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Deep Decarbonization of the U.S. Electricity Sector: Is There a Role for Nuclear Power?

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Abstract: Continued improvements in wind turbine and solar PV technologies have reduced their costs to the point that they are nearly competitive with natural gas generation. This would seem to suggest there is little reason to look at other low carbon power sources such as nuclear, considering that the cost of building nuclear power plants, one of the main low carbon alternatives in the power sector, has remained high. However, simple costs metrics such as levelized cost of electricity are poor indicators of the full system cost and the competiveness of different technologies. We use then an hourly electricity dispatch and capacity investment model, EleMod, to investigate whether nuclear power has a potential role in decarbonizing the US power sector, assuming that the cost of wind and solar continue to decline such that they become the least expensive of any generation option in terms of levelized cost.

We find that solar and wind expand to about 40% of generation even in a scenario without any carbon policy. Under an electricity-sector policy to reduce CO_2 emissions by 90%, we find that existing nuclear is almost phased out, and no advanced nuclear, at a cost of $0.076/kWh (2006$), is built while solar and wind expand to provide over 60% of power generation in 2050, with most of the rest coming from gas, hydro and some still operating existing nuclear plants. However, if the cost of advanced nuclear is reduced to $0.05/kWh (2006$), in the emissions reduction policy case wind and solar expand until they reach about 40% of generation, as they did in the no policy scenario, and then nuclear expands to meet the remaining low carbon power supply. Our simulations show that the availability of nuclear reduces the needed carbon price in the power sector to meet the 90% reduction target from near $120/ton (2006$) of CO_2 to under $40/ton (2006$) by 2050. From these results, we can conclude that the additional system costs of wind and solar are minimal until they reach about 40% of power supply, but after that level these extra costs rise, making room for other power technologies such as nuclear, which can significantly reduce the carbon price needed to achieve deep decarbonization in the US.

1. Introduction

The cost of building nuclear power plants, one of the main low carbon alternatives in the power sector, has remained high even as there have been continued improvements in wind turbine and solar PV technologies that have reduced their costs and improved operating characteristics. This would seem to suggest that the path to a future low cost, carbon-free power sector is with renewable power, with little reason to look at other low carbon power generation sources such as nuclear, especially given issues of safety, management of spent fuel, and nuclear proliferation. We investigate whether their is a possible role for nuclear given the intermittent nature of wind and solar power. To do so, we employ an hourly capacity planning and dispatch model, and assume continued aggressive reductions in the costs of wind and solar, so that the main limitation on them is the challenge of matching their daily and seasonal pattern of supply with demand patterns. Note that to be consistent all dollar costs and prices are reported in 2006 constant dollars, the base year of the EleMod. Based on the chain-weighted BEA implicit GDP price deflator, reporting in 2018 dollars would increase all of these costs by about 22.6%

According to the IEA (2018b), the average installed cost per kW for PV fell on order of 40 to 50% between 2012 and 2017. IRENA (2018) projects that the global average levelized cost for on-shore wind will fall to near $0.04 per kWh by 2020 with solar PV not far behind at around $0.05. This is comparable to U.S. Energy Information Administration (EIA)'s recent estimates for the US that put the wind cost at $0.0498 and solar PV at $0.0533 per kWh. That does not quite beat out natural gas combined cycle costs given the low cost of gas in the US. However, EIA (2018) further estimated that the levelized value of tax credits are $0.009 and $0.0112 per kWh for wind and solar respectively, making them competitive with their estimates for gas generation from an investor's perspective and so, as long as these tax incentives remain in place, renewables are basically competitive with the lowest cost fossil fuel alternative. These lower costs can be passed onto electricity consumers as well, but of course taxpayers ultimately bear the cost of these tax expenditures as a larger deficit and higher taxes at some point. EIA (2017) estimated the cost of advanced nuclear at $0.076–0.084/kWh. In a set of sensitivity analyses for nuclear, the EIA (2018c) varied nuclear costs +/- 20% from the reference cost, but even the low side is well above the estimated current cost of wind and solar. And, various analysts suggest that there is room for further cost reductions for these renewables, possibly bringing their levelized cost below $0.034 per kWh.

Given the falling costs and various policy incentives, wind and solar technologies have dominated investment in the power sector globally in recent years, as shown for 2017 (**Figure 1**). Among generation technologies, IEA data show wind and solar accounting for 65% of the investment, with

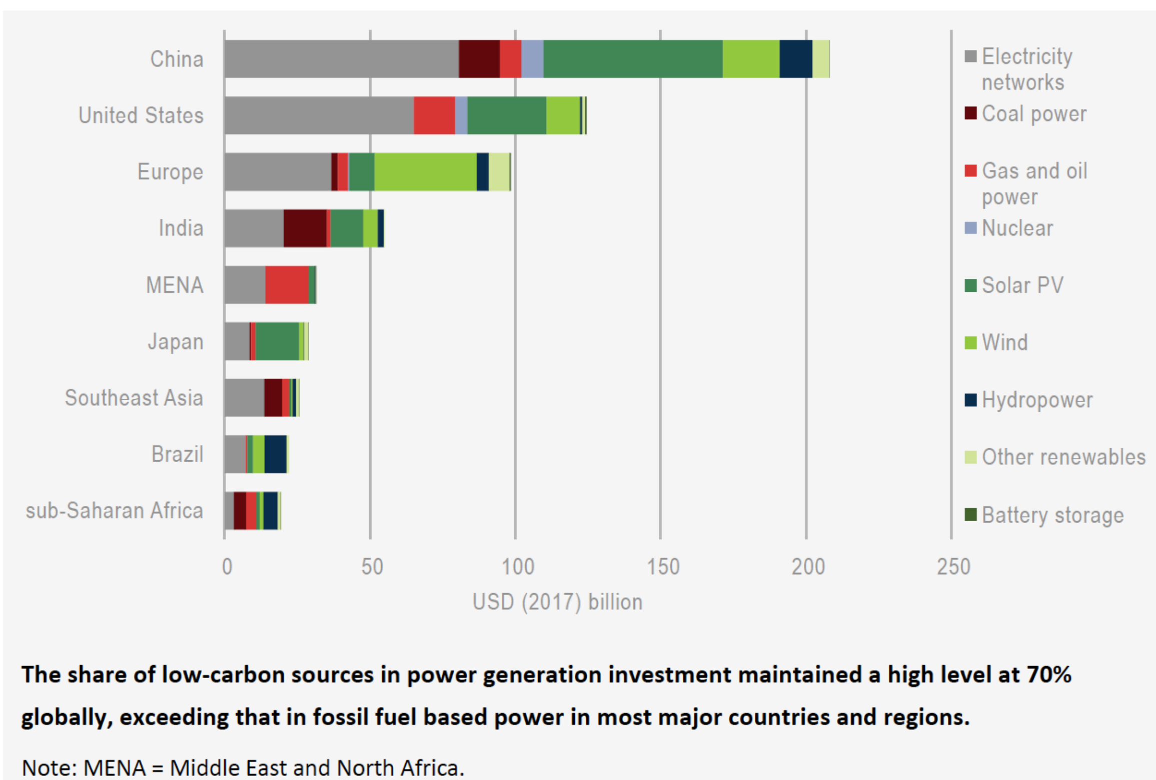

Figure 1. Power Sector Investment by major country and region, 2017. Source: IEA (2018)

another large chunk of investment in electricity networks, which may have a number of purposes, but generally improvement in the power grid is seen as a necessary enabler of renewable development. The dominant level of investment by these sources is not by itself proof that these are the cheapest options everywhere, as, like in the US, there are various policy incentives for renewables in many if not most countries. These incentives range from combinations of tax incentives and renewable portfolio requirements as in the US, to other incentives such as guaranteed feed-in tariffs for renewables, or carbon pricing through taxes, or cap and trade systems. From an economic perspective, carbon pricing is the most efficient way to achieve needed emissions reductions. Given the relative levelized costs, it would appear to not take much of a carbon price to tip the balance toward wind and solar and away from gas, even without additional production tax credits or renewable requirements, and these renewables would continue to have a significant cost advantage over nuclear. If not fully competitive yet, the cost data cited above suggests they are nearly so and, if costs continue downward, they could soon be competitive suggesting other policy measures would be unnecessary—it might appear that the power sector could be carbon free without a carbon policy.

So why even consider nuclear power as an option? It is now a fairly standard refrain to note that the sun does not always shine and the wind does not always blow. These intermittent renewables are not "dispatchable" and so cannot follow the pattern of demand that varies by season, during the week, and over the course of a day. This makes the levelized cost calculation a poor guide to the full cost of providing reliable, dispatchable power. The pattern of renewable supply and demand varies from country to country and across the US depending on climate and weather, heating and cooling demands, the pattern of industrial demand and other factors. Hence, there is not a simple calculation that can replace the levelized cost calculation. In general, in the US the power peak is in the summer when air conditioning demand is high, with a secondary peak in the winter for furnace blowers and/or growing use of heat pumps in some regions. Daily peak for power demand is late afternoon and early evening, and weekend use is generally lower. Wind generation, at least on land, tends to be strongest and most reliable in the spring and fall and especially weak in late summer. Solar is a better seasonal match at least for the summer peak, but the daily solar supply peak is at noon, a few hours before the demand peak, and cloudy days can severely limit solar generation. So far, in most regions of the country (and the world) these intermittent sources are providing a few percent of power needs. At this level, intermittency issues generally have not arisen as there is adequate reserve in the system. In a few countries including UK, Germany, and Spain, intermittent sources have reached a sizable share and that can then increase the system cost of providing reliable supplies (Klessman *et al.*, 2008), and require changes in how electricity markets are structured to assure demand and supply are met continuously as intermittent renewable supply varies (Hass *et al.*, 2013).

In this paper, we set out to investigate the potential role of nuclear power under a scenario of deep decarbonization of the electricity sector, focusing on the United States, recognizing that even if renewables were very inexpensive in terms of their levelized costs, the reserve requirements to meet demand could make a somewhat more expensive nuclear power option attractive from an economic standpoint. To investigate this question, we further developed an hourly dispatch and capacity expansion electricity model. This model allows evaluation of how hourly patterns of demand and intermittent renewable supply match up across the country, including transmission options to get electricity from high supply to high demand regions. The model finds the combination of power generation investment options and optimal operation of those generation technologies that provide the lowest system cost while reliably meeting hourly demands.

In the following section we briefly describe the electricity model we use in this work. We then describe the scenarios we specified to investigate whether there is a role for nuclear, followed by results, and some final conclusions.

2. An Hourly Electricity Dispatch and Capacity Investment Model

There are a wide range of electricity sector models with different levels of detail, covering timeframes that range from milliseconds to years or decades. Capacity planning considers investment in power plants with lifetimes of 20 to 30 years or more, and therefore focuses on years to decades (**Figure 2**). On the other end are concerns about stability of the grid, and network flows at minutes, seconds, and milliseconds. To look at decarbonization scenarios, we look at periods of years to decades, with a major focus on what types of electricity generation will be needed to meet low carbon constraints. Historically, it has been possible to largely separate the capacity planning problem from the dispatch problem. Decisions could be made about various baseload generation options, depending on the outlook for demand, fuel prices, and other investment costs, and then separately consider some flexible dispatch technologies such as gas turbines, and other operation decisions such as spinning reserves to respond to changes in demand and to meet peak demand.

Intermittent renewable investment makes it more difficult to separate the problem into a simple choice of base load technology, from the need for flexibility to respond to daily and seasonal expected (and unexpected) changes in demand. Renewables produce only when the resource is

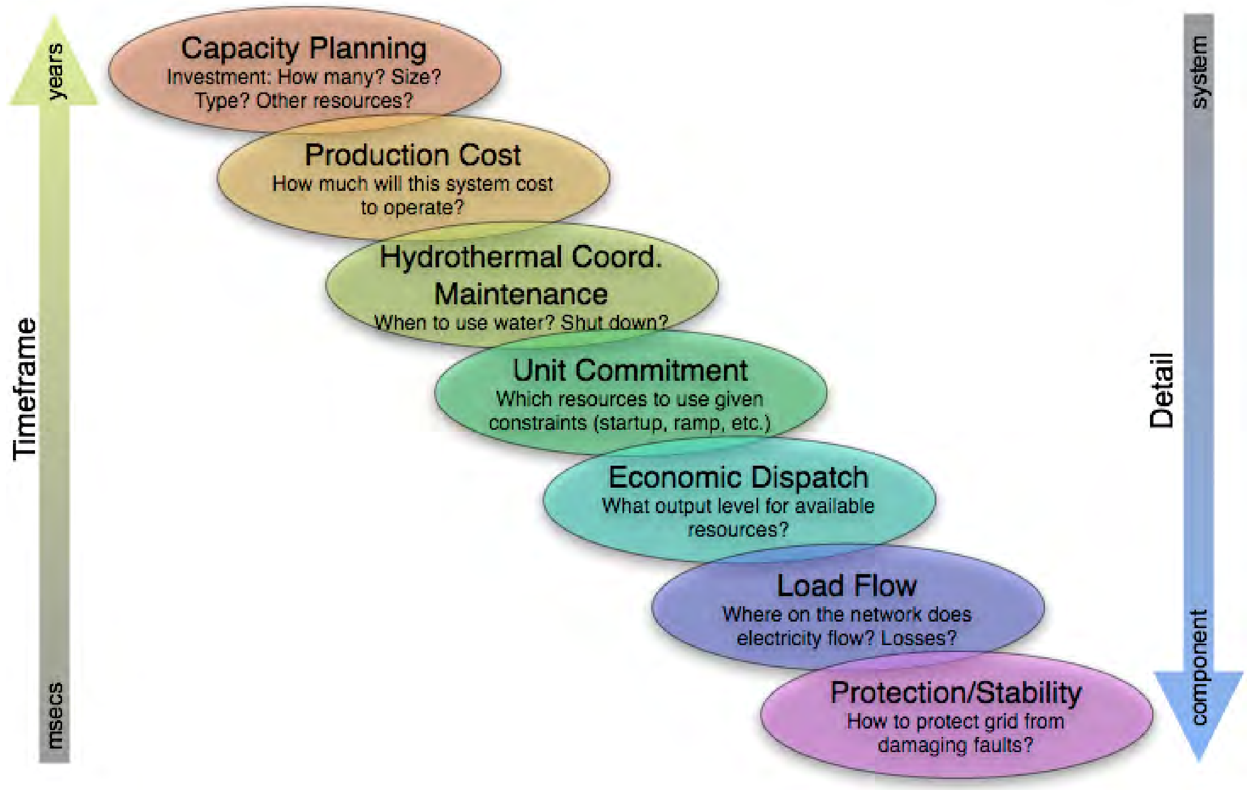

Figure 2. Hierarchical decision-making process in power systems (Palmintier, 2013).

available, and so they cannot be reliably dispatched when more power is needed. But they also do not produce a steady flow of baseload power. One way to look at this, is to identify the likely pattern of renewable generation and then subtract that supply out to look at net demand. What this looks like will depend on how the specific renewable investment supply matches up with the pattern of demand. In many, if not most cases, this results in much more extreme changes in net demand over the course of the day, week, and year. One strategy is to build excess capacity of renewables at many different geographic locations with strong interconnections to take advantage of geographic differences in insolation and wind, and if necessary "spill" the potential power by cutting out the turbine or solar PV even if the wind is blowing and the sun is shining. This raises the overall system costs because the effective capacity factor falls. Other options are to maintain larger operational reserves, ramp traditional base load capacity up and down, fill in with more flexible generation, use various storage options, or better predict net demand changes. Better prediction of net demand can mean less reserves and more time to ramp, but does not eliminate the need to carry more capacity to meet demand (either that or manage demand).

In addition, flexbility of generation has two components. One is the technical capability to rapidly switch on or off a technology. A second is the economics of doing so—the current nuclear fleet is not very flexible from a technical standpoint. Adding flexibility to nuclear is possible, but it is costly to have a large capital investment idle much of time and so, even if technically possible, it may not be economic to use nuclear.

EleMod was designed specifically to determine the most cost-effective electric generation expansion and operation subject to technical and policy constraints (Perez-Arriaga & Meseguer, 1997; Tapia-Ahumada *et al.* 2014). It does not address load flow and stability of the system that arise at time intervals of less than 1 hour. However, among the technical constraints, there are short- and long- term reserve requirements and minimum loading limits to recognize the need to manage the system at sub-hourly levels. These are exogenously specified and not optimized for specific stability and load flow issues that may arise from integrating renewables.

EleMod is solved as a linear programing (LP) problem, formulated to minimize the total cost of producing electricity. It is deterministic with a recursive-dynamic structure. Optimal solutions are computed sequentially for every two-year period, adding new capacity as needed to meet growing demand, replace retired units, or meet new policy constraints. It includes capacity expansion planning, operation planning and operation dispatch decisions, and

Table 1. Conventional Generation Technologies: Operational Parameters and Performance. Sources: Data mostly based on reports from EIA AEO, NREL's ReEDS, and 2016 ATB reports.

		Minimum Plant Loading [%]	Availability Factor [p.u.]	Forced Outage Rate [p.u.]	Electric Heat Rate [MMBtu/kWh]	CO2 Emission Factor [Metric ton/MMBtu]
Gas Combustion Turbine	GasCT	0%	0.9215	0.0300	0.010033	0.0540
Gas Combined Cycle	GasCC	0%	0.9024	0.0400	0.006682	0.0540
Gas Combined Cycle with Carbon Capture & Sequestration	GasCCS	0%	0.9024	0.0400	0.007525	0.0081
Oil/gas Steam Turbine	OGS	40%	0.7927	0.1036	0.011500	0.0540
Pulverized Coal Steam with SO2 scrubber	CoalOldScr	40%	0.8460	0.0600	0.010400	0.0930
Pulverized Coal Steam without SO2 scrubber	CoalOldUns	40%	0.8460	0.0600	0.011380	0.0930
Advanced Supercritical Coal Steam with SO2 & NOx Controls	CoalNew	40%	0.8460	0.0600	0.008784	0.0930
Integrated Gasification Combined Cycle Coal	CoalIGCC	50%	0.8096	0.0800	0.010062	0.0930
IGCC with Carbon Capture & Sequestration	CoalCCS	50%	0.8096	0.0800	0.010062	0.0140
Pulverized Coal Steam with SO2 scrubber & Biomass Cofiring	CofireOld	40%	0.8463	0.0700	0.010740	0.0930
Advanced Supercritical Coal Steam with Biomass Cofiring	CofireNew	40%	0.8463	0.0700	0.009370	0.0930
Nuclear Plant	Nuclear	100%	0.9024	0.0400	0.010452	-

* The Availability Factor derates the installed capacity for regular planned/forced outages, as in input to the model. An often used term "capacity factor" can be computed as an output of the model, reflecting the actual usage of the available capacity given daily and seasonal patterns of demand, renewable supply, and dispatch order.

Table 2. Technology Costs (2006$). Sources: EIA AEO 2017, NREL ATB 2016, NREL reports.

		Annualized Capital and Fixed Costs [$/kW]	Variable O&M [$/kWh]	Lifetime [yr]
Gas Combustion Turbine	GasCT	83.58	0.0104	30
Gas Combined Cycle	GasCC	143.67	0.0027	30
Gas Combined Cycle with Carbon Capture & Sequestration	GasCCS	218.79	1.0000	30
Oil/gas Steam Turbine	OGS	55.35	0.0048	50
Pulverized Coal Steam with SO2 scrubber	CoalOldScr	158.76	0.0068	60
Pulverized Coal Steam without SO2 scrubber	CoalOldUns	129.42	0.0101	60
Advanced Supercritical Coal Steam with SO2 & NOx Controls	CoalNew	293.34	0.0034	60
Integrated Gasification Combined Cycle Coal	CoalIGCC	644.49	0.0058	60
IGCC with Carbon Capture & Sequestration	CoalCCS	505.94	1.0000	60
Pulverized Coal Steam with SO2 scrubber & Biomass Cofiring	CofireOld	175.05	0.0101	60
Advanced Supercritical Coal Steam with Biomass Cofiring	CofireNew	305.91	0.0068	60
Nuclear Plant	Nuclear	640.54	0.0034	40
Wind	Wind	253.51	0.0143	20
Utility Solar	Solar	205.85	0.0109	30
Pumped Hydro Storage	PHS	93.90	0.0071	50

hourly details include regional load demands and regional wind, solar, hydroelectricity profiles estimates.

Generation options include 12 conventional technologies (**Table 1**) and on-shore wind, utility scale PVs, and hydro. It also includes an option to add a generic storage technology, which is assumed to be pumped hydro. Electricity storage is broadly based on characteristics of pumped hydro storage drawn from various sources including NREL (Short *et al.*, 2011), ORNL (Connor, *et al.*, 2015), Locatelli, *et al,* (2015), and the EIA's Annual Energy Outlook (EIA, 2018a) following an approach described by Meseguer *et al.* (1995). The assumptions that determine its economic competitiveness are costs and technical specifications. Since we do not relate the costs to specific resources that may be unique to pumped hydro, it can also be thought of as a generic storage option with cost and technical characteristics as specified. Namely, overnight capital costs are assumed to be $1500 per kW with fixed operating and maintenance (O&M) costs of $35.60/kWyr and variable O&M of $0.00712/kWhr. We assume a plant life of 50 years with a fixed energy to power ratio of 8 hours, a one way efficiency of 0.85 and a loss of 0.5% per hour.

Wind and solar generation can be curtailed depending on technical constraints and system's oversupply conditions. Existing regional transmission interties are approximated, and the existing installed capacity per technology is represented in the base year as the total capacity for each technology in each region. This representation requires simplified cost and performance characteristics, minimum loading requirement, availability factors, forced outage rates, and heat rates for thermal plants. Costs include fixed and variable O&M, capital, start-up, and fuel. There is also a capacity reserve requirement to ensure long-term reliability of the system to unexpected peaks in demand, assumed tobe between 10 and 18% depending on the region.

Annualized capital and fixed O&M, and variable O&M differ among the technologies available for expansion in the future (**Table 2**).

Annual demand and fuel costs (**Table 3**) are based on fuel price projections by the Energy Information Administration (EIA) and assumed heat rates. The most relevant are gas, coal, and nuclear fuel costs which rise slowly over time.

Wind and solar hourly profiles are taken from NREL data at the regional aggregation level of the model. These are far less variable than a single site as they integrate over fairly large regions and reflect anti-coincidence of resource availability among sites within the region. However, there are still large swings in wind resource availability hour-by-hour, from near full capacity (a value of 1.0) to little or no availability (a value near or at 0.0). Examples of wind resource normalized hourly profiles for two regions, Texas (TX) and New England (NENGL) for a winter and summer week are shown in **Figure 3**. In both regions wind availability is somewhat lower in the June week shown than in the January week, with the June week never achieving more than about .8 capacity availability whereas in January there are periods of .9 or above.

Solar profiles for the same two regions in weeks of January and June show the strong diurnal pattern of availability with no resource during night time, higher availability in June than in January and some variation day-to-day, reflecting cloudiness, and time zone differences (**Figure 4**). Production is also less in January, reflecting shorter days.

The model currently does not endogenously optimize existing hydro power dispatch. Much of the US hydropower supply is based on large dams that serve multiple purposes including providing irrigation water, flood control, recreation use, urban and commercial water supply, and maintaining instream environmental flows. Hence flows cannot be optimized only on electricity demand requirements, especially over seasons. Many of these reservoirs store water from snowmelt in the spring, while managing flooding, to provide irrigation, residential and commercial water supplies, and instream water over dry summer months, and until the next snowmelt. Hence they may need to release water even in the spring to maintain capacity for controlling floods, and must maintain water in the reservoir so that it refills in the next spring. There is more flexibility to vary flow release (and power generation) over the course of a day. Based on historical records using USGS data (UCS, 2012) as described in Boehlert *et al.*, 2016, we established Wet, Medium, and Dry annual hydro supply conditions. We developed the ability to distribute monthly reservoir release over the course of an average day or across months to account for the possibility of flexing it to better match intermittent renewable supply and daily and seasonal peaking needs. Our base supply pattern is drawn from current hydroelectricity operations.

Table 3. Demand and Fuel Costs (2006$) Projections. Source: EIA AEO 2017.

Year	DEMAND *TWh*	DFO *$/MMBtu*	RFO *$/MMBtu*	GAS *$/MMBtu*	COL *$/MMBtu*	NUC *$/MMBtu*
2016	3726	11.95	8.09	3.01	2.16	0.56
2017	3718	14.33	9.3	3.52	2.18	0.6
2018	3773	16.22	10.57	3.81	2.24	0.62
2019	3804	17.25	12.65	4.15	2.29	0.62
2020	3820	17.76	13.26	4.52	2.32	0.62
2021	3848	18.09	13.75	4.58	2.32	0.64
2022	3886	18.35	14.14	4.62	2.34	0.66
2023	3927	18.68	14.53	4.67	2.36	0.69
2024	3963	18.99	14.78	4.73	2.37	0.7
2025	3992	19.48	15.39	4.78	2.38	0.74
2026	4015	19.81	15.85	4.84	2.39	0.76
2027	4042	19.99	15.99	4.88	2.39	0.78
2028	4065	20	16.12	4.96	2.4	0.8
2029	4089	20.26	16.32	5.03	2.41	0.81
2030	4105	20.66	16.64	5.07	2.42	0.82
2031	4121	21.03	16.99	5.14	2.43	0.84
2032	4139	21.49	17.35	5.16	2.44	0.86
2033	4162	21.42	17.28	5.15	2.46	0.89
2034	4191	21.75	17.53	5.13	2.48	0.91
2035	4222	21.9	17.62	5.19	2.5	0.94
2036	4252	22.43	17.97	5.25	2.53	0.96
2037	4284	22.55	18	5.31	2.55	0.99
2038	4320	22.65	18.11	5.31	2.57	1.02
2039	4353	23	18.41	5.36	2.58	1.05
2040	4374	23.22	18.58	5.35	2.6	1.08
2041	4394	23.26	18.67	5.33	2.61	1.11
2042	4421	23.28	18.53	5.4	2.62	1.14
2043	4451	23.33	18.4	5.47	2.62	1.17
2044	4481	23.44	18.29	5.53	2.63	1.21
2045	4510	23.55	18.14	5.6	2.64	1.24
2046	4539	23.73	18.28	5.67	2.65	1.28
2047	4567	24.03	18.48	5.73	2.65	1.31
2048	4597	24.18	18.64	5.78	2.66	1.35
2049	4628	24.23	18.7	5.87	2.67	1.39
2050	4661	24.52	18.95	5.91	2.68	1.43

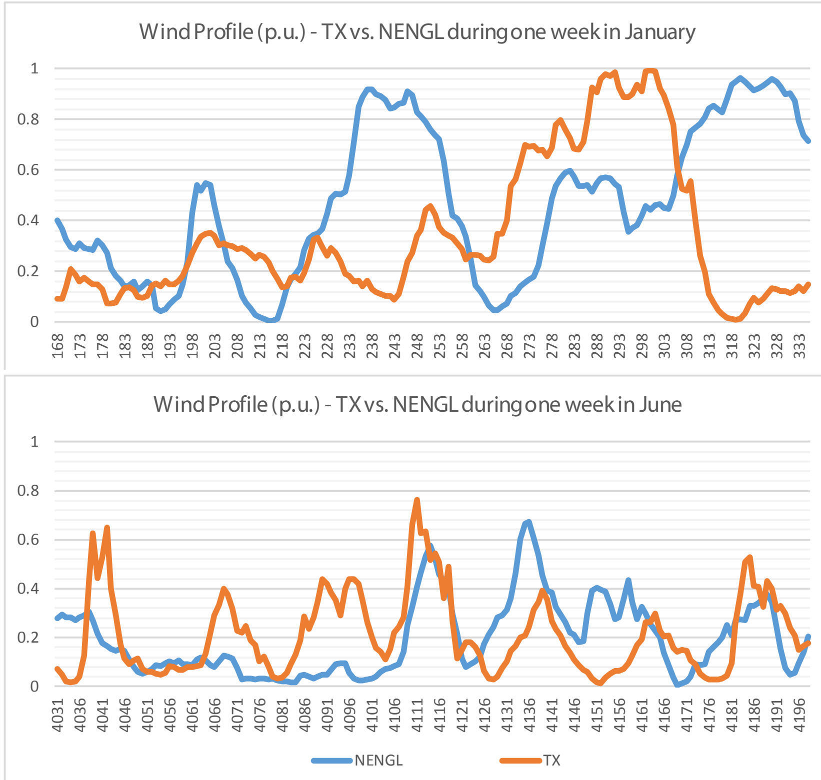

Figure 3. Wind Profile - Texas vs. New England, One Week in January (top panel), and One Week in June (bottom panel).

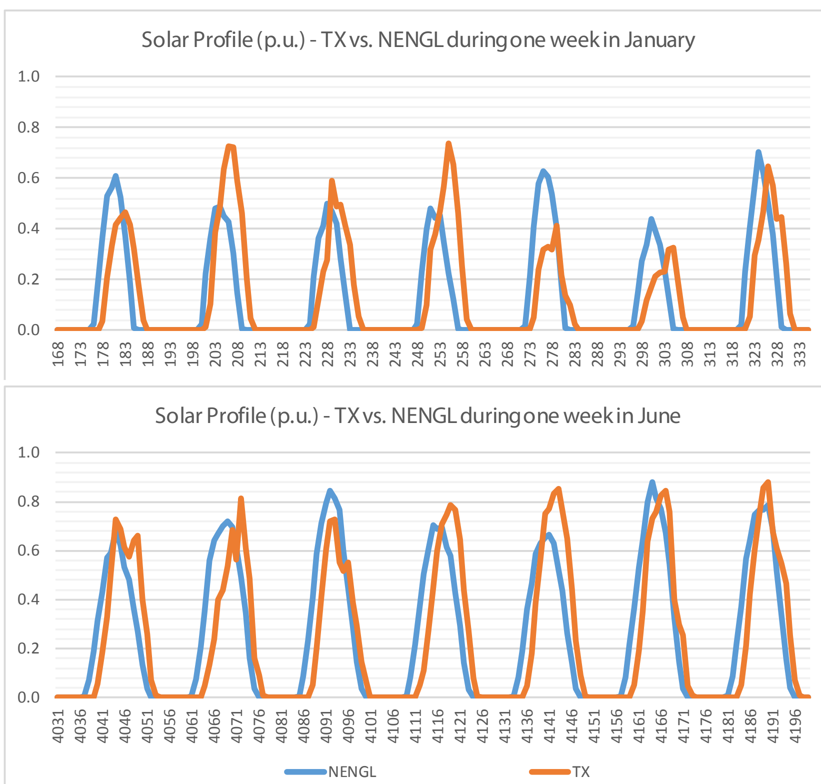

Figure 4. Solar Profile - Texas vs. New England, week in January (top panel), and week in June (bottom panel).

3. Scenarios

We assume a prescribed annual demand path for electricity based on the EIA Annual Energy Outlook (AEO). We have generally assumed that technology costs, in a reference case, are those used by the EIA's AEO 2017, except for wind and solar where we have assumed costs continue to decline for both at 3% per year. This rate of decline achieves costs of $0.024–0.038/kWh LCOE for wind and $0.040–0.062/kWh LCOE for solar by 2050 based on the level of generations estimated by EleMod. This is below our costs for natural gas combined cycle costs of $0.025–0.047/kWh or advanced nuclear of $0.076–0.082/kWh. We did not allow new coal plant without CCS based on regulations for CO_2 emissions from new power plants, however, the current operation costs of fossil steam plants are around $0.025 according to EIA data. These costs include just fuel and variable costs. Hence, based on levelized cost, the assumptions we have for wind and solar would place them at a lesser cost than any other option, and it could pay to prematurely retire fossil plants simply because of the fuel and operation costs, given the increases in fuel costs shown in Table 3. While wind and solar cost reductions may be optimistic, our goal is to formulate a case where levelized cost is not a constraint on adoption and, hence, if we see limited market uptake we can ascribe it to intermittency.

We specify a *Reference* scenario with Hydropower supply set at Medium conditions with a Base fixed seasonal and hourly profile based on current operations. We specify a *Cap* scenario with an emissions cap set to achieve a 90% reduction from 2005 levels, phased in fully by 2050 with the same hydropower conditions.[1] The latter deep decarbonization scenario is also simulated assuming a *Lower Cost Nuclear* starting in 2030 based on the mid-range value found in EIRP (2017). An additional *Flexible Nuclear* scenario retains the low cost assumption for nuclear, while reducing the minimum loading requirement to evaluate the case with more advanced reactors capable of cycling to match load. We retain in all the scenarios an RPS that reflects existing and planned state initiatives—the RPS requirement reaches a maximum renewable generation of 16% of total generation in 2032 and remains at that percentage requirement through 2050. We allow electricity trade among regions within the same interconnect, but not among the Texas, Western, and Eastern interconnects. Electricity trade is limited to existing transmission capacity, aggregated from NREL data derived from Gridview.

4. Results

Figure 5 provides annual generation by technology for the US as a whole in all four scenarios. As might be expected given the costs assumptions, as costs of wind turbine generation fall, power generation from wind begins to expand considerably in the Reference scenario. The RPS reaches a maximum of 16% in 2032 but renewables continue to expand beyond the 2032 level—so at that point it is the low cost, not the RPS, driving this expansion. We see less solar expansion –we have not included other existing policies and measures (such as tax credits) that provide more in-

1 Once linked to the macro-economic-energy model, the reduction in the electricity sector will be determined endogenously given an economy-wide constraint and will differ depending on technology cost assumptions in electricity production and the rest of the economy.

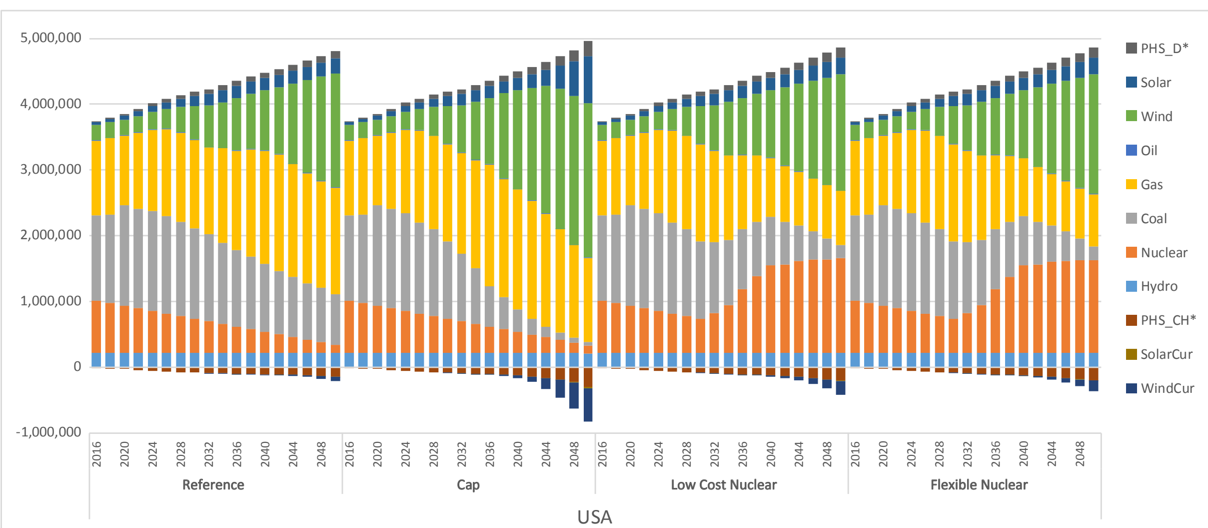

Figure 5. Electricity Generation for the United States (GWh/yr)

** PHS_CH is electricity into Pumped Hydro Storage, PHS_D is electricity discharged back to the grid from storage. The difference is conversion losses.*

centives for solar. Coal power drops in later years as older plants retire, and renewable costs continue to fall below the fuel and other variable costs of coal. Nuclear declines as plants retire along a prescribed path. In earlier years, gas and coal generation reflect changes in fuel prices as taken from EIA. Gas power generation remains fairly steady from 2020 onward, with wind replacing mainly coal and nuclear. So even with the continued falling costs of wind and solar to levels that would be below gas generation costs, we do not see gas power displaced by renewables in the reference case.

In the *Cap* scenario, wind and solar expand considerably after 2040 while coal nearly phases out. Gas plays a strong role and it remains steady until 2050 in this scenario. As plotted, we include as "negative" generation wind curtailments (WindCur), solar curtailments (SolarCur) and Pumped Hydro Charging (PHS_CH), i.e. electricity going into pumped hydro storage. Curtailments result when renewable generation is in excess of demand (including exports to other regions) and available storage capacity for specific hours. As modeled, this occurs when it is less expensive to simply curtail production rather than build additional storage or flexible generation capacity. Power going into pumped hydro, shown as negative production in the figure, is balanced over the long-term, less efficiency losses, by pumped hydro discharge (PHS_D) into the system. By 2050 curtailments and storage are over half a million GWh/year, more than ten percent of the electricity produced (and used), an amount approaching one fifth of the electricity produced from wind and solar. This represents an extra system cost for use of intermittent renewables—the combined cost of building storage, losses in the storage process, and lower capacity utilization of renewables.

In the *Lower Cost Nuclear* scenario, wind also expands well beyond the 16% RPS requirement, again suggesting as in *Reference*, that there is considerable wind development potential that can match demand fairly well. In fact, wind and solar production is almost identical to that in *Reference*—the carbon emissions reduction requirement, and resulting carbon price stimulates little additional development of these resources. Instead, the additional carbon emissions reductions are largely met with rapid expansion of nuclear, even though in *Lower Cost Nuclear* wind is two-thirds to one-half the levelized cost of nuclear by 2050.[2] Coincidentally, the low (~\$0.050/kWh) and high (~\$0.076/kWh) nuclear cost scenarios are pretty clearly bounds on the additional intermittency system costs—at \$0.076kWh nuclear phases out, and intermittency is addressed large through curtailments, storage, and flexible gas generation, but at \$0.050 kWh once renewables reach a level that begins imposing additional system costs nuclear enters rapidly.

There is somewhat less gas generation in *Lower Cost Nuclear*, but gas continues to play an important role as it is a technology that can be flexibly dispatched. Curtailments are slightly higher than in *Reference* with an equal amount of wind generation because of the presence of nuclear which is less flexible. Nuclear may dispatch ahead of some of the wind once built, because of the inflexibility. It may also reflect different build-out of regional wind capacity and its relationship to demand patterns. Also, coal phases out more slowly in *Lower Cost Nuclear* than in *Cap*. No new coal plants are being built so this slower phase out means existing plants are less likely to be prematurely retired, contributing to lower system costs because within the carbon constraint there is room to operate these coal plants that still have a useful life.

Adding nuclear cycling capability (*Flexible Nuclear*) has relatively little effect. There is a small reduction in the curtailment compared with *Lower Cost Nuclear*. The lower capital cost of gas generation still makes it a likely lower cost option for backing up renewables and adding flexibility to the system. And, given our assumption of very low cost renewables, as long as they can match demand patterns, we would not expect nuclear to supplant them. Flexible nuclear could be more important in a tighter cap scenario where the carbon price would raise the cost of using gas so that cycling nuclear was economic. Or a tighter cap could simply reduce the role of renewables if operating the flexible gas technology was too expensive given the carbon price. Finally, note that total generation is identical in all four simulations as it is prescribed and in EleMod there is no demand response to changing electricity prices.

We model all regions in the country, providing in **Figure 6** annual generation from 2016 to 2050 by technology in 4 example regions: Pacific (PACIF), California (CA), New England (NENGL), and Florida (FL) with *Reference*, *Cap*, and *Flexible Nuclear* scenarios, left to right. (We have omitted *Lower Cost Nuclear* because it is very similar to *Flexible Nuclear*.)

The different generation patterns illustrate the varying resource availabilities in different regions (and how they match with demands). Florida's wind resources are generally poor, and so it relies much more on gas, and even some nuclear in the *Cap* scenario. It has a considerable amount of solar, but virtually no wind. As a result, solar curtailments in Florida are marginal, although the region clearly exports part of its generation to neighboring regions – electricity imports and exports can be inferred by comparing generation (bars) with prescribed regional demand (dashed lines). The PACIF, CA and NENGL have considerable wind, and show significant curtailment. The PACIF and CA regions have more solar, whereas NENGL

2 Low cost nuclear ranges between \$0.045–0.059/kWh.

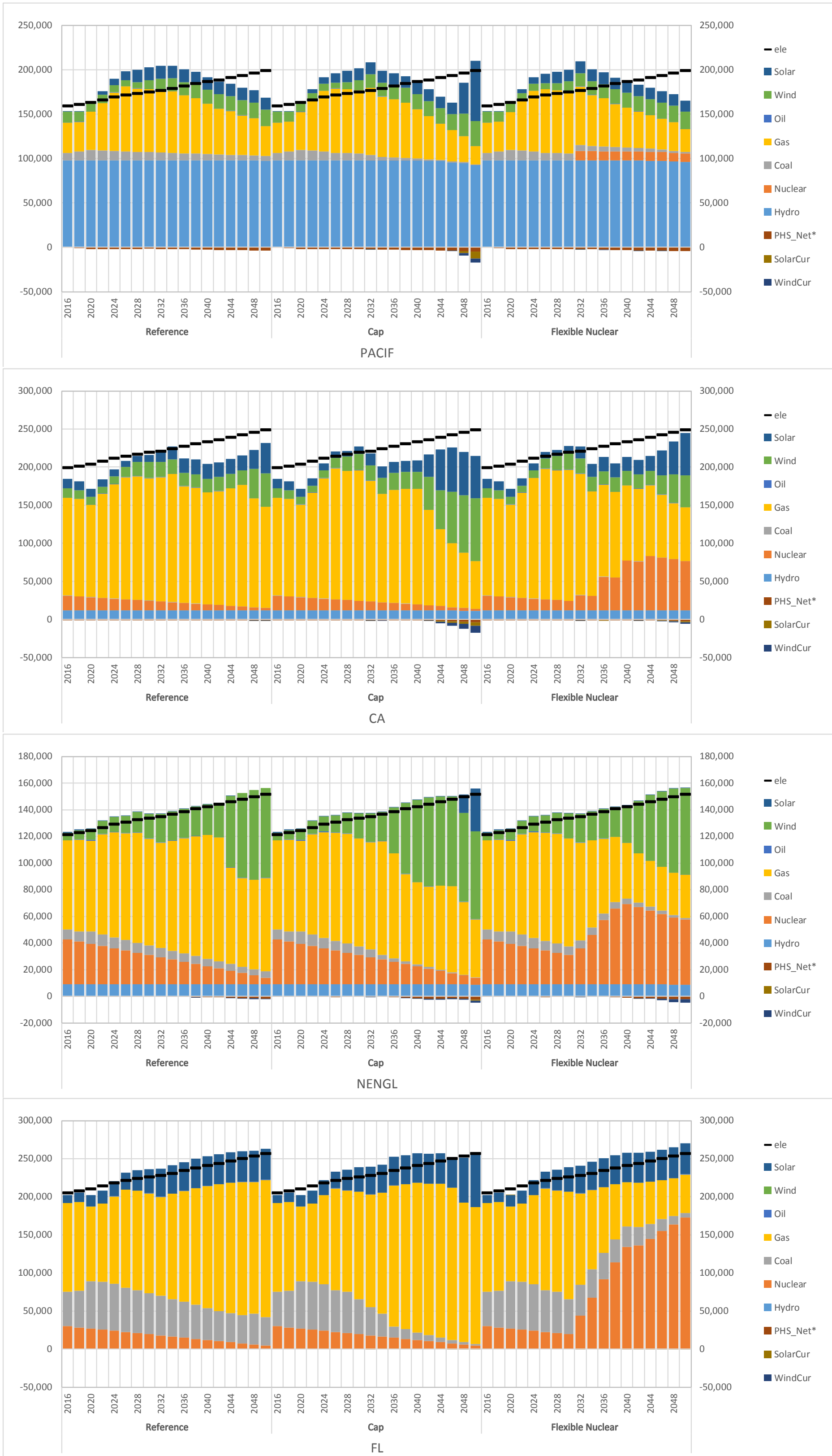

Figure 6. Electricity Generation in four Example Regions (GWh.yr). Note: The dash line represents prescribed regional electricity demand. The blue for SOLAR is darker than that for OIL. There is virtually no OIL in these regions.

**PHS_Net is the difference between charging and discharge of pumped hydro storage. It is negative, reflecting the efficiency loss in conversion.*

has little. With trading of emissions allowances, individual regions do not necessarily need to meet the prescribed reduction below 2005 levels. Regions can emit more by purchasing allowances, meaning other regions will reduce more than the prescribed amount. For example, with the significant amount of gas generation in Florida, it will have higher CO_2 emissions than the prescribed reduction path.

Figure 7 shows total exports and imports among regions. While there is no requirement that these net to zero (and they generally do not), exports and imports are often nearly balanced. This may be because trading of emissions allowances can substitute for electricity trade. Already noted with regard to Figure 6, Florida clearly does not reduce emissions by 80% from 2005 levels by 2050 because gas

Figure 7. Electricity Net Trade among Regions (GWh.yr). For each pair of trading partners, positive net trade represents net export from the first region to the second region. Negative net trade represents net import from the second region to the first region. For example, there is net export from NEAST to NY for most of the years across scenarios. Also, NY receives net imports from NENGL.

generation continues to grow. While coal generation falls, coal is not a large generation source in 2005 in Florida. To meet the carbon constraint, it might have instead greatly reduced gas generation and coal generation, and imported large amounts of generation from elsewhere (e.g. wind from NCENT). But it is much easier to simply purchase allowances than move the electricity, and, in particular, allowance purchases can substitute for expansion of transmission capacity where it is a constraint. Transmission capacity could still be a constraint in regions with very large potential renewable capacity if highly variable renewables required very large flows into or out of the region that eclipsed transmission capacity.

Figure 8 provides results of the total installed capacity (GW) by technology type. Results show a slight reduction in capacity in early years, as the model allows excess capacity to depreciate away. Relative to generation, nuclear and coal, are relatively small shares of capacity, because that capacity tends to operate at 80 or 90%. Gas flexes more to fill in shoulder and peak periods, so shows a higher share of capacity relative to generation as compared with nuclear or coal. Wind and solar have a much larger share of capacity than generation because they operate at well under a 50% capacity factor (because e.g. the sun shines for less than ½ the day—the capacity is necessarily idle during the night—and wind capacity factors depend on regional wind patterns but a factor of 40% is considered high quality wind.[3]). These base capacity factors are typically considered in LCOE calculations, however, those calculations cannot take account of lower actual capacity because of curtailments. Curtailments (electricity prices at zero) or even electricity prices below the LCOE, will begin to undermine the incentive to invest in the technology unless it coincidentally is also available during hours when the electricity price is very high. Continued expansion of an intermittent technology is thus somewhat limited by the economic return it earns unless one can find sites that are anti-coincident. If there are no other options with reasonable prices, then electricity prices will need to be higher on average to bring forth more investment, even if that means more periods of zero electricity prices.

Notable is that generation capacity is about ~40% higher in *Cap* than in the other two scenarios by 2050. This reflects the greater use of wind and solar that have much lower capacity factors (given the daily patterns of wind and solar—see examples in Figure 3 and Figure 4). In addition, there is curtailment of these sources, as shown in Figure 5, further lowering the effective capacity utilization, and the capacity utilization of other sources, such as gas generation, also falls as it cycles off when renewable supply is available. All of these factors mean there is more generation capacity for a given amount of generation required. This also suggests why, even at these low costs for wind and solar, nuclear at twice the cost in *Flexible Nuclear* contributes substantially. Nuclear firm capacity contributes largely to the long-term system reliability of the system.

Figure 9 shows generation capacity expansion for 8 regions. At a broad scale, it mirrors the national capacity figures, showing more capacity in *Cap* than in the other two scenarios.[4] The MOUNT (MT, ID, WY, NV, UT, CO,

3 The wind is more reliable (blows more regularly) at higher altitude above the surface because it is less affected by interactions with the earth's surface, and hence the trend toward increasing turbine heights and higher capacity factors.

4 As the cap constraint gets tighter in the *Cap* case, installed capacity increases by the end of the time horizon.

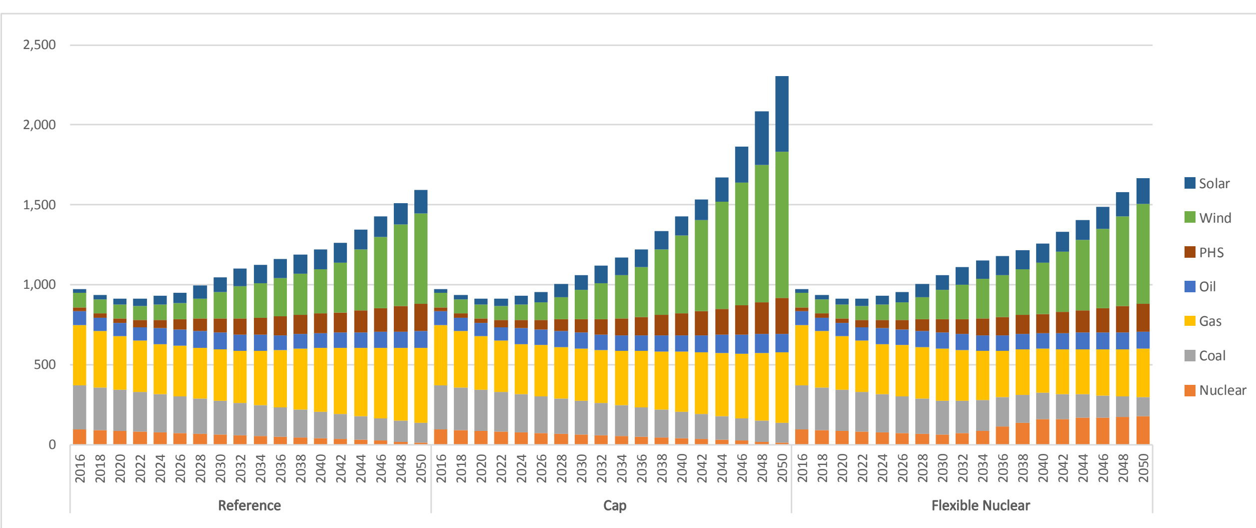

Figure 8. Electricity Generation Expansion (total installed capacity) for the United States (GW).

AZ, NM), NCENT (MO, ND, SD, NE, KS, MN, IA), FL and to some extent NENGL regions are exceptions. As we saw earlier, there were almost no curtailments in the *Cap* scenario in FL, and so it is not unexpected that generation capacity is similar to the other two scenarios. Solar expansion is nearly unchanged across scenarios. Between the Cap scenarios, the role of gas and nuclear differs, with nuclear showing larger expansion in the *Flexible Nuclear* scenario. For the other 3 regions (NCENT, MOUNT, and NENGL) the similar capacity expansion is due to similar expansion of wind in all scenarios. These regions are seen as generally wind resource-rich areas, and so it is not surprising that expansion occurs in these regions. However, their expansion depends not only on their ability to match temporal demand patterns, but also on whether or not they can fully recover their costs through the incomes

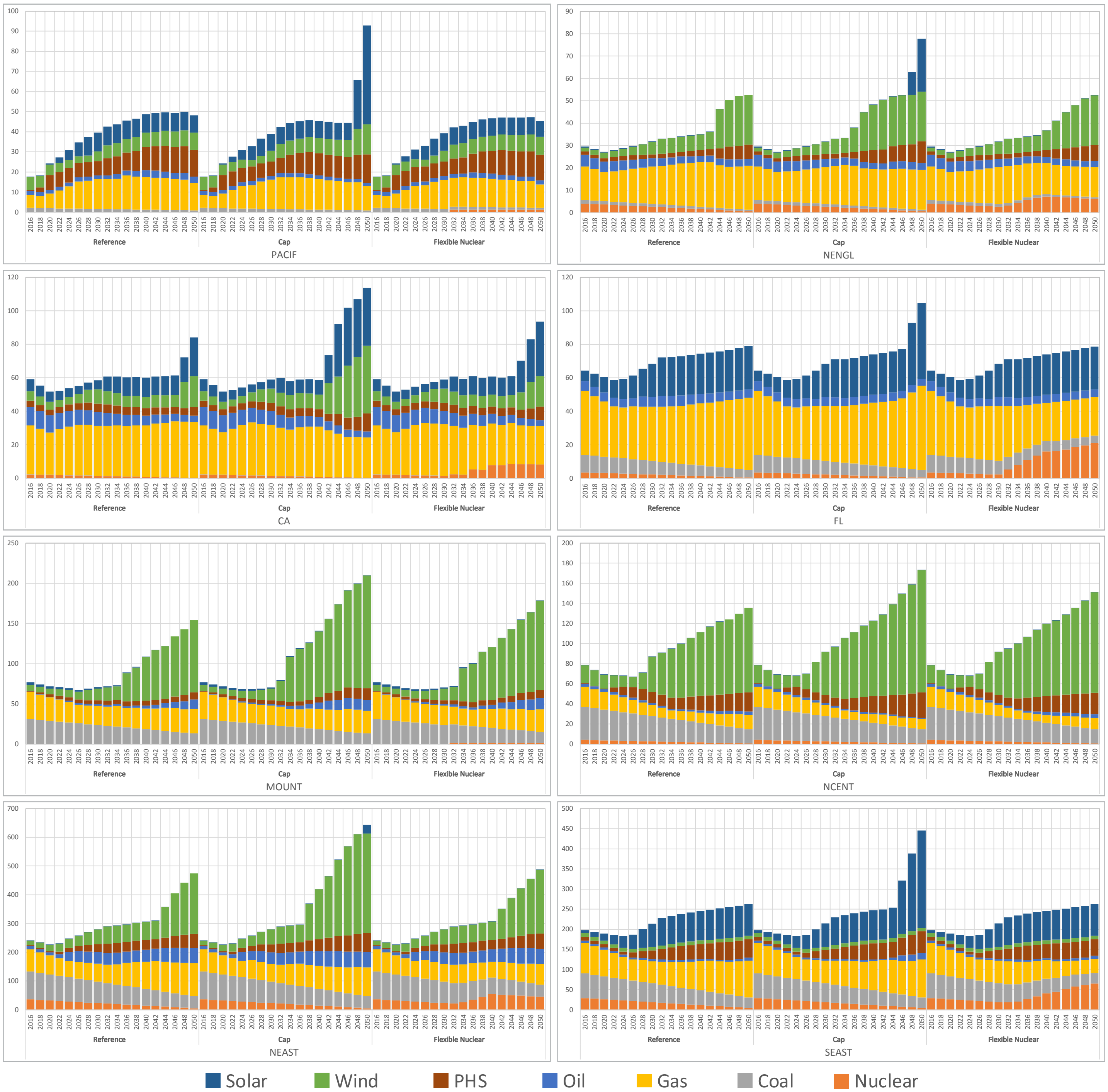

Figure 9. Cumulative Installed Generation Capacity, 8 Selected Regions (GW).

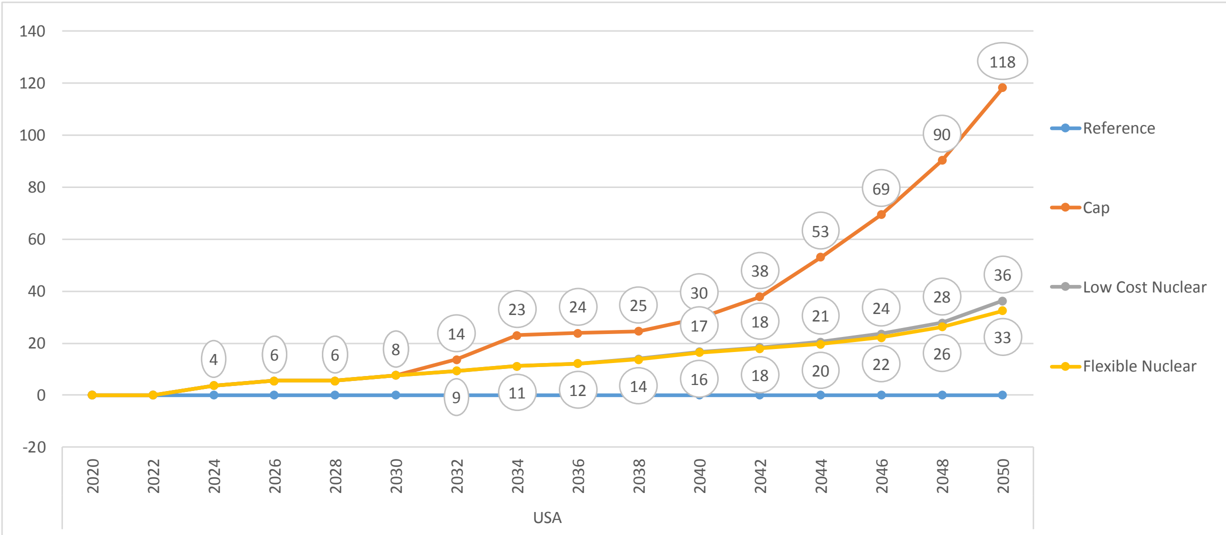

Figure 10. The CO_2 Price (2006$/tonne).

they obtain for providing energy and reserves.[5] The lower cost and more flexible nuclear in *Flexible Nuclear* does not squeeze out wind significantly.

Figure 10 shows the CO_2 prices, obviously zero in the *Reference* scenario, but notably the price in 2050 in the *Cap* scenario is about $80 higher than in the *Lower Cost Nuclear* and *Flexible Nuclear* scenarios. Even though the costs of wind and solar are less than any other technology specified in the model, it still takes a very substantial CO_2 price, absent a dispatchable low carbon, low cost alternative, because of the intermittency of renewables that require some combination of storage, flexible capacity from gas, and redundant capacity of renewables that lead to significant curtailments. Again, there is no electricity demand response, a channel that could lead to lower CO_2 prices in all the policy cases.[6] However, extending the reduction to the rest of the economy could have competing effects. If emissions abatement is more difficult there, then deeper cuts may be forced on the power sector, and CO_2 charges on fuels would lead to possible substitution toward electricity to replace fuels in other sectors of the economy.

Another measure of cost we can compute from EleMod is the net present value (discounted at 4%) total system cost. By this metric the carbon cap scenario raises the total system cost over the period by $46 billion in net present value terms, a 3.3% increase. With *Lower Cost Nuclear* the total system cost with carbon cap is $17 billion less than in the *Cap* case, increasing the total cost by just under 2.1% compared with the *Reference* case.

Figure 11 shows average annual wholesale electricity prices, with the annual average weighted by the amount of electricity sold at those prices. Prices in the wholesale market are resolved on an hourly basis to match supply and demand. All regions and scenarios show similar patterns of rising prices. This reflects the implicit current disequilibrium situation in the electricity market given the modeling assumptions, and is reflected in the early-year declines in total generation capacity. With excess capacity in these early years, the average marginal price is below the full cost of replacing the capacity because existing facilities are willing to supply as long as variable costs are met. However, as the excess capacity shuts down, new builds require prices that recover the full cost of producing electricity. The current "disequilibrium" may be partly a reflection of modeling assumptions regarding reserve requirements, demand patterns, and capacity availability of existing power plants that "over-optimize" power supply, however, there is considerable evidence of excess capacity given the recent history in the sector. The dramatic fall in natural gas prices led to expansion of gas generation capacity, which has idled coal and nuclear capacity. Various state and federal renewable energy policies have also added capacity for wind and solar generation.

There is the greatest price increase in the *Cap* scenario (compared with *Reference*), ranging from about a 20% increase in the PACIF, CA, and MOUNT regions to an increase of 45–50% in NENGL, FL, SEAST (VA, KY, NC,

Continued on page 20.

5 Their remuneration will depend on those hours when wind is producing electricity, so the flattening effect of wind penetration on market prices that apply to wind production (and subsequent revenue drop in the short-term) will prevent additional installation of wind in the system. See Tapia-Ahumada *et al.* (2014) for some discussion about this topic.

6 Our model has also limitations on the current representation of hydro reservoirs, which could also provide additional flexibility and storage for higher penetration levels of RES.

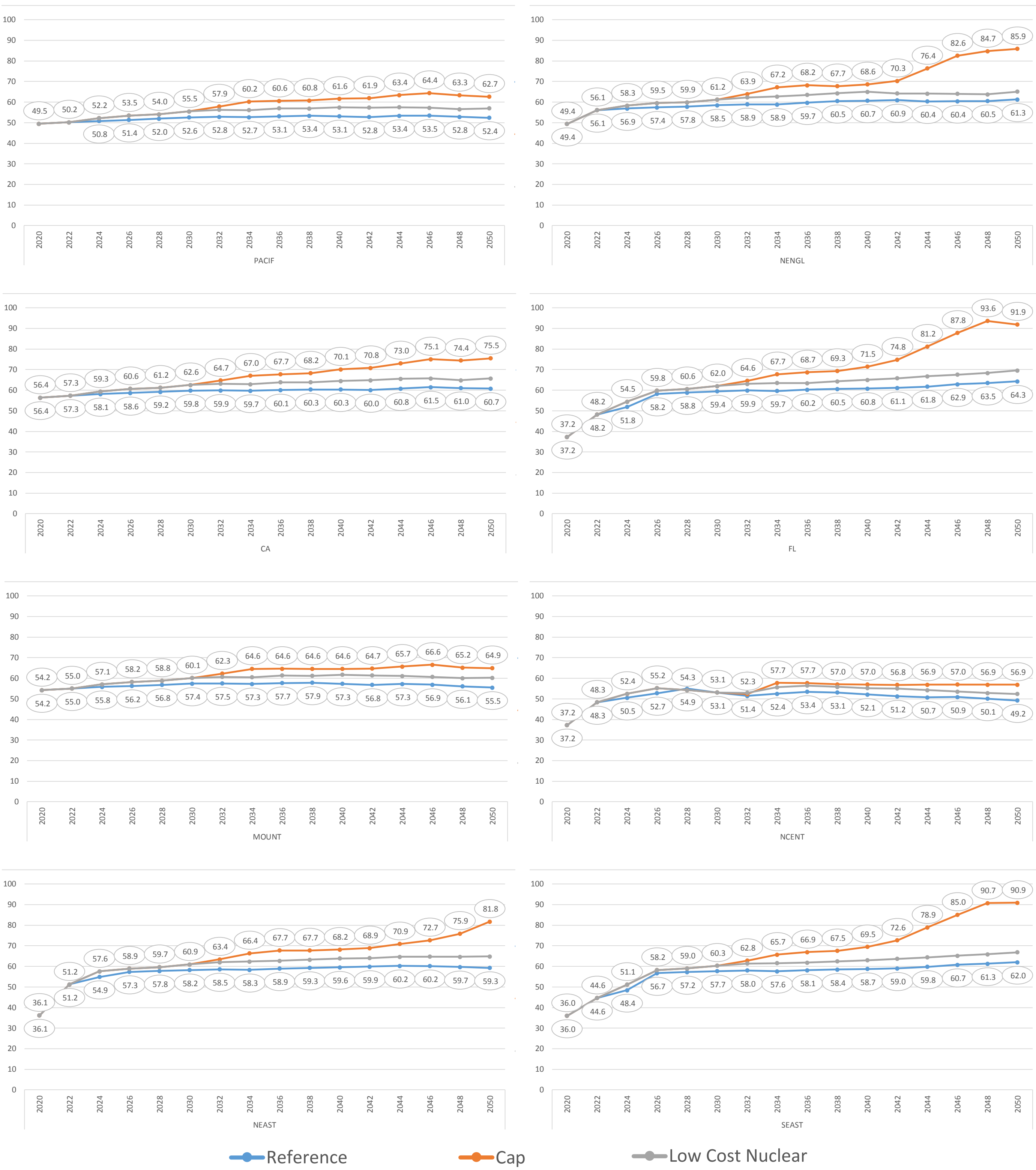

Figure 11. Annual Average Wholesale Electricity Prices, 8 Selected Regions (2006$/MWh).

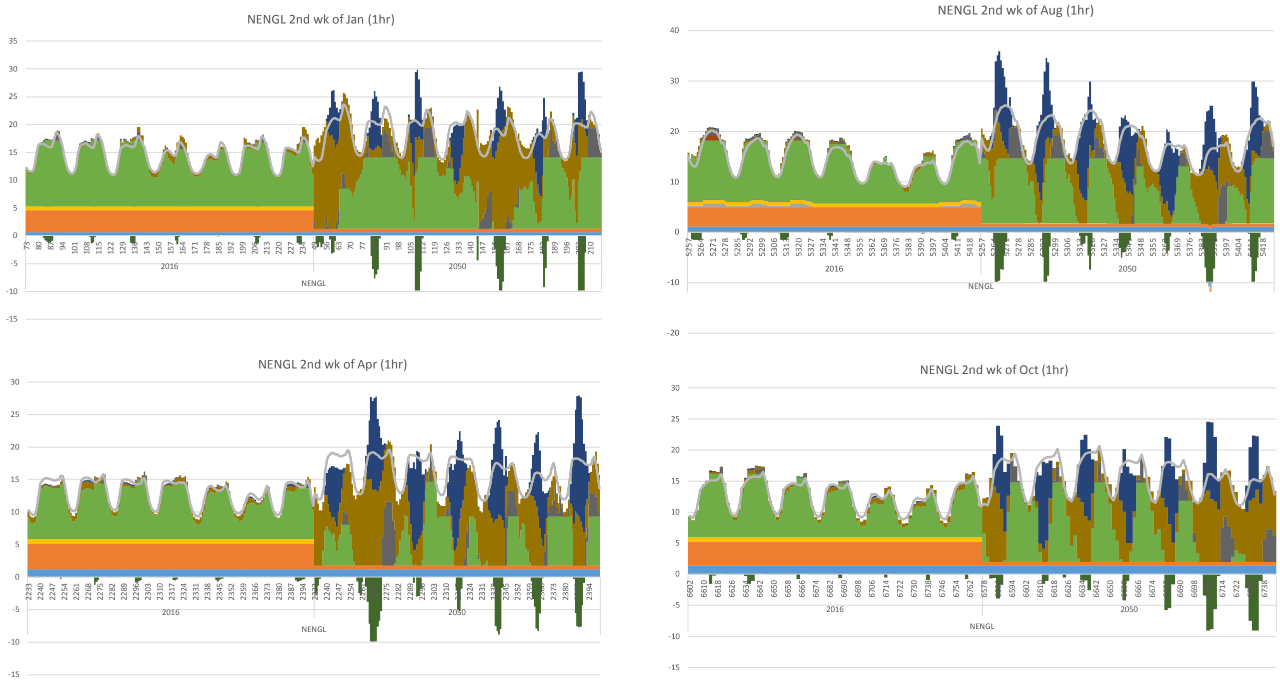

Figure 12, Panel a. New England

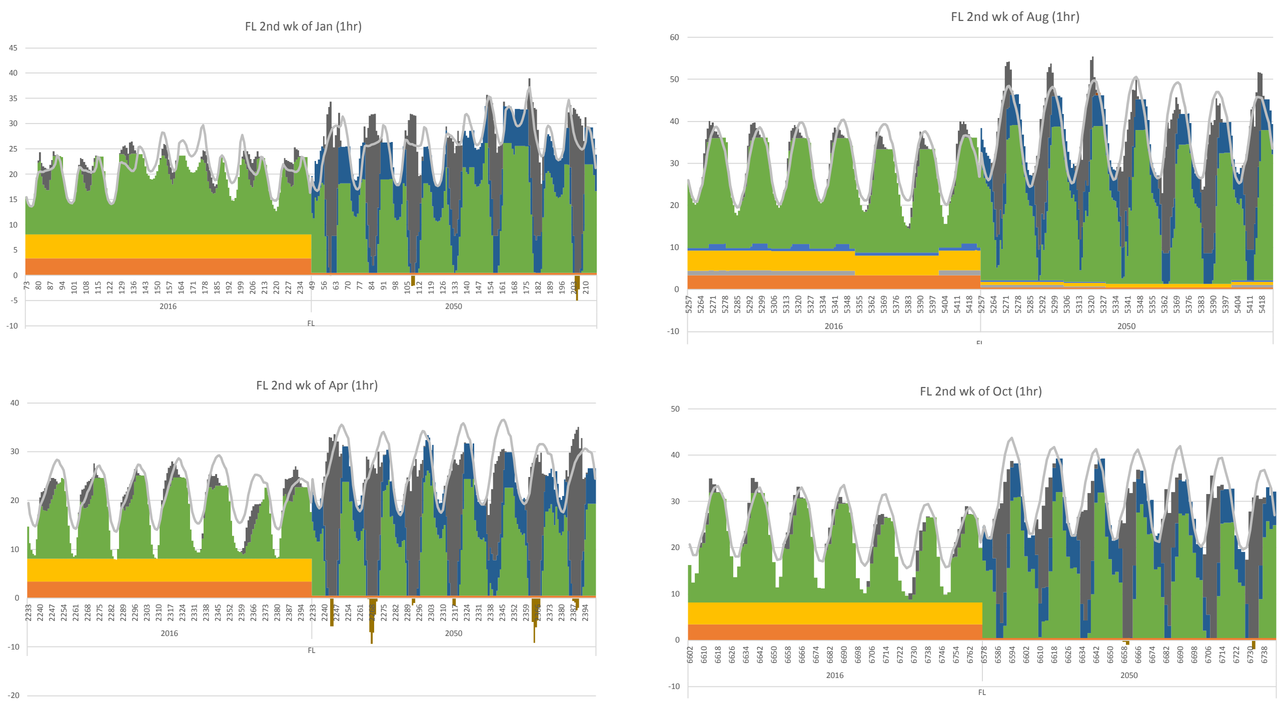

Figure 12, Panel b. Florida

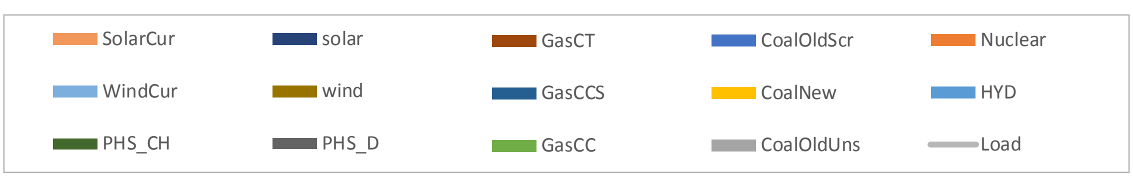

Figure 12. Generation for 2nd Weeks of January, April, August, and October for 8 Selected Regions, for 2015 and 2050 in the CapHMB Scenario.

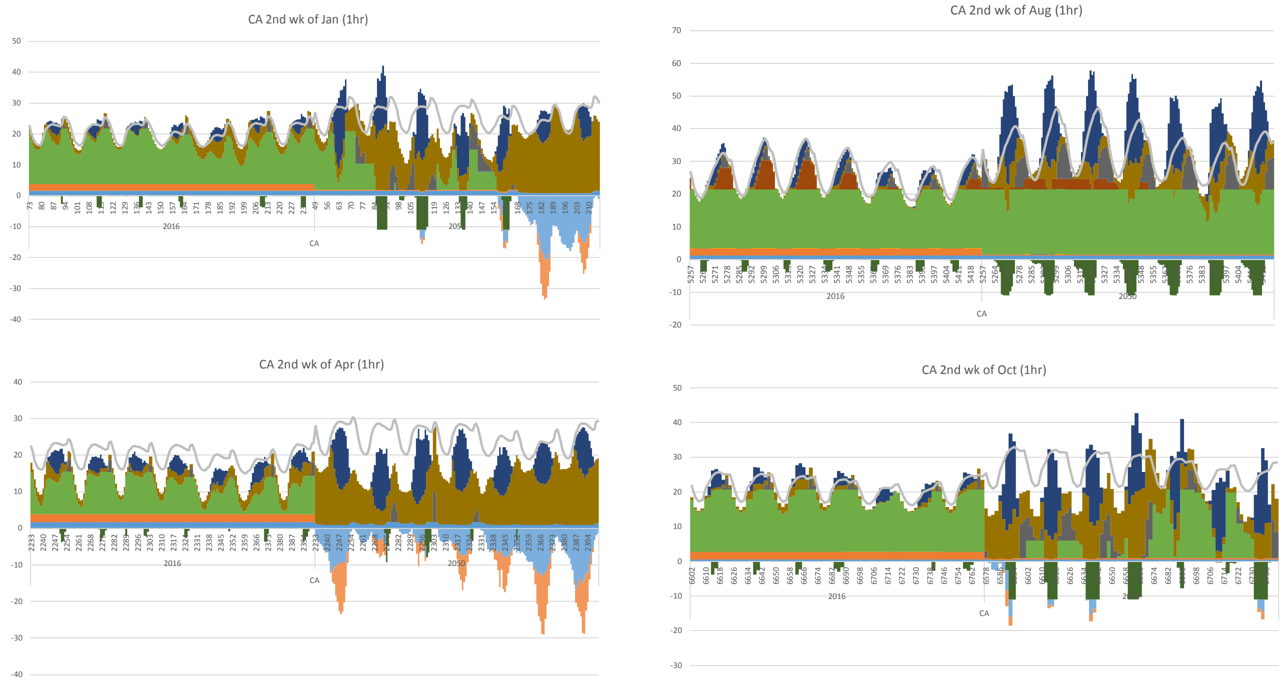

Figure 12, Panel c. California

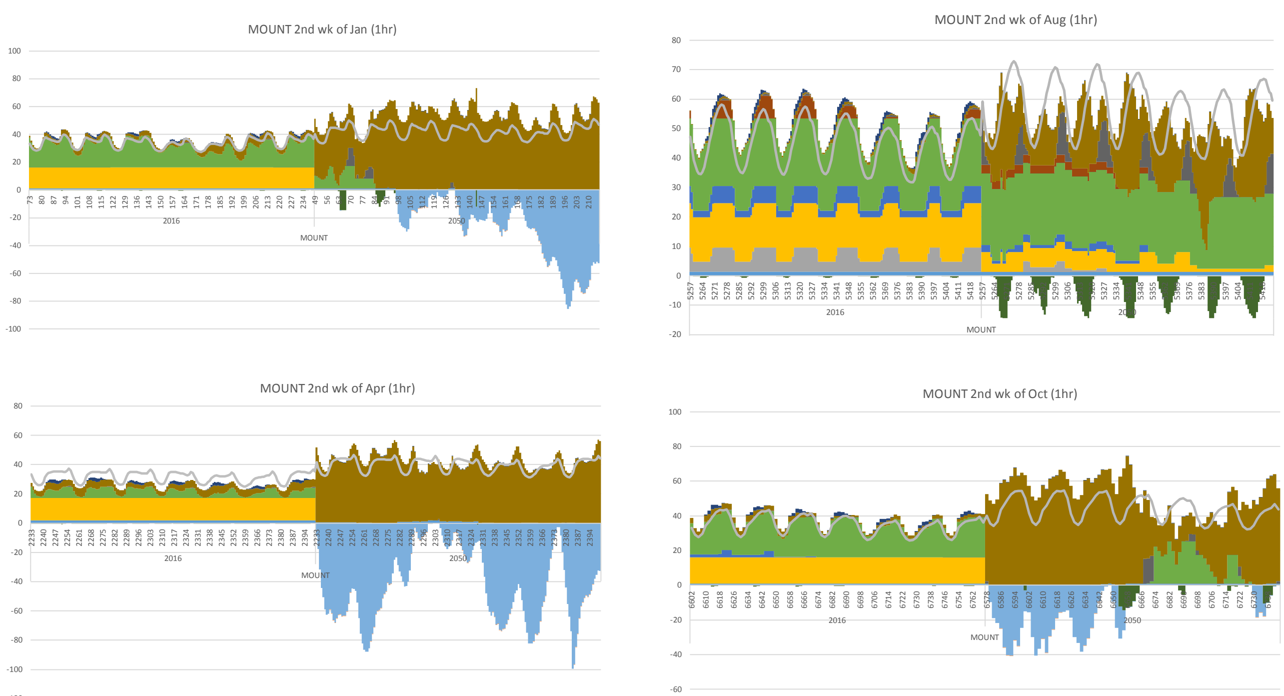

Figure 12, Panel d. Mountain

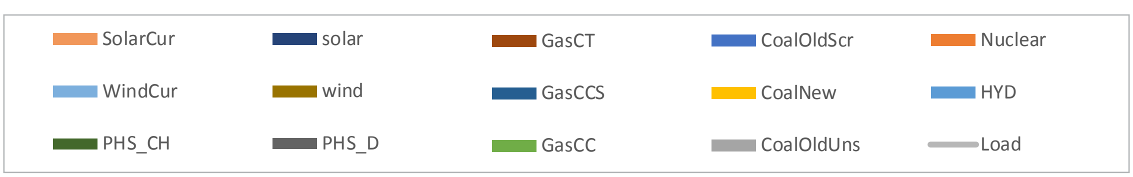

Figure 12 (cont'd). Generation for 2nd Weeks of January, April, August, and October for 8 Selected Regions, for 2015 and 2050 in the CapHMB Scenario.

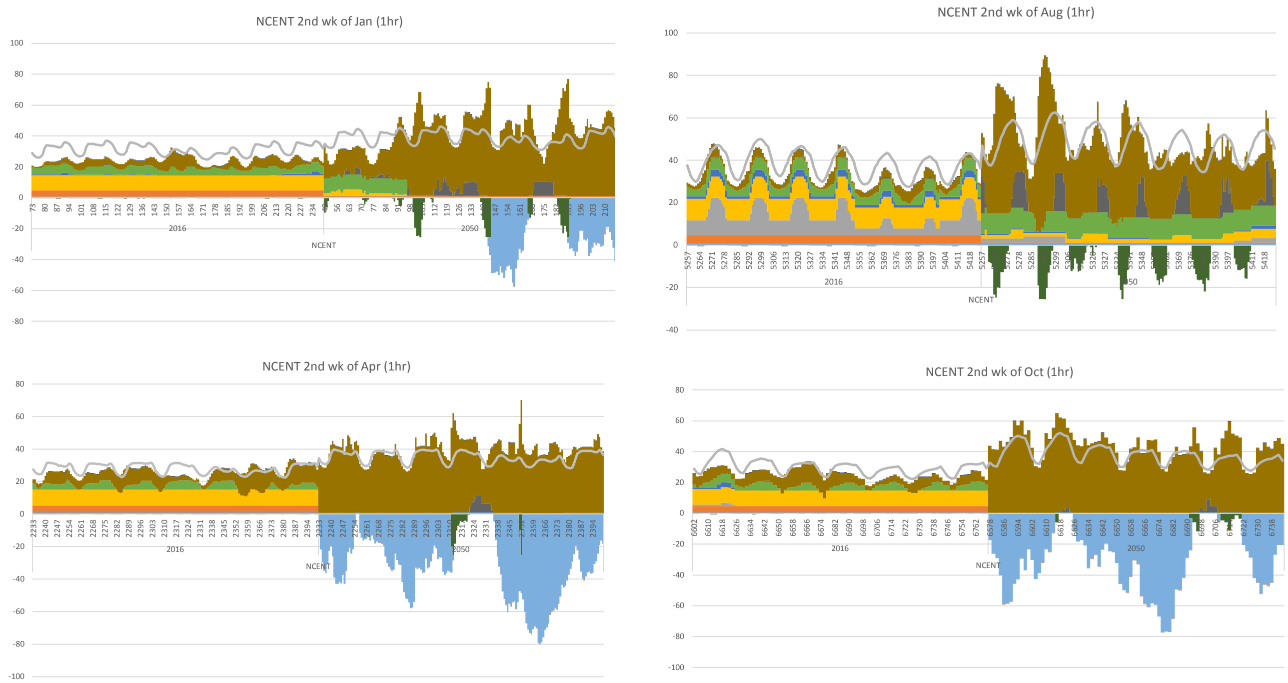

Figure 12, Panel e. North Central

Figure 12, Panel f. North East

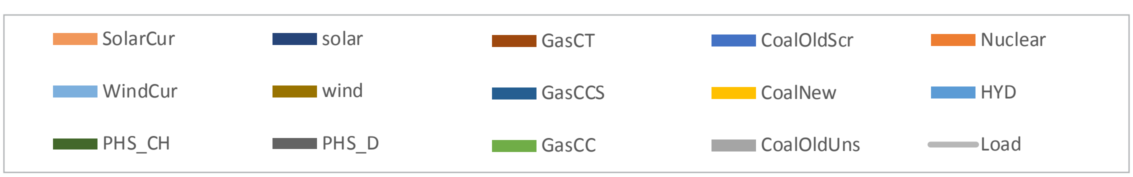

Figure 12 (cont'd). Generation for 2nd Weeks of January, April, August, and October for 8 Selected Regions, for 2015 and 2050 in the CapHMB Scenario.

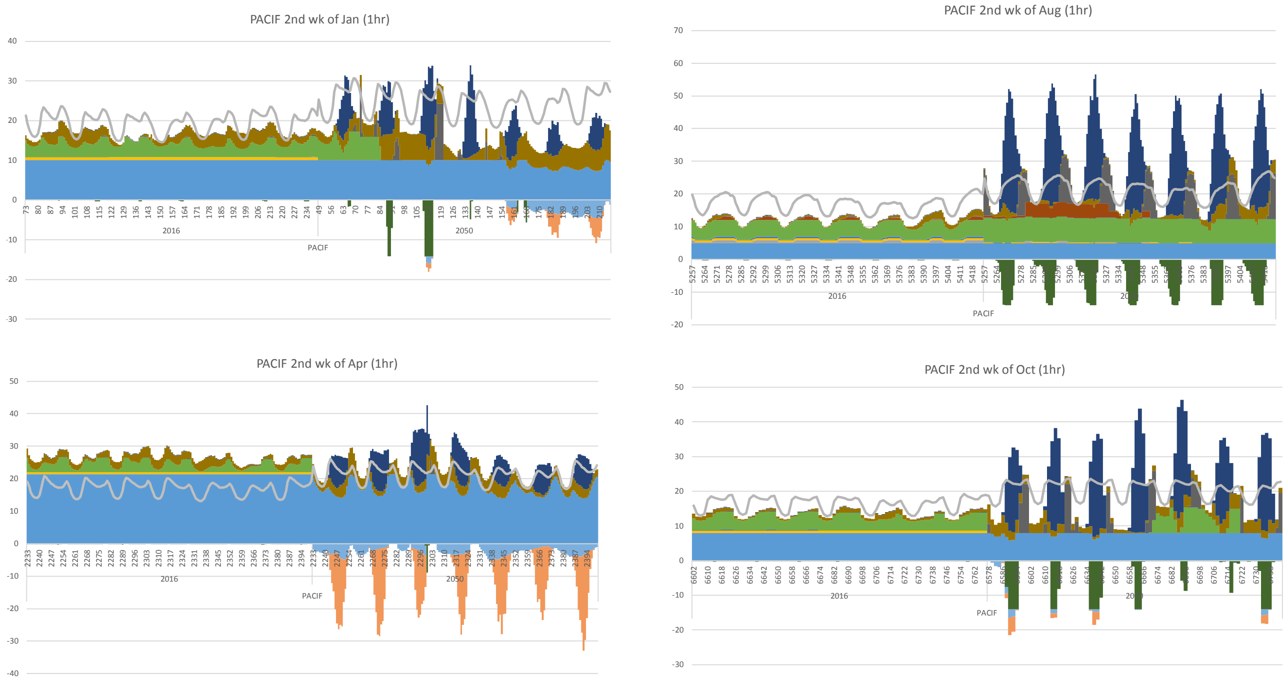

Figure 12, Panel g. Pacific

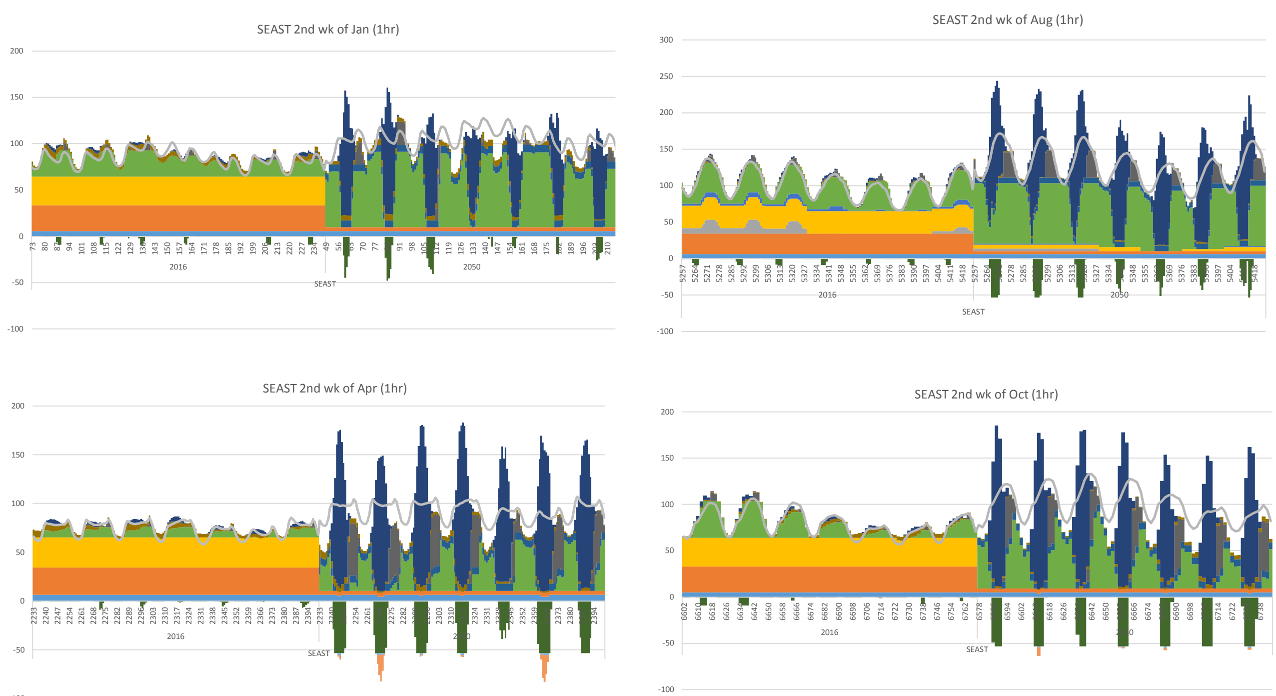

Figure 12, Panel h. South East

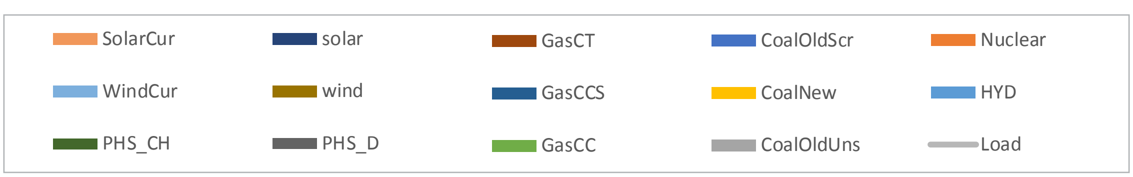

Figure 12 (cont'd). Generation for 2nd Weeks of January, April, August, and October for 8 Selected Regions, for 2015 and 2050 in the CapHMB Scenario.

TN, SC, GA, AL, MS) and the NEAST (WV, DE, MD, WI, IL, MI, IN, OH, PA, NJ, DC). Prices rose least, about 16%, in the NCENT. This likely reflects the situation hypothesized earlier—the NCENT could be a larger net exporter of renewables, especially to the higher cost regions, but transmission capacity limits exports. Substitution of allowance trade for electricity trade is limited because the region can only reduce emissions to at most zero—and because exports and imports of electricity are limited even reaching zero emissions is unlikely because the regions hourly demand must be met, without creating excess curtailment. Wholesale electricity price increases in *Cap* are less, and more similar across regions (generally<10%).

Figure 12 shows hourly demand and generation for the 2nd week of January, April, August, and October, for 8 regions in the *Cap* scenario for years 2016 and 2050 in order to note changes in generation mix as well as system's operations. These periods and regions were picked to highlight demand variations at different times of the year in different regions, and seasonal differences in the availability of renewable resources. Most of the country experiences the annual demand peaks in August when air conditioning demand is high. Wind resources tend to be strongest in the winter and spring. Solar insolation is low in the winter months when days are short and the sun is at a low angle, and obviously has a peak mid-day and is non-producing at night. Compared with current supply and demand, a carbon-constrained scenario that relied primarily on wind and solar has a much more highly variable set of supplies over the course of a day or week, with large curtailments in most regions in most of the weeks. The generally higher peaks of generation reflect the effect of greater interregional transmission across regions and PHS_C charging during those hours. Regional trade in the figures can be seen as the difference between demand and total generation, with exports occurring during oversupply and imports during periods of undersupply. Actual demand profiles are assumed unchanged through time, other than shifted up as demand increases over time.

In New England, wind can supply a relevant portion of the demand during many days of the year, which results in relying on Pumped Hydro Storage to absorb oversupply from other technologies like solar and also Gas Combined Cycle to provide additional flexibility. Solar, PHS, and Gas CC and Combustion Turbines fill in for demand peaks during the day. As seen, our PHS storage option, as specified, can be reasonably effective in dealing with shorter term (i.e. diurnal) inconsistencies in supply and demand but becomes less cost effective for longer term storage (i.e. over weeks or seasons).

Other regions show similar but varying patterns. Florida shows the strongest effects of solar, with production during the day and none at night. In general, with peak demand for power during the day, there is some match between supply and demand. However, solar is not able to completely fill the earlier morning, and later afternoon demand, and so Gas (with CCS or CC) fill in these periods, with nuclear providing a baseload throughout the day in April with similar patterns in January. These mismatches are stronger in April, with curtailments appearing on almost a daily basis. October remains fairly warm, requiring air conditioning and so demand in October is very similar to that in August, however solar is not able to cover demand requiring, in addition to Gas CC and CCS, imports from the SEAST region. In contrast, in New England, October demand is more similar to April. (Electricity trade is also modifying demand for generation and so the generation patterns are not driven solely by regional demand.) The large wind capacity in North Central and Mountains results in large curtailments during peak production in Spring and Winter when demand is the lowest. The extensive solar in the Pacific (presumably the high desert in e.g. central Washington, Oregon) leads to high peaks of production during the day and, when combined with its large hydro production, significant curtailments appear during some seasons. These are illustrative weeks out of the year, demand and wind and solar supply profiles are based on existing data. These supply profiles are representative of each week, but will obviously vary with weather patterns.

Finally, **Figure 13** shows generation, curtailments, and demand load for New England during one week of January, as well as the wholesale price in the *Cap* scenario. Mainly this emphasizes the fact that curtailments drive the wholesale price of electricity to zero. Investments in capacity must consider that over parts of the year the winning bids into the wholesale market will be a zero (or negative) price, and so their returns on investment is completely dependent on being able to supply power during those periods with a positive price.

5. Summary

We demonstrate that the US electricity sector can meet projected electricity demand while reducing CO_2 emissions by 90% from 2005 levels. If nuclear generation costs remain at current levels as estimated by the US Energy Information Administration, and renewable costs fall substantially, so that LCOE costs are well below even gas generation costs, we see a considerable expansion, especially of wind even without a CO_2 price. Given the low LCOE, we might expect a complete phase out of carbon fuel-based electricity without a carbon price. However, we find that it takes a substantial carbon price to get deep decarbonization. Moreover, modest advances in lowering the cost of nuclear (from \$.076/kWh to ~\$0.050/kWh) create a substantial role for nuclear, and reduce the needed carbon price by 2/3. Wind and solar continue to play a substantial in the

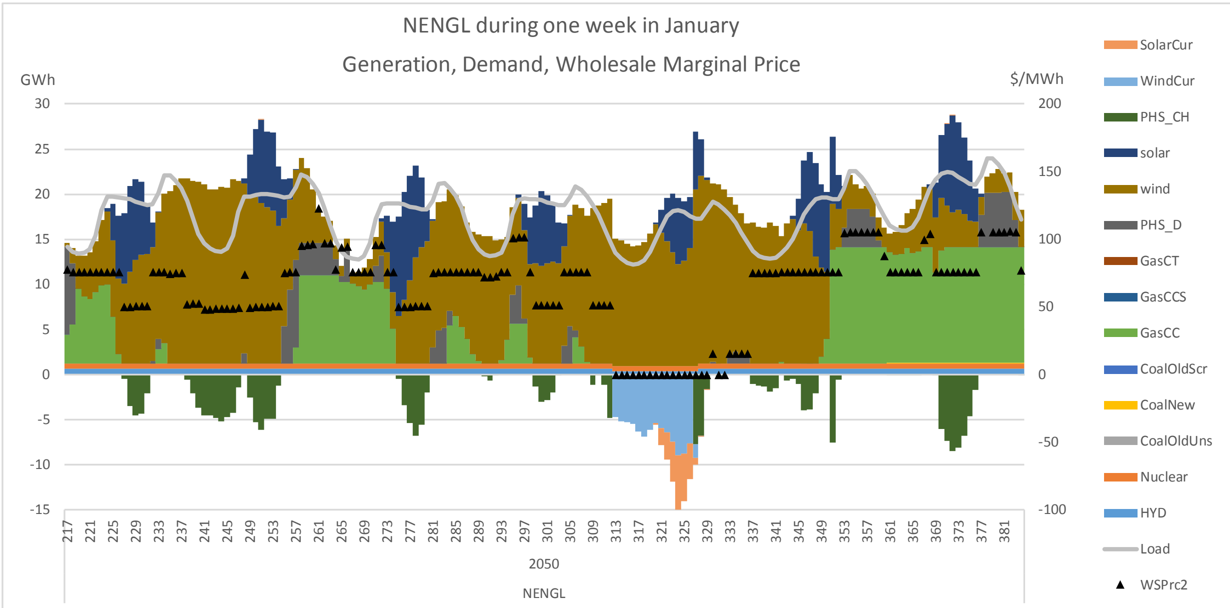

Figure 13. Generation, Demand, and Wholesale Price of Electricity (One Week of January) for New England in the CapHMB Scenario.

power sector, but only so far as their hourly availability matches well with demand. Once these sources account for about 40–45% of electricity then curtailments, storage, and back-up capacity add to system costs. As modeled, adding more technical flexibility to nuclear did not allow for more wind and solar or much use of nuclear to back-up intermittent sources. While technically flexible, the relatively higher capital costs for nuclear did not justify investing in the plants if they were not fully utilized. We were intentionally very optimistic about the possibility for reduction in the LCOE of producing wind and solar, with them reaching one-half to one-third the cost of other technologies, so their cost is not a major constraint on their deployment. Continued focus on lowering the cost of baseload generation from low carbon sources such as nuclear would make achieving deep reductions in carbon emissions much less costly.

Several caveats are in order: (1) we are not addressing possible within region grid enhancements that would likely be needed for solar and wind because of the dispersed nature of the supply source—any costs of such enhancements are implicitly assumed to be negligible. (2) we have not considered expanding interties among regions within the three US interconnects, or connections between the interconnnects which could lead to better balancing of load and renewable supply across the US; however, emissions trading across regions is a partial substitute for electricity trade. (3) We have assumed fairly aggressive additional reductions in solar and wind costs to highlight the role of their intermittency in increasing costs/limiting their use. With smaller reductions in solar and wind costs, nuclear—even at our base cost—could play a bigger role, or even lower cost nuclear could squeeze out more renewables. (4) The nature of our model does not require us to specify in detail the technical characteristics of our advanced nuclear and we have included no limits on nuclear expansion due to regulatory barriers or public acceptance. (5) The existing nuclear fleet has a prescribed retirement schedule. Under the carbon pricing policy we represent, it could well pay to invest further in the existing nuclear fleet to relicense and extend the life of these plants, assuming they can meet safety requirements.

Acknowledgments

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