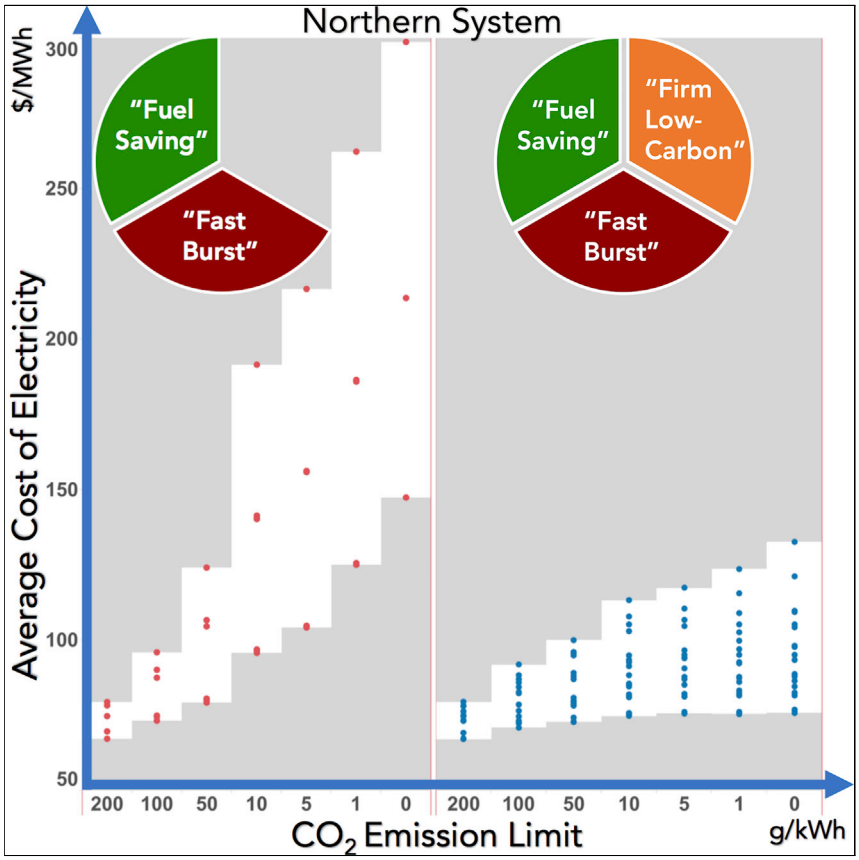
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The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation



Full decarbonization of the electricity sector is critical to global climate mitigation. Across a wide range of sensitivities, firm low-carbon resources—including nuclear power, bioenergy, and natural gas plants that capture CO_2—consistently lower the cost of decarbonizing electricity generation. Without these resources, costs rise rapidly as CO_2 limits approach zero. Batteries and demand flexibility do not obviate the value of firm resources. Improving the capabilities and spurring adoption of firm low-carbon technologies are key research and policy goals.

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HIGHLIGHTS

Firm low-carbon resources consistently lower decarbonized electricity system costs

Availability of firm low-carbon resources reduces costs 10%–62% in zero-CO_2 cases

Without these resources, electricity costs rise rapidly as CO_2 limits near zero

Batteries and demand flexibility do not substitute for firm low-carbon resources

Sepulveda et al., Joule 2, 1–18
October 17, 2018 © 2018 Elsevier Inc.
https://doi.org/10.1016/j.joule.2018.08.006

Please cite this article in press as: Sepulveda et al., The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation, Joule (2018), https://doi.org/10.1016/j.joule.2018.08.006

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The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation

Nestor A. Sepulveda,[1,2,4,*] Jesse D. Jenkins,[2] Fernando J. de Sisternes,[3] and Richard K. Lester[1,*]

SUMMARY

We investigate the role of firm low-carbon resources in decarbonizing power generation in combination with variable renewable resources, battery energy storage, demand flexibility, and long-distance transmission. We evaluate nearly 1,000 cases covering varying CO_2 limits, technological uncertainties, and geographic differences in demand and renewable resource potential. Availability of firm low-carbon technologies, including nuclear, natural gas with carbon capture and sequestration, and bioenergy, reduces electricity costs by 10%–62% across fully decarbonized cases. Below 50 gCO_2/kWh, these resources lower costs in the vast majority of cases. Additionally, as emissions limits decrease, installed capacity of several resources changes non-monotonically. This underscores the need to evaluate near-term policy and investment decisions based on contributions to long-term decarbonization rather than interim goals. Installed capacity for all resources is also strongly affected by uncertain technology parameters. This emphasizes the importance of a broad research portfolio and flexible policy support that expands rather than constrains future options.

INTRODUCTION

Full decarbonization of the electric power sector will be pivotal to global climate mitigation efforts. The Paris Climate Agreement of 2015—ratified by 176 countries to date—declares the need to hold increases in global average temperatures to "well below" 2°C and to achieve a net balance of anthropogenic sources and sinks of greenhouse gases by the second half of this century.[1,2] To reach these goals, recent studies have concluded that CO_2 emissions from electricity generation must fall nearly to zero[3–5] or even below zero[6–8] by mid-century, even as electricity generation expands to supply a greater share of transportation, heating, and industrial energy use.[3,9–11]

Despite general agreement on the need for deep decarbonization of the electric power sector, views differ as to the relative importance of various low-carbon electricity resources in near-zero-emissions power systems.

Technological developments have enlarged the array of low-carbon electricity generation resources to include solar, wind, hydro, biomass, nuclear, geothermal, and fossil energy with carbon capture and sequestration (CCS). Technologies for energy storage and for managing electricity demand are also available. The economic and operational characteristics of these resources vary, as does their ability to contribute to meeting electricity demand reliably. As a result of this diversity, power systems are

Context & Scale

Mitigating climate change while fueling economic growth requires decarbonizing the electricity sector at reasonable cost. Some strategies focus on wind and solar energy, supported by energy storage and demand flexibility. Others also harness "firm" low-carbon resources such as nuclear, reservoir hydro, geothermal, bioenergy, and fossil plants capturing CO_2. This paper presents a comprehensive techno-economic evaluation of two pathways: one reliant on wind, solar, and batteries, and another also including firm low-carbon options (nuclear, bioenergy, and natural gas with carbon capture and sequestration). Across all cases, the least-cost strategy to decarbonize electricity includes one or more firm low-carbon resources. Without these resources, electricity costs rise rapidly as CO_2 limits approach zero. Batteries and demand flexibility do not substitute for firm resources. Improving the capabilities and spurring adoption of firm low-carbon technologies are key research and policy goals.

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likely to benefit from harnessing a blend of resources, with the various resource types playing complementary roles and adding distinct value to the overall mix of energy services.

Electricity generation technologies have traditionally been classified based on their relative variable costs and the resulting frequency with which they are called upon to meet electricity demand or "load"; e.g., "baseload," "load-following," and "peaking" resources. This classification is no longer meaningful in power systems with substantial penetration of wind and solar energy, since dispatch of each technology is also driven by the irregular variability of these renewable resources. Moreover, most available low-carbon technologies are capital intensive and have very low variable costs. In this context, the distinguishing attributes of electricity technologies relate more to their resource availability and ability to adapt production output in order to meet instantaneous demand. We therefore propose a new taxonomy that divides low-carbon electricity technologies into three different sub-categories (see Figure S1):

1. "Fuel-saving" variable renewable energy (VRE) resources. These include wind power, solar photovoltaics (PV), concentrating solar power, and run-of-river hydropower. They harness renewable energy inputs (wind, solar insolation, water) that vary on timescales ranging from seconds to hours to seasons, have zero (or near-zero) variable costs, and have no fuel costs. At lower penetration levels, they may displace the need for firm capacity, but, at higher shares, capacity needs are driven by periods with low VRE availability. At high energy shares, these technologies therefore contribute value primarily by displacing other higher variable cost generating technologies whenever available and reducing the total fuel consumption and variable costs of the system.
2. "Fast-burst" balancing resources. These include short-duration energy storage (e.g., Li-ion batteries), flexible demand (or schedulable loads), and demand response (or price-responsive demand curtailment). They are either energy constrained (storage, demand flexibility) or have very high variable cost (demand curtailment). These technologies are therefore poorly suited to operating continuously over long periods of time and are better used during high-value periods when relatively fast bursts of power or quick demand adjustments are needed to balance supply and demand.
3. "Firm" low-carbon resources. These are technologies that can be counted on to meet demand when needed in all seasons and over long durations (e.g., weeks or longer) and include nuclear power plants capable of flexible operations,[12–15] hydro plants with high-capacity reservoirs, coal and natural gas plants with CCS and capable of flexible operations,[16,17] geothermal power, and biomass- and biogas-fueled power plants.[7]

In light of recent cost improvements and the rapid expansion of wind power and solar photovoltaics, many recent papers have explored opportunities and challenges associated with achieving very high shares of these VRE resources in power systems.[18–33] Much of this work has focused on how to provide the enhanced operational flexibility on various time scales (from seconds to seasons) needed to balance variable output from high shares of wind and solar energy,[21–23,28] including the potential role of energy storage,[24,29,34,35] demand-side flexibility,[20] and long-distance transmission expansion to smooth variability of renewable output across wider geographic areas.[20,27,31]

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Some of this work has excluded firm low-carbon resources *ex ante*, in part because of the societal challenges or current costs associated with some of these resources. Other research[17,23,34–36] has found that harnessing firm low-carbon resources capable of responding to variations in both demand and renewable energy output can lower the cost of low-carbon power systems by reducing the amount of needed generating and storage capacity, improving asset utilization, and avoiding substantial curtailment of renewable energy output. These studies have typically focused on the role of a specific resource (e.g., energy storage[34,35] or CCS[17]) and have explored a relatively narrow range of possible uncertainties.[23]

Global deployment of nuclear and CCS is lagging well behind the pace envisioned by scenarios to limit global warming to 2°C in the 2014 Intergovernmental Panel on Climate Change assessment report.[37] Both technologies face a range of challenges to greater adoption, including high construction costs and financial risks, technology immaturity (in the case of CCS and next-generation nuclear designs), and risk (both real and perceived). Use of biomass for energy is currently on pace with global 2°C scenarios,[37] but large-scale reliance on bioenergy for power generation competes with other land uses, including food and environmental conservation, as well as other uses for bioenergy in transportation, heat, and industrial sectors. Other firm low-carbon resources are constrained to specific favorable geographies (conventional geothermal, reservoir hydropower), entail significant environmental impacts (reservoir hydro), or remain pre-commercial (enhanced geothermal energy systems). Overcoming challenges to large-scale use of these firm low-carbon resources may prove difficult. Whether it makes sense to take on this task depends partly on the benefits associated with having one or more viable firm low-carbon resources available to contribute to power sector decarbonization.

In this paper we provide a more comprehensive evaluation of the economic and operational benefits of firm low-carbon technologies in achieving deep decarbonization targets, with a focus on nuclear, natural gas with CCS, biogas, and biomass. The analysis examines the interactions between these firm low-carbon resources; fuel-saving variable renewable resources; and fast-burst resources, including short-duration battery energy storage and demand-side flexibility. It also investigates the impact of long-distance transmission interconnections.

We use an advanced electric power system investment and operations model[38] to compare, under several increasingly ambitious decarbonization targets, the economic performance of two kinds of power systems: those that include firm low-carbon technologies among the available resources, and those that exclude these firm resources *ex ante*. Operational details captured by the model include a full year of hourly chronological variability in both renewable energy output and electricity demand and detailed power system operating constraints such as integer power plant start-up and shut-down costs, minimum stable output limits for thermal power plants, and limits on hourly changes in power plant output. Commonly used but simpler models can result in significant errors due to abstraction of relevant power system details and the failure to account for the full variability of renewable resources and inter-temporal constraints on energy storage and thermal power plants.[26,39–42]

A large number of scenarios are analyzed. First, we account for geographic differences in renewable resource potential and patterns of demand using data from two dissimilar US regions: a "northern" system with the demand profile and relatively modest renewable resource potential typical of New England (peak demand of

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Table 1. Technological Assumptions

Technology	Conservative	Mid-range	Very Low
Solar ($/kW-AC)	1,800[a]	900[b]	670[c]
Wind ($/kW)	1,455[d]	1,091[e]	927[f]
4-hr Li-ion battery ($/kWh)	440[g]	220[h]	110[i]
6-hr Li-ion battery ($/kWh)	420[j]	210[j]	105[i]
Natural gas CCGT with CCS ($/kW) ($CO_2$ capture rate)	NA	1,720 (90%)[k]	1,050 (100%)[l]
Nuclear ($/kW) (size)	7,000 (1,000 MW)[m]	4,700 (1,000 MW)[n]	4,200 (300 MW)[o]
Biomass ($/kW) (maximum energy share) ($/MMBTU)	3,800 (5%) (3)[p]	3,800 (5%) (3)[p]	3,400 (35%) (7)[q]
Biogas ($/kW) (maximum energy share) ($/MMBTU)	NA	890 (2%) (7.5)[r]	790 (10%) (15)[r]

CCGT, combined-cycle gas turbine; NA, not available.
[a]From NREL[43] 2017 "Utility PV - Low."
[b]50% cost reduction from conservative.
[c]From NREL[43] 2047 "Utility PV - Low."
[d]From NREL[43] 2017 "Land Base Wind, TRG 1 - Low."
[e]25% cost reduction from conservative.
[f]From NREL[43] 2047 "Land Base Wind, TRG 1 - Low."
[g]From Lazard[44] "Li-ion Peaker Replacement."
[h]50% cost reduction from conservative.
[i]75% cost reduction from conservative.
[j]From Lazard[44] "Distribution Substation."
[k]From NREL[43] 2047 "Gas-CC-CCS - Mid."
[l]Net power N^{th} of a kind plant, May 2015 briefing.
[m]Based on Georgia Public Service Commission.[45]
[n]From NREL[43] 2047 "Nuclear."
[o]From IEA and NEA[46] assuming modular reactor.
[p]From NREL[43] 2017 "Biopower Dedicated - Mid."
[q]From NREL[43] 2047 "Biopower Dedicated - Mid."
[r]From NREL[43] same as gas CT.

34 GW at 4:00 pm on a July weekday), and a "southern" system with the demand profile and higher renewable resource availability characteristic of the Electricity Reliability Corporation of Texas region (peak demand of 94 GW at 4:00 pm on an August weekday).

Second, we account for uncertainties surrounding future technology costs and availabilities by introducing discrete cost assumptions ("conservative," "mid-range," and "very low"; see Table 1) for each of three groupings of technologies: (1) VRE resources (onshore wind and solar PV) and Li-ion battery energy storage (with 4 or 6 hr of output at maximum discharge rate; see footnotes in Table 2). (2) Light-water nuclear reactors and natural gas plants with CCS. (3) Biogas- and solid biomass-fueled plants (see footnotes in Table 2). Using these cost assumptions, we construct and analyze 19 technology cost and availability scenarios (see Table 2). Additionally, we analyze the impact of increasing flexibility in demand scheduling and price-responsive demand curtailment, as well as the effect of increasing long-distance transmission interconnection capacity between the northern and southern systems.

Third, we analyze the economic impact of different emissions reduction targets by modeling each technology and regional scenario subject to seven progressively more stringent CO_2 emissions limits, from 200 gCO_2/kWh down to zero emissions. For context, the direct emissions rate of CO_2 from power generation in the United

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Table 2. Technological Scenarios

Scenario	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
VRE and storage[a,b]	C	M	M	M	L	L	L	M	M	M	L	L	L	M	M	M	L	L	L
Nuclear and CCS[b]	C	C	C	C	C	C	C	M	M	M	M	M	M	L	L	L	L	L	L
Biomass and biogas[b]	C	C	M	L	C	M	L	C	M	L	C	M	L	C	M	L	C	M	L

C, conservative; M, mid-range; L, very low technology cost assumptions (Table 1).

[a]This analysis is limited to lithium-ion battery energy storage systems, which are currently widely scalable, face no geographic constraints, and are expected to benefit from further cost reductions due to economies of scale, learning-by-doing, and spillovers from battery production for electric vehicles. Longer-duration pumped-hydro storage resources are difficult to expand due to siting challenges, and medium- and long-duration energy storage options that may provide longer-duration storage capacity (e.g., days rather than hours) are currently too costly or face scalability challenges. However, if a storage technology capable of supplying several days or more of sustained power output becomes economically and technically viable, this technology could serve as a firm low-carbon resource (unlike shorter-duration battery storage). It would be productive for future research to explore the impact of long-duration energy storage options on deep decarbonization and the cost and performance parameters necessary for very-long-duration storage to cost-effectively contribute to decarbonization.

[b]These resources are grouped in order to keep the number of scenarios manageable. Solar, wind, and battery storage are grouped to reflect the more rapid pace of likely cost declines for these technologies. Nuclear and gas with CCS are likewise grouped based on their relatively high costs and slower rate of likely cost declines. Finally, biomass and biogas resources are grouped to reflect their common feedstocks, with the three technology cases reflecting increasing levels of feedstock supply.

States in 2017 was 436.6 g/kWh. Emissions reductions pledged by the United States under the Paris Agreement use 2005 as a baseline year, in which the CO_2 emissions rate from power generation was 595.8 g/kWh.[47,48]

Altogether we evaluate 912 distinct scenarios. A "core" set of 532 scenarios comprises the 19 technology availability and cost scenarios in each of the two power systems, subject to seven different decarbonization targets with and without firm low-carbon resources. We also consider 380 "sensitivity" scenarios that explore the effects of five different levels of demand-side resource availability and two levels of long-distance transmission capacity linking the two power systems.

To our knowledge, this is the first work to systematically explore the feasibility and cost of achieving deep decarbonization goals (up to 100% reductions in power sector CO_2 emissions) across such a wide range of conditions and technology cost projections. This comprehensive analysis increases the robustness of our findings.

The next two sections of the paper present the results of our analysis, focusing first on our core scenarios and subsequently on the impact of demand-side flexibility and increased regional interconnections. This is followed by a discussion of the policy implications and recommendations, and a description of the experimental procedure and assumptions used in our work.

RESULTS

Core Cases

Across the wide range of technology assumptions and power system characteristics considered in our core scenarios, we find that the availability of firm low-carbon resources consistently reduces the system cost of decarbonizing power generation relative to scenarios in which these resources are excluded from the eligible resource mix. As Figures 1 and S2 illustrate, in the absence of firm low-carbon resources, the cost of decarbonizing power generation rises very rapidly as the emissions limit approaches zero. The cost of full decarbonization (zero CO_2 emissions) without firm resources is from 42% to 163% higher in the northern system, and from 11% to 105% higher in the southern system, relative to cases in which firm low-carbon resources are available. The precise difference in cost depends on specific technology cost

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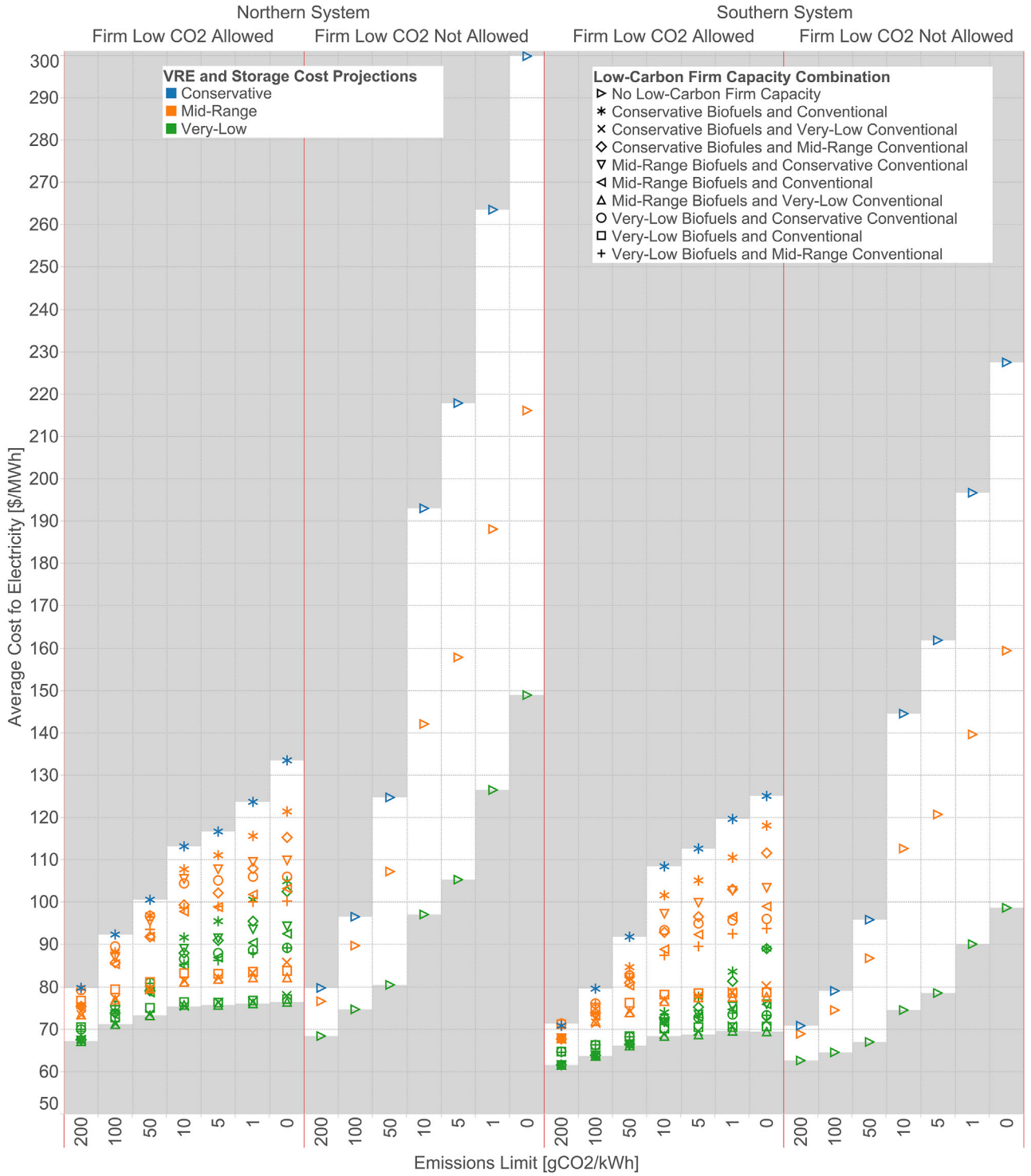


Figure 1. Average Cost of Electricity under Different Technology Assumptions and CO_2 Emission Limits for the Northern and Southern Systems

For cost comparisons, compare visually each of the green (or orange or blue, depending on the VRE and storage cost assumptions) cases in the first panel (where firm resources are included) with the green case in the second panel (where firm resources are excluded). In the "very low" cost projection (green), wind and solar fall by roughly one-third and two-thirds relative to 2017 costs, respectively, and battery costs decline by roughly three-quarters (see Table 1).

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and availability assumptions. Even with very-low-cost projections for wind, solar, and energy storage and conservative assumptions for firm low-carbon resources (i.e., the costs of nuclear, natural gas with CCS, biomass, and biogas resources remain unchanged relative to their current levels), the cost of achieving zero carbon emissions in each region is lower when firm resources are available than when they are not (see Figure 1 legend).

These results suggest that firm low-carbon resources are particularly valuable in regions with more modest renewable energy potential (e.g., the northern system) and that these technologies provide an effective hedge against the risk that additional steep reductions in the cost of variable renewables may not be achieved. More generally, the results indicate that including firm resources in the portfolio of available low-carbon technologies is a more robust strategy for achieving affordable deep decarbonization of power generation.

The rapid increase in system cost as the emission limit approaches zero when firm low-carbon resources are excluded contrasts with the much more gradual increase when firm resources are available (Figure 1). The former behavior is explained by the sharp decline in the marginal energy and marginal capacity substitution value of VRE[49,50] and battery storage[35,36] technologies at high penetration levels. As Figure 2 demonstrates, VRE and batteries are only weak-capacity substitutes for firm low-carbon resources, and significantly more than one megawatt of combined VRE and storage capacity is required to replace one megawatt of firm low-carbon capacity in equally reliable systems achieving the same CO_2 emission reductions. To meet demand reliably during periods of low wind and solar availability, large amounts of VRE capacity must be deployed, along with energy storage to shift available supply from high to low VRE output periods. For zero emissions cases without firm resources, the total required installed generation and storage power capacity in each system would be five to eight times the peak system demand, compared with 1.3–2.6 times peak demand when firm resources are available (see Figure 2 legend). For example, in the northern system assuming mid-range costs for all technologies, the total installed power capacity with firm resources available is 48 GW, including 16 GW of VRE and 4 GW of storage capacity. In the absence of firm resources, the installed capacity of VRE and storage would increase to 130 GW and 47 GW respectively. Additionally, fully decarbonized cases without firm resources feature 320–1,160 GWh of installed energy storage capacity, versus 29–380 GWh when firm resources are available (Figure S15). We also demonstrate the robustness of our findings to the availability of longer-duration storage technologies (see Figures S16–S18).

As VRE penetration increases, a growing share of annual VRE generation occurs during periods when a zero marginal cost resource (e.g., wind, solar) is the marginal generator, reducing the energy substitution or fuel-saving value of VRE. In addition, during periods of abundant wind and solar insolation, large installed VRE capacities produce significant excess supply, and it is not cost-effective to build enough energy storage capacity to accommodate all of this surplus. For example, in a fully decarbonized power system, the amount of available wind and solar output that would be wasted due to curtailment in VRE-dominated scenarios would be sufficient to supply 60%–130% of total annual electricity demand (Figure S3). In contrast, when firm low-carbon capacity can be deployed, wind and solar curtailment is reduced to 0%–14% of total annual demand.

As the CO_2 emissions limit grows more stringent, the energy share of high-carbon resources in the least-cost resource portfolio declines monotonically, as expected.

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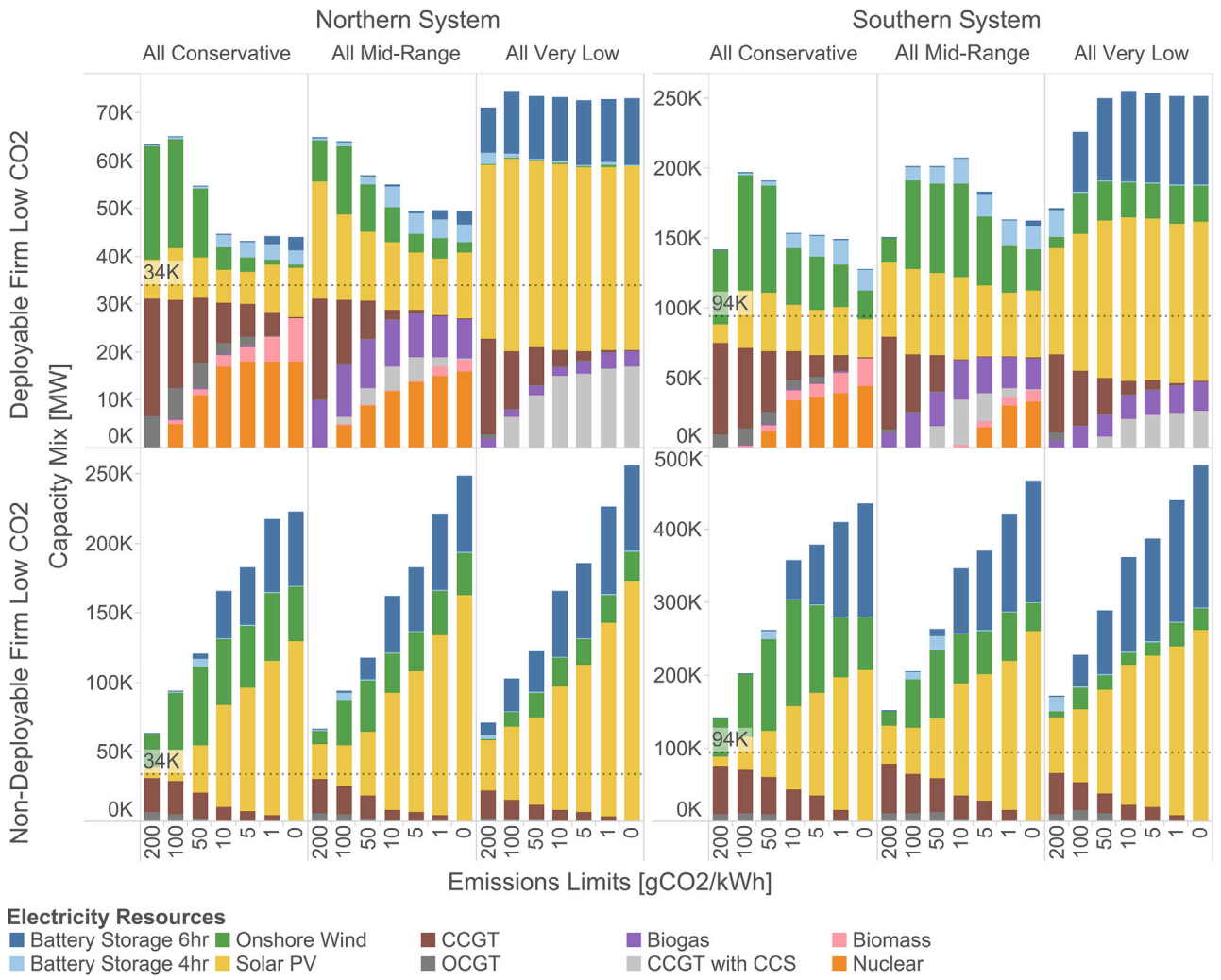


Figure 2. Least-Cost Capacity Mix in the Northern and Southern Systems for Different Carbon Emission Limits

For each system, the plot shows the least-cost capacity mix for the technology scenario combinations of all conservative, all mid-range, and all very low costs for all three groupings of resources, with the northern system on the left and southern system on the right. The top portion of the plot shows the resulting mix when firm low-carbon capacity can be deployed, while the bottom portion shows the resulting mix when these resources are excluded. Note that the y axis has been re-scaled on each sub-plot and a dotted line representing the peak demand of each system has been added as a visual reference. Battery storage capacity has been plotted in instant capacity (MW) instead of energy capacity (MWh) for consistency with generation resources. See Figures S4 and S5 for the capacity mix under the full range of different scenario combinations. CCGT, combined-cycle gas turbine; OCGT, open-cycle gas turbine.

For the cases without low-carbon firm capacity, the outsized installed capacity is driven both by the oversizing of wind and solar capacity and the large volume of energy storage capacity needed to provide sustained energy output during periods of low VRE availability. Commercially available energy storage options such as Li-ion batteries are ill suited to these long-duration storage needs. If firm low-carbon resources are to be eschewed, energy storage resources capable of both sustained output over dozens of hours or longer and very low costs of energy storage capacity suited to low annual utilization rates would be needed.

However, in many scenarios, the energy share of wind and solar in the least-cost portfolio *also declines* as the emission limit continues to tighten (Figure 3). As the penetration of VRE resources increases, the marginal value of additional VRE capacity is linked to its fuel-saving role; that is, to its ability to displace fuel-based generation and thereby to reduce system variable costs. Accordingly, if fossil-fueled generation is replaced by low-carbon firm resources with zero or near-zero marginal costs (i.e., nuclear, hydro, geothermal) as the emission limit tightens, the energy substitution value of wind and solar declines as well (Figure S9). As a result, the energy shares from wind or solar in the least-cost portfolio may fall as the emissions limit

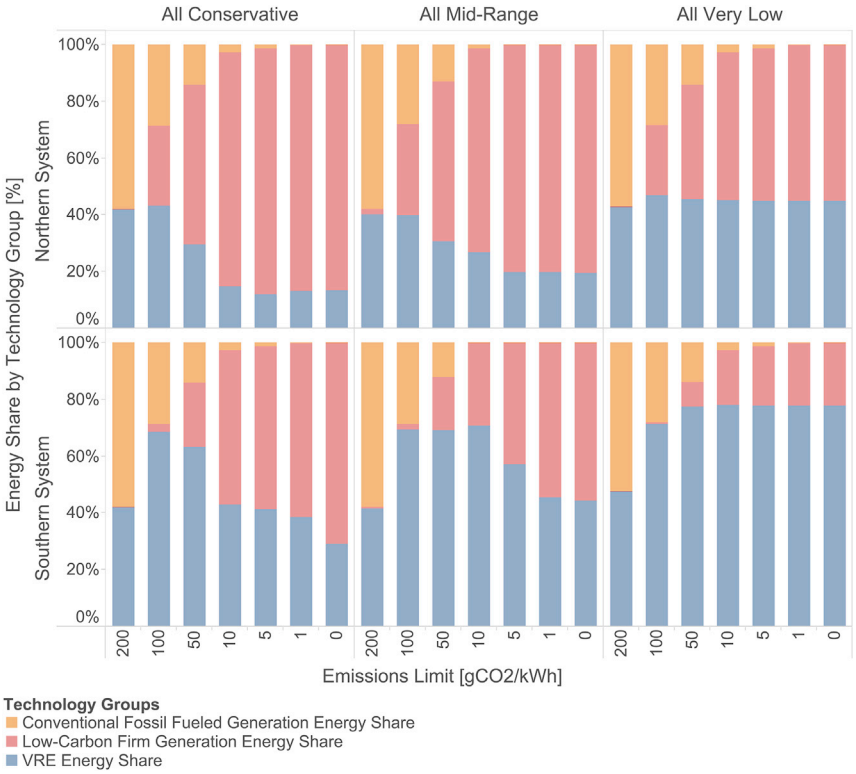


Figure 3. Energy Shares of Least-Cost Portfolio in the Northern and Southern Systems by Technology Group under Different Carbon Emissions Limits

For each system, the plot shows the energy shares of the least-cost mix for the technological scenario combinations of all conservative, all mid-range, and all very low, with the northern system on the left and southern system on the right. The energy shares are calculated as the quotient of the total energy injected into the system by each technology over the total demand of the system plus energy storage losses. See Figure S8 for energy shares under different scenario combinations.

approaches zero. In contrast, if fossil-fueled generation is replaced by firm low-carbon resources with higher fuel costs (e.g., biomass, biogas, natural gas with CCS), the fuel-saving value of wind and solar is preserved and the least-cost energy shares of VRE increase asymptotically as the emissions target goes to zero.

Similar non-monotonic behavior in the energy shares of natural gas with CCS can be observed for the mid-range technology case in which the CO_2 capture rate is assumed to be 90% (Figure S9). Without complete CO_2 capture, the energy share from natural gas plants with CCS shrinks as the emission limit approaches zero. In contrast, natural gas with CCS increases its energy share monotonically when a 100% capture rate is assumed.

The non-monotonic changes in the least-cost share of both VREs and natural gas power plants with 90% CO_2 capture rate indicate that assets that may be optimal under more modest emissions limits may become stranded in a deeply decarbonized power system. Both low-carbon technology investments and near-term policies should therefore be evaluated in light of their potential contributions to eventual deep decarbonization goals and not solely on their more immediate impacts.

Finally, we find that firm low-carbon resources operate in two different modes, depending on technology type and the specific case.

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First, firm resources may operate in a "flexible base" mode, in which they provide a reliable base of power throughout the year, infrequently cycle off entirely, and are flexible enough to modulate output between their minimum stable output and maximum rated capacity to integrate variable renewable resources when economically advantageous for the system. We define here the "annual commitment factor" (ACF) for a given resource i as

$$\mathrm{ACF}_i = \sum_{h=1}^{H} C_{i,h} / (g_i \cdot H)$$

where $c_{i,h}$ is the number of generating units of resource type i committed in each hour h, g_i is the total number of generating units of resource i installed, and H is the total number of hours in the year. We consider a technology with an ACF >50%—meaning that the technology is online and generating more often than not—as operating in a flexible base manner in that case. Nuclear power plants most consistently operate in flexible base mode in our results, as do natural gas plants with 100% CO_2 capture rate (see Figures S6 and S14). Gas plants with a lower capture rate and biomass power plants occasionally operate in a flexible base mode but cycle more frequently in other cases.

Notably, in more than three-quarters of cases (122 of 152) with emissions limits less than 10 gCO_2/kWh, the least-cost resource mix includes at least one technology that operates in a flexible base mode. In higher carbon cases, combined-cycle natural gas plants operate as flexible base but emit too much CO_2 to continue in this role at low emissions limits. The availability of a cost-effective low-carbon alternative to combined-cycle natural gas plants substantially reduces average electricity costs as the emissions limit approaches zero (Figure S2). Even a relatively modest amount of low-carbon firm capacity operating in flexible base mode can have a substantial effect on total power system costs (Figures S4 and S5).

In a smaller number of cases, firm low-carbon resources are too costly relative to variable renewables to warrant operation as flexible base resources, and wind and solar (complemented by battery energy storage) dominate the energy supply (Figures 3 and S8; this includes all cases under 10 gCO_2/kWh with very low VRE and storage cost assumptions and, in the northern system, conservative costs for nuclear and natural gas with CCS, or, in the southern system, conservative or mid-range costs for these firm resources). Any firm resources deployed in these cases (e.g., biomass and biogas, or natural gas plants with a 90% CO_2 capture rate) operate as "firm cyclers." This operating mode is characterized by prolonged periods in which all generating units of this type are cycled off entirely and where these units primarily contribute valuable power output during prolonged periods of low solar and wind availability in which energy storage becomes insufficient to meet demand reliably. Firm cyclers are indicated by low values (generally less than 35%) for both commitment factor and capacity factor (Figures S6 and S7). Firm cyclers also reduce total system costs in these cases relative to cases that entirely exclude firm resources (Figure S2).

Demand-Side Resource and Transmission Interconnection Cases

We next consider the role of demand-side flexibility, in the form of reschedulable loads and price-responsive or curtailable loads. Table 3 summarizes five scenarios with progressively increasing demand-side flexibility of each type.

As Figure 4 indicates, firm low-carbon resources (the cases labeled in the figure as "firm allowed") continue to play an important role in containing the cost of deep

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Table 3. Demand-Side Resource Scenarios

	1	2	3	4	5
Percentage of hourly demand that can be re-scheduled	5	10	15	20	20
Maximum time to serve re-scheduled demand (hr)	6	6	6	6	6
Number of price-responsive demand segments	1	2	3	4	5
Marginal cost of demand curtailment in each demand segment as a percentage of the value of lost load ($15,000/MWh)	70	70–50	70–50–20	70–50–20–10	70–50–20–10–5
Size of each demand segment as a percentage of hourly demand	5	5	5	5	5
Total price-responsive demand as a percentage of hourly demand	5	10	15	20	25

decarbonization even with significant demand flexibility (i.e., when up to 20% of demand is reschedulable at no cost for up to 6 hours and up to 25% of demand is price responsive). Across the range of demand-side flexibility cases, it is 30%–83% more expensive to fully decarbonize electricity generation without low-carbon firm resources in the southern system and 74%–130% more expensive in the northern system.

In cases that exclude firm low-carbon resources, demand-side flexibility plays an important role in reducing the costs of deep decarbonization (Figure 4). However, the marginal value of each increment of demand flexibility declines as VRE and energy storage costs fall (indicated by the tighter spread of system-wide costs in the very low VRE and storage cases). Figure 5 shows how increased demand-side flexibility affects the capacity mix and energy shares in the least-cost power systems. When firm low-carbon resources are excluded, greater demand flexibility lowers average costs by substantially reducing required energy storage and VRE capacity. In effect, greater demand flexibility reduces (but does not eliminate) the need for excess installed VRE and storage capacity to reliably meet demand.

With firm low-carbon resources, however, increased demand flexibility has a more modest effect on total cost and total installed capacity in decarbonized power systems. In these cases, demand flexibility acts most directly as a substitute for energy storage, an indication of their competing roles in the fast-burst balancing resources category (see Figure 5). Increased demand flexibility also has secondary and more ambiguous effects on capacity and energy shares of VRE and firm resources, generally reducing the capacity of the most expensive resources and increasing utilization of lower-cost resources in each case.

We also find that reschedulable or "shiftable" demand is utilized more significantly in cases when firm low-carbon capacity is allowed in the system (see Figure S10). In these cases, demand is regularly shifted in order to optimize the utilization of the firm resource with the highest variable cost (e.g., biomass or natural gas with CCS; Figures S11 and S12). Rather than act as a strong substitute for firm low-carbon resources, demand flexibility instead optimizes their utilization and increases their marginal value.

We also analyzed the potential gains from adding long-distance transmission capacity between the northern and southern systems. Fixed line capacities

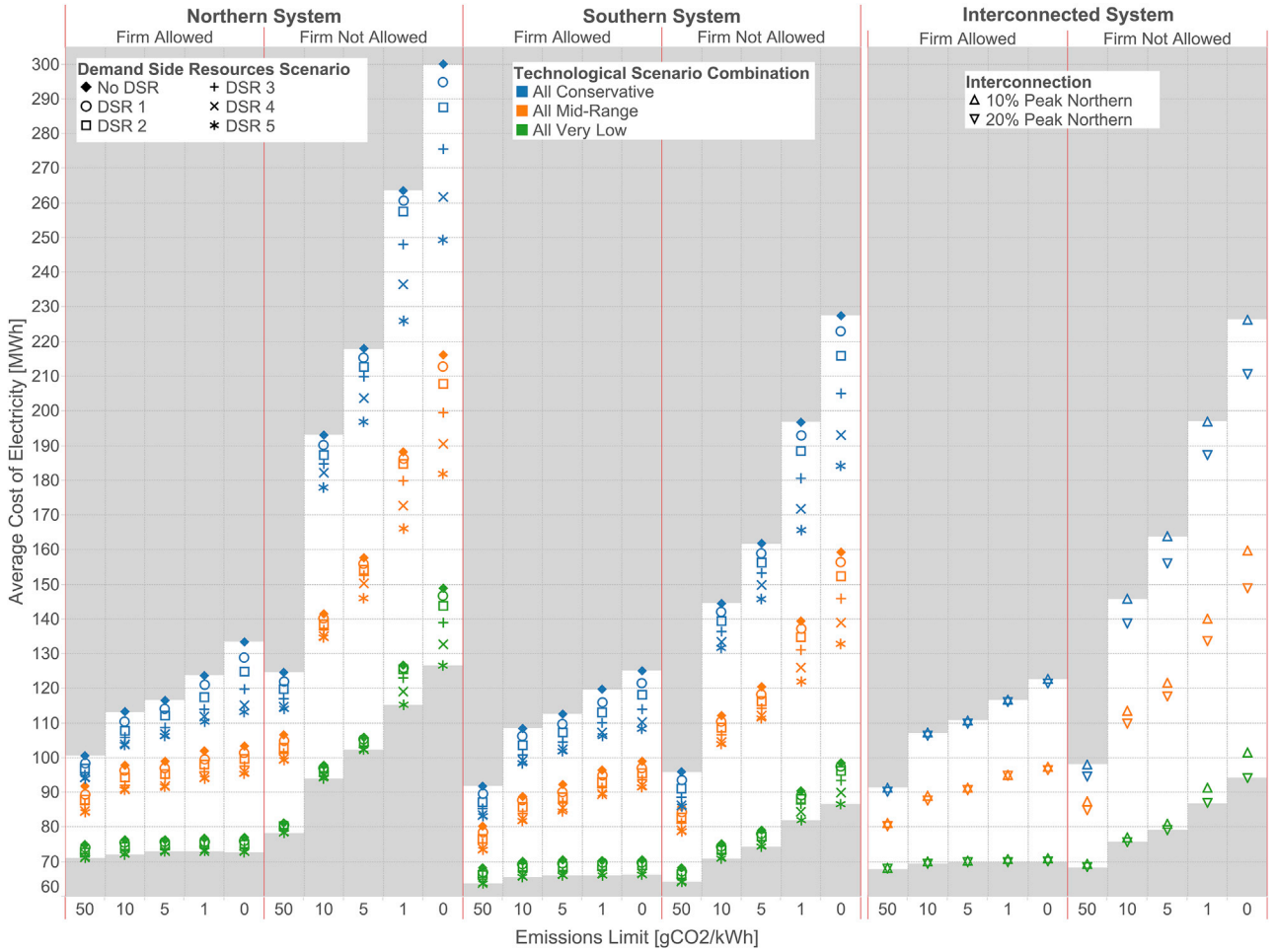


Figure 4. Average Cost of Electricity under Different Technological Assumption Scenarios, and CO_2 Emissions Limits for the Northern and Southern Systems with Different Demand-Side Resources Scenarios and the Interconnected System

The plots show the average cost of electricity for the northern and southern systems under different demand-side resource (DSR) scenarios and the interconnected system under different interconnection capacity scenarios. For each system, results are shown when low-carbon firm capacity is allowed and when it is not. Different colors distinguish scenarios with conservative, mid-range, and very-low-cost projections for all technologies.

equivalent to 10% and 20% of the northern system's peak demand were each considered (see Table 4).

When firm resources are available, connecting the two regions with transmission capacity equal to 10% of the northern system's peak demand has a modest effect on the cost of full decarbonization in each region. In the northern system, the average electricity cost is reduced by between 8.5% (in the conservative case) and 9% (in the very low case) relative to the cost without interconnection, while in the southern system the average electricity cost is reduced by between 2% (in the conservative case) and 0.5% (in the very low case). The marginal benefit of additional interconnection capacity is effectively zero (Figure 4). The first increment of capacity allows for optimal placement of VRE (solar capacity shifts to the southern system; see Figure S14) and better usage of VRE generation due to reduced output variability (with some solar capacity being replaced by wind generation; see Figure S9). These effects enable VRE to substitute to some degree for more expensive technologies, such as energy storage or firm low-carbon resources, in certain scenarios (see Figure 5).

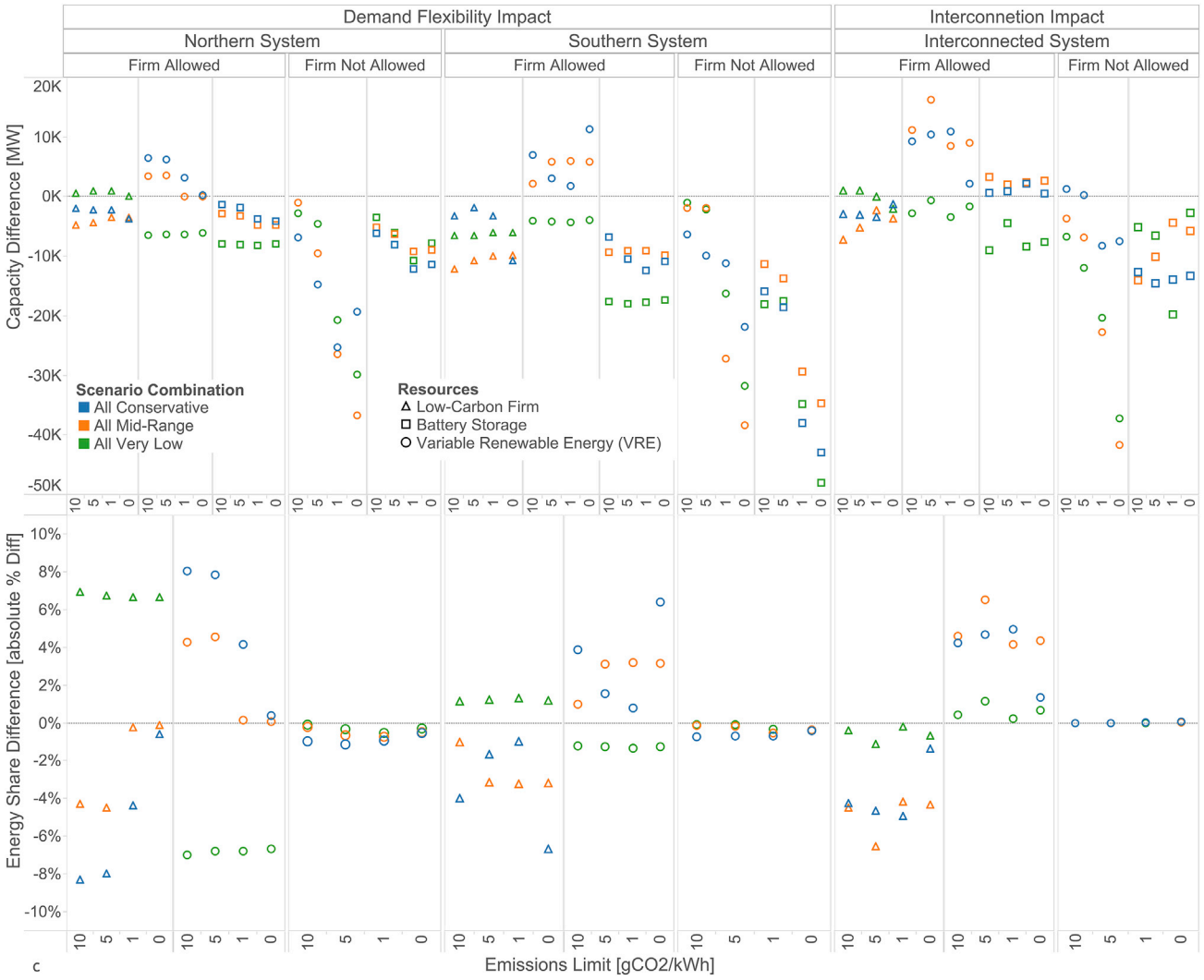


Figure 5. Effect on Capacities and Energy Shares of DSRs (DSR 5 versus DSR 1) and Interconnection (20% versus 10%) as a Function of Emissions Limit

Effect of flexible demand and transmission interconnection on the capacities (top) and energy shares (bottom) of different resources. The effects are shown as the difference between scenarios DSR 5 versus DSR 1 for the impact of demand flexibility (left) and the difference between the 20% and 10% interconnect scenarios for the impact of transmission interconnection (right). Different technologies are shown with different data markers and different technological scenario combinations are shown in different colors. Battery storage capacity differences have been plotted in power capacity (MW) instead of energy capacity (MWh) for consistency; this is done by dividing the total energy capacity by the storage time constant (4 and 6 hr).

If firm resources are not available, transmission interconnection has a greater economic benefit. As Figure 4 illustrates, the first increment of transmission capacity (10% of the northern system peak) reduces the average cost of the combined system to 68%–75% of the cost of the northern system in isolation (and to roughly the level of the average cost of the southern system in isolation). The benefit of the next increment of transmission capacity (increasing to 20% of the northern system peak) is also noticeable, with average electricity costs in the combined system falling below those of either individual system in isolation in all cases.

Finally, Figure 4 shows that, even when zero-cost, zero-loss transmission capacity is available to connect the two regions, the cost of achieving deep decarbonization

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Table 4. Interconnection Scenario Assumptions

	10% Case	20% Case
Line capacity (MW)[a]	3,400	6,800

[a]The two systems are assumed to be interconnected at zero cost, with no transmission losses, i.e., transmission costs and losses are not included in the capacity expansion optimization. Instead, transmission interconnection capacity between the two regions is exogenously increased and the effects on other decision variables and costs are analyzed. Figure S13 shows the interconnection usage as function of emissions limit for the different scenarios.

is at least 35% higher in the absence of firm low-carbon resources, providing further evidence of the broad value of these firm resources for cost-effective decarbonization.

DISCUSSION

The availability of firm low-carbon resources is an important factor in containing the cost of power sector decarbonization and thus the overall cost of climate mitigation efforts. This finding appears robust in the face of uncertainties in future technology costs, in the scale of adoption of demand-side flexibility services, and in the availability of long-distance transmission interconnections. The cost-containing role of firm resources is particularly important where solar or wind resources are of lower quality, and will also be especially valuable if solar, wind, and storage costs do not continue to fall rapidly. However, even in regions with abundant renewable resources, firm low-carbon resources can lower the cost of deep decarbonization significantly, even if the firm resources have much higher levelized costs than do variable renewables, and even if very-low-cost battery energy storage technologies are available. In the majority of scenarios analyzed here, firm low-carbon resources operate as a flexible base in decarbonized power systems, providing a steady supply of reliable and adjustable power output throughout the year.

We find that in the absence of firm low-carbon resources, affordable decarbonization of the power sector would simultaneously require further steep reductions in the cost of VRE and battery energy storage technologies, significantly oversizing installed capacity relative to peak demand, significantly greater demand flexibility, and expansion of long-distance transmission capacity connecting wide geographic regions. Development of energy storage resources capable of sustained output over days or longer with very low energy capacity costs suited to low utilization rates could also lower the costs of high VRE pathways, but this potential was not modeled in this study. Given large current uncertainties in all of these outcomes, our results suggest that the availability of firm low-carbon resources—even if much costlier than VRE resources in terms of overnight capital cost or levelized cost of energy—will improve the robustness of decarbonization efforts.

The analysis shows that in decarbonized power systems, short-duration battery energy storage, and demand-side resources play a role (as fast-burst balancing resources) that is distinct from firm low-carbon resources. We also show that firm resources play a key role even with enhanced long-distance transmission interconnections. If fast-burst balancing resources or transmission interconnections are available and cost-effective, these options can help to optimize asset utilization and reduce electricity costs for systems without firm resources and for more balanced systems alike.

Power system assets are long-lived investments, and capacity installed during the next decade is likely to remain in operation until 2050. Recognizing the

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importance of firm low-carbon resources to the cost of deep decarbonization thus has immediate implications for climate change mitigation and electric power system planning, energy technology and climate policy, and energy research prioritization.

First, although a wide range of public policies currently support the growth of variable renewable resources, policy support for firm low-carbon resources such as nuclear power, geothermal energy, biofuels, and CCS is modest in most jurisdictions. Our results indicate that having one or more firm low-carbon resources available for widespread deployment at reasonable cost will greatly improve the odds that zero or near-zero power sector emissions can be achieved cost-effectively. At present, available firm low-carbon resources face a variety of challenges that impede their widespread adoption, from cost to technology immaturity to risk. If these resources are to be viable options when needed, greater policy support for demonstration, deployment, and improvement of the existing portfolio of firm low-carbon resources is needed today.

Second, further development and improvement of firm low-carbon technologies, particularly those capable of operating as flexible base resources, should be a research and innovation priority. An improved and expanded set of firm low-carbon resources could have a substantial and positive impact on the eventual cost of deep decarbonization of power generation.

Third, given the sensitivity of the least-cost mix of low-carbon electricity resources to uncertain technology cost and performance trajectories, as well as large and potentially non-monotonic changes in the composition of the least-cost resource portfolio as the emission limit is tightened, policies should internalize long-term decarbonization goals and should allow the flexibility to implement the most cost-effective combination of fuel-saving, fast-burst, and firm low-carbon resources to meet those goals. Such policies could include a long-term emissions limit trajectory, a steadily increasing carbon price, or a technology-neutral low-carbon resource procurement requirement. Alternatively, an expanded mix of technology-specific policies that includes significant support for investment in research, demonstration, and deployment of low-carbon firm resources could ensure that these resources would remain a viable part of the climate mitigation portfolio.

EXPERIMENTAL PROCEDURES

Modeling Technique

This research uses the GenX model, an electric power system investment and operations model described in detail in.[38] In its application in this paper, the model considers detailed operating characteristics such as thermal power plant cycling costs (unit commitment), limits on hourly changes in power output (ramp limits), and minimum stable output levels. The model also captures a full year of hourly chronological variability of electricity demand and renewable resource availability (see Figures S19 and S20). The mixed integer linear programming model selects the cost-minimizing set of electricity generation and storage investments and operating decisions to meet forecasted electricity demand reliably over the course of a future year, subject to a specified CO_2 emissions limit.

The GenX model can be configured to co-optimize several interlinked power systems decision layers. Computational limitations entail tradeoffs along each dimension or decision layer, so more detail in one dimension (e.g., time,

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operational constraints, networks) typically means greater abstraction in other areas. For this study, we configure GenX to deliver high accuracy in hourly operational and unit commitment decisions. This temporal resolution and operational detail is important to capture the effects of chronological variability in renewable energy availability and demand patterns on investment and operating decisions, particularly under scenarios with very high wind and solar energy penetrations. Computational complexity is also increased by the inclusion of stringent annual limits on total CO_2 emissions. However, this level of detail comes at the expense of other limitations that are important to note when interpreting the results of this work. See the Supplemental Experimental Procedures section for full discussion of the limitations of this modeling approach.

Cost and Availability Assumptions

Cost and availability assumptions describing the different analyses are shown in Tables 1, 2, 3, and 4. Economic and technical assumptions can be found in Tables S1–S3.

SUPPLEMENTAL INFORMATION

Supplemental Information includes Supplemental Experimental Procedures, 20 figures, and 4 tables and can be found with this article online at https://doi.org/10.1016/j.joule.2018.08.006.

ACKNOWLEDGMENTS

N.A.S. would like to thank the Chilean Navy and MIT for their financial support, and to acknowledge Dr. Charles W. Forsberg for his advice in the thesis work that evolved into this research. J.D.J. thanks the MIT Energy Initiative and the Martin Family Society of Fellows for Sustainability for their financial support. The authors would like to thank the Julia for Mathematical Programming (JuMP) team at MIT for their support in developing the optimization programming package used in this research. Significant computing resources at MIT's Engaging Cluster at the Massachusetts Green High Performance Computing Center were used in this research. Finally, we thank three anonymous reviewers for detailed and constructive comments on a prior version of this paper that helped us strengthen and refine the analysis and discussion herein.

AUTHOR CONTRIBUTIONS

N.A.S. performed the modeling, developed the initial experimental design, contributed to and coordinated the manuscript production, and produced the figures. J.D.J. was lead editor of the manuscript. N.A.S. and J.D.J. jointly developed the capacity expansion model, refined the initial experimental design, and performed analysis of results. R.K.L. and F.J.d.S. advised on experimental design and analysis and reviewed and revised the manuscript.

DECLARATION OF INTERESTS

J.D.J. provides consulting and advisory services for the Clean Air Task Force, a nonprofit environmental advocacy organization, and the Clean Energy Program at Third Way, a nonprofit think tank. R.K.L. serves on the Scientific Advisory Council of Engie.

Received: November 29, 2017
Revised: May 14, 2018
Accepted: August 15, 2018
Published: September 6, 2018

Please cite this article in press as: Sepulveda et al., The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation, Joule (2018), https://doi.org/10.1016/j.joule.2018.08.006

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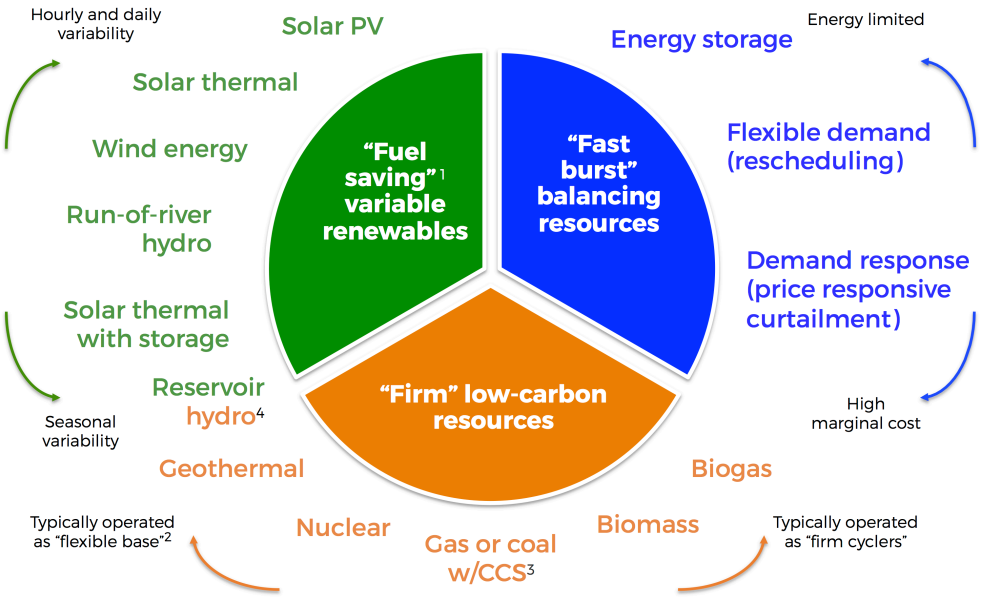
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Supplemental Information

The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation

Nestor A. Sepulveda, Jesse D. Jenkins, Fernando J. de Sisternes, and Richard K. Lester

Supplemental Figures and Results



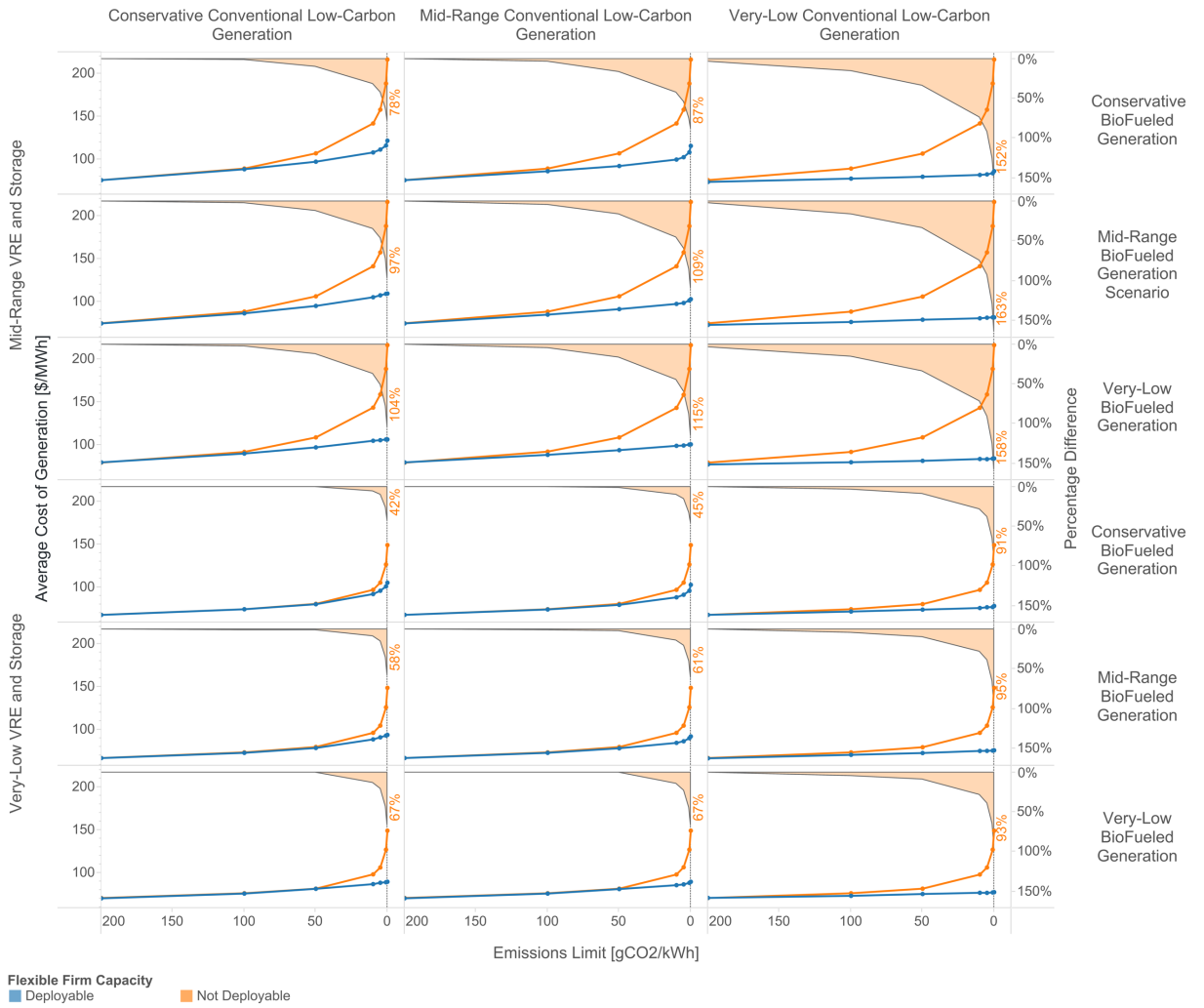
[1] Variable renewable energy resources do contribute some capacity value to power systems (e.g. they reduce total installed capacity required to reliably meet demand in all periods), but their variable nature means this capacity value is smaller than for other resources. In addition, as these resources reach higher energy shares, the need for investment in reliable generation or storage capacity is increasingly driven by periods of time when VRE output is low (or zero). The marginal capacity value of these resources to the power system thus steadily declines steadily towards zero as VRE shares increase.[1]–[3]

[2] Fossil power plants without CCS equipment, including pulverized coal and natural gas combined cycle power plants, can act as flexible base resources as well, but emit too much CO_2 to serve in this capacity in very low-carbon power systems.

[3] Note that if CCS capture rates do not approach 100%, gas or coal units with CCS may be unable to play a flexible base role under very strict emissions limits (e.g. <50 gCO_2/kWh), as illustrated in Figure 5 of the main paper and Figure SI.4 below. We find that under strict emissions limits, gas plants with CCS with 90% CO_2 capture instead serve as "fast burst" resources, providing only occasional power output in high-value periods to avoid breaching the CO_2 constraint. Capacity factors for gas with CCS in these cases are only 4-6% for a 1 gCO_2/kWh limit, for example (see Figure SI.4). Under less stringent emissions limits (e.g. 50-100 gCO_2/kWh), gas with 90% carbon capture rate does serve as a flexible base resource.

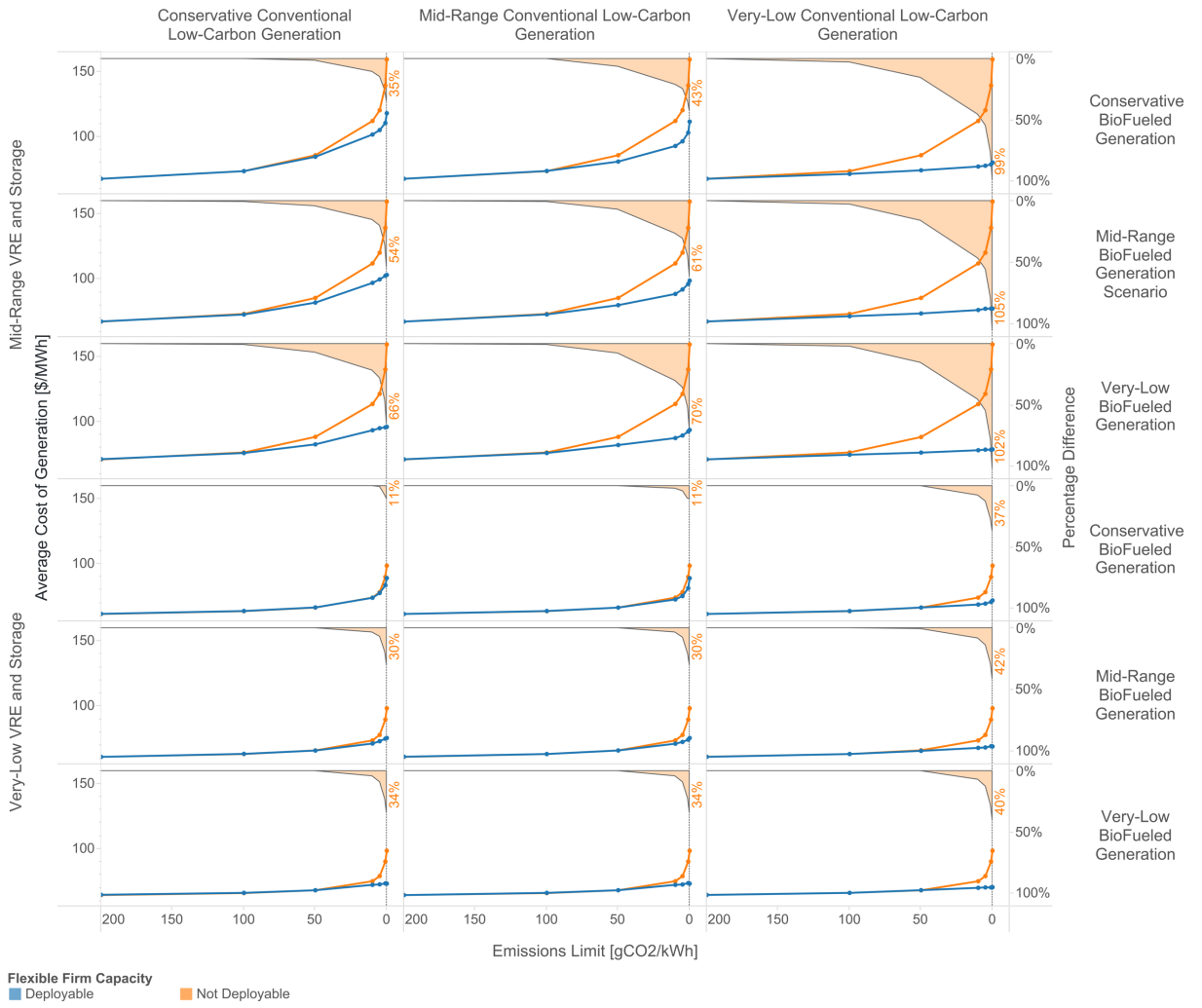
[4] Variable renewable resources such as solar, wind, and hydro with very long duration storage sufficient to manage seasonal variability may also be capable of acting as flexible base resources in low-carbon power systems.[4] This area is relatively unexplored, however, and should be the focus of further research.

Figure S1 Taxonomy of resources in a low carbon power system



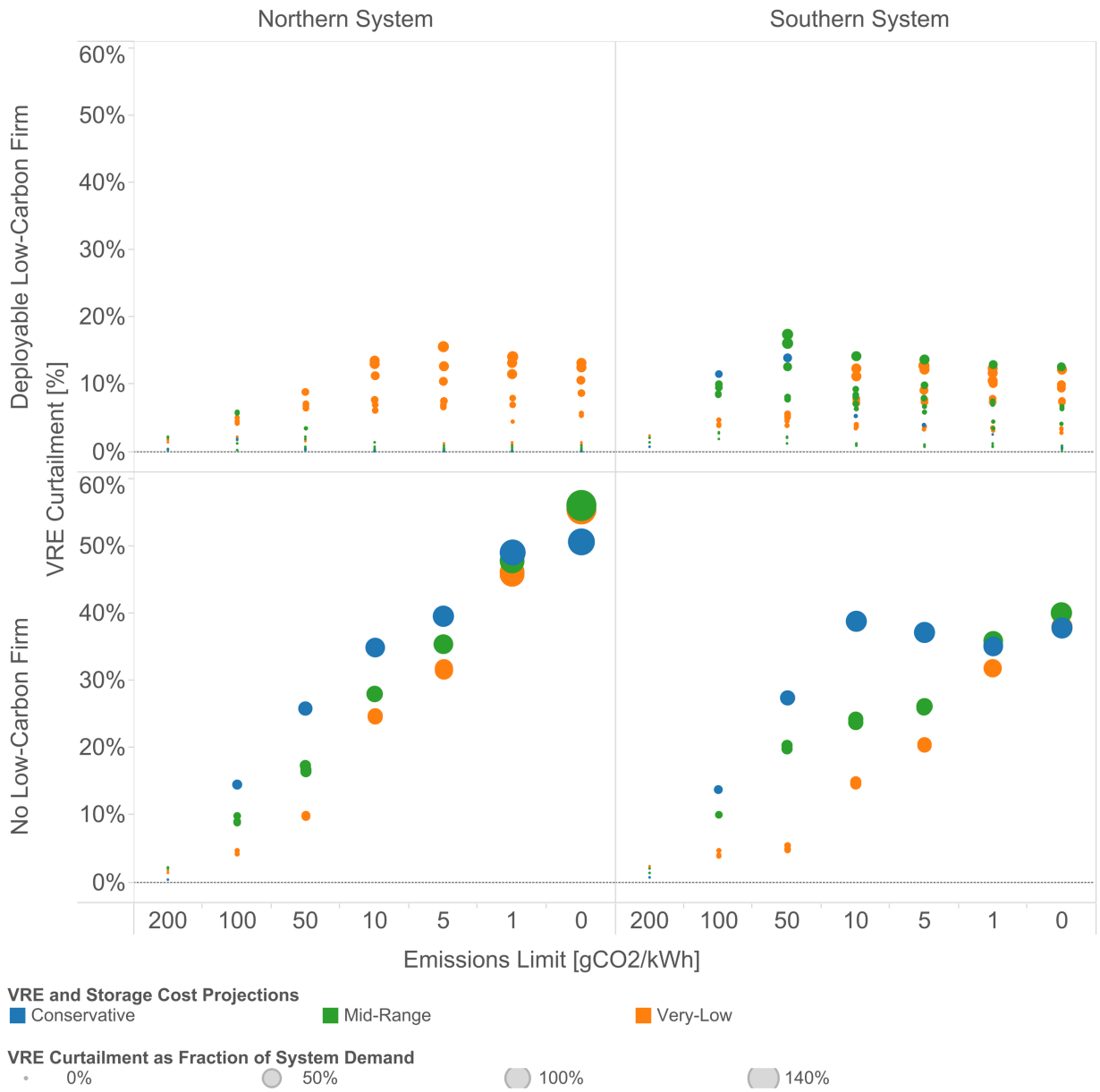
The percentage number located right to each subplot shows the maximum percentage difference between scenarios with and without low-carbon firm generation.

Figure S2a Average cost of generation (lines, left axis) for different combination of scenarios in the Northern System with and without low-carbon firm generation and percentage difference (cost reduction, area, right axis) between cases with low-carbon firm generation to cases without low-carbon firm generation.



The percentage number located right to each subplot shows the maximum percentage difference between scenarios with and without low-carbon firm generation.

Figure S2b Average cost of generation (lines, left axis) for different combination of scenarios in the Southern System with and without low-carbon firm generation and percentage difference (cost reduction, area, right axis) between cases with low-carbon firm generation to cases without low-carbon firm generation.



Right axis present the value of curtailment as fraction of VRE total potential production given installed capacity and hourly capacity factors. Size of marks show total curtailment as fraction of system's total demand over the year.

Figure S3 Curtailment of VRE generation with and without low-carbon firm resources.

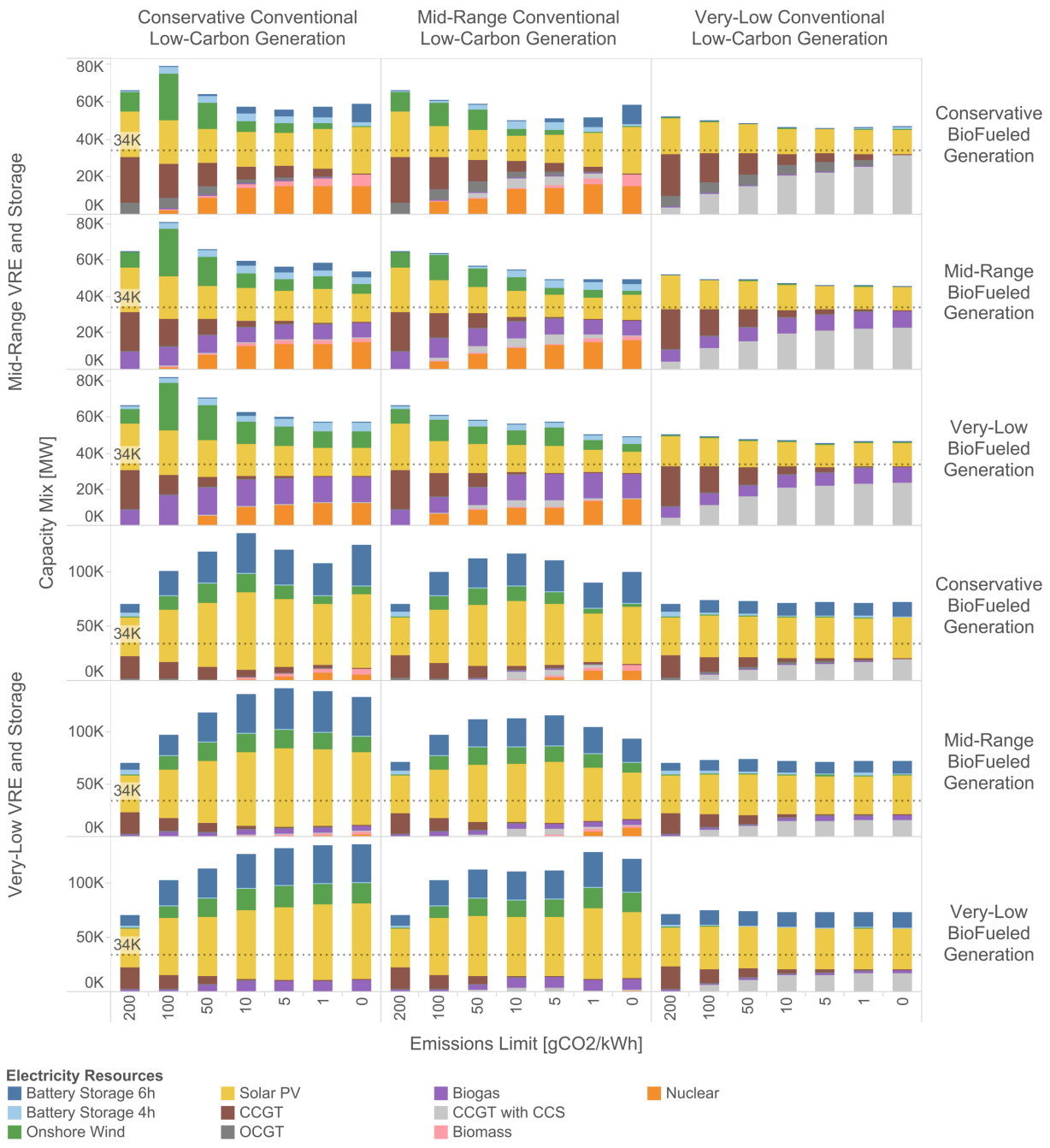


Figure S4 Northern system least-cost capacity mix for different scenario combination when low-carbon firm resources are allowed in the mix.

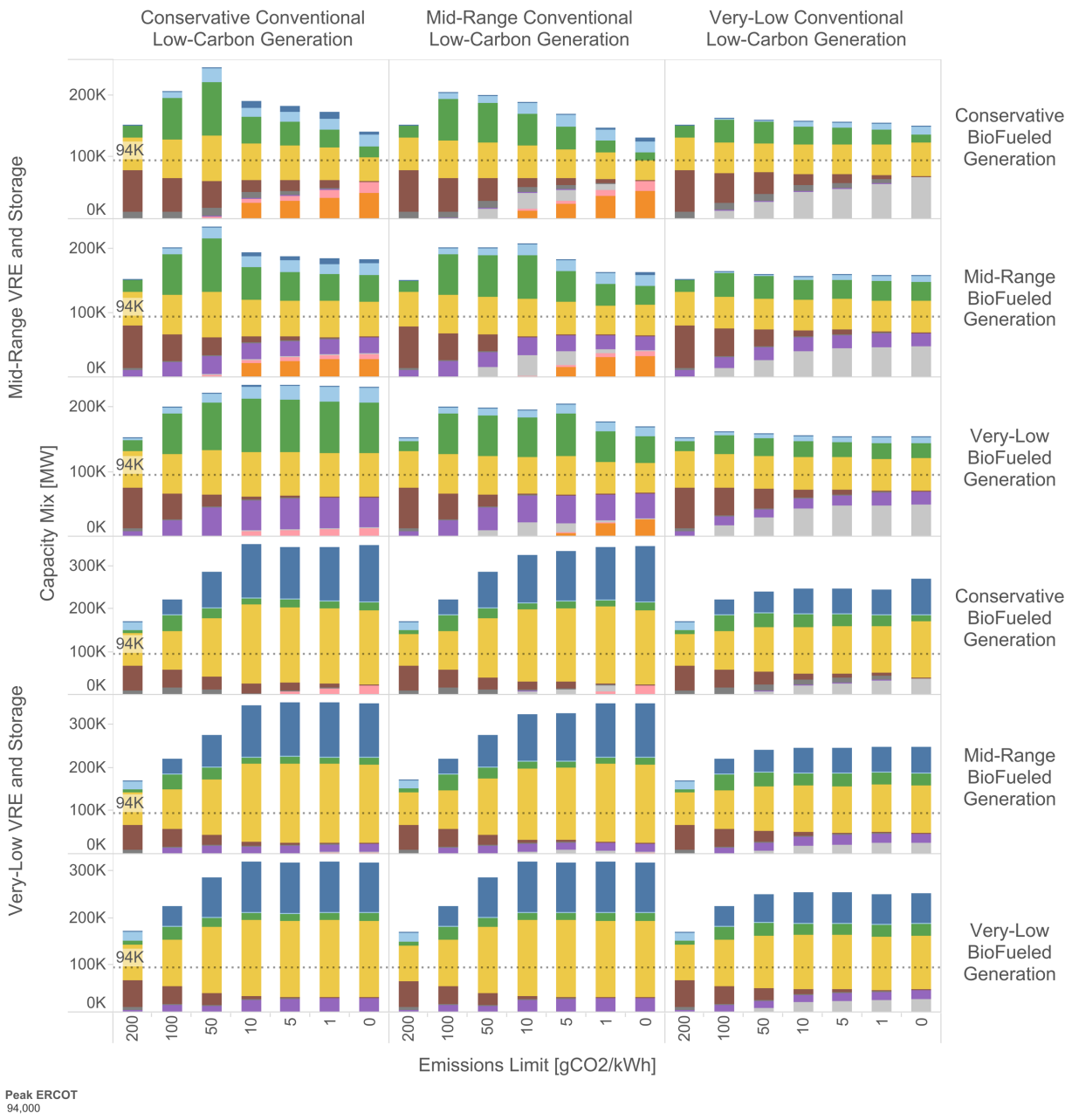


Figure S5 Southern system least-cost capacity mix for different scenario combination when low-carbon firm resources are allowed in the mix.

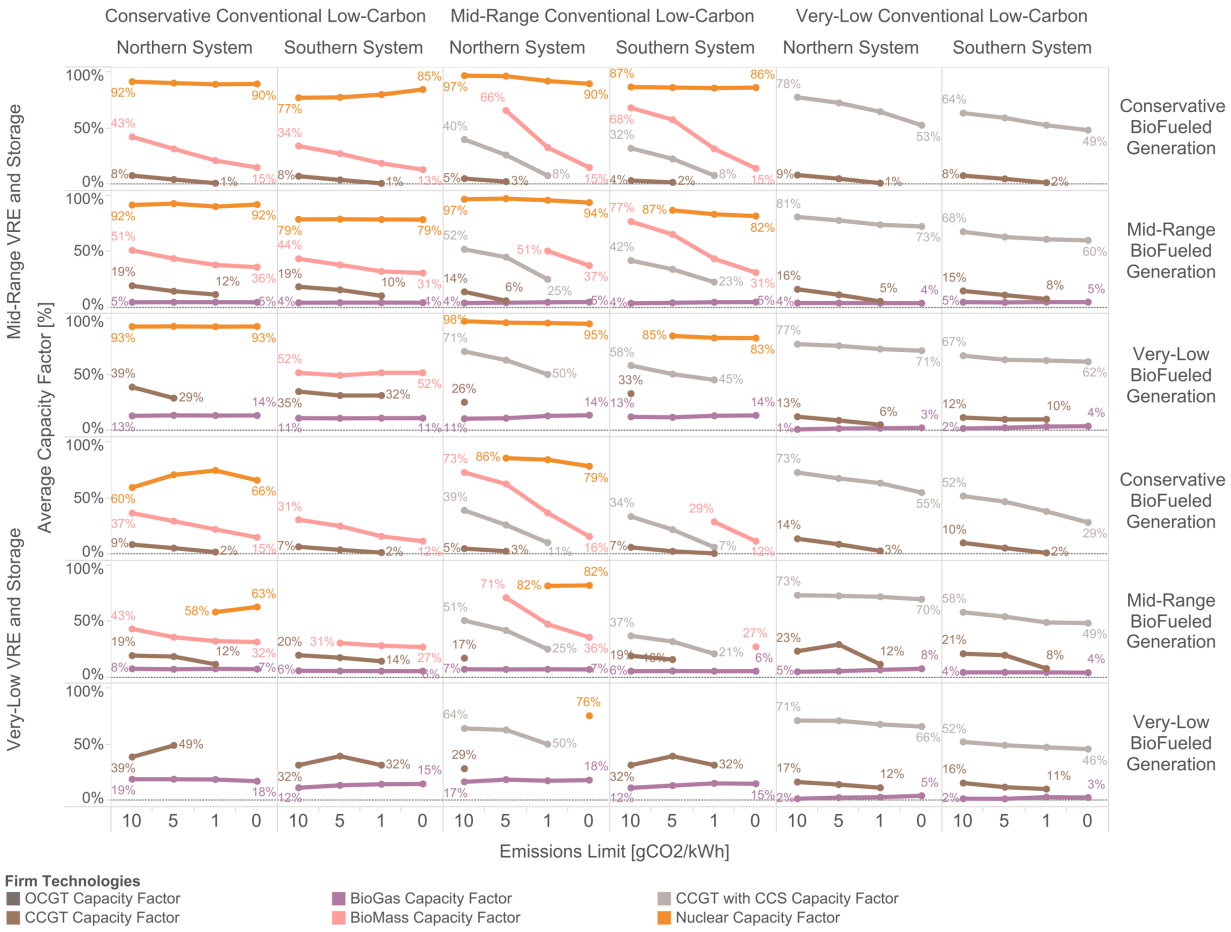


Figure S6 Capacity Factors of thermal resources for different scenario combinations in both systems when low-carbon firm resources are allowed in the mix.

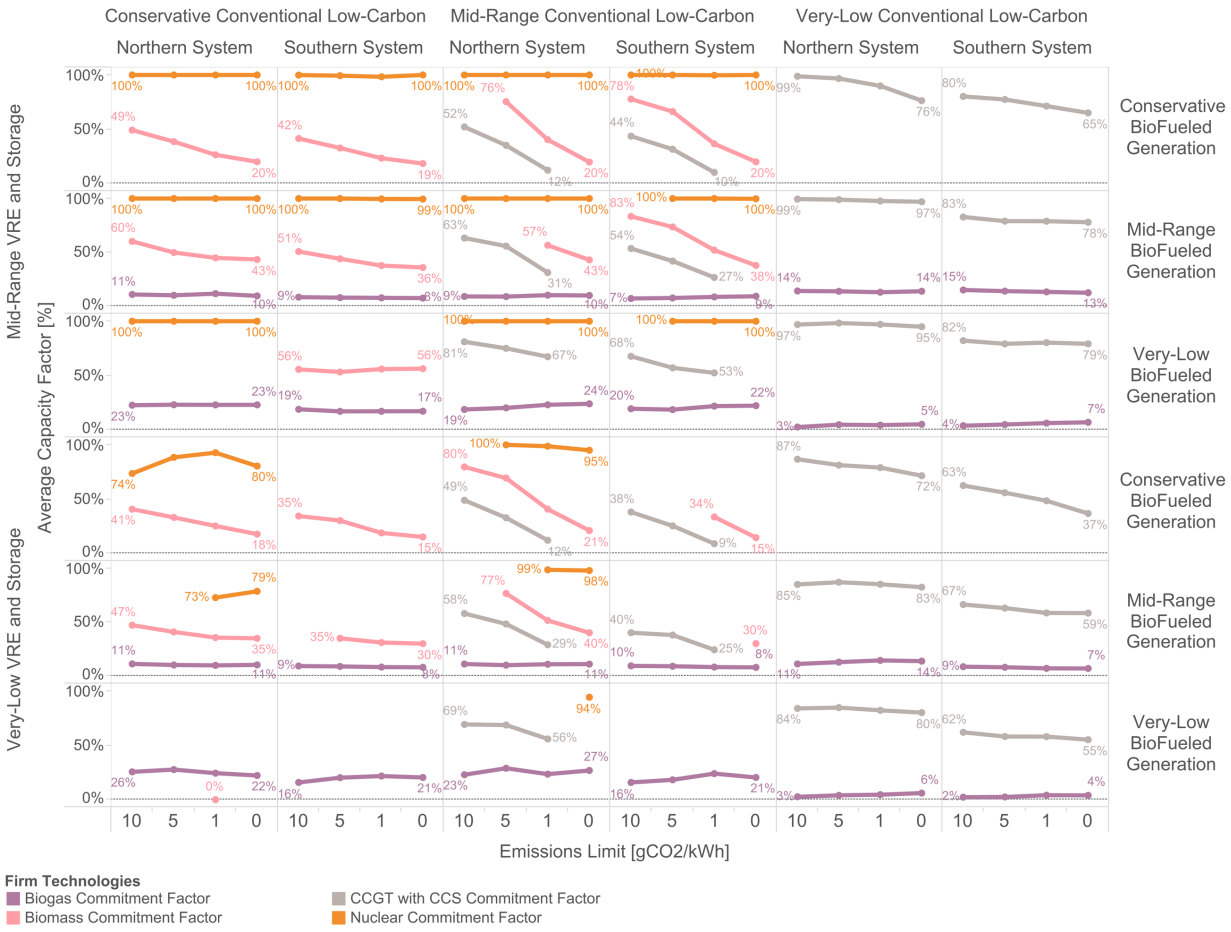


Figure S7 Commitment Factors of low-carbon firm capacity

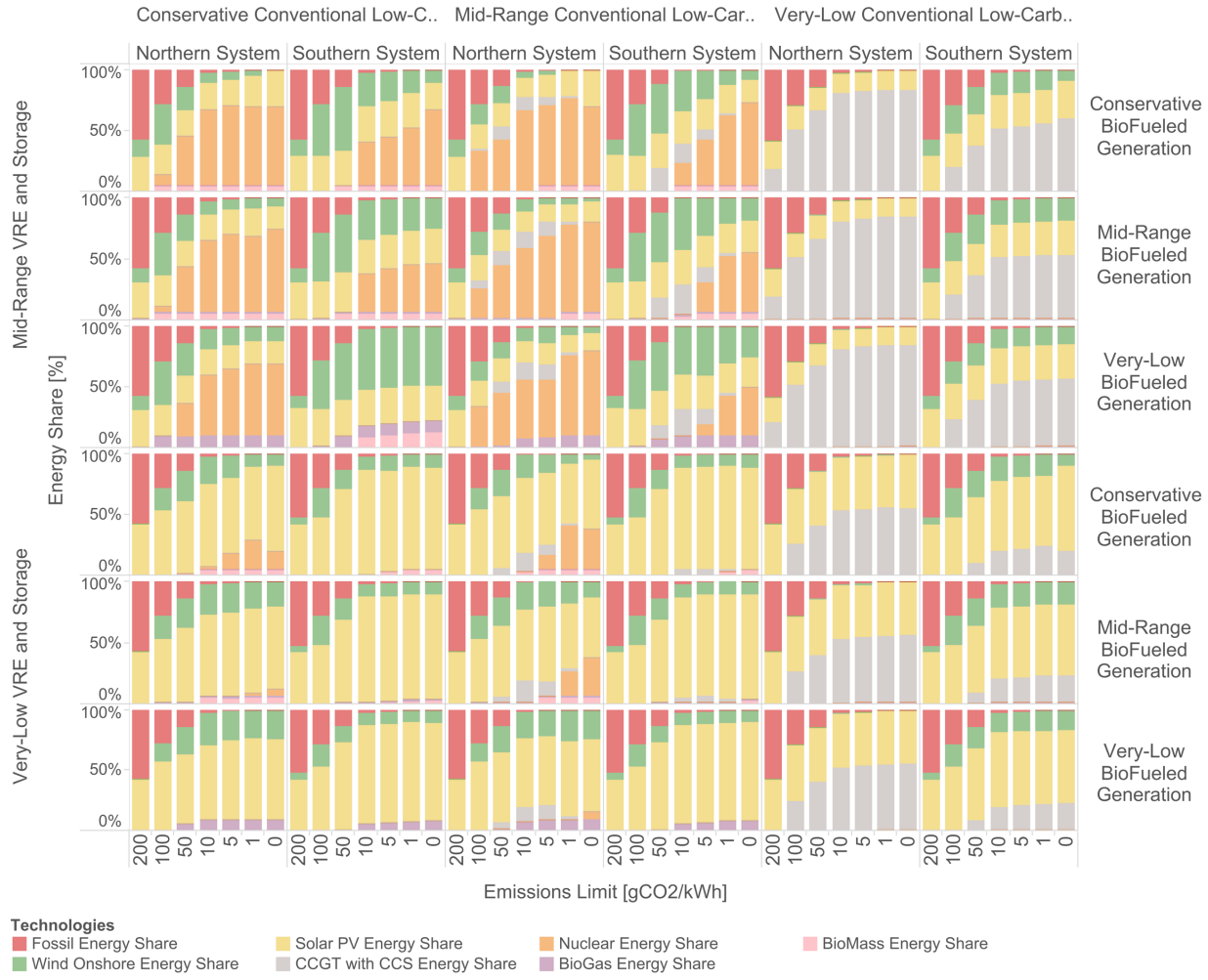
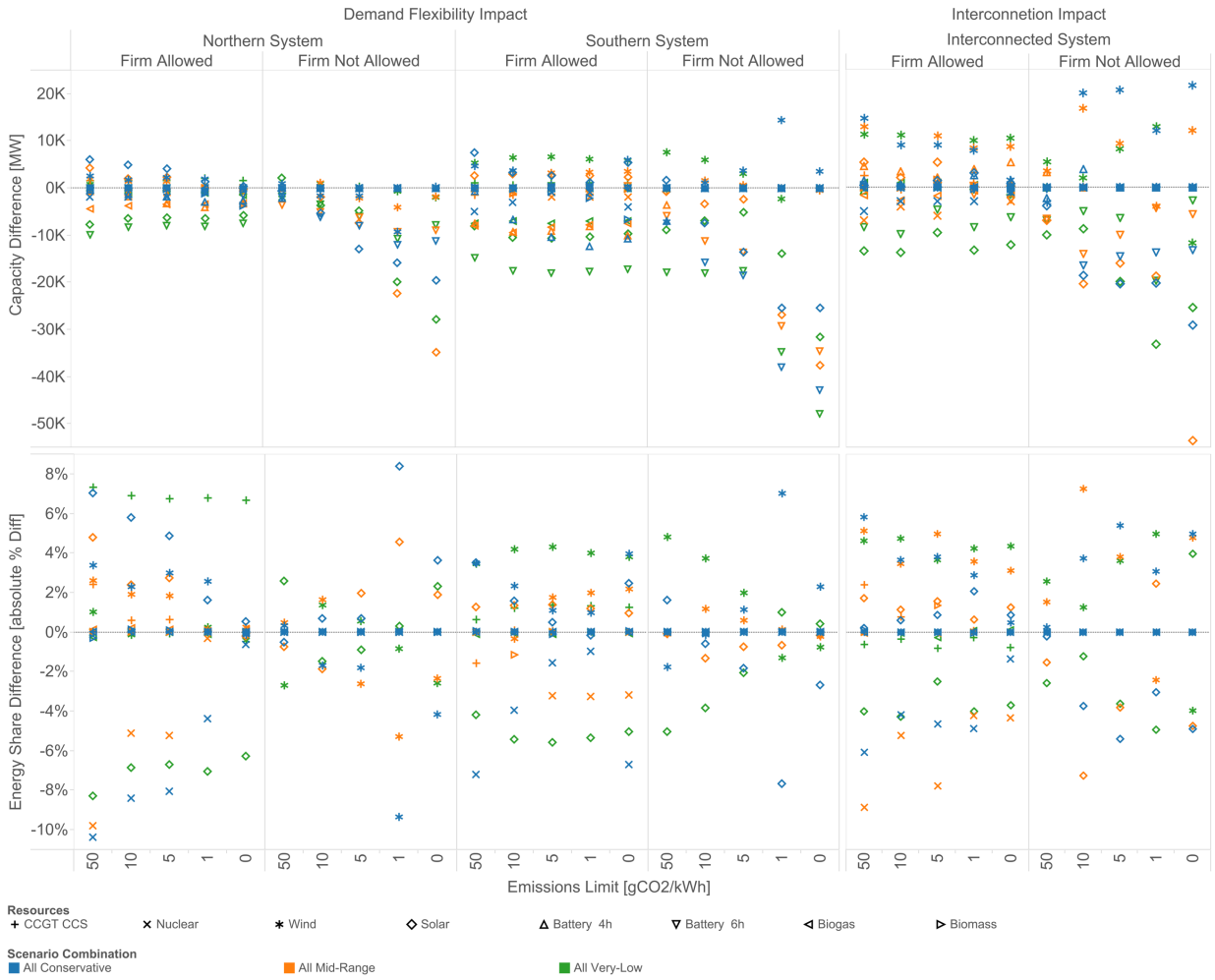
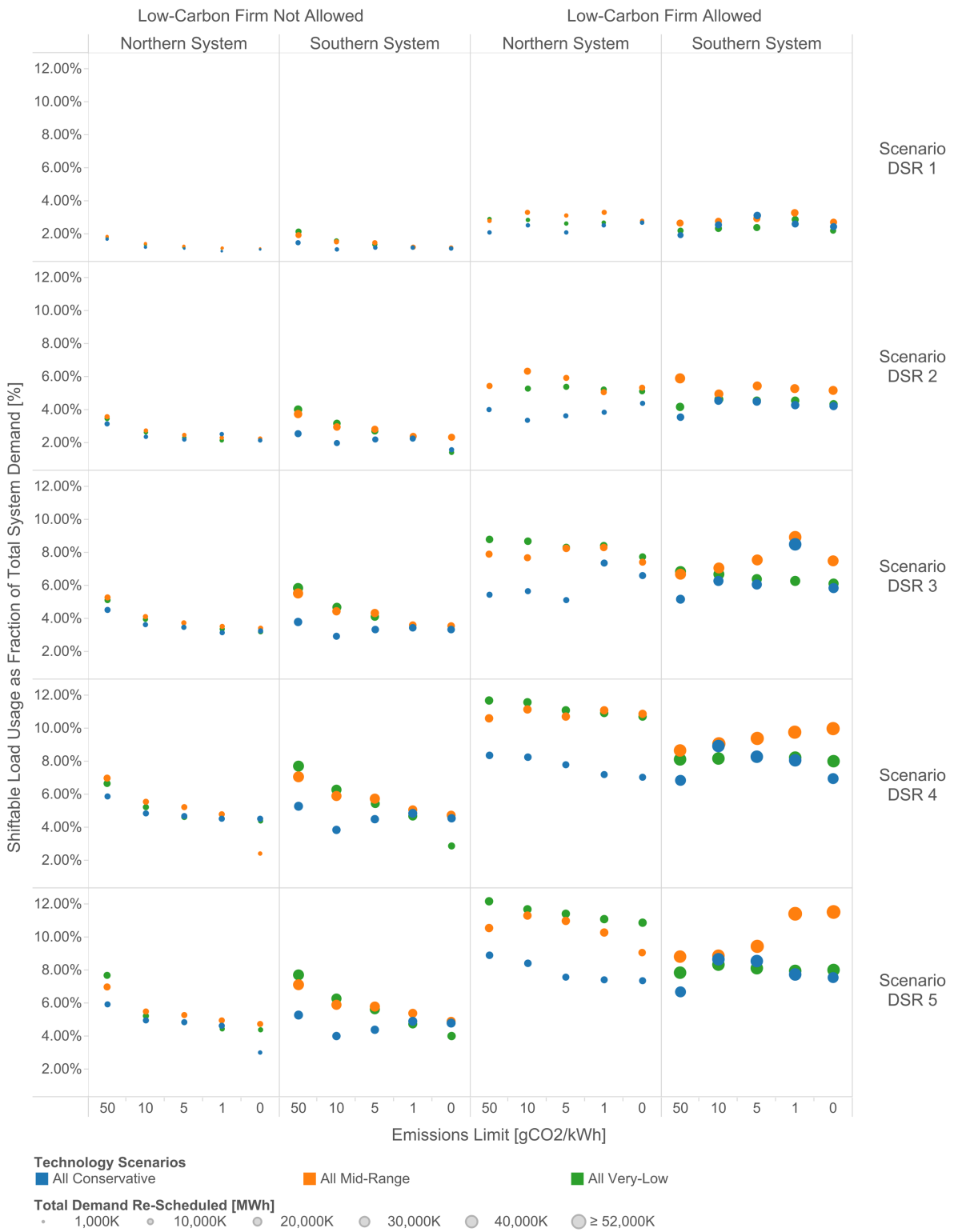


Figure S8 Energy shares under different scenario combinations in both systems when low-carbon firm resources are allowed in the mix.



Impact of additional demand flexibility is calculated comparing the optimal energy shares and least-cost capacity mix between DSR1 and DSR5 scenarios. Impact of additional interconnection capacity is calculated comparing the optimal energy shares and least-cost capacity mix between "10% peak northern system" and "20% peak northern system" scenarios.

Figure S9 Effect of additional demand flexibility (shiftable load and price-responsive demand) and interconnection capacity on optimal energy shares and capacity deployed.



Right axis present the value of total shifted energy as fraction of system's total demand over the year. The marker size represents the amount of load shifted in MWh.

Figure S10 Shiftable load usage

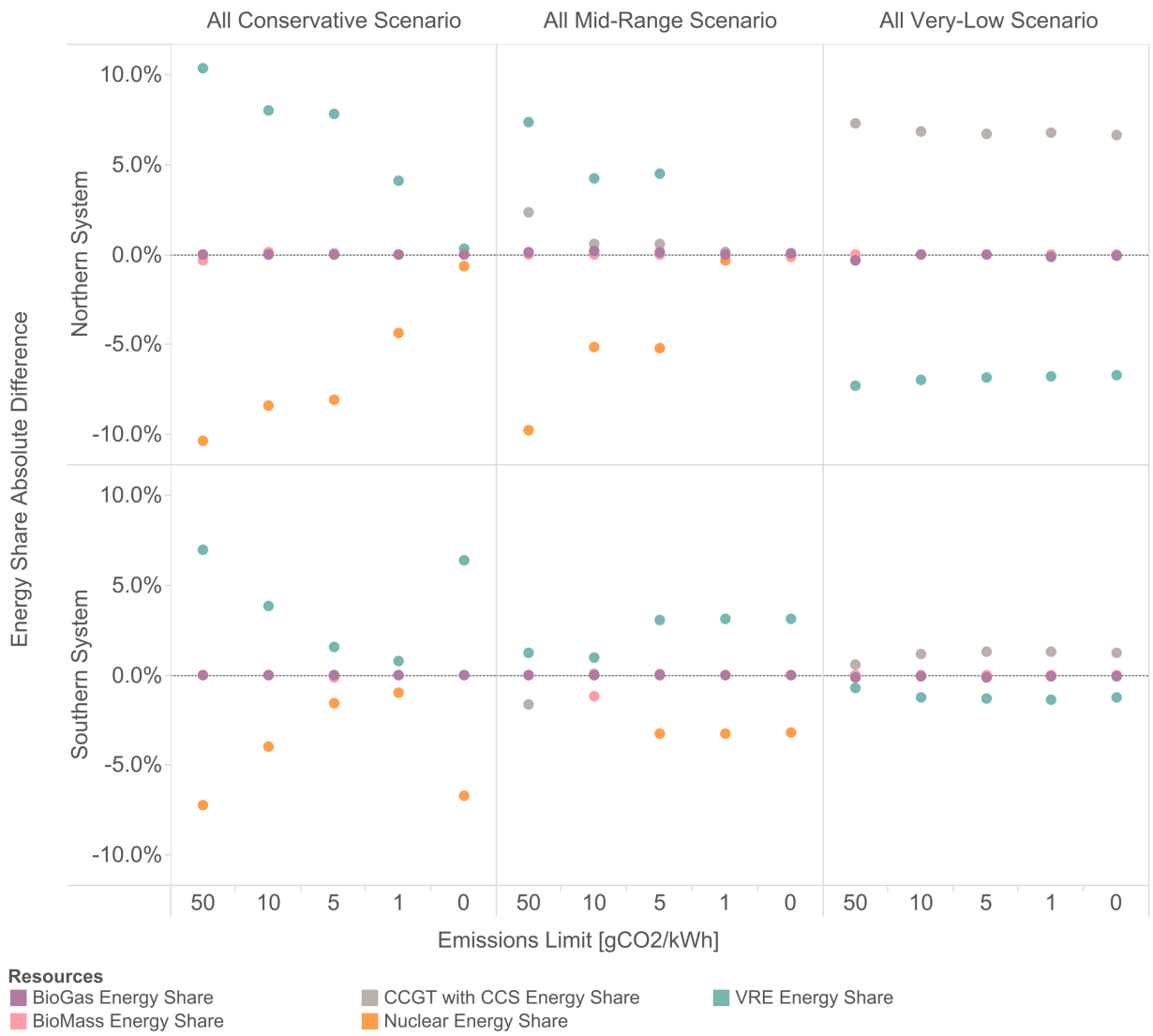


Figure S11 Changes in energy shares: DSR5 scenario compared to DSR1 scenario in cases where firm resources are allowed

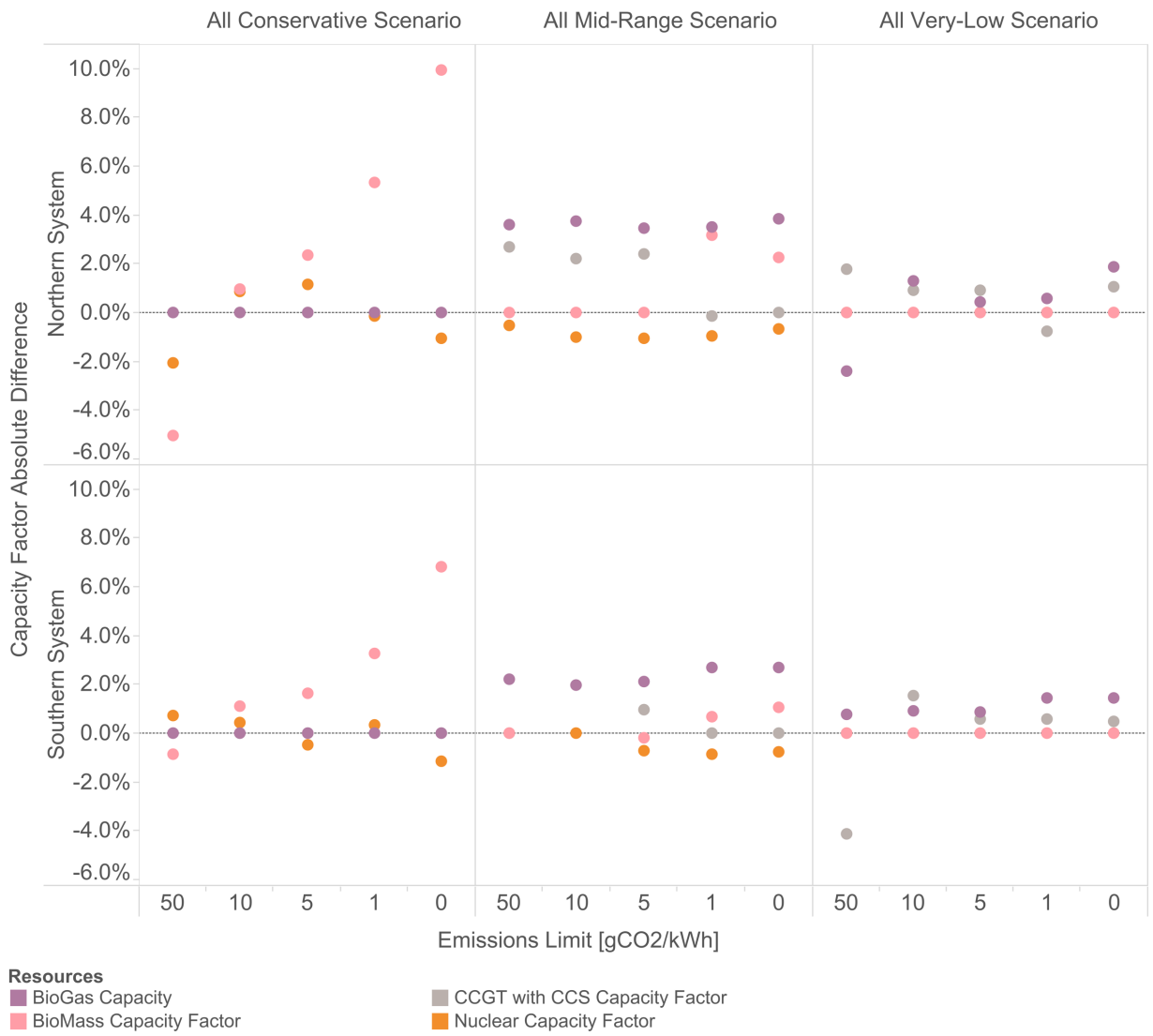
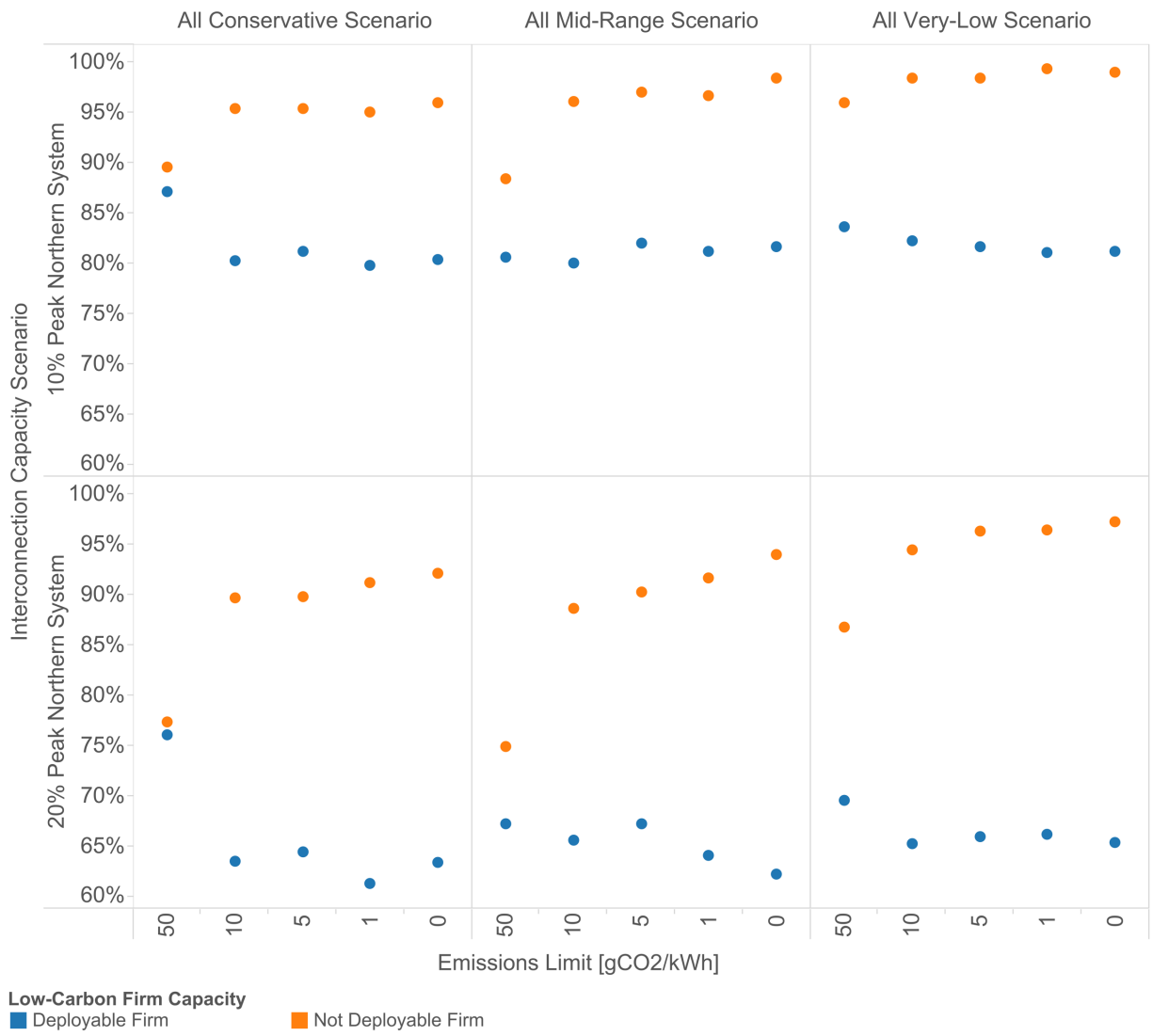


Figure S12 Changes in capacity factors of low-carbon firm resources: DSR5 compared to DSR1



Interconnection usage is calculated by addition of the absolute value of the hourly flows across all hours divided over the total line energy capacity (line capacity times 8760 hours of the year).

Figure S13 Interconnection Usage

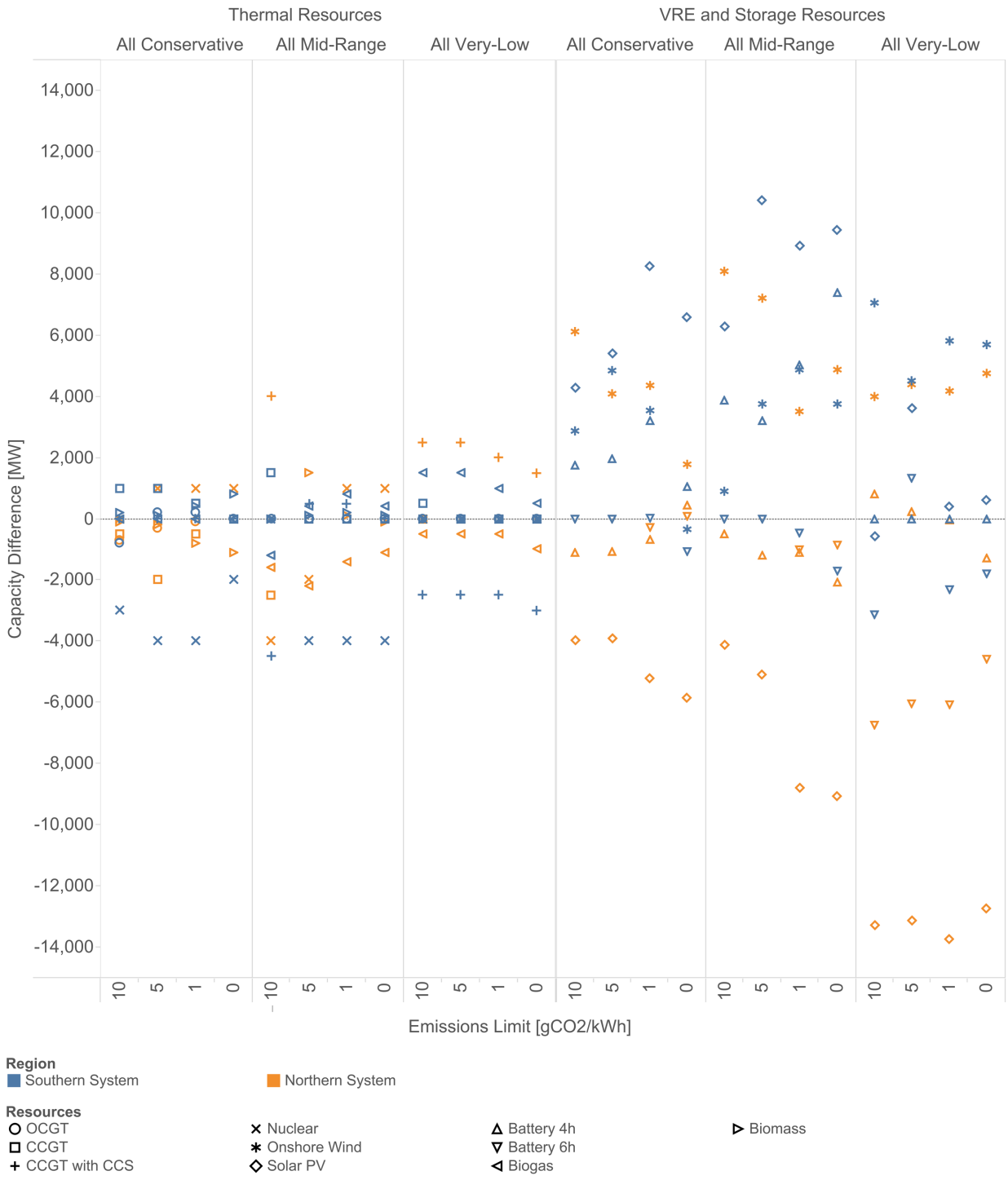


Figure S14 Changes in capacity and location due to interconnection capacity going from 10% to 20% scenario for cases with low-carbon firm capacity

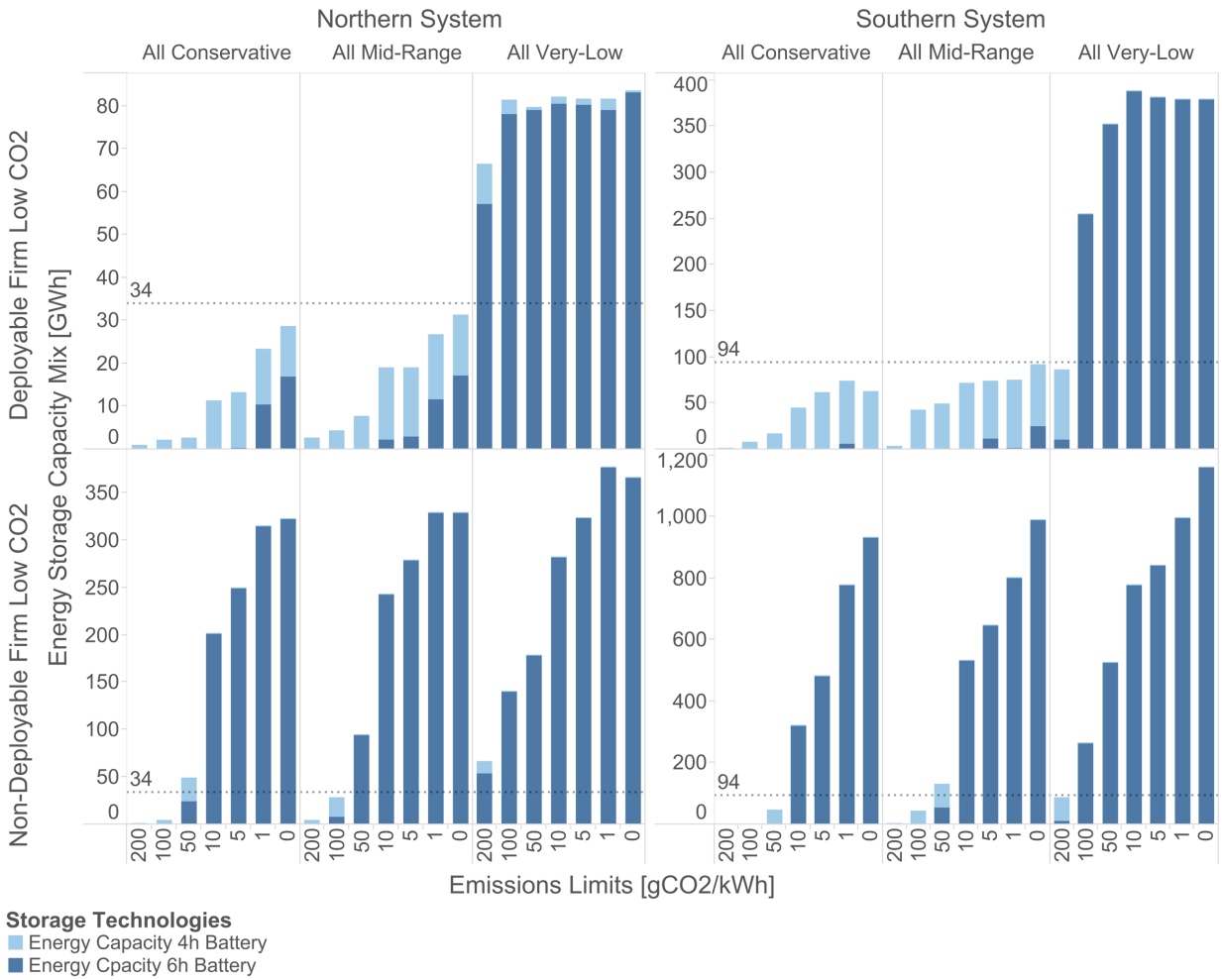
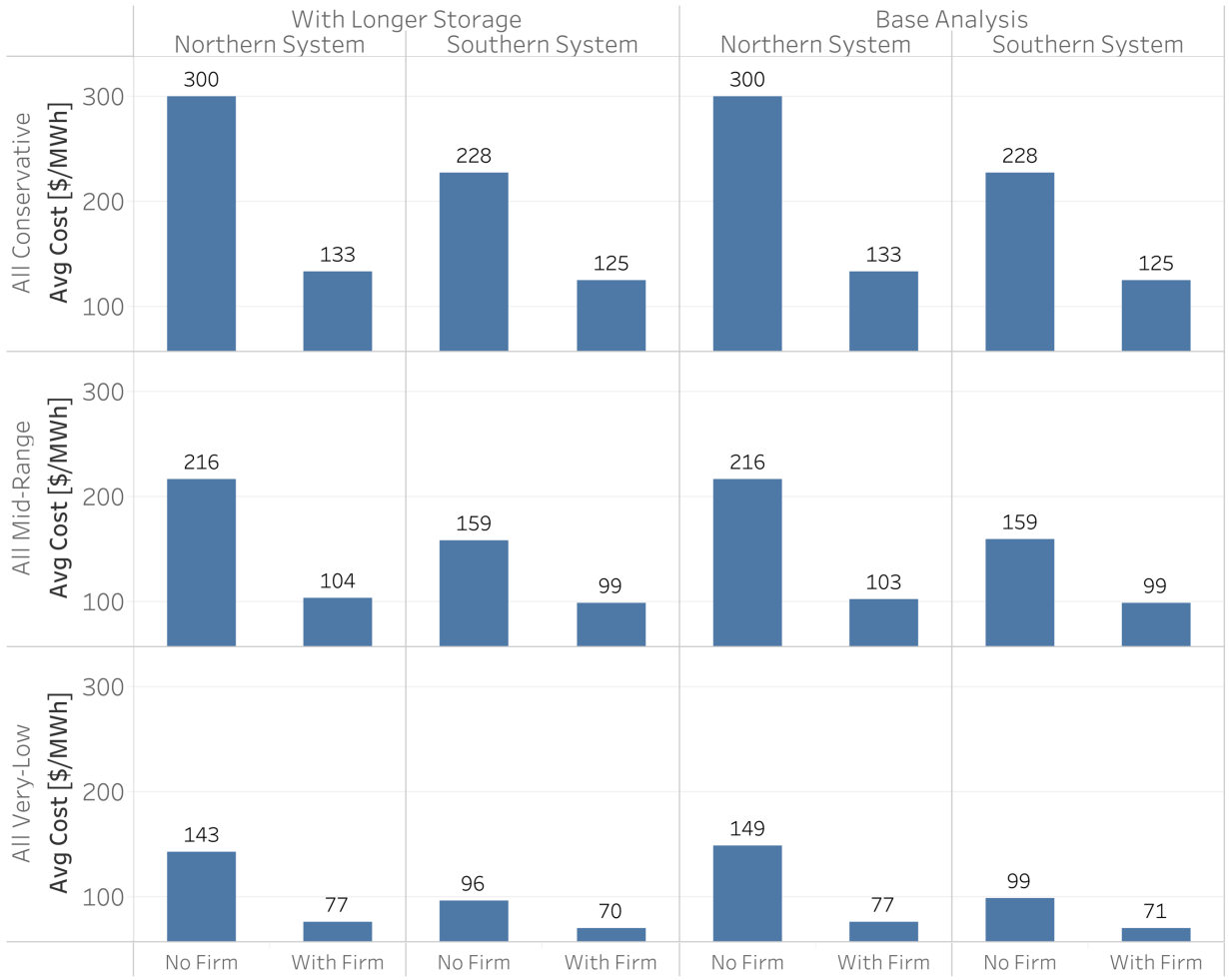


Figure S15 Energy storage capacity mix with and without low-carbon firm resources.



Figures S16 through S18 present results comparing the base analysis with a set of sensitivities for the fully decarbonized (0 grams CO_2/kWh) Northern and Southern test systems with the all conservative, all mid-range and all very-low cost assumptions, and with and without the availability of firm resources. On these sensitivity runs, we included two new storage options: (a) a 24-hour duration energy storage resource with a 15% reduction in capital cost per kWh of energy storage capacity compared to the 6-hour duration battery option. The resulting cost range is from $357-89/kWh (compared to $420-105/kWh for the 6-hour Li-ion battery option); and (b) a 100-hour duration energy storage resource with a 30% reduction in capital cost compared to the 6-hour duration battery option. The resulting range is from $294-73.5/kWh. In both cases, for simplicity we use the same fixed O&M and charge/discharge efficiency assumptions as we use for Li-ion storage. These particular combinations of costs and performance characteristics therefore may not correspond to existing storage technologies. Instead, these assumptions are meant as an expedient analysis to demonstrate the sensitivity / robustness of our results to the exogenous maximum storage duration included in our core cases while including some arbitrary energy capacity cost reductions reflecting economies of scale or cheaper storage medium suited to larger energy (rather than power) capacity than currently available battery storage options. We note that the 24-hour storage option costs are roughly comparable to the range of costs for pumped-hydro storage (generally in the $100-300/kWh cost range), although we assume this is a generic storage technology that is not geographically limited as pumped hydro storage is and we also model a higher round-trip efficiency (comparable to Li-ion storage) than pumped hydro systems display. The 100-hour storage option also does not correspond to any commercially available storage option but is intended to model a potential future option that would be suitable for managing synoptic-scale weather variability (such as prolonged high-pressure fronts and resulting prolonged low wind speed periods).

Figure S16 Comparison of average cost of electricity across cases with and without longer duration storage

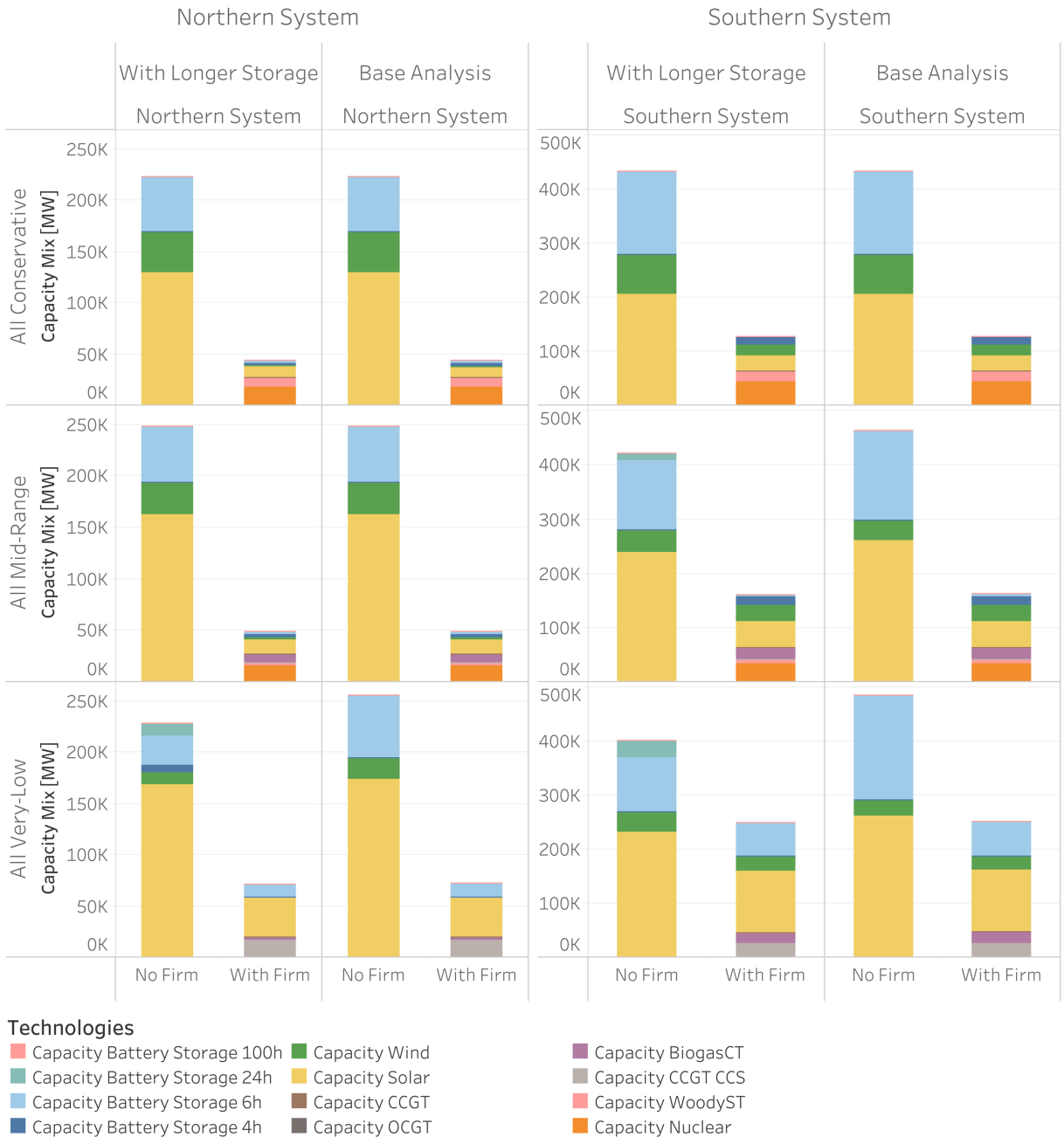


Figure S17 Comparison of installed power capacity across cases with and without longer duration storage

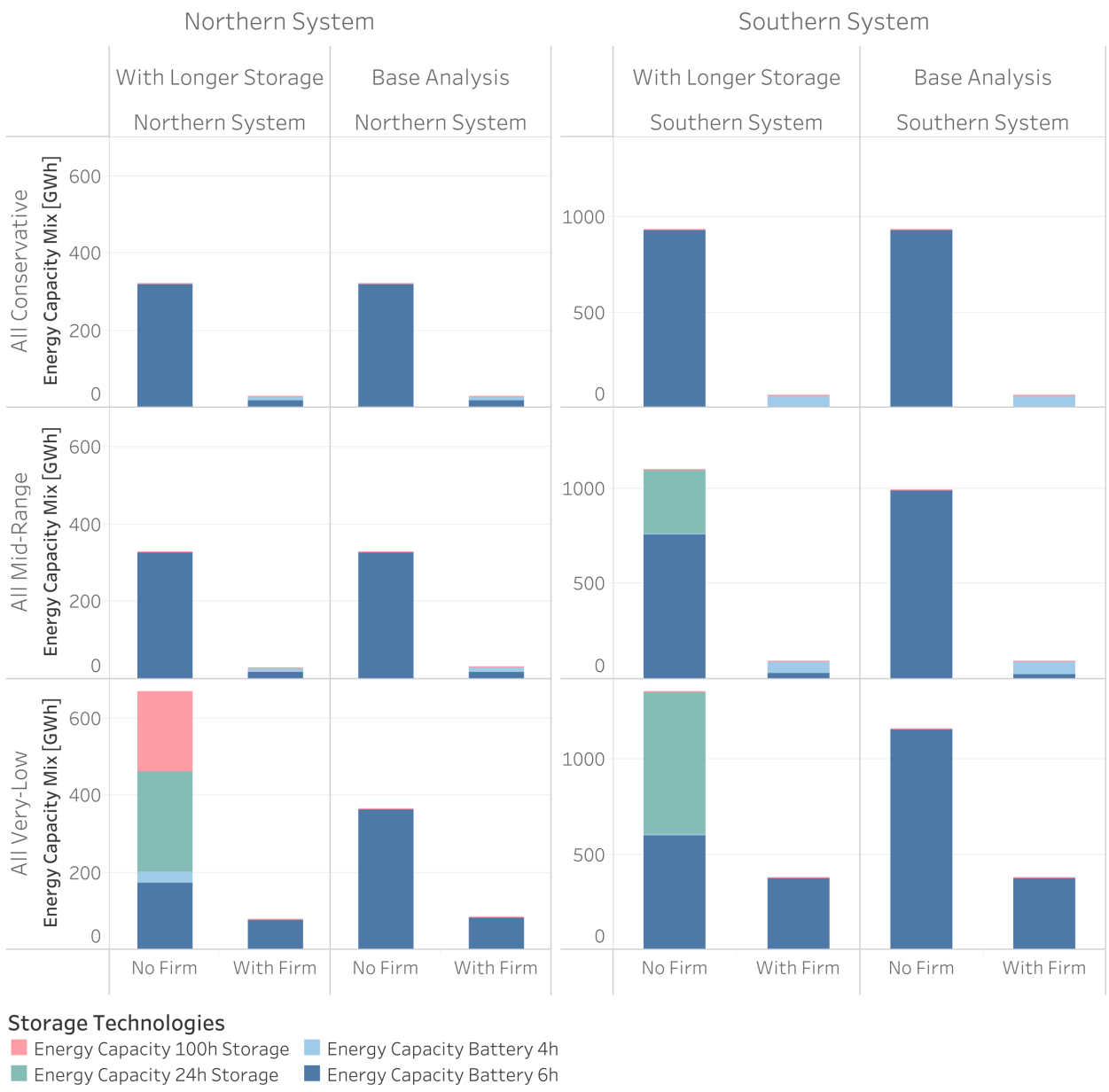


Figure S18 Comparison of storage energy capacity installed across cases with and without longer duration storage

Supplemental Experimental Procedures

Economic and Technical Assumptions

Table S-1 through S-4 present the economic and technical assumptions used in this research. Overnight cost numbers were transformed into equivalent future worth values after construction and then transformed into annuities using after-tax Weighted Average Cost of Capital (WACC) of 5.38% for Conservative (current) scenarios and 8.75% for Mid-Range and Very-Low (future) scenarios. Both WACC were calculated using NREL's ATB 2017 assumptions, considering a change in tax rates (according to 2017 tax reform) for future scenarios[5].

Table S1 Operational Cost Assumptions

Technology	Overnight Cost [$/kW]	Fixed O&M cost [$/MW-yr]	Variable O&M cost [$/MWh]	Start-up Cost [$/per MW Cap]	Asset Life Time [years]
Solar[b]	Table 1	$13,300	-	-	20
Wind[b]	Table 1	$52,400	-	-	20
4-Hour Li-ion Battery[a]	Table 1	$11,000	-	-	10[1]/15[2]
6-Hour Li-ion Battery[a]	Table 1	$15,876	-	-	10[1]/15[2]
CCGT with CCS[b]	Table 1	$33,900	$7.2	$84	20
Nuclear[b]	Table 1	$104,700	$2.05	$1,000	40
Biomass[b]	Table 1	$110,900[1]/ $32,800[2]	$5.1	$106	20
Biogas[b]	Table 1	$12,300[1]/ $10,300[2]	$7.2[1]/$3.1[2]	$84[1]/34[2]	20
OCGT[b]	$880[1]/$780[2]	$12,300	$7.2	$84	20
CCGT[b]	$1,000[1]/$920[2]	$10,300	$3.1	$34	20

[1] Numbers correspond to scenarios Conservative and Mid-Range
[2] Numbers correspond to scenario Very-Low
[a] From [6]
[b] From [5], [7], [8]

Table S2 Technical Assumptions Thermal Generator

Technology	Power Plant Size [MW]	Heat Rate [mmBTU /MWh]	Fuel Type	Min. Stable Output	Hourly Ramp Rates	Min Up/Down Times [h]	Startup Fuel [mmBTU /Start]
CCGT with CCS[a]	500	7.53[1]/ 6.46[2]	Natural Gas	40%	60%	4/3	590
Nuclear[b]	1000[1]/300[2]	10.46	Uranium	50%	25%	36/36	-
Biomass[c]	100[1]/600[2]	13.50[1]/ 8.80[2]	Biomass	50%	30%	24/12[1] ; 4/1[2]	430[1]/ 2600[2]
Biogas[d]	100[1]/500[2]	9.91[1]/ 6.46[2]	Biogas	10%[1]/ 30%[2]	100%	1/1[1] ; 2/1[2]	188[1]/ 590[2]
OCGT[e]	100	9.91	Natural Gas	10%	100%	1/1	188
CCGT[e]	500	6.46	Natural Gas	30%	70%	2/1	590

[1] Numbers correspond to scenarios Conservative and Mid-Range
[2] Numbers correspond to scenario Very-Low
[a] From [5], [9], [10]
[b] From [5], [11], [12]
[c] Assuming proxy coal plant from [5], [8] and availability estimated from [13]
[d] Assuming proxy NG plant from [5] and availability estimated from [14]

Table S3 Technical Assumptions VRE Generation and Storage

Technology	Power Plant Size [MW]	Min. Stable Output	Hourly Ramp Rates	Efficiency up/down	Power to Energy Ratio [1/h]
Solar	Cont.	0%	100%	-	-
Wind	Cont.	0%	100%	-	-
4-Hour Li-ion Battery	Cont.	0%	100%	92%/92%	0.25
6-Hour Li-ion Battery	Cont.	0%	100%	92%/92%	0.17

Biofuels (solid biomass and biogas) are modeled as resources for which the maximum contribution to annual energy generation is constrained by availability of feedstocks. Estimates of available biomass feedstocks are drawn from [13] for solid biomass and [14] for biogas. These references describe national availability of solid biomass and biogas as equivalent to some percentage of existing U.S. coal and natural

gas supplies, respectively. We apply these shares to U.S. Energy Information Administration data from [15] on coal and natural gas energy supplies to derive the available biomass and biogas supplies as a percent of annual electricity generation. This method implicitly assumes that our Northern and Southern test systems have access to biomass feedstocks in proportion to their annual electricity generation, which is a simplifying assumption. Biomass availability and cost across the United States differs by region, and a more precise analysis should be conducted for studies that attempt to model specific regions in greater detail.

Table S4 Fuels Assumptions

Fuel	Cost [$/mmBTU]	CO_2 [kg/mmBTU]	Limited Energy Share
Uranium	1.0	0	-
Natural Gas	7.5	53.1	-
Natural Gas with CCS	7.5	5.3/0	-
Biogas	7.5[1]/15.0[2]	0	2%[1]/10%[2]
Biomass	3.0[1]/7.0[2]	0	10%[1]/35%[2]

[1] Numbers correspond to scenarios Conservative and Mid-Range
[2] Numbers correspond to scenario Very-Low

As shown in Table 2, two demand-side resources were considered in the present study. First, we consider 'demand-side management' (DSM) or 'shiftable' load, which allows a fraction of the hourly demand to be deferred and then served within a maximum time. This resource represents flexible loads that could be re-scheduled, such as electrical vehicles, irrigation pumping, and/or some heating and cooling systems. In this work, we assume shiftable loads can be deferred at no cost for up to six hours and with no rebound in net energy demand due to deferral. Further detailed analysis and empirical experimentation is needed to determine the degree of flexibility and precise characteristics of various flexible loads. We use these simple parameters here only to explore the potential impact of flexible demand, not to project the future degree of flexibility that may be achieved in practice.

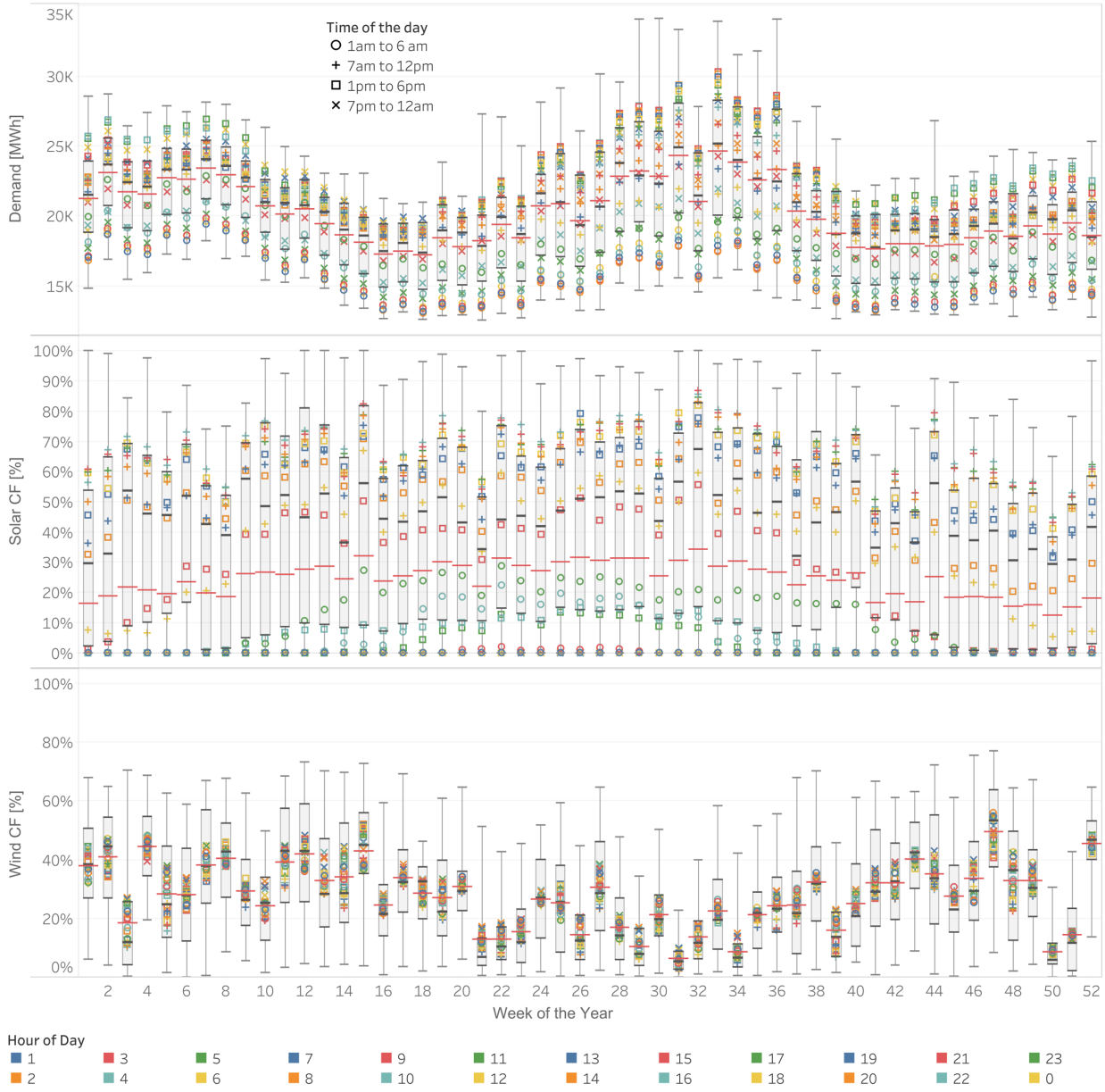
The second demand-side mechanism corresponds to 'demand response' (DR) or price-responsive curtailable load. For this case, different fractions of the hourly demand of the system can be curtailed at different marginal costs, representing the willingness to pay or marginal value of electricity for classes of price-elastic consumers. Consumer segments are represented as fractions (percentage) of the hourly demand with different willingness to pay (cost) as percentage of the value of lost load (VOLL), where the VOLL corresponds to the cost of indiscriminate emergency load curtailment or rolling brownouts. This is effectively a piecewise approximation of own-price elasticity of electricity demand. We assume no cross-price elasticity between time periods (e.g. no rebound in energy consumption in adjacent time periods when demand is curtailed). Again, assumptions here are used only for indicative purposes and actual costs of demand response may differ in various contexts.

Regional Data

In this analysis, we focus on two distinct test systems: one named the "Northern" system with the demand profile and relatively modest renewable resource potential typical of the New England region of the United States; and a "Southern" system with the demand profile and higher renewable resource availability characteristic of the Electricity Reliability Corporation of Texas (ERCOT) region. Data from these two ISO regions were selected because they represent two distinct cases for renewable resource availability, weather conditions and demand profiles, and because hourly time series data is readily available for electricity demand and wind generation in each region. We stress that we are not attempting to perform a detailed planning study for either New England or Texas. Instead, we use data from the two regions to construct two "test systems" with very different climates as a way to explore the general impact of different demand profiles and wind and solar availability on outcomes of interest. Our results should therefore not be interpreted as indication of outcomes for either New England or ERCOT.

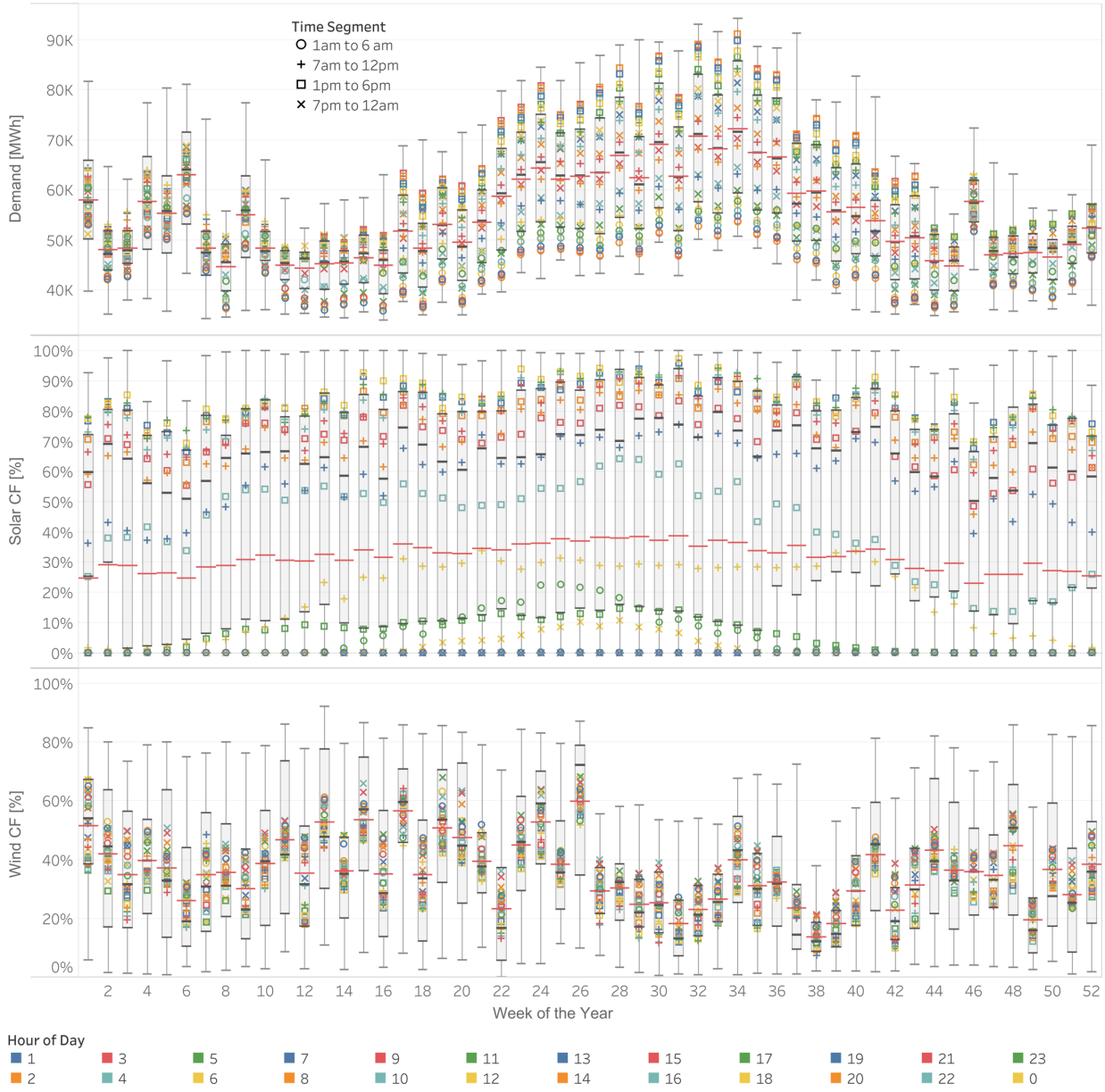
Historical 2015 hourly electricity demand for New England and ERCOT grids [16], [17] was increased at an annual growth rate of 1% to estimate 2050 demand. Wind resource availability was obtained from 2015 historical hourly wind power injections into ISO-NE and ERCOT systems [16], [17] normalized to a per unit availability factor using 2015 installed wind generation capacity. The maximum annual average

wind availability factor is 27.5% in the Northern system and 35.7% in the Southern system. Hourly solar resource availability was estimated by aggregating hourly generation profiles from NREL's PVWatts Model [18] for eight geographically diversified locations in each region, assuming single-axis backtracking systems. The following input settings for the PVWatts model were employed: array tilted at latitude (which reduces seasonal variability of solar output), premium modules (19% efficiency), 1.5 DC-AC ratio (or inverter loading ratio, as per common industry practice for utility-scale systems in 2016 [19]), south-facing systems (azimuth of 180°), 96% inverter efficiency, 14% total system losses, and ground cover ratio of 0.4 (the final four parameters reflect PVWatts default settings). Note that we describe solar PV capacity in AC terms throughout this paper, including assumed construction costs and fixed O&M costs. The hourly availability factors produced by PVWatts represent kWh of AC injection per kW of DC-rated capacity. Since we report values per kW of AC capacity, the hourly availability factors from PVWatts were scaled by the assumed 1.5:1 DC to AC ratio to reflect the kWh of AC injection per kW of AC-rated capacity. The resulting maximum annual average availability factor per kW-AC is 24.3% in the Northern system and 31.8% in the Southern system. Figures SI-15 and SI-16 show the underlying data used to characterized each system. The plots show data for each week of the year, presenting a box plot for all hours in a specific week and point for the average value for each hour of the day for the specific week.



Whisker box plot made for all the hours in a specific week, Distinct colors and shapes show the average value for each hour of the day for a specific week. Red lines show the average value for that specific week.

Figure S19 Regional data (New England) used to characterize the Northern System



Whisker box plot made for all the hours in a specific week, Distinct colors and shapes show the average value for each hour of the day for a specific week. Red lines show the average value for that specific week.

Figure S20 Regional data (ERCOT) used to characterize the Southern System

Experimental Setup

The GenX electricity resource planning model [20] developed at MIT was used in the present research. For this analysis, we model a "greenfield" capacity plan—i.e., everything is built from scratch. The previous assumption is justified given the lifetime of existing generation assets (less than 30 years) and the explored year 2050. Arguably, the electricity generation resources operating in 2050 will have to be built in the decades to come and most current resources will not be in operation. In addition, we are not attempting to perform a planning study for a specific region. Instead, we use two "test systems" with differing climates as a way to explore the general impact of different demand profiles and wind and solar availability on outcomes of interest.

We model a time interval of one full year, divided into discrete one-hour periods and representing a future year (e.g., 2050). In this sense, the formulation produces a static long-run equilibrium outcome, because its objective is not to determine when investments should take place over time, but rather to produce a snapshot of the minimum-cost generation capacity mix under some pre-specified future conditions.

The model uses integer unit commitment constraints for thermal power plants (natural gas, nuclear, biomass, and biogas plants in this study) as developed in [8] and [23]. This approach helps reducing the number of integer variables in a full binary unit commitment formulation (one binary variable for each thermal generator) to a more tractable formulation that uses integer variables to represent a set of resources of the same type in a cluster. This method produces two sources of abstraction error [22], [23]: first, it treats the technical and economic characteristics of all units in a cluster as identical; and second, it assumes that power output from all committed units in any given time step is equal (e.g. if 100% of units are committed and operating at 80% of maximum output for the cluster, the assumption is that all units in the cluster are producing at 80% of their maximum power rating). The first source of abstraction is not relevant here, because greenfield capacity planning already typically assumes one standard available model for each generator type. All units of a given technology type are therefore already identical and clustering them results in no additional abstraction. The second source of abstraction error is relevant and should be noted. However, as shown in [23], the induced error due to the approximation of this method is

generally less than 0.06% in the total cost of the system and less than 0.1% on the energy shares of different resources while the gains in computational tractability are substantial.

Reserve requirements can be model in GenX at the expense of computational tractability. In preliminary analysis, we required frequency regulation commitments to meet or exceed 1% of forecasted demand (before any demand response or load shifting) plus 0.36% of forecasted wind and solar availability (before any curtailment) in each hour. Operating reserve requirements in the upward direction included a contingency reserve equal to the largest generation unit that can be installed in the scenario (e.g. 1000 MW nuclear unit or 500 MW CCGT unit, depending on case) as well as 3.3% of forecasted demand and 7.95% of forecasted wind and solar availability to cover forecast errors. Operating reserves in the downward direction were set to equal or exceed 3.3% of forecasted demand and 2% of forecasted wind and solar availability. Regulation and reserve requirements are adapted from [8]. Modeling reserve requirements did not have a significant effect on total system costs (less then 2%). Imposing reserve requirements resulted in relatively small changes in total installed capacity for thermal generators and variable renewable energy resources with some relative small increments of energy storage deployment. Due to the increased computational complexity required to account for reserve requirements and the second-order impact of these requirements on the results, reserve requirements were not modeled in the final set of cases reported in this paper.

Limitations and Future Work

As with all large-scale optimization problems, the simulations in this paper face computational constraints that necessitate certain modeling tradeoffs. In the current paper, we configure GenX to deliver high accuracy in hourly operational and unit commitment decisions. These decisions were important to capture the effects of chronological variability in renewable energy availability and demand patterns on investment and operating decisions, particularly under scenarios with very high wind and solar energy penetrations. Computational complexity is also increased by the inclusion of stringent annual limits on

total CO_2 emissions. However, this level of detail comes at the expense of other limitations that are important to note when interpreting the results of this work.

First, we assume that transmission networks in both regional power systems are unconstrained. That is, each system is represented as a "single node" without considering transmission losses or congestions between generators and demand. In principle, significant transmission reinforcements and expansions could take place in these systems by the year 2050 that would allow dispersed renewable resources, storage systems, and new generators to be accommodated. However, explicit consideration of transmission losses, congestions, and expansion decisions significantly increases model solution time. In addition, transmission networks typically represent a relatively modest share (around 5% [24]) of total power system costs. In the interest of computational tractability, transmission power flows and expansion decisions are not considered. However, to explore the general impact of long-distance transmission expansion, our sensitivity cases include cases where we exogenously increase interconnection capacity between the two test regions.

Second, our model is fully deterministic and assumes perfect foresight in planning and operational decisions. The model is capable of modeling day-ahead commitment of frequency regulation and operating reserves, which are employed by system operators to deal with errors in renewable energy or demand forecasts or unanticipated failures of generators or transmission lines. As already mentioned we consider regulation and reserve requirements in several preliminary analyses and found that these requirements did not have a significant effect on outcomes. In the interest of computational tractability and the ability to model a greater number of total cases, we therefore do not consider regulation or reserve requirements in the cases reported. Finally, we model only a single year of chronological variability for wind and solar availability and demand patterns, while both renewable energy and demand can vary on an inter-annual basis as well. As a result of these limitations, our results underestimate to some degree the cost of managing wind and solar variability, particularly in scenarios where these resources reach high energy shares, and accordingly under-estimate the value of firm resources such as nuclear, biogas, or gas CCGTs and OCGTs.

Third, we do not perform sensitivity analysis for natural gas prices or changes in electricity demand patterns (e.g. due to electrification of heating or transportation or adoption of new electric-consuming devices), both of which may affect our results. We chose not to model uncertainty in these parameters in the interest of covering a wide range of variation in potential technology cost, emissions limits, and regional renewable resource availability. Future work can consider the impact of a wider range of parametric uncertainty on the role and value of various resources in deep decarbonization.

Finally, the impact of distributed resources has not been examined, as large-scale bulk resources are generally the most cost effective options for decarbonization of power systems due to economies of unit scale [24]. The role and impact of distributed energy resources in decarbonization of power systems could also be explored in future work.

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