Energy Policy 43 (2012) 436–447

Contents lists available at SciVerse ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

High-resolution modeling of the western North American power system demonstrates low-cost and low-carbon futures

James Nelson [a,b], Josiah Johnston [a,b], Ana Mileva [a,b], Matthias Fripp [c], Ian Hoffman [a,b,d], Autumn Petros-Good [a,b], Christian Blanco [a], Daniel M. Kammen [a,b,e,*]

[a] Renewable and Appropriate Energy Laboratory, University of California, Berkeley, CA 94720-3050, United States
[b] Energy and Resources Group, University of California, Berkeley, CA 94720-3050, United States
[c] Environmental Change Institute, Oxford University, South Parks Road, Oxford, OX1 3QY, UK
[d] Electricity Markets and Policy Group, Lawrence Berkeley National Laboratory, Berkeley, CA 94720, United States
[e] Goldman School of Public Policy, University of California, Berkeley, CA 94720-3050, United States

ARTICLE INFO

Article history:
Received 18 August 2011
Accepted 14 January 2012
Available online 3 February 2012

Keywords:
Energy modeling
Renewable energy
Carbon emissions

ABSTRACT

Decarbonizing electricity production is central to reducing greenhouse gas emissions. Exploiting intermittent renewable energy resources demands power system planning models with high temporal and spatial resolution. We use a mixed-integer linear programming model – SWITCH – to analyze least-cost generation, storage, and transmission capacity expansion for western North America under various policy and cost scenarios. Current renewable portfolio standards are shown to be insufficient to meet emission reduction targets by 2030 without new policy. With stronger carbon policy consistent with a 450 ppm climate stabilization scenario, power sector emissions can be reduced to 54% of 1990 levels by 2030 using different portfolios of existing generation technologies. Under a range of resource cost scenarios, most coal power plants would be replaced by solar, wind, gas, and/or nuclear generation, with intermittent renewable sources providing at least 17% and as much as 29% of total power by 2030. The carbon price to induce these deep carbon emission reductions is high, but, assuming carbon price revenues are reinvested in the power sector, the cost of power is found to increase by at most 20% relative to business-as-usual projections.

1. Introduction

Decarbonization of the electric power sector is critical to achieving greenhouse gas reductions that are needed for a sustainable future. In the United States, for example, the electricity sector accounts for 41% of U.S. carbon emissions (U.S. Energy Information Administration, 2008). A number of low-carbon power generation technologies are available today, but many of them are less flexible than conventional generators. Nuclear and geothermal must be run in baseload mode (steady round-the-clock), while wind and photovoltaics have intermittent, site-specific output. Consequently, it is unclear how these resources should be combined in future power systems. The literature on the cost-reduction potential of individual renewable technologies is extensive, but less research has explored cost and emission reductions achieved by leveraging synergies among a wide range of technologies. Such analyses are needed to aid climate policymaking and to preserve power system reliability while achieving emission reductions at the lowest possible cost.

Existing electric power system models primarily address either day-to-day operation or long-term capacity planning, but not both. Multiple studies have been conducted examining the impact of higher levels of intermittent generation on grid operations (e.g. EnerNex Corp, 2006, 2010; GE Energy, 2010). These studies evaluate the daily grid operations and costs of specific, predefined deployment levels of renewable energy, but provide little information on how the grid *should* be developed to achieve policy objectives at the lowest cost. Economic dispatch models (Wood and Wollenberg, 1996) are used in these studies to simulate the operation and production costs of a predefined fleet of generators, transmission lines, and storage systems, but cannot plan optimal capacity additions. In contrast, specialized capacity-expansion models (Kagiannas et al., 2004; DeCarolis and Keith, 2006; U.S. Energy Information Administration, 2009; National Renewable Energy Laboratory, 2010a; Chen et al., 2010) are used to inform long-term planning of generation, storage, and transmission projects, but these models have limited operational resolution. Many models use statistical methods to represent

* Corresponding author at: Renewable and Appropriate Energy Laboratory, University of California, Berkeley, CA 94720-3050, United States.
Tel.: +1 510 642 1640.
E-mail addresses: kammen@berkeley.edu, kammen@socrates.berkeley.edu (D.M. Kammen).

0301-4215/$ - see front matter © 2012 Elsevier Ltd. All rights reserved.
doi:10.1016/j.enpol.2012.01.031

intermittent generators, but are unable to evaluate the dynamic interplay between wind power, solar power, and load. Others are limited in their geographic scope, geographic resolution, or the range of technological options they consider. As long-term grid planning increasingly looks to intermittent generation sources such as solar and wind, the need increases for large-scale, high-resolution modeling that merges the capabilities of capacity expansion and economic dispatch models.

2. SWITCH model

2.1. Model introduction

The SWITCH model – a loose acronym for Solar, Wind, Hydro, and Conventional generation and Transmission Investment – uses an unprecedented combination of spatial and temporal detail to design realistic power systems and plan capacity expansion to meet policy goals and carbon emission reduction targets at minimal cost (Fripp, 2008, in review). SWITCH is a planning tool for the electric power system (Figs. 1 and 2) that optimizes capacity expansion of renewable and conventional generation technologies, storage technologies, and the transmission system, while explicitly accounting for the hourly variability of intermittent renewables and electricity loads. SWITCH improves on other capacity expansion models by incorporating elements of the day-to-day operation and dispatch of a large, interconnected electric power grid. For this paper, we use SWITCH to investigate decarbonization options for the synchronous region of the Western Electricity Coordinating Council (WECC). WECC includes 11 western U.S. States, Northern Baja Mexico, and the Canadian provinces of British Columbia and Alberta. WECC provides an ideal case to examine system dynamics in a complex, interconnected region with significant greenhouse gas emissions and many low-carbon generation resources.

SWITCH is a mixed-integer linear program whose objective function (Fig. 2) is to minimize the societal cost of meeting projected electricity demand with generation, storage, and transmission between present day and 2030. The optimization is subject to reliability, operational, and resource-availability constraints, as well as both existing and possible future climate policies. SWITCH was originally developed to study the cost of achieving high renewable energy targets in California (Fripp, 2008, in review), using existing facilities along with new wind, solar, and natural gas plants. For this study, we have extended SWITCH to include more generation and storage technologies, incorporated a state-based renewable portfolio standard (RPS) requirement, and implemented a post-optimization reliability assessment. The updated model is applied to the entire WECC power system. A description of the version of SWITCH used for this paper is provided below; the complete model formulation is available in the Online Supplemental Information.

2.2. Geographic resolution: load areas and transmission

For the purpose of identifying where power is generated and where it is used, we divide the synchronous WECC region into fifty "load areas". These represent areas of the grid within which there is significant existing local transmission and distribution, but between which there may be limited long-range, high-voltage existing transmission. Consequently, load areas are regions between which transmission investment may be beneficial. Power flow between WECC and the Eastern and Texas interconnects is not considered, as less than 2 GW power transfer capacity currently exists between these regions (Ventyx Corp, 2009), relative to WECC peak load of more than 150 GW.

A total of 124 existing and new transmission corridors between pairs of load areas are included in each optimization. Existing transmission capacity is determined from Federal Energy Regulatory Commission (FERC) data on the thermal limits of individual power lines (Federal Energy Regulatory Commission, 2009). New high-voltage transfer capability can be built along existing transmission corridors at a cost of \$1000/MW km. If no transmission exists between two adjacent load areas, new capacity can be installed at a cost of \$1500/MW km.

SWITCH does not currently model the electrical properties of the transmission network in detail and, as such, is not a power flow model based on Kirchhoff's laws. Optimal power flow models identify the least expensive dispatch plan for existing generators to meet a pre-specified set of loads, while respecting the physical

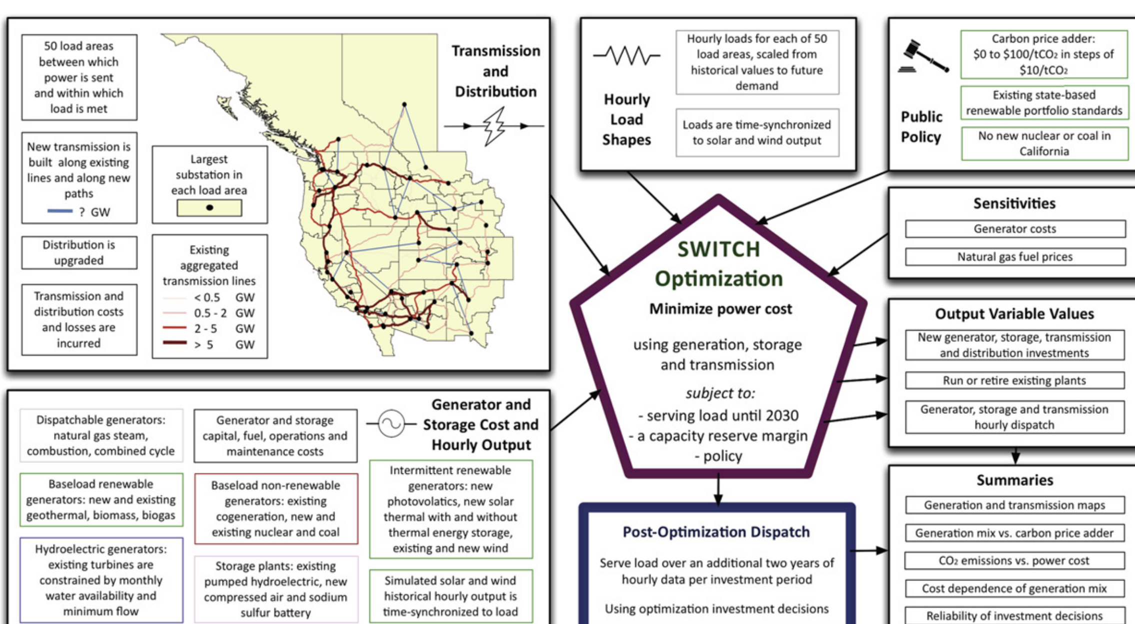


Fig. 1. Optimization and data framework of the western North American SWITCH model.

Objective function: minimize the total cost of meeting load			
Generation and Storage	Capital	$\sum_{g,i} G_{g,i} \cdot c_{g,i}$	The capital cost incurred for installing a generator at plant *g* in investment period *i* is calculated as the generator size in MW $G_{g,i}$ multiplied by the cost of that type of generator in \$2007 / MW $c_{g,i}$.
	Fixed O&M	$+ (ep_g + \sum_{g,i} G_{g,i}) \cdot x_{g,i}$	The fixed operation and maintenance costs paid for plant *g* in investment period *i* are calculated as the total generation capacity of the plant in MW (the pre-existing capacity ep_g at plant *g* plus the total capacity $G_{g,i}$ installed through investment period *i*) multiplied by the recurring fixed costs associated with that type of generator in \$2007 / MW $x_{g,i}$.
	Variable	$+\sum_{g,t} O_{g,t} \cdot \left(m_{g,t} + f_{g,t} + c_{g,t}\right) \cdot hs_t$	The variable costs paid for plant *g* operating in study hour *t* are calculated as the power output in MWh $O_{g,t}$ multiplied by the sum of the variable costs associated with that type of generator in \$2007 / MWh. The variable costs include per MWh maintenance costs $m_{g,t}$, fuel costs $f_{g,t}$, and carbon costs $c_{g,t}$, and are weighted by the number of hours each study hour represents, hs_t.
Transmission		$+\sum_{a,a',i} T_{a,a',i} \cdot l_{a,a'} \cdot t_{a,a',i}$	The cost of building or upgrading transmission lines between two load areas *a* and *a'* in investment period *i* is calculated as the product of the rated transfer capacity of the new lines in MW $T_{a,a',i}$, the length of the new line $l_{a,a'}$, and the regionally adjusted per-km cost of building new transmission in \$2007 / MW · km, $t_{a,a',i}$. Transmission can only be built between load areas that are adjacent to each other or that are already connected.
Distribution		$+\sum_{a,i} d_{a,i}$	The cost of upgrading local transmission and distribution within a load area *a* in investment period *i* is calculated as the cost of building and maintaining the upgrade in \$2007 / MW $d_{a,i}$.
Sunk		$+ s$	Sunk costs include ongoing capital payments incurred during the study period for existing plants, existing transmission networks, and existing distribution networks. The sunk costs do not affect the optimization decision variables, but are taken into account when calculating the cost of power at the end of the optimization.

Fig. 2. Optimization objective function. Further information on the objective function and a full description of optimization constraints and state variables not present in the objective function can be found in the Online Supplemental Information.

constraints on the flow of power on every line in the network (Bergen and Vittal, 2000). They become non-linear when investment choices or AC properties are included, making them computationally infeasible for optimizing the evolution of the power system, especially over a large area and many hours. Instead, SWITCH treats the electrical transmission system as a generic transportation network with maximum transfer capabilities equal to the sum of the thermal limits of individual transmission lines between each pair of load areas. SWITCH models the capabilities of the transmission network, and the cost of upgrading those capabilities, rather than simulating the physical behavior of the transmission network directly.

2.3. Temporal resolution: investment periods and dispatch hours

To simulate power system dynamics over the course of the next twenty years, SWITCH employs four levels of temporal resolution: investment periods, months, days, and study hours. For our analysis, there are four four-year-long investment periods: 2014–2017, 2018–2021, 2022–2025, and 2026–2029, each of which contains historical data from 12 months, two days per month, and six study hours per day. This results in (4 investment periods) × (12 months/investment period) × (2 days/month) × (6 study hours/day) = 576 sampled hours over which the system is dispatched. The peak and median days from each historical month are sampled to represent a large range of possible load and weather conditions over the course of each investment period. Each sampled day is assigned a weight: peak load days are given a weight of one day per month while median days are given a weight of the number of days in a given month minus one. This weighting scheme ensures that the total number of days simulated in each investment period is equal to the number of days between the start and end of that investment period, emphasizes the economics of dispatching the system under typical load conditions, and forces the system to plan for capacity availability at times of high grid stress (Fripp, 2008).

2.4. Infrastructure investment and dispatch

The SWITCH model includes two main sets of decision variables: capacity investment variables and dispatch variables. At the beginning of each of the model's investment periods, capacity investment decision variables determine the amount of new capacity to install of each generator or storage type, the amount of transmission capacity to add along each transmission corridor, and whether to operate or retire each existing non-hydroelectric power plant. The power output of baseload (coal, nuclear, geothermal, biomass, biogas, cogeneration) and intermittent (solar and wind) generation is specified through capacity investment decision variables. For baseload generators, the power produced in each hour is equal to the generator capacity de-rated for forced and scheduled outages. For intermittent generators, the power produced in each hour is equal to the generator capacity multiplied by an exogenously calculated capacity factor for that hour.

In each study hour, dispatch variables control the amount of power to generate from each dispatchable (hydroelectric or natural gas) generator, the amount of power to store and release at each storage facility (pumped hydroelectric, compressed air energy storage, or sodium-sulfur battery), and the amount of power to transfer along each transmission corridor. Storage projects must meet an energy balance constraint over the course of each study day. Similarly, the dispatch of hydroelectric projects over the course of each study day is constrained to equal average historical monthly generation. Hydro projects must also meet a minimum flow requirement in each study hour. All dispatch decisions are subject to capacity constraints set by investment decision variables. However, the hourly dispatch of generation, transmission, and storage within each investment period is optimized *concurrently* with investment decisions: in the SWITCH optimization framework, dispatch and investment decisions are made simultaneously rather than iteratively.

2.5. Operational and policy constraints

The model includes three main sets of constraints: those that ensure that projected demand is met, those that maintain the reserve margin, and those that enforce RPS.

The first set of constraints requires that the available power system infrastructure is dispatched to meet load in every hour in every load area while providing the least expensive power based on expected generation, storage, and transmission availability. The nameplate capacity of grid assets is de-rated by their forced outage rates to represent the amount of power generation capacity that is available on average in each hour. Baseload generator output is further de-rated by the scheduled outage rate of each generator.

To further address system risk, a second set of constraints requires that the power system maintain a planning reserve margin at all times, i.e. that it has sufficient capacity available to provide at least 15% extra power above load in every load area in every hour if all generators, storage projects and transmission lines are working properly. In calculating the reserve margin, the outputs of these grid assets are therefore not de-rated by forced outage rates. SWITCH determines the reserve margin schedule concurrently with the load-serving dispatch schedule.

The set of RPS constraints ensures that a minimum fraction of load is met with renewable energy sources in each investment period in each load area. This fraction is consistent with current state RPS targets. Procurement of renewable energy credits from areas outside WECC is not considered.

2.6. Dispatch verification

While each optimization considers a large number of study hours, the proposed power system must also successfully meet load on many more possible states of load and renewable resource availability than are input into the core optimization. Consequently, the grid's ability to meet load in hours other than the 576 study hours used in the optimization is assessed by fixing all investment decision variables, uploading new hourly datasets, and optimizing dispatch for lowest cost. In total, investment decisions made in each of the four investment periods are dispatched over 16,800 historic hours (almost two years) from 2004 and 2005, in batches of weeks.

Similar to the investment optimization, dispatch verification does not include forecast error, unit commitment, generator ramping constraints, security constraints, or load flow transmission constraints. Flow on transmission corridors is constrained to not exceed their thermal limits, but power flow equations are not explicitly solved. Further work will investigate power system behavior under strict operational constraints.

2.7. Costs

The present day capital cost of building each type of power plant or storage project is reduced via an exponential decay function using a capital cost declination rate (Fig. 3). The capital cost of each project is locked in at the first year of construction. Construction costs for power plants are tallied yearly, discounted to present value at the online year of the project, and then amortized over the operational lifetime of the project. Only those payments that occur during the study period are included in the objective function. The cost to connect new power plants to the grid is incurred in the year before operation begins. Operation and maintenance costs are incurred throughout each project's operational lifetime.

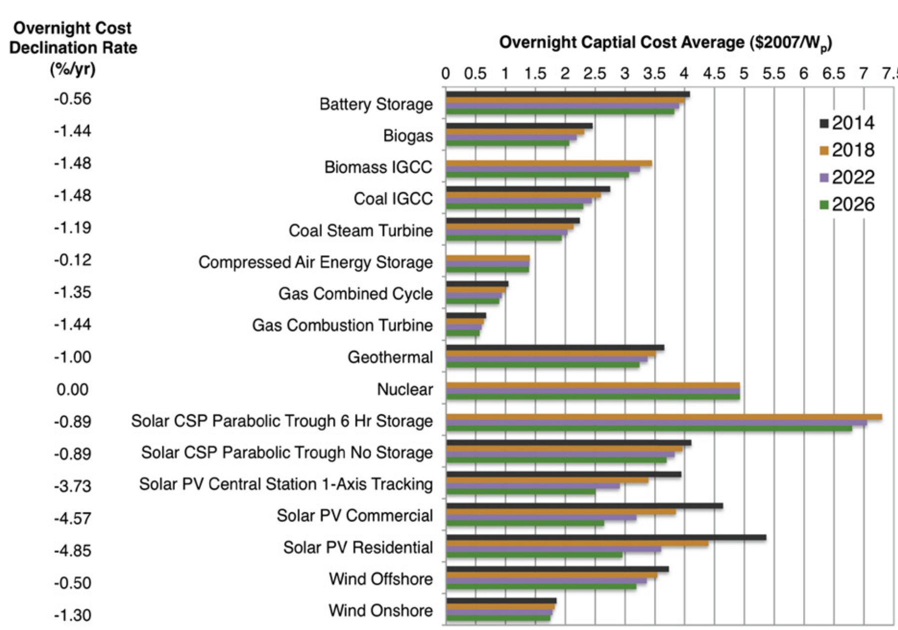


Fig. 3. Annual overnight cost declination rates and overnight capital costs by investment period in the Base Cost scenario for each generator and storage technology. Costs for technologies not available for installation in 2014 are not shown. CSP denotes concentrating solar power (solar thermal). Many of these values are varied in generator cost sensitivity scenarios described in Section 3. Overnight capital costs do not include regional capital cost multipliers, interest during construction, grid connection costs, local grid upgrade costs, and operations and maintenance costs, though these costs are included in each optimization. See the Appendix A for more information.

For optimization purposes, all costs during the study are discounted to a present day value using a real discount rate of 7%, so that costs incurred later in the study have less impact than those incurred earlier. The discount rate is based on the base case from the White House Office of Management and Budget's Circular A-94, "Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs" (White House Office of Management and Budget, 2010). All costs are specified in real terms, indexed to the reference year 2007.

Coal and natural gas fuel prices are as specified in the reference case of the United States Energy Information Agency's 2009 Annual Energy Outlook (U.S. Energy Information Agency, 2009), with coal and natural gas reaching average prices of $1.52/MMBtu and $8.13/MMBtu in $2007 respectively by 2030. Uranium price projections are taken from the California Energy Commission's 2007 Cost of Generation Model (Klein, 2007) and reach a price of $2.20/MMBtu by 2030. Solid biomass costs are included through a piecewise linear supply curve. Yearly fuel price projections are averaged over each investment period. Fuel price elasticity is not currently included.

2.8. Load and resource data

Electricity demand and intermittent renewable output are both dependent on weather conditions. We use simulated historical hourly generation profiles from 2004–05 for a portfolio of 3362 wind, 3375 solar photovoltaic (PV), and 2380 solar thermal parabolic trough systems (also known as concentrating solar power or CSP) sites as well as hourly load profiles that are time-synchronized to the renewable output data. Hourly load data is scaled to projected future demand, while resource availability is used directly from historical data. Using time-synchronized hourly load and generation profiles allows SWITCH to capture the temporal relationship between load and renewable power output levels.

Hourly loads are derived from the Federal Energy Regulatory Commission's (FERC) Annual Electric Balancing Authority Area and Planning Area Report (Federal Energy Regulatory Commission, 2005) and apportioned to load areas.

Hourly wind turbine output is obtained from the 3TIER wind power output dataset produced for the Western Wind and Solar Integration Study (WWSIS) (3TIER, 2010). Hourly solar generation output is derived by merging 10 km-resolution gridded satellite insolation data from the State University of New York (SUNY) (Perez et al., 2002; National Renewable Energy Laboratory, 2010b) and $\sim$38 km-resolution weather data from the National Center for Environmental Prediction's (NCEP) Climate Forecast System Reanalysis (CFSR) (Saha et al., 2010; National Climatic Data Center, 2010). The resultant weather files are used as inputs to the National Renewable Energy Laboratory's Solar Advisor Model (National Renewable Energy Laboratory, 2010c) to calculate the simulated historical output of various types of solar projects.

A broad range of generation options and their projected costs are input into each optimization (Figs. 1 and 3). The model can select from nearly 10,000 possible wind, solar, geothermal, biomass, biogas, nuclear, coal, and natural gas power plants to install and operate in each investment period.

Large existing thermal generators in WECC are included (Ventyx Corp, 2009), totaling 578 power plants, each of which is given a binary decision variable to operate or not during each investment period. Once retired, an existing generator cannot be re-started. The hourly output of 232 existing wind farms is also included. Existing hydroelectric generators are aggregated to the load area level, operated subject to streamflow constraints, and cannot be retired. Existing pumped hydroelectric storage plants are included, as well as the option to install new compressed air energy storage (CAES) and sodium-sulfur (NaS) battery storage projects.

Carbon capture and sequestration (CCS) is a low-carbon technology that may compete with nuclear and/or renewable power. This technology is still at a prototype phase, and its feasibility and future costs are uncertain (McKinsey and Company, 2008). Future work will include CCS as well as other early-phase technologies.

2.9. Implementation

SWITCH uses a layered architecture consisting of data stores, middleware, a high-level modeling language, and a Mixed Integer Program (MIP) solver. Non-spatial data are stored in MySQL while spatial data are stored in PostgreSQL/PostGIS. The SWITCH model is written in AMPL, a high level mathematical programming language. AMPL compiles a MIP for a particular set of inputs and policy options, which is passed to CPLEX for optimization. For this study, a typical cost optimization problem has a reduced MIP with approximately 800,000 constraints, 800,000 linear decision variables, and 2000 binary variables. The middleware that reformats data and manages execution is a collection of BASH shell scripts. The optimizations run on a cluster of IBM Dataplex server nodes, each containing two 2.7 GHz quad-core processors and 24 GB of RAM.

2.10. Future model development

SWITCH captures many important dynamics of the electric power sector at high resolution but the inherent complexity of the electric power system necessitates even greater detail in many areas. Work is underway to integrate sub-hourly ancillary services such as regulation, spinning, and non-spinning reserves, which will provide additional assurance of grid reliability. The inclusion of additional hours during the investment optimization is also a near-term priority in order to develop more finely tuned investment plans. Further extensions will examine the large-scale deployment of electric vehicles, load response, and robustness of energy scenarios to climate impacts on the electricity system.

3. Scenario descriptions

We use SWITCH to investigate the carbon emissions from and cost of power in the WECC power system under multiple realistic generator cost and fuel price scenarios (Table 1), and under varying carbon policy. In all scenarios investigated here, consistent with current policy, existing state RPS targets are met, and new nuclear and coal generation are prohibited from being built in California.

The future costs of generation technologies are highly uncertain. For example, estimates of the capital cost of nuclear power range widely (Harding, 2007; Cooper, 2009). It is also unclear how much public opposition new nuclear plants would face, especially in light of the recent Fukushima Daiichi accident. Reflecting these issues, we model two nuclear capital cost scenarios. The Base Cost scenario assumes a capital cost of $5/W for nuclear plants in order to investigate low-carbon power systems that can be achieved without low-cost nuclear power. The Low Nuclear Cost scenario assumes that nuclear power is available at a capital cost of $4/W in order to explore optimal power system deployment with low-cost nuclear power. In both nuclear cost scenarios, the overnight capital cost of nuclear power is assumed to stay constant through 2030.

Similarly, the rate of technological progress in the solar industry is uncertain, especially in the 2030 timeframe (Tidball

Table 1
Generator cost and fuel price scenarios investigated in this study. For scenarios other than the Base Cost scenario, the 'Scenario Description' column describes the only changes made relative to the Base Cost scenario.

Scenario name	Scenario description
Base Cost	Generator overnight capital costs and capital cost declination rates are as shown in Fig. 3. Natural gas prices are as described in Section 2.7
Low Nuclear Cost	The overnight capital cost of new nuclear power plants is lowered to \$4/W from the base \$5/W
Low Gas Price/High Gas Price	The inter-annual percentage change in natural gas fuel prices is calculated from the Base Cost scenario. These values are increased by 1% for the High Gas Price scenario and lowered by 1% for the Low Gas Price scenario, and then used to recalculate natural gas fuel prices
High PV Cost	PV costs are higher than in the Base Cost scenario in all investment periods. This is achieved by reducing the magnitude of the base PV capital cost declination rate (see Fig. 3) by 1.5% percent per year
Low CSP Cost/High PV Cost	PV costs are higher and CSP costs are lower than in the Base Cost scenario in all investment periods. This is achieved by lowering the base PV capital cost declination rate (see Fig. 3) by 1.5% per year and increasing the base CSP capital cost declination rate by 2.5% per year

et al., 2010). We model three solar capital cost scenarios. In the Base Cost scenario, the capital cost of PV systems decreases as shown in Fig. 3. In the High PV Cost scenario, PV capital costs decline more slowly, reflecting the possibility that the PV industry may not meet future cost targets. Relative to cost assumptions in the Base Cost scenario, overnight capital costs for central station PV in the High PV Cost scenario are 28% higher in the 2026 investment period. In the Low CSP Cost/High PV Cost scenario, CSP costs outperform PV costs: CSP capital costs decline more quickly than in the Base Cost scenario and PV costs are kept as in the High PV Cost scenario. CSP overnight capital costs are 34% lower than in the Base Cost scenario in the 2026 investment period.

Natural gas is an important fuel due to its relatively low carbon intensity as well as its dispatchability and hence ability to compensate for variable renewable output. However, the delivered price of natural gas has historically been difficult to predict. We explore scenarios with a higher and a lower price trajectory for natural gas relative to the Base Cost scenario – the High Gas Price scenario and Low Gas Price scenario respectively – to determine the effect of long-term uncertainty in natural gas prices on the cost of power and the optimal power mix. Natural gas prices reach a WECC-wide average of \$6.74/MMBtu in the Low Gas Price scenario and \$9.76/MMBtu in the High Gas Price scenario in \$2007 by 2030.

Within each cost scenario, we vary an exogenous "carbon price adder" in order to force SWITCH to redesign the power system to achieve a range of CO_2 emissions. For each cost scenario, we vary the carbon price adder from \$0/tCO_2 to \$100/tCO_2. This adder is held constant through all investment periods for each carbon price adder. The carbon price adder could correspond to a carbon tax or the cost of permits under a cap and trade policy. The revenue from this carbon adder is assumed to be re-invested in the electricity sector and re-distributed to electricity consumers, and as such it does not directly affect the average cost of power (transaction costs are assumed to be negligible). Rather, it does so indirectly, by changing the relative costs of power generating technologies. As the carbon adder is increased, generation from previously inexpensive but carbon-intensive power plants becomes less economically attractive relative to other generation options.

At the end of the optimization, we calculate carbon emissions from the resultant power system for each carbon price adder. In order to stabilize the climate at or below an atmospheric concentration of 450 ppm CO_2, the International Energy Agency finds that annual power sector emissions should drop to 54% of 1990 levels by 2030 for Organization for Economic Co-operation and Development (OECD) countries, with further declines thereafter (International Energy Agency, 2008). Below, we discuss power systems that are consistent with this 450 ppm CO_2 climate stabilization target, assuming a proportional contribution of the WECC power system, which is part of the OECD, to global emission targets.

4. Results

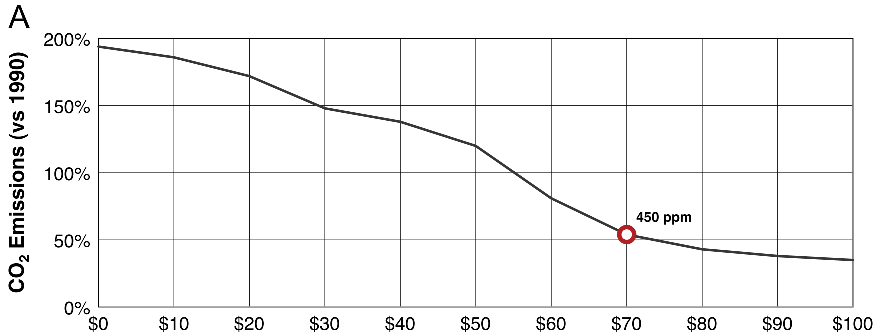
4.1. Base Cost scenario

In the Base Cost scenario, if no carbon policy is implemented (a carbon price adder of \$0/tCO_2), the least-cost system would obtain 47% of its power from coal in 2026–29, as shown at the far left side of Fig. 4B. This system is similar to present day power systems, and, owing to load growth, emits 194% of the 1990 baseline CO_2 level by 2030 (Fig. 4A). In the Base Cost scenario, as the carbon adder is increased above \$0/tCO_2, a combination of solar, wind, biomass, biogas, geothermal, and natural gas displaces coal generation (Fig. 4B). New coal is not installed at carbon adders above \$40/tCO_2 and, at \$70/tCO_2, almost all existing coal plants are retired. Existing nuclear capacity continues operation under all carbon adders, but new nuclear generation appears in this power system only at carbon adders of \$70/tCO_2 and above in the Base Cost scenario. Geothermal and biogas renewable baseload capacity are installed under all carbon adders to help satisfy RPS requirements.

Power system carbon emission levels equal 54% of 1990 emissions by 2030 in the Base Cost scenario at a carbon adder of \$70/tCO_2. These emission levels are consistent with the 450 ppm climate stabilization target. In this low-carbon power system, new natural gas generation is installed as early as 2014 to replace retiring capacity (Fig. 5A). The available geothermal and biogas resources are brought on early as an inexpensive way to help meet RPS targets. Wind generation is the primary technology that helps to meet increasing RPS requirements between 2018 and 2022, but generation from solid biomass also makes a contribution to RPS and decreased CO_2 emissions in this timeframe.

Investment in solar does not begin until 2026 when falling PV costs and rising RPS demand make central station solar PV attractive. Solar PV comprises almost all capacity additions in the final investment period of 2026–2029. It should be noted that should solar PV costs decline faster than modeled in this scenario, this technology would be deployed more quickly and at a larger scale. Such cost trajectories have been proposed by the United States Department of Energy SunShot Initiative, which has the goal of reaching an installed overnight solar PV capital cost of \$1/W_p by 2020.

At a carbon adder of \$70/tCO_2, non-baseload generation dominates the generation mix by 2030, with solar, wind, hydroelectric, and gas providing 11%, 15%, 18%, and 35% of generation, respectively (Fig. 4B). While gas fuel costs increase between the third and fourth investment periods, the total amount spent on gas fuel decreases in the fourth period relative to earlier periods because solar displaces peaking natural gas generation (Fig. 5B). This power system contains 44 GW of central station PV capacity, which provides power during peak load hours, and 52 GW of onshore wind capacity, which provides power mostly during the



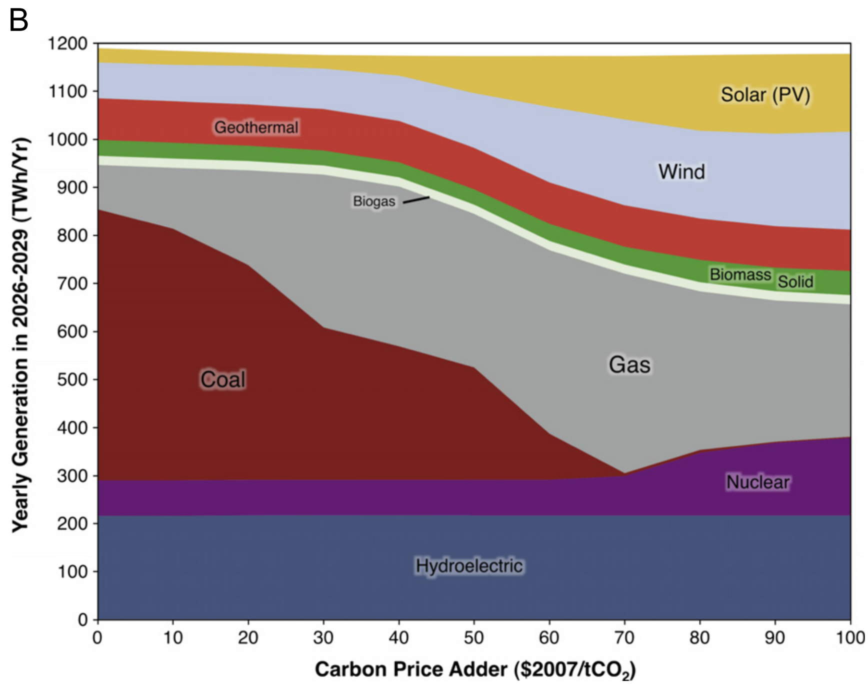
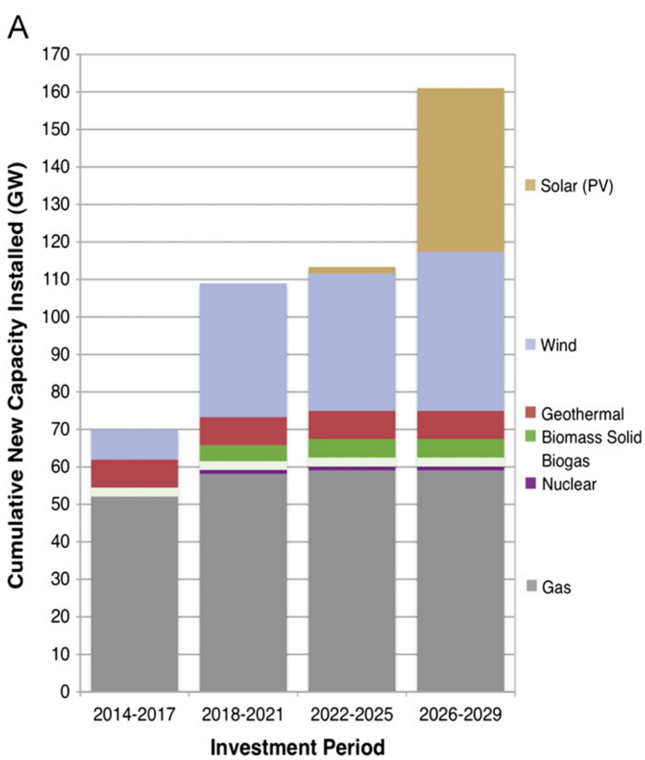


Fig. 4. Base Cost scenario CO_2 emissions relative to 1990 emission levels (A) and yearly power generation by fuel (B) in 2026–2029 as a function of carbon price adder. As shown in panel A, the climate stabilization target of 450 ppm is reached at a carbon price adder of \$70/tCO_2.



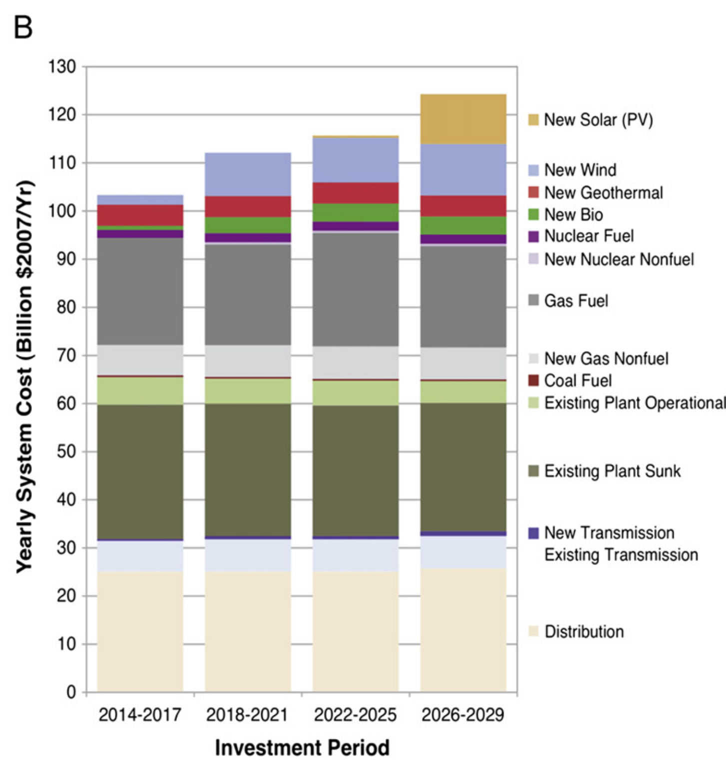


Fig. 5. Base Cost scenario cumulative new capacity additions (A) and yearly average system costs (B) by investment period at \$70/tCO_2 carbon price adder. Nonfuel costs include capital, operations, and maintenance costs.

winter, spring, and fall. In addition, 68 GW of hydroelectric and 100 GW of natural gas plants meet the remaining load and provide reserve capacity for the system. A plot of hourly power system operation is shown in Fig. 6. Note that this power system contains substantially less baseload generation than is found in the present day WECC power system.

Fig. 7 shows the geographic distribution of power production in 2026–2029. Solar and gas generation, which complement each other temporally as dispatched by the optimization (Fig. 6), are co-located in the Desert Southwest. Wind generation is largely sited in the Rocky Mountains. While the existing transmission network is used extensively, 9800 GW-km of new long-distance high-voltage transmission is also built, mainly to enable delivery of power from high-quality Rocky Mountain wind sites to load centers (Fig. 7). Installation of PV in 2026–2029 does not spur much new transmission investment, except for a new 1 GW transmission line to bring solar power from northern Nevada to the San Francisco Bay Area.

4.2. Low Nuclear Cost scenario

With carbon policy that reduces emissions below 1990 levels (285 $MtCO_2$/yr) by 2030, the optimal power system design is highly responsive to the capital cost of nuclear. At carbon price adders of less than or equal to \$50/tCO_2, the Low Nuclear Cost and Base Cost scenarios are identical because no new nuclear is built under weak carbon policy in either scenario. As the carbon price adder is increased, the least-cost strategy for reducing CO_2 emissions in the Low Nuclear Cost scenario relies on fuel-switching from coal to nuclear power.

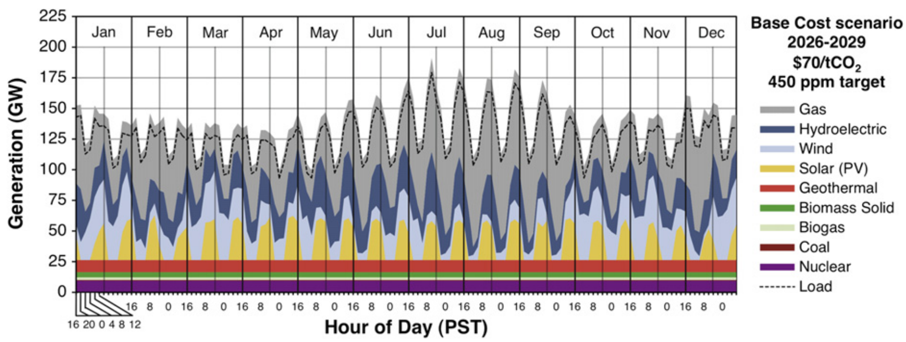


Fig. 6. Base Cost scenario hourly power system dispatch at 54% of 1990 emissions in 2026–2029. This scenario corresponds to a \$70/tCO_2 carbon price adder. The plot depicts six hours per day, two days per month, and twelve months. Each vertical line divides different simulated days. Optimizations are offset eight hours from Pacific Standard Time (PST) and consequently start at hour 16 of each day. Total generation exceeds load due to distribution, transmission, and storage losses. Hydroelectric generation includes pumped storage when storing and releasing.

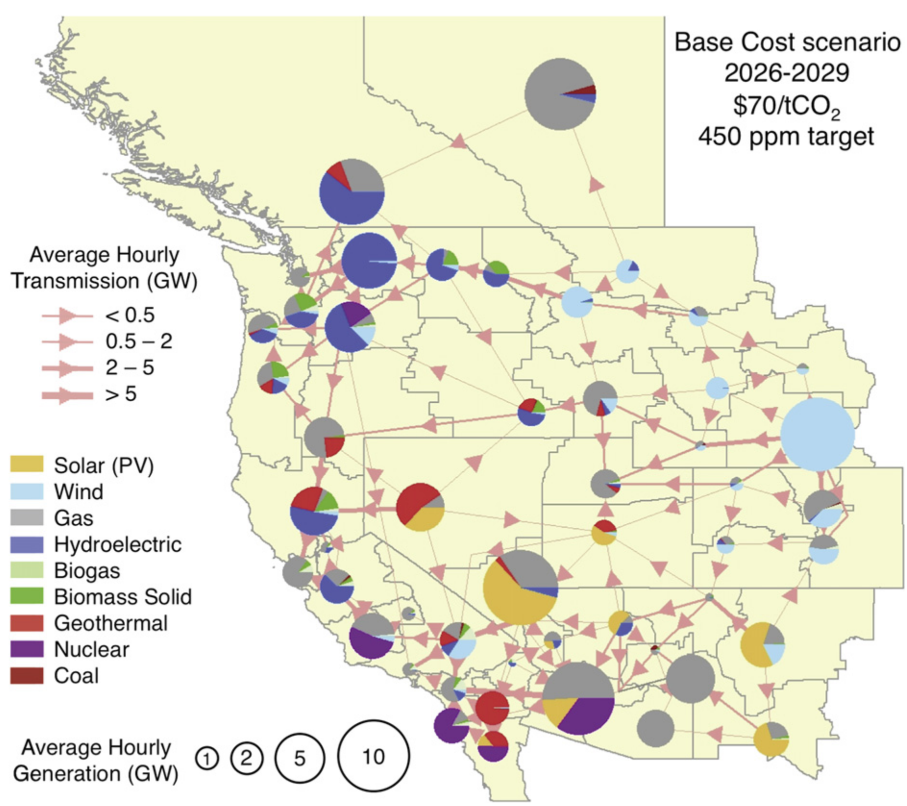


Fig. 7. Average generation by fuel within each load area and average transmission flow between load areas in 2026–2029 at 54% of 1990 emissions for the Base Cost scenario. This scenario corresponds to a \$70/tCO_2 carbon price adder. Transmission lines are modeled along existing transmission paths, but are depicted here as straight lines for clarity. The Rocky Mountains run along the eastern edge of the map, whereas the Desert Southwest is located in the south of the map.

Above $50/t$CO_2$, new nuclear power appears in the Low Nuclear Cost scenario. In this scenario, the 450 ppm climate stabilization target of 54% of 1990 carbon emissions by 2030 is reached at a carbon price adder of $59/t$CO_2$. A considerably different power system is designed relative to the Base Cost scenario due to the inclusion of large amounts of new nuclear capacity. The energy generated by nuclear in 2026–2029 is 25% of the total (Fig. 8), with an installed capacity of 37 GW—four times the current WECC-wide capacity of 9 GW. Solar, wind, hydroelectric, and gas plants provide the remaining generation above baseload, at 6%, 11%, 18%, and 21% of total electricity, respectively.

Of the six scenarios explored here, the Low Nuclear Cost scenario results in the smallest transmission build-out. A total of 6000 GW-km of new transmission capacity is installed, which is considerably less than the 9800 GW-km found in the Base Cost scenario. New nuclear plants are built at key junctions where existing transmission capacity is present but is underutilized due to the retirement of existing coal power plants. Hourly system operation is similar to that in present day, except with nuclear in the place of coal. In this scenario, nuclear and coal are found to be suitable substitutes. The strength of carbon policy determines which of these two large-scale baseload generation options should be installed on an economic basis.

4.3. Low Price Gas scenario

Recent projections (U.S. Energy Information Agency, 2011) suggest that natural gas prices may remain low in the future, a possibility that we explore in the Low Gas Price scenario. In this scenario, at the 450 ppm climate stabilization target, the 2030 optimal power system is very similar to that in the Base Cost scenario. In both scenarios, virtually all emissions originate from natural gas, with the share of generation from this fuel effectively constrained by the 450 ppm target. Due to the lower cost of natural gas in the Low Gas Price scenario, it takes a carbon price adder of $87/t$CO_2$ to reach the 450 ppm target in the Low Gas Price scenario, whereas in the Base Cost scenario only $70/t$CO_2$ is necessary. The difference in cost of natural gas generation resulting from the two natural gas price levels is roughly equivalent to that induced by a $17/t$CO_2$ difference in carbon price adder. As a result, similar generation fleets are deployed in the Base Cost and Low Gas Price scenarios.

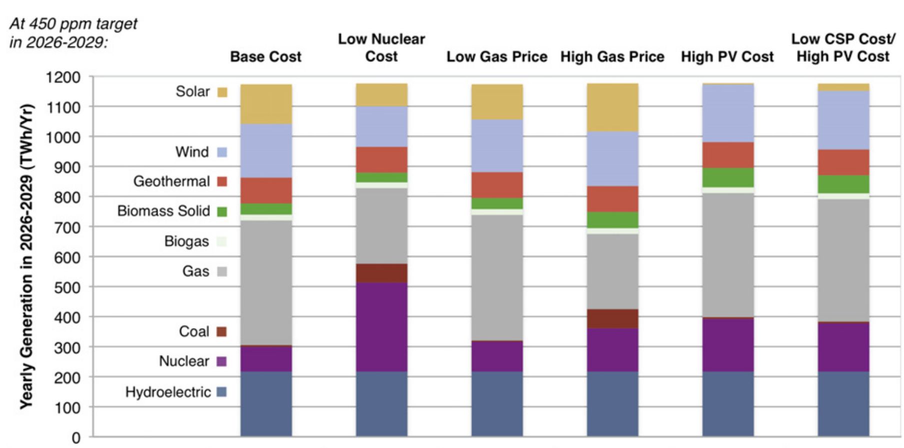
4.4. High Gas Price scenario

The High Gas Price scenario demonstrates that many other generation sources can substitute for natural gas if gas prices become high in the 2030 timeframe. To reach the 450 ppm climate stabilization target in this scenario, the reliance of the optimal power system on gas-fired generation is substantially decreased. Only 21% of power in the High Gas Price scenario is generated from gas, a 40% reduction relative to the Base Cost scenario. Low-carbon generation from new nuclear, biomass solid, wind, and solar displaces gas generation. In addition, instead of retiring virtually all existing coal plants as in the Base Cost scenario, some existing coal is kept online in the High Gas Price scenario, generating 5% of electricity and producing 31% of carbon emissions. The carbon price adder at which the target is reached in the High Gas Price scenario is $66/t$CO_2$, which is $4/t$CO_2$ lower than is found in the Base Cost scenario. In combination with the reduced overall emissions resulting from lower natural gas deployment, a lower carbon adder allows for the retention of existing coal in the optimal power mix in the High Gas Price scenario.

4.5. Solar Cost scenarios

In all scenarios above, solar PV deployment is an important driver of lowering emissions by 2026–2029. The capital costs of this technology are assumed to decline substantially between present day and 2030 at a rate of 3.7%/yr, resulting in large-scale deployment in the last investment period. To explore the dynamics of a low-carbon power system without the availability of low-cost solar PV, we explore a scenario with a higher PV cost.

Despite continued capital cost reduction in the High PV Cost scenario (2.2%/yr), multi-GW-scale solar PV investment does not occur at 54% of 1990 carbon emissions by 2030, with just over 1 GW of capacity installed. Natural gas and solar are both peaking



	Base Cost	Low Nuclear Cost	Low Gas Price	High Gas Price	High PV Cost	Low CSP Cost/ High PV Cost
Carbon price adder ($2007/t$CO_2$)	70	59	87	66	84	86
Power cost ($2007/MWh)	113	110	110	114	114	114
Cumulative new transmission built by 2030 (10^3 GW-km)	9.8	6.0	9.0	11.7	12.0	12.3

Fig. 8. Yearly generation by fuel in 2026–2029 for all scenarios discussed in this paper at an emission level consistent with the 450 ppm climate stabilization target (54% of 1990 carbon emission levels by 2030). The carbon price adder, cost of power, and cumulative new transmission built at the 450 ppm climate stabilization target are also tabulated for each scenario in 2026–2029. Results in this figure are obtained by varying the carbon price adder for each scenario until the target emission level is reached.

resources and are generally considered substitutes, but the 450 ppm target limits the total amount of gas generation in both the Base Cost and High PV Cost scenarios, effecting deployment of other types of generation instead. Relative to the Base Cost scenario, solar PV is replaced by a combination of nuclear, biomass solid, and wind power rather than natural gas.

In the Low CSP Cost/High PV Cost scenario, 9 GW of CSP parabolic trough systems without thermal storage are deployed in the Desert Southwest by 2030, generating 2% of WECC-wide electricity. These CSP plants preclude installation of PV generation, as the economics of CSP are favorable relative to those of central station PV in this scenario. CSP technology with thermal energy storage is not deployed. The Low CSP Cost/High PV Cost scenario is very similar to the High PV Cost scenario because the amount of CSP generation deployed in the former is small relative to system load.

In both of the solar cost scenarios, the 450 ppm target occurs at a power cost of \$114/MWh, \$1/MWh higher than is found in the Base Cost scenario. However, the carbon adder that makes the power system reach the target is found to be much higher at \$84–\$86/tCO_2 relative to \$70/tCO_2 in the Base Cost scenario.

4.6. Post-optimization dispatch results

To ensure reliability, after each cost optimization, the performance of the proposed power system is tested using 16,800 distinct hours of data for each investment period. This check ensures that enough capacity has been built to serve load under conditions that were not included in the optimization stage. For this paper, a total of more than 4 million hours were simulated under all cost and carbon price adder scenarios discussed. Among these, no combination of cost scenarios and carbon price adders results in power shortages, even for a single hour or a single load area. The success of the dispatch check adds validity to the model's method of sampling median and peak load study hours to plan an electric power system with intermediate levels of intermittent renewable generation.

5. Discussion

To build an electricity sector consistent with a 450 ppm climate stabilization target, our results indicate that the RPS might be a logical first step that guarantees that renewable capacity is added in the near term. In advance of national or regional carbon-reduction policies, RPS targets establish a policy environment that begins to decarbonize the energy mix. In our simulations, RPS policies effect reductions in emission levels primarily by promoting cost-effective baseload renewable technologies such as geothermal, biomass, and biogas in the near term. However, in a scenario with existing RPS and a carbon price adder of \$0/tCO_2 – a business-as-usual case – emissions from the lowest-cost western North American electric power system would be roughly double the 1990 levels by 2030 (Fig. 4B). Current RPS targets in western North America are not set high enough to put electric power sector emissions on track to stabilize the climate at or below 450 ppm (i.e. allow no more than 54% of 1990 emissions in 2030). To reduce emissions below 1990 levels by 2030, optimal power systems determined via SWITCH include more renewable electricity generation than is mandated by RPS targets.

We demonstrate that the ambitious 450 ppm climate stabilization trajectory can be achieved using a fleet of existing generation technologies. Across the scenarios investigated here, the composition of the fleet varies substantially but the resulting power systems also exhibit a number of commonalities. In all 450 ppm scenarios, no new coal-fired generation is added to the power mix as investment in carbon-intensive generation is not consistent with long-term climate targets. Some existing coal is still operated until 2030 in scenarios with a carbon price adder below \$70/tCO_2, as its economics remain favorable relative to gas generation below this carbon price.

In most 450 ppm scenarios, virtually all emissions originate from gas-fired generation, with this fuel accounting for between 21% and 36% of total generation. At the upper bound of 36%, the amount of gas generation is effectively constrained by the 450 ppm target. Despite this upper bound on gas generation, the system appears to have sufficient flexibility to integrate between 17% and 29% of electricity from intermittent renewable generation cost-effectively in all scenarios using natural gas and hydroelectric resources. This is evident from the High Gas Price scenario in which the share of natural gas is the smallest, but the share of intermittent renewables is the largest of any 450 ppm scenario investigated (Fig. 8).

Electricity storage is not used extensively due to round-trip efficiency losses and high costs. For these reasons, battery storage, compressed air energy storage, and solar thermal systems with thermal energy storage are not installed at any carbon price adder in the scenarios discussed here. Existing pumped hydroelectric storage provides hourly arbitrage sparingly as there is sufficient lower-cost dispatchable generation already present. The inclusion of ancillary services to compensate for contingencies such as uncertain solar, wind, and load forecasts may add enough value to enable the addition of new storage projects to the optimal electric power system.

Given the large amount of system flexibility discussed above, wind and solar combined with natural gas and hydroelectric act as substitutes for baseload generation from biomass solid and nuclear. In this study of western North America, these technologies are acceptable substitutes on an operational basis within the levels of intermittent renewable penetration and carbon emissions explored. They are also substitutes on an economic basis as can be seen by their levels of deployment within the SWITCH cost optimization framework.

We find that achieving the 450 ppm target by 2030 has similar costs across the scenarios we investigate (Fig. 8). In the scenarios presented here, WECC-wide average power costs are between \$110/MWh and \$114/MWh. While the system receives modest cost benefits from low-cost nuclear or low-cost PV generation, neither of these technologies alone is integral to meeting the 2030 emissions target. The cost of achieving deeper emission reductions without nuclear in the Base Cost scenario would be only slightly higher relative to the Low Nuclear Cost scenario: about 3% higher to reach 54% of 1990 levels by 2030 (Fig. 8). This suggests that it is possible to build a reliable, low-carbon power system without nuclear power for similar costs to a nuclear-centered system. We also show that even if PV capital costs or natural gas prices are higher than projections in the Base Cost scenario, it is possible to achieve significant de-carbonization at only a slight cost premium. In both the High PV Cost and High Gas Price scenarios, at 54% of 1990 emissions by 2030, the increase in power cost is \$1/MWh or 1% relative to the same emission levels in the Base Cost scenario.

In the scenarios presented here, the lowest-cost power system designed for a 450 ppm target occurs at a carbon price adder of between \$59/tCO_2 and \$87/tCO_2. While the carbon price adder in these scenarios may appear high, the actual cost increase to redesign the grid in order to achieve these deep emissions reductions is relatively low (Fig. 9), with a power cost increase of between 16% and 20% relative to scenarios without any carbon price adder (i.e. business-as-usual).

In addition to comparing scenarios consistent with a 450 ppm target, we investigate the cost of power in all six cost scenarios at

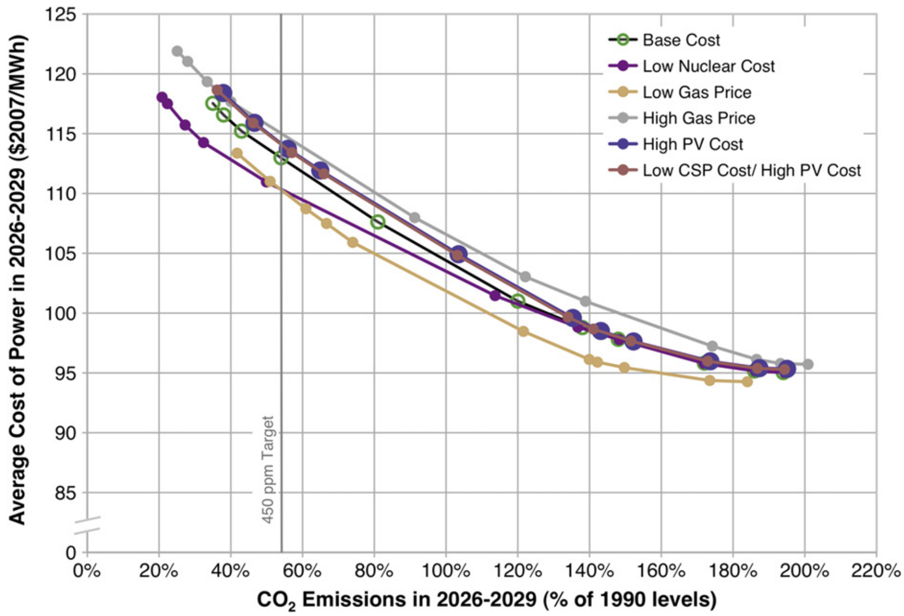


Fig. 9. Average cost of power in 2026–2029 as a function of carbon emissions for all scenarios. Each point represents an optimization performed at a distinct carbon price adder, with the rightmost and leftmost points on each line representing optimizations at $0/t$CO_2$ and $100/t$CO_2$ respectively. Intermediate points range between these values in steps of $10/t$CO_2$. The broken *y*-axis allows for ease of comparison of the cost of power between scenarios but visually overstates the magnitude of power cost differences. For example, the Base Cost scenario power cost increases by only 18% when moving from the far right of this plot to the 450 ppm target line.

different levels of carbon emissions. At all carbon emission levels above 40% of 1990 levels by 2030, the projected cost of power is found to differ by at most 5% between any pair of scenarios achieving similar decarbonization (Fig. 9). Further decarbonization beyond this point could be realized by replacing all the remaining coal power and much of the natural gas with renewables and/or nuclear power, but is not investigated in this study.

By optimizing capacity expansion and hourly generation dispatch simultaneously, SWITCH is uniquely suited to explore both the value of and synergies among various power system technology options, providing policymakers and industry leaders with important information about the optimal development of the electricity grid. Integrating long-term, coordinated generation, storage, and transmission planning improves the ability of the electric power sector to meet economic and climate goals. Analyses like this can help identify the least-expensive response to climate change, but concerted action will be needed to develop this system, such as ensuring that the cost of renewable technologies continues to decrease, securing low-cost financing for renewable power, and developing market structures that can accommodate changes in grid operation that will result from the deployment of low-carbon technologies.

6. Conclusions

This study illustrates realistic future grid scenarios with baseload, dispatchable and intermittent generation, transmission, and storage at minimal cost, taking into account the variability of renewable technologies. The least expensive power system studied, which implements current RPS policies but no further carbon policy, would deliver power at an average cost of $95/MWh, but would have roughly double the 1990 emission levels by 2030. Achieving emission levels of 54% of 1990 levels is shown to be possible by 2030 under a range of possible future costs and with many different combinations of low-carbon and conventional generation technologies. We find that intermittent renewable technologies can make an important contribution to emission reductions, comprising between 17% and 29% of total electricity generated by 2030 in scenarios consistent with the 450 ppm target. Despite differences in power mix due to the range of cost assumptions investigated in this study, the resultant power systems deliver power at similar costs. The carbon price to induce these deep carbon emission reductions is high, but the delivered cost of power increases by at most 20% over business-as-usual. High-resolution models like SWITCH make it possible to find low-cost solutions that challenge the assumption that the deployment of the low-carbon grid is very expensive.

7. Author contributions

M.F. envisioned and wrote the core of the SWITCH model; J.N, J.J, A.M., I.H., A.P-G., C.B., and D.M.K. expanded and adapted the SWITCH model to WECC; D.M.K. oversaw and raised funds for the WECC expansion; J.N., J.J., and I.H. collected and integrated WECC datasets; J.J implemented the post-optimization dispatch algorithm, and maintained software and hardware; J.J., J.N., and C.B. implemented the RPS constraint; J.N., J.J., and A.M. expanded the suite of installable technologies; A.P-G. wrote the transmission line path-following algorithm; J.N., J.J., A.M., M.F., and D.M.K. analyzed results and wrote the paper.

Acknowledgments

M.F. was funded by an EPA STAR graduate fellowship (No. FP916698) and NSF DDRI grant (No. 0602884) while developing the SWITCH model, and was funded by NextEra Energy Resources while contributing to this paper. The WECC analysis and writing were funded by the Karsten Family Foundation, Vestas Wind LLC, the UC Berkeley Class of 1935, and the CPV Consortium. A.P-G. was funded by an NSF Graduate Research Fellowship and C.B. received a Berkeley Nerds Fellowship. The findings were not subject to review or approval by any of the funders; the authors declare no competing financial interests.

Appendix A. Supplementary material

Supplementary data associated with this article can be found in the online version at doi:10.1016/j.enpol.2012.01.031. For updates on SWITCH results and online manuals, see http://rael.berkeley.edu/switch.

References

3TIER, 2010. Development of Regional Wind Resource and Wind Plant Output Datasets. National Renewable Energy Laboratory (NREL/SR-550-47676, March 2010).

Bergen, A.R., Vittal, V., 2000. Power Systems Analysis, second ed. Prentice Hall, Upper Saddle River, NJ., pp. 323–374.

Chen, Q., Kang, C., Xia, Q., Zhong, J., 2010. Power generation expansion planning model towards low-carbon economy and its application in China. IEEE Transactions on Power Systems 25 (2), 1117–1125.

Cooper, M., 2009. The economics of nuclear reactors: renaissance or relapse? Vermont Law School, South Royalton. VT. 〈http://www.vermontlaw.edu/Documents/Cooper%20Report%20on%20Nuclear%20Economics%20FINAL%5B1%5D.pdf〉 (accessed 2011).

DeCarolis, J.F., Keith, D.W., 2006. The economics of large-scale wind power in a carbon constrained world. Energy Policy 34, 395–410.

EnerNex Corporation, 2006. 2006 Minnesota Wind Integration Study. Minnesota Public Utilities Commission. 〈http://www.uwig.org/windrpt_vol%201.pdf〉 (accessed 2011).

EnerNex Corporation, 2010. Eastern Wind Integration and Transmission Study. National Renewable Energy Laboratory (NREL/SR-550-47078, 2010). 〈http://www.nrel.gov/wind/systemsintegration/pdfs/2010/ewits_final_report.pdf〉 (accessed 2011).

Federal Energy Regulatory Commission, 2005. Form 714: Annual Electric Balancing Authority Area and Planning Area Report, 2005. Washington, DC.

Federal Energy Regulatory Commission, 2009. Form 715: Annual Transmission Planning and Evaluation Report, 2009. Washington, DC.

Fripp, M., 2008. Optimal Investment in Wind and Solar Power in California. Doctoral Dissertation, University of California, Berkeley. 〈http://disexpress.umi.com/dxweb#download?&type=pdf&dpubno=3388273〉 (accessed 2011).

Fripp, M., Least-cost planning for emission reductions via wind and solar power in California, in review.

GE Energy, 2010. Western Wind and Solar Integration Study. National Renewable Energy Laboratory (NREL/SR-550-47434, 2010). 〈http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf〉 (accessed 2011).

Harding, J., 2007. Economics of nuclear power and proliferation risk in a carbon-constrained world. The Electricity Journal 20, 65–76.

International Energy Agency, 2008. World Energy Outlook 2008. 〈http://www.iea.org/weo/2008.asp〉 (accessed 2011).

Kagiannas, A.G., Askounis, D.T., Psarras, J., 2004. Power generation planning: a survey from monopoly to competition. Electrical Power and Energy Systems 26, 413–421.

Klein, J., 2007. Comparative Costs of California Central Station Electricity Generation Technologies: Cost of Generation Model. California Energy Commission (CEC-200-2007-011-SD, 2007). 〈http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SD.PDF〉 (accessed 2011).

McKinsey & Company, 2008. Carbon Capture and Storage: Assessing the Economics. 〈http://www.mckinsey.com/clientservice/ccsi/pdf/ccs_assessing_the_economics.pdf〉 (accessed 2011).

National Renewable Energy Laboratory, 2010a. Regional Energy Deployment System (ReEDS). 〈http://www.nrel.gov/analysis/reeds/〉 (accessed 2011).

National Renewable Energy Laboratory, 2010b. Renewable Resource Data Center. 〈http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/〉 (accessed 2010).

National Renewable Energy Laboratory, 2010c. Solar Advisor Model. 〈https://www.nrel.gov/analysis/sam/〉 (accessed 2010).

National Climatic Data Center, 2010. Climate Forecast System Reanalysis (CSFR). Asheville, North Carolina. 〈http://nomads.ncdc.noaa.gov/data/cfsr/〉 (accessed 2010).

Perez, R., et al., 2002. A new operational satellite-to-irradiance model. Solar Energy 73, 307–317.

Saha, S., et al., 2010. The NCEP climate forecast system reanalysis. Bulletin of the American Meteorological Society. Early Online Release, 2010. 〈http://journals.ametsoc.org/doi/pdf/10.1175/2010BAMS3001.1〉 (accessed 2010).

Tidball, R., Bluestein, J., Rodriguez, N., Knoke, S., 2010. Cost and Performance Assumptions for Modeling Electricity Generation Technologies. National Renewable Energy Laboratory (NREL/SR-6A20-48595, 2010). 〈http://www.nrel.gov/docs/fy11osti/48595.pdf〉 (accessed 2011).

U.S. Energy Information Administration, 2008. Emissions of Greenhouse Gases Report (DOE/EIA-0573, 2008). 〈http://www.eia.gov/oiaf/1605/ggrpt/carbon.html〉 (accessed 2011).

U.S. Energy Information Administration, 2009. The National Energy Modeling System (NEMS). Report #:DOE/EIA-0581. 〈http://www.eia.doe.gov/oiaf/aeo/overview/〉 (accessed 2011).

U.S. Energy Information Administration, 2011. The National Energy Modeling System (NEMS). Report #:DOE/EIA-0383. 〈http://www.eia.doe.gov/oiaf/aeo/overview/〉 (accessed 2011).

Ventyx Corp, 2009. Ventyx Energy Map. 〈http://www.ventyx.com/velocity/ev-energy-map.asp〉 (accessed 2011).

White House Office of Management and Budget, 2010. Circular No. A94 Revised. Washington, DC. 〈http://www.whitehouse.gov/omb/circulars_a094#8〉 (accessed 2011).

Wood, A.J., Wollenberg, B.F., 1996. Power Generation, Operation, and Control, second ed. Wiley, Hoboken, NJ., pp. 29–91.