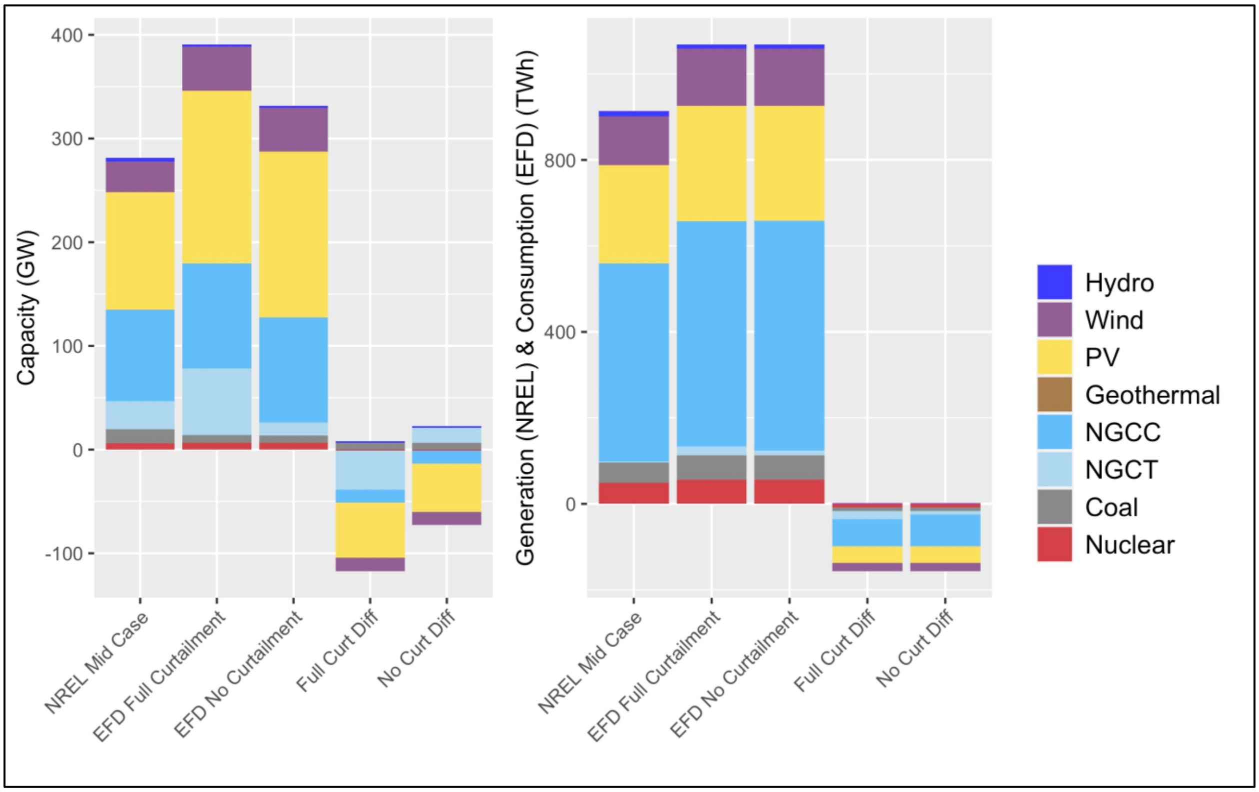
Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

All generation differences by technology are within the 10% margin for both the *full curtailment* and *no curtailment* solutions. The *no curtailment* solution has 17% more capacity from PV, and the *full curtailment* solution has 19% more capacity from PV and 13% more from NGCT. All other capacity differences by technology are less than 10% of the total ReEDS Mid Case capacity.

CO_2 emissions, 2020-2050 (*no curtailment*/*with storage*): The ReEDS Mid Case reports 280 $MtCO_2$ more cumulative emissions than the EFD solution (Table 7). This discrepancy in emissions derives from the EFD calculating 348 and 715 TWh more cumulative natural gas and coal generation respectively.

CO_2 emissions, 2020-2050 (*full curtailment*/*no storage*): The difference for 2020-2050 CO_2 emissions remains roughly the same for the *full curtailment*/*no storage* solution.

Figure S 21 Mid Atlantic (MA) Region: Comparisons of results for the year 2050



From the NREL 2020 Standard Scenario Mid Case to the counterpart Scenario L of the EFD, per generation technology, for (left) operating capacity (GW) and (right) generation (TWh).

S.4.8: Results Summary: Southeast (SE)

Table S 21 Southeast: 2050 *full curtailment* (no storage)

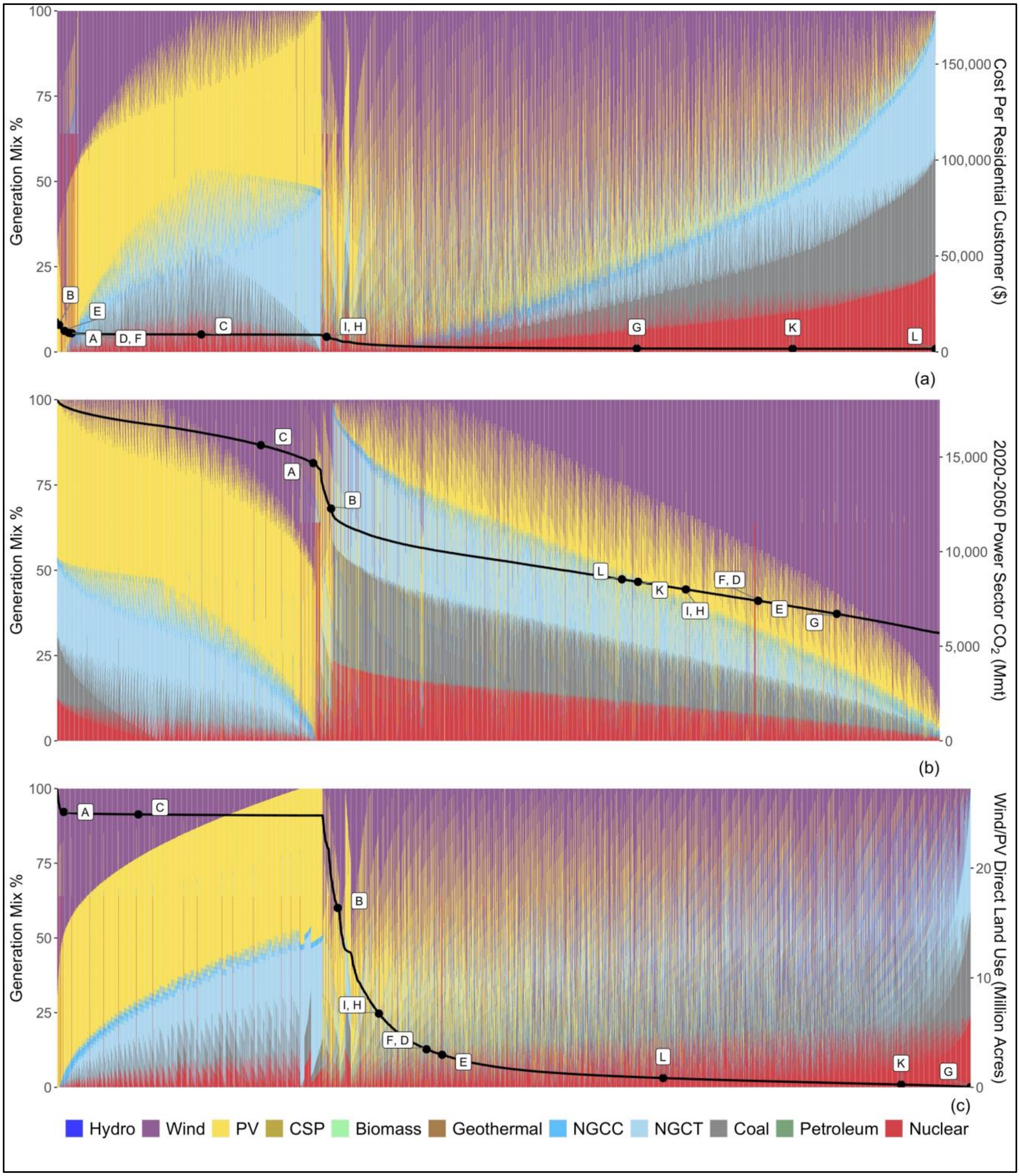
Scenario	Hyd/Wind/PV/Nuc/Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
A	2M/49/48/0/1	$11,000	15.0%	12.0%	3,390(10,700)
B	2M/73/24/0/1	$2,500	0.8%	4.5%	3,390(945)
C	3M/23/53/0/21	$19,000	30.0%	30.0%	4,230(19,700)
D	2M/79/18/0/1	$2,400	0.4%	4.8%	3,380(720)
E	2M/97/0/0/1	$3,500	0.1%	9.8%	3,390(679)
F	2M/88/9/0/1	$2,600	0.2%	6.3%	3,390(616)
G	0M/0/0/31/69	$1,300	-	-	6,240(29.6)
H	0M/67/2/31/0	$8,700	0.4%	25.0%	3,310(1,910)
I	3M/0/38/31/28	$19,000	30.0%	33.0%	4,520(19,600)
J	No Solution	-	-	-	-(-)
K	2M/83/9/2/4	$2,000	0.1%	4.2%	3,600(429)
L	3M/2/33/24/37	$1,500	0.6%	0.6%	5,110(451)
NREL Mid	4/2/23/24/37	NA	NA	NA	5,570(-)

Table S 22 Southeast: 2050 *no curtailment* (with storage)

Scenario	Hyd/Wind/PV/Nuc/Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
A	3M/49/48/0/0	$65,400	0.6%	1.1%	3,310(513)
B	3M/73/24/0/0	$50,600	0.3%	1.7%	3,320(335)
C	3M/24/73/0/0	$103,000	1.0%	0.8%	3,310(706)
D	3M/74/23/0/0	$50,600	0.2%	1.7%	3,320(328)
E	3M/97/0/0/0	$60,100	< 0.1%	2.4%	3,320(171)
F	3M/96/1/0/0	$59,400	< 0.1%	2.4%	3,320(175)
G	0M/0/0/31/69	$1,340	-	-	6,240(29.6)
H	0M/57/12/31/1	$40,900	0.1%	1.4%	3,350(212)
I	3M/54/12/31/1	$37,900	0.1%	1.3%	3,340(208)
J	3M/46/28/9/14	$28,400	0.3%	1.0%	4,220(328)
K	3M/28/4/25/40	$2,000	< 0.1%	0.7%	5,940(98.5)
L	3M/2/33/24/37	$15,300	0.4%	0.4%	5,080(308)
NREL Mid	4/2/23/24/37	NA	NA	NA	5,570(-)

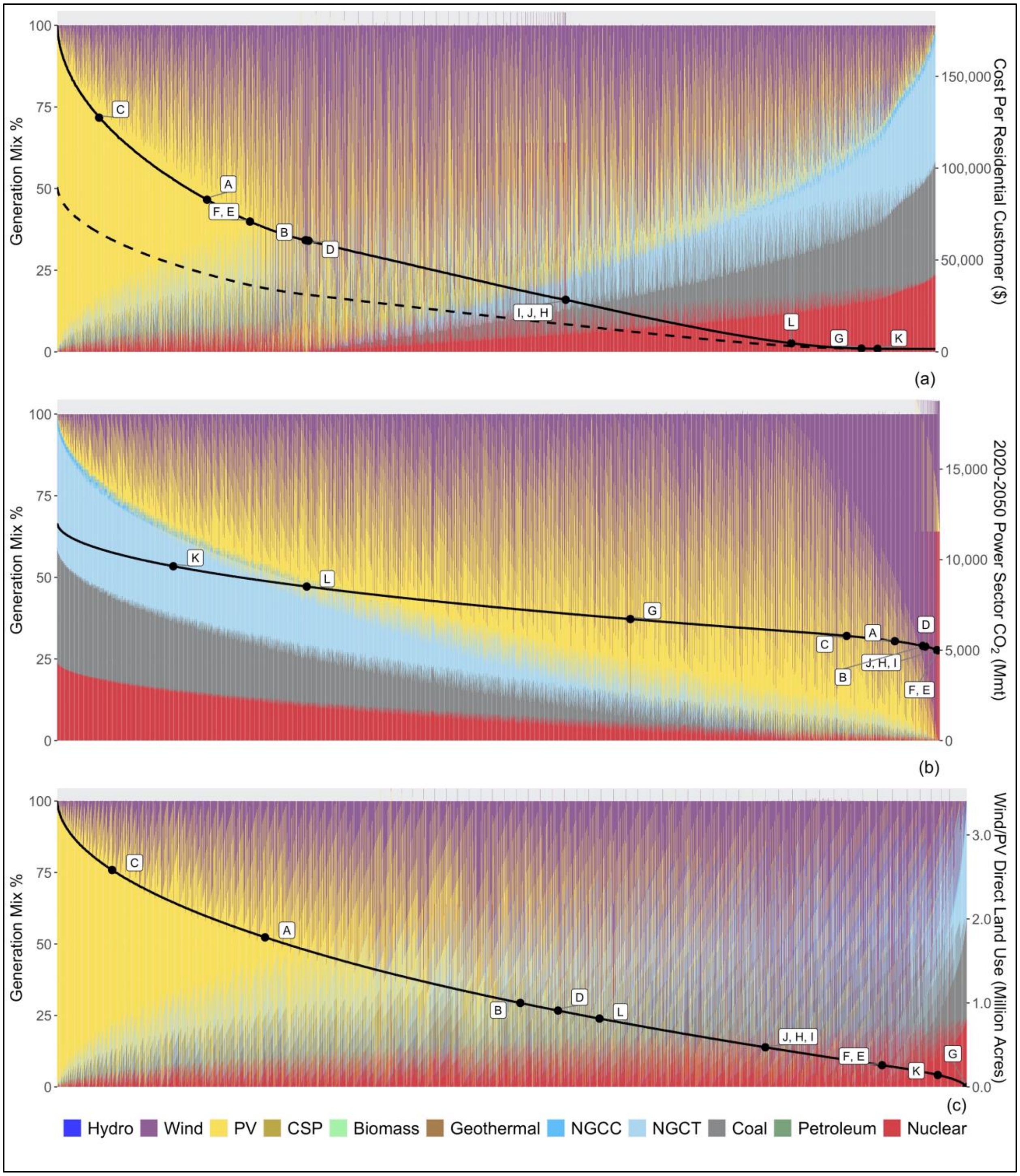
[1] "Disp." refers to dispatchable technologies: coal, natural gas, geothermal, CSP, and biomass. This will mostly consist of coal and natural gas in many regions.
[2] We report carbon emissions from generation as well as emissions embodied in power plants. This is indicated in the final column as "emission from generation (embodied emissions)".
Green cells highlight the lowest value per column. Minimum emissions is based on summing emissions from power generation and embodied in power plants.

Figure S 22 Southeast scenarios for the *full curtailment (no storage)* solution



Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

Figure S 23 Southeast scenarios for the *no curtailment (with storage)* solution



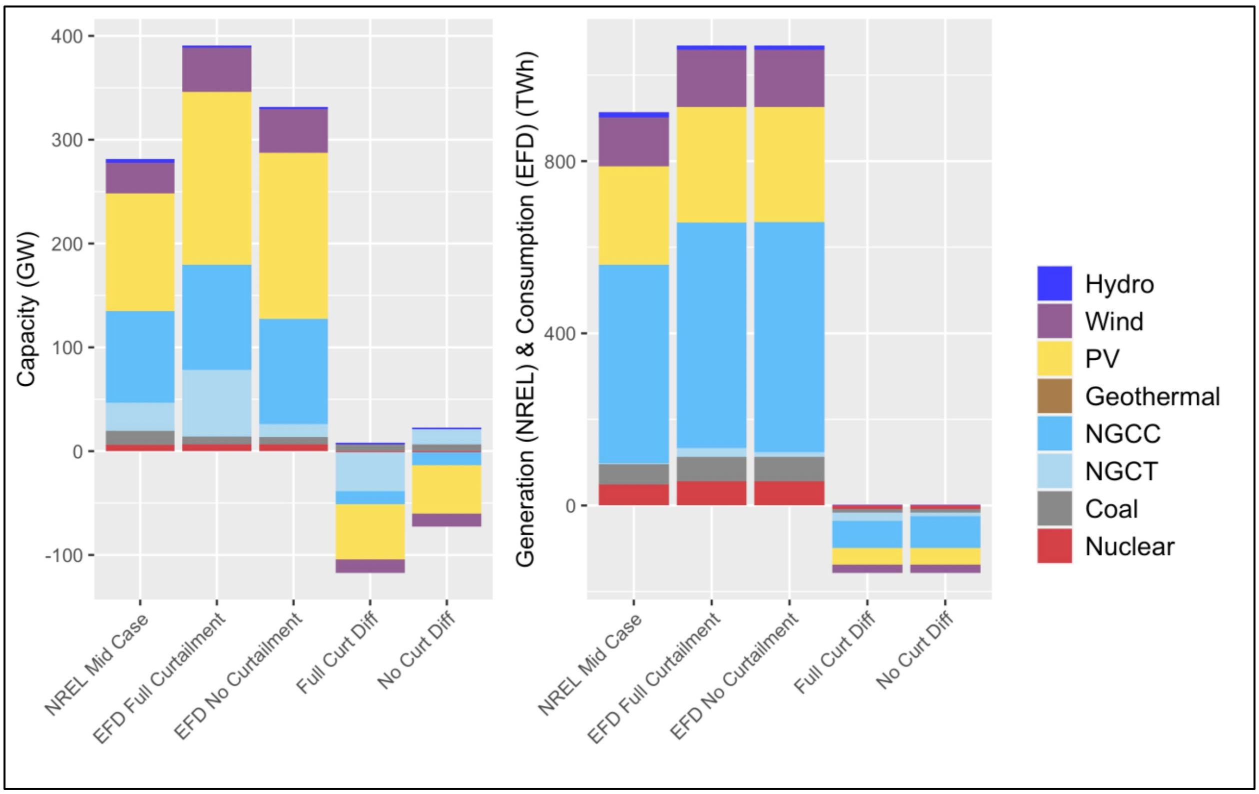
Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

All generation differences by technology are within the 10% margin for both the *full curtailment* and *no curtailment* solutions. The *no curtailment* solution has 12% more capacity from PV, and the *full curtailment* solution has 40% more capacity from PV and 12% more from NGCT. All other capacity differences by technology are less than 10% of the total ReEDS Mid Case capacity.

CO_2 emissions, 2020-2050 (*no curtailment*/*with storage*): The ReEDS Mid Case reports 490 $MtCO_2$ more cumulative emissions than the EFD solution (Table 7). This discrepancy in emissions derives from the EFD calculating 2,031 TWh more cumulative natural gas generation and 627 less cumulative coal generation.

CO_2 emissions, 2020-2050 (*full curtailment*/*no storage*): The EFD *full curtailment* solution reports 460 $MtCO_2$ lower cumulative emissions than the NREL Mid Case Scenario, primarily due to 2,030 TWh more natural gas generation and 627 TWh less coal generation.

Figure S 24 Southeast (SE) Region: Comparisons of results for the year 2050



From the NREL 2020 Standard Scenario Mid Case to the counterpart Scenario L of the EFD, per generation technology, for (left) operating capacity (GW) and (right) generation (TWh).

S.4.9: Results Summary: Florida (FL)

Table S 23 Florida: 2050 *full curtailment* (no storage)

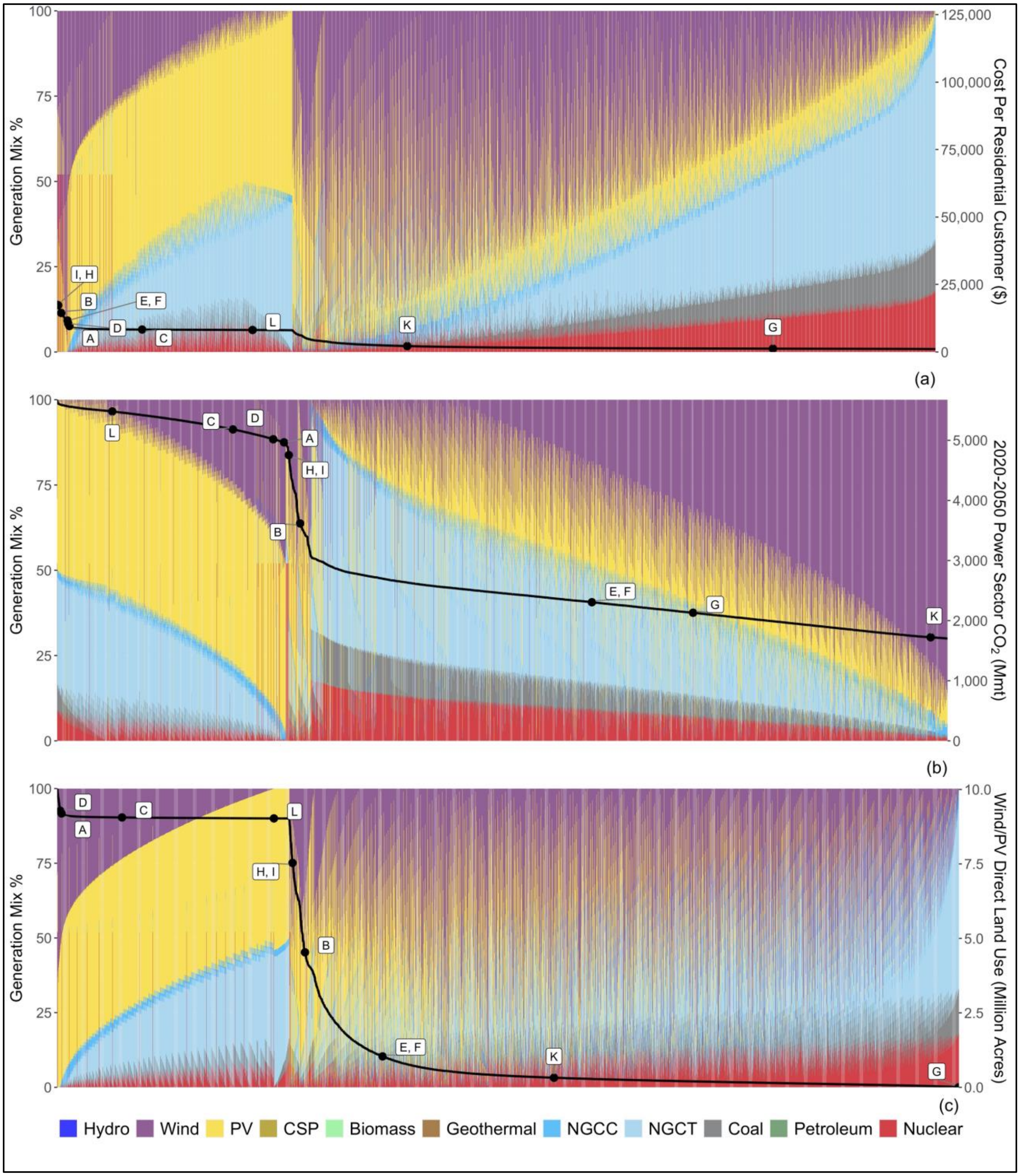
Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
A	0M/49/49/0/2	$9,600	26.0%	24.0%	1,420(3,550)
B	0M/75/25/0/0	$14,000	9.1%	33.0%	1,380(2,240)
C	0M/24/53/0/23	$8,300	26.0%	27.0%	1,750(3,430)
D	0M/53/47/0/1	$11,000	26.0%	24.0%	1,390(3,630)
E	0M/100/0/0/0	$12,000	0.4%	29.0%	1,380(926)
F	0M/100/0/0/0	$12,000	0.4%	29.0%	1,380(926)
G	0M/0/0/52/48	$1,200	-	-	2,120(11.4)
H	0M/31/17/52/0	$17,000	18.0%	38.0%	1,380(3,380)
I	0M/31/17/52/0	$17,000	18.0%	38.0%	1,380(3,380)
J	No Solution	-	-	-	-(-)
K	0M/78/14/1/7	$2,200	0.5%	4.0%	1,530(190)
L	0M/0/50/10/41	$8,100	26.0%	29.0%	2,080(3,410)
NREL Mid	0/0/52/9/39	NA	NA	NA	2,190(-)

Table S 24 Florida: 2050 *no curtailment* (with storage)

Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
A	0M/50/50/0/0	$59,200	1.2%	1.8%	1,380(194)
B	0M/75/25/0/0	$50,500	0.5%	2.0%	1,380(132)
C	0M/25/75/0/0	$89,800	1.8%	1.8%	1,380(260)
D	0M/73/27/0/0	$50,100	0.6%	2.0%	1,380(137)
E	0M/100/0/0/0	$63,100	< 0.1%	2.3%	1,380(75.3)
F	0M/99/1/0/0	$62,300	< 0.1%	2.3%	1,380(76)
G	0M/0/0/52/48	$1,220	-	-	2,120(11.4)
H	0M/31/17/52/1	$31,100	0.4%	0.9%	1,390(81.8)
I	0M/31/17/52/1	$31,100	0.4%	0.9%	1,390(81.8)
J	0M/31/17/52/1	$31,100	0.4%	0.9%	1,390(81.8)
K	0M/0/0/52/48	$1,220	-	-	2,120(11.4)
L	0M/0/52/10/39	$28,200	1.2%	1.4%	2,030(164)
NREL Mid	0/0/52/9/39	NA	NA	NA	2,190(-)

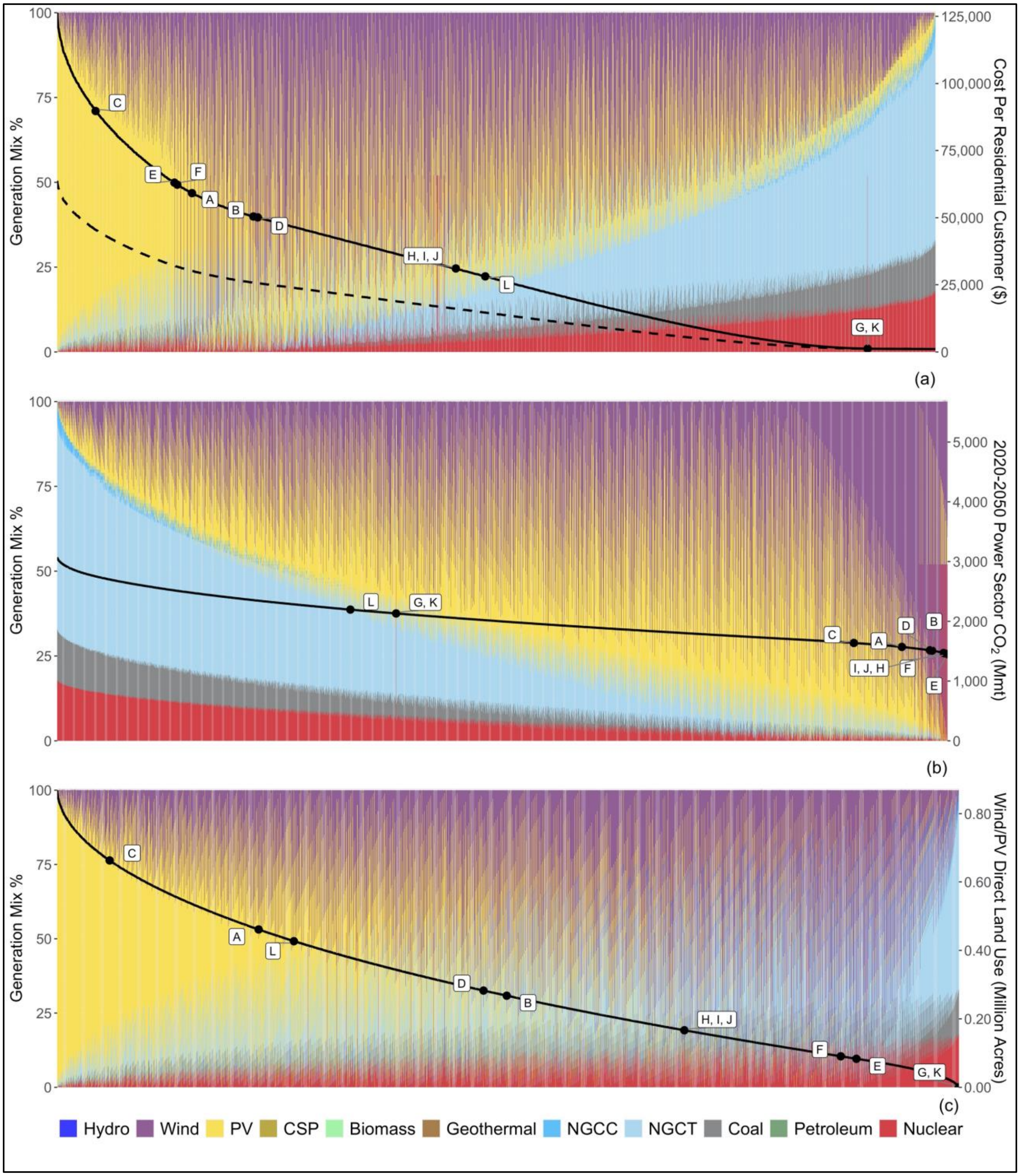
[1] "Disp." refers to dispatchable technologies: coal, natural gas, geothermal, CSP, and biomass. This will mostly consist of coal and natural gas in many regions.
[2] We report carbon emissions from generation as well as emissions embodied in power plants. This is indicated in the final column as "emission from generation (embodied emissions)".
Green cells highlight the lowest value per column. Minimum emissions is based on summing emissions from power generation and embodied in power plants.

Figure S 25 Florida scenarios for the *full curtailment (no storage)* solution



Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

Figure S 26 Florida scenarios for the *no curtailment (with storage)* solution



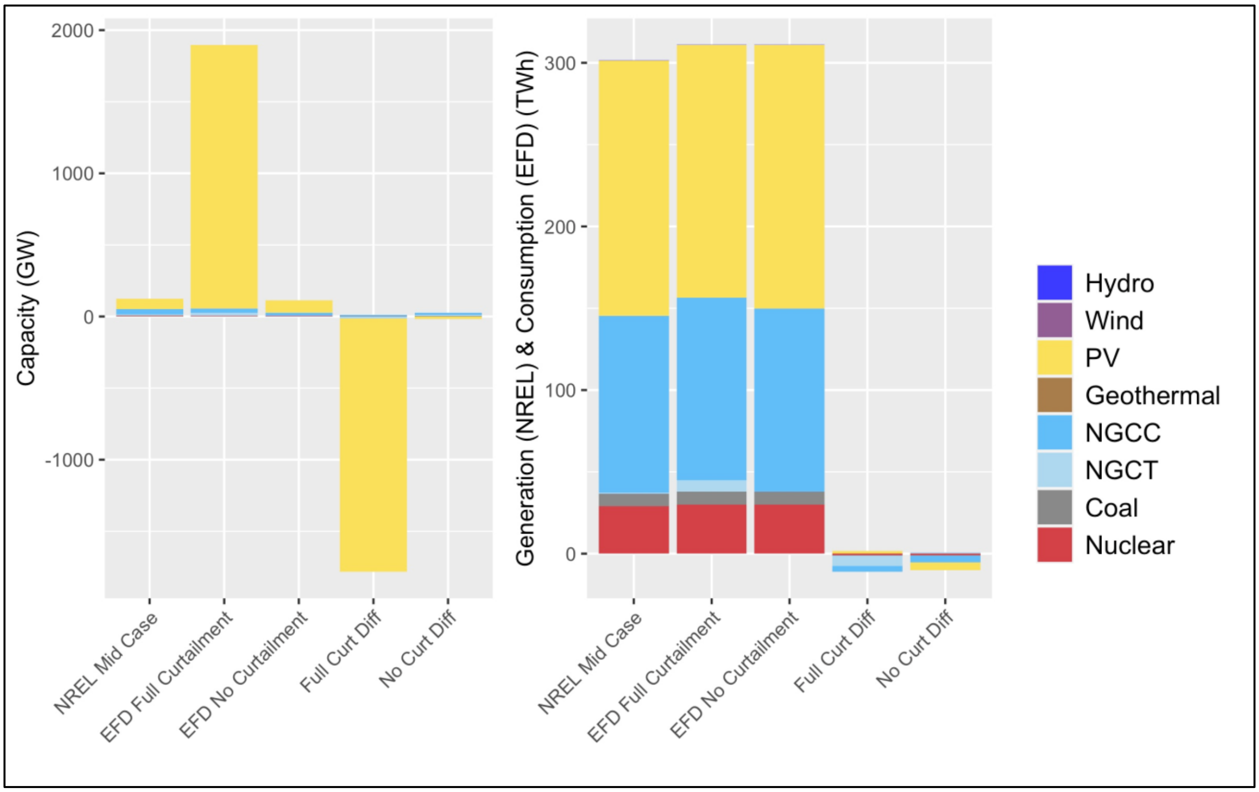
Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

All generation differences by technology are within the 10% margin for both the *full curtailment* and *no curtailment* solutions. The *no curtailment* solution has 13% more capacity from PV and 13% less from NGCC when compared to the ReEDS Mid Case total capacity. Additionally, in the *full curtailment* solution, the EFD has 1,429% more capacity from PV and 11% more from NGCT. All other capacity differences by technology are less than 10% of the total ReEDS Mid Case capacity.

CO_2 emissions, 2020-2050 (*no curtailment/with storage*): The ReEDS Mid Case reports 160 $MtCO_2$ more cumulative emissions than the EFD solution (Table 7). This discrepancy in emissions derives from the EFD calculating 260 TWh more cumulative natural gas generation and 1.55 less cumulative coal generation.

CO_2 emissions, 2020-2050 (*full curtailment/no storage*): The EFD *full curtailment* solution reports 110 $MtCO_2$ lower cumulative emissions than the NREL Mid Case Scenario, primarily due to 361 TWh more cumulative natural gas generation and 1.55 less cumulative coal generation.

Figure S 27 Florida (FL) Region: Comparisons of results for the year 2050



From the NREL 2020 Standard Scenario Mid Case to the counterpart Scenario L of the EFD, per generation technology, for (left) operating capacity (GW) and (right) generation (TWh).

S.4.10: Results Summary: New York (NY)

Table S 25 New York: 2050 *full curtailment* (no storage)

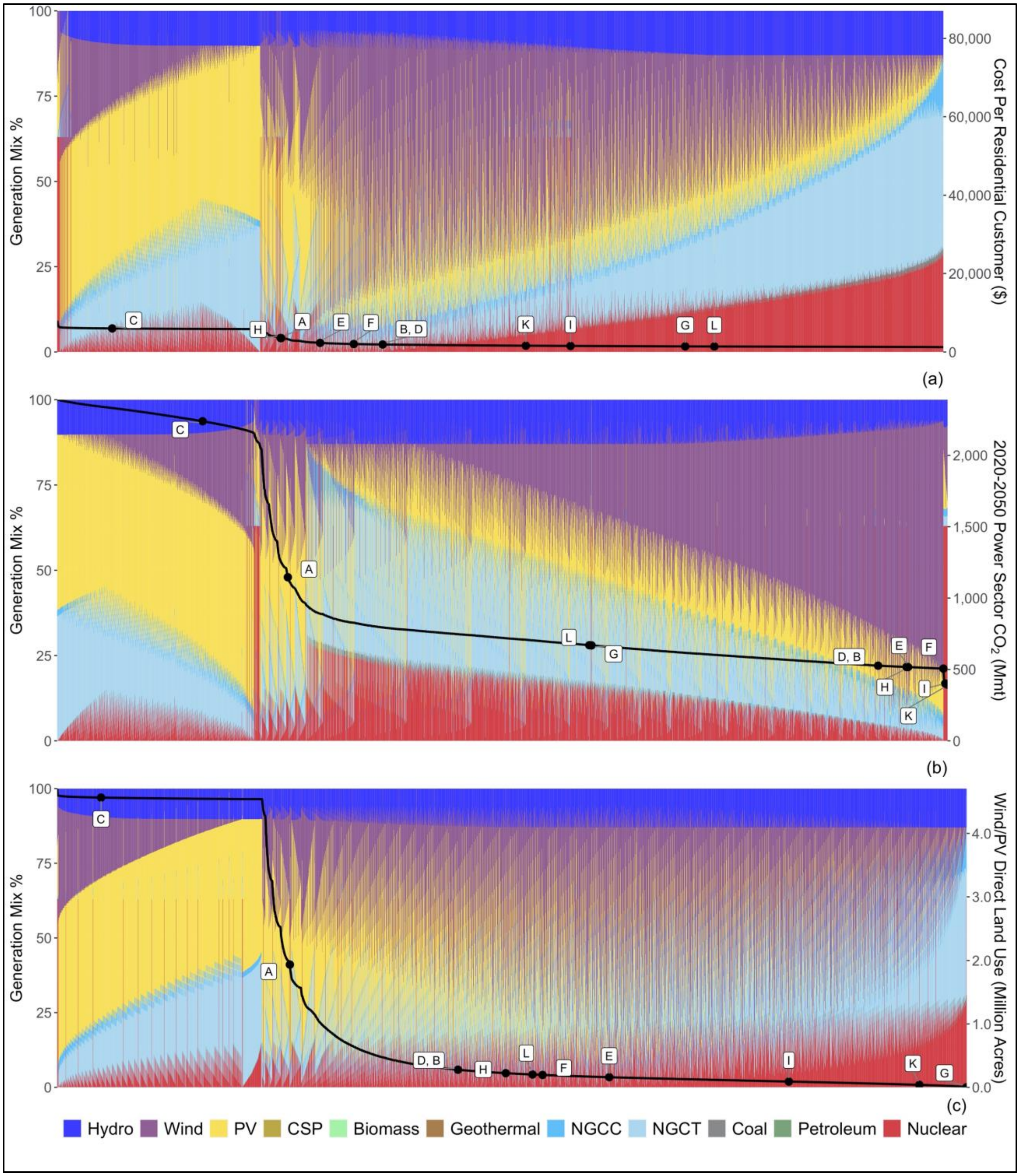
Scenario	Hyd/Wind/PV/Nuc/Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
A	6M/44/43/0/7	$3,500	6.2%	11.0%	383(763)
B	6M/65/22/0/7	$1,900	0.7%	7.3%	380(146)
C	10M/21/50/0/20	$6,000	15.0%	18.0%	502(1,740)
D	6M/65/22/0/7	$1,900	0.7%	7.3%	380(146)
E	6M/84/3/0/7	$2,300	0.2%	12.0%	385(131)
F	6M/75/12/0/7	$2,000	0.4%	8.9%	379(127)
G	0M/0/0/63/37	$1,400	-	-	661(7.63)
H	0M/36/0/63/1	$3,600	0.3%	19.0%	313(204)
I	8M/14/10/63/5	$1,500	0.3%	1.4%	354(46.9)
J	No Solution	-	-	-	-(-)
K	8M/22/2/63/5	$1,600	0.1%	2.3%	360(33.8)
L	13M/31/27/0/29	$1,400	0.6%	2.6%	579(90.9)
NREL Mid	20/31/27/27/25	NA	NA	NA	487(-)

Table S 26 New York: 2050 *no curtailment* (with storage)

Scenario	Hyd/Wind/PV/Nuc/Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
A	11M/44/43/0/2	$37,000	0.9%	3.5%	320(126)
B	10M/65/22/0/3	$29,700	0.5%	4.5%	325(91.5)
C	12M/22/65/0/1	$59,500	1.3%	2.6%	311(165)
D	12M/33/54/0/1	$47,100	1.1%	3.1%	314(146)
E	12M/33/54/0/1	$47,100	1.1%	3.1%	314(146)
F	12M/33/54/0/1	$47,100	1.1%	3.1%	314(146)
G	0M/0/0/63/37	$1,420	-	-	661(7.63)
H	0M/24/13/63/0	$21,800	0.3%	1.8%	301(50.4)
I	10M/16/8/63/4	$8,400	0.2%	1.1%	336(33.5)
J	10M/13/11/63/3	$8,920	0.2%	1.0%	331(38.4)
K	0M/0/0/63/37	$1,420	-	-	661(7.63)
L	13M/31/27/0/28	$7,960	0.5%	2.4%	568(81.6)
NREL Mid	20/31/27/27/25	NA	NA	NA	487(-)

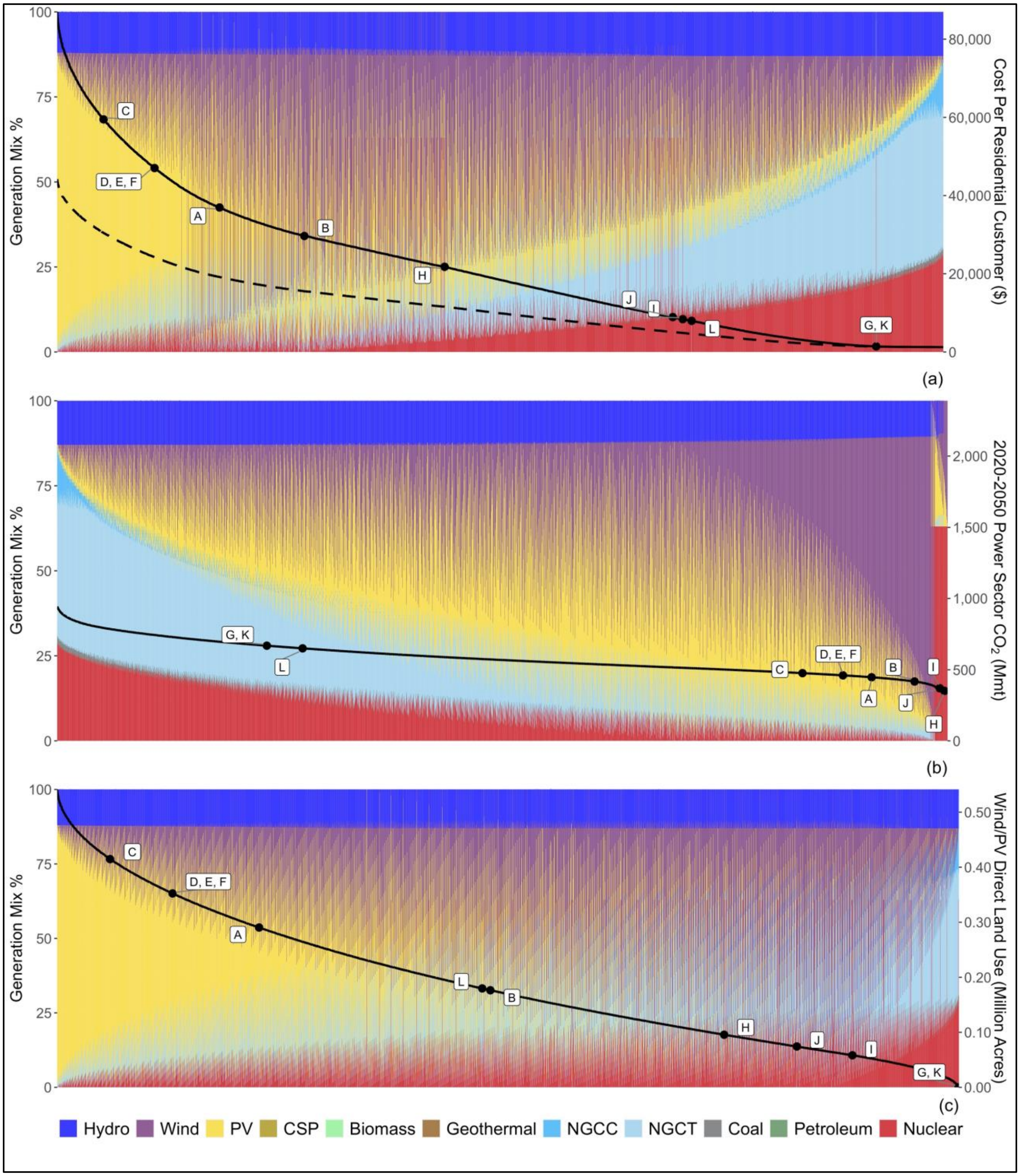
[1] "Disp." refers to dispatchable technologies: coal, natural gas, geothermal, CSP, and biomass. This will mostly consist of coal and natural gas in many regions.
[2] We report carbon emissions from generation as well as emissions embodied in power plants. This is indicated in the final column as "emission from generation (embodied emissions)".
Green cells highlight the lowest value per column. Minimum emissions is based on summing emissions from power generation and embodied in power plants.

Figure S 28 New York scenarios for the *full curtailment (no storage)* solution



Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

Figure S 29 New York scenarios for the *no curtailment (with storage)* solution



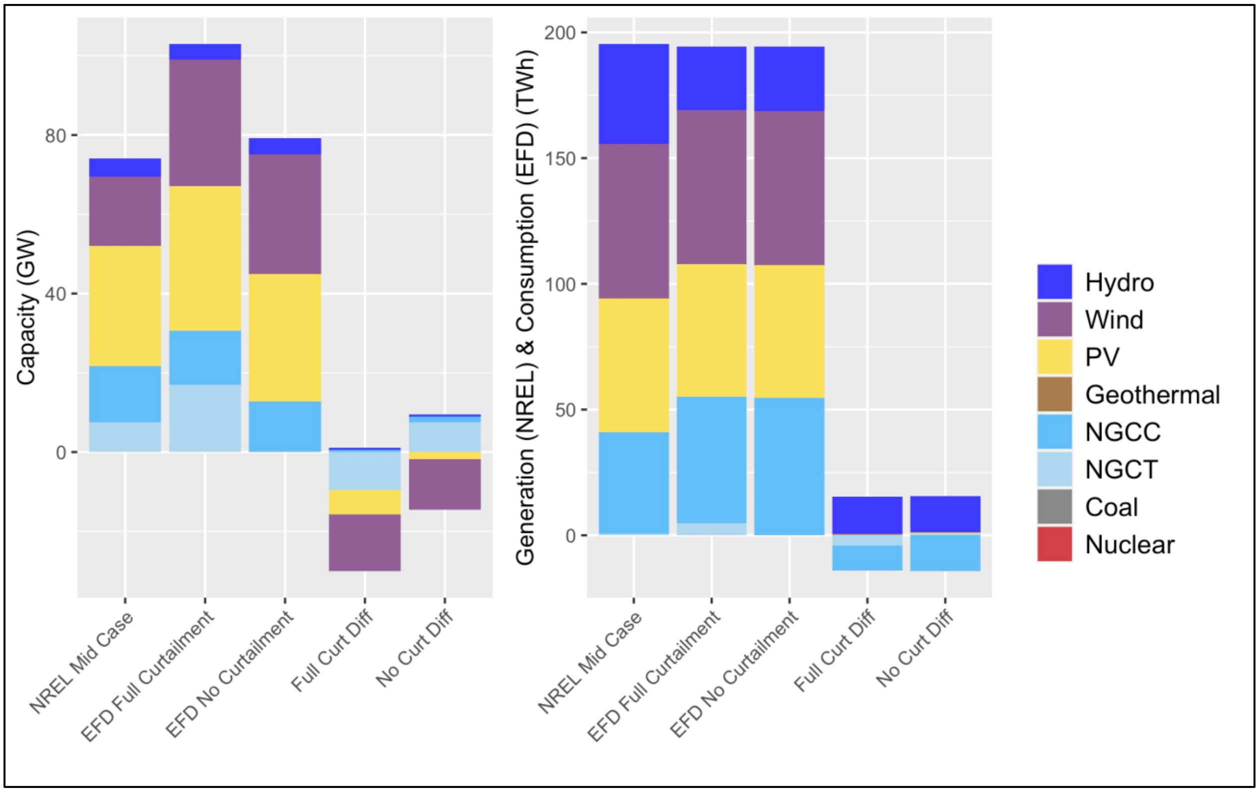
Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

All generation differences by technology are within the 10% margin for both the *full curtailment* and *no curtailment* solutions. The *no curtailment* solution has 17% more capacity from wind and 14% less from NGCT when compared to the ReEDS Mid Case total capacity. Additionally, in the *full curtailment* solution, the EFD has 19% more capacity from wind and 13% more from NGCT. All other capacity differences by technology are less than 10% of the total ReEDS Mid Case capacity.

CO_2 emissions, 2020-2050 (*no curtailment*/*with storage*): The ReEDS Mid Case reports 81 $MtCO_2$ less cumulative emissions than the EFD solution (Table 7**Error! Reference source not found.**). This discrepancy in emissions derives from the EFD calculating 433 TWh more cumulative natural gas generation and 25 less cumulative coal generation.

CO_2 emissions, 2020-2050 (*full curtailment*/*no storage*): The EFD *full curtailment* solution reports 92 $MtCO_2$ higher cumulative emissions than the NREL Mid Case Scenario, primarily due to 438 TWh more cumulative natural gas generation and 25 less cumulative coal generation.

Figure S 30 New York (NY) Region: Comparisons of results for the year 2050



From the NREL 2020 Standard Scenario Mid Case to the counterpart Scenario L of the EFD, per generation technology, for (left) operating capacity (GW) and (right) generation (TWh).

S.4.11: Results Summary: New England (NE)

Table S 27 New England: 2050 *full curtailment* (no storage)

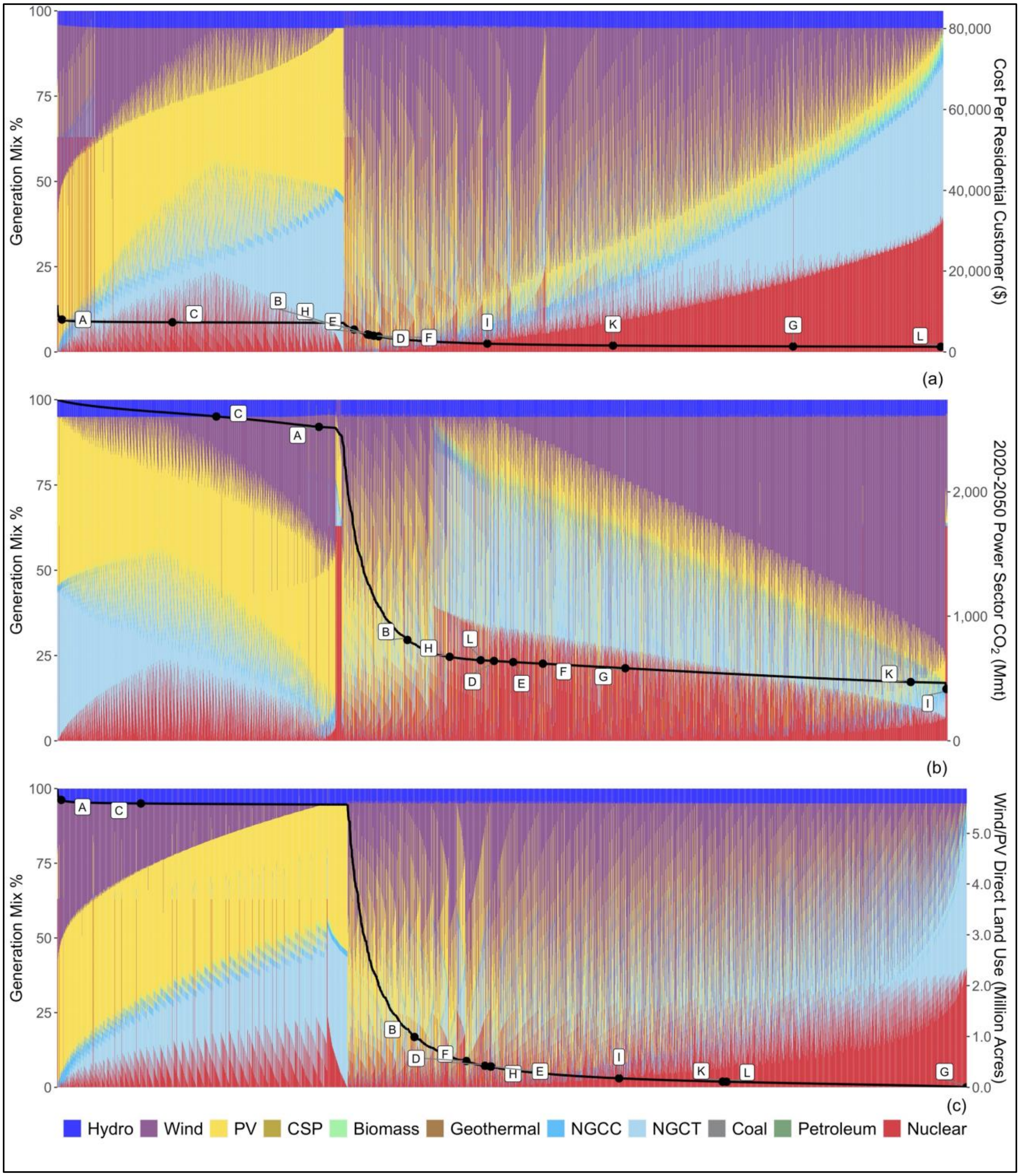
Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
A	4M/47/45/0/4	$8,000	14.0%	25.0%	342(2,180)
B	4M/71/24/0/1	$4,200	2.2%	29.0%	314(497)
C	5M/23/48/0/24	$7,300	14.0%	17.0%	487(2,120)
D	4M/81/14/0/1	$3,900	1.1%	30.0%	313(328)
E	4M/89/6/0/1	$4,300	0.8%	37.0%	313(319)
F	4M/86/9/0/1	$4,000	0.8%	33.0%	313(306)
G	0M/0/0/63/37	$1,400	-	-	577(5.52)
H	0M/37/0/63/0	$5,500	0.7%	47.0%	306(369)
I	4M/25/7/63/1	$2,100	0.4%	7.5%	313(103)
J	No Solution	-	-	-	-(-)
K	5M/61/11/10/13	$1,600	0.2%	5.9%	403(69.3)
L	6M/27/20/7/40	$1,300	0.3%	2.0%	597(50.8)
NREL Mid	20/27/21/7/25	NA	NA	NA	472(-)

Table S 28 New England: 2050 *no curtailment* (with storage)

Scenario	Hyd/Wind/PV/Nuc/ Disp[1] (%)	Annual Cost Per Customer ($)	Direct Land Use	Total Land Use	Carbon Emissons[2] (Mmt)
A	5M/48/47/0/0	$41,400	0.6%	3.5%	304(103)
B	5M/71/24/0/0	$33,300	0.3%	4.7%	304(74.5)
C	5M/24/71/0/0	$61,000	0.8%	2.3%	306(134)
D	5M/72/23/0/0	$33,300	0.3%	4.8%	304(73.3)
E	5M/95/0/0/0	$40,700	0.1%	6.0%	304(47.4)
F	5M/94/1/0/0	$40,100	0.1%	6.0%	304(48)
G	0M/0/0/63/37	$1,380	-	-	577(5.52)
H	0M/18/17/63/3	$14,900	0.2%	1.4%	326(41.9)
I	5M/18/13/63/2	$13,400	0.2%	1.3%	319(34.2)
J	5M/12/18/63/3	$13,900	0.2%	1.0%	328(40.2)
K	0M/0/0/63/37	$1,380	-	-	577(5.52)
L	6M/27/20/7/40	$4,580	0.2%	1.9%	591(47.4)
NREL Mid	20/27/21/7/25	NA	NA	NA	472(-)

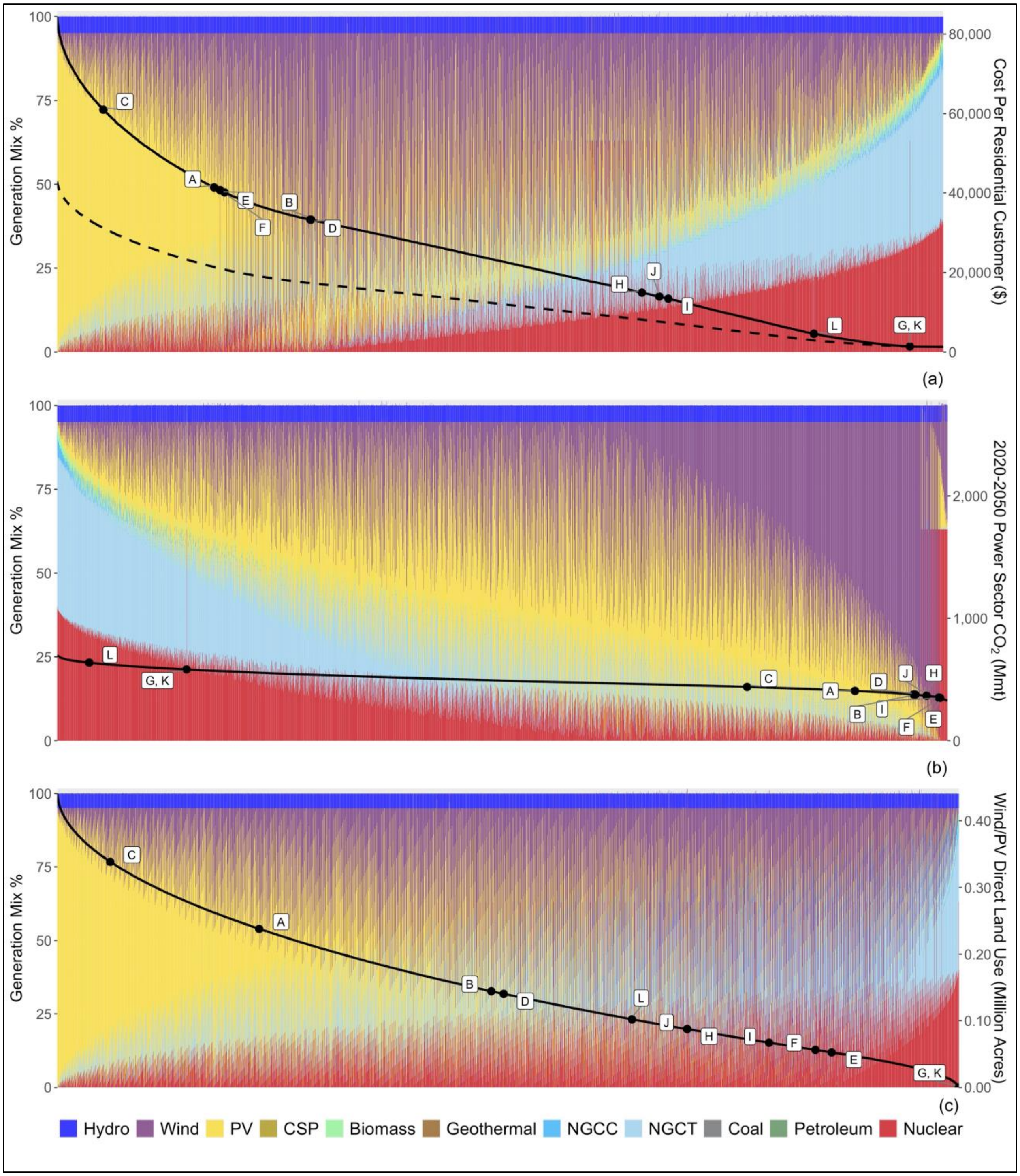
[1] "Disp." refers to dispatchable technologies: coal, natural gas, geothermal, CSP, and biomass. This will mostly consist of coal and natural gas in many regions.
[2] We report carbon emissions from generation as well as emissions embodied in power plants. This is indicated in the final column as "emission from generation (embodied emissions)".
Green cells highlight the lowest value per column. Minimum emissions is based on summing emissions from power generation and embodied in power plants.

Figure S 31 New England scenarios for the *full curtailment* (*no storage*) solution



Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

Figure S 32 New England scenarios for the *no curtailment* (*with storage*) solution



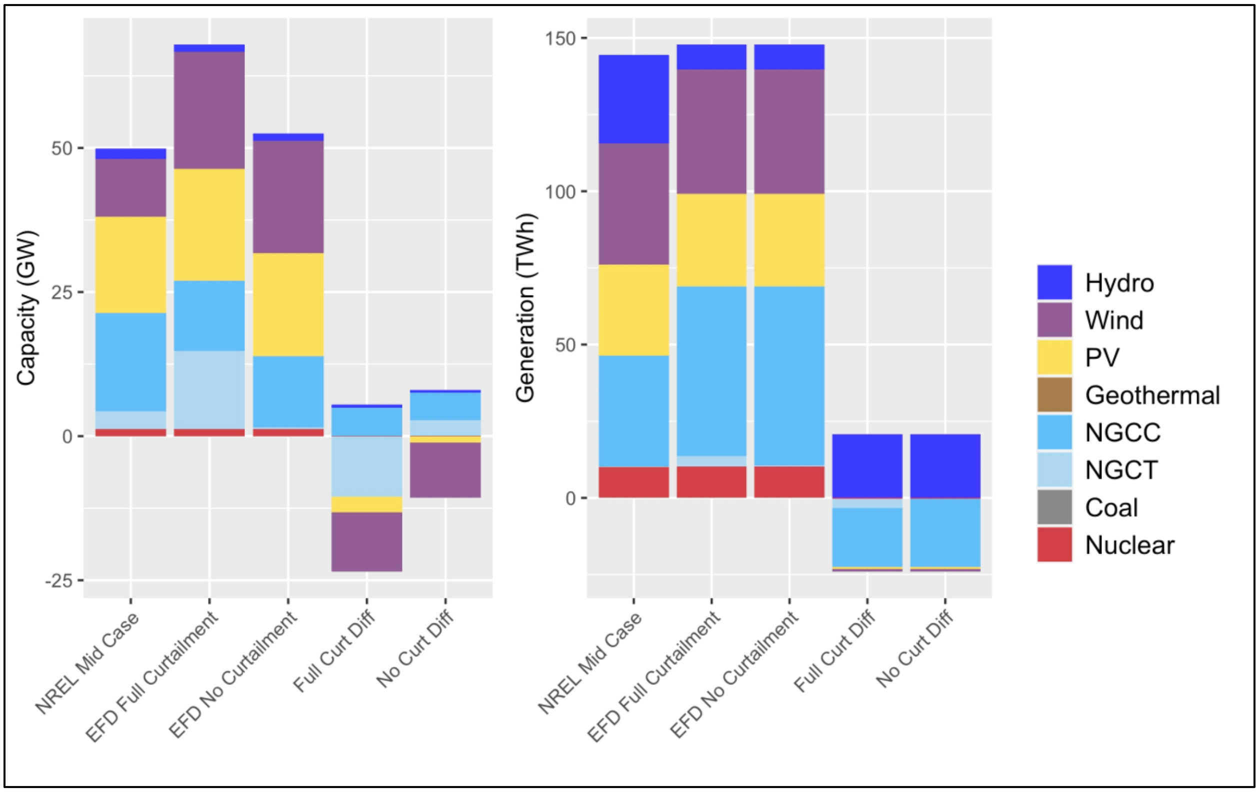
Summarizing how the 2050 electricity mix (left axis, colored vertical bars) relates to metrics (right axis, black line) for (a) annual cost per residential customer ($2017/customer/year), (b) cumulative CO_2 emissions from 2020 to 2050 (including embodied emissions), and (c) direct land use by wind and solar farms (million acres).

Both the *no curtailment* and *full curtailment* solutions show 14% less generation from hydro and 15% and l3% more generation from NGCC respectively when compared to the ReEDS Mid Case. All other generation differences by technology are less than 10% of the total ReEDS Mid Case generation. Additionally, the *no curtailment* solution reports 19% more capacity from wind and 10% less from NGCC. The *full curtailment* solutions report 21% more capacity from wind, 10% less from NGCC, and 21% more from NGCT when compared to the ReEDS Mid Case. All other capacity differences by technology are less than 10% of the total ReEDS Mid Case capacity.

CO_2 emissions, 2020-2050 (*no curtailment*/*with storage*): The ReEDS Mid Case reports 119 $MtCO_2$ less cumulative emissions than the EFD solution (Table 7). This discrepancy in emissions derives from the EFD calculating 475 and 16 TWh more cumulative natural gas and coal generation respectively.

CO_2 emissions, 2020-2050 (*full curtailment*/*no storage*): The difference for 2020-2050 CO_2 emissions remain roughly the same for the *full curtailment*/*no storage* solution.

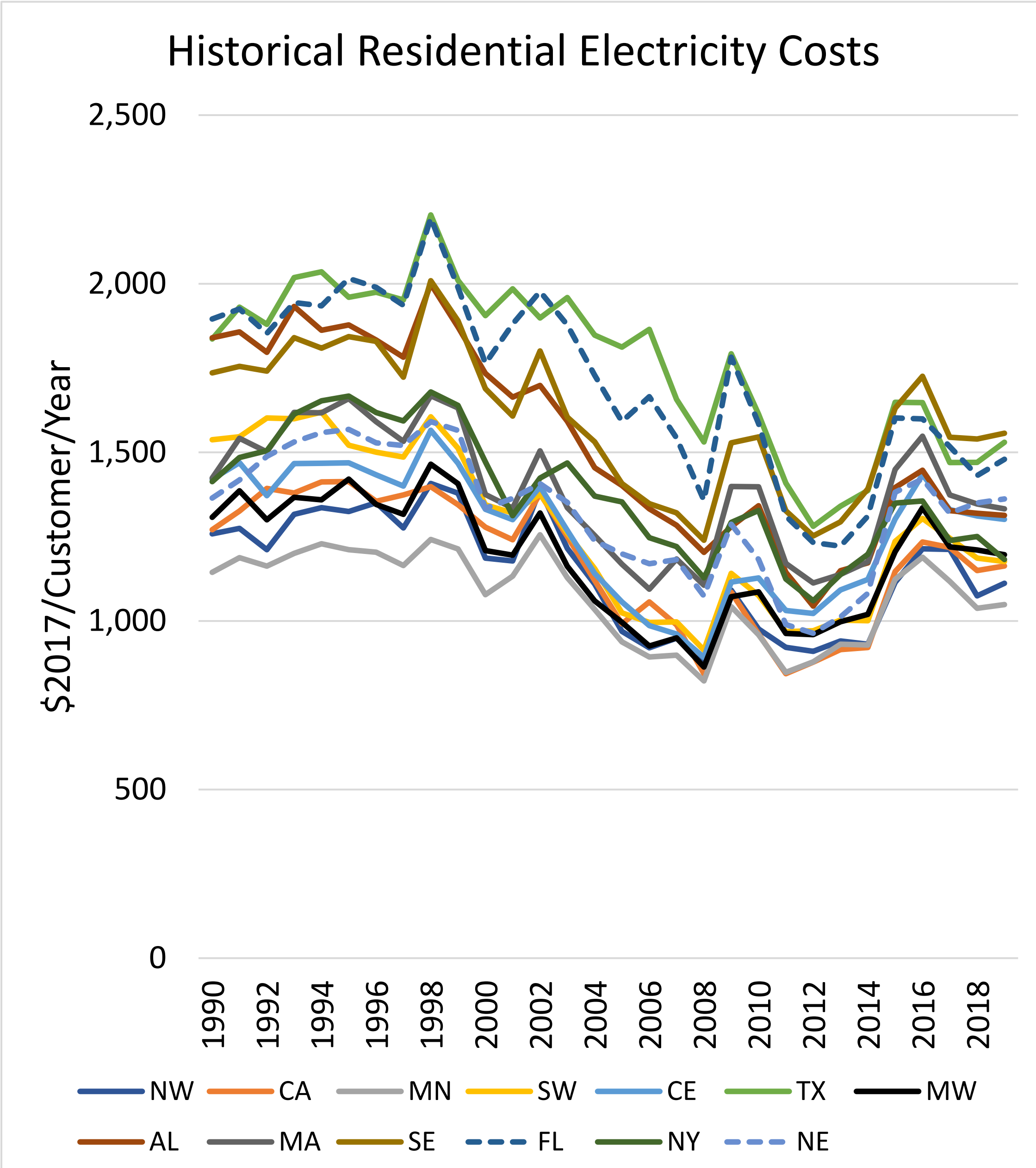
Figure S 33 New England (NE) Region: Comparisons of results for the year 2050



From the NREL 2020 Standard Scenario Mid Case to the counterpart Scenario L of the EFD, per generation technology, for (left) operating capacity (GW) and (right) generation (TWh).

S.5 Historical Electricity Costs Per Residential Customer

Figure S 34 Data from Energy Information Administration Form 861



Summarizing the annual electricity expenditures for residential customers per EFD region (= residential revenues ($) / residential sales (kWh) / residential customers).