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Technical Report
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List of Abbreviations and Acronyms

AC	alternating current
AEO	Annual Energy Outlook
ALL	combination of NG-EUR, NCR, WG-2ETI, and HI-VAR sensitivities (sensitivity scenario)
Btu	British thermal unit
CC	combined cycle
CF	capacity factor
CR-80	80 GW of regionally based coal retirements by 2026 (sensitivity scenario)
CR-35	35 GW of regionally based coal retirements by 2020 (sensitivity scenario)
CSP	concentrating solar power
CT	combustion turbine
DC	direct current
DOE	U.S. Department of Energy
EGS	enhanced geothermal system
EHS	enhanced hydrothermal system
EIA	Energy Information Administration
ETI	evolutionary technology improvement
EUR	estimated ultimate recovery
Gas-CC	natural gas combined cycle
Gas-CT	natural gas combustion turbine
GW	gigawatts
HI-VAR	high solar variability (sensitivity scenario)
HT	hydrothermal
ITC	investment tax credit
LCOE	levelized cost of energy
LD	low electricity demand trajectory (sensitivity scenario)
LD ALL	combination of LD, NG-EUR, NCR, WG-2ETI, and HI-VAR sensitivities (sensitivity scenario)
MMBtu	million Btu
MW	megawatts
NCR	no coal retirements (sensitivity scenario)
NEMS	National Energy Modeling System
NG	lower natural gas price (sensitivity scenario)
NG-EUR	lower natural gas price, high estimated ultimate recovery case (sensitivity scenario)
NoDPV	no distributed PV (sensitivity scenario)
NREL	National Renewable Energy Laboratory
OMB	Office of Management and Budget
PV	photovoltaic
RE	renewable electricity
RE Futures	Renewable Electricity Futures
ReEDS	Regional Energy Deployment System
RSMG	relaxed solar market growth (sensitivity scenario)
SolarDS	Solar Deployment System
SP-62.5	62.5% solar price reduction (sensitivity scenario)

SP-50	50% solar price reduction (sensitivity scenario)
SSVS	SunShot Vision Study
TWh	terawatt-hours
USD	U.S. dollars
USMG	unlimited solar market growth (sensitivity scenario)
W	watts
WG-ETI	ETI cost and performance metrics for wind and geothermal only (sensitivity scenario)
WG-2ETI	twice the cost reduction of the WG-ETI scenario for wind and geothermal (sensitivity scenario)

Executive Summary

The U.S. Department of Energy (DOE) *SunShot Vision Study* (U.S. DOE 2012) explores the impact of reducing solar prices by about 75% between 2010 and 2020 on potential U.S. deployment of solar technologies. DOE's SunShot Initiative envisions reaching, by 2020, an installed system price of $1/W_{DC}$ for utility-scale photovoltaics (utility PV) and $3.60/W_{AC}$ for concentrating solar power (CSP) with up to 14 hours of thermal storage capacity. The National Renewable Energy Laboratory's Regional Energy Deployment System (ReEDS) model was used to simulate utility PV and CSP deployment based on these price projections and market assumptions. In the *SunShot Vision Study*, U.S. total utility PV and CSP deployment reaches 209 GW by 2030 and 475 GW by 2050.

Utility PV and CSP deployment is sensitive to several factors in addition to installed system prices. In this study, we explore the sensitivity of utility-scale solar deployment to eight key model assumptions:

1. Solar technology prices: 50%, 62.5%, and 75% (SunShot scenario) solar price reductions by 2020
2. Electricity demand: flat demand and 1% growth per year (SunShot scenario) through 2050
3. Lower natural gas prices: natural gas prices reaching $7.40 and $9.50 per MMBtu by 2050 versus $10.20 per MMbtu in the SunShot scenario
4. Coal retirements: no retirements, retire 35 GW by 2020, retire 76 GW by 2030 (SunShot scenario), and retire 80 GW by 2026
5. Cost and performance of non-solar renewable technologies: 10% and 20% lower wind costs combined with 11%–17% and 22%–34% lower geothermal costs (relative to the SunShot scenario)
6. PV resource variability: 50% lower and higher output variability and solar resource correlation (relative to the SunShot scenario)
7. Distributed photovoltaic (PV) deployment: no distributed PV adoption versus 240 GW of distributed PV adoption by 2050 in the SunShot scenario
8. Solar market supply growth limits: rapid growth cost penalty, maximum deployment level (SunShot scenario), and no annual growth limit

We generated a total set of 45 sensitivity scenarios by varying model assumptions both individually and in various combinations. We find that installed price is the most important driver behind utility-scale solar adoption. However, our analysis also indicates that non-price factors can have significant impacts. By 2030, assuming the SunShot solar price targets are met, ReEDS builds utility-scale solar capacity between 175–212 GW for most scenarios under the SunShot-electricity-demand assumptions and 86–154 GW for the scenarios under the low-electricity-demand assumptions (compared with 209 GW in the SunShot scenario). By 2050, ReEDS builds utility-scale solar capacity between 229–567 GW for the scenarios under the SunShot-electricity-demand assumptions and 90–236 GW for the scenarios under the low-electricity-demand assumptions (compared with 475 GW in the SunShot scenario).

With solar prices being equal, low electricity demand suppresses solar deployment the most, followed by lower natural gas prices. The other individual factors generally have a smaller impact, although relaxed solar market supply growth restrictions can boost utility-scale solar deployment substantially beyond SunShot levels by 2030 (up to 342 GW in one instance). Some combinations of factors have a major impact on solar deployment and generation, especially under the low-electricity-demand assumption. For example, there is a six-fold increase in 2050 utility-scale solar capacity from the combination scenario with the lowest deployment to the scenario with the highest deployment. In fact, the worst-case combination scenario examined here results in utility-scale solar deployment that is lower even than the deployment in the sensitivity scenario where solar prices are two times higher than the SunShot scenario. Most combinations under the SunShot-electricity-demand assumptions, however, are in line with SunShot solar generation results through 2030, with discrepancies growing larger between 2030 and 2050.

Table of Contents

List of Figures

List of Tables

1 Introduction

The U.S. Department of Energy (DOE) SunShot Initiative aims to reduce the price of solar energy systems by about 75% between 2010 and 2020. Achieving this target is expected to make the unsubsidized cost of solar energy competitive with the cost of other currently operating energy sources, paving the way for rapid, large-scale adoption of solar electricity across the United States.

To assess the potential impacts of achieving the SunShot targets, DOE's Solar Energy Technologies Program produced the *SunShot Vision Study* (SSVS) (U.S. DOE 2012). The SSVS assumes that the SunShot price targets are achieved by 2020 and models the resulting penetration of solar technologies in the United States using two models: the National Renewable Energy Laboratory's (NREL's) Regional Energy Deployment System (ReEDS) model is used to simulate utility-scale solar deployment, and NREL's Solar Deployment Systems (SolarDS) model is used to simulate distributed solar deployment. The results suggest that solar energy could satisfy roughly 14% of U.S. electricity demand by 2030 and 27% by 2050.[1] Solar growth based on non-cost factors (e.g., greenhouse gas reduction and energy security benefits) is not considered in the analysis but could result in additional solar market penetration.

The actual deployment of solar will be driven by a large number of highly uncertain factors, including the cost of all generation technologies and fuels, future characteristics of the electric sector, and challenges associated with integrating variable energy sources. Thus, it is important to examine the sensitivity of the projected solar deployment in the SSVS to these types of factors. In this report, we explore the sensitivity of projected utility-scale solar deployment using the ReEDS model; a companion paper explores the sensitivity of projected distributed solar deployment using the SolarDS model (Drury et al. 2013).

To examine the sensitivity of utility-scale solar[2] penetration in ReEDS and explore variations on the SSVS assumptions, this report analyzes the sensitivity of utility-scale solar deployment to a variety of factors, both individually and in combination:

1. Solar technology prices: 50%, 62.5%, and 75% (SunShot scenario) solar price reductions by 2020
2. Electricity demand: flat demand and 1% growth per year (SunShot scenario) through 2050
3. Lower natural gas prices: natural gas prices reaching $7.40 and $9.50 per MMBtu by 2050 versus $10.20 per MMBtu in the SunShot scenario
4. Coal retirements: no retirements, retire 35 GW by 2020, retire 76 GW by 2030 (SunShot scenario), and retire 80 GW by 2026

[1] All results in this report refer to the contiguous United States (excluding Alaska and Hawaii). The contribution of solar to total demand does not include the allocation of curtailment among various renewable energy sources (wind and solar). As a result, the actual contribution of solar could be slightly lower. This issue is discussed in detail in Section 4.
[2] Throughout this report, utility-scale solar refers to utility-scale PV and CSP.

5. Cost and performance of non-solar renewable technologies: 10% and 20% lower wind costs combined with 11%–17% and 22%–34% lower geothermal costs (relative to the SunShot scenario)
6. PV resource variability: 50% lower and higher output variability and solar resource correlation (relative to the SunShot scenario)
7. Distributed photovoltaic (PV) deployment: no distributed PV adoption versus 240 GW of distributed PV adoption by 2050 in the SunShot scenario
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As observed in the SSVS, installed price is the most important driver behind solar adoption. However, our analysis also indicates that non-price factors have significant impacts. By 2030, assuming the SunShot solar price targets are met, ReEDS builds utility-scale solar capacity between 175–212 GW for most scenarios under the SunShot-electricity-demand assumptions and 86–154 GW for the scenarios under the low-electricity-demand assumptions (compared with 209 GW in the SunShot scenario). By 2050, ReEDS builds utility-scale solar capacity between 229–567 GW for the scenarios under the SunShot-electricity-demand assumptions and 90–236 GW for the scenarios under the low-electricity-demand assumptions (compared with 475 GW in the SunShot scenario).

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The remainder of this report is structured as follows. Section 2 summarizes the modeling framework used in the SSVS, including a discussion of the capacity-expansion model and base assumptions as well as the SSVS results. Section 3 describes the sensitivity analyses performed in this study and details the various modified input assumptions. Section 4 presents the results of the individual and combined sensitivity analyses and the range of projected solar deployment. Section 5 summarizes the results and provides conclusions.

2 Modeling Framework

2.1 Scenario Development

Two models were used to develop the SSVS scenarios: ReEDS (Short et al. 2011) and the SolarDS model (Denholm et al. 2009). ReEDS was the primary model used to simulate utility-scale solar deployment. Developed at NREL, it is a linear-optimization, capacity-expansion model that simulates the least-cost deployment and dispatch of generation resources. ReEDS determines the geographic deployment of PV, concentrating solar power (CSP), and other generation technologies based on a number of factors: future technology and fuel price projections, future U.S. electricity demand projections, regional solar resource quality and resource limitations, impacts of variability in renewable generation, transmission requirements, and grid reliability requirements. The model does not choose technologies based simply on their levelized cost of energy (LCOE). Rather, ReEDS co-optimizes energy, capacity, and ancillary service requirements—along with the temporal characteristics of variable generators among other factors—to produce an overall mix of generators that minimizes the system cost. Additionally, ReEDS optimizes transmission capacity expansion to accommodate the regional deployment of technologies. Through this economic optimization, ReEDS was used to examine one possible set of impacts on the U.S. electric sector resulting from achieving the SunShot price targets. Major impacts include regional solar deployment levels, additional transmission capacity expansion requirements, additional firm and flexible resource requirements, emissions reductions, and electricity price and overall system cost impacts.

Because ReEDS is not designed to account for distributed rooftop PV generation, the penetration of distributed rooftop PV was exogenously specified in ReEDS from the SolarDS model for the SSVS. SolarDS—also developed at NREL—is a market-penetration model for commercial and residential rooftop PV. It simulates rooftop PV deployment based on regional electricity prices, financial incentives, regional solar resource quality, rooftop availability, and market-diffusion characteristics.

A third model, ABB's GridView (ABB Inc. 2008) was used to determine the operational feasibility of the SunShot results by performing hourly simulations of the ReEDS system, subject to more rigorous treatment of power-flow transmission constraints than can be captured by ReEDS.

2.2 Reference and SunShot Main Scenario

The SSVS includes a reference scenario with moderate solar energy price reductions to compare with the costs, benefits, and challenges of achieving the SunShot price targets. Future installed system price estimates for all technologies, including solar, are based on Black & Veatch (2012) in the reference scenario. In both the SunShot and reference scenarios, electricity demand is assumed to increase by about 1% per year through 2050. This assumption is consistent with U.S. Energy Information Administration (EIA) projections through 2035 (U.S. EIA 2010) and an extension of EIA's projected trend through 2050. At this rate, demand reaches about 4,400 TWh by 2030 and 5,100 TWh by 2050.

For the SunShot scenario, solar technology installed system prices are assumed to reach the SunShot price targets by 2020: $1/$W_{DC}$[3] for utility PV systems, $1.25/$W_{DC}$ for commercial rooftop PV, $1.50/$W_{DC}$ for residential rooftop PV, and $3.60/$W_{AC}$ for CSP systems with up to 14 hours of thermal storage capacity. Table 1 provides a breakdown of PV and CSP prices including benchmarked prices in 2010 and projected prices in 2020 for the SunShot and reference scenarios. The SunShot prices represent a set of very aggressive, but technically possible, targets that would give solar technology a similar LCOE as competing electricity sources in each market segment. Pathways to achieving these cost and performance targets are discussed in detail in the SSVS (U.S. DOE 2012).

Table 1. Projected PV and CSP Installed System Prices and Performance (2010 U.S. Dollars/W)

	Utility PV		Residential Rooftop PV		Commercial Rooftop PV		CSP					
	SunShot	Ref.	SunShot	Ref.	SunShot	Ref.	SunShot			Ref.		
	$/$W_{DC}$	$/$W_{DC}$	$/$W_{DC}$	$/$W_{DC}$	$/$W_{DC}$	$/$W_{DC}$	$/$W_{AC}$	Hours Storage[a]	CF[b] (%)	$/$W_{AC}$	Hours Storage[a]	CF[b] (%)
2010	4.00	4.00	6.00	6.00	5.00	5.00	7.20	6	43	7.20	6	43
2020	1.00	2.51	1.50	3.78	1.25	3.36	3.60	14	67	6.64	6	43
2030	1.00	2.31	1.50	3.32	1.25	2.98	3.60	14	67	5.40	6	43
2040	1.00	2.16	1.50	3.13	1.25	2.79	3.60	14	67	4.78	6	43
2050	1.00	2.03	1.50	2.96	1.25	2.64	3.60	14	67	4.78	6	43

[a] The number of hours of thermal energy storage for CSP is optimized in ReEDS and is slightly different than the numbers in this table due to restrictions on the solar multiple within ReEDS (see Appendix A of the SSVS).
[b] Capacity factor (CF)

For the purposes of modeling the SunShot scenario, the SunShot system prices are assumed to remain constant through the 2020–2050 timeframe (i.e., no further price reductions are modeled for solar technologies beyond 2020). Installed system price estimates for all conventional and other renewable (including wind) electricity-generating technologies are based on Black & Veatch (2012). Fuel prices and price elasticities are based on EIA's *Annual Energy Outlook* (AEO) 2010 and are extrapolated through 2050 based on modeled fuel demand (U.S. EIA 2010). Future costs are discounted using a 7% real discount rate, per guidance from the U.S. Office of Management and Budget (OMB 2003). Additional details on model assumptions are provided in the SSVS (U.S. DOE 2012).

Both scenarios assume the federal investment tax credit (ITC) and production tax credit run through their currently established expiration dates[4]—end of 2016[5] and 2012, respectively—but that existing supports for conventional technologies that are embedded in the tax code or through other provisions continue indefinitely. Further, the scenarios do not incorporate any pending or proposed regulations associated with criteria pollutants or carbon emissions.

[3] Unless otherwise noted, all prices and values in the study are given in 2010 U.S. dollars.
[4] These assumptions are based on policies that existed at the time the SSVS was published in February of 2012.
[5] The SSVS assumes the ITC ends in 2016 even though current U.S. law maintains a 10% ITC after 2016. This choice is made to be consistent with the SunShot Initiative's goal of making large-scale solar energy systems cost competitive without subsidies by the end of the decade (U.S. DOE 2012).

2.3 Solar Growth Results

Achieving the SunShot targets is projected to result in the cumulative installation of approximately 302 GW of PV and 28 GW of CSP by 2030. By 2050, the cumulative installed capacities are projected to increase to 632 GW of PV and 83 GW of CSP. To achieve this level of cumulative installed capacity, annual installations would need to reach about 25–30 GW for PV and about 3–4 GW for CSP. Solar grows much more slowly in the reference scenario (Figure 1).

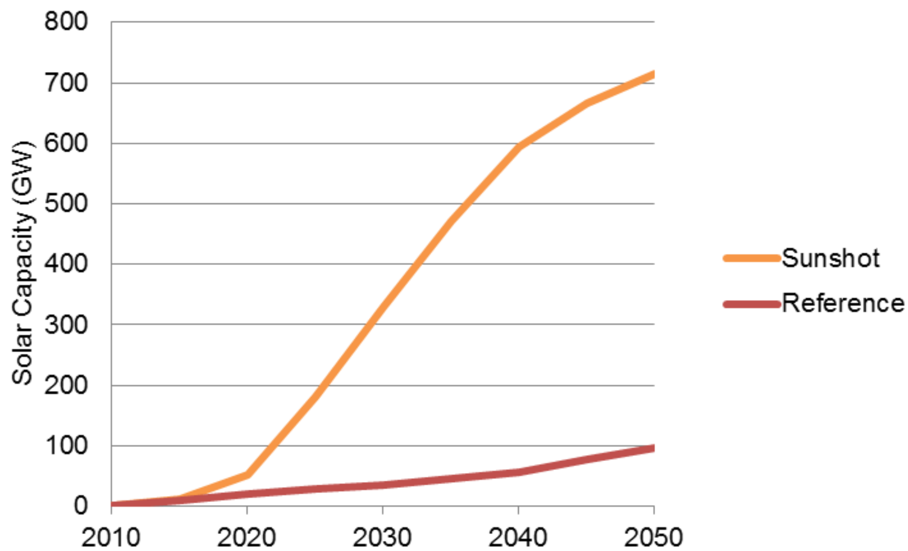

Figure 1. Total solar capacity under the SunShot and reference scenarios

By 2030, the SunShot scenario levels of installations translate into PV generating 505 TWh of electricity, or 11% of total electricity demand, and CSP generating 137 TWh, or 3% of total demand. By 2050, PV is projected to generate 1,036 TWh, or 19% of total demand, and CSP is projected to generate 412 TWh, or 8% of total demand. Table 2 summarizes the electricity generation and installed capacity of PV and CSP in 2030 and 2050.

Table 2. Overview of SunShot Scenario Results

Year	Technology	Electricity Generation (TWh)	Installed Capacity (GW)
2030	PV	505	302
	CSP	137	28
2050	PV	1,036	632
	CSP	412	83

The SunShot scenario results in a reduction in the need for new conventional generation capacity and the use of fossil fuels—primarily natural gas and coal. Figure 2 shows the evolution of the electric sector in the SunShot and reference scenarios. Before 2030, solar generation[6] primarily offsets natural gas generation in the SunShot scenario. This is because midday solar generation corresponds well with times of peak midday electricity demand, and solar electricity frequently offsets more expensive peaking generation resources, like natural gas combustion turbines (CTs). However, once a large amount of solar generation has been added to the system (14% of demand by 2030), the "net load" of the system, defined as electricity demand minus solar and wind generation, shifts from midday to evening. Once this happens, solar generation offsets the new build-out of coal capacity seen in the reference scenario, and solar begins to significantly offset coal use after 2030. Additional natural gas resources developed after 2030 satisfy the evening peak in net load, and CSP resources deployed with several hours of storage provide a dispatchable solar generation resource.

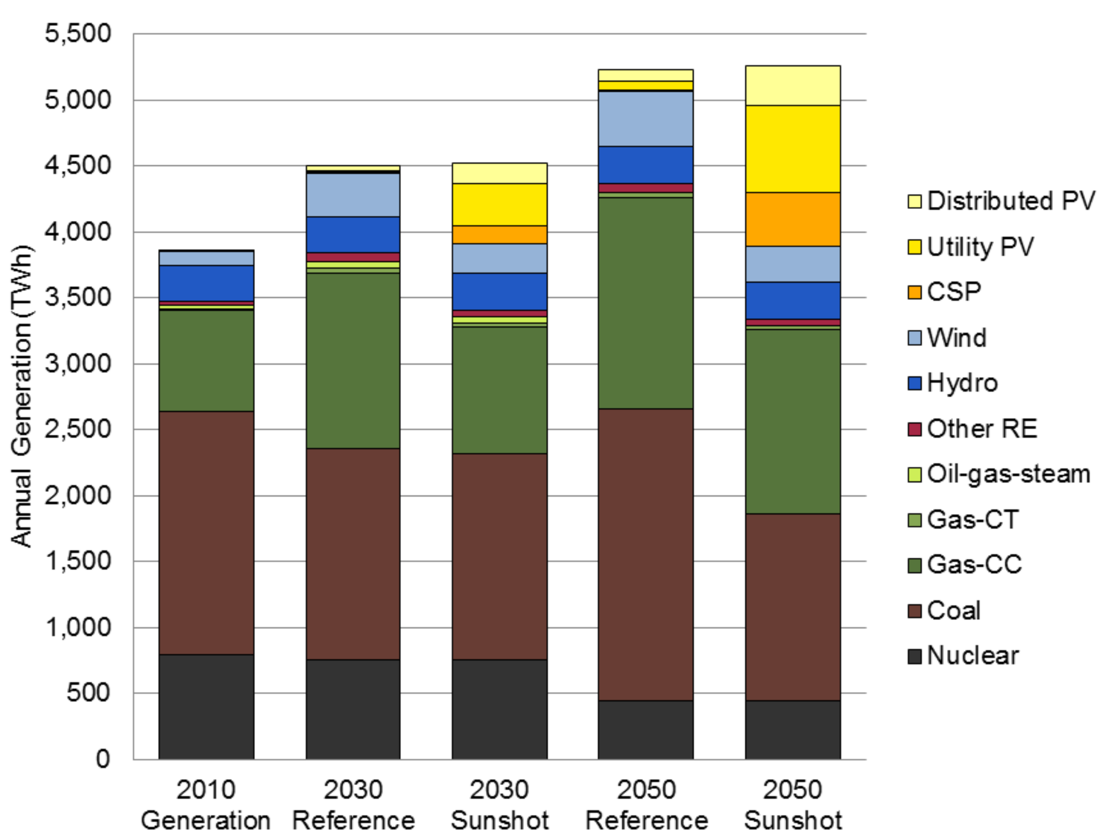

Figure 2. Evolution of electricity generation in the reference and SunShot scenarios

PV (Photovoltaic), CSP (Concentrating Solar Power), Other RE (Other Renewable Electricity), Gas-CT (Natural Gas Combustion Turbine), Gas-CC (Natural Gas Combined Cycle).

[6] Note that generation numbers are reported at the bus. Therefore, generation from distributed rooftop PV has been multiplied by 1.053 (U.S. DOE 2012) to account for distribution losses that centralized generation systems incur. This adjustment allows for a more equal comparison of generation from distributed PV systems with that from other technologies.

3 Defining Sensitivity Scenarios

Here we present the assumptions behind a set of 45 sensitivity scenarios created in order to examine key drivers of potential solar market adoption. This analysis also provides greater understanding of basic model performance, which will help to improve the representation of solar technologies in models in the future.

Table 3. Descriptions of Single-Factor Sensitivity Scenarios

Sensitivity Category	Scenario Abbreviation	Brief Description
Baseline	**SunShot**	SunShot main scenario (baseline scenario for this sensitivity analysis)
1. Solar Technology Prices[a]	**SP-62.5**	62.5% reduction in SSVS *reference scenario*[b] solar prices
	SP-50	50% reduction in SSVS *reference scenario*[b] solar prices
2. Electricity Demand[a]	**LD**	Low electricity demand trajectory
3. Lower Natural Gas Prices[a]	**NG**	Natural gas prices based on AEO 2011 reference case
	NG-EUR	Natural gas prices based on AEO 2011 high estimated ultimate recovery case
4. Coal Retirements[a]	**NCR**	No coal retirements
	CR-80	80 GW of regionally based coal retirements by 2026
	CR-35	35 GW of regionally based coal retirements by 2020
5. Cost and Performance of Non-Solar Renewable Technologies[a]	**WG-ETI**	Evolutionary technology improvement (ETI) cost and performance metrics *for wind and geothermal only*
	WG-2ETI	Twice the cost reduction of the WG-ETI scenario for wind and geothermal
6. PV Resource Variability[a]	**0.5σ**	Technical ReEDS parameter analysis scenarios examining the treatment of PV resource variability
	1.5σ	
	ρ = 0	
	0.5ρ	
	1.5ρ	
	HI-VAR	
7. Distributed PV Deployment[c,d]	**NoDPV**	No distributed rooftop PV systems are allowed
8. Solar Market Supply Growth Limits[c,e]	**USMG**	Unlimited solar market growth; solar growth penalties applied as cost
	RSMG	Relaxed solar market growth (remove 15-GW annual growth cap); utility PV and CSP growth can double every 2 years

[a] Sensitivity scenario is based on exogenous model parameter assumptions (light blue).
[b] The SSVS *reference scenario* is different than the baseline scenario (SunShot main scenario) for these sensitivities (see Section 2.2).
[c] Sensitivity scenario is based on endogenous model assumptions (dark blue).
[d] Rooftop PV deployment results from the SSVS are held constant in all these scenarios except for the NoDPV scenario that eliminates all rooftop PV.
[e] The growth of utility PV and CSP is limited in all of these scenarios except for the two scenarios that relax these limits.

Nineteen single-factor sensitivity scenarios are summarized in Table 3 and detailed in Sections 3.1–3.8. As shown in Table 3, the scenarios in this analysis are designed around eight sensitivity categories, including a mix of exogenous data inputs to the model (light blue) and endogenous model assumptions (dark blue): solar prices, electricity demand projection, natural gas prices, coal retirements, cost and performance of non-solar renewable technologies, PV resource variability, distributed PV deployment, and limits on solar market supply growth.

In addition to the 19 single-factor sensitivity scenarios explored in this analysis (Table 3), 26 sensitivity scenarios are generated through a combination of five of the factors shown in Table 3: (1) low demand (LD), (2) lower natural gas prices (NG-EUR), (3) no coal retirements (NCR), (4) improved economic performance of wind and geothermal (WG-2ETI), and (5) high variability of PV (HI-VAR). These five factors are chosen as the basis for the 26 combination sensitivities because each factor represents the worst-case scenario (with respect to solar deployment) for the sensitivity categories examined here related to exogenous model inputs (Table 3). All of the combination scenarios assume the SunShot solar prices (Table 1). The 26 combination scenarios (Table 4) explored in this analysis represent only a subset of the possible sensitivity combinations that could be explored using the single-factor sensitivities from Table 3. The combinations were chosen to provide the widest possible range of impacts due to the factors examined here.

Table 4. Sensitivity Combinations Using the LD, NG-EUR, NCR, WG-2ETI, and HI-VAR Single-Factor Scenario Assumptions

Low-Demand Scenarios					
1	LD	NG-EUR	NCR	WG-2ETI	HI-VAR
2	LD		NCR	WG-2ETI	HI-VAR
3	LD	NG-EUR	NCR		HI-VAR
4	LD	NG-EUR		WG-2ETI	HI-VAR
5	LD	NG-EUR	NCR	WG-2ETI	
6	LD		NCR		HI-VAR
7	LD			WG-2ETI	HI-VAR
8	LD	NG-EUR			HI-VAR
9	LD		NCR	WG-2ETI	
10	LD	NG-EUR	NCR		
11	LD	NG-EUR		WG-2ETI	
12	LD				HI-VAR
13	LD		NCR		
14	LD			WG-2ETI	
15	LD	NG-EUR			

AEO 2010 Demand Scenarios				
1	NG-EUR	NCR	WG-2ETI	HI-VAR
2		NCR	WG-2ETI	HI-VAR
3	NG-EUR	NCR		HI-VAR
4	NG-EUR		WG-2ETI	HI-VAR
5	NG-EUR	NCR	WG-2ETI	
6		NCR		HI-VAR
7			WG-2ETI	HI-VAR
8	NG-EUR			HI-VAR
9		NCR	WG-2ETI	
10	NG-EUR	NCR		
11	NG-EUR		WG-2ETI	

3.1 Solar Technology Prices (SP-62.5, SP-50)

To explore the sensitivity of solar deployment to solar technology prices, two additional price scenarios were modeled, each less aggressive than the SunShot targets: (1) PV prices decline 50% (the SP-50 scenario) between 2010 and 2020, and (2) PV prices decline 62.5% (the SP-62.5 scenario) between 2010 and 2020. Both sensitivity scenarios include comparable price declines for CSP. Table 5 shows the SunShot and sensitivity scenario prices for all solar technologies and applications. The SunShot scenario's 2010 utility PV benchmarked price is $4/$W_{DC}$; thus, the sensitivity scenarios' 2020 utility PV prices are $2/$W_{DC}$ (SP-50) and $1.50/$W_{DC}$ (SP-62.5). Similarly, the sensitivity scenarios' 2020 distributed PV (residential and commercial) prices are 50% and 62.5% lower in relation to their 2010 benchmarked prices. For CSP, the decline in installed capital cost was set to yield a similar level of relative cost reduction on an LCOE basis, including a shift to increased storage. The increased levels of storage assumed for CSP are reflected in Table 1, with higher values for capacity factors assumed in all scenarios. All conventional and non-solar renewable technology prices are the same for the SunShot and the solar price sensitivity scenarios. For all other parameters, the sensitivity analysis matches the SunShot analysis.

Table 5. Price Inputs for SunShot and Solar Price Sensitivity Scenarios

Technology/Application	SunShot Scenario 2020 -75% Price	Sensitivity Scenario 2020 -62.5% Price (SP-62.5)	Sensitivity Scenario 2020 -50% Price (SP-50)	Reference Scenario 2020
PV – Residential ($/$W_{DC}$)	1.50	2.25	3.00	3.78
PV – Commercial ($/$W_{DC}$)	1.25	1.88	2.50	3.36
PV – Utility Scale ($/$W_{DC}$)	1.00	1.50	2.00	2.51
CSP, 6/14 hour Storage ($/$W_{AC}$)[a]	3.60	4.87	6.14	6.64

[a] All values are for CSP systems with 14 hours of thermal storage except for the reference scenario value, which is for 6 hours of thermal storage.

3.2 Low Electricity Demand Growth (LD)

Adapted from *Renewable Electricity Futures* (RE Futures), the low-demand (LD) scenario assumes a high level of energy efficiency within the buildings and industrial sectors, resulting in essentially flat load growth, despite substantial growth in electric vehicle deployment. Figure 3 provides the demand profile. Additional details are in RE Futures Volume 3 (NREL 2012).

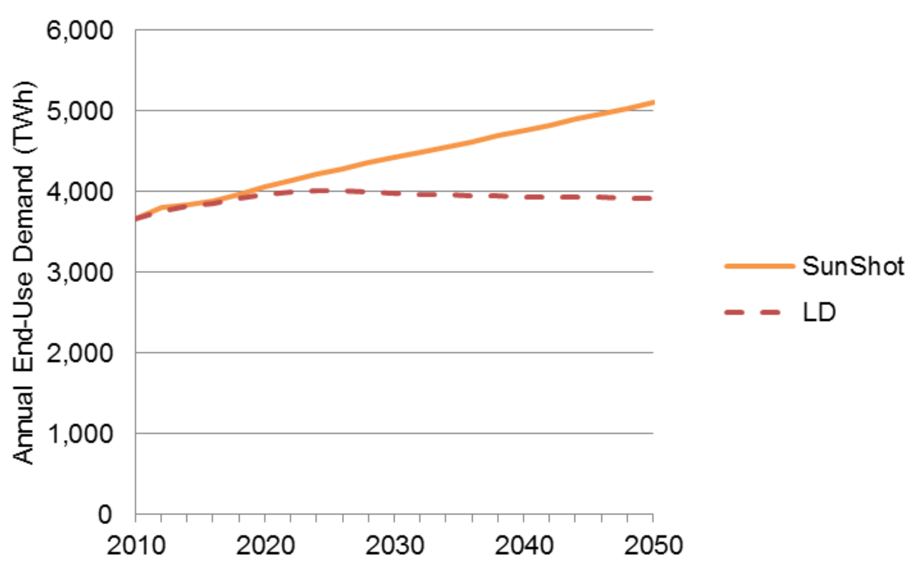

Figure 3. Comparison of end-use demand projections between the SunShot and low-demand scenarios

3.3 Lower Natural Gas Prices (NG, NG-EUR)

Natural gas prices for the SunShot scenario are based on AEO 2010 natural gas price projections (U.S. EIA 2010). ReEDS adjusts these projections upward or downward based on estimated electric-sector consumption and a demand-elasticity estimate. This analysis considers two lower natural gas price trajectories: (1) the AEO 2011 natural gas price reference case trajectory (the NG scenario) and (2) the AEO 2011 high estimated ultimate recovery case trajectory (the NG-EUR scenario), which projects high shale gas recovery (U.S. EIA 2011). Figure 4 compares natural gas price projections from the AEO 2010–2012 reference cases as well as the AEO 2011 high EUR case through 2035. The AEO 2012 reference case projections are not considered in the sensitivity analysis because of their similarity with the AEO 2011 reference case projections (U.S. EIA 2012).

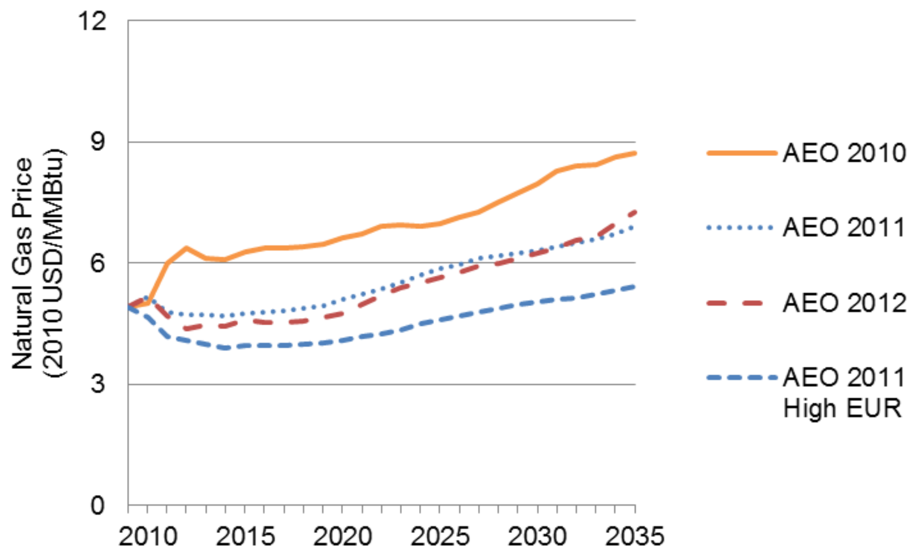

Figure 4. Comparison of AEO natural gas price projections through 2035

AEO 2010 base case (baseline for the SunShot analysis), AEO 2011 base case (intermediate lower natural gas, NG for this analysis), AEO 2011 high EUR case (NG-EUR for this analysis), AEO 2012 base case (not considered for this analysis).

3.4 Coal Retirements (CR-35, CR-80, NCR)

Under the assumption that coal plants have an 80-year lifetime, the SunShot scenario requires 1/80th of the existing coal fleet from 2010[7] to retire each year beginning in 2012. The 1/80th retirement percentage is applied to every plant across all regions irrespective of plant vintage. Furthermore, this particular approach does not consider retirements on an economic basis. Approximately 76 GW of the 2010 coal fleet are retired by 2030, and approximately half (152 GW) are retired by 2050.

Coal fleet retirement is a potentially important driver for the construction of new generation capacity. To explore the impact of a range of retirements, this analysis includes a scenario without any retirements (the NCR scenario) as well as two additional retirement scenarios. The two additional scenarios consider near-term retirements due to various existing and pending regulations[8] and decreased competitiveness due to low natural gas prices. The first of these scenarios (CR-80) assumes 80 GW of coal retirement by 2026. The second scenario (CR-35) assumes 35 GW of coal retirements by 2020. Both CR-80 and CR-35 retirement schedules use geographically specified[9] retirements loosely based on Logan et al. (2012).

[7] The existing coal fleet totaled approximately 305 GW in 2010.
[8] Pending regulations include the Cross States Air Pollution Rule, Mercury and Air Toxic Standard (aka Utility MACT), 316(b) water intake rule, and Coal Combustion Residual rule.
[9] The retirements in the SSVS are not geographically specified.

Figure 5 compares cumulative coal retirements through 2050 among the base SunShot, CR-35, and CR-80 scenarios. Beyond 2020 and 2026, coal retirements continue out to 2050 according to regionally based coal retirement projections from Ventyx (2010). The Ventyx retirements are based on lifetime estimate data for power plants.

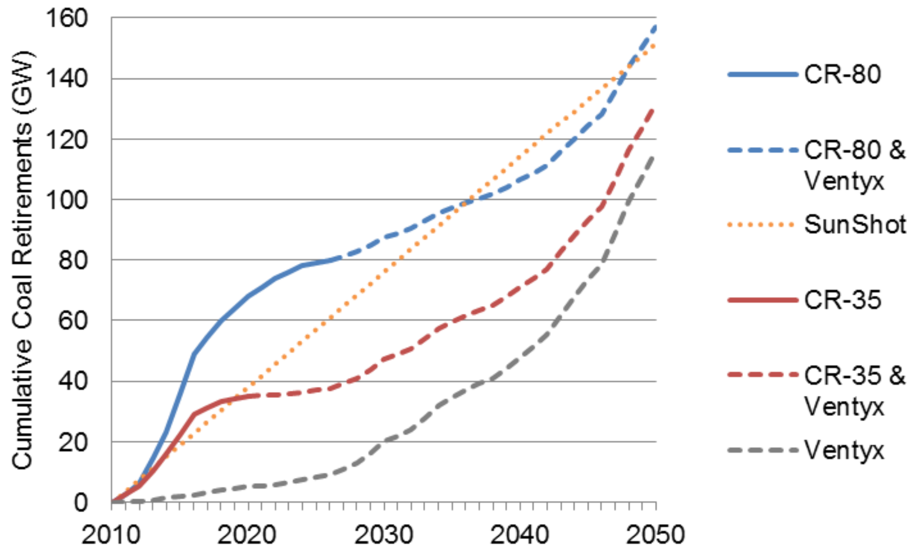

Figure 5. Comparison of coal retirement trajectories through 2050

SunShot (1/80th of existing coal fleet retired each year), CR-35 (35 GW retired by 2020 and Ventyx retirements to 2050), CR-80 (80 GW retired by 2026 and Ventyx retirements to 2050).

The CR-35 and CR-80 scenarios have coal retirements that differ from the baseline SunShot scenario in both location and timing. These coal retirement scenarios account for expected retirements in the Ohio River Valley and eastern states that have many old coal plants. By 2030, the CR-80 scenario retires more coal in the Ohio River Valley than the SunShot scenario; the largest difference is about 5.5 GW, in both Pennsylvania and Kentucky. By 2050, CR-80 retires more coal in most of the Southeast (Figure 6); the largest differences are in Illinois (4.5 GW) and Tennessee (4.11 GW). Conversely, the SunShot scenario has more retirements in the West (where the best CSP resource exists) than the CR-80 scenario; the largest difference is in Texas, where the SunShot scenario retires 4.25 GW more coal by 2030 and 7.55 GW more by 2050 (Figure 6).

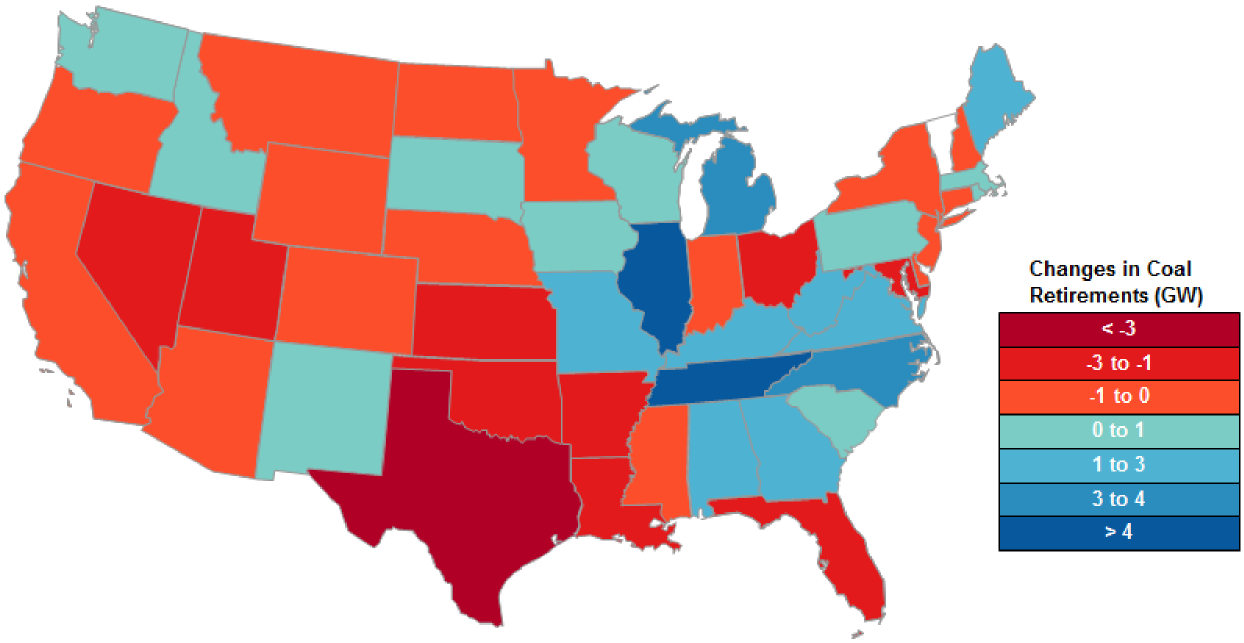

Figure 6. Geographic differences in coal retirements between the CR-80 and SunShot scenarios

(+) More coal retirements in CR-80 scenario; (-) more coal retirements in SunShot scenario

3.5 Cost and Performance of Non-Solar Renewable Technologies (WG-ETI, WG-2ETI)

The SunShot scenario assumes limited cost and performance improvements for wind and geothermal technologies. Competitive costs for these technologies could enable their projected capacity to increase, displacing capacity previously assigned to solar or conventional generators. Two capital cost reduction trajectory scenarios are based on the evolutionary technology improvement (ETI) costs in RE Futures (NREL 2012).[10] The first (the WG-ETI scenario) adapts capital cost trajectories for wind and geothermal[11] directly from RE Futures ETI scenarios. The second (the WG-2ETI scenario) assumes capital cost reductions equal to twice the difference between the wind and geothermal capital costs in the SunShot and RE Futures ETI scenarios. Figure 7 compares offshore and land-based wind capital costs among the SunShot, WG-ETI, and WG-2ETI scenarios.

[10] Capacity factors and operations and maintenance costs for wind are adapted from RE Futures for these scenarios as well.
[11] There is a large range of estimates for possible cost reductions of wind and other renewable energy technologies. These are discussed in more detail in the technology chapters within RE Futures. While RE Futures considers cost and performance improvements for biomass and hydropower, these changes are not considered in this analysis.

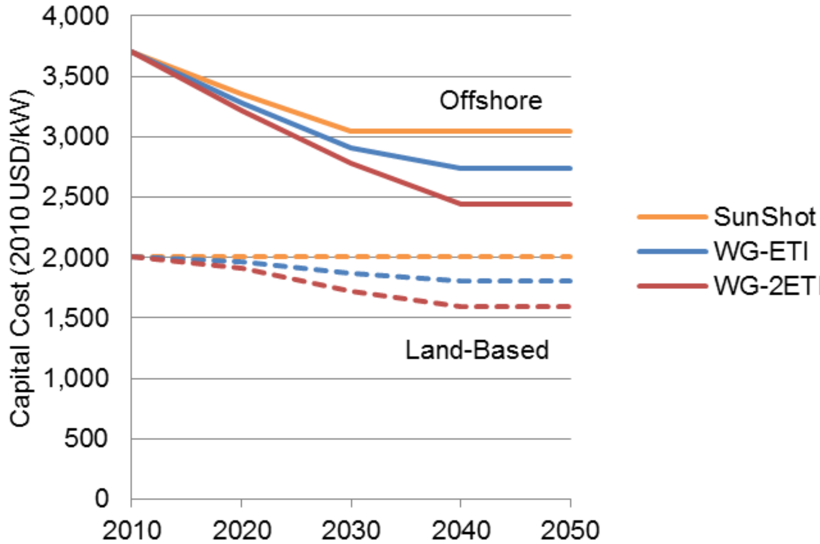

Figure 7. Capital cost for land-based and offshore wind for SunShot, WG-ETI, and WG-2ETI scenarios

Geothermal technologies modeled include hydrothermal (HT), enhanced hydrothermal systems (EHS), and enhanced geothermal systems (EGS). In addition to capital cost reductions, HT includes additional undiscovered resources as defined in RE Futures. Figure 8 shows the geothermal resource supply curves from the SunShot scenario in 2010 as well as the cost improvements for the WG-ETI and WG-2ETI scenarios by 2050. The SunShot scenario assumes no cost reductions through 2050 for all three geothermal technologies. The WG-ETI and WG-2ETI scenarios assume cost reductions through 2050 for all three geothermal technologies (Figure 8). Note that Figure 8 only shows the first 20,000 MW of resources less than $8,000/kW for each geothermal type.

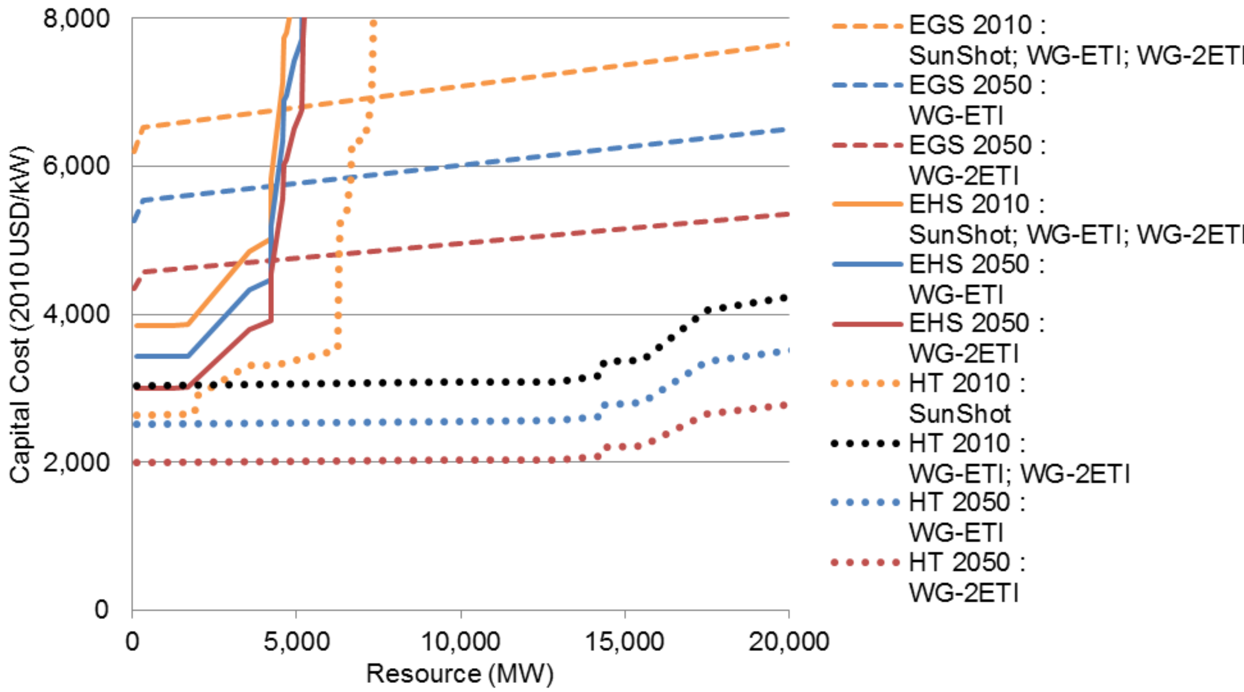

Figure 8. Geothermal resource supply curves in 2010 and 2050 for SunShot, WG-ETI, and WG-2ETI scenarios

3.6 PV Resource Variability (0.5σ, 1.5σ, ρ = 0, 0.5ρ, 1.5ρ, HI-VAR)

ReEDS considers the seasonal and diurnal variability of expected output of wind and solar plants. For variable resource renewable technologies like wind and solar, resource variability impacts the evaluation of capacity value, operating reserve requirements, and curtailments associated with these technologies. ReEDS statistically calculates these metrics by considering the current system characteristics including electricity demand, existing capacity mix, variance in expected output, and inter-region correlations of expected output. To determine the sensitivity of ReEDS to these factors, several parametric scenarios are evaluated.

Hourly wind and solar resource data are used to calculate average production profiles and the standard deviation of expected plant output for each of the 17 ReEDS times-slices[12] for these technologies. Variable resource technologies with a large variance in expected plant output for a typical hour in a time-slice exhibit lower capacity value and higher curtailments. Furthermore, variable resource technologies with a large variance in expected plant output from one hour to the next within a time-slice exhibit high expected forecast error reserve requirements. For this analysis, the effects of solar variability on solar deployment are addressed by varying these standard deviations (symbolized as σ) up and down by a multiplier (1.5σ or 0.5σ). Figure 9 shows these changes in standard deviations for each time-slice.

[12] The 17 time-slices in ReEDS consist of four representative time segments (morning, afternoon, evening, night) in a typical day for each season (summer, fall, winter, spring) as well as a peak-load summer time-slice.

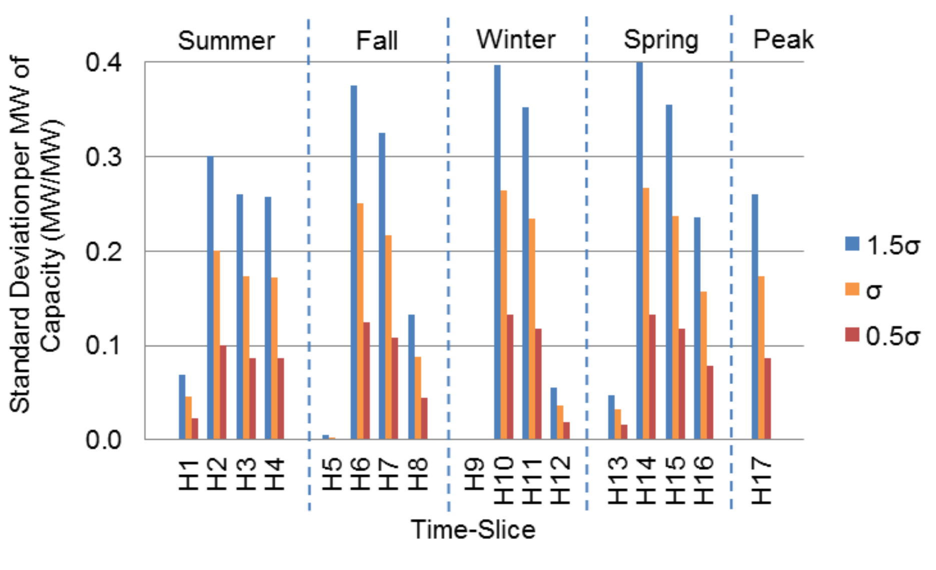

Figure 9. Standard deviations of expected utility PV plant output for each time-slice

All else being equal, ReEDS will select wind and solar resource sites based on geographic diversification of resource (i.e., preferentially selecting an untapped solar resource site that is less correlated with existing solar capacity). Resource sites that are less correlated (i.e., two sites with correlation coefficients near zero) in a time-slice will exhibit higher capacity value and lower curtailments. Furthermore, resource sites that are less correlated from one hour to the next within a time-slice will exhibit lower expected forecast error reserve requirements. To this effect, additional sensitivity scenarios include varying geographic solar resource correlations (symbolized as ρ) up and down by a multiplier (1.5ρ or 0.5ρ). Figure 10 shows these changes in correlation coefficients. Table 6 summarizes all of the solar variability scenarios considered.

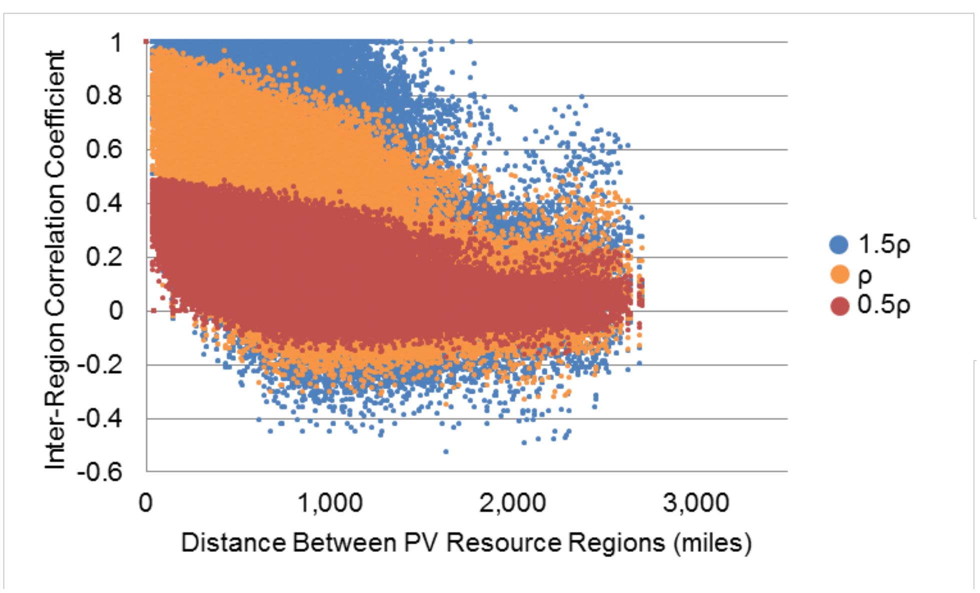

Figure 10. Inter-region correlations of expected power output between PV resource Regions

Table 6. Descriptions of PV Resource Variability Scenarios

PV Resource Variability Scenarios	Brief Description
0.5σ	Standard deviation in expected PV output is reduced by 50% (i.e., less uncertainty)
1.5σ	Standard deviation in expected PV output is increased by 50% (i.e., more uncertainty)
ρ = 0	PV resource is assumed to be uncorrelated between different resource regions[a]
0.5ρ	All inter-regional correlation coefficients for PV are decreased by 50% (i.e., PV resource becomes more geographically uncorrelated)
1.5ρ	All inter-regional correlation coefficients for PV are increased by 50% (i.e., PV resource becomes more geographically correlated[b])
HI-VAR	Combination of 1.5σ and 1.5ρ PV resource variability scenarios (i.e., more uncertainty and more correlated)

[a] Correlation coefficients for resource sites that are more correlated (i.e., ρ is near -1 or 1) change more in absolute terms than those for resource site that are nearly uncorrelated (i.e., ρ is near 0) in the ρ = 0 scenario.
[b] Correlation coefficients must range from -1 to 1. Therefore, correlation coefficients less than -0.67 or greater than 0.67 will increase (i.e., approach -1 or 1) less than 50% in the 1.5ρ scenario.

3.7 Distributed PV Deployment Assumptions (NoDPV)

Because ReEDS is not designed to account for distributed rooftop PV generation, the deployment of distributed (residential and commercial) PV capacity is exogenously specified in ReEDS from the SolarDS model (see Denholm et al. 2009 for a description of SolarDS). Distributed PV deployment totals 121 GW by 2030 and 240 GW by 2050. This specification of distributed PV capacity effectively changes the net load shape in ReEDS. To assess the tradeoff between distributed PV and central utility PV, the NoDPV scenario sets distributed generation deployment to zero through 2050. Note that Drury et al. (2013) examine sensitivities of distributed generation adoption in the SSVS to market assumptions.

3.8 Solar Market Supply Growth Assumptions (RSMG, USMG)

The SSVS limits the annual installed capacity growth of CSP and utility PV to no more than double in each 2-year model period, and it limits U.S. annual demand to no more than 15 GW of utility PV and no more than 15 GW of CSP.[13] These constraints were added to avoid boom-bust cycles in supply and demand in which demand rises to a very high level for a few model periods and then collapses. The constraints could also suggest the fact that manufacturers would consider longer-term market sustainability before developing manufacturing capacity and that market distribution and installation infrastructure takes time to develop. For the purposes of defining the initial allowable solar growth (to no more than double in each 2-year model period), a starting capacity of 500 MW[14] per year is used as a reference point in the SSVS and all scenarios discussed here. Using this 500-MW starting capacity means that, until the existing system has

[13] For the solar market supply growth sensitivities, there is no interaction with the distributed PV market supply growth.
[14] The 500-MW starting capacity does not reflect the actual installed utility PV or CSP capacity at the beginning of the ReEDS optimization.

built more than 500 MW of utility PV or CSP, the model allows each of these solar technologies to grow by up to 1,000 MW over a 2-year model period.

For the present sensitivity analysis, the solar growth limits are relaxed in two different scenarios. The first growth relaxation scenario (relaxed solar market growth, or RSMG) simply removes the 15 GW per year cap on utility PV and CSP installations. The second (unlimited solar market growth, or USMG) also removes the 15-GW per-year cap but also replaces the doubling-every-2-years constraint with a growth penalty cost curve. The growth penalty costs are a function of installed capital cost and the increase in new construction over previous years.

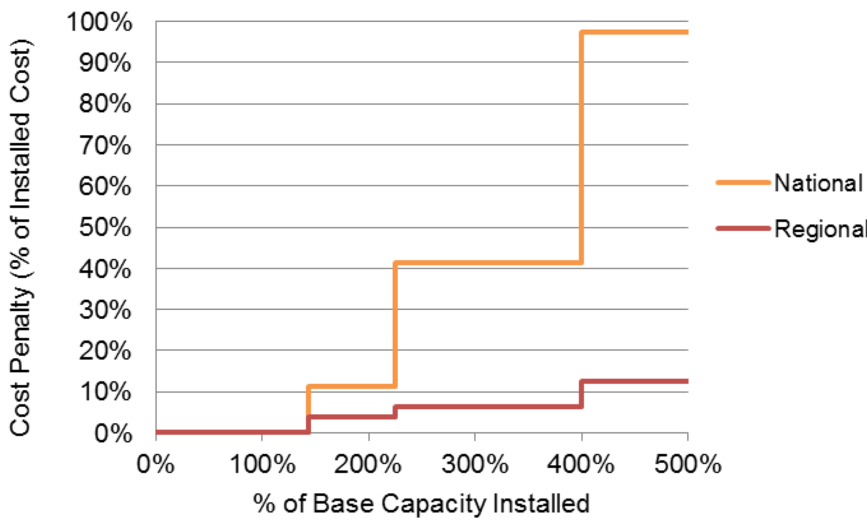

Figure 11. Utility PV growth penalty curve

Using the growth penalty cost curve shown in Figure 11, ReEDS allows the rate of new utility PV installations to increase by 44% of the base utility PV capacity in every 2-year model period on both a national and regional level before growth cost penalties apply. The base capacity is reset in every 2-year model period. On the national level, the base utility PV capacity is defined as the highest of 1,000 MW *or* the national total of new utility PV installations from the previous 2-year period *or* 90% of the *base* capacity from the previous 2-year period. On the regional level, the base utility PV capacity is defined as the highest of 600 MW *or* the new regional utility PV installations from the previous 2-year model period *or* 90% of the *base* capacity from the previous 2-year period. Therefore, as a minimum, ReEDS can add up to 1,440 (1.44 x 1,000) MW and 864 (1.44 x 600) MW of new capacity nationally and regionally, respectively, in each 2-year model period before incurring a growth penalty.

Other models have used similar constructs to control market dynamics. For example, the RenewMarket model from the Union of Concerned Scientist has historically used growth penalties applied as cost when the average growth in installed capacity over previous years exceeds some growth rate threshold (UCS 1999). The National Energy Modeling System (NEMS) from EIA has historically used growth constraints and penalties applied as cost to represent capacity growth limitations on a national and regional level (U.S. EIA 1998).

4 Sensitivity Scenario Results

A slightly updated version of ReEDS was used for these sensitivity analyses than was used for the SSVS. Therefore, the SunShot main scenario results presented here as the sensitivity baseline scenario deviate slightly from those in the SSVS. Figure 12 shows the difference in capacity build-out between the updated ReEDS model and the ReEDS model used in the SSVS. In general, there are no significant capacity changes between the scenarios. The updated ReEDS model produces a modest 6.7 GW (1.7%) increase in utility PV, to 398 GW by 2050.

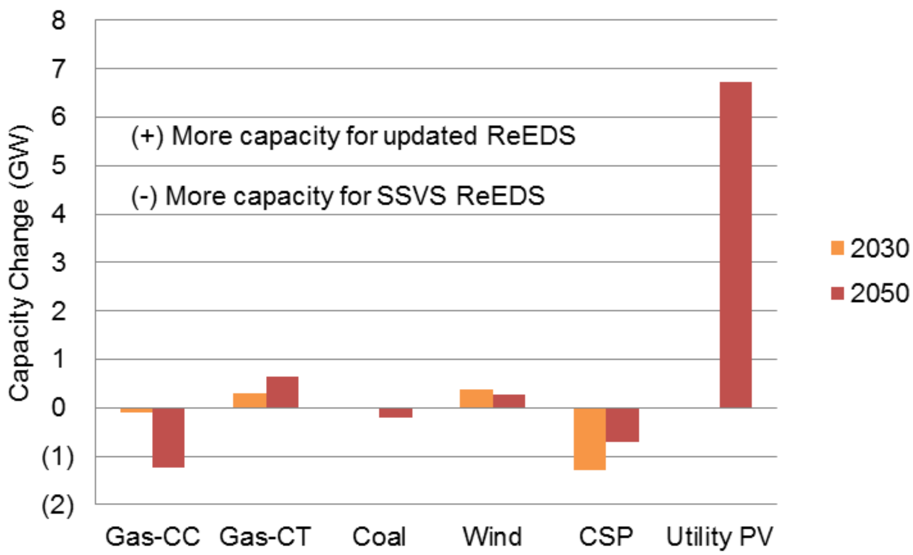

Figure 12. Change in capacity from SSVS ReEDS code to updated ReEDS code

Gas-CC (Natural Gas Combined Cycle), Gas-CT (Natural Gas Combustion Turbine), CSP (Concentrating Solar Power), Utility PV (Utility-Scale Photovoltaic).

The results presented in the following sections focus on changes in CSP and utility PV deployment rather than changes in solar deployment as a whole. Most of the scenarios explored in this analysis maintain the SunShot solar price assumptions described in Section 2.2. Distributed PV adoption is determined by SolarDS based on these price assumptions (among other inputs) and then specified exogenously in ReEDS.[15] By considering changes in solar deployment as a whole for these sensitivities, the fixed deployment schedule for distributed PV dilutes the impacts of changes in market and performance assumptions on deployment of solar technologies that can vary endogenously in ReEDS (i.e., CSP and utility PV); therefore, the results for this analysis focus on changes in solar technologies over which ReEDS has endogenous control.

In the SunShot scenario, ReEDS simulates 80 TWh of curtailments for variable resource technologies (wind and solar), representing 1.6% of demand and 4.6% of wind and solar generation. ReEDS accounts for curtailments of variable resource technologies as a whole but does not assign specific curtailment levels to particular technologies. Therefore, generation

[15] For the solar price sensitivities, the SolarDS model was rerun to provide deployment trajectories for distributed PV based on the adjusted distributed PV prices.

numbers presented in the SSVS reflect the potential generation that could contribute to electricity demand assuming the generation from wind and solar is not curtailed (see Section 2.3). The actual contributions of solar generation to electricity demand would be slightly lower than reported in the SSVS after considering curtailments.[16]

For some of the sensitivity scenarios in this analysis, total curtailments can be significantly larger than in the SSVS scenarios. Thus, for all generation results presented in the following sections, we have developed a method for allocating curtailments in ReEDS to wind and PV.[17] In this approach, bulk curtailments for each time-slice modeled in ReEDS are allocated to wind and PV based on the fraction of generation from these technologies in each time-slice. As a result, most of the curtailments in night time-slices (10 p.m. to 6 a.m.) are assigned to wind because PV generation will be minimal during these hours. Most curtailments during afternoon time-slices (1 p.m. to 5 p.m.) are assigned to PV because of both high PV deployment compared with wind deployment and, in general, peak PV generation compared with typically non-peak wind (specifically onshore wind) generation during these hours.

The following subsections discuss the sensitivity results by category. First we discuss the 19 single-factor sensitivity cases (Sections 4.1–4.8). Then we discuss two of the multi-factor sensitivity cases (Section 4.9). Finally we examine the full range of multi- and single-factor sensitivity cases together (Section 4.10). Note that some figures have different scaling to improve readability. Also, note that generation numbers are reported at the bus. Therefore, generation from distributed rooftop PV has been multiplied by 1.053 (U.S. DOE 2012) to account for distribution losses that centralized generation systems incur. This adjustment allows for a more equal comparison of generation from distributed PV systems with that from other technologies.

4.1 Solar Technology Prices (SP-62.5, SP-50)

Figure 13 shows the strong dependence of CSP and utility PV deployment on solar prices. In the SunShot scenario, total installed CSP and utility PV capacity reaches 209 GW in 2030 and 475 GW in 2050. In the 62.5% price-decline scenario (SP-62.5), total CSP and utility PV capacity reaches 176 GW in 2030 (16% lower than in the SunShot scenario) and 331 GW in 2050 (30% lower). In the 50% price-decline scenario (SP-50), total CSP and utility PV deployment drops dramatically: to 85 GW in 2030 (59% lower than in the SunShot scenario) and 117 GW in 2050 (75% lower). In the reference scenario, total CSP and utility PV capacity reaches 11 GW in 2030 (95% lower than in the SunShot scenario) and 35 GW in 2050 (93% lower).

Figure 14 shows similar results for total generation from CSP and utility PV. Solar market penetration is sensitive to the projected level of PV and CSP price reductions. These results indicate a threshold at which solar deployment increases non-linearly as price decreases. This threshold is somewhere between \$2.00/W_{DC} (SP-50) and \$1.50/W_{DC} (SP-62.5) for utility PV (and an equivalent level of price reduction for CSP).

[16] From the SSVS, solar technologies are projected to satisfy roughly 14% of *contiguous* U.S. electricity demand by 2030 and 27% by 2050.

[17] Because ReEDS mainly deploys CSP technology with storage, no curtailments are assigned to CSP in these estimates.

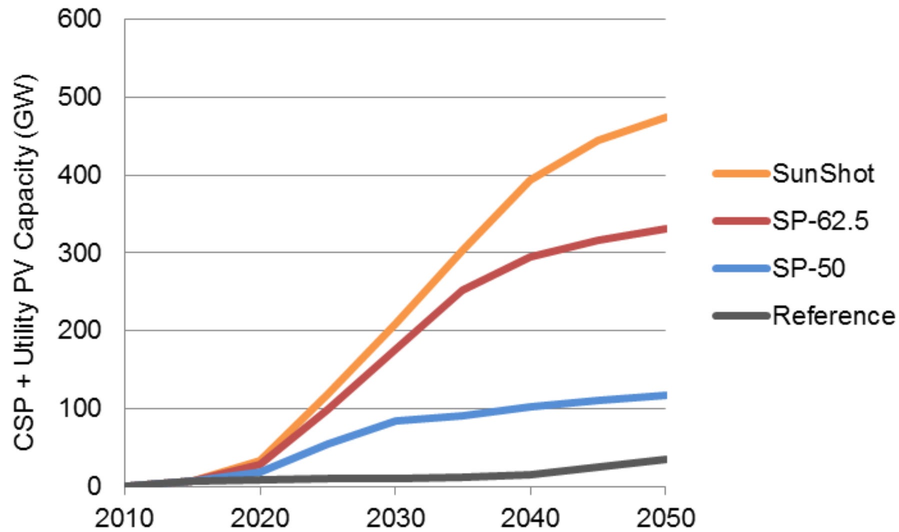

Figure 13. Utility-scale solar capacity under a range of SunShot solar price-reduction scenarios

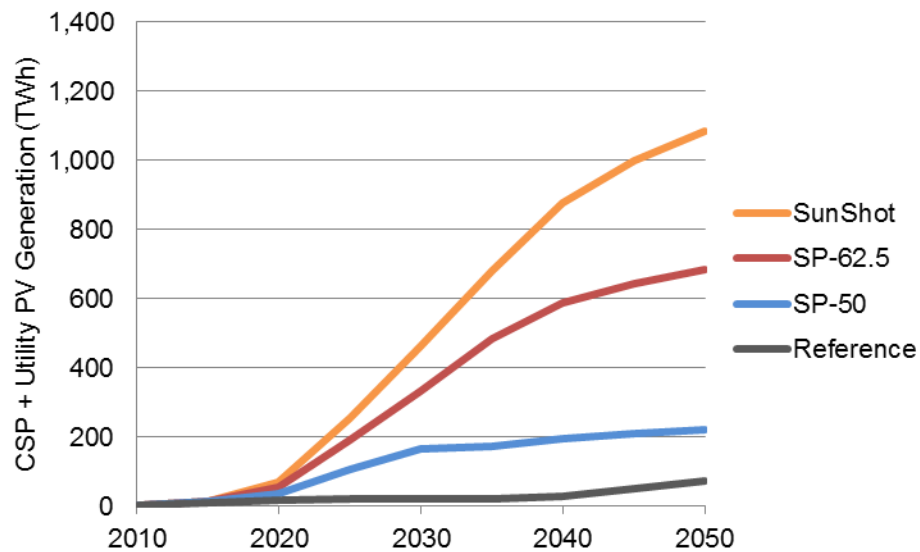

Figure 14. Utility-scale solar generation under a range of solar price-reduction scenarios

4.2 Low Electricity Demand Growth (LD)

Compared with the SunShot scenario, by 2030 the LD scenario yields changes in capacity, including 4 GW less wind (5% change), 40 GW less gas-CC (22% change), 12 GW less gas-CT (5% change), 11 GW less CSP (down to 16 GW, 41% change), and 43 GW less utility PV (down to 138 GW, 24% change). Generation from CSP and utility PV declines 139 TWh (down to 321 TWh, 30% change) to 8% of total generation (versus 10% in the SunShot scenario). With distributed PV, this corresponds to a total solar generation fraction of 11% by 2030 (versus 13% in the SunShot scenario).

By 2050, changes in capacity include 13 GW less wind (14% change), 46 GW less coal (22% change), 79 GW less gas-CC (29% change), 63 GW less gas-CT (20% change), 35 GW less CSP (down to 47 GW, 43% change), and 210 GW less utility PV (down to 189 GW, 53% change). Generation from CSP and utility PV declines 531 TWh (down to 565 TWh, 48% change) to 14% of total generation (versus 20% in the SunShot scenario). With distributed PV, this corresponds to a total solar generation fraction of 21% by 2050 (versus 26% in the SunShot scenario). Figure 15 compares the LD and SunShot scenario results.

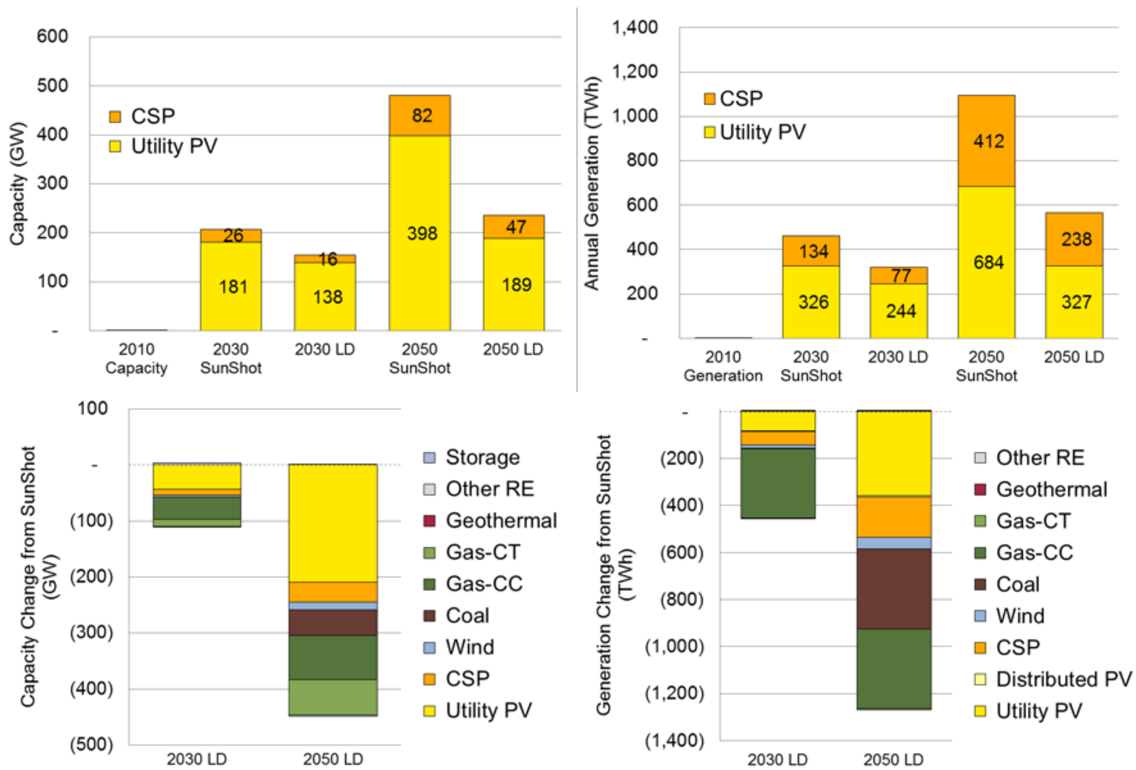

Figure 15. Capacity and generation comparisons between LD and SunShot scenarios

Low electricity demand (essentially flat electric load growth through 2050) substantially reduces future capacity and generation from all generating technologies compared with the SunShot scenario. The deployment of CSP and utility PV is cut approximately in half by 2050. Because distributed PV deployment levels are left constant between the SunShot and LD scenarios, distributed PV contributes a larger portion of demand in the LD scenario. Therefore, there is less room for growth in utility PV and CSP in general.

4.3 Lower Natural Gas Prices (NG, NG-EUR)

Using AEO 2011 natural gas prices (the NG scenario) produces 400 TWh more electricity generation from natural gas CC plants—7% of total electricity generation—compared with the SunShot scenario in 2050. However, 350 TWh of this additional gas generation merely replaces coal generation, mostly from new coal plants that are built in the SunShot scenario after 2030. The CSP and utility PV generation fraction for this sensitivity scenario is relatively unchanged from the SunShot scenario. These results suggest that, if solar prices reach the SunShot targets, solar will compete with natural gas generation at a range of natural gas fuel prices, and natural gas does not compete directly with solar at high solar penetrations because the net load shape shifts.

Compared with the SunShot scenario, by 2030 the NG-EUR scenario yields changes in capacity, including 9 GW less wind (11% change), 10 GW less gas-CC (6% change),[18] 31 GW additional gas-CT (14% change), and 20 GW less CSP (down to 7 GW, 75% change). Generation from CSP and utility PV declines 106 TWh (down to 355 TWh, 23% change) to 8% of total generation (versus 10% in the SunShot scenario). With distributed PV, this corresponds to a total solar generation fraction of 11% by 2030 (versus 13% in the SunShot scenario).

By 2050, changes in capacity include 20 GW less wind (22% change), 53 GW less coal (25% change), 93 GW additional gas-CC (34% change), 16 GW additional gas-CT (5% change), 48 GW less CSP (down to 35 GW, 58% change), and 84 GW less utility PV (down to 314 GW, 21% change). Generation from CSP and utility PV declines 385 TWh (down to 711 TWh, 35% change) to 13% of total generation (versus 20% in the SunShot scenario). With distributed PV, this corresponds to a total solar generation fraction of 19% by 2050 (versus 26% in the SunShot scenario). Figure 16 compares the NG-EUR and SunShot scenario results.

In the NG-EUR scenario, gas prices are low enough to suppress utility PV deployment such that the net load shape is not shifted as far into the evening as in the NG scenario whereby natural gas still competes directly with utility PV. Lower natural gas prices in the NG-EUR scenario increase electricity generation from natural gas and reduce the contribution of other generating technologies, including solar. Gas-CCs operate at a higher average capacity factor in the NG-EUR scenario than in the SunShot scenario by reducing gas-CC use to provide operating reserves and increasing gas-CC use to serve load. Consequently, gas-CTs provide a higher portion of operating reserves.

[18] A 10-GW decrease of gas-CC capacity by 2030 in a lower natural gas price scenario is not intuitive. In this scenario, ReEDS operates gas-CCs at a higher average capacity factor (0.7) than that in the SunShot scenario (0.6), which accounts for the lower gas-CC capacity in the NG-EUR scenario.

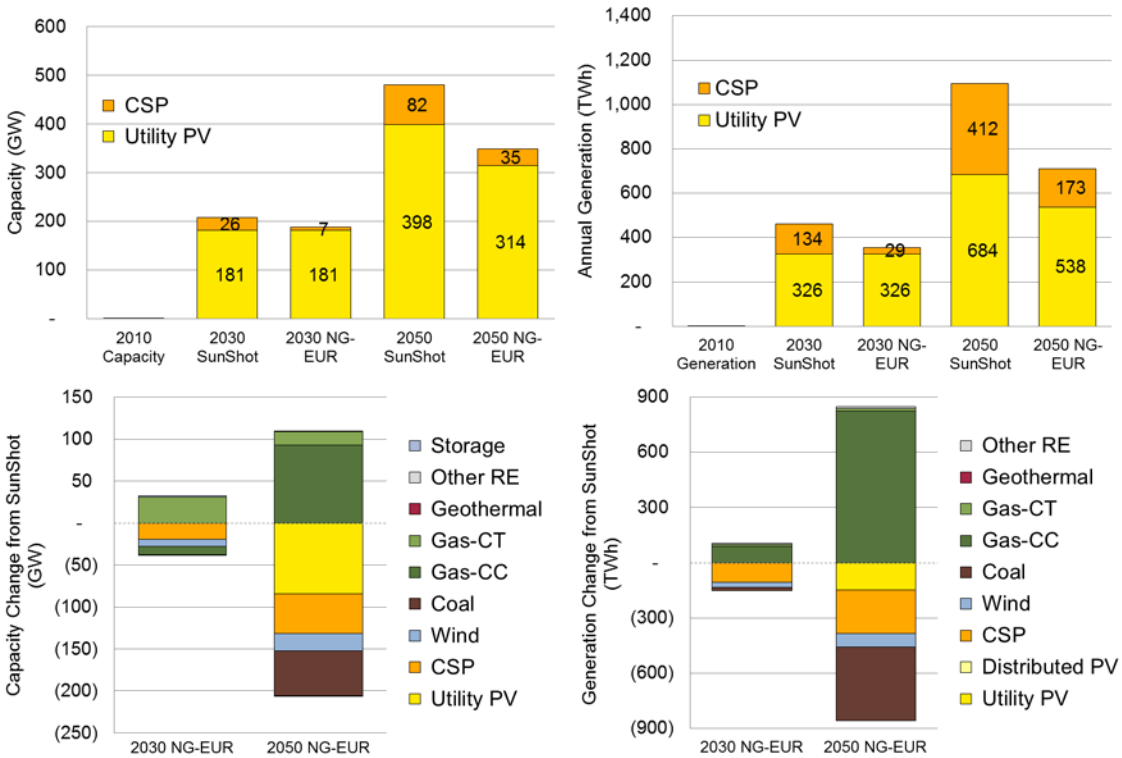

Figure 16. Capacity and generation comparisons between the NG-EUR and SunShot scenarios

Figure 17 shows the national average natural gas price and consumption outputs from ReEDS through 2050 for scenarios using the AEO 2010 reference case (the natural gas cost trajectory used in the SunShot scenario), AEO 2011 reference case (NG), and AEO 2011 high EUR case (NG-EUR). As natural gas prices decrease, the electricity generation from natural gas increases.

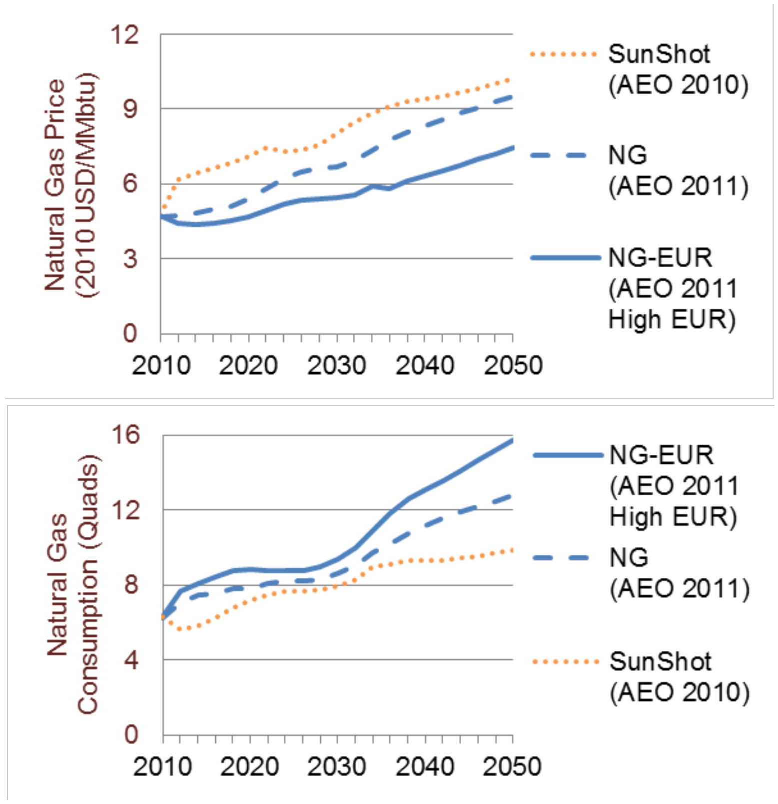

Figure 17. National average electric-sector natural gas prices and consumption outputs from ReEDS through 2050

4.4 Coal Retirements (CR-35, CR-80, NCR)

Compared with the SunShot scenario, by 2030 the 76 GW of unretired coal in the NCR scenario yield changes in capacity, including 4 GW less wind (4% change), 45 GW less gas-CC (25% change), 12 GW less gas-CT (6% change), and 15 GW less CSP (down to 11 GW, 57% change). Generation from CSP and utility PV declines 82 TWh (down to 378 TWh, 18% change) to 8% of total generation (versus 10% in the SunShot scenario). With distributed PV, this corresponds to a total solar generation fraction of 11% by 2030 (versus 13% in the SunShot scenario).

By 2050, the 152 GW of unretired coal yield changes in capacity, including 13 GW less wind (14% change), 54 GW less new coal,[19] 64 GW less gas-CC (23% change), 30 GW less CSP (down to 52 GW, 37% change), and 50 GW less utility PV (down to 348 GW, 13% change). Generation from CSP and utility PV declines 234 TWh (down to 862 TWh, 21% change) to 16% of total generation (versus 20% in the SunShot scenario). With distributed PV, this corresponds to a total solar generation fraction of 21% by 2050 (versus 26% in the SunShot scenario).

[19] The main SunShot scenario builds 54 GW of new coal between 2030 and 2050, whereas the NCR scenario does not build any additional coal in the same timeframe. Therefore, there is a net difference in coal capacity of 98 GW (152 GW of unretired coal capacity from the NCR scenario minus 54 GW of new builds from the SunShot scenario) between the NCR and SunShot scenarios.

Under the NCR scenario, the unretired coal capacity displaces natural gas that would have otherwise been built to cover the coal plant retirements. Figure 18 shows capacity and generation comparisons between the NCR and SunShot scenarios.

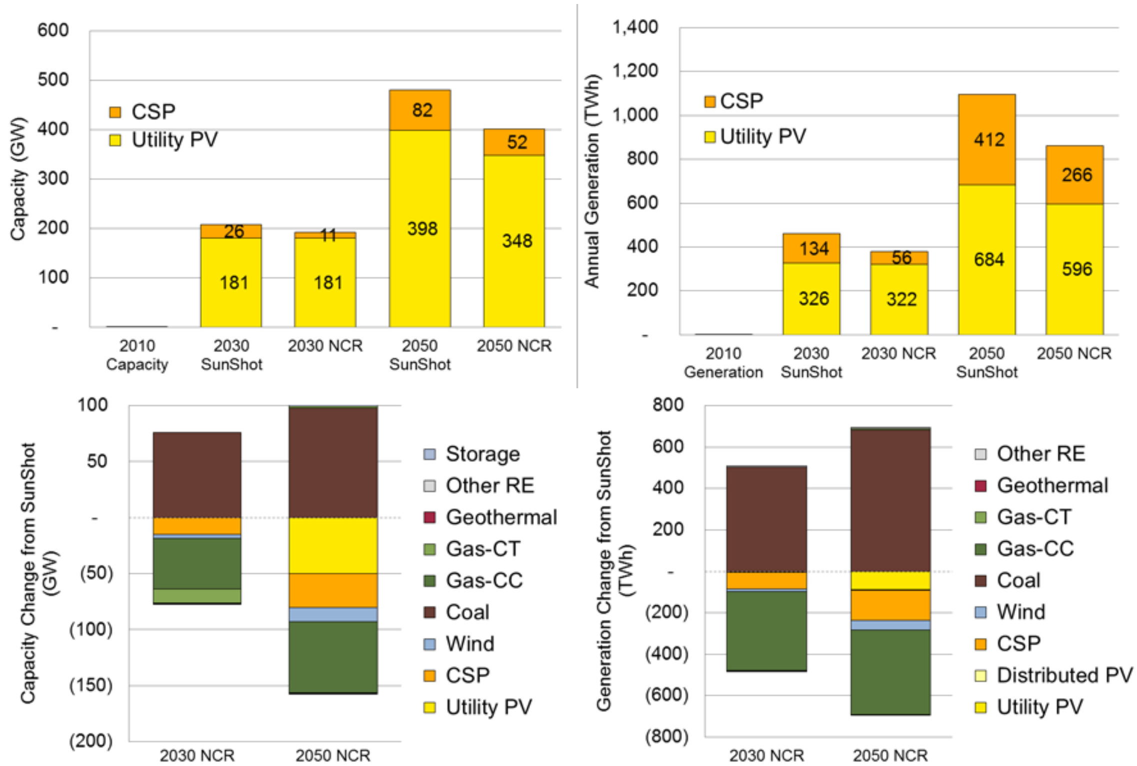

Figure 18. Capacity and generation comparisons between the NCR and SunShot scenarios

The cumulative deployment of utility PV does not change from the SunShot scenario until after 2030 in the NCR scenario. Therefore, the lower requirement for new capacity to provide energy and firm power due to foregone coal retirements does not affect utility PV deployment in the near and mid-term horizons. Although coal plants are not retired in this scenario, gas-CC, gas-CT, oil-gas-steam, and nuclear retirements in conjunction with load growth create a need for new capacity to provide energy and firm power.

The assumed coal retirements in the SunShot scenario do not distinguish plant vintage nor incorporate near-term planned retirements. The CR-35 and CR-80 sensitivity scenarios consider retirements based on plant vintage and near-term retirements due to various existing and pending regulations. The CR-35 and CR-80 scenarios result in state-specific variation of utility PV deployment, but aggregate utility PV deployment and generation is largely unaffected (Table 7). This is expected given the diversity of PV solar resource. Additionally, because the CR-35 and CR-80 scenarios retire less coal in the West where the best CSP solar resource exists (Section 3.4), these scenarios result in lower CSP generation in 2030 and 2050 than the SunShot scenario (Table 7).

By 2030, the CR-35 scenario enforces fewer coal retirements than the SunShot scenario, thus coal-fired generation is higher in the CR-35 scenario and solar generation is lower (Table 7). Conversely, the CR-80 scenario enforces slightly higher coal retirements than the SunShot scenario, thus coal-fired generation is lower. By 2050, total coal retirements in CR-35 and CR-80 are nearly the same as in SunShot; therefore, the utility-scale solar generation fraction is nearly unchanged (Figure 19).

Table 7. 2030 and 2050 Annual Generation from Utility-Scale Solar and Coal

Generation (TWh)	2030			2050		
	Utility PV	CSP	Coal	Utility PV	CSP	Coal
SunShot	326	134	1,684	684	412	1,532
CR-35	324	88	1,894	691	382	1,598
CR-80	323	116	1,600	692	384	1,535
NCR	322	56	2,188	596	266	2,214

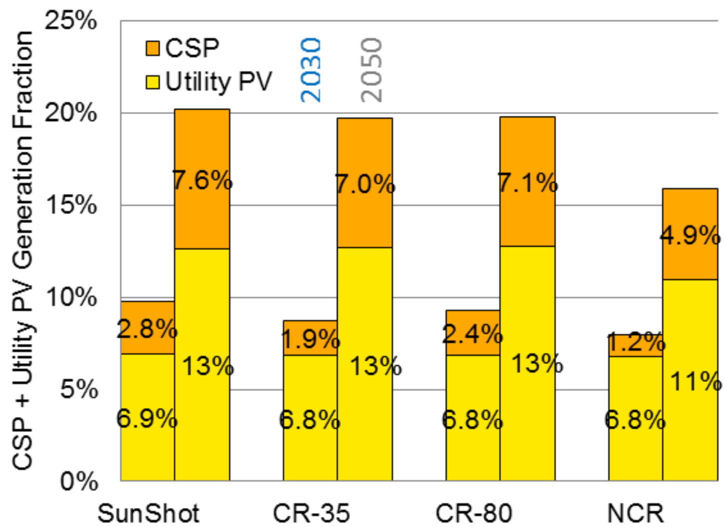

Figure 19. Annual utility-scale solar generation fraction in 2030 and 2050 for all coal retirement scenarios

4.5 Cost and Performance of Non-Solar Renewable Technologies (WG-ETI, WG-2ETI)

Compared with the SunShot scenario, by 2030 the WG-ETI scenario yields changes in capacity, including 39 GW of additional wind (50% change), 10 GW of additional geothermal (up to 15 GW), 17 GW less gas-CC (9% change), 9 GW additional gas-CT (4% change), and 12 GW less CSP (down to 14 GW, 47% change). Generation from CSP and utility PV declines 70 TWh (down to 390 TWh, 15% change) to 8% of total generation (versus 10% in the SunShot scenario). With distributed PV, this corresponds to a total solar generation fraction of 12% by 2030 (versus 13% in the SunShot scenario).

By 2050, capacity changes include 152 GW of additional wind (up to 244 GW), 12 GW of additional geothermal (up to 16 GW), 33 GW less coal (16% change), 20 GW less gas-CC (7% change), 47 GW additional gas-CT (15% change), 26 GW less CSP (down to 56 GW, 31% change), and 31 GW less utility PV (down to 367 GW, 8% change). Generation from CSP and utility PV declines 192 TWh (down to 904 TWh, 18% change) to 17% of total generation (versus 20% in the SunShot scenario). With distributed PV, this corresponds to a total solar generation fraction of 22% by 2050 (versus 26% in the SunShot scenario). Figure 20 compares the WG-ETI and SunShot scenarios.

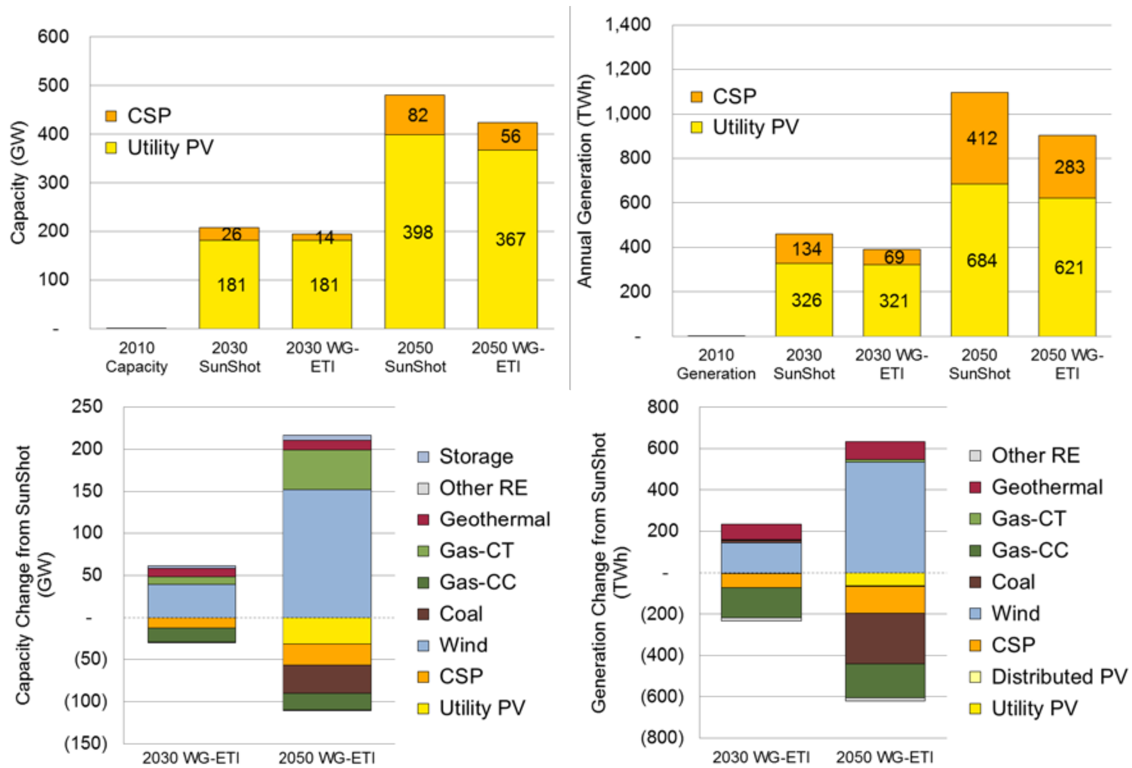

Figure 20. Capacity and generation comparisons between the WG-ETI and SunShot scenarios

From the WG-ETI scenario, the WG-2ETI scenario produces only a small additional decrease of utility-scale solar capacity by 2050 (4 GW less CSP, 9 GW less utility PV). Wind capacity expands an additional 60 GW beyond the levels in the WG-ETI scenario at the expense of coal, gas-CC, and geothermal.[20] Finally, 21 GW of additional gas-CTs are required beyond the WG-ETI capacity levels for operating reserves for the increased wind capacity. Note that bulk curtailments from wind and PV nearly double in this scenario (relative to the SunShot scenario). Most of these increased curtailments are associated with the wind increase. Although utility PV generation declines by 77 TWh in 2050 (relative to the SunShot scenario) due to less utility PV capacity in the system, estimated curtailments associated with utility PV increase slightly. Higher curtailments are expected with higher levels of variable resource renewable technology penetration.

[20] Although both wind and geothermal costs are lower in the WG-2ETI than in the WG-ETI scenario, the incremental decrease in wind costs makes wind more competitive than geothermal.

The results of the WG-ETI and WG-2ETI scenarios highlight the complementary nature of solar and wind resources both in geography and in generation profiles. Overall, decreasing the costs of wind and geothermal technologies reduces the contribution of fossil generators much more than solar generation, as wind generation is not highly correlated with solar generation. However, in some locations, wind replaces solar to add net system benefits. For example, decreased wind costs result in additional wind in the Southwest, where the system has extremely high solar penetration. This very high penetration of solar creates generation that exceeds local demand and requires export or curtailment. Replacing solar with wind in this area actually improves the coincidence of renewable energy supply with demand.

4.6 PV Resource Variability (0.5σ, 1.5σ, ρ = 0, 0.5ρ, 1.5ρ, HI-VAR)

The following scenarios evaluate the impacts and potential benefits of the treatment of solar variability in ReEDS. ReEDS statistically calculates the capacity value, curtailments, and operating reserve requirements associated with variable generation technologies like solar. A detailed description of these calculations can be found in the ReEDS documentation (Short et al. 2011).

Increasing the uncertainty in power output of PV resource (1.5σ) or increasing the resource correlation among PV sites (1.5ρ) causes capacity value to decline and curtailments to increase, both of which reduce the value of PV and thus reduce PV market penetration. The combination of more uncertainty in the expected output from PV (1.5σ) and more correlated inter-region PV resource (1.5ρ) defines the HI-VAR scenario. The HI-VAR scenario reduces capacity value and increases curtailments more than either the 1.5σ or the 1.5ρ scenarios. This section uses curtailment level as a proxy for the value of PV to illustrate the effect of changing these parameters. Table 8 compares marginal utility PV curtailments at various levels of deployed utility PV capacity[21] for the variability scenarios.

Table 8. Marginal Utility PV Curtailment Fractions at Various Levels of Deployed Utility PV Capacity – Variability Scenarios

	Description	90 GW	210 GW	300 GW	385 GW
0.5 σ	Less Uncertainty	4%	5%	8%	14%
ρ = 0	Uncorrelated	3%	6%	10%	14%
0.5ρ	Less Correlated	3%	7%	13%	15%
SunShot	**Baseline**	**3%**	**8%**	**15%**	**22%**
1.5ρ	More Correlated	3%	7%	16%	24%
1.5σ	More Uncertainty	2%	9%	24%	28%
HI-VAR (1.5σ & 1.5ρ)	More Correlated and More Uncertainty	2%	12%	25%	28%

[21] The different levels are based on the approximate deployment points from the model in different years.

Compared with the SunShot scenario, by 2030 the HI-VAR scenario yields changes in capacity, including 2 GW additional storage (5% change), 11 GW additional gas-CT (5% change) and 2.5 GW additional CSP[22] (up to 29 GW, 9.5% change). Generation from CSP and utility PV is nearly unchanged at 9.8% of total generation (versus 10% in the SunShot scenario). With distributed PV, this corresponds to a total solar generation fraction of 13% by 2030 (versus 13% in the SunShot scenario).

By 2050, capacity changes include 4 GW additional storage (10% change), modest increases in coal (12 GW, 6% change) and gas-CTs (12 GW, 4% change) and 13 GW less utility PV (down to 385 GW, 3% change). Generation from CSP and utility PV remains nearly unchanged at 19% of total generation (versus 20% in the SunShot scenario). With distributed PV, this corresponds to a total solar generation fraction of 24% by 2050 (versus 26% in the SunShot scenario). Figure 21 shows capacity and generation comparisons between the HI-VAR and SunShot scenarios.

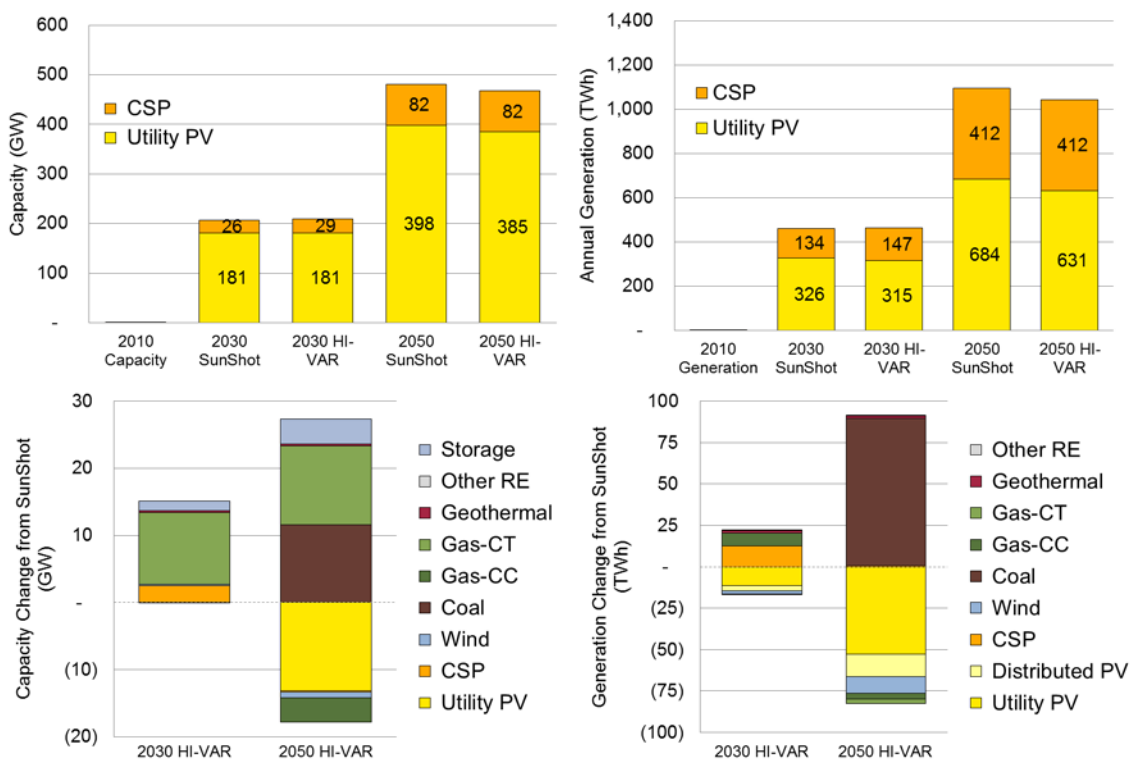

Figure 21. Capacity and generation comparisons between the HI-VAR and SunShot scenarios

Note: The total generation change between the HI-VAR and SunShot scenarios does not sum to zero due to differences in transmission losses.

Although increasing the uncertainty in power output of the PV resource and increasing the resource correlation among PV sites reduce the value of PV, a high-variability (HI-VAR) scenario that increases both of these factors by 50% has a minimal effect on CSP and utility PV deployment and generation. The deployment of coal and natural gas increases modestly to

[22] The 2.5 GW of additional CSP is not unexpected because CSP is not directly affected by the changes in input PV variability parameters.

compensate for the firm capacity deficits created by the higher solar variability. The additional gas-CTs also help provide the additional operating reserves required as a result of more variable output from utility PV. Even with approximately the same utility PV deployment in the HI-VAR and SunShot scenarios, the HI-VAR scenario shows an additional 27 TWh of estimated curtailments for utility PV. At a 12% generation fraction for utility PV, this increase in curtailments corresponds to an increase in the curtailment fraction of utility PV generation from 6% to 10% (Figure 22).

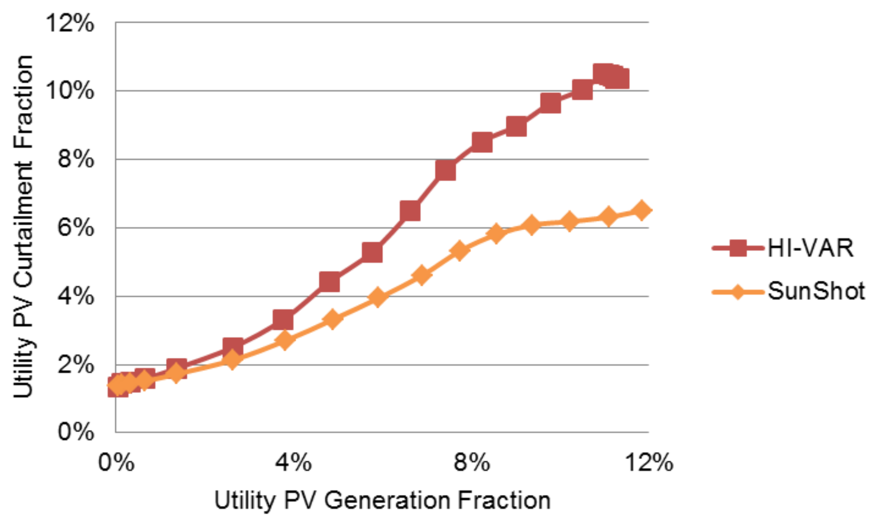

Figure 22. Estimated utility PV curtailments for the HI-VAR and SunShot scenarios

4.7 Distributed PV Deployment Assumptions (NoDPV)

Distributed PV deployment in the SunShot scenario totals 121 GW by 2030 and 240 GW by 2050. The NoDPV scenario sets distributed generation deployment to zero through 2050.

Compared with the SunShot scenario, by 2030 the 121 GW of foregone distributed PV capacity deployment in the NoDPV scenario yield changes in capacity, including 2 GW additional wind (2% change), 13 GW additional gas-CC (7% change), 6 GW additional gas-CT (3% change), and 4 GW additional CSP (up to 31 GW, 16% change). Generation from CSP and utility PV increases by 43 TWh (up to 503 TWh, 9% change) to 11% of total generation (versus 10% in the SunShot scenario). This corresponds to a total solar generation fraction of 11% by 2030 (versus 13% in the SunShot scenario).

By 2050, the 240 GW of foregone distributed PV capacity deployment in the NoDPV scenario yield changes in capacity, including 3 GW additional wind (3% change), 12 GW additional coal (6% change), 7 GW less gas-CC (3% change), 11 GW less gas-CT (4% change), 4 GW additional CSP (up to 86 GW, 5% change), and 83 GW additional utility PV (up to 481 GW, 21% change). Generation from CSP and utility PV increases by 193 TWh (up to 1,288 TWh, 18% change) to 24% of total generation (versus 20% in the SunShot scenario). This corresponds to a total solar generation fraction of 24% by 2050 (versus 26% in the SunShot scenario). Figure 23 shows capacity and generation comparisons between the NoDPV and SunShot scenarios.

Eliminating rooftop PV reduces total solar deployment and generation. However, much of this gap is filled by increased deployment of utility PV, CSP, wind and coal by 2050. Note that utility PV deployment is constrained by a market growth cap (see Section 3.8), and this cap limits annual utility PV growth in the SunShot scenario through 2030 (see Section 4.8); although utility PV growth slows between 2030 and 2050 as the market saturates.[23] For the SunShot scenario, this market saturation occurs at about 570 GW of total PV deployment. In the NoDPV scenario, utility PV growth is constrained by the annual growth limit through 2050 because the market does not saturate (i.e., the total PV deployment by 2050 is only 481 GW, which is significantly lower than the 570-GW saturation level observed in the SunShot scenario).

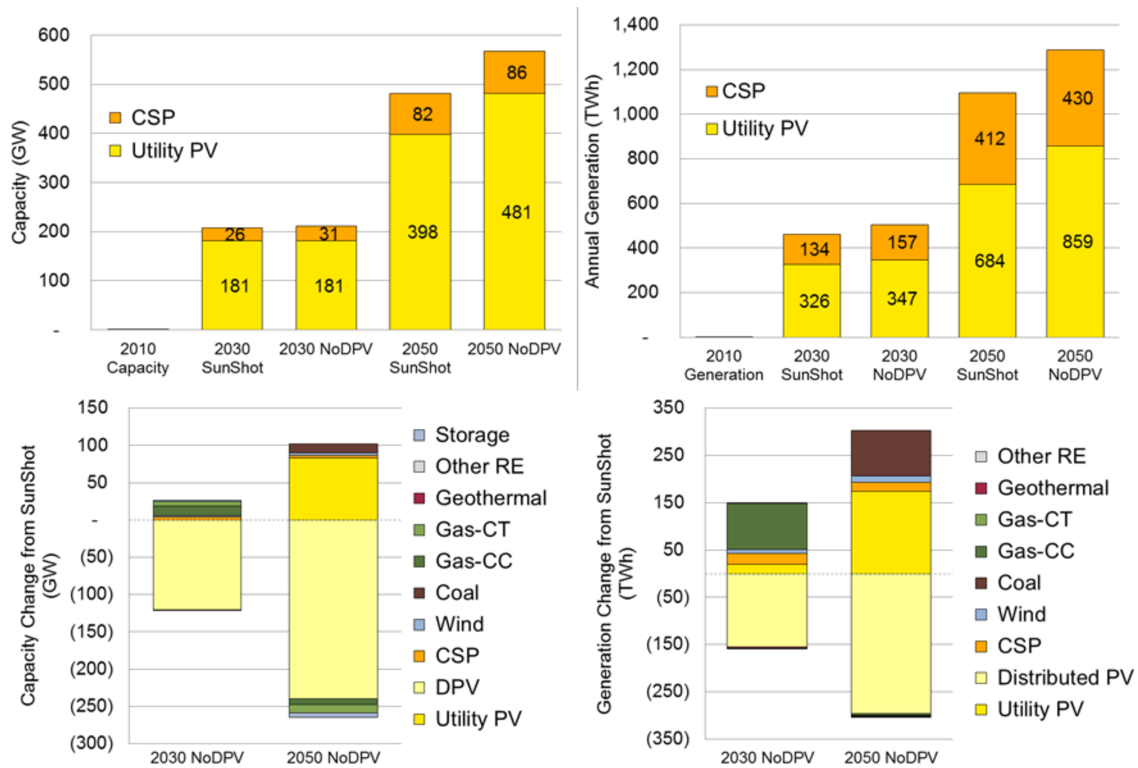

Figure 23. Capacity and generation comparisons between the NoDPV and SunShot scenarios

4.8 Solar Market Supply Growth Assumptions (RSMG, USMG)

The solar growth limits are relaxed in two different manners: the RSMG scenario assumes utility PV and CSP can each double every 2 years without a 15-GW annual limit, and the USMG scenario assumes solar capacity can grow according to successively higher growth penalty cost bins. Although both the RSMG and USMG scenarios result in similar utility PV deployment trajectories, the USMG scenario is the more aggressive of the two. Therefore, the results in this section focus on the USMG scenario.

[23] In this analysis, market saturation refers to the point where utility PV no longer reaches the annual growth limit because the PV economics are less favorable due to curtailments and a shift in the net load from midday to evening.

Compared with the SunShot scenario, by 2030 the USMG scenario yields changes in capacity, including 10 GW less wind (13% change), 13 GW less gas-CC (7% change), 17 GW less gas-CT (8% change), 3 GW less CSP (down to 23 GW, 11% change), and 138 GW additional utility PV (up to 319 GW, 76% change). Generation from CSP and utility PV increases 197 TWh (up to 657 TWh, 43% change) to 14% of total generation (versus 10% in the SunShot scenario). With distributed PV, this corresponds to a total solar generation fraction of 17% by 2030 (versus 13% in the SunShot scenario).

By 2050, capacity changes include 10 GW less wind (11% change); minor changes (less than 2%) in coal, gas-CC, and gas-CT; 2 GW additional CSP (up to 84 GW, 2% change); and 29 GW additional utility PV (up to 427 GW, 7% change). Generation from CSP and utility PV increases 52 TWh (up to 1,148 TWh, 5% change) to 21% of total generation (versus 20% in the SunShot scenario). With distributed PV, this corresponds to a total solar generation fraction of 27% by 2050 (versus 26% in the SunShot scenario). Figure 24 compares the USMG and SunShot scenarios.

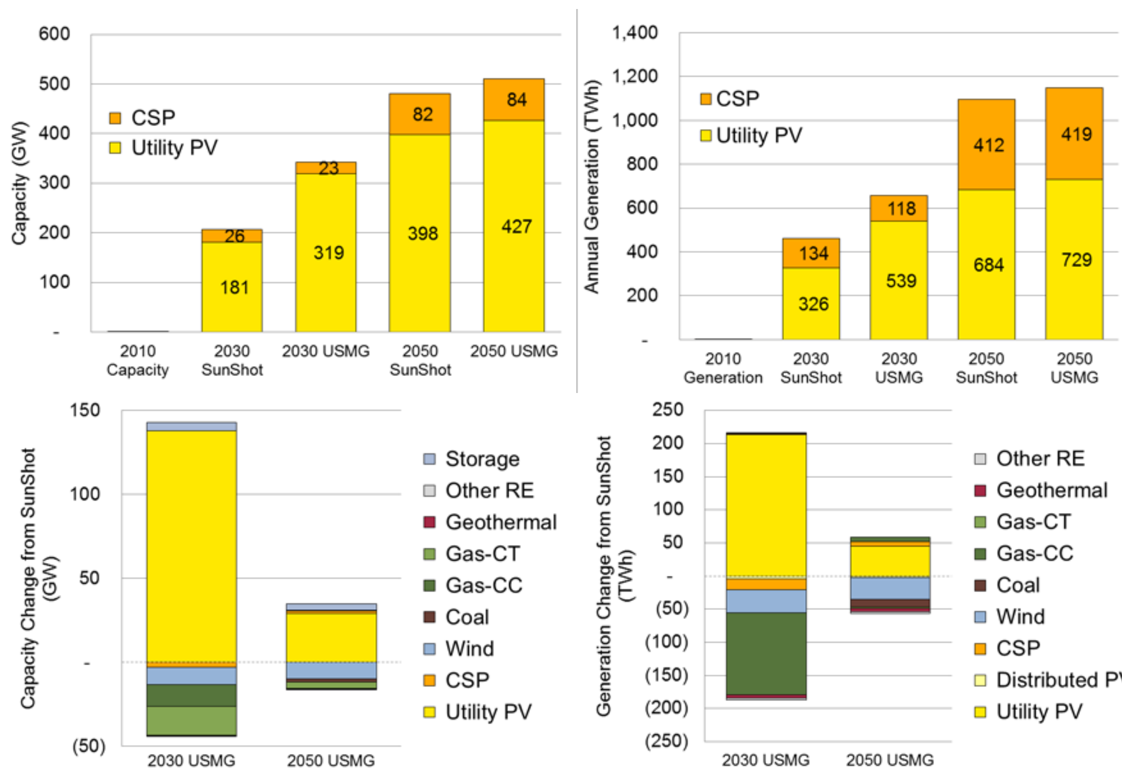

Figure 24. Capacity and generation comparisons between the USMG and SunShot scenarios

Figure 25 shows how annual and cumulative utility PV deployment changes under the RSMG and USMG scenarios. The USMG scenario uses relatively low growth cost penalties, and therefore utility PV grows faster than the doubling-every-2-years constraint. The additional supply-chain cost due to rapid market growth might be higher than the growth cost penalties used for the USMG scenario. Additional work is required to better understand the implications of scaling up manufacturing to accommodate high solar deployment scenarios.

In general, the main SunShot scenario attempts to avoid boom-bust cycles that occur in the RSMG and USMG scenarios. Although the deployment trajectories based on relaxing the growth constraints might not be sustainable from a manufacturing standpoint on an annual growth basis, they do suggest that utility PV could achieve higher deployment levels by 2030 than the SunShot levels depending on supply-chain costs. By 2050, the two solar growth relaxation scenarios reach deployment levels only marginally greater than in the SunShot scenario.

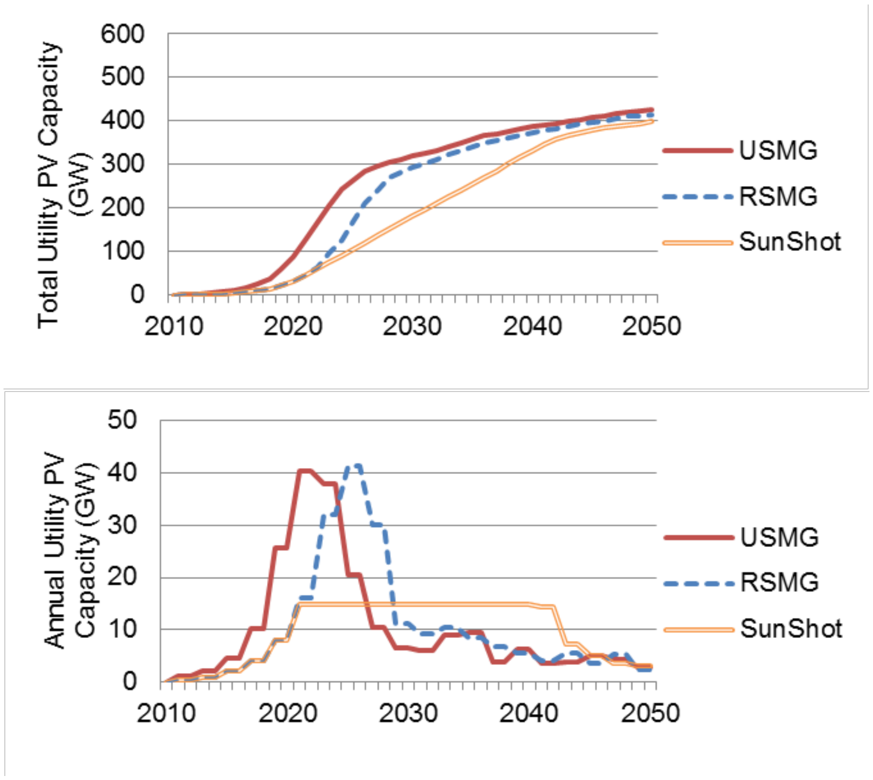

Figure 25. Cumulative and annual utility PV capacity deployment for all solar market supply growth scenarios

4.9 Combination Scenarios

This subsection discusses results for two combination scenarios generated using a mix of five sensitivity factors discussed in Section 3, including: (1) low electricity demand (LD), (2) lower natural gas prices (NG-EUR), (3) no coal retirements (NCR), (4) improved economic performance of wind and geothermal (WG-2ETI), and (5) high variability of PV (HI-VAR). These combination scenarios were chosen to provide the widest possible impact due to the factors examined in this report.

4.9.1 AEO 2010 Demand Plus NG-EUR, NCR, WG-2ETI, and HI-VAR (ALL)

The first combination scenario (the ALL scenario), including a mix of factors (2)-(5) listed above, decreases the overall competitiveness of solar technologies.

Compared with the SunShot scenario, by 2030 the ALL scenario (NG-EUR, NCR,[24] WG-2ETI, and HI-VAR) yields changes in capacity, including 5 GW more wind (7% change), 49 GW less gas-CC (27% change), 15 GW more gas-CT (7% change), 24 GW less CSP (down to 2 GW, 92% change), and 8 GW less utility PV (down to 173 GW, 5% change). Generation from CSP and utility PV declines 151 TWh (down to 309 TWh, 33% change) to 7% of total generation (versus 10% in the SunShot scenario). With distributed PV, this corresponds to a total solar generation fraction of 10% by 2030 (versus 13% in the SunShot scenario).

By 2050, changes in capacity include 13 GW more wind (14% change), 28 GW less gas-CC (10% change), 53 GW more gas-CT (17% change), 77 GW less CSP (down to 5 GW, 93% change), and 174 GW less utility PV (down to 224 GW, 44% change). Generation from CSP and utility PV declines 692 TWh (down to 404 TWh, 63% change) to 7% of total generation (versus 20% in the SunShot scenario). With distributed PV, this corresponds to a total solar generation fraction of 13% by 2050 (versus 26% in the SunShot scenario). Figure 26 compares the ALL and SunShot scenarios.

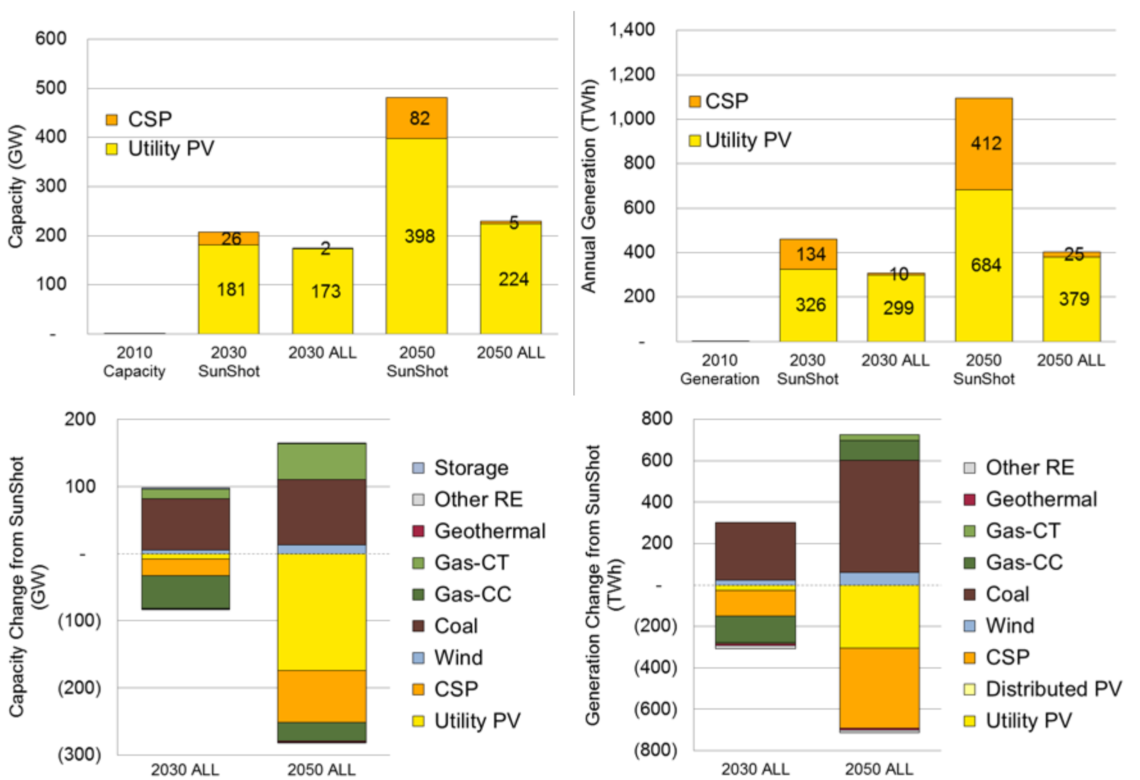

Figure 26. Capacity and generation comparisons between the ALL and SunShot scenarios

[24] This scenario has 76 GW of unretired coal by 2030 and 152 GW by 2050. No new coal is built in this scenario.

4.9.2 Low Demand Plus NG-EUR, NCR, WG-2ETI, and HI-VAR (LD ALL)

For the second combination scenario (the LD ALL scenario), adding a reduced demand to the previous combination scenario (the ALL scenario) further reduces PV penetration.

Compared with the SunShot scenario, by 2030 the LD ALL scenario (LD, NG-EUR, NCR, WG-2ETI, and HI-VAR) yields changes in capacity, including 6 GW additional wind (8% change), 50 GW less gas-CC (27% change), 50 GW less gas-CT (23% change), 24 GW less CSP (down to 2 GW, 92% change), and 97 GW less utility PV (down to 84 GW, 54% change). Generation from CSP and utility PV declines 308 TWh (down to 153 TWh, 67% change) to 4% of total generation (versus 10% in the SunShot scenario). With distributed PV, this corresponds to a total solar generation fraction of 7% by 2030 (versus 13% in the SunShot scenario).

By 2050, changes in capacity include 3 GW less wind (3% change), 148 GW less gas-CC (54% change), 83 GW less gas-CT (26% change), 80 GW less CSP (down to 2 GW, 97% change), and 310 GW less utility PV (down to 88 GW, 78% change). Generation from CSP and utility PV declines 940 TWh (down to 155 TWh, 86% change) to 4% of total generation (versus 20% in the SunShot scenario). With distributed PV, this corresponds to a total solar generation fraction of 10% by 2050 (versus 26% in the SunShot scenario). Figure 27 compares the LD ALL and SunShot scenarios.

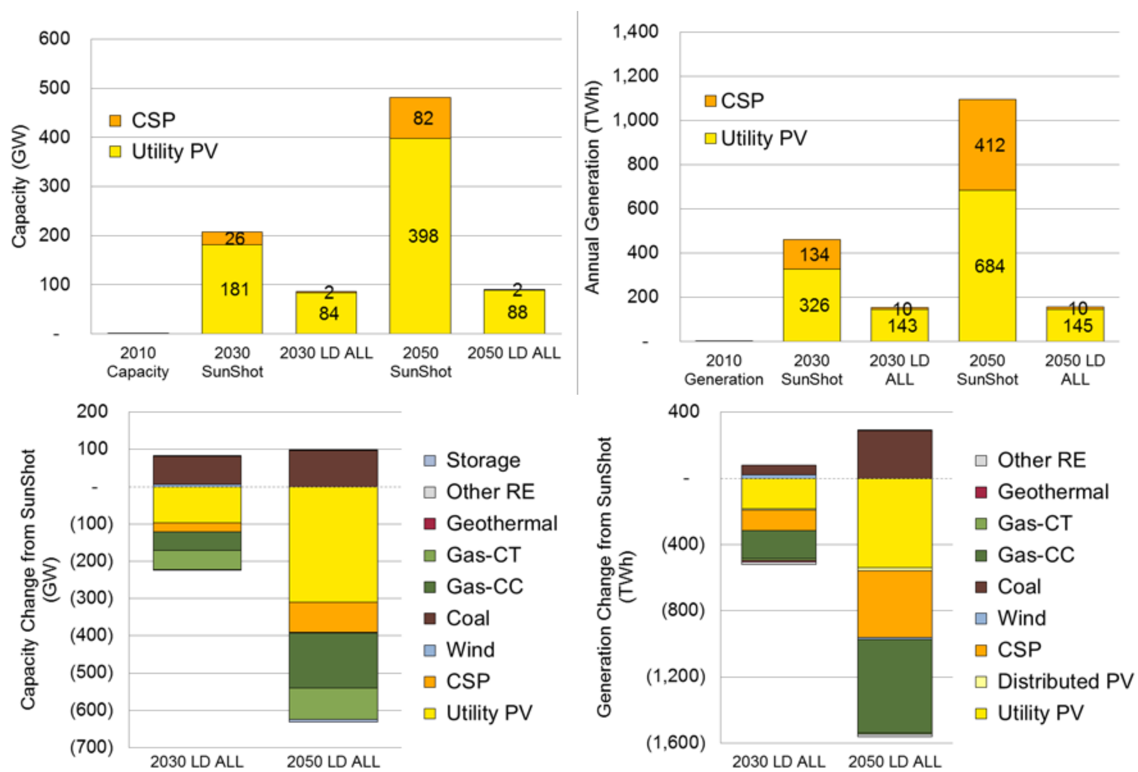

Figure 27. Capacity and generation comparisons between the LD ALL and SunShot scenarios

4.10 Summary of Scenarios

Figure 28 and Figure 29 summarize the range of utility-scale solar deployment and generation results, respectively, for the sensitivity scenarios in Section 4 that use the SunShot solar price assumptions.[25] These figures are intended to provide context for the range of results in this analysis. Showing all 45 sensitivity scenarios (Section 3) in these figures would make the results difficult to interpret, so only a subset of these scenarios are showcased here. All of the 45 sensitivity scenarios presented in this report produce CSP and utility PV deployment trajectories in between the best-case (NoDPV) scenario and the worst-case (LD ALL) scenario examined here (with respect to CSP and utility PV penetration). Note that there is a six-fold increase in utility-scale solar capacity from the LD ALL to the NoDPV scenario. The total CSP and utility PV deployment in the LD ALL scenario is comparable to the SP-50 (50% solar price reduction) scenario (Section 4.1).

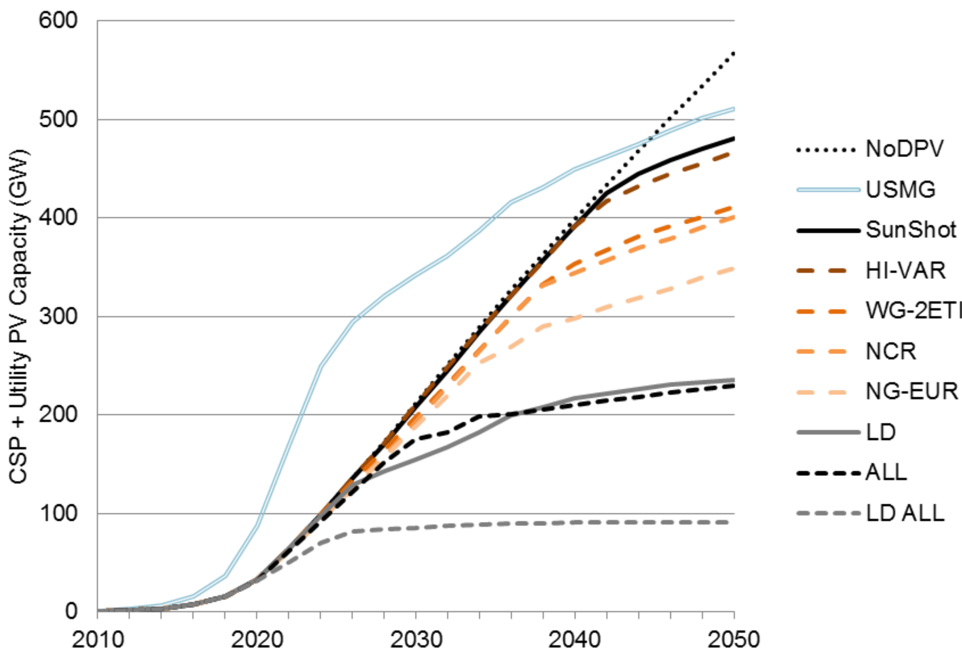

Figure 28. Cumulative utility-scale solar capacity through 2050 for selected sensitivity scenarios in Section 4

Note: These scenarios all use the SunShot solar price assumptions.

[25] Section 4.1 includes similar capacity and generation figures for the solar price sensitivities.

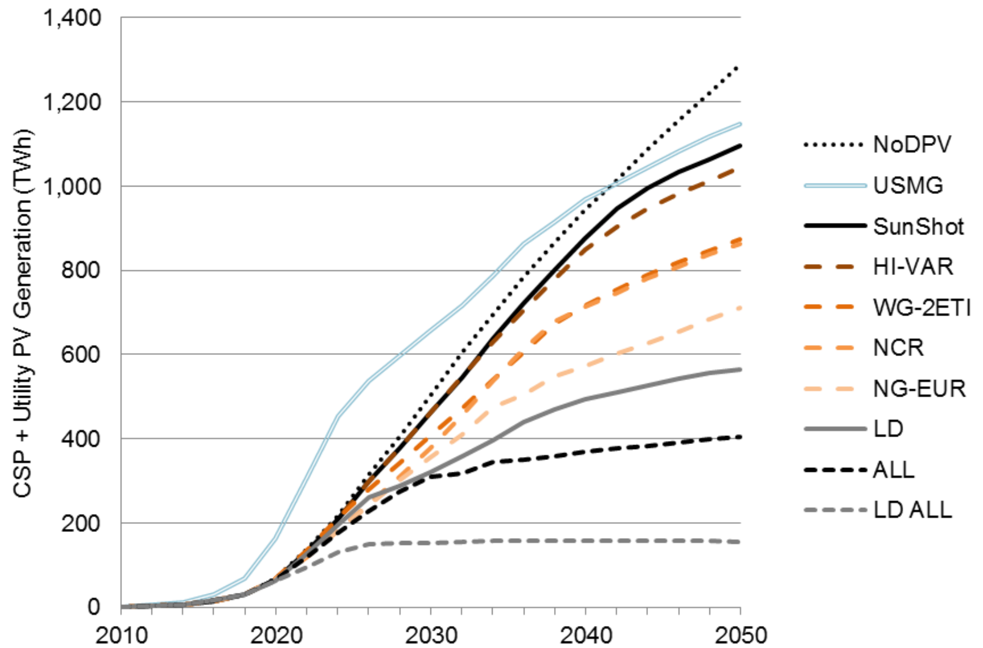

Figure 29. Utility-scale solar generation through 2050 for selected sensitivity scenarios in Section 4

Note: These scenarios all use the SunShot solar price assumptions.

Figure 30 (low-demand scenarios) and Figure 31 (AEO 2010 demand scenarios) show the generation fraction for utility-scale solar technologies in 2030 and 2050 in order of decreasing generation by 2050 for the combination scenarios of Table 4 (as well as the single-factor scenarios used to generate the combination scenarios). In most low-demand scenarios, the total CSP and utility PV generation fraction is below 7% in 2030 (versus 10% in the SunShot scenario) and below 10% in 2050 (versus 20% in the SunShot scenario). In most AEO 2010 demand scenarios, the total CSP and utility PV generation fraction is 7%–10% in 2030 (versus 10% in the SunShot scenario) and 7%–20% in 2050 (versus 20% in the SunShot scenario). The utility PV generation fraction is nearly insensitive to changes in input assumptions by 2030, but variations in CSP are more noticeable (Figure 31). Changes in both utility PV and CSP generation fractions are larger in 2050.

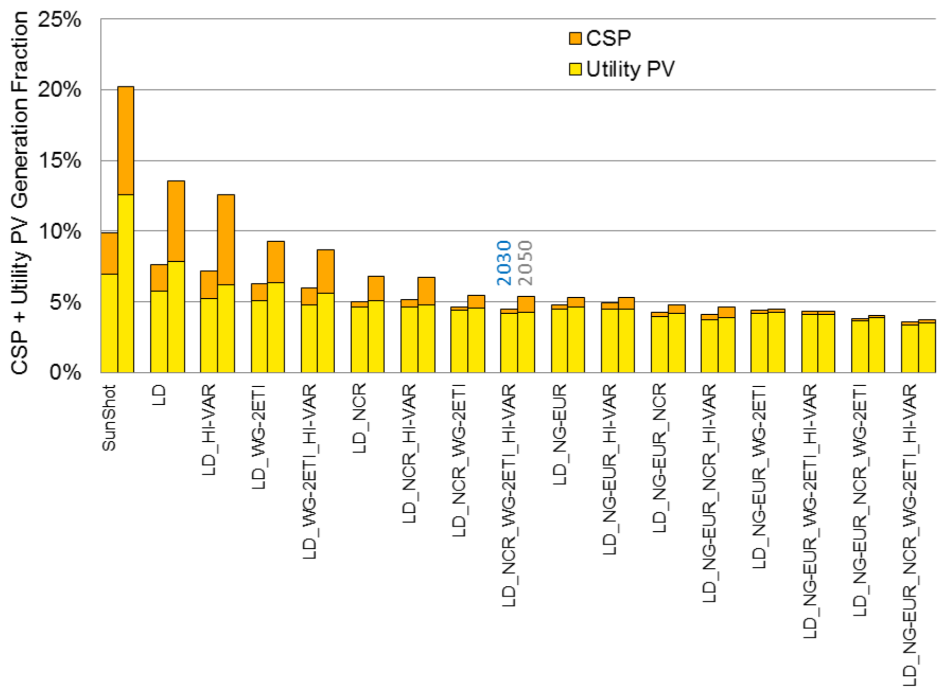

Figure 30. Annual utility-scale solar generation fraction in 2030 and 2050 for combination scenarios – low demand

Note: The single-factor scenarios used to generate these combination scenarios are included.

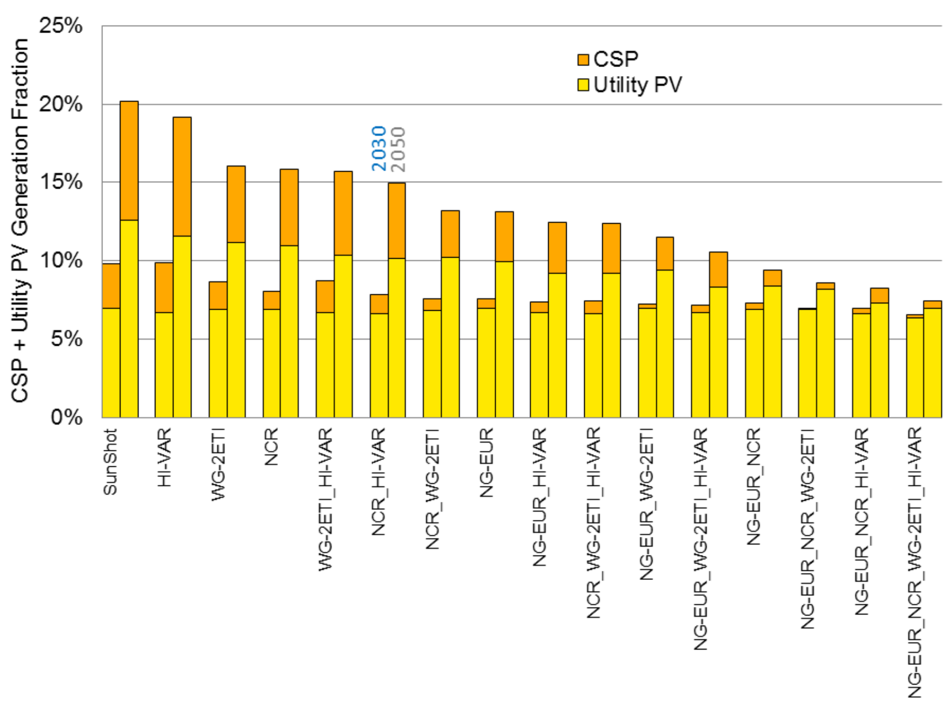

Figure 31. Annual utility-scale solar generation fraction in 2030 and 2050 for combination scenarios – AEO 2010 demand

Note: The single-factor scenarios used to generate these combination scenarios are included.

5 Conclusions

The SSVS (U.S. DOE 2012) projected U.S. utility PV and CSP solar deployment using the ReEDS capacity-expansion model (with inputs from the SolarDS model for rooftop PV). Under the SunShot scenario, 302 GW of PV (181 GW of utility PV, 121 GW of rooftop PV) and 28 GW of CSP capacity are installed by 2030 with solar contributing 14% of total electricity generation. By 2050, 632 GW of PV (391 GW of utility PV, 240 GW of rooftop PV) and 83 GW of CSP capacity are installed with solar contributing 27% of total electricity generation.

In this study, we expand on these SSVS results by analyzing the sensitivity of ReEDS-generated utility PV and CSP deployment projections to combinations of additional variables: different solar prices, low electricity demand, lower natural gas prices, different coal retirement assumptions, low-cost wind and geothermal technologies, different levels of PV variability, no distributed PV deployment, and different solar market supply growth assumptions. The rooftop PV deployment results from the SSVS are held constant in all these scenarios except for one sensitivity case: the NoDPV scenario. The growth of utility PV and CSP is limited in all of these scenarios except for the two scenarios that relax theses limits: the USMG and RSMG scenarios. The main insights from our analysis include the following:

- Varying the SunShot solar price targets indicates a threshold somewhere between \$2.00/W_{DC} (SP-50) and \$1.50/W_{DC} (SP-62.5) for utility PV (and an equivalent reduction for CSP) at which utility-scale solar deployment increases non-linearly as price decreases. When solar prices decline only 50% by 2020 (compared with a 75% decline in the SunShot scenario), total CSP and utility PV deployment is 75% lower by 2050 than in the SunShot scenario.
- Low electricity demand (essentially flat electric-load growth through 2050) substantially reduces future capacity and generation from all generating technologies compared with the SunShot scenario. The deployment of CSP and utility PV is cut approximately in half by 2050.
- Lower natural gas prices increase electricity generation from natural gas and reduce the contribution of other generating technologies, including solar. By 2050, CSP deployment is 58% lower and utility PV deployment is 21% lower under the lowest natural gas price scenario (NG-EUR), compared with the SunShot scenario. Total CSP and utility PV deployment is 27% lower. If natural gas prices are low enough (somewhere between prices in the NG and NG-EUR scenarios), they will suppress utility PV deployment such that the net load shape is not shifted as far into the evening whereby natural gas still competes directly with utility PV.
- Changing assumptions about coal plant retirements has a relatively small effect on solar deployment. Assuming no coal retirements (NCR) reduces total CSP and utility PV deployment in 2050 by 17% compared with the SunShot scenario. The contribution from natural gas decreases substantially as the contribution from coal increases. Results from two scenarios (CR-35 and CR-80) show that changing the total number of retirements as well as the location and timing of those retirements causes state-specific variations of utility PV deployment, but aggregate utility PV deployment is largely unaffected due to

the diversity of PV solar resource. CSP deployment declines due to less geographic diversity of CSP solar resource.

- Doubling the capital cost reductions for wind and geothermal technologies (compared with the SunShot and RE Futures ETI scenarios) reduces total CSP and utility PV deployment in 2050 by 14% (WG-2ETI). At the same time, total renewable capacity and generation, especially from wind, increase substantially. Because of the complementary nature of solar and wind resources (both in geography and in generation profiles), fossil generation is reduced much more than solar generation.
- Although increasing the uncertainty in power output of the PV resource and increasing the resource correlation among PV sites reduce the value of PV, a high-variability (HI-VAR) scenario that increases both of these factors by 50% has a minimal effect on utility-scale solar deployment and generation. However, the curtailment fraction for utility PV increases with increasing utility PV deployment; for example, at a 12% generation fraction for utility PV, the curtailment fraction of utility PV generation increases from 6% (SunShot scenario) to 10% (HI-VAR). The deployment of coal and natural gas increases modestly to compensate for the firm capacity deficits created by the higher solar variability.
- Eliminating rooftop PV (NoDPV) reduces total solar deployment and generation. However, much of this gap is filled by increased deployment of utility PV, CSP, wind, and coal by 2050.
- Different solar market supply growth assumptions produce a large effect by 2030, but this effect tapers off by 2050. Under the unlimited growth (USMG) scenario, total CSP and utility PV deployment increases 65% by 2030 but only 6% by 2050 compared with the SunShot scenario. The boom-bust trajectories associated with this relaxed growth-restriction assumption might not be sustainable from an annual manufacturing standpoint. Additional work is required to better understand the implications of scaling up manufacturing to accommodate high solar deployment scenarios.
- Combining factors from the individual sensitivity scenarios can affect solar deployment dramatically. For example, combining low electricity demand with lower natural gas prices, no coal retirements, more competitive wind and geothermal technologies, and a highly variable PV resource reduces total CSP and utility PV deployment 81% and total CSP and utility PV generation 86% by 2050. This combined sensitivity case (LD ALL) is the most extreme scenario analyzed here. Using the SunShot electricity-demand assumptions, most combinations of sensitivity factors result in total CSP and utility PV generation fractions between 7% and 10% in 2030 (compared with 10% in the SunShot scenario) and between 7% and 20% in 2050 (compared with 20% in the SunShot scenario).

Although not included in this sensitivity analysis, additional scenarios could consider the implications of time delays in SunShot solar price reductions.

In conclusion, installed price is the most important driver behind utility-scale solar adoption. However, our analysis also shows that non-price factors have significant impacts. This analysis projects by 2030, assuming the SunShot solar price targets are met, utility-scale solar deployment of 175–212 GW for most scenarios under the SunShot-electricity-demand assumptions and 86–154 GW for the scenarios under the low-electricity-demand assumptions (compared with 209 GW in the SunShot scenario). By 2050, utility-scale solar deployment projections are 229–567 GW for the scenarios under the SunShot-electricity-demand assumptions and 90–236 GW for the scenarios under the low-electricity-demand assumptions (compared with 475 GW in the SunShot scenario).

With solar prices being equal, low electricity demand suppresses solar deployment the most, followed by lower natural gas prices. The other individual factors generally have a smaller impact, although relaxed solar market supply growth restrictions can boost utility-scale solar deployment substantially beyond SunShot levels by 2030 (up to 342 GW in the USMG scenario). Some combinations of factors have a major impact on solar deployment and generation, especially under the low-electricity-demand assumption. For example, there is a six-fold increase in 2050 utility-scale solar capacity from the combination scenario with the lowest deployment (LD ALL) to the scenario with the highest deployment (NoDPV). In fact, this low-demand combination (LD ALL) scenario results in utility-scale solar deployment that is lower even than the deployment in the sensitivity scenario where solar prices are two times higher than the SunShot scenario (SP-50). However, most combinations under the SunShot electricity demand assumptions are in line with SunShot solar generation results through 2030, with discrepancies growing larger between 2030 and 2050.

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