Energy Research and Development Division
FINAL PROJECT REPORT

SOLID STATE BATTERIES FOR GRID-SCALE ENERGY STORAGE

Prepared for: California Energy Commission
Prepared by: Seeo, Inc.

OCTOBER 2014
CEC-500-2014-101

PREPARED BY:

Primary Author(s):
Hal Zarem
Ulrik Grape

Seeo, Inc.
3906 Trust Way
Hayward, CA 94545
Phone: 510-782-7336
www.seeo.com

Contract Number: PIR-11-001

Prepared for:

California Energy Commission

Avtar Bining, PH.D.
Contract Manager

Fernando Pina
Office Manager
Energy Systems Research Office

Laurie ten Hope
Deputy Director
ENERGY RESEARCH AND DEVELOPMENT DIVISION

Robert P. Oglesby
Executive Director

DISCLAIMER

This report was prepared as the result of work sponsored by the California Energy Commission. It does not necessarily represent the views of the Energy Commission, its employees or the State of California. The Energy Commission, the State of California, its employees, contractors and subcontractors make no warranty, express or implied, and assume no legal liability for the information in this report; nor does any party represent that the uses of this information will not infringe upon privately owned rights. This report has not been approved or disapproved by the California Energy Commission nor has the California Energy Commission passed upon the accuracy or adequacy of the information in this report.

ACKNOWLEDGEMENTS

This work was supported with match funding by the California Energy Commission's Public Interest Energy Research Program for the American Recovery and Reinvestment Act of 2009 award under the United States Department of Energy's Smart Grid Demonstrations Funding Opportunity Announcement DE-FOA-0000036.

Seeo, Inc. would like to thank the California Energy Commission and its staff for the support under this project.

Seeo, Inc. would also like to thank and recognize the University of California, Berkeley for their assistance and support with the impact analysis report. Specifically, Professor Dan Kammen and graduate student Ana Mileva of the Renewable and Appropriate Energy Laboratory should be commended for their excellent work on the report, which provides a very thorough analysis and good recommendations for the Western Electricity Coordinating Council.

PREFACE

The California Energy Commission Energy Research and Development Division supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The Energy Research and Development Division conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The Energy Research and Development Division strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

Energy Research and Development Division funding efforts are focused on the following RD&D program areas:

Buildings End-Use Energy Efficiency

Energy Innovations Small Grants

Energy-Related Environmental Research

Energy Systems Integration

Environmentally Preferred Advanced Generation

Industrial/Agricultural/Water End-Use Energy Efficiency

Renewable Energy Technologies

Transportation

Solid State Batteries for Grid-Scale Energy Storage is the final report for the Grid-Scale Energy Storage project (contract number PIR-11-001) conducted by Seeo, Inc. The information from this project contributes to Energy Research and Development Division's Energy Systems Integration Program.

For more information about the Energy Research and Development Division, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-327-1551.

ABSTRACT

Currently, the materials used to manufacture lithium ion (Li-ion) batteries are unstable, leading to premature battery failure and inhibiting wider application and use of Li-ion batteries. This project demonstrated a solid polymer electrolyte technology for lithium batteries developed by Seeo, Inc. and introduces a new generation of rechargeable lithium batteries with higher energy density, improved safety and lifetime, and possible lower costs. The project also expanded the polymer electrolyte battery cells from research and development size to a 10 kilowatt-hour (kWh) first-ever, grid-scale energy storage application. A University of California, Berkeley report confirmed that grid-scale energy storage is a vital component of renewable energy solutions and crucial to reducing greenhouse gas emissions and climate change mitigation. Solid polymer technology can benefit California by expanding renewable energy sources with lithium energy storage solutions for the grid. Continued development of this technology will increase energy densities, making even lighter and more compact systems, and lowering costs.

Keywords: California Energy Commission, United States Department of Energy, Seeo, Inc., University of California, Berkeley, solid polymer electrolyte, cells, battery pack, energy storage, grid-scale energy storage,

Please use the following citation for this report:

Zarem, Hal; Grape, Ulrik. Seeo, Inc. 2014. Solid State Batteries for Grid-Scale Energy Storage. California Energy Commission. Publication number: CEC-500-2014-101.

TABLE OF CONTENTS

Acknowledgements ..... **i**

PREFACE ..... **ii**

ABSTRACT ..... **iii**

TABLE OF CONTENTS ..... **iv**

LIST OF FIGURES ..... **v**

LIST OF TABLES ..... **vi**

EXECUTIVE SUMMARY **1**

Introduction 1

Project Purpose 1

Project Results 1

Project Benefits 2

CHAPTER 1: Introduction **3**

1.1 Seeo Solid-State Battery Technology 3

1.2 Smart Grid Program 4

1.3 Project Targets 4

CHAPTER 2: Materials Development **5**

2.1 Development of Polymer Materials 5

2.2 Scale-Up of Polymer 5

2.3 Results 6

CHAPTER 3: Cell Scale-Up **8**

3.1 Electrode Fabrication Scale-Up 8

3.2 Cell Fabrication 8

3.3 Development of Solid-State Manufacturing Process 10

3.4 Results 11

CHAPTER 4: Pack Prototyping **14**

4.1 Prototype Pack Architecture 14

4.2 Fabrication of Cells 15

4.3 Assembly of Prototype Pack 16
4.4 Results 17
CHAPTER 5: Pack Demonstration 18
5.1 Prototype Test Plan 18
5.2 Pack Demonstration 18
5.3 Results 19
CHAPTER 6: Economic and Environmental Assessment 21
6.1 Summary of Impact Analysis Study 21
6.2 Seeo Production Readiness Business Plan 22
6.3 Results 23
CHAPTER 7: Conclusions, Recommendations and Benefits to California 24
7.1 Conclusions 24
7.2 Recommendations 24
7.3 Benefits to California 25
GLOSSARY 26
Definition 26
REFERENCES 27
APPENDIX A: Exploring Cost-Effective Deployment of Storage Technologies in the WECC Power System with the SWITCH Model 1

LIST OF FIGURES

Figure 1: Structure of Seeo DryLyteTM Cell 3
Figure 2: Scale-Up of Seeo DryLyteTM Polymer 6
Figure 3: Seeo R&D Cell 8
Figure 4: Seeo Large Format Cell 1 9
Figure 5: Seeo Large Format Cell 2 10
Figure 6: Process Flow – Seeo Pilot Manufacturing Line 11
Figure 7: Yield from Seeo Cell Pilot Production (2013) 12
Figure 8: Cycle Stability of R&D and Large Format Cells 13
Figure 9: Architecture of Seeo 10 kWh Energy Storage System 15

Figure 10: Specification of Seeo 1.6 kWh Module 16
Figure 11: Specification of Seeo 10 kWh Energy Storage System 17
Figure 12: Field Installation of Seeo 10 kWh Energy Storage System 18
Figure 13: System Testing Data of Seeo 10 kWh Energy Storage System 19
Figure 14: Field-Testing Data from Seeo 10 kWh Energy Storage System 20

LIST OF TABLES

Table 1: Polymer Scale-Up Timeline 7
Table 2: Cell Characterization Data from Continuous Cell Build (2013) 12

EXECUTIVE SUMMARY

Introduction

Materials currently used for making lithium ion (Li-ion) batteries are unstable and chemical degradation leads to premature battery failure. Inferior durability of Li-ion batteries prevents wider application and deployment of Li-ion batteries. Efforts, however, to increase energy longevity of Li-ion batteries while minimizing costs have exposed this system to safety issues and potential battery failures which are a concern for the industry and consumers. A California company, Seeo Inc., has developed a proprietary polymer electrolyte platform that supports a new generation of rechargeable lithium batteries with unprecedented energy density, lifetime, and safety, and potentially significant materials cost advantage compared to conventional systems. Seeo's technology, originally developed at the University of California's Lawrence Berkeley National Laboratory, is a unique solution for addressing the critical demand for electric vehicles and grid-scale energy storage combined with renewable energy.

Project Purpose

This project delivered the first ever large-scale or grid-scale prototype of advanced lithium ion rechargeable batteries. The technology combined unprecedented energy density, lifetime, safety, and cost. This technology can be widely deployed in smart grid applications as demonstrated by a large scale 10 kilowatt-hour (kWh) prototype battery storage system developed by the contractor. This development effort, funded by the California Energy Commission and the United States Department of Energy, can help address the utility market requirements for community energy storage systems applications, specifically for residential and commercial customers tied to solar photovoltaic (PV) installations.

Project Results

The Seeo core technology difference is its electrolyte: it is entirely solid state, with no flammable or volatile components. This solid polymer electrolyte material is able to transport Li-ions while providing inherently safe and stable support for high-energy electrodes. As a result, the batteries can make transforming and quantifiable improvements in cost, energy density, safety, and lifetime. Numerous tasks were necessary to achieve the goals of the project: materials development, boosting size of cells, building and demonstrating a pack prototype and providing an economic and environmental assessment.

The core technology, the solid polymer electrolyte material was produced in quantities from lab size batches of 50-100 grams (g) to more than 100 kilogram (kg) batch sizes. Seeo has developed and demonstrated a low cost manufacturing process of the polymer and the solid polymer electrolyte can be manufactured using high volume commodity materials.

Seeo scaled up cells from small research & development (R&D)-sized cells to large format cells with 100 times the capacity and energy of the R&D cells. The large format cells are made on pilot line manufacturing equipment with processes that are easily transferable to a high volume-manufacturing set-up.

Seeo further designed and built a prototype battery pack based on the large format cells developed. This battery pack has 10 kWh of energy and is a size that is particularly relevant for residential energy storage applications when paired with a photovoltaic array. This system has been tested and included a field demonstration, showing that the battery system performed as designed. The system design can easily be scaled to larger (or smaller) system solutions depending on the application or customer demand.

An analysis, performed by the University of California, Berkeley, concludes that energy storage using low cost batteries will be an important contributor to mitigating greenhouse gas emissions in the future. Their analysis also encourages continued government support of energy storage R&D and deployment programs. Seeo sees strong and growing interest from potential customers and strategic partners for their technology, and are committed to commercializing it.

Project Benefits

The California Energy Commission's support of this project provides the following future potential benefits:

- Seeo successfully scaled up the core solid polymer electrolyte technology and cells from lab scale to commercial large form factor cells on equipment that is easily adopted into a high volume manufacturing environment, demonstrating the potential for commercial success.
- Energy storage for grid applications is vital to expanding renewables, especially photovoltaic but also wind energy. Seeo's technology is ideally suited to address and meet this demand with a higher energy density technology, enhanced safety characteristics and uniform performance and longer calendar life regardless of ambient temperatures.
- Transforming markets – potential to lower energy costs for customers, through a combination of renewables and energy storage. For example, customers could lower their energy bills by storing energy from photovoltaics for use during the evening hours, or charge up the battery during lower off-peak hours for use during peak hours together with photovoltaics. There is also the potential opportunity for self-reliance or even selling energy back to utilities or other users.

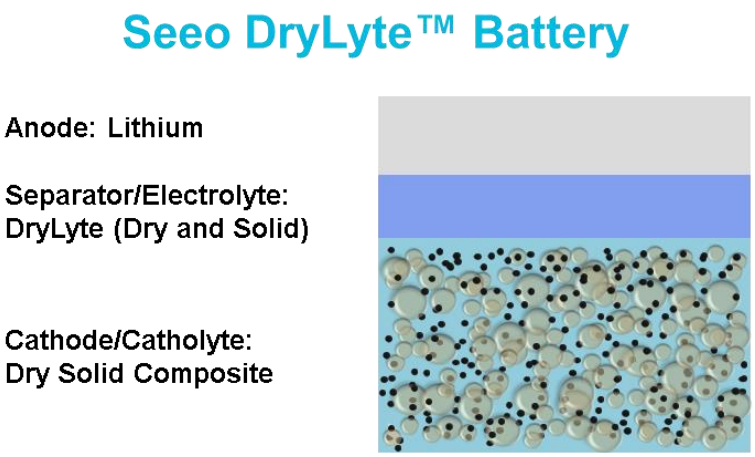
CHAPTER 1: Introduction

1.1 Seeo Solid-State Battery Technology

Seeo has solved fundamental problems enabling safer batteries that go farther on a charge and last longer. The key to these products lies in Seeo's solid DryLyteTM electrolyte, which replaces the flammable liquid electrolyte typically found in other Li-ion batteries. A battery, such as a lithium battery, consists of an anode (negative electrode), a cathode (positive electrode), a separator in between the anode and cathode that insulates the anode and cathode from each other, and an electrolyte that provides the transport of ions from one side of the battery to the other. The direction of the transport of the ions depends on whether one is charging or discharging the battery.

The unique characteristics of Seeo's DryLyteTM solid polymer electrolyte is that it functions both as a separator and an electrolyte, and allows Seeo to safely use the lightest and most energy efficient anode material, lithium metal. In this way, Seeo cells use standard cathode materials and manufacturing processes and achieve 50 percent higher energy density than other existing Li-ion technologies. The structure of Seeo's unique technology is shown in Figure 1.

Figure 1: Structure of Seeo DryLyteTM Cell



Source: Seeo, Inc.

1.2 Smart Grid Program

This award and project supplements Seeo's American Recovery and Reinvestment Act of 2009 (ARRA) award under the United States Department of Energy's (DOE) Smart Grid Demonstrations Funding Opportunity Announcement (FOA) (DE-FOA-0000036). The intent of the Smart Grid Demonstration project was to build a large scale battery pack based on Seeo's solid state lithium ion technology and show the improvements they offer in energy density, lifetime, safety and cost relative to state-of-the-art lithium ion batteries. Originally this was outlined as a 25 kilowatt-hour (kWh) battery pack, but was later proposed and agreed to change to a 10 kWh battery pack that was better fit with the residential or commercial application that it would be tested towards. The Seeo core technology difference is its electrolyte: it is entirely solid state, with no flammable or volatile components. This solid polymer electrolyte material is able to transport Li-ions while providing inherently safe and stable support for high-energy electrodes. As a result, the batteries can make transformational and quantifiable improvements in cost, energy density, safety, and lifetime.

The scope of the DOE Smart Grid Program was to range from fundamental studies and improvements of the active materials associated with the Seeo's technology to building a proof of concept demonstration unit to assess the benefits of the technology to address the utility market needs for Community Energy Storage System (CESS). Significant functional activities would involve material optimization, material synthesis, and cell assembly process development, and pack design and construction.

1.3 Project Targets

The goal of the project was to demonstrate that Seeo's entirely new class of lithium-based batteries could enable the widespread deployment in Smart Grid applications through dramatic improvement in safety, stability, and energy density, along with significant reduction in cost.

The objectives (targets) of the project as originally outlined were to:

optimize materials to improve cell power and energy capabilities;

scale-up materials, cell size and fabrication capacity;

build a fully functional prototype demonstration pack to meet and surpass Smart Grid requirements;

test the demonstration battery pack under simulated grid-tied conditions for a prolonged time period and gather operating data for analysis;

perform Environmental and Economic Impact Analysis;

develop a Business Plan to justify building a commercial manufacturing venture to produce and distribute the developed battery product across the United States and abroad for grid-tied energy storage applications

CHAPTER 2:
Materials Development

The goal of this task was to optimize the material properties of Seeo's proprietary polymer electrolyte, scale-up of the polymer from lab-scale amounts to amounts required for prototype manufacturing to at least 10 kg batches.

2.1 Development of Polymer Materials

The mechanical rigidity and ionic conductivity of Seeo's proprietary solid polymer electrolyte are crucial to the low-cost, efficient, safe, and long-life performance promised by Seeo's solid-state lithium batteries. Seeo's core solid polymer electrolyte is a composite with multiple polymers covalently bonded as a block copolymer, with one block responsible for mechanical stability and one for high conductivity. Previous attempts to develop an electrolyte compatible with rechargeable lithium metal anodes have failed; for instance, cross-linked polymer electrolytes have at best achieve a mechanical storage modulus on the order of only 1 MegaPascal (MPa), 1000-fold less rigid than what is theoretically required to cycle stably against lithium metal anodes.

2.2 Scale-Up of Polymer

Seeo's technology evolved from fundamental research originally performed at University of California, Berkeley's (UCB) Lawrence Berkeley National Laboratory (LBNL). At that stage, the polymer materials were synthesized in small quantities using laboratory techniques capable of producing tens of grams per batch. These early techniques had extreme sensitivities and required dangerous synthetic methods in order to achieve the high molecular weight polymers that resulted in the best electrochemical performance. As successive generations of the technology have come on-line, Seeo's materials research team has explored numerous synthetic approaches keeping cost, safety, and scalability in mind. By taking this approach, Seeo has developed an extremely low-cost, energy-efficient, and scalable synthetic process for volume manufacturing of high molecular weight copolymers useful in energy applications. Seeo's current generation solid polymer electrolyte can be manufactured using high volume commodity reagents that help ensure a long term cost-down approach as demand for the electrolyte grows. Figure 2 shows actual images from the fabrication of Seeo's solid polymer electrolyte in larger quantities.

Figure 2: Scale-Up of Seeo DryLyteTM Polymer

Source: Seeo, Inc.

Through various development stages, Seeo has collaborated with different chemical companies to produce its proprietary solid polymer electrolyte material. Using an approach of separating the syntheses of the different components of the copolymer amongst different partners, Seeo has demonstrated that crucial knowledge can be compartmentalized and that intellectual property (IP) security can be maintained.

2.3 Results

Scale-up of core material has been demonstrated in large volume (greater than 100 kg) batches using techniques and equipment easily modified to multi-ton batch sizes. Table 1 shows the progress Seeo has made over the years since its start in 2007 in increasing the batch size and scaling the process of fabricating the DryLyte™ solid polymer electrolyte. The materials are meeting performance and quality specifications for high-capacity cells, as demonstrated in Seeo's pilot line facility in Hayward, California.

Table 1: Polymer Scale-Up Timeline

Year	Polymer Scale-Up
2007-2009	50-100 g lab batches synthesized at Seeo
2010	500 g lab batches synthesized at Seeo
2011	Scalable process demonstrated at Seeo, 500 g synthesized
2012	Scalable process tested outside Seeo at 3rd party, 10 kg synthesized
2013	Scalable process used to manufacture polymer in >100 kg batches
2014	On-going cost down optimization

Source: Seeo, Inc.

CHAPTER 3:
Cell Scale-Up

The goal of this part of the project was to scale-up the technology from using small single electrode cells (Research & Development (R&D) cells) to large format cells, including incrementally scaling up and validation testing of polymer synthesis, electrode coating and cell fabrication. The large format cells are intended for the demonstration pack.

3.1 Electrode Fabrication Scale-Up

One of the essential steps was for Seeo to transition from a small R&D coater to a large form factor coater that could coat both the cathode material and the polymer onto a substrate that would match the commercially available dimensions of lithium metal anode material.

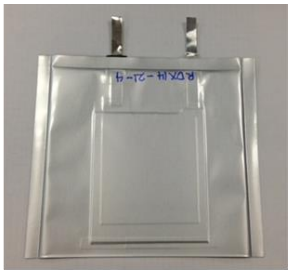
Seeo invested in and installed a pilot line coater in its facility in Hayward in 2011. Seeo also hired key personnel that had previous experience in successfully transferring and scaling-up Li-ion technology from research and development level technology to large-scale manufacturing of Li-ion electrodes and cells. Part of this transition was to switch from the lab scale coating to consistent high quality coating on a pilot coating machine that has the same quality levels as the high volume coating machines that will be required for mass production.

Through a tight collaboration between the R&D and the pilot production teams Seeo successfully achieved this, the results of which are shown in the following sections.

3.2 Cell Fabrication

Seeo employs a R&D cell with a capacity of 50-100 milli-Amp-hour (mAh) as the platform with which it carries out the primary development work. This is both from a practical point of view as many iterations are required to find the ideal combination, and it is also a more cost-effective way to perform the development work as less materials (and hence less costs) are required for each experiment and trial. Figure 3 shows an image of a R&D cell, with dimensions and capacity of these R&D cells listed below the image.

Figure 3: Seeo R&D Cell



R&D Cell
Capacity: < 100 mAh
Size: 95 x 95 x 0.4 mm

Source: Seeo, Inc.

Once the basic experiments and development work has been performed Seeo transitions the technology to large form factor cells. It is important to note that incorporating the technology developed in the R&D cells to the larger form factor cells is not a trivial matter and requires extensive focus on reproducibility and quality, as the surface areas are increasing exponentially and potential for inconsistencies in quality increase many fold. Seeo therefore has elected to take a two-step approach whereby it first transfers and demonstrates the technology on what Seeo identifies as Large Format Cell 1 (or Single-bundle cell). The Large Format Cell 1 has a capacity of about 2 Ampere-hour (Ah) (see Figure 4 for an image and for further details). This scale-up allows for a measured transition of the technology to larger form factors, and reflects a lower cost approach as it is a cell of about 20 percent of the capacity of the final large format cell that is required for the battery pack.

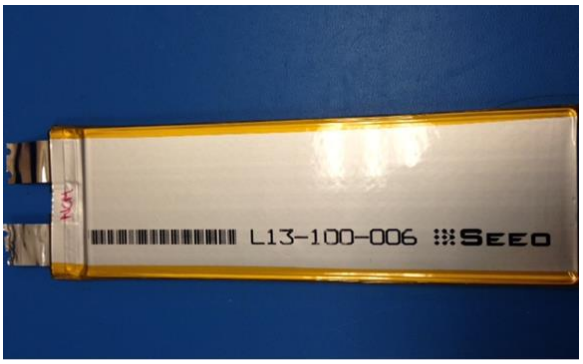
Figure 4: Seeo Large Format Cell 1

Large Format Cell 1
Capacity: ~2 Ah
Size: 72 x 234 x 2 mm

Source: Seeo, Inc.

Once the performance had been verified in the Large Format Cell 1 (Single-bundle cell) Seeo proceeds to combine five of these into a single Large Format Cell 2, which has a capacity of over 10 Ah, and consists of five of the single bundle cells of 2 Ah each. An image of such a cell is shown in Figure 5, with the dimensions and capacity of the cell noted.

Figure 5: Seeo Large Format Cell 2



Large Format Cell 2
Capacity: 10-20 Ah
Size: 72 x 234 x 9 mm

Source: Seeo, Inc.

In 2012 and 2013, Seeo has successfully transitioned through these phases and has a fully functional Large Format Cell 2 that was used to build up the battery pack system.

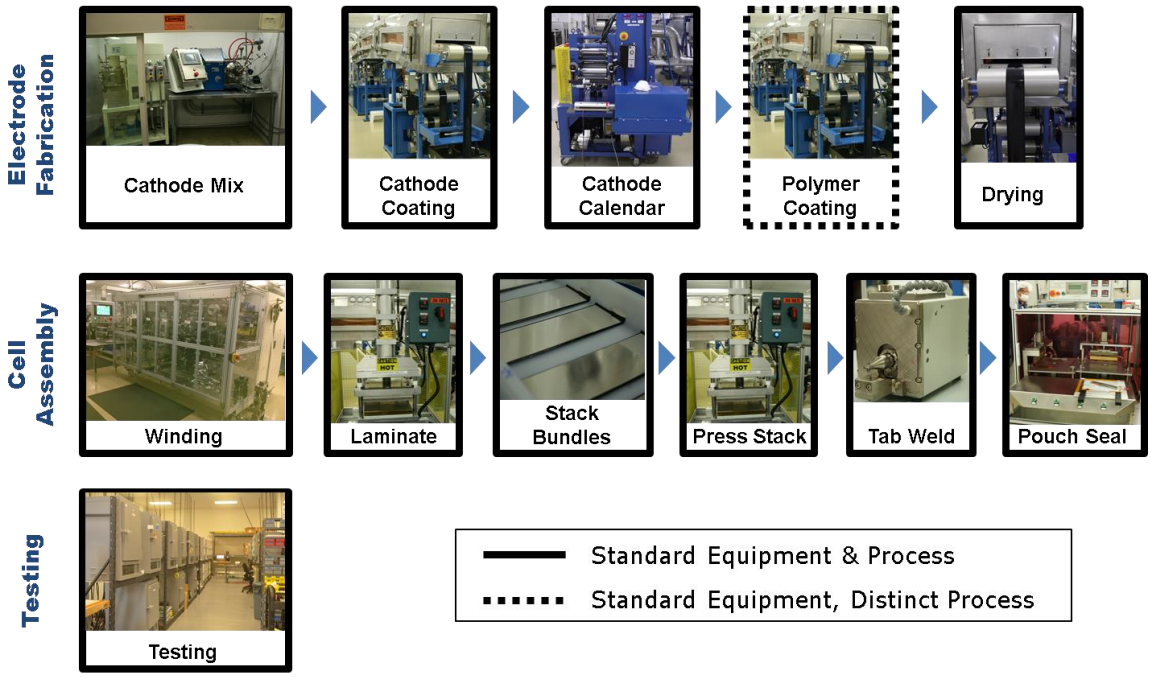
3.3 Development of Solid-State Manufacturing Process

In addition to the electrode fabrication, which is one of the most critical processes in the manufacturing of quality Li-ion cells, Seeo also built up a pilot production line at its facility in Hayward, California? Seeo's manufacturing process is very similar to traditional Li-ion manufacturing with three main differences:

- No need for anode coating as Seeo's technology employs a lithium metal anode
- Seeo employs a second coating on the cathode to apply its proprietary polymer electrolyte (this eliminates the electrolyte filling mentioned below)
- No need for electrolyte filling, which is a more cumbersome and quality sensitive process step in traditional Li-ion cell fabrication, as they require a liquid electrolyte.
- No formation (time consuming and costly investment in traditional Li-ion manufacturing).

In Figure 6, the flow diagram and images illustrate Seeo's cell manufacturing process. The images are of the actual equipment installed at Seeo's facility in Hayward, California.

Figure 6: Process Flow – Seeo Pilot Manufacturing Line



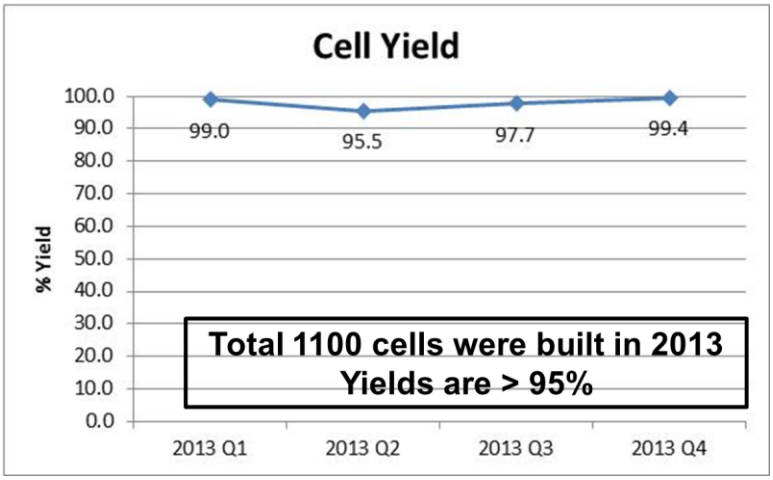
Source: Seeo, Inc.

3.4 Results

Seeo made significant progress in its scale-up of the cell manufacturing over the duration of this project. Seeo has matured the technology from small R&D sized cells to large format cells with a capacity greater than 10 Ah. At the same time, the company made great strides in achieving a high level of maturity in its manufacturing of the large format cells, both in terms of duplicating the performance from the small R&D cells, but even more importantly achieving a consistent output from the pilot line in Hayward.

In 2013, Seeo manufactured 1,100 large form factor cells and the yields from the manufacturing line were greater than 95 percent for the whole year, with the first and fourth quarter of the year achieving 99 percent yield (see Figure 7). These values are the targets for volume manufacturing in order to have a high quality and cost effective production. Seeo is already achieving this on its pilot line, and the processes being employed on the pilot line are all transferable to high volume manufacturing.

Figure 7: Yield from Seeo Cell Pilot Production (2013)



Source: Seeo, Inc.

The data in Table 2 and Figure 8 further reinforces the high level of quality in the output from Seeo's pilot production line. Table 2 shows data for 152 cells that were manufactured sequentially, with some of the key performance characteristics of the cells listed. All cells are according to specifications set by Seeo, and have a very tight distribution of the values.

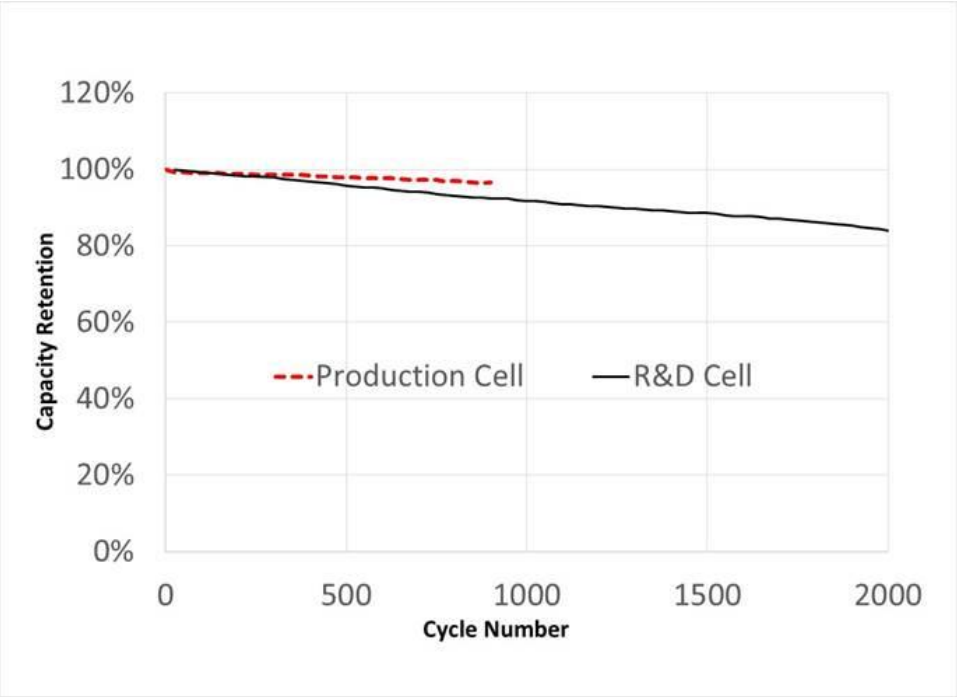
Table 2: Cell Characterization Data from Continuous Cell Build (2013)

Performance Characteristic	Unit of Measure	Average	Standard Deviation
Cell Weight	Grams	173.5	1.362
Equivalent Series Resistance (ESR)	mOhm	16.36	0.55
Capacity @ C/5	Ah	11.2	0.09
Energy Density, Gravimetric	Wh/kg	221	1.77

Source: Seeo, Inc.

Figure 8 shows the cycling performance of small R&D cells and large form factor production cells. The data shows that the large form factor production cells are tracking the performance demonstrated in the R&D cells.

Figure 8: Cycle Stability of R&D and Large Format Cells



Source: Seeo, Inc.

The scale-up of the cells has been demonstrated and the data from the large form factor cells shows the same performance as the R&D cells, and a uniform high quality.

CHAPTER 4:
Pack Prototyping

The goal of this task was to design, build, and perform validation testing of a battery pack for grid-tied demonstration and performance testing. Originally this had been planned as a 25 kWh system, but was later in agreement with the DOE and California Energy Commission revised to be a 10 kWh battery pack. The background for this change was that a 10 kWh battery system was determined to be a better fit with the photovoltaic system it would be paired with for a field demonstration program that Seeo had been awarded under the DOE's Sunshot program. The overall battery pack architecture would be virtually identical whether it was a 25 kWh or 10 kWh system, only with a lower energy content, and would therefore serve the same purpose.

4.1 Prototype Pack Architecture

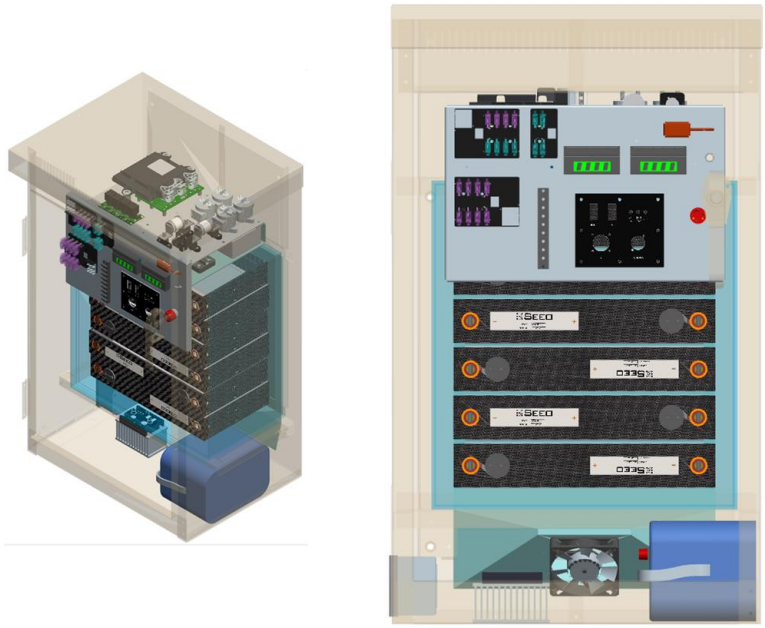
In order to achieve a 10 kWh battery pack a total of 288 cells would be required. As part of Seeo's system development effort Seeo had designed a module that would be a sub-system and a building block for designing the complete battery pack. The module would consist of 48 cells that would be coupled in series to achieve the desired voltage.

The contents of the 10 kWh battery pack became as follows:

- 288 cells – packaged into 6 modules
- Six (6) Modules – 1.6 kWh each
- Insulation
- Heating elements
- Cooling system (including fan)
- Battery Management System
- High Voltage Direct Current
- High Voltage Power Distribution

The architecture of the 10 kWh battery system can be seen in Figure 9. The battery pack consists of six (6) modules, coupled two in series and three in parallel, and the various other components including a cooling system and high voltage circuit and connectors.

Figure 9: Architecture of Seeo 10 kWh Energy Storage System



Source: Seeo, Inc.

4.2 Fabrication of Cells

Seeo manufactured the 288 cells required for the system on its pilot production line in Hayward during 2013. As mentioned earlier Seeo manufactured 1100 cells of the 10 Ah Large Format Cell 2 during 2013, all of which were used for various forms of testing and for assembly into modules. The modules were either used for testing of the modules themselves or used for the 10 kWh battery pack encompassed by this project.

4.3 Assembly of Prototype Pack

The most critical part of the assembly of the pack is the actual assembly of the module, which is the building block for the system. Each module consists of 48 cells, heating elements, battery management system to monitor and control the cells, and the mechanical parts to hold the various components. Seeo specifically designed the module with lightweight mechanical parts to ensure that the already superior energy density of the cell technology was reinforced by the mechanical construction of the module. Figure 10 shows an image of the module with the main specifications of the module listed in the table on the right.

Figure 10: Specification of Seeo 1.6 kWh Module

1.6kWh Module
Configuration – 48S1P

Electrical Specification	
Capacity (Ah)	10.0
Nominal Voltage (V)	164
Energy (kWh)	1.6
Continuous Power (kW)	0.8
Specific Energy (Wh/kg)	150
Energy Density (Wh/l)	185
Mechanical Specification	
Dimensions (mm)	445 x 79 x 250
Volume (l)	8.8
Weight (kg)	10.5
Temperature Specification	
Operating Temp (°C)	-40 to +70
Other Specification	
Environmental	IP68, IP6K9K
Communication Protocol	CAN 2.0B Modbus 1.03

Source: Seeo, Inc.

Assembly of the cells into the modules, the assembly of the module with its additional electrical and mechanical components, and subsequently assembly of the complete battery pack was performed by Seeo internally. Seeo has performed extensive testing and validation of the modules.

4.4 Results

Seeo successfully assembled the 10 kWh battery pack in house by our own employees. From the cell fabrication through the electrical and mechanical assembly of the modules and pack, Seeo designed and built up a complete battery pack.

In Figure 11 an actual image of the 10 kWh battery pack is shown and the specifications of the battery pack are also listed in the table on the right. The housing of the battery pack was specifically chosen to meet requirements for the system to be able to be installed outdoors. In addition to the assembly of the battery pack, it was also tested at Seeo to confirm full functionality.

Figure 11: Specification of Seeo 10 kWh Energy Storage System

Electrical Specification	
Min. Capacity (Ah)	30.0
Nominal Voltage (V)	328
Cutoff Voltage Discharge	240
Cutoff Voltage Charge	345
Continuous Power (kW)	5.0
Mechanical Specification	
Dimensions (in)	36 x 18 X 24
Weight (kg)	180
Temperature Specification	
Storage Temp (°C)	-20 to 65
Lifetime Specification	
Cycle Life[1]	3000
Calendar Life (years)	15
Other Specification	
Environmental	NEMA4
Communication Protocol	CAN 2.0B Modbus 1.03

[1] Dependent on customer application requirements

Source: Seeo, Inc.

CHAPTER 5:
Pack Demonstration

The goal of this task was to demonstrate the performance capabilities and advantages of the battery technology in simulated testing of a grid-tied energy storage device. As the project progressed Seeo was awarded a separate program by the DOE's Sunshot Program. Because of this development, it was decided to use some of the testing parameters from this program in the testing of the 10 kWh battery pack that was built.

5.1 Prototype Test Plan

From the start of the project, the intention had been to develop a prototype test plan using utility-derived specifications. Later it was decided to base this testing on the test protocol recommended by the photovoltaic collaboration partner on the Sunshot program. The discharge profiles were derived from *2009_CA_Retail_PV_ESS Data.*

5.2 Pack Demonstration

The battery pack was initially tested at Seeo to ensure all performance parameters were functioning as designed. Subsequently the battery pack was installed at a field location paired with a photovoltaic array and a bi-directional inverter. Images from the field location are shown in Figure 12.

Figure 12: Field Installation of Seeo 10 kWh Energy Storage System

Source: Seeo, Inc.

5.3 Results

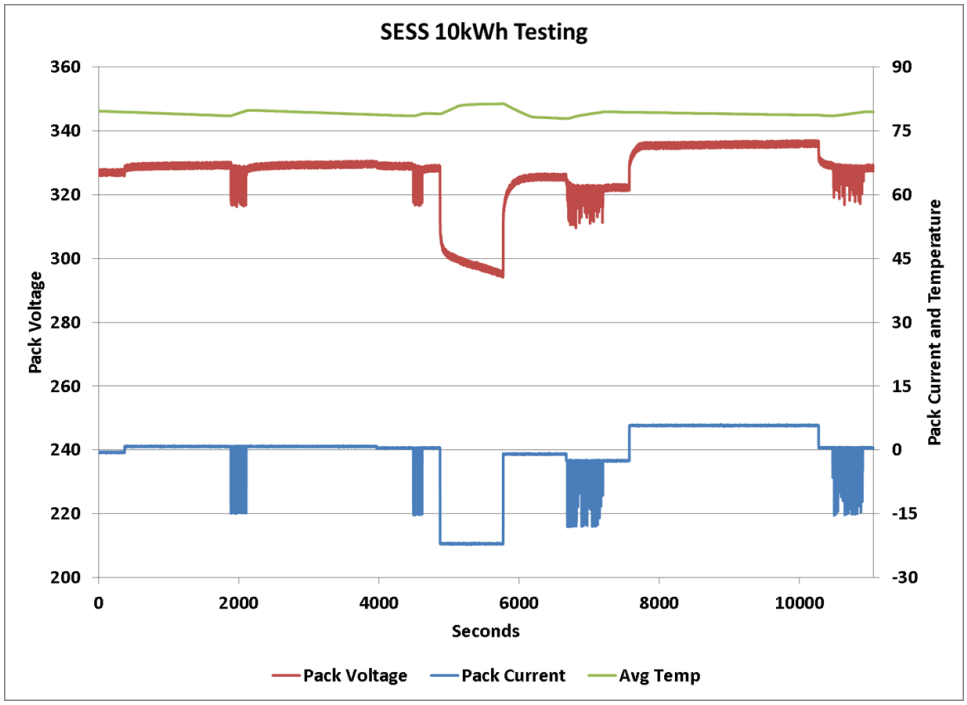
Seeo performed initial testing of the battery pack at Seeo, with simulated discharges and charges. An example of this testing is shown in Figure 13, which shows the voltage, current and temperature (of the cells).

The objective of this testing was to validate the pack, ensuring the various subsystems were working: communication, battery management system (BMS) functions (state-of-charge (SOC) calculations, power limits, charge control, discharge control), thermal management and safety management.

The profile used for testing was a series of discharge pulses with a low rate charge to simulate load leveling. In addition, a continuous three-hour (C/3-rate) discharge followed by a full charge was also performed. Following the full discharge / charge, the module then resumed the load leveling testing.

The results validated the master control modules ability to monitor SOC and control the pack within its operating conditions. The thermal management system proved capable of maintaining the cells in the specified operating temperature window.

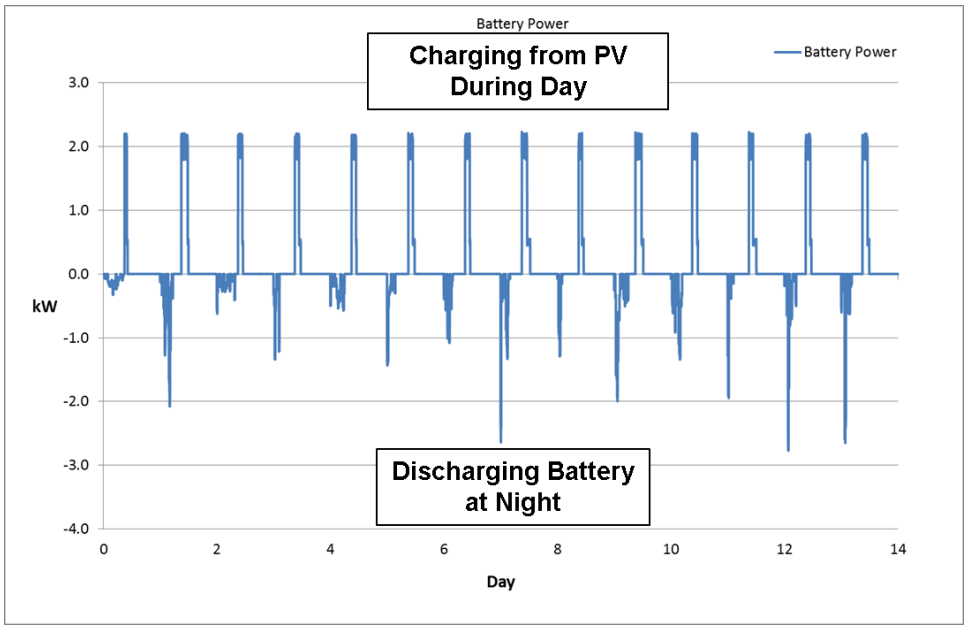
Figure 13: System Testing Data of Seeo 10 kWh Energy Storage System



Source: Seeo, Inc.

In Figure 14 two weeks' worth of field test data are illustrated. This data, which is based on using the *2009_CA_Retail_PV_ESS Data* for discharging, shows the battery pack receiving charge from the photovoltaic array during the day and discharging during nighttime.

Figure 14: Field-Testing Data from Seeo 10 kWh Energy Storage System



Source: Seeo, Inc.

The data shows the battery pack performing as intended and validating the use of energy storage coupled with an intermittent renewable energy source such as a photovoltaic array.

CHAPTER 6:
Economic and Environmental Assessment

The goal of this task was to provide both an environmental and economic impact analysis of energy storage for grid-tied applications, as well as outline a business plan for how Seeo would intend to commercialize the technology encompassed by this project.

6.1 Summary of Impact Analysis Study

The University of California, Berkeley (UCB) conducted an environmental and economic impact analysis of energy storage for grid-tied applications using the SWITCH Model ("a loose acronym for solar, wind, conventional and hydroelectric generation, and transmission," according to Matthias Fripp, 2012[1)]). Dr. Matthias Fripp and UCB originally developed the SWITCH model to study the cost of achieving high renewable energy targets in California and later expanded to cover the Western Electricity Coordinating Council (WECC) area. A report in connection with this project is titled "Exploring Cost-Effective deployment of Storage Technologies in the WECC Power System with the SWITCH Model" by Ana Mileva of UCB's Renewable and Appropriate Energy Laboratory (RAEL). The complete report is provided as Appendix A, a separate reference document.

The report is specifically focused on the WECC area, which includes 11 western states of the United States, Northern Baja Mexico and British Columbia and Alberta. The report takes into consideration traditional and renewable energy sources, as well as energy storage, and "the goal has been to incorporate into a single investment framework the ability to account for both the additional flexibility requirements imposed by intermittency, such as the need for additional reserves and frequent cycling and startups of generation, and the flexibility that can be provided by existing and yet-to-be-deployed technologies." [2)] The report encompasses the various available energy sources for electricity in the region, including renewables such as wind and solar PV, and specifically addresses energy storage as an important component and solution in the years through to 2050.

The following are excerpts of the main summary points regarding energy storage from the report[2)]:

- Solar PV deployment is the main driver of compressed air energy storage (CAES) and battery storage deployment: its diurnal periodicity provides opportunities for daily arbitrage that these technologies are well-suited to provide
- Storage operation is very different from present day patterns – storage tends to charge during the day when solar PV is available and discharge in the evening and at night
- Similarly, the ability to shift loads to the daytime solar peak could have cost-reduction benefits for the system

- If low solar PV costs and low battery costs are achieved, the two technologies may be deployed at large-scale, displacing concentrated solar power (CSP) with 6 hours of thermal storage
- The combination of Sunshot solar technology and advanced battery technology has the largest impact on total storage capacity deployment in 2050
- The combination of SunShot solar PV and low-cost batteries can provide substantial savings through 2050, greatly mitigating the cost of climate change mitigation

One of the most important findings, according to the report, is that the combination of achieving the DOE's SunShot initiative targets (for PV) and the Low-Cost Batteries targets set by Advanced Research Projects Agency-Energy (ARPA-E) projects the lowest cost of all the scenarios that are investigated in the report. The report states that the SunShot and Low-Cost Batteries scenario projects "the average cost is less than $147 per MWh in 2050," and "also provide substantial savings in the near- and mid-term)."[2)]

Seeo finds that the report validates the support and funding by the California Energy Commission for energy storage technologies, such as Seeo's technology, as energy storage solution, and especially low cost batteries will be crucial to climate change mitigation. The report does state that the most significant impact of energy storage will come by the 2050 timeframe, but points out that R&D funding of new technologies (like Seeo's) and deployment of energy storage technologies and especially batteries now and in the years to come is important in order to drive the costs down. Even though initial costs may be higher than targets, these costs will be small in comparison to the overall costs of the power system.

6.2 Seeo Production Readiness Business Plan

Through the work performed under this project, and the support of the California Energy Commission and the Department of Energy, as well as Seeo's investors, Seeo has been able to scale-up the technology and demonstrate that Seeo's technology can be mass-manufactured. Seeo is committed to commercializing the technology here in California and intends to further scale up its manufacturing capability to be able to more widely sample and qualify its technology with potential customers. The initial step will be to expand its existing pilot line in Hayward and has plans to increase the capacity ten-fold from its present 2-300 kWh production capacity.

Seeo has actively been pursuing customers in the United States and globally in both the grid storage and automotive markets. Seeo has received strong interests from a broad range of well-recognized companies in both of these market segments. Seeo would use the increased capacity of its line in Hayward to sample and proceed through the qualification process with several of these customers. Seeo's goal is to commercialize this technology to customers in California and globally.

In collaboration with strategic partners, Seeo expects to bring the technology into high volume manufacturing in the future. Commercialization of this technology, and future generations of the technology, is the sole focus of Seeo.

6.3 Results

Seeo believes that the technology developed by Seeo and encompassed by this project and the support of the California Energy Commission is ideally suited for grid-tied applications. It had been the intention of using the data gathered from the field demonstration of the battery pack to include in the analysis performed by the University of California, Berkeley. The initial testing of the Seeo battery pack and the analysis and conclusions from the Berkeley report show the relevance and importance of energy storage, and specifically low cost batteries, to the reduction of greenhouse gas emissions and climate change mitigation.

Seeo's business plan and interest from potential customers and strategic partners demonstrates the strong interest for Seeo's technology. Seeo intends to commercialize its technology both in California and globally through these opportunities. Seeo is confident the materials and manufacturing of the technology can be achieved in highly cost competitive manner allowing for the mass adoption of Seeo's technology for grid-scale energy storage, as well as for electric vehicles.

CHAPTER 7: Conclusions, Recommendations and Benefits to California

7.1 Conclusions

The support and funding by the California Energy Commission has been instrumental in the success that has been achieved during this project. The scale-up of Seeo's solid polymer electrolyte (DryLyte™) to large batches using known mass manufacturing equipment and processes and scaling up the cell technology from small to large form factor cells that are being manufactured on a pilot line with processes that for the most part are identical to existing lithium manufacturing processes demonstrates that Seeo's technology has achieved the level that it can be mass-manufactured. After designing and building a 10 kWh battery pack based on these large form factor cells it was demonstrated that Seeo's technology performs as expected in a grid-scale application. Seeo has gained valuable experience through this project and recognizes that further testing and validation in field applications with potential customers will be important going forward. Seeo believes that the results from this project shows that Seeo's technology that encompasses the DryLyte™, cell technology and systems experience has strong commercial potential, and work will continue to commercialize the technology here in California for the benefit of California's rate payers and globally.

7.2 Recommendations

Seeo believes that the California Energy Commission has an important role in California's leadership position and to the goals that California has set for reduction of greenhouse gas emissions and climate change mitigation. Seeo therefore recommends that the California Energy Commission provide further support in the form of:

- Research and development projects for the advancement of new technologies and further development of existing energy storage technologies
- Programs for the deployment of energy storage systems on the grid, in the form of residential, commercial and utility-scale systems
- Consider rebates or subsidies for customers adopting energy storage systems

Seeo believes that the California Energy Commission can play a vital role in supporting and funding these types of projects that increase the deployment and proliferation of energy storage technologies. This will allow for further experience with energy storage as a component of the overall electricity system, how it works with the other components of the system, and allow for defining the exact requirements as more renewable energy is built out in California.

As demonstrated in this project and as concluded in the impact analysis performed by UCB, energy storage will be a vital component in combination with renewable energy sources such as wind and solar, especially due to the intermittent nature of the energy generation from these

sources. Seeo is pleased to see that the California Energy Commission is already demonstrating its continued strong commitment to research and development projects and field demonstration projects of energy storage technologies through the recent Electric Program Investment Charge (EPIC) solicitation projects.

7.3 Benefits to California

The benefits to California from this project can be seen in that the technology was invented here, the work performed has taken place in California, and Seeo has built up a work force here and expects to continue to develop its team here in California. Seeo has collaborated with the University of California, Berkeley in this project, and both the testing that has been done and the conclusions listed in UCB's impact analysis report show that Seeo's technology is an ideal technology for grid-tied energy storage, especially in residential and commercial applications combined with photovoltaic systems. Seeo also intends to expand its manufacturing capability in California and expects to be successful in deploying its technology in California. Further,

- Seeo has successfully scaled up the core solid polymer electrolyte technology and cells from lab scale to commercial large form factor cells on equipment that is easily adopted into high volume manufacturing environment demonstrates the potential for commercial success.
- Energy storage for grid applications is vital to further expansion of renewables, especially photovoltaic but also wind energy. Seeo's technology is ideally suited to address and meet this need with a higher energy density technology, enhanced safety characteristics, and uniform performance regardless of ambient temperatures.
- There exists the potential to lower energy costs for customers, through combination of renewables and energy storage. For example, customers could lower their energy bills by storing energy from photovoltaics for use during the evening hours, or charge up the battery during lower off-peak hours for use during peak hours together with photovoltaics. There is also the potential opportunity for self-reliance or even selling energy back to utilities or other users.

Energy storage, and specifically low-cost batteries, such as those offered by Seeo's technology will be crucial to the further expansion and adoption of photovoltaics and potentially wind. The fact that energy storage allows for the storing of intermittent energy, such as solar and wind, for use at different times than actual generation is a major benefit for the growing demand for renewable energy sources to reduce greenhouse gas emissions and mitigate climate change.

GLOSSARY

Term	Definition
Ah	Ampere-Hour
ARPA-E	Advanced Research Projects Agency-Energy
ARRA	American Recovery and Reinvestment Act of 2009
BMS	Battery Management System
C (rate)	Current, rate of discharge or charge of cell or battery, e.g. C/3 is defined as a 3-hour discharge or charge of cell or battery
CAES	Compressed Air Energy Storage
CESS	Community energy storage system
CSP	Concentrated solar power
DOE	United States Department of Energy
EPIC	Electric Program Investment Charge
ESR	Equivalent series resistance
FOA	Funding Opportunity Announcement
g	Gram
IP	Intellectual Property
kg	Kilogram
kWh	kilowatt-hour
LBNL	Lawrence Berkeley National Laboratory
Li-ion	lithium-ion
MPa	Mega-Pascal
PV	Photovoltaic
RAEL	Renewable and Appropriate Energy Laboratory
R&D	Research and Development
SOC	State-of-Charge
SWITCH	Solar, Wind, Conventional Hydroelectric generation and Transmission
UCB	University of California, Berkeley
WECC	Western Electricity Coordinating Council

REFERENCES

Fripp, Matthias. "Switch: A Planning Tool For Power Systems with Large Shares of Intermittent Renewable Energy," Environmental Science & Technology. 2012

Mileva, Ana. "Exploring Cost-Effective Deployment of Storage Technologies in the WECC Power System with the SWITCH Model." Renewable and Appropriate Energy Laboratories (RAEL), University of California, Berkeley. 2014

APPENDIX A:
Exploring Cost‐Effective Deployment of Storage Technologies in the WECC Power System with the SWITCH Model

APPENDIX A: Exploring Cost-Effective Deployment of Storage Technologies in the WECC Power System with the SWITCH Model

Prepared by:

Ana Mileva
Energy and Resources Group
Renewable and Appropriate Energy Laboratory (RAEL)
University of California, Berkeley, CA

for

Seeo, Inc.

under

California Energy Commission Grant Agreement PIR-11-001
"SOLID STATE BATTERIES FOR GRID-SCALE ENERGY STORAGE"
&
United States Department of Energy Award Number DE-OE0000223
"SOLID STATE BATTERIES FOR GRID-SCALE ENERGY STORAGE"

May 2014

Background **3**

Modeling Storage in Low-Carbon Systems **5**

The SWITCH Model **6**

Model Development: SWITCH System Flexibility Module **8**

Power Adequacy and Capacity Credit 8
Operating Reserves 10
Cycling and Startups of Thermal Generation 11
Electricity Storage Technologies 12
Compressed Air Energy Storage *14*
Battery Storage *15*
Concentrated Solar Power (CSP) with Thermal Energy Storage (TES) 15
Load Flexibility 16
Demand Response from Thermal Loads *16*
Demand Response from Electric Vehicles *17*
Total Potential *17*
Hydropower 18

Scenarios **19**

Reference Scenario 19
SunShot Scenario 21
Low-Cost Batteries Scenario 22
SunShot and Low-Cost Batteries Scenario 23
High-Price Natural Gas Scenario 23
Flexible Load Scenario 23

Results **25**

Summary of System Development, 2020-2050 25
Electricity Production and Generation Capacity, 2020-2050 28
System Unit-Commitment 39
The 2030 Timeframe *39*
The 2050 Timeframe *48*
The Role of Storage 61
System Costs 64
The 2030 Timeframe *65*
The 2050 Timeframe *66*

Conclusion **68**

Background

Deep de-carbonization of the electric power sector is indispensable to achieving climate change mitigation. In the United States, the electricity sector accounts for more than 40 percent of greenhouse gas (GHG) emissions ("Emissions of Greenhouse Gases Report" 2008). Recent studies have suggested that in order to meet emission reduction targets of 80 percent below 1990 levels by 2050,[1] many of the end-uses of natural gas and oil would have to be electrified, adding sizable load from electric vehicles and heating ("California's Energy Future: The View to 2050" 2011; Williams et al. 2012). Williams et al. (2012) dub this a transformation from the 'oil economy' to the 'electricity economy,' a revolutionary transition – with the associated changes to the way energy is produced and consumed – that may require substantial modifications to electricity grid planning and operations, technological advancement and cost reductions, transmission expansion, and evolving energy markets.

Recent trends suggest that renewable energy technologies may make a contribution to power grid de-carbonization. While renewable wind and solar resources are abundant, a main challenge for these technologies is that they are intermittent: their energy output is variable and uncertain, and, as such, less flexible than conventional generation. Integrating increased levels of these renewable energy sources into the electricity grid poses new challenges to system planning, operation, and reliability. At higher penetration levels, the intermittency of wind and solar presents operational challenges for the grid in making scheduling and dispatch decisions. Minimizing the cost and reliability impacts of relying on intermittent renewables to expand and de-carbonize the electricity system requires detailed investigation of the evolution of the power system over the time and long-term strategic planning to ensure that the correct operational practices, policies, and market structures and incentives are put in place.

Research so far has focused on evaluating the costs and operational impacts associated with integrating low to medium levels of intermittent energy sources into the current power system. A large number of integration studies have been conducted for many different regions in the United States and Europe.[2] Notably, the Western Wind and Solar Integration Study (GE Energy

[1] This target is consistent with the Intergovernmental Panel on Climate Change's (IPCC) 450 parts per million (ppm) stabilization target for atmospheric concentration of carbon dioxide equivalent (CO_2-e), which would limit planetary warming to 2°C above preindustrial levels ("Contribution of Working Group III to the Fourth Assessment Report of the IPCC" 2007).

[2] See Meibom et al.; GE Energy 2008; "Arizona Public Service Wind Integration Study" 2007; EnerNex Corp 2007; Shiu et al. 2006; EnerNex Corp 2011; "European Wind Integration Study: Final Report"; EnerNex Corp 2006b; "Impact of Wind Power Generation in Ireland on the Operation of Conventional Plant and the Economic Implications" 2004; "Impacts of Large Amounts of Wind Power on Design and Operation of Power Systems, Results of IEA Collaboration" 2009; "Integration of Renewable Resouces: Operational Requirements and Generation Fleet Capability at 20% RPS"; "Integration of Renewable Resouces: Operational Requirements and Generation Fleet Capability at 20% RPS"; GE Energy 2007; GE Energy 2006; "Operational Costs Induced by Fluctuating Wind Power Production in Germany and Scandinavia"; "Operational Impacts of Integrating Wind Generation into Idaho Power's Existing Resource Portfolio" 2007; "Planning of the grid integration of wind energy in Germany onshore and

2010) found that it is technically feasible for the existing western U.S. grid to accommodate 30 percent wind and 5 percent solar energy penetration, provided substantial changes to current operating practices. However, these studies investigate a limited range of candidate portfolios: they assume pre-specified deployment levels and locations of intermittent renewables and take the rest of the grid including generation, transmission, and storage as fixed. Considerable cost-reduction and intermittency-mitigation potential may exist through the optimization of the full generating fleet mix to get to high penetration levels of intermittent renewable generation.

Instead of treating the legacy power system as static, the next step should be to plan power systems that are better suited for the flexibility needs of intermittent renewables in order to minimize the cost of integration. The grid can derive flexibility from a wide range of sources, including but not limited to fast-ramping generation, various storage technologies, demand response, and transmission interconnections. It is also crucial to consider balancing possibilities over large regions and the potential ability of neighboring systems to participate in the increased balancing in an economically beneficial way. As most of the intermittent generation and supporting infrastructure has not been deployed yet, employing an *investment* framework is critical to finding the most cost-effective combinations of low-carbon resources. This is particularly important because many renewable energy technologies and flexibility options such as storage have low variable costs but require investment in capital-intensive infrastructure.

---

offshore up to the year 2020 (DENA Grid Study)" 2005; Rodriguez-Bobada 2006; GE Energy 2005; Holttinen 2004; GE Energy 2010; EnerNex Corp 2006a.

Modeling Storage in Low-Carbon Systems

Modeling the costs and benefits of storage technologies has generally taken one of the following two approaches:
1) use data on historical market prices to determine the revenue that would be available to a storage project, or
2) run production cost simulation models of the whole system with and without storage to determine how the availability of storage affects system operational costs.

A problem with the first approach is that storage participation in the market would affect market prices by increasing demand during times when the storage is charging (thus raising the market price) and increasing supply during times when the storage is discharging (thus lowering the price). Historical market prices may provide a reasonable approximation for the revenue stream available to storage only at low storage deployment levels but becomes more and more inaccurate as additional storage is added or other components of the system are changed.

The second approach explores the difference in operational costs between systems with and without storage. For example, the availability of storage may result in a less frequent use of peaker natural gas plants with high fuel costs, thus reducing overall system variable cost. A main problem with this approach is that it does not consider capital costs dynamically. The operational cost savings provided by storage are compared to its capital cost to determine whether the revenue available to it would justify investment. However, the rest of the system is held as fixed, so this approach does not provide information on how other generation and transmission infrastructure should be deployed and how the grid should be developed to minimize cost as demand, technologies, and policies change.

Capacity-expansion modeling provides an additional approach to examining the role of storage in low-carbon grids. A main contribution of the work described here is to provide a modeling platform to evaluate storage as a flexibility option in a long-term *investment* framework. The purpose is to explore how total system cost (capital and variable costs) can be minimized and to co-optimize storage deployment and investment in other system infrastructure to meet projected load as well as reliability and other policy goals. As variable renewable generation achieves even higher penetration levels, flexibility alternatives such fast-ramping generation, storage, and demand response must be considered and compared. Specifically, the goal of this work has been to incorporate operational detail into the long-term investment framework of the SWITCH model to allow for more accurate evaluation of the potential contribution of intermittent renewable technologies to electricity decarbonization, the associated system flexibility requirements, and the role and relative value of various system flexibility of alternatives.

The SWITCH Model

SWITCH is free and open-access software that can be redistributed and modified under the terms of the GNU General Public License version 3. It was created by Dr. Matthias Fripp for his PhD dissertation and Berkeley's Energy and Resources Group to study the cost of achieving high renewable energy targets in California (Fripp 2008; Fripp 2012), using both existing infrastructure and new generation and transmission. Several researchers, including Josiah Johnston, Dr. James H. Nelson, and the author, have since extended the model to the entire Western Electricity Coordinating Council (WECC), incorporated a number of additional technologies, and enhanced capabilities with the goal of capturing both the impacts of intermittency and the range of system flexibility options that may help mitigate those impacts (Nelson et al. 2012; Wei et al. 2013; Mileva et al. 2013).

Documentation for the original version of the model created by Matthias Fripp can be found at http://switch-model.org. Documentation for the WECC version of the model that has been developed and maintained at the Renewable and Appropriate Energy Laboratory at U.C. Berkeley is available at http://rael.berkeley.edu/switch.

SWITCH attempts to capture the temporal relationship between load and renewable power generation levels – both of which can be driven by weather conditions – by using hourly profiles for each intermittent technology. The goal of the model is to inform power system investment decisions by ensuring that the temporal and spatial relationships between load and generation options are taken into account. The work presented here improves on other capacity-planning tools by incorporating elements of the day-to-day operations of a large, interconnected electric power grid in its investment framework.

The version of the model maintained at the Energy and Resources Group at U.C. Berkeley, referred to here as SWITCH-WECC, encompasses the synchronous region of the Western Electricity Coordinating Council (WECC). WECC includes 11 western U.S. states, Northern Baja Mexico, and the Canadian provinces of British Columbia and Alberta. WECC provides an ideal case to examine system dynamics in a complex, interconnected region with significant greenhouse gas (GHG) emissions and many low-carbon generation resources. In addition, versions of SWITCH for the entire North America as well as China, India, Chile, and Nicaragua are currently in development.

SWITCH-WECC is a linear program whose objective function is to minimize the cost of meeting projected electricity demand with existing and new generation, storage, and transmission between present day and a future year of interest. The optimization is subject to planning reserve margin, operating reserves, resource availability, operational, and policy constraints. In SWITCH-WECC, existing transmission and plant-level generators are included and can be either used through the end of their operational lifetimes or retired (existing hydro plants are allowed to run indefinitely into the future). The WECC is divided into fifty "load zones" between which new transmission can be built. The optimization is allowed to install conventional generation in

each load zone, and it chooses from thousands of possible wind and solar sites in determining renewable generation deployment. In order to account for correlations between demand and renewable generation, the model uses time-synchronized hourly load data and site-specific intermittent renewable generation data to determine least-cost investment in and hourly dispatch of generation, transmission, and storage.

New capacity can be built at the start of each of several "investment periods." The investment decisions determine the availability of power infrastructure to be dispatched in each "study hour," sampled from a year of hourly load and renewable output data for each period. Investment and dispatch decisions over the entire period of the study are optimized simultaneously. Study hours are initially sub-sampled from the peak and median load day of every month. Every fourth hour is selected, and dispatch decisions are initially made for (4 periods) x (12 months/period) x (2 days/month) x (6 hours/day) = 576 study hours. Increasing temporal resolution is a key modeling goal that can be achieved with enhanced computational resources and/or implementing a decomposition technique.

As the SWITCH-WECC investment optimization uses a limited number of sampled hours over which to dispatch the electric power system, unit-commitment verification is performed at the end of each optimization to ensure that the model has designed a power system that can meet load reliably. In this verification, investment decisions are held fixed and new hourly data for a full year are tested in batches of one day at a time. The SWITCH-WECC research team is working on performing the dispatch check with an established security-constrained unit-commitment and economic dispatch model such as PLEXOS.

Model Development: SWITCH System Flexibility Module

For this work, a series of enhancements have been implemented to the SWITCH model's treatment of system operations and generator types – the SWITCH "system flexibility module" – in order to simulate unit commitment as realistically as possible, at an unprecedented resolution for a capacity-expansion model of a large geographic area, offering some of the most detailed treatment to date of day-to-day system operations in an investment model. The goal has been to incorporate into a single investment framework the ability to account for both the additional flexibility requirements imposed by intermittency, such as the need for additional reserves and frequent cycling and startups of generation, and the flexibility that can be provided by existing and yet-to-be-deployed technologies.

Capacity-expansion modeling can help assess the feasibility of high wind and solar penetration levels as well as the costs associated with integration. However, an enhanced treatment of both the impacts of intermittency and possible mitigating policies and enabling technologies is necessary to accurately reflect the conditions the system is likely to face. The SWITCH system flexibility module aims to simulate system unit-commitment as realistically as possible, at an unprecedented resolution for a long-term investment model of a large geographic area. Such detailed treatment of system flexibility and dispatch in an investment framework could provide valuable insight into cost-effective system development to meet environmental and policy goals.

Detailed documentation on the SWITCH system flexibility module, including he linear program implementation, is available in Mileva (2014). A brief description of the main features of the system flexibility module is included below.

Power Adequacy and Capacity Credit

Electrical systems have traditionally been designed to balance two main sources of uncertainty: customer demand and the availability of generators, which experience differing probabilities of mechanical and electrical failures, i.e. forced outages (Milligan and Porter 2008). A planning reserve must therefore be maintained in excess of load requirements to maintain reliability. One approach is to have a fixed level of planning reserves, e.g. installed generation fleet capacity 15 percent above the expected load, but this approach does not take into account generator forced outage rates, which may differ significantly from system to system, nor does it quantify the frequency of system outages. Another method is to consider loads, generation capacity, and forced outage rates to arrive at a loss of load probability (LOLP) for each day and at the corresponding annual measure: the loss of load expectation (LOLE). A commonly used reliability target is 1 day per 10 years outage rate, which is equivalent to a probability of 0.9997 that generation will be sufficient to meet load on a given day (LOLP = 0.0003) without the need for imports. In the United States, capacity requirements currently vary from region to region, although the North American Electric Reliability Corporation (NERC) is developing consistent

requirements for adequacy assessment (Milligan and Porter 2008; "2008 Long-Term Reliability Assessment, 2008-2017" 2008).

Because renewable power output is intermittent – both variable and uncertain – at high renewable penetration levels it is important to consider the amount of power in the system that is likely to be available during peak load periods. A commonly used measure of a power plant's contribution toward system reliability is its capacity value or effective load-carrying capability (ELCC). Other approaches such as exceedance methodologies have also been implemented. The 70 Percent Exceedance methodology currently used by the CPUC to determine resource adequacy is an example of this method (CPUC 2009). Plants that can consistently deliver power during periods of high demand have a high ELCC. For a conventional power plant that has a relatively low probability of failure (low forced outage rate), the ELCC value will usually be a large percentage of the power plant's rated capacity and can often be approximated simply by $(1-r)*C$ where C is the rated capacity and r is the forced outage rate. Similarly, with renewable energy generation, the goal is to determine the capacity value for wind and solar power relative to a perfectly reliable generating unit, or preferably, because such a unit does not exist, to a benchmark unit such as a gas plant with an outage rate of five percent (Milligan and Porter 2008).

In SWITCH, it is not possible to run a stochastic simulation to evaluate the LOLP of the system or the ELCC of generators. To account for outages, the capacity of all generator, storage, and transmission projects is de-rated by their outage rates for the purposes of satisfying load. A simple approach is used of holding a planning reserve margin of 15 percent above load in every load zone in every timepoint. Intermittent renewable generators can contribute to the planning reserve margin an amount equal to their capacity factor in that hour times their capacity. This approach has a number of limitations. Among them is that the sampling method used to create a training set of timepoints over which to commit the power systems created by the SWITCH investment optimization may miss the times of highest grid stress. As a result, the system created by SWITCH may experience outages when tested on a larger test set of timepoints.

Increasing the temporal resolution of the investment optimization is one way to address this problem, as it would make it more likely that the critical periods for the grid are included and accounted for. However, this approach is currently not feasible due to computational constraints. Instead, I address this problem through an iterative method of 1) running the SWITCH investment optimization, 2) testing the system designed by the model on a larger set of timepoints, and 3) including the timepoints with the highest capacity shortfalls from step 2 into the main optimization, then returning to step 1. I repeat the process until all capacity shortfalls are eliminated. This approach of finding the times of highest grid stress – the peak net load hours – was first implemented in Mileva et al. 2013 and ensures that those time are accounted for by the SWITCH investment optimization in designing the power system

Operating Reserves

Operating reserves in the WECC are currently determined by the "Regional Reliability Standard to Address the Operating Reserve Requirement of the Western Interconnection" ("WECC Standard BAL-STD-0020 - Operating Reserves" 2007). This standard dictates that operating reserves (spinning and quickstart) must be at least: "the sum of five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation." At least half of those reserves must be spinning, i.e. online and synchronized to the grid but backed off from full output. In practice, this NERC standard has usually meant a spinning reserve requirement of 3 percent of load and a quickstart reserve requirement of 3 percent of load.

Similarly, the WECC version of SWITCH holds a base operating reserve requirement of 6 percent of load in each study hour, half of which is spinning. In addition, "variability" reserves: spinning and quickstart reserves each equal to 5 percent of the wind and solar output in each hour are held to cover the additional uncertainty imposed by generation variability at the subhourly timescale. These default requirement levels can be readily varied.

The default operating reserve requirement is based on the "3+5 rule" developed in the Western Wind and Solar Integration Study as one possible heuristic for determining reserve requirements that is "usable" to system operators (GE Energy 2010). The 3+5 rule means that spinning reserves equal to 3 percent of load and 5 percent of wind generation are held. When keeping this amount of reserves, the report found, at the study footprint level there were no conditions under which insufficient reserves were carried to meet the implied $3\Delta\sigma$ requirement for net load variability.[3] For most conditions, a considerably higher amount of reserves were carried than necessary to meet the $3\Delta\sigma$ requirement. Performance did vary at the individual area level, so in the future customized reserve rules may be implemented for different areas.

SWITCH's operating reserve requirement is more stringent, as quickstart reserves of 3 percent of load and 5 percent of variable renewable generation are also held in addition to spinning reserves. We assume that solar generation, with the exception of CSP with 6 hours of storage, which exhibits little 10-min variability, impose reserve requirements similar to wind's (i.e. 5 percent of generation). Solar CSP without storage contributes only to the quickstart requirement.

The size of the entity responsible for providing balancing services is important both in terms of ability to meet the reserve requirement and the cost of doing so. The sharing of generation resources, load, and reserves through interconnection and market mechanisms is one of the

[3] The statistical technique of combining the variability of VERs with load variations to arrive at the net load variability on various timescales – and corresponding balancing needs – is often referred to as the "$3\Delta\sigma$ method." Three times the standard deviation (σ) of the distribution of the deltas (Δ), i.e. the differences in net load from one point in time to the next (e.g. every 10 minutes), is taken as the confidence level for how much of the variations should be covered by reserves. Three standard deviations covers about 99.7 percent of the observed variations (Milligan 2003).

least-cost methods for dealing with load variability. Multiple renewable integration studies have now also demonstrated the benefits of increased balancing area size (through consolidation or cooperation) in managing the variability of variable renewable output. At present, WECC operates as 39 balancing areas (GE Energy 2010), but in light of the large benefits of increased balancing area size, their functions will likely be consolidated in the future. The Western Wind and Solar Integration Study assumes five regional balancing area in WECC for operating reserves – Arizona-New Mexico, Rocky Mountain, Pacific Northwest, Canada, and California – as their "statistical analysis showed, incorporating large amounts of variable renewable generation without consolidation of the smaller balancing areas in either a real or virtual sense could be difficult." Similarly, the WECC version of SWITCH assumes the primary NERC subregion as the balancing area in its optimization by default. Six balancing areas are modeled: Arizona-New Mexico, Rocky Mountain, California, Pacific Northwest, Canada, and Baja California. The balancing area size can be varied.

The current implementation of operating reserves in SWITCH-WECC allows natural gas generators (including gas combustion turbines, combined-cycle natural gas plants, and steam turbine natural gas plants), hydro projects, and storage projects (including compressed air energy storage, batteries, and pumped hydro) to provide operating reserves. Coal plants and concentrated solar power plants with thermal storage do not provide operating reserves in the model. It is assumed that natural gas generators back off from full load and operate with their valves partially closed when providing spinning reserves, so they incur a heat rate penalty. The spinning reserve heat rate penalty is calculated from the generator's part-load efficiency curve (London Economics and Global Energy Decisions 2007).

Cycling and Startups of Thermal Generation

When operating below full load (deep-cycling), a heat rate penalty is applied for flexible baseload plants (coal steam turbines and coal integrated gasification combined cycle turbines (IGCC)) and intermediate combined cycle gas turbine (CCGT) plants. At times when these generator types are deep-cycled, the additional fuel and carbon cost from heat-rate degradation is added to the objective function. If a carbon cap is enforced, the additional emissions are added to the carbon cap constraint.

Non-cogeneration coal generators in SWITCH-WECC are operated as flexible baseload generators. These generators are assumed to be online throughout their operational lifetime, but can vary output level between a minimum loading level and their nameplate capacity, de-rated by their forced and scheduled outage rates. A minimum loading level is enforced, as operating below a certain output level is expensive or technically infeasible, for flexible baseload generators. The operational constraints for flexible baseload generation in SWITCH-WECC are included below.

Natural gas combined cycle plants (CCGTs) and natural gas steam turbines in SWITCH-WECC are operated as intermediate generators. They can commit no more capacity to be online in each

hour than their nameplate capacity, de-rated by their forced outage rate. Intermediate generation can provide no more power, spinning reserves, and quickstart reserves in each hour than the amount of capacity that was committed to be online in that hour. Spinning reserves cannot exceed a pre-specified fraction of online capacity equal to the generator's 10-minute ramp rate. Combined heat and power natural gas generators (cogenerators) are operated in baseload mode and are not included here.

Natural gas combustion turbines are operated as dispatchable generators in SWITCH-WECC. They can provide no more power, spinning reserve, and quickstart capacity in each hour than their nameplate capacity, de-rated by their forced outage rate. Spinning reserve can only be provided in hours when the plant is also producing useful generation and cannot exceed a pre-specified fraction of capacity.

Electricity Storage Technologies

A number of energy storage technologies are available with varying characteristics ("Electricity Energy Storage Technology Options: A White Paper Primer on Applications, Costs, and Benefits" 2010). To this day, however, only a few storage technologies have been deployed at a large scale, i.e. a total world capacity of more than 100 MW. Those include sodium-sulfur batteries, pumped hydro, compressed-air energy storage (CAES), and thermal storage. In the United States, there are 25 GW of utility-scale electric storage, most of which is pumped hydro storage (PHS) ("Grid Energy Storage" 2013). Multiple other technologies are currently being developed that can be deployed to provide grid services at various timescales.

Storage technologies are characterized by the total amount of energy they can store and the rate at which they can release it. A storage device therefore has two components: a storage unit with a $/kWh cost and a power conversion unit with a $/kW cost (Schoenung 2011; see Figure 1). Here, I will refer to the former as the storage project's *energy subsystem* and the latter as its *power subsystem*. For example, pumped hydro storage has a power subsystem consisting of hydro turbines and water pumps while its energy subsystem comprises of the lower and upper water reservoirs. Compressed air energy storage includes a combustion turbine and compressor as its power subsystem and an underground cavern for compressed air where energy is stored. Electrochemical cells are the energy subsystem component of most batteries while converter and control electronics determine the rate at which energy is released (the power output). I will use the term storage *duration* as the amount of time it would take for a fully charged storage project to fully discharge if releasing energy at its maximum possible rate. The overall cost of the system will be equal to the sum of total cost of its power subsystem (kW x $/kW) and the total cost of its energy subsystem (kWh x $/kWh).

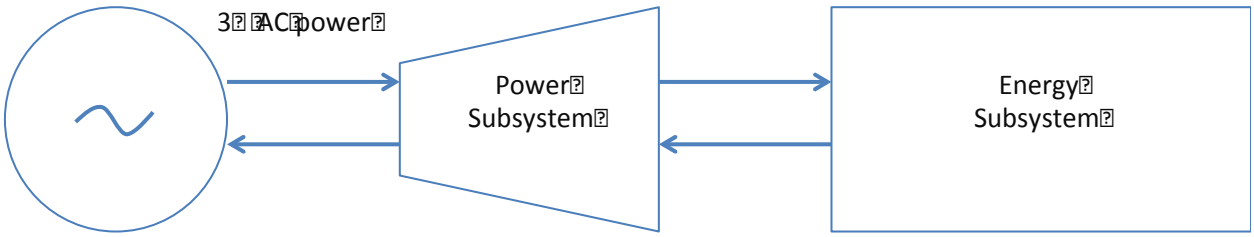


Figure 1. Energy storage subsystems. Based on Schoenung 2011.

The costs of the energy and power subsystems vary greatly across technologies and determine the suitable applications for each technology. Energy storage applications for the grid can be divided into several categories depending on the required power and duration, and are described below (Denholm et al. 2010; Schoenung 2011). Short-duration applications include frequency regulation, which requires the ability to continuously cycle and respond within less than a second in case of disturbances, as well as power quality applications, which require less frequent discharge. Technologies for short-duration applications include flywheels, supercapacitors, and a variety of battery chemistries. Longer duration applications include provision of operating reserves, which generally requires the ability to maintain the committed level of output for an hour, and of load following to compensate for unit-commitment errors. A small amount of cycling is generally required, as reserves are called upon infrequently, and a wide range of technologies is suitable for these applications.

On the super-hourly scale, energy management refers to the ability of storage to shift energy demand and supply over several hours. To provide energy management services, storage technologies must be able to discharge continuously over longer periods of time. Long-duration storage technologies include high-energy batteries, pumped hydro storage (PHS), compressed air energy storage (CAES), and thermal storage. Technologies suitable for energy management applications have lower $/kWh cost for the energy subsystem.

New storage in SWITCH-WECC includes two technologies, which are modeled after compressed air energy storage (CAES) and a generic battery technology respectively. Investment decision variables for storage projects determine both the power capacity of the project (the maximum rate at which energy can be released) and its energy capacity (the total amount of energy that can be stored by the project). For example, the model may decide to install a 1 MW project with 10 MWh of energy storage (a project that can release energy at a maximum rate of 1 MW for 10 hours) or a 10 MW project with 1 MWh of energy storage (a project that can release energy at a maximum rate of 10 MW for 6 minutes).

Per unit costs are input separately for storage power capacity and energy capacity. Default costs for CAES and batteries are based on sources by the Electric Power Research Institute and Black and Veatch respectively ("Electricity Energy Storage Technology Options: A White Paper Primer on Applications, Costs, and Benefits" 2010; "Cost and Performance Data for Power Generation Technologies" 2012) and are shown in Table 1 below.

	Batteries		CAES	
Year	Power subsystem cost 2014$/KW	Energy subsystem cost 2014$/KWh	Power subsystem cost 2014$/KW	Energy subsystem cost 2014$/KWh
2010	1093	383	863	22
2015	1066	373	863	22
2020	1039	363	863	22
2025	1011	354	863	22
2030	984	344	863	22
2035	956	335	863	22
2040	929	325	863	22
2045	902	316	863	22
2050	874	306	863	22

Table 1. Storage power capacity and energy capacity costs by year.

Compressed Air Energy Storage

Compressed air energy storage (CAES) is a hybrid storage and gas turbine technology. Conventional gas turbines expend some of their gross energy to compress the air/fuel mixture for the turbine intake. CAES uses energy from the grid to compress air in an underground reservoir and uses that compressed air, adding it to the natural gas fuel for the turbine, for the turbine intake. Storage round-trip efficiency for CAES is assumed to be of 81.7 percent and plant round-trip efficiency is assumed to be 1.4 (Succar and Williams 2008). The plant round-trip efficiency is higher than 1 as CAES plants use both natural gas and electricity from the grid energy stored in the form of compressed air to produce power. A compressor to expander ratio of 1.2 (Greenblatt et al. 2007) is assumed.

CAES sites are assumed to be in aquifer geology. Geospatial aquifer layers are obtained from the United States Geological Survey ("Principal Aquifers of the 48 Conterminous United States, Hawaii, Puerto Rico, and the U.S. Virgin Islands" 2003) and all sandstone, carbonate, igneous, metamorphic, and unconsolidated sand and gravel aquifers are included (Succar and Williams 2008; "Handbook of Energy Storage for Transmission and Distribution Applications" 2003). A density of 83 MW/km^2 is assumed (Succar and Williams 2008), following, resulting in large CAES potential in almost all SWITCH-WECC load zones.[4]

[4] Geospatial work and CAES potential calculations were done by Dr. James H. Nelson.

Battery Storage

Batteries are available for installation in all load zones and investment periods in SWITCH-WECC. An AC-DC-AC round-trip storage efficiency of 75 percent is assumed. Battery lifetime is based on Lu et al. 2009. SWITCH-WECC allows 100% depth of discharge, so we take a battery life of 3142 cycles. Assuming frequent utilization, I calculate a battery lifetime of 10 years (3142 cycles / (10 yrs * 365 days/yr) = 0.86 cycles/day on average). In SWITCH, batteries are explicitly replaced at the end of their lifetime, so we assume that the variable O&M cost is zero (Walawalker 2008; Lu et al. 2009; "Electricity Energy Storage Technology Options: A White Paper Primer on Applications, Costs, and Benefits" 2010). Battery capital and fixed O&M costs are from Black and Veatch ("Cost and Performance Data for Power Generation Technologies" 2012). Note that Black and Veatch includes the cost of battery replacement in the variable O&M cost for batteries and their variable O&M value is not used here.

Concentrated Solar Power (CSP) with Thermal Energy Storage (TES)

Five different solar technologies, each with different output characteristics, resource availability, and costs, are modeled in SWITCH-WECC, including residential, commercial, and central-station photovoltaic (PV) technologies and concentrated solar power (CSP) technologies with and without thermal energy storage (TES). CSP projects are assumed to be dry-cooled solar thermal trough systems sited on available rural land and a range of land exclusion criteria are applied (Nelson et al. 2012). For each project of a given technology, the hourly capacity factor of that project over the course of the year 2006 is simulated using the System Advisor Model (SAM) (*System Advisor Model* 2014)from the National Renewable Energy Laboratory (Nelson et al. 2013).

CSP systems with 100 MW nameplate capacity and without thermal storage are modeled in SAM using the 'CSP Trough Physical' model for parabolic trough systems. A solar multiple of 1.4 is assumed for systems without thermal storage. For prior work, the power output of CSP thermal storage was embedded in the hourly capacity factor calculated with SAM, using a pre-specified schedule of releasing energy from sunset through the early part of the night. Six hours of storage and a solar multiple of 2 were assumed.

As the power system generation mix and load profile change over time in response to climate change mitigation policy, population growth, efficiency implementation, or other factors, the optimal commitment schedule for CSP thermal storage is also likely to change. For this work, I have implemented the ability to determine how to optimally release energy from CSP with storage as an endogenous variable in SWITCH-WECC in response to power system conditions rather than as an exogenously specified input parameter.

To obtain the hourly energy availability for CSP projects with 6 hours of storage, I first match these projects via a location ID index to projects with no storage at the same location. I use the

data on energy availability for CSP projects without storage, which are assumed to have solar multiples of 1.4, and assign hourly energy availability from the solar collection field of systems with 6 hours of storage by assuming they have a solar multiple of 2. The solar multiple is the ratio of the power capacity of the solar collection field to the capacity of the power block. For systems with same power block size, the hourly energy available from the solar collection field of CSP projects with 6 hours of storage is therefore (2/1.4) times the solar collection field energy availability of the projects without storage at the same location. This is the "capacity factor" that is input to SWITCH that determines the availability of energy to be scheduled from CSP projects with TES.

Due to computational constraints, the hourly commitment variables of CSP projects with 6 hours of storage are aggregated to the load zone level. They are then apportioned back to the project level based on relative project capacity. Parasitic losses from CSP plants with storage are ignored in this implementation as allowing them greatly increased runtime. In each timepoint, SWITCH can decide whether to directly release energy or to store it subject to hourly energy availability and capacity constraints. At this stage, CSP plants are not allowed to provide spinning or quickstart reserves.

Load Flexibility

By default, shiftable load is disabled. When it is enabled, the amount of load that can be moved from or to an hour via demand response for each demand category in each load zone is limited to a pre-specified amount of energy. Over the course of a day, the total demand moved from and to all hours must sum to zero for each demand category in each load zone – the total amount of demand met over the course of a day is the same with or without demand response. The two demand categories that can participate in demand response are electric vehicles and residential and commercial buildings. The amount of demand that can be moved from or to an hour from electric vehicles is calculated based on battery charging rates.

Demand Response from Thermal Loads

To calculate hourly shiftable-load potentials, we use hourly load data from Itron for commercial and residential loads disaggregated by end-use, along with assumptions about the fraction of each of these types of demand that will be shiftable in 2020, 2030, 2040, and 2050 (extrapolated linearly for years in between). The residential demand types we assume can be shifted include space heating and cooling, water heating, and dryers. Shiftable commercial building demand types include space heating and cooling as well as water heating.

Sector	End Use	2020	2030	2040	2050
Residential	Space heating	2%	20%	40%	60%
	Water heating	20%	40%	60%	80%
	Space cooling	2%	20%	40%	60%
	Dryer	2%	20%	60%	80%
Commercial	Space heating	2%	20%	40%	60%
	Water heating	20%	40%	60%	80%
	Space cooling	2%	20%	40%	60%

Table 2. Fraction of demand that is shiftable, by end use and year.

Based on the values in Table 2, we calculate the fraction of total residential and commercial demand respectively (after energy efficiency and heating electrification) in California that can be shifted and apply this fraction to each of SWITCH's California load zones to arrive at a total potential for shiftable demand by hour. We assume this demand can be shifted to any other hour in the same day. Since demand data disaggregated by sector and end-use is not available for the rest of WECC, we used the overall fraction of total non-EV demand calculated to be shiftable in California in each hour and applied that fraction to the hourly non-EV demand in each load zone in the rest of WECC to calculate shiftable demand availability. We assumed that shiftable demand potential in the rest of WECC lags that in California by a decade.

Demand Response from Electric Vehicles

Demand from electric vehicles (EV) is assumed to be shiftable subject to the battery charging rates of the EV fleet shown below.

	Percent of total EV demand				
Hours needed for full charge	**2012**	**2020**	**2030**	**2040**	**2050**
10	98.0%	91%	60%	20%	10%
4	1.8%	8%	38%	68%	70%
0.33	0.2%	1%	2%	12%	20%

Table 3. Assumed battery charging times of the electric vehicle fleet.

Total Potential

Shiftable load potential is shown below and reaches an average of 20 percent of total hourly demand by 2050.

Year	Residential and Commercial		Electric Vehicles		Total	
	WECC-wide Average Hourly Shiftable Potential (MW)	Average Shiftable Percentage of Hourly Total Demand	WECC-wide Average Hourly Shiftable Potential (MW)	Average Shiftable Percentage of Hourly Total Demand	WECC-wide Average Hourly Shiftable Potential (MW)	Average Shiftable Percentage of Hourly Total Demand
2020	5	0.2%	2	0.1%	7	0.3%
2030	48	2%	32	1%	80	3%
2040	174	6%	154	5%	328	11%
2050	330	10%	368	10%	698	20%

Table 4. Shiftable load potential by load type and year.

Hydropower

Hydroelectric generators must provide output in each hour equal to or exceeding a pre-specified fraction – usually 50% – of the average hydroelectric capacity factor for the month in which the study day resides in order to maintain downstream water flow. The total energy (which, for pumped hydro, includes energy released from storage) and operating reserves provided by each hydro project in each hour cannot exceed the project's total turbine capacity, de-rated by the forced outage rate of hydroelectric generators. Operating reserves from hydro cannot exceed a pre-specified fraction of installed capacity, 20 percent by default. The capacity factor for all hydroelectric facilities in a load area over the course of each study day must equal the historical daily average capacity factor for the month in which that day resides. New hydroelectric facilities are not built, but existing facilities are operated indefinitely. The dispatch of hydroelectric projects is aggregated to the load area level to reduce the number of decision variables. All load area level hydro dispatch decisions are allocated to individual projects on an installed capacity basis.

Scenarios

Reference Scenario

A brief description of the main data inputs to the SWITCH-WECC model is included here. A complete discussion of the SWITCH-WECC data as well as assumptions and model formulation is available at http://rael.berkeley.edu/switch.

In the *Reference* scenario (as well as all but the *Nuclear and CCS* scenario), it is assumed that neither nuclear plants nor fossil fuel plants with carbon capture and sequestration (CCS) will be built through 2050. The focus is on systems in which low-carbon baseload technologies are not available and intermittent renewable technologies are the main source of carbon-free electricity. The goal is to understand the flexibility requirements – and in particular the role of storage – in such systems. Biomass fuel is assumed not to be available to the electricity sector but is instead used for transportation purposes, further limiting the availability of carbon-free baseload. The potential for bio energy carbon capture and sequestration (BECCS) and negative emissions from such plants is not explored here.

The hourly demand profiles used in this study are based on historical demand data from 2006 and modified in future years by the introduction of energy efficiency measures, vehicle electrification, and heating electrification. The implementation of efficiency measure and the addition of demand from electric vehicles and heating drive large changes to the demand profile, notably a shift in the timing of the peak in load from the summer afternoons today to the early winter mornings by 2050. A detailed discussion of the profiles is available in Wei et al. 2013.

Very little technological progress is assumed and costs for most technologies are modeled as constant between present day and 2050. Exceptions include modest decreases in the capital cost of solar PV, concentrated solar power (CSP), and batteries. Table 5 shows the overnight capital cost, fixed operations and maintenance costs, and variable operation and maintenance cost input parameters used in this study. Low-carbon baseload technologies such as nuclear and CCS are excluded from the *Reference* scenario but are shown in Table 5.

The price of natural gas in the *Reference* is based on the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2012 Base Case ("Annual Energy Outlook" 2012) and is shown in Figure 2. The EIA AEO 2012 does not project the price of natural gas beyond 2035, so value between 2035 and 2050 are extrapolated based on the data for 2025-2035.

The cost of new transmission capacity is assumed to be $1,130 per MW of thermal capacity per km ($2013).

Fuel	Technology	Overnight Capital Cost ($2013/W)	Fixed O&M ($2013/MW/Yr)	Variable O&M ($2013/MWh)
Bio Gas	Bio Gas	1.98	60000	15
Coal	Coal IGCC	4.21	33000	6.9
Coal	Coal Steam Turbine	3.04	24000	3.9
Coal CCS	Coal IGCC CCS	6.94	47000	11.1
Coal CCS	Coal Steam Turbine CCS	5.93	37000	6.3
Gas	CCGT	1.29	7000	3.9
Gas	Gas Combustion Turbine	0.68	6000	31.4
Gas CCS	CCGT CCS	3.94	19000	10.5
Geothermal	Geothermal	6.24	0	32.6
Solar	Central PV (2020)	2.64	47000	0
Solar	Central PV (2030)	2.43	43000	0
Solar	Central PV (2040)	2.27	39000	0
Solar	Central PV (2050)	2.13	35000	0
Solar	Commercial PV (2020)	3.51	47000	0
Solar	Commercial PV (2030)	3.11	43000	0
Solar	Commercial PV (2040)	2.91	39000	0
Solar	Commercial PV (2050)	2.75	35000	0
Solar	CSP Trough 6h Storage (2020)	6.86	53000	0
Solar	CSP Trough 6h Storage (2030)	5.58	53000	0
Solar	CSP Trough 6h Storage (2040)	4.94	53000	0
Solar	CSP Trough 6h Storage (2050)	4.94	53000	0
Solar	CSP Trough No Storage (2020)	4.77	53000	0
Solar	CSP Trough No Storage (2030)	4.38	53000	0
Solar	CSP Trough No Storage (2040)	3.99	53000	0
Solar	CSP Trough No Storage (2050)	3.6	53000	0
Solar	Residential PV (2020)	3.94	47000	0
Solar	Residential PV (2030)	3.46	43000	0
Solar	Residential PV (2040)	3.25	39000	0
Solar	Residential PV (2050)	3.08	35000	0
Uranium	Nuclear	6.41	133000	0
Wind	Offshore Wind (2020)	3.31	105000	0
Wind	Offshore Wind (2030)	3.14	105000	0
Wind	Offshore Wind (2040)	3.14	105000	0
Wind	Offshore Wind (2050)	3.14	105000	0
Wind	Wind	2.08	63000	0

Table 5. Generator and storage costs, in real 2013 dollars.

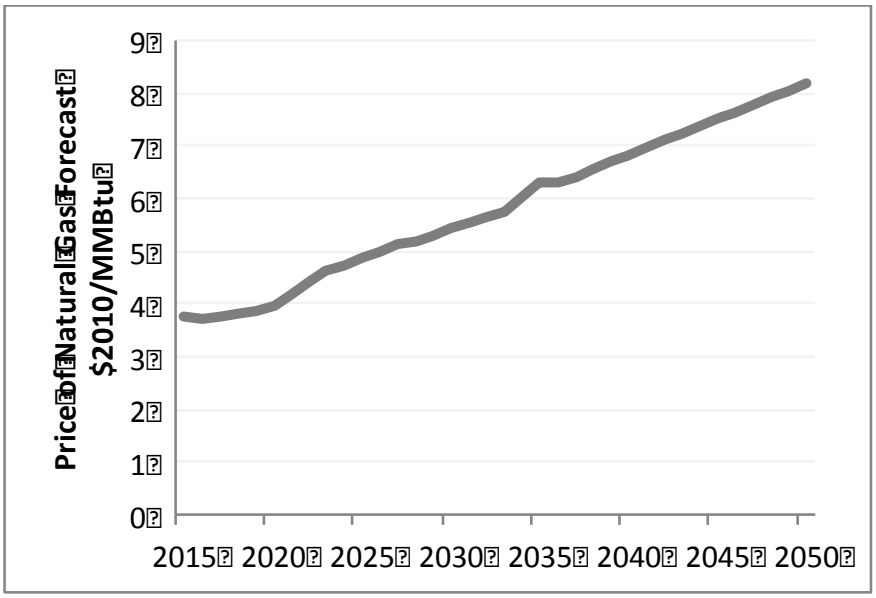


Figure 2. Price of natural gas in the EIA AEO 2012 Base Case.

SunShot Scenario

In 2011, the United States Department of Energy (DOE) launched the SunShot Initiative, a comprehensive lab-to-market program that seeks to drive innovation and lower the cost of solar technologies, including photovoltaics (PV) and concentrating solar power (CSP) ("SunShot Initiative" 2014). The SunShot Vision Study ("SunShot Vision Study" 2012) provides an extensive analysis of the innovation required to reach the SunShot targets and the effect on solar deployment in the United States and we have previously explored the implications of achieving these targets for technology deployment and electricity costs in the WECC in scenarios limiting carbon emission from the electricity sector (Mileva et al. 2013).

SunShot solar costs are used in the *SunShot* scenario and the *SunShot and Low-Cost Batteries* scenario.

Solar Technology	Year	*Reference* Capital Cost $2014/$W_p$	*SunShot* Capital Cost $2014/$W_p$
Central Station PV	2020	2.64	1.08
Central Station PV	2030	2.43	1.08
Central Station PV	2040	2.27	1.08
Central Station PV	2050	2.13	1.08
Commercial PV	2020	3.51	1.34
Commercial PV	2030	3.11	1.34
Commercial PV	2040	2.91	1.34
Commercial PV	2050	2.75	1.34
Residential PV	2020	3.94	1.61
Residential PV	2030	3.46	1.61
Residential PV	2040	3.25	1.61
Residential PV	2050	3.08	1.61
CSP Trough No Thermal Storage	2020	4.77	2.69
CSP Trough No Thermal Storage	2030	4.38	2.69
CSP Trough No Thermal Storage	2040	3.99	2.69
CSP Trough No Thermal Storage	2050	3.60	2.69
CSP Trough 6 Hours Thermal Storage	2020	6.86	3.29
CSP Trough 6 Hours Thermal Storage	2030	5.58	3.29
CSP Trough 6 Hours Thermal Storage	2040	4.94	3.29
CSP Trough 6 Hours Thermal Storage	2050	4.94	3.29

Table 6. Reference and SunShot solar costs by year and solar technology.

Low-Cost Batteries Scenario

Storage technologies have two cost components: a storage unit with a $/kWh cost and a power conversion unit with a $/kW cost. This treatment of storage is an enhancement over prior work, in which the duration of storage was an input to SWITCH rather than a variable. Only CAES with 16 hours of storage and batteries with 8 hours of storage were available to the optimization in prior studies (Nelson et al. 2012; Wei et al. 2013; Mileva et al. 2013; Nelson et al. 2013). For this study, a two-variable treatment of storage investment has been implemented in SWITCH-WECC: the optimization decides both the capacity of the power subsystem component and the energy subsystem component of both CAES and batteries endogenously. The model can therefore determine the optimal size of storage devices for a given cost structure.

Two distinct cost trajectories for batteries are modeled here. *Reference* scenario costs are based on cost projections by Black and Veatch ("Cost and Performance Data for Power Generation Technologies" 2012) and decline slowly between present day and 2050. To explore the effect of strong technological innovation and deep cost-reductions in battery technology, I also run two scenarios in which battery costs decline to ~$500/kW for the power subsystem

component and ~50/kWh for the energy subsystem component, a likely lower bound for what is achievable by flow batteries (Larochelle 2012). This is equivalent to the ARPA-E battery total-system cost target of about $100/kWh. For comparison, CAES costs are ~800/kW for the power subsystem component and ~$20/kWh for the energy subsystem component.

Battery costs at the ARPA-E target level are used in the *Low-Cost Batteries* scenario and the *SunShot and Low-Cost Batteries* scenario.

	Reference		***ARPA-E***	
Year	**Power subsystem cost** 2014$/kW	**Energy subsystem cost** 2014$/kWh	**Power subsystem cost** 2014$/kW	**Energy subsystem cost** 2014$/kWh
2015	1066	373	805	192
2020	1039	363	518	46
2030	984	344	518	46
2040	929	325	518	46
2050	874	306	518	46

Table 7. Reference and ARPA-E costs of the power subsystem and the energy subsystem of battery technology by year.

SunShot and Low-Cost Batteries Scenario

This scenario combines SunShot solar costs and battery costs at the ARPA-E target. All other inputs are as in the *Reference* scenario.

High-Price Natural Gas Scenario

Natural gas generation, in particular quick-ramping combined cycle gas turbines and combustion turbines, are an important source of flexibility to the power system. Their cost-effectiveness relative to other sources of flexibility is dependent on both the capital cost of natural gas plant infrastructure and on the variable fuel cost for running those plants. To investigate the effect of higher natural gas prices on the infrastructure deployment and unit-commitment in the WECC power system, I investigate a *High-Price Natural Gas* scenario in which natural gas prices is doubled relative the EIA AEO 2012 Base Case projections for a given consumption level.

Flexible Load Scenario

The availability of flexible loads may make it possible to increase the penetration level of intermittent renewables while potentially also reducing system costs by aiding in load balancing and allowing for more inexpensive – but temporally constrained – resources to be used. To

explore how flexible loads can contribute to increased utilization of intermittent renewables and lower system costs, load response availability estimates by end-use for the commercial and residential sectors were obtained through collaboration with Dr. Max Wei from the Lawrence Berkeley National Laboratory (LBNL).

This potential is included in the *Load-Shifting* scenario and allows SWITCH to shift load within each day, thus providing flexibility to the power system. The ability to shift load is excluded in other scenarios, as little information currently exists about the true shiftable load potential and the costs. In the *Reference* scenario, therefore, shiftable load is not included to provide an upper bound on system costs. In the *Load-Shifting* scenario, demand response is a zero-cost resource that can be used by the optimization to help integrate renewables. The difference in costs between the *Reference* scenario and the *Load-Shifting* scenario can therefore be interpreted as the value of shiftable load resource.

Results

Summary of System Development, 2020-2050

The development of the WECC power system through 2030 varies little across scenarios before diverging widely in later investment periods. The 2020 *Reference* scenario system is similar to the present day power system (Figure 3). Generation in California is dominated by natural gas and complemented by some wind and solar deployment as well as existing hydropower and the Diablo Canyon nuclear plant. The rest of the Southwest also relies on natural gas as well as deployment of solar PV. The Pacific Northwest is reliant on hydropower and exports some hydro energy to California. Existing coal plants, located largely in the eastern part of the WECC, are a major energy source in those areas, complemented by deployment of wind power in the Rockies, and some of this energy is transmitted southward and westward.

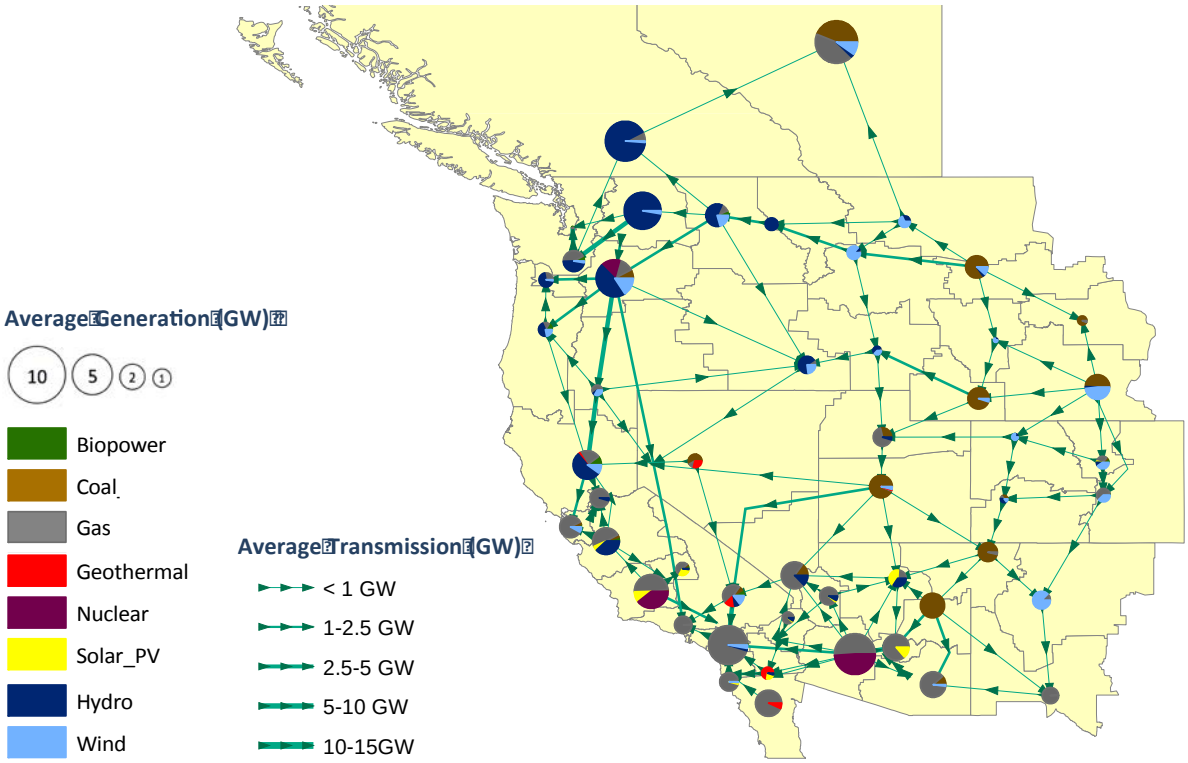


Figure 3. Map of average hourly generation and transmission, Reference *scenario, 2020.*

By 2030, changes take place in the *Reference* system, with almost all coal replaced by natural gas plants as well as further expansion in renewable deployment: solar PV in California and Arizona, wind in the Pacific Northwest and the eastern part of the WECC (Figure 4). Natural gas use also increases in California and hydropower continues to provide a large fraction of energy

in the Pacific Northwest, but transmission lines to California are used less than in 2020. Wind power is deployed in the eastern part of the WECC and shipped to the load centers in the Southwest.

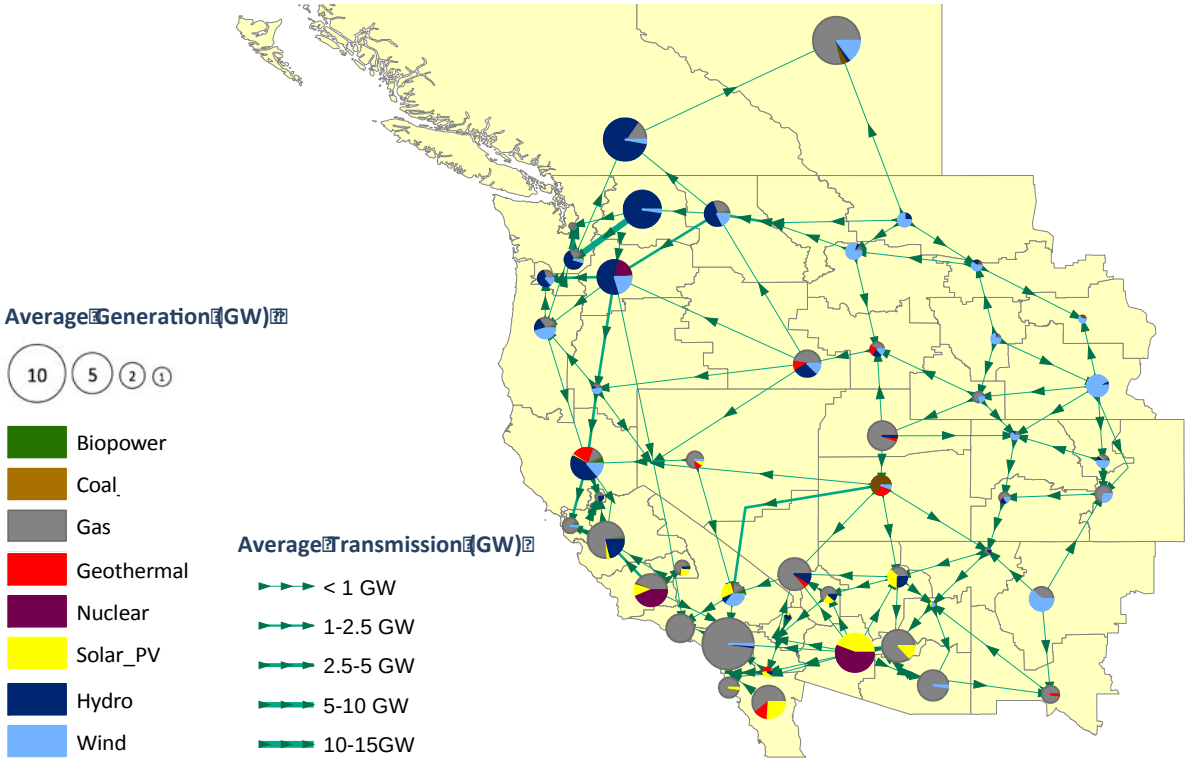


Figure 4. Map of average hourly generation and transmission, Reference *scenario, 2030.*

By 2040, considerably more renewables are deployed in the *Reference scenario*. Wind has the most significant share and is installed across the WECC, with the largest capacities in the eastern WECC, Alberta, and California (Figure 5). Solar PV and CSP with TES are installed in the Desert Southwest. Geothermal potential is tapped out in this timeframe. By 2040, transmission flows change considerably from present-day patterns. The largest flows are from east to west, with wind energy in the east being sent to the coastal load centers. Hydropower imports to California via the Pacific DC intertie are minimal.

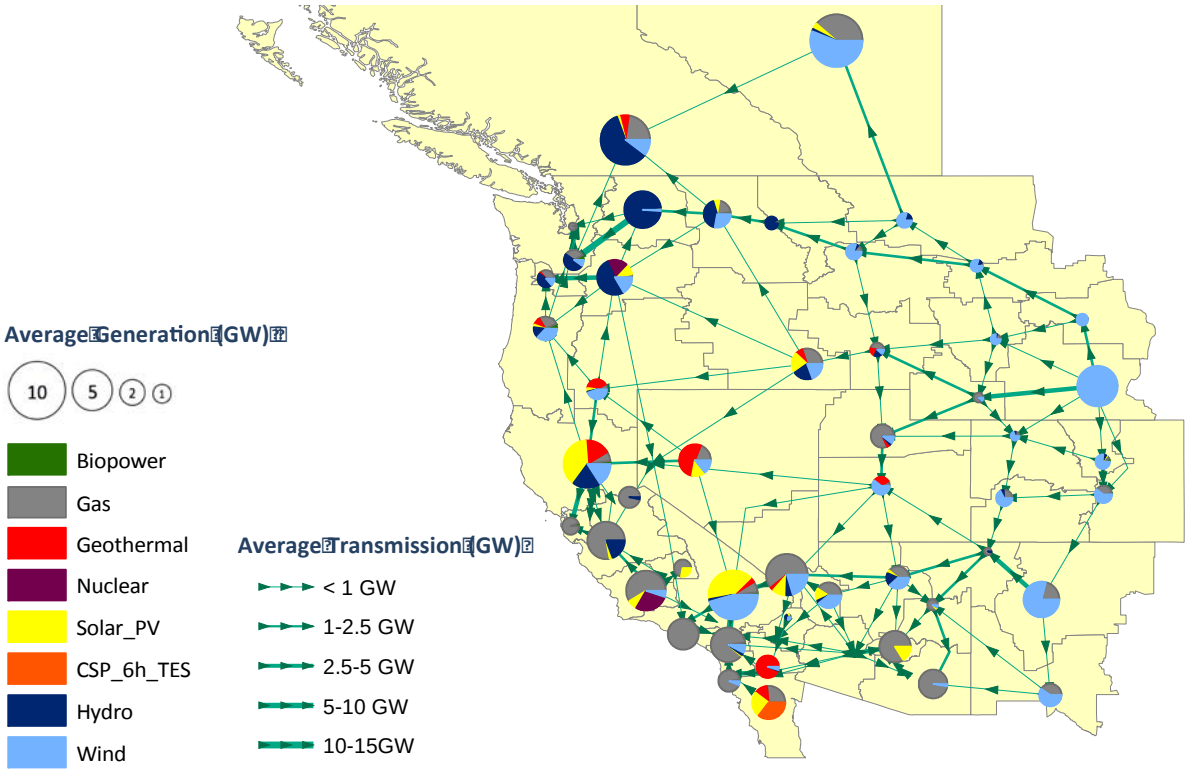


Figure 5. Map of average generation and transmission, Reference *scenario, 2040.*

These trends are continued and amplified in the 2050 timeframe (Figure 6). Large-scale flows of wind energy from east to west are a dominant feature of the *Reference* scenario. By 2050, the system is very reliant on CSP with TES deployed in the Southwest. The Pacific Northwest generates a mix of hydro, wind, and solar energy. Gas plants are a large component of local generation in California and Arizona as well as in Canada.

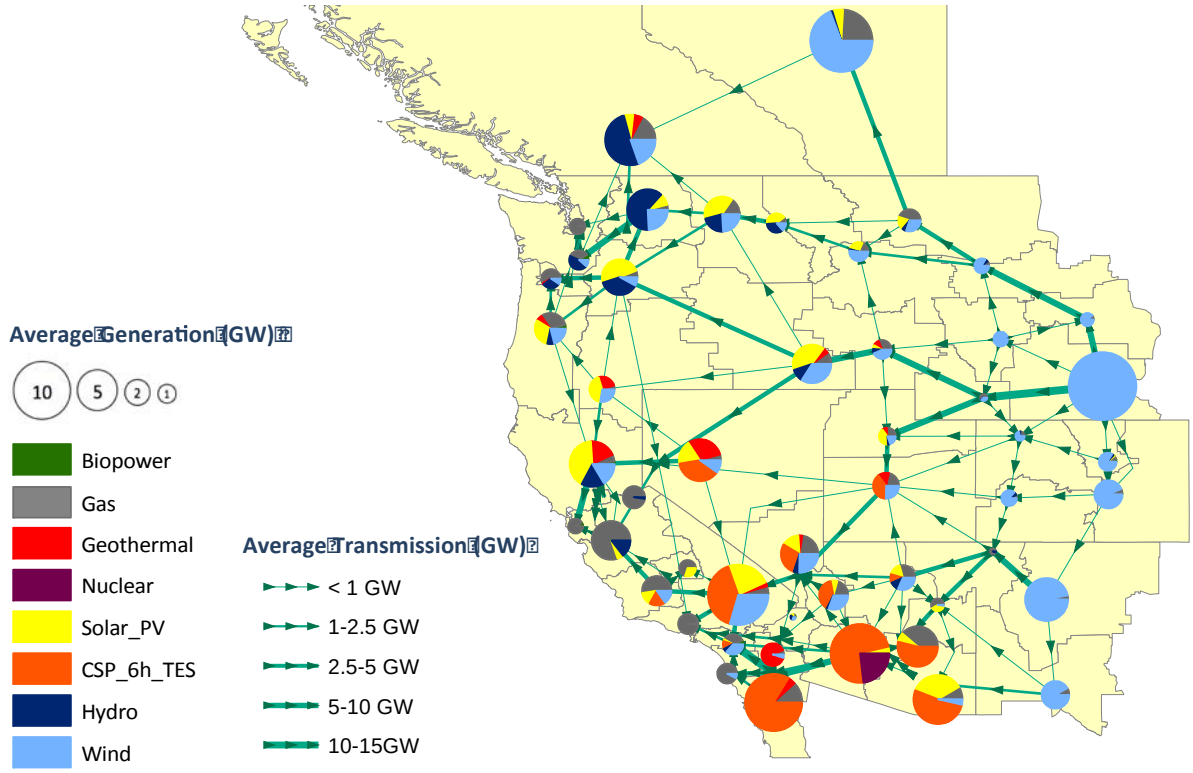


Figure 6. Map of average generation and transmission, Reference *scenario, 2050.*

Electricity Production and Generation Capacity, 2020-2050

Figure 7 shows the WECC electricity production mix in 2020 across the modeled scenarios. Coal, gas, and hydro generation dominate these systems. Among renewable technologies, wind is the largest energy contributor, providing around 10 percent of all electricity production in most scenarios. The effect of the parameters varied across scenarios tends to be small in this timeframe. The largest changes relative to the *Reference* scenario occur if solar technologies become inexpensive in the *SunShot* scenario or if the price natural gas fuel is higher in the *High-Price Natural Gas* scenario.

If SunShot solar costs are reached by 2020, solar deployment displaces most wind, providing 8 percent of generated electricity in this timeframe, but the rest of the electricity mix stays similar. Inexpensive solar also displaces some gas generation whose share goes from 33 percent in the *Reference* scenario to 30 percent in the *SunShot and Low-Cost Batteries* scenario. In the 2020 timeframe, the fraction of electricity generated from natural gas is not very sensitive to the parameters varied across the scenarios presented here. Even if the price of natural gas is doubled in the *High-Price Natural Gas* case, gas generation provides 26 percent of WECC electricity in 2020.

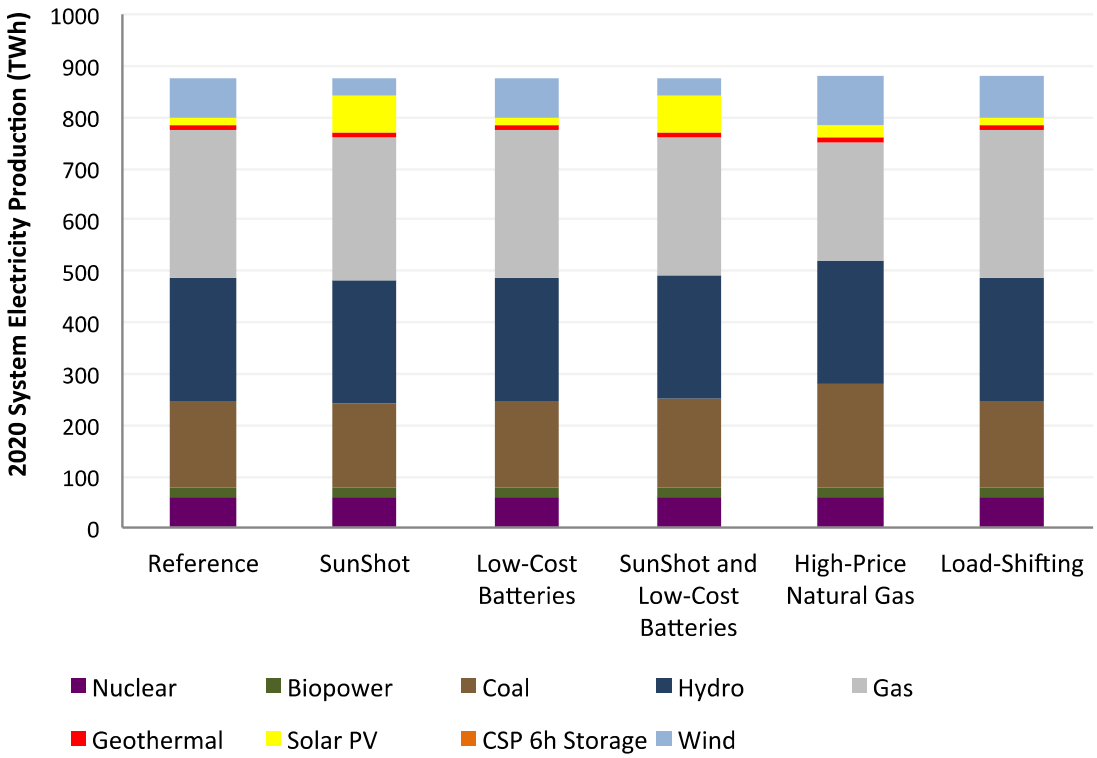


Figure 7. WECC system energy mix in 2020 by scenario.

Figure 8 shows system capacity in 2020 across scenarios. No new storage is deployed in any of the scenarios in this timeframe. The combined output of wind and solar PV generation is between 10 and 14 percent of all electricity generation in the scenarios studied in 2020. In the systems created by SWITCH, little need for storage exists as flexible natural gas and hydro generation are deployed widely and can compensate for these levels of wind and solar generation.

It is important to note that the results presented here do not consider storage devices that are designed for shorter durations and applications mostly in the regulation and other ancillary service markets. Frequency regulation has been shown to provide the most value for storage devices capable of responding quickly to frequency signals ("Cost-Effectiveness of Energy Storage: Application of the EPRI Energy Storage Valuation Tool to Inform the California Public Utilities Commission Proceeding R. 10-12-007" 2013). Rather, only storage with duration of several hours is modeled that can shift energy in bulk and provide energy arbitrage over the course of the day, moving energy from times of load net demand and low prices to peak net load hours when prices are high.

Three factors prevent storage deployment in the near term: 1) the cost of storage, which remains high, 2) the losses associated with storing energy, necessitating higher total electricity production, and 3) the availability of other low-cost sources of flexibility such as existing

hydropower and low-cost natural gas generation. Little bulk energy storage can be deployed cost-effectively for energy arbitrage in the 2020 timeframe. This conclusion may change if the amount of flexibility from hydropower and/or natural gas is reduced, but holds true across the scenarios presented here including the *High-Price Natural Gas* scenario, which has lower levels of natural gas use (26 percent of energy as opposed to 33 percent in the *Reference* scenario).

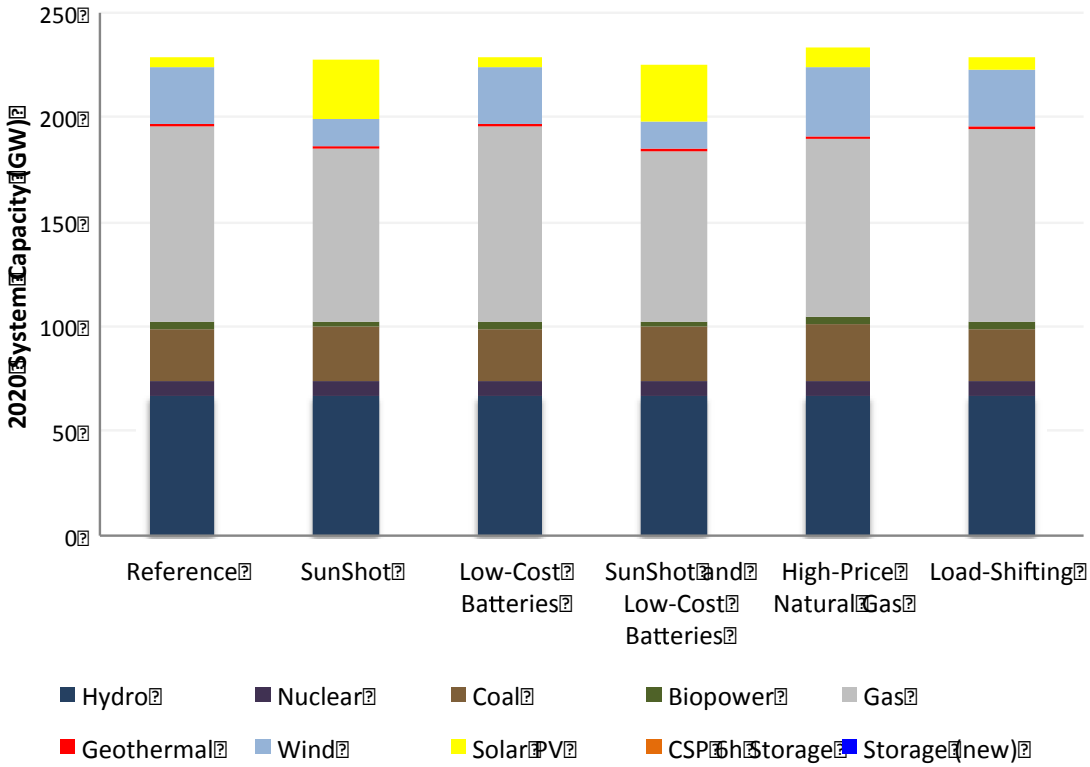


Figure 8. WECC system capacity in 2020 by scenario.

By 2030, natural gas replaces most coal in the fuel mix across scenarios (Figure 9) and coal capacity is largely retired (Figure 10). If natural gas prices remain as projected, natural gas would likely be a dominant source of electricity in the 2030 timeframe. If the price of natural gas is doubled as in the *High-Price Natural Gas* scenario, the optimization finds it more cost effective to increase the build-out of wind and geothermal energy capacity, reducing the share of natural gas to 30 percent of electricity production.

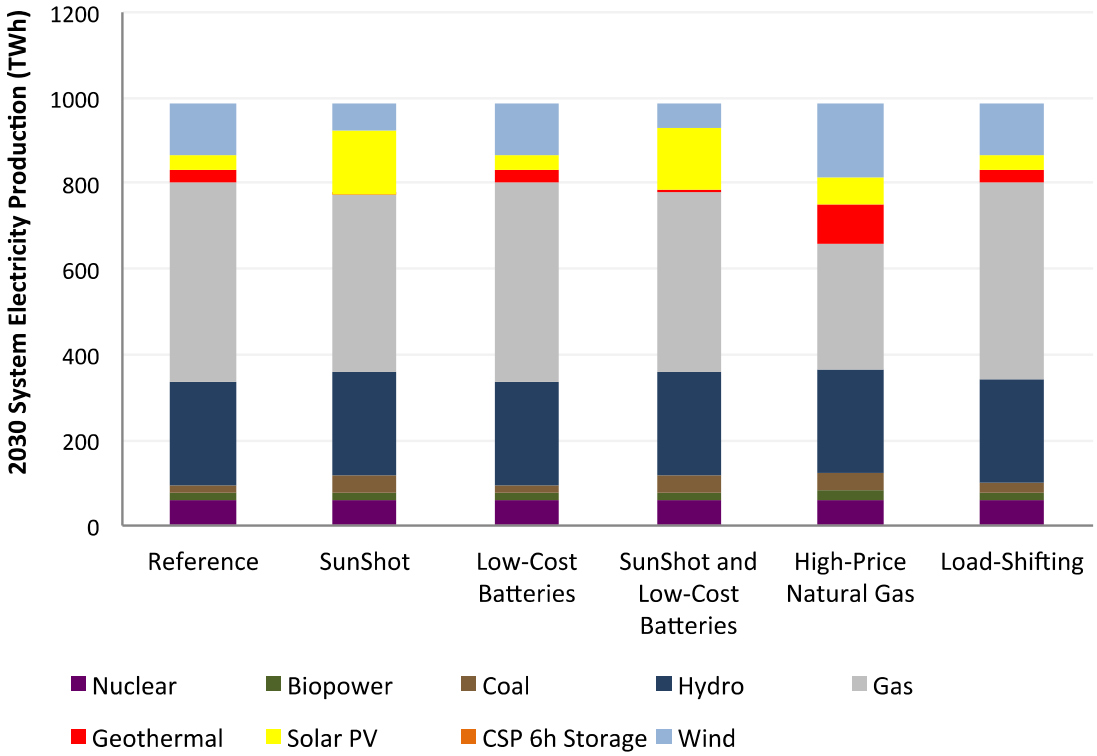


Figure 9. WECC system energy mix in 2030 by scenario.

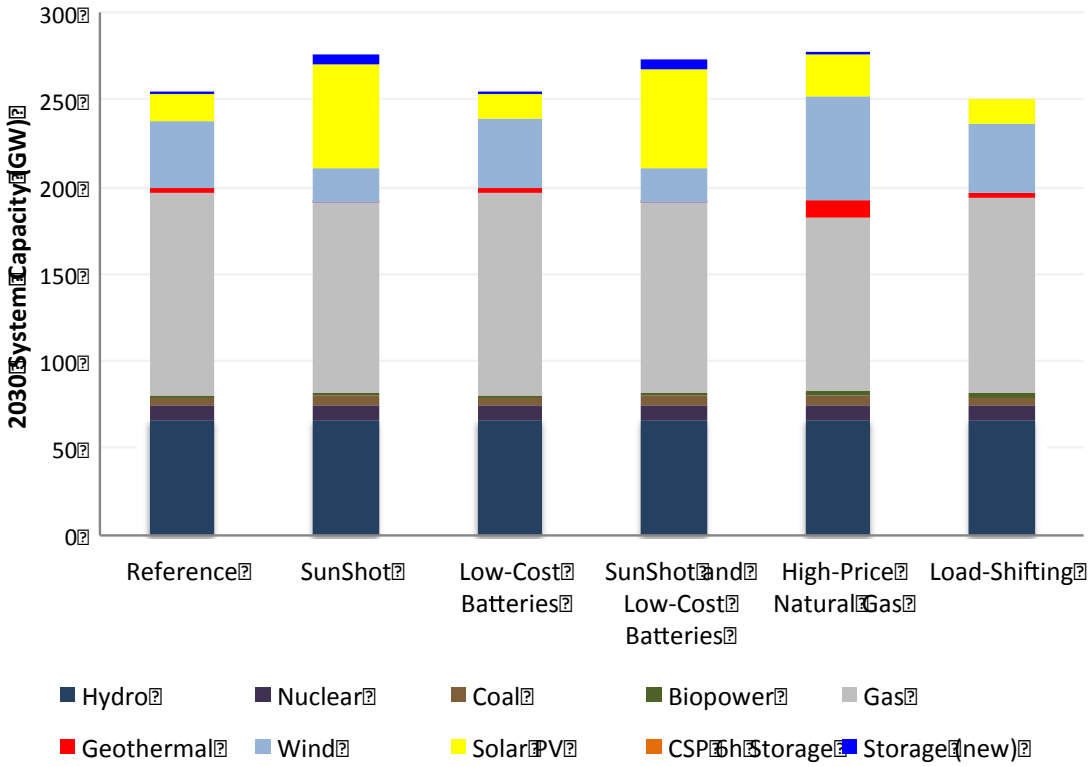


Figure 10. WECC system capacity in 2030 by scenario.

In the 2030 timeframe, deployment of new storage begins to take place in most of the scenarios investigated here, almost doubling current storage power capacity in some cases (Figure 11). The total amount installed varies across assumptions about the rest of the system.

In the *Reference* scenario, about 700 MW of CAES with 7-8 hours of full-load duration are installed. The availability of cheaper batteries in the *Low-Cost Batteries* scenario does not result in their deployment at a large-scale in this timeframe, with 240 GW of battery capacity installed in the *Low-Cost Batteries* scenario in 2030. This battery capacity replaces CAES capacity relative to the *Reference* case, but total storage capacity is approximately the same between the two scenarios, suggesting that the system has sufficient flexibility available at a cost lower than what the storage technologies can provide.

The most storage in 2030 is installed in the *SunShot* scenario: 5 GW of compressed air energy storage with 8-hour duration are deployed largely in Arizona where large solar installations are built in this timeframe. As with default solar costs, the availability of low-cost batteries in addition to SunShot solar costs does not result in deployment of additional storage, but simply in the substitution of batteries for CAES (less than half a GW of batteries with ~5-hour duration), suggesting CAES – with costs as modeled here – has better economics in the 2030 timeframe. Unlike batteries, CAES does produce emissions; however, batteries are modeled as

less efficient than CAES, so require additional energy generation, and CAES also benefits from the low price of natural gas in this timeframe.

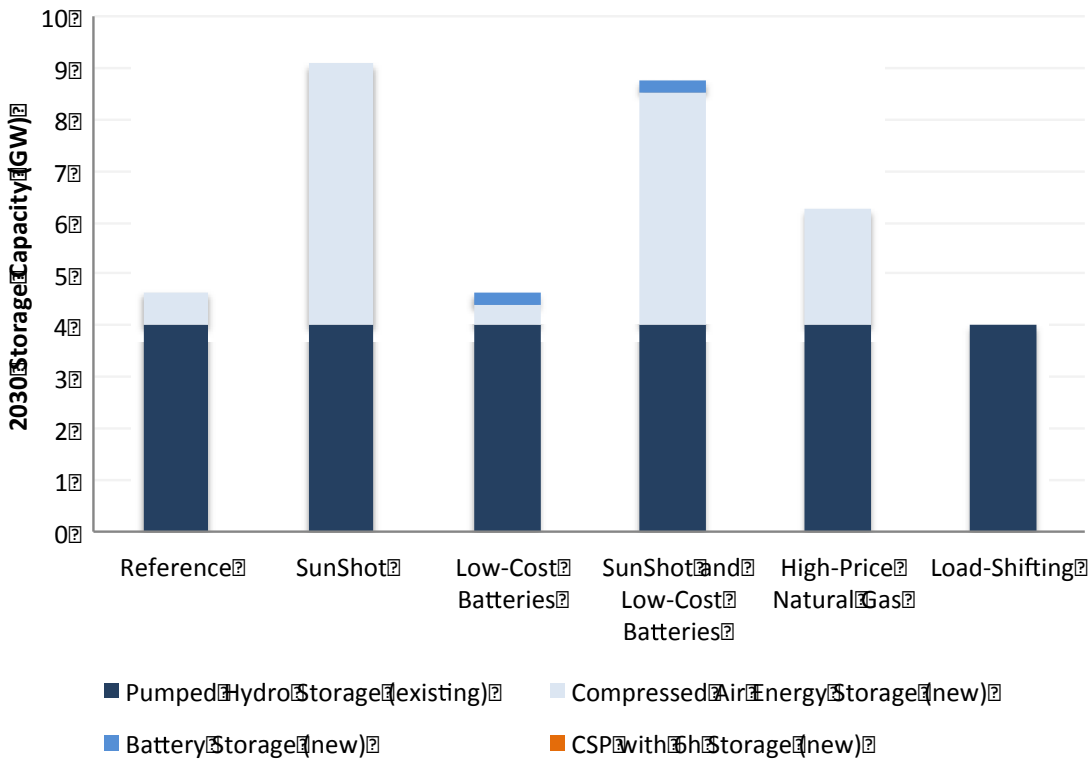


Figure 11. Storage power capacity in the WECC in 2030 by scenario.

As the carbon cap becomes more and more stringent over time after 2030, the amount of natural gas that can remain in the system becomes limited. Across scenarios, natural gas provides between 300 and 330 TWh yearly in the 2040 timeframe, equivalent to about a quarter of total electricity production in most scenarios (Figure 12). CSP with TES appears in the system for the first time in 2040, but PV is still the most widely deployed solar technology across scenarios in this timeframe. The largest PV deployment takes place under the assumptions of the *SunShot and Low-Cost Batteries* scenario, in which solar PV deployment reaches 120 GW by 2040. Carbon-free, baseload geothermal energy is deployed across scenarios, tapping out the available potential by 2040 in all by the two *SunShot* scenarios.

New storage capacity in the 2040 timeframe varies between 5 GW in the *Load-Shifting* scenario and 32 GW in the *SunShot and Low-Cost Batteries* scenario. In the latter, storage capacity is almost 10 percent of total system capacity in 2040.

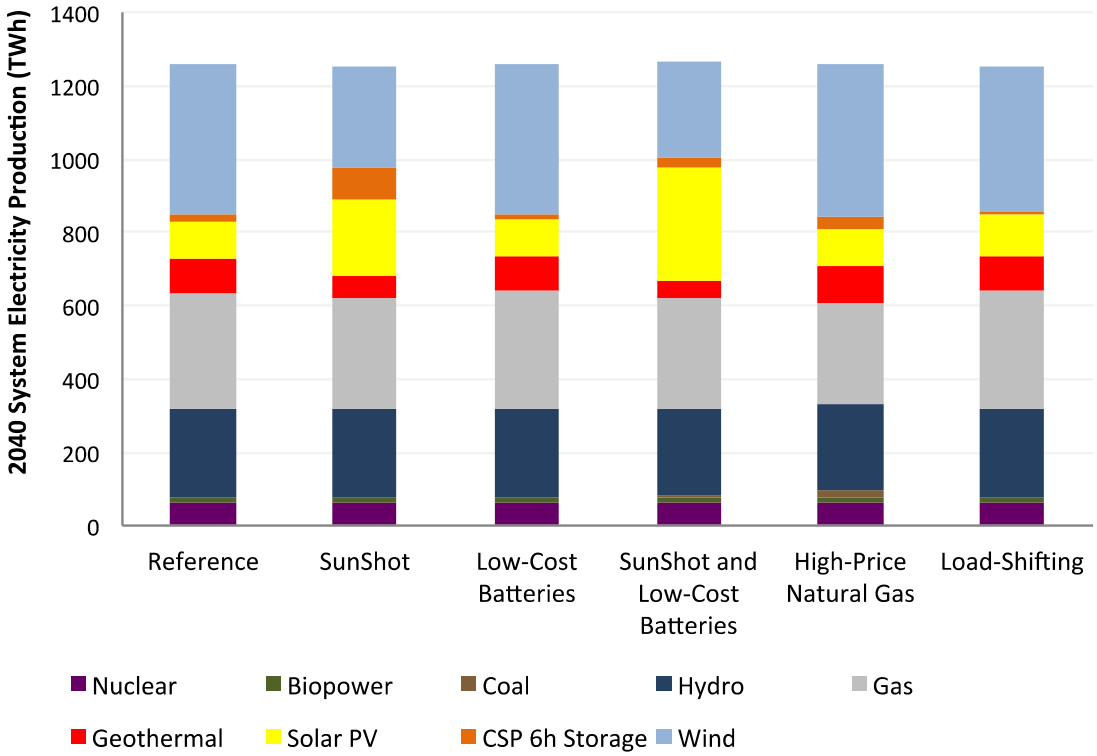


Figure 12. WECC system energy mix in 2040 by scenario.

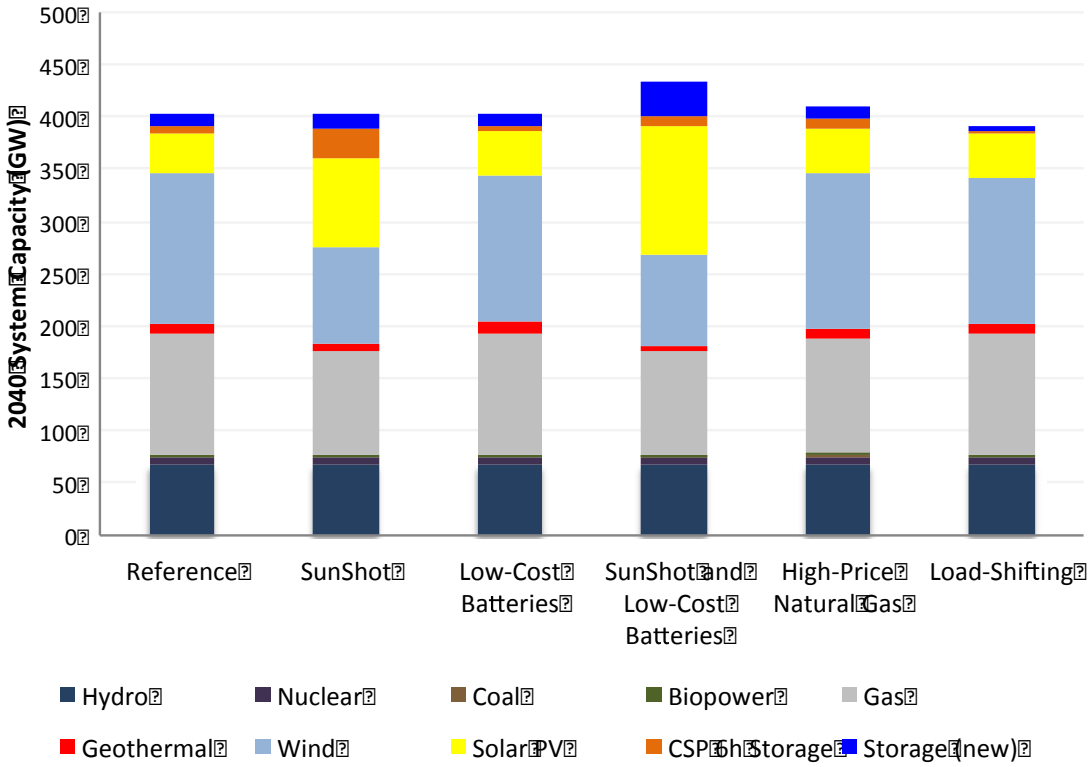


Figure 13. WECC system capacity in 2040 by scenario.

Several of input parameters varied here that make a difference for the system energy and capacity mix in the 2030 timeframe do not have the same effect in the 2050 timeframe within the range of values tested in the scenarios investigated. For example, doubling the price of natural gas price limits the amount of natural gas generation in the system in 2030, but does not make a difference for the composition of the system in 2050 (the system cost does increase). In the long term, it is the cap on carbon emissions that becomes the determining factor for the amount of natural gas that the system can utilize. Under a strict carbon constraint, natural gas is very valuable to the system as it provides flexible generation that can both be ramped quickly and be available at all times of the year as needed. As a result, doubling the price of natural gas in the *High-Price Natural Gas* scenario does not effect changes in the generation mix.

CSP with TES, which first appears in the generation mix in 2040, is deployed widely by 2050 across scenarios. It outcompetes PV in the *Reference* scenario, even though it is more expensive on a levelized cost basis. This suggests that its dispatchability relative to PV is valuable to the power system. If instead low-cost batteries are available to provide flexibility, as in the *Low-Cost Batteries* scenario, PV becomes the dominant technology. In the *Reference* case, 120 GW of CSP-TES and 70 GW of solar PV are deployed, and 20 GW of new storage are also installed; in the *Low-Cost Batteries* scenario 170 GW of solar PV and 80 GW of CSP with storage are

deployed as well as 80 GW of new storage installations. Similarly, if low-cost flexibility is available in the form of demand response and flexible charging of electric vehicles, the ratio of solar PV to CSP-TES capacity deployment increases. The availability of SunShot solar technologies increases both the capacity of PV and of CSP-TES relative to the *Reference* scenario.

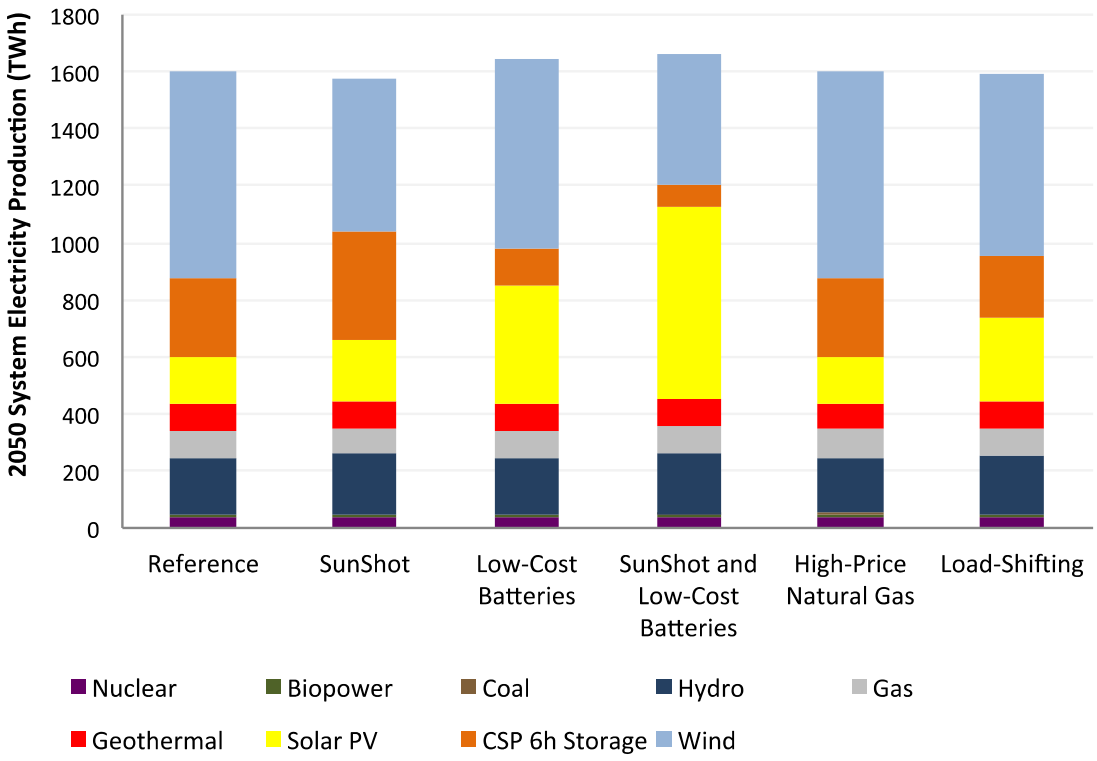


Figure 14. WECC system energy mix in 2050 by scenario.

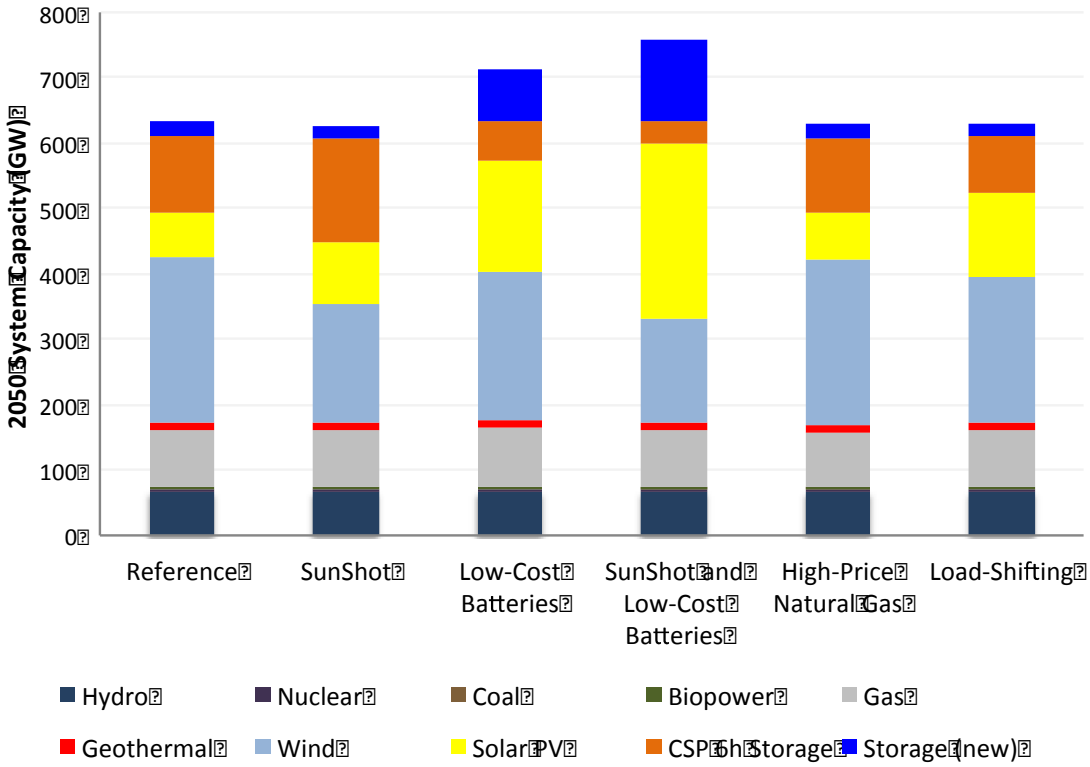


Figure 15. WECC system capacity in 2050 by scenario.

Storage deployment reaches power capacities in the multi-GW scale in most scenarios by 2040 and by 2050 storage plays a pivotal role in the WECC power system across the scenarios explored here (Figure 16). However, assumptions about technological costs and availability greatly affect which storage technology is deployed and at what scale in the long-term.

Having first appeared in the storage mix in 2040 in the *Reference* scenario, thermal energy storage deployed at CSP plants is the dominant storage technology in 2050. Note that TES is different from other storage technologies modeled here in that it does not store electricity from the grid; rather, it stores thermal energy collected by the CSP plant for later conversion into electricity. In the *Reference* scenario, 120 GW of CSP with 6 hours of storage are installed. In addition, 14 GW of compressed air energy storage with an average of 10 hours maximum-load duration and 6 GW of batteries with an average of 2 hours of maximum-load duration are deployed.

Unlike in the 2030 timeframe when the cost of batteries does not strongly affect their deployment level, the availability of low-cost batteries in the very-low-carbon 2050 system results in their installation at a large scale. In the *Low-Cost Batteries* scenario, 70 GW of batteries are deployed, with an average duration of 6 hours. The largest battery deployment occurs in the *SunShot and Low-Cost Batteries* scenario, in which 110 GW of batteries with 6-

hour duration are installed, largely in the Desert Southwest (Figure 17) where they support large-scale solar PV development.

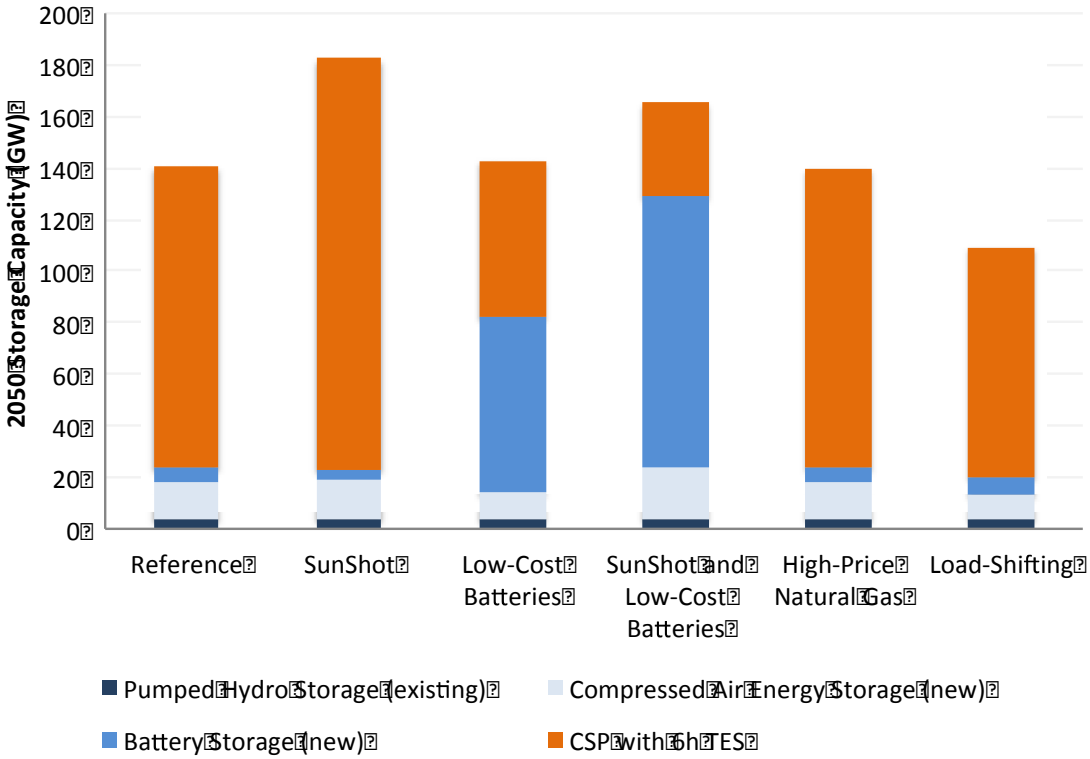


Figure 16. Storage deployment in the WECC in 2050 by scenario.

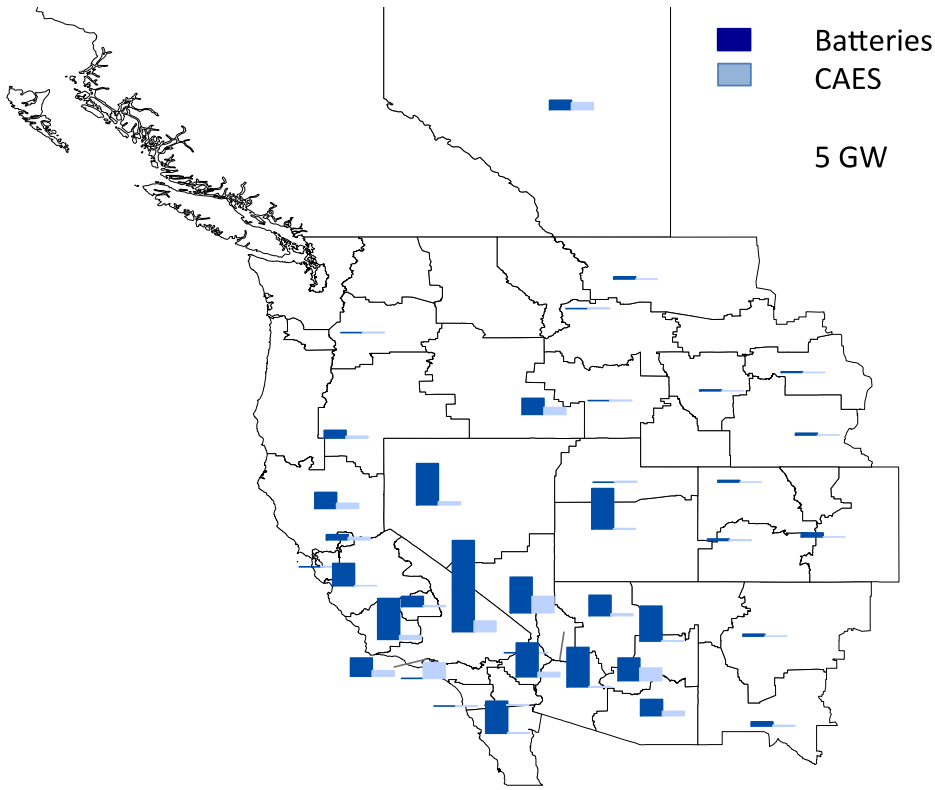


Figure 17. Map of storage deployment in the WECC, SunShot and Low-Cost Batteries Scenario*, 2050.*

System Unit-Commitment

The 2030 Timeframe

To understand the reasons for the differing levels of storage deployment across scenarios, I explore the system unit-commitment to understand how storage is used in each case. The infrastructure decisions of the main SWITCH investment optimization are fixed and the system is then optimally committed over a full year of time-synchronized load and renewable output data. Each day of the year is optimized on its own. All unit-commitment figures shown here are based on results from the secondary unit-commitment check phase following the SWITCH investment optimization.

Reference Scenario

In the *Reference* scenario in 2020, coal provides 19 percent of WECC electricity and a third is supplied by gas generation. Existing pumped hydro storage is used regularly, especially in the summer months, to shift energy from the nighttime to the daytime peak (Figure 18). Most coal

generation is replaced by gas by 2030 and an expansion in wind and solar capacity helps to meet the rise in demand.

By 2030, gas dominates the WECC electricity mix, providing 47 percent of electricity while wind and solar PV contribute 12 percent and 4 percent respectively. About 700 MW of CAES are installed in the *Reference* scenario, considerably less than in several other scenarios explored here. Storage in the 2030 *Reference* scenario system is used less in 2030 than in 2020 during the spring months and in parts of the summer (Figure 19 and Figure 20). Of note is in particular that storage is inactive during the peak load times in July, even though peaker gas combustion turbines are used extensively in the second half of the month.

On the median day in July, storage is used according to a pattern of nighttime charging when net load is low and CCGTs are the marginal generator, and releasing energy in the afternoon and evening hours when load increases, solar is not available any more, and net load is at its peak for the day requiring the use of the high-marginal-cost combustion turbines (Figure 21, top panel).

This dispatch pattern is typical for much of the summer. However, in late July in this scenario, the pattern of storage use changes (Figure 21, bottom panel). On the peak net load day in July, which is also the overall peak net load day for 2030, combustion turbines are used throughout the day to help meet an increase in load. Nighttime load during this 10-day period in July remains high and wind dies down, resulting in a high net load during the night as well during the day. The system is stressed throughout the day and there is as scarcity of low-marginal-cost excess energy available for storage to shift to other times of the day. As a result, storage is inactive during this period. Combustion turbines are run throughout and are the marginal generator for many consecutive hours, so no price difference exists for storage to take advantage of and provide energy arbitrage. (All combustion turbines are modeled as having the same heat rate, so have the same marginal cost except for regional variation in natural gas prices due to different fuel extraction and transportation costs.) While combustion turbine could be run at night and the energy stored for use during the day, the inefficiency of the storage process means that a larger price difference than seen in this scenario is necessary for storage to be active. CAES round-trip efficiency is 82 percent, pumped hydro's is 74 percent, and batteries are at 75 percent in the *Reference* scenario, requiring the respective difference in energy price to justify storage use.

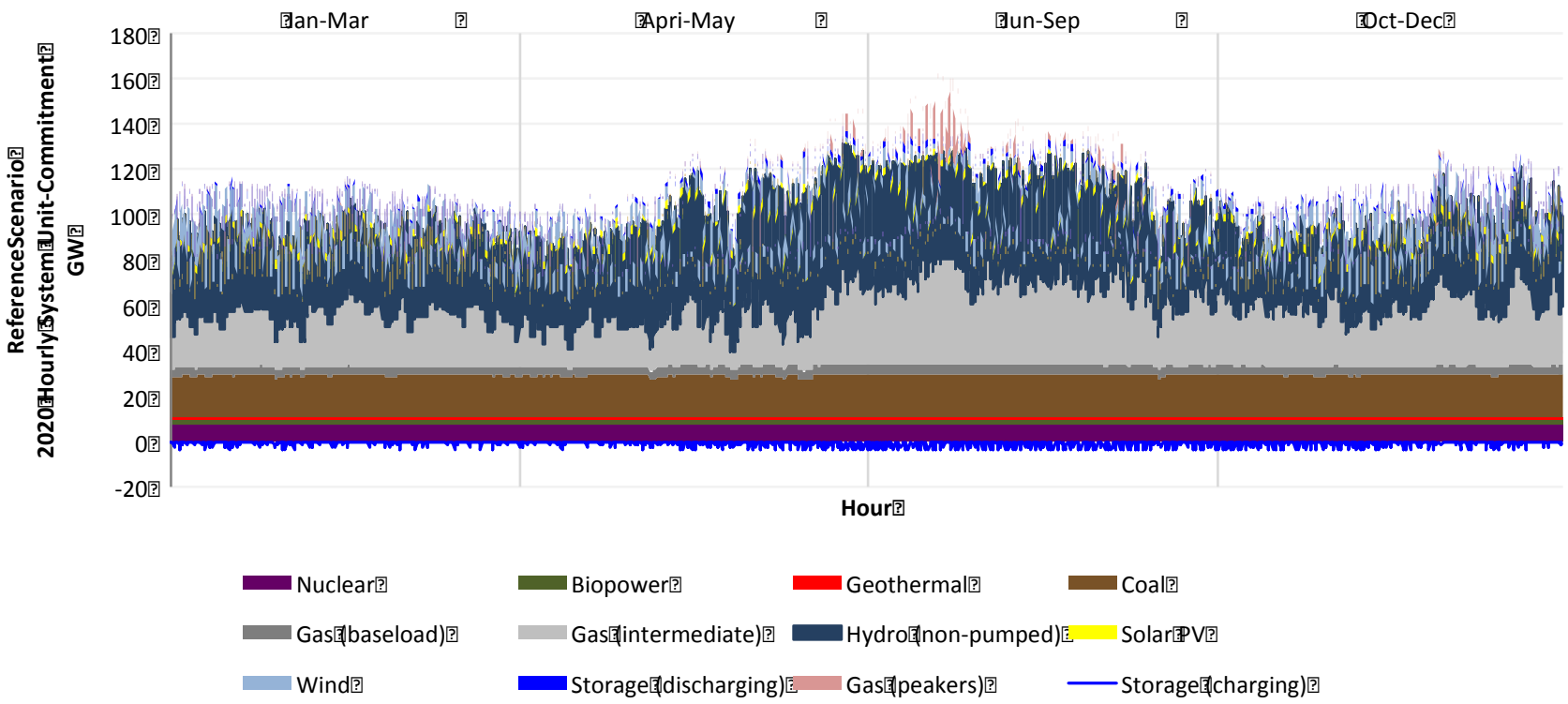


Figure 18. WECC System Hourly Unit-Commitment, Reference *Scenario, 2020.*

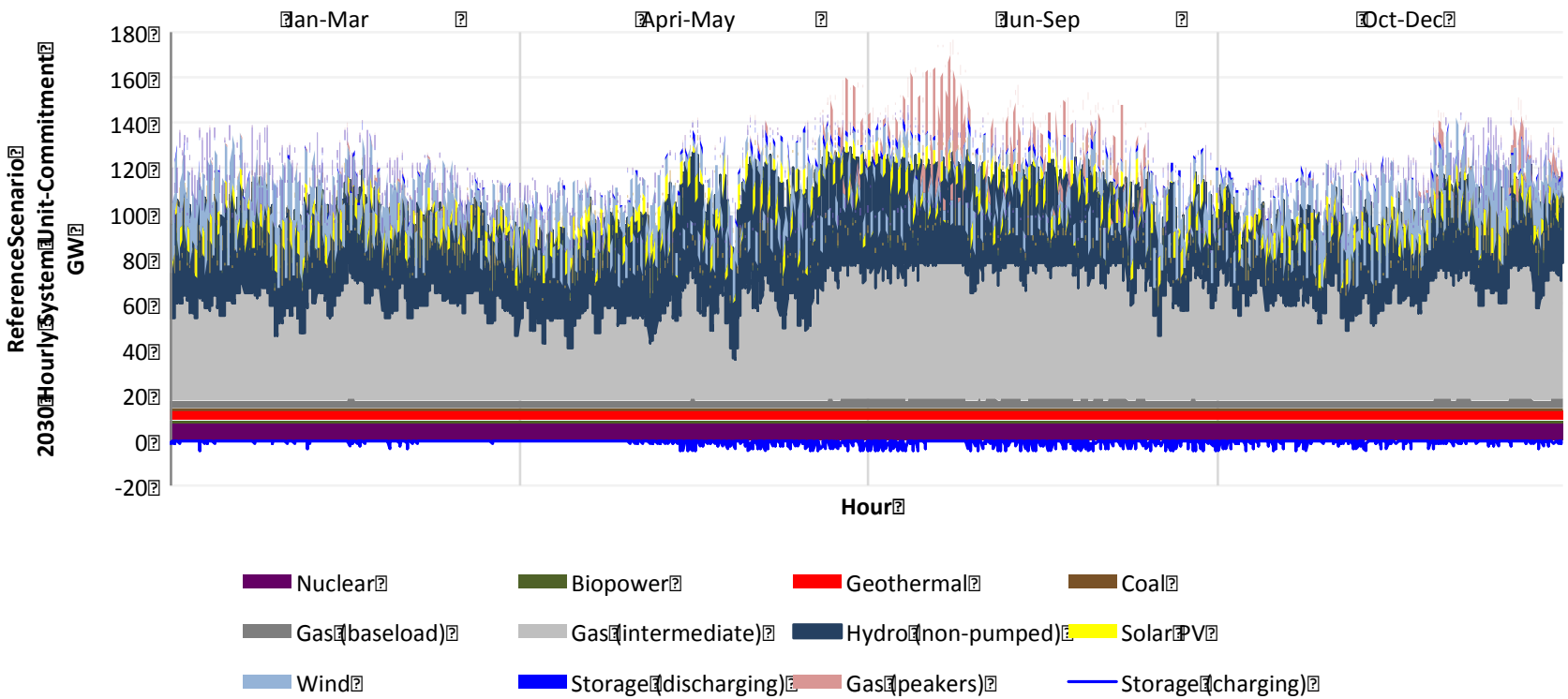


Figure 19. WECC System Hourly Unit-Commitment, Reference *Scenario, 2030.*

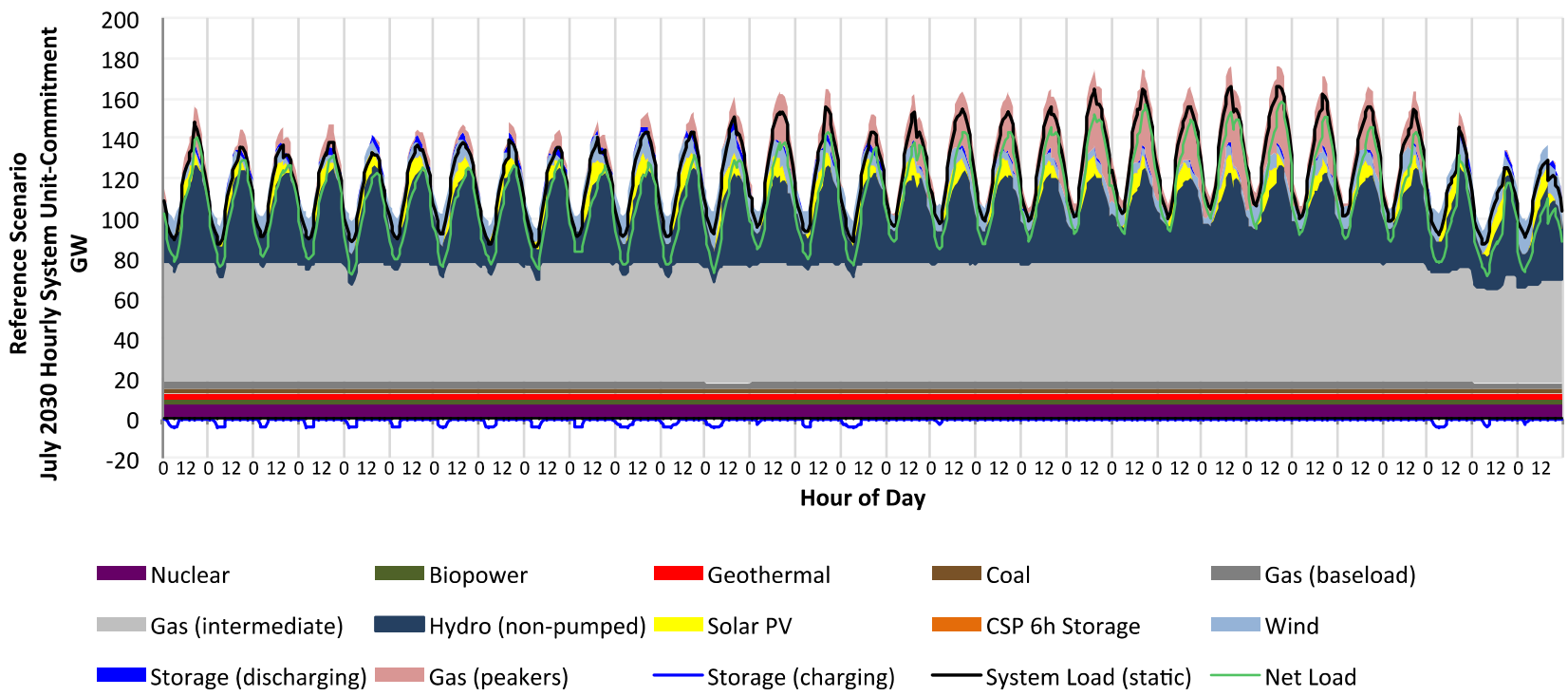


Figure 20. WECC System Hourly Unit-Commitment, Reference *Scenario, July 2030.*

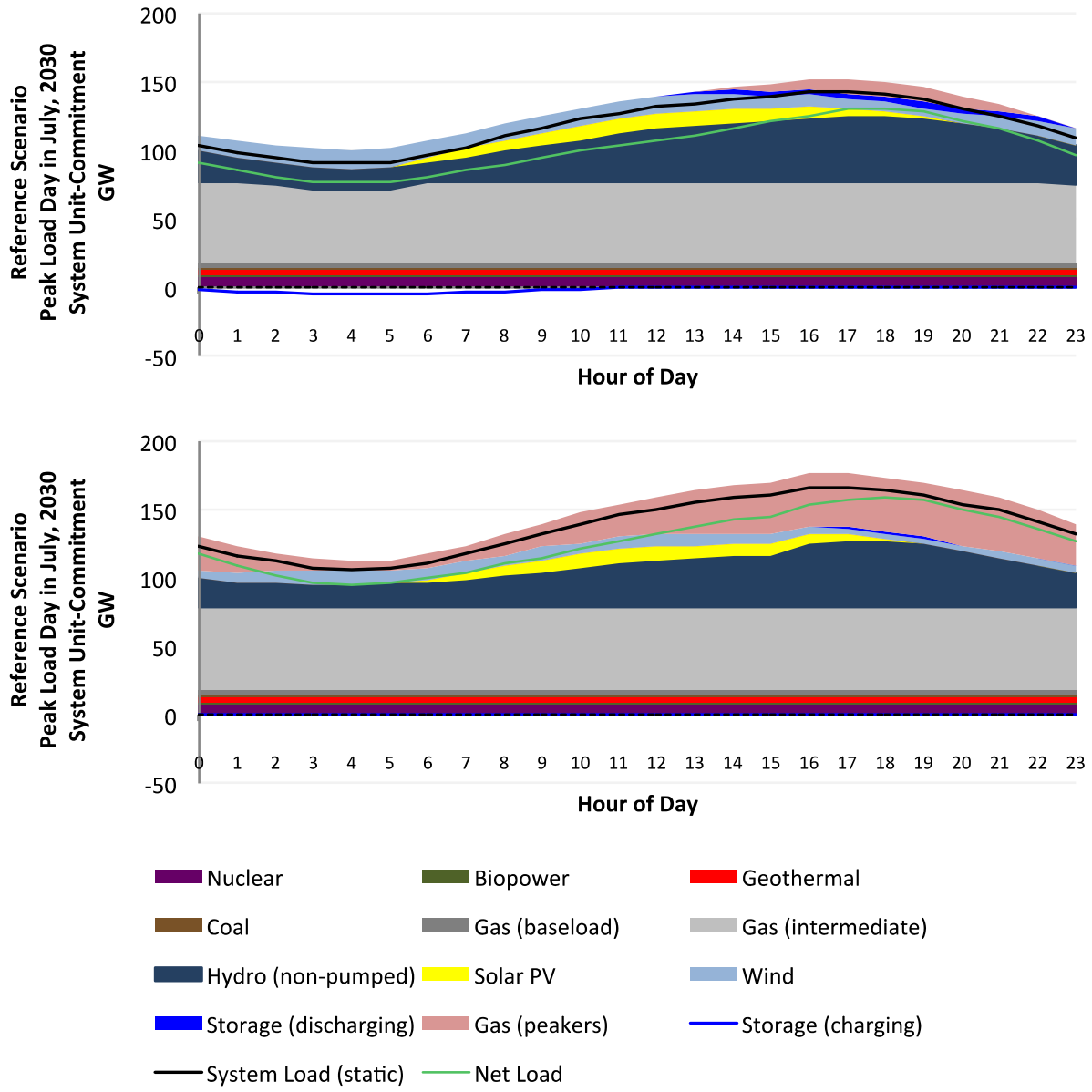


Figure 21. WECC system hourly unit-commitment on the median load day in July (top panel) and the peak net-load day (bottom panel) in 2030, Reference *Scenario*, 2030.

SunShot Scenario

The *SunShot* case has the most storage – about 5 GW of CAES with 8 hours duration – installed by 2030 of all scenarios investigated. In the *SunShot* scenario, large-scale deployment of solar PV takes place by 2030: 59 GW of solar PV are installed in that timeframe as opposed to 15 GW in the *Reference* case. The presence of this level of solar PV on the power system results in changes to the typical system unit commitment schedule because of changes to the net load profile.

Unlike in the *Reference* scenario, storage in the *SunShot* scenario in 2030 is used throughout the year (Figure 22). The pattern of storage use changes relative to the *Reference* scenario and to present day: instead of charging at night, storage tends to charge in the morning when the net load is at its daily minimum as solar PV is producing energy at full output and load level is low (CCGTs are the marginal generator); storage then releases energy in the evening hours and at night when the sun has gone down and solar energy is not available while load is still high, resulting in net load reaching its daily peak and necessitating the startup of combustion turbines with high marginal cost (Figure 23, top panel). Even during the times of highest stress in late July, this charging pattern for storage is in place, although less excess low-marginal-cost energy is available in the morning during that period for storage to shift to the high-price times in the evening (Figure 23, bottom panel).

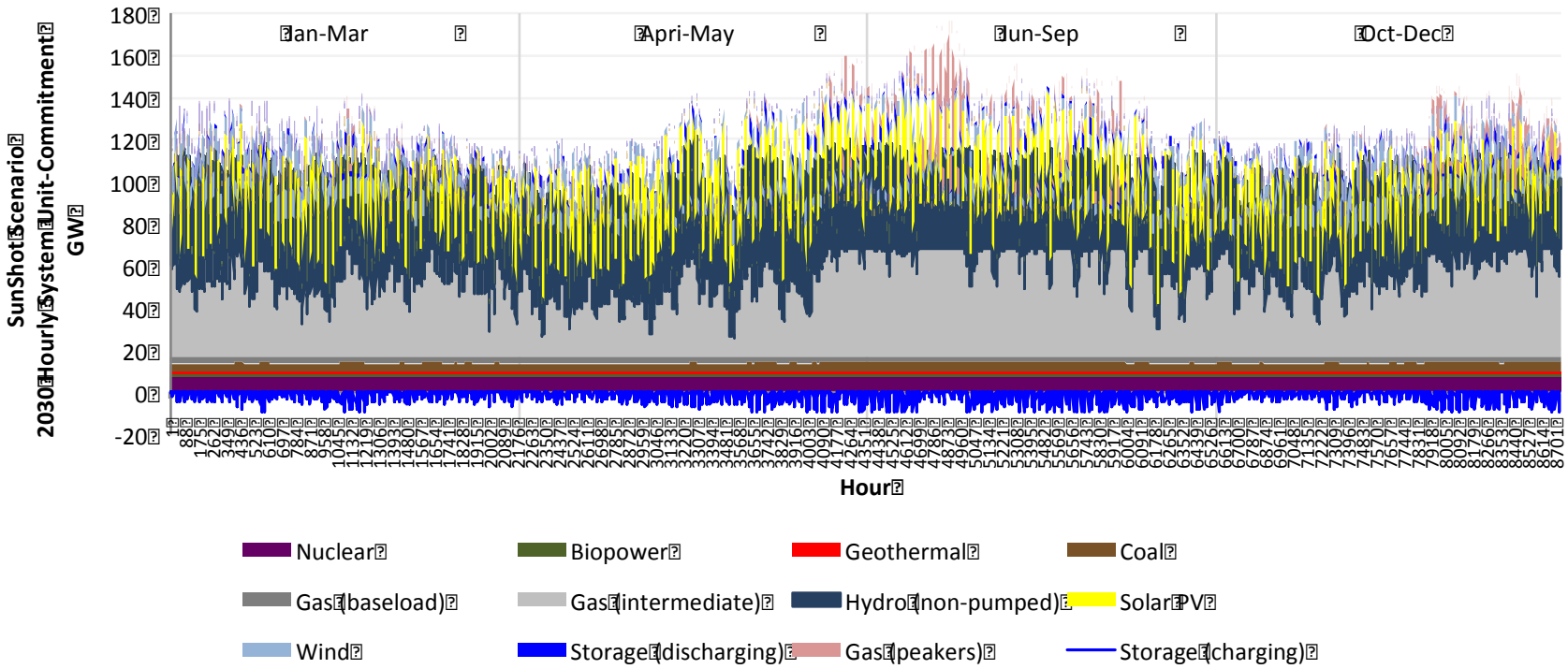
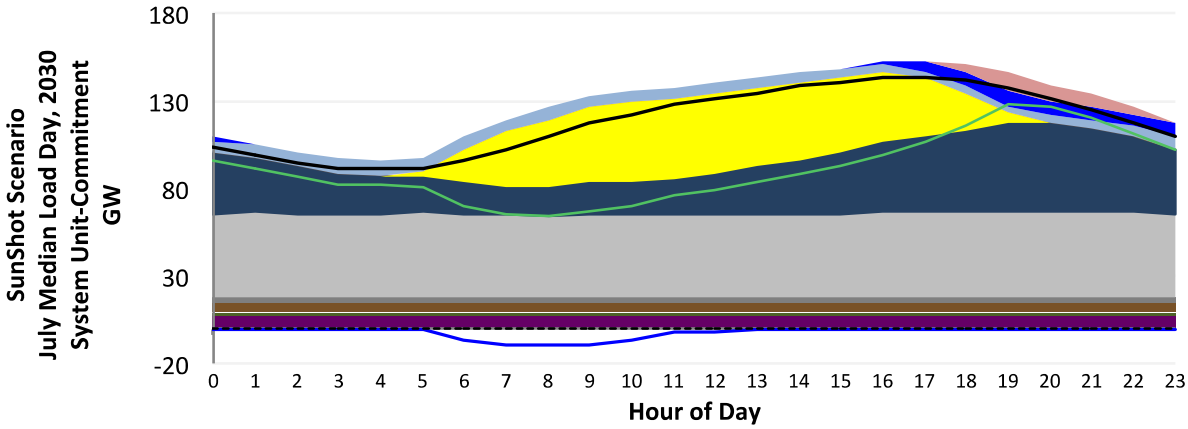
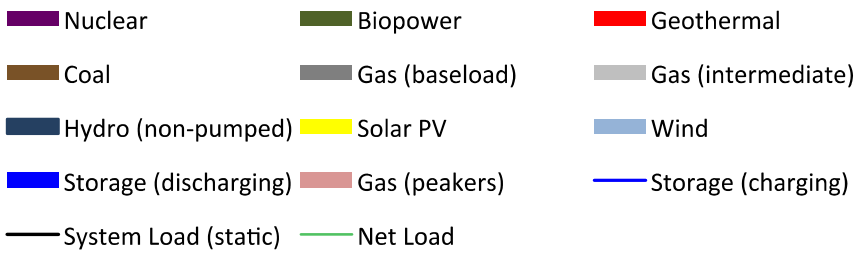


Figure 22. WECC System Hourly Unit-Commitment, SunShot *Scenario, 2030.*


SunShot Scenario
July Median Load Day, 2030
System Unit-Commitment
GW
180
130
80
30
-20
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour of Day


Nuclear
Biopower
Geothermal
Coal
Gas (baseload)
Gas (intermediate)
Hydro (non-pumped)
Solar PV
Wind
Storage (discharging)
Gas (peakers)
Storage (charging)
System Load (static)
Net Load

The 2050 Timeframe

Reference Scenario

Between 2030 and 2050, the unit commitment of the *Reference* scenario system experiences drastic changes relative to present day as a result of growth in total load, changes to the annual load profile due to efficiency implementation and electrification of heating and vehicles, and a stringent carbon cap that pushes carbon emissions from the system down to 85 percent below 1990 levels. In 2040, gas still provides 25 percent of total electricity production in the WECC in the *Reference* scenario, although it used much less outside of the summer months as load tends to be lower and wind more available during those times (Figure 24).

By 2050, the amount of gas in the system is reduced even more – to 6 percent of total electricity produced – as emissions allowances are very limited. As the system has to meet a more and more stringent carbon cap after 2030, considerable expansion in renewable capacity takes place accompanied by a build-out of 20 GW of storage by 2050. Wind dominates in this scenario, generating 45 percent of electricity in 2050, and CSP with 6h of storage and solar PV contribute 17 percent and 10 percent respectively. Geothermal generates an additional 6 percent, providing carbon-free, baseload electricity.

Large seasonal variations in how units are committed and load is met become a prominent feature of this system, with wind dominating electricity production in the winter and spring months while CSP with storage, intermediate gas generators, and gas peakers help to meet load in the summer. In January for example, the 2050 *Reference* system experiences consistently low net load levels, including frequent negative net load during the middle of the day when solar PV is at its peak (Figure 26). (The net load is calculated as the load minus intermittent generation, which includes wind and solar PV; CSP with storage is dispatchable within solar thermal energy availability constraints, so is not a part of the net load calculation.) CSP with storage provides energy at night and complements daytime PV generation, with their combined output staying relatively constraint throughout the month of January.

More than 250 GW of wind capacity are installed by 2050 in the *Reference* scenario, so a large amount of excess energy is consistently available in the winter and spring when wind output is high. SWITCH-WECC can only shift energy within the day, with each day optimized separately, and does not consider long-duration storage options such as large-reservoir pumped hydro storage or hydrogen storage. For many consecutive days, net load is low throughout the day with no high-stress times for the system, so storage is idle, as no opportunities to provide daily arbitrage exist. In the *Reference* scenario, 14 GW of CAES with an average of 10 hours of storage are installed as well as 6 GW of batteries with an average of less than 2 hours of storage, for a combined 152 GWh of total energy storage capacity. This amount is well below the total excess energy available during that period: the installed storage could charge cheaply on one of those days but would not have an opportunity to sell that energy back to the grid for

many days as excess wind energy is available for many consecutive days during the winter and spring months, requiring many GW-days of storage to be fully utilized at a later time.

The 2050 Reference system unit-commitment in July (Figure 27) looks very different from that in January. In the summer months in the *Reference* scenario, wind output is low. This is partly compensated for by the availability of a large solar thermal resource in the summer. CSP with storage provides flexibility to the system, charging at night and releasing energy in the evening and at night when solar PV is not available. Deployment of CSP with storage in 2050 in the *Reference* scenario is 120 GW and it supplies 17 percent of total electricity production.

Pumped hydro, CAES, and battery storage in the July 2050 *Reference* system are used infrequently, on a few days when wind output is relatively high, providing some excess energy to shift to other times of the day. However, for most of the month, the *Reference* system is energy-constrained throughout the day. For example, for ~2 weeks in the second half of July, load reaches its peak summer levels, remaining high even at night, and the system must run intermediate gas generation at full output for many consecutive days as well as make heavy use of peaker gas generation in order to meet demand. During this period, the storage deployed in the 2050 *Reference* system is not used because lower-cost energy is not available at any point for many consecutive days (combustion turbines are the marginal generator for many consecutive hours). If long-duration storage were available and inexpensive, it could potentially shift energy from other times of the year to this period of high stress for the grid and replace the gas generation used to meet load.

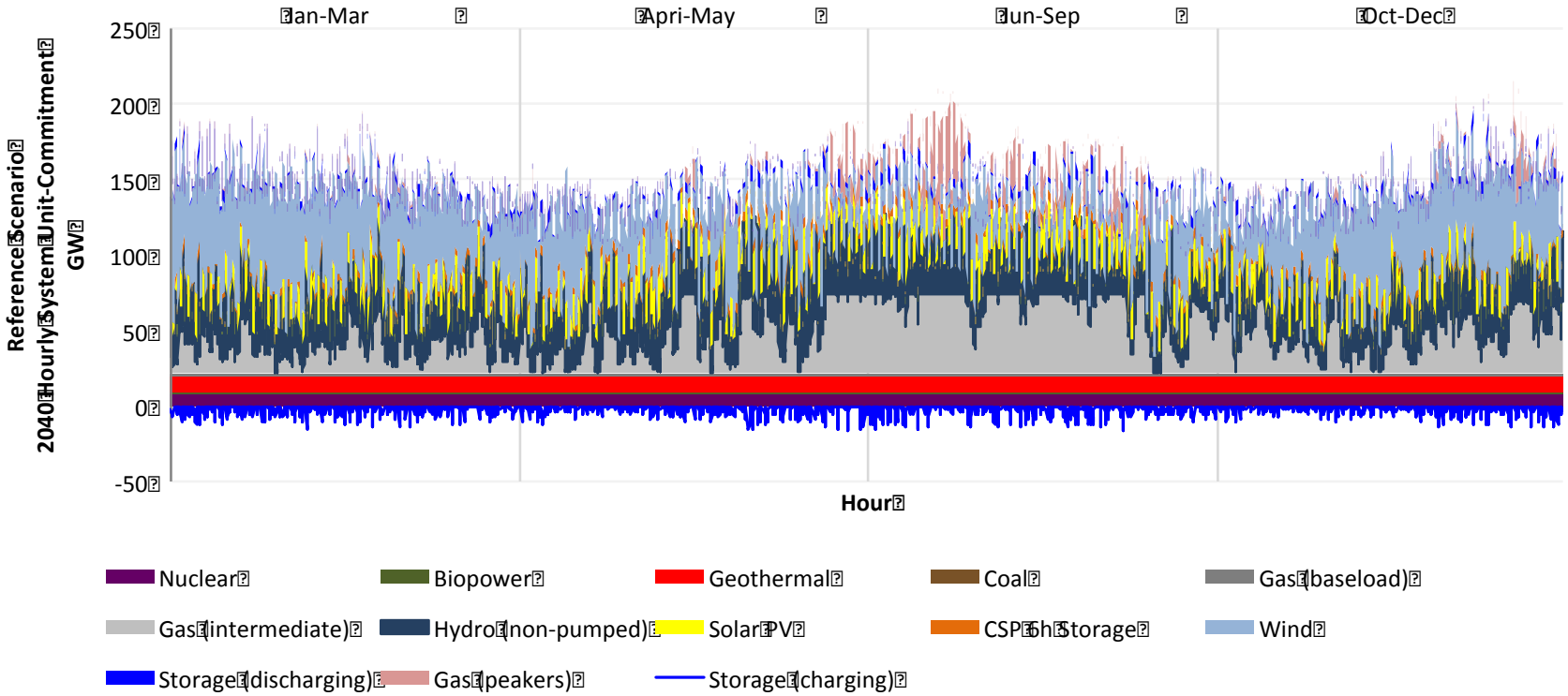


Figure 24. WECC System Hourly Unit-Commitment, 2040, Reference *Scenario.*

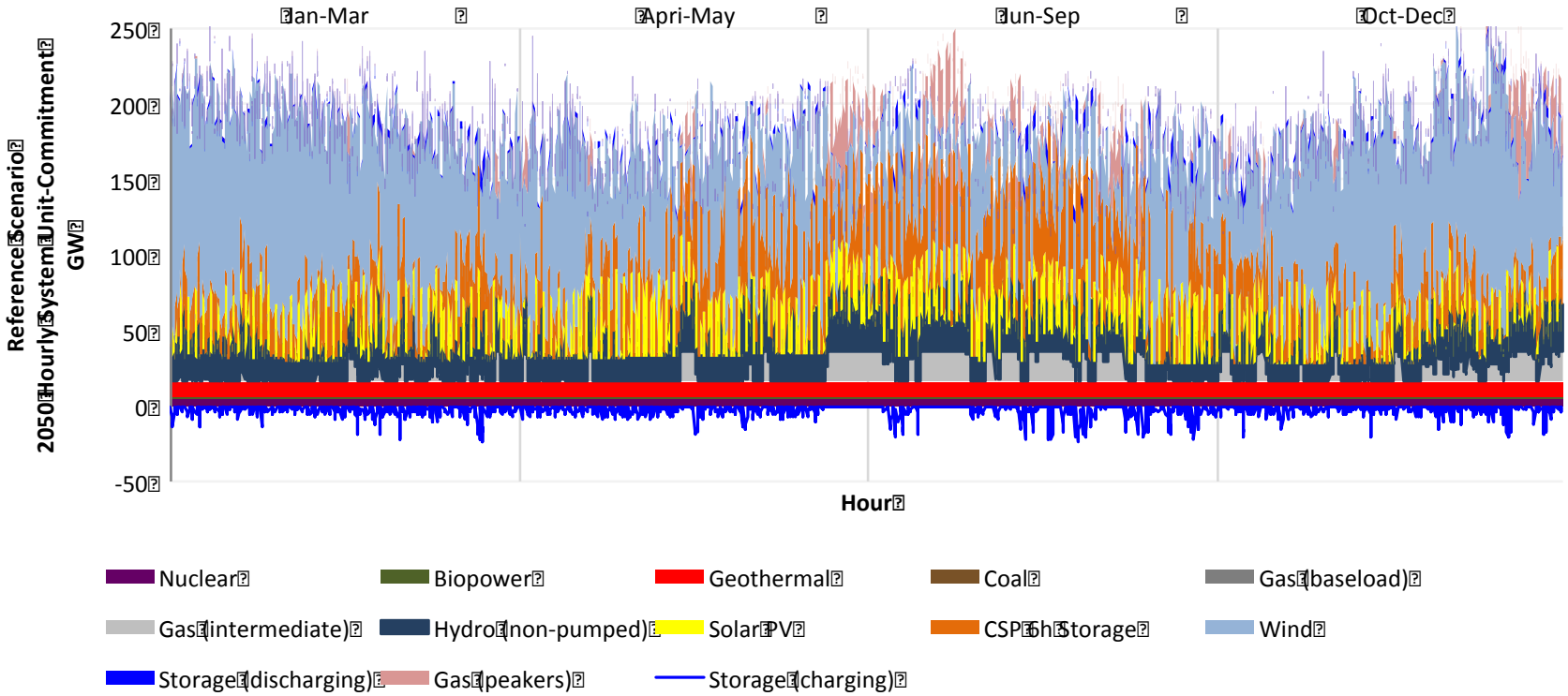


Figure 25. WECC System Hourly Unit-Commitment, Reference *Scenario*, *2050.*

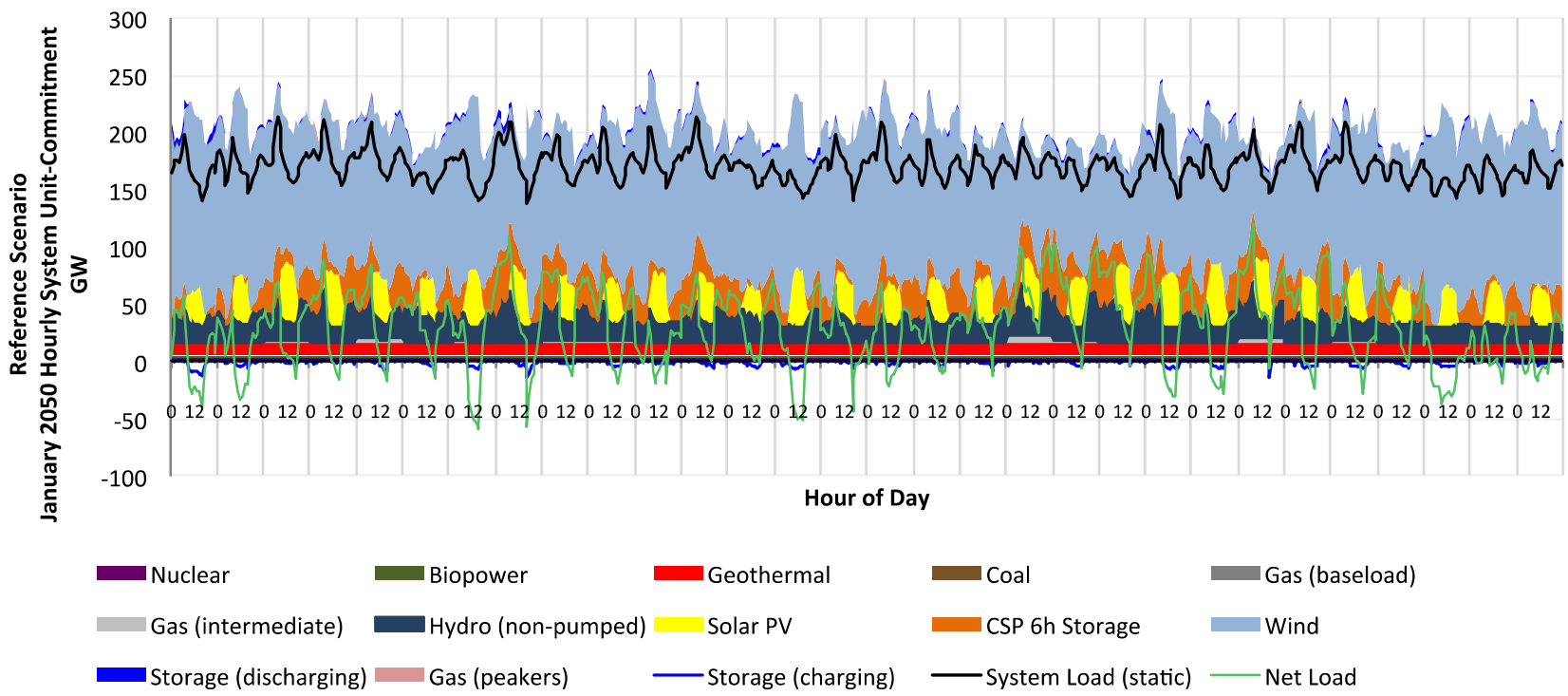


Figure 26. WECC System Hourly Unit-Commitment, Reference *Scenario, January 2050.*

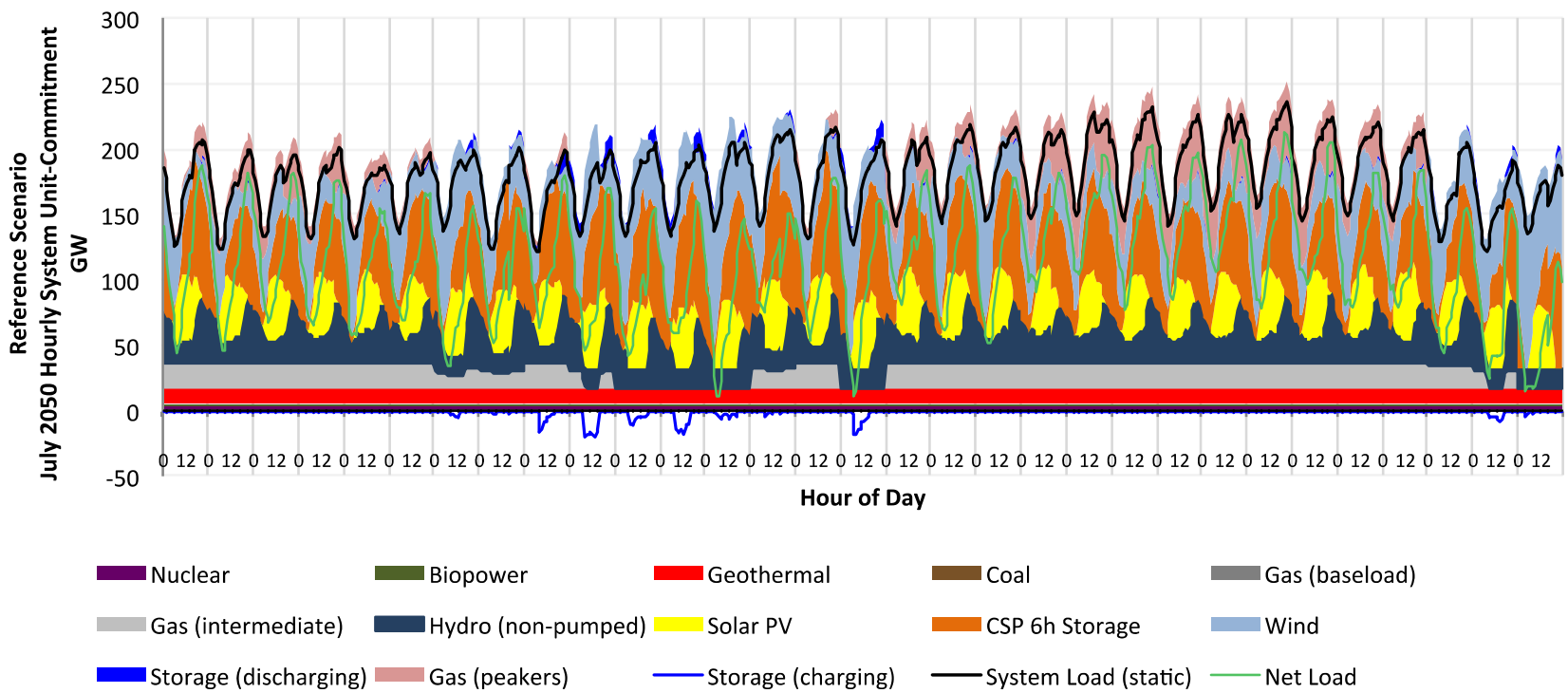


Figure 27. WECC System Hourly Unit-Commitment, Reference *Scenario, July 2050.*

SunShot and Low-Cost Batteries Scenario

The *SunShot and Low-Cost Batteries* scenario has the highest amount of new storage installed in 2050 of all scenarios investigated here. In this case, 110 GW of batteries with an average of 6 hours of storage and 20 GW of CAES with an average of 12 hours of storage are installed. Both technologies are deployed predominantly in the Desert Southwest (Figure 17), in California, Arizona, and Nevada, to support large-scale solar PV installations. In this scenario, 270 GW of solar PV are installed while deployment of CSP with storage is less than 40 GW and wind installation levels are at 160 GW. In the Reference case, deployment levels for the three technologies are 70 GW, 120 GW, and 250 GW respectively.

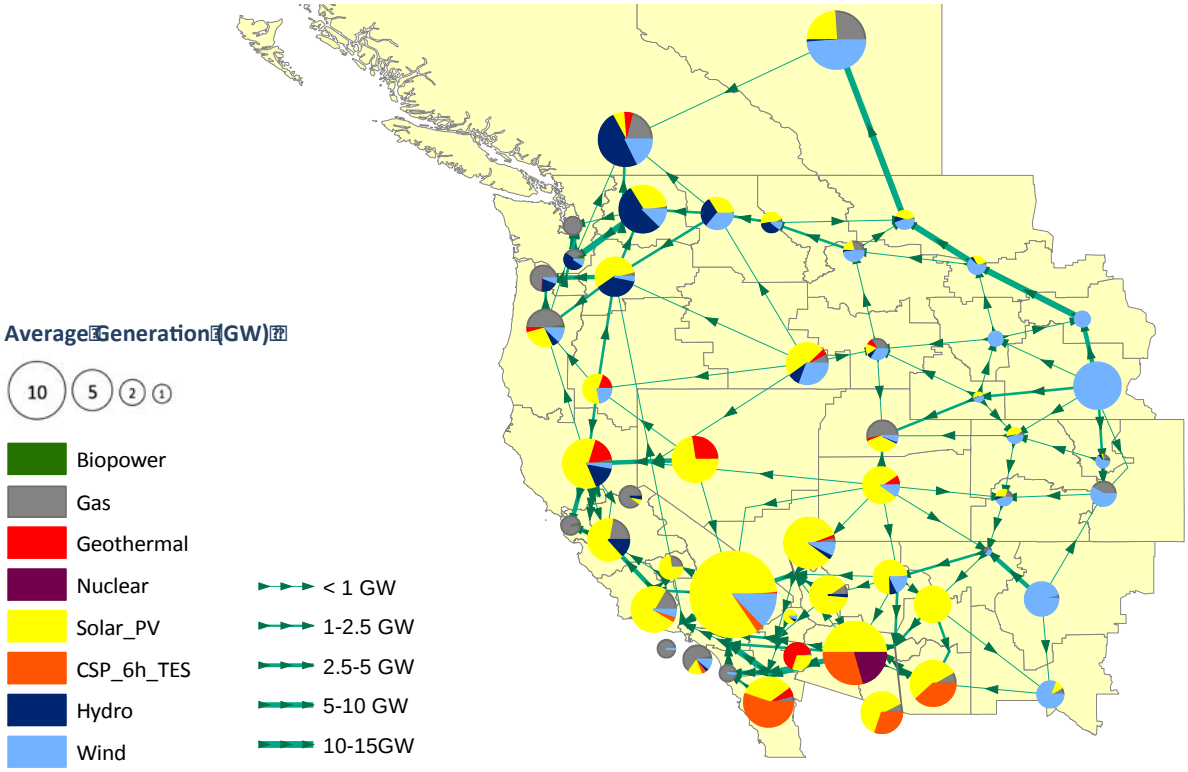


Figure 28. Map of average generation and transmission, SunShot and Low-Cost Batteries Scenario*, 2050.*

Relative to the *Reference* case, the unit-commitment schedule of the *SunShot and Low-Cost Batteries* system is much more similar across seasons and storage is used extensively throughout the year (Figure 29). The typical pattern for storage use is charging in the daytime – when PV is producing electricity, net load is usually negative, and prices are low – and shifting that energy to other times of the day, including the morning, evening, and night when more expensive generation would otherwise have to be run. This pattern of storage use holds throughout the year. In January, storage charges during the day and helps to meet nighttime load together with wind (Figure 30). In April (Figure 31) and November (Figure 33), the pattern is very similar. Even during the time of highest system stress when load is at its peak

levels in July, excess energy is available when PV is producing at full output, net load is negative, and the deployed storage can be used to shift that energy to other times of the day where it is aided by hydro and gas peaker generation in meeting load (Figure 32).

The cyclical nature of solar PV, which is inexpensive in the *SunShot and Low-Cost Batteries* scenario, allows SWITCH-WECC to design a system that also exhibits diurnal periodicity. The model overbuilds solar PV capacity above daytime load and deploys low-cost storage capacity to provide daily arbitrage, shifting the excess solar PV energy to other times of the day when an energy deficit exists. Unlike in the *Reference* scenario, in which the system must address seasonal variations in energy availability from wind and build large amounts of additional generation to ensure that load is met when wind output is low, the *SunShot and Low-Cost Batteries* system relies on solar PV output levels that are similar across seasons. With the storage technologies modeled here, PV generation can be readily balanced on the daily timescale.

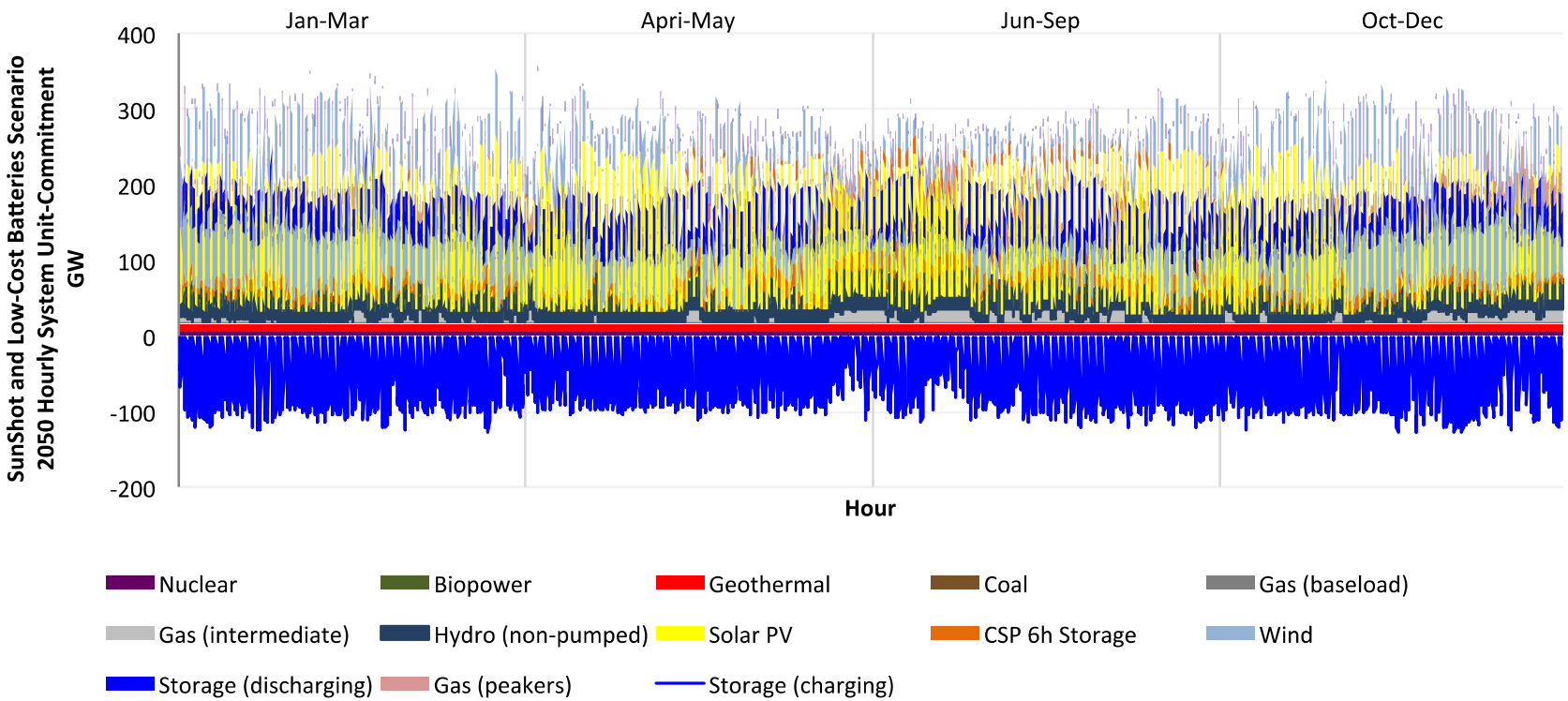


Figure 29. WECC System Hourly Unit-Commitment, SunShot and Low-Cost Batteries Scenario, 2050.

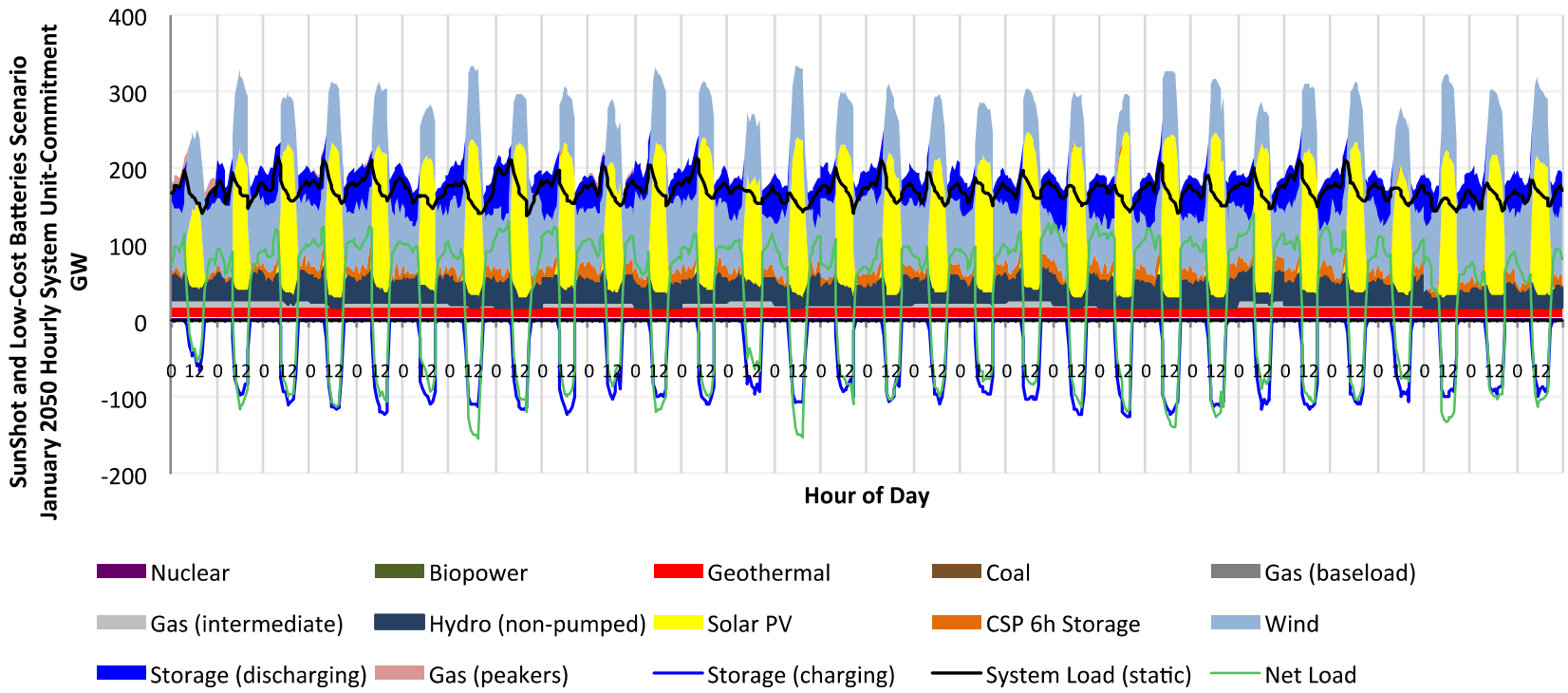


Figure 30. WECC System Hourly Unit-Commitment, SunShot and Low-Cost Batteries Scenario, January 2050.

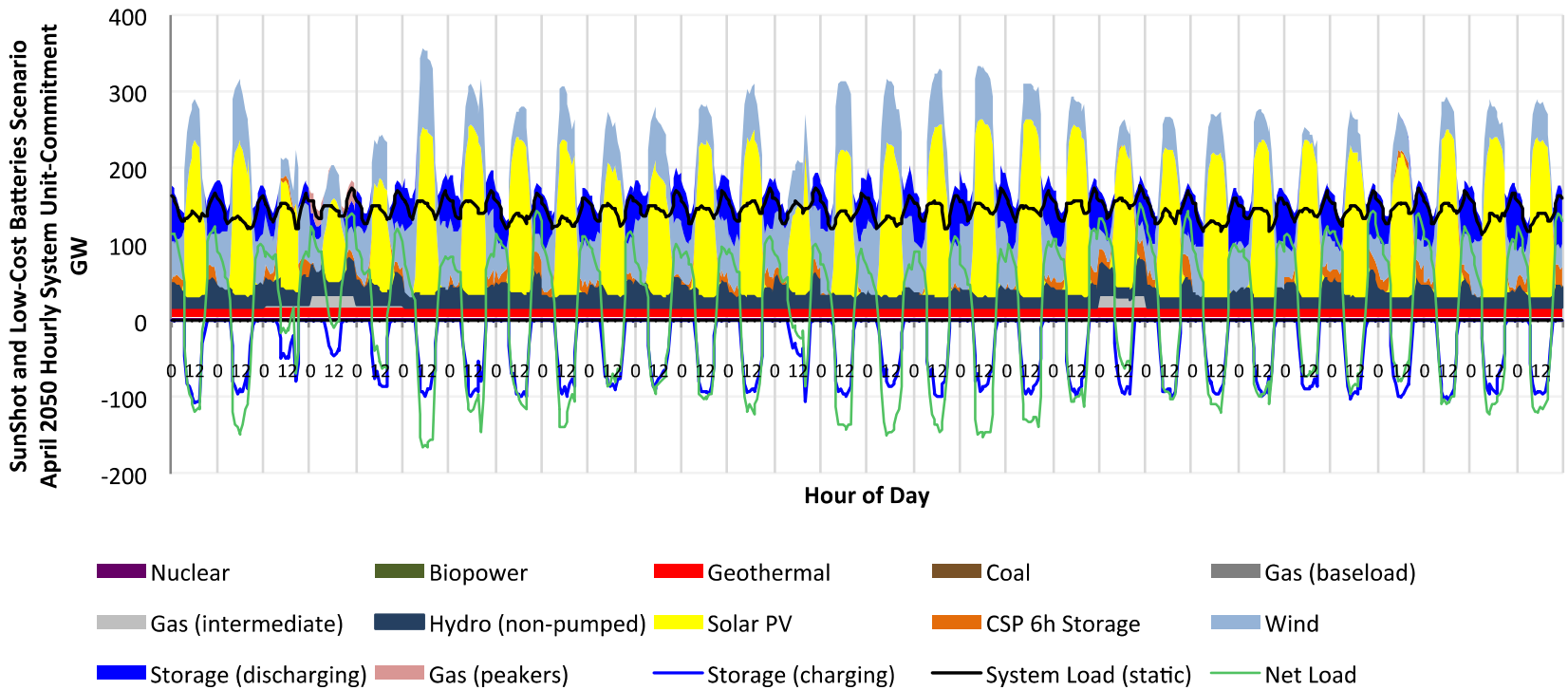


Figure 31. WECC System Hourly Unit-Commitment, SunShot and Low-Cost Batteries Scenario, April 2050.

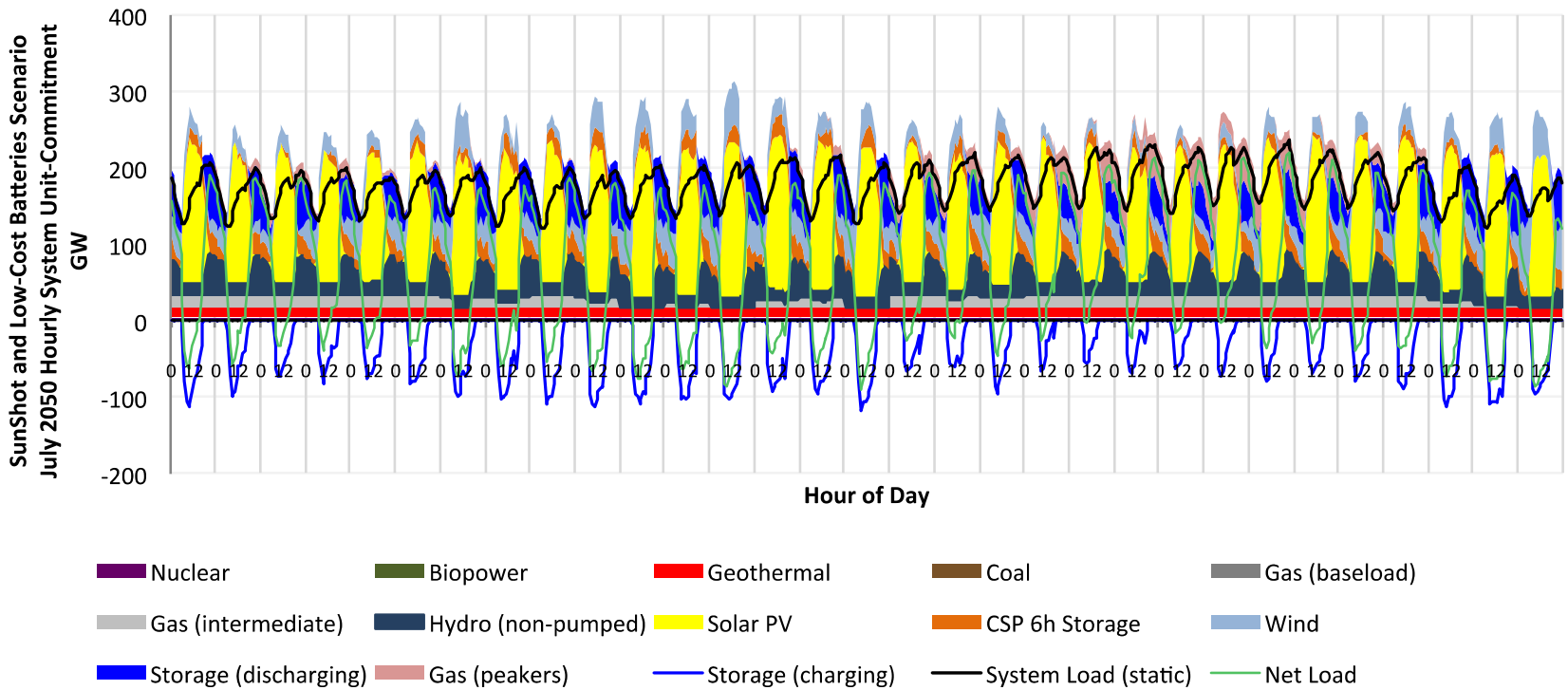


Figure 32. WECC System Hourly Unit-Commitment, SunShot and Low-Cost Batteries Scenario, July 2050.

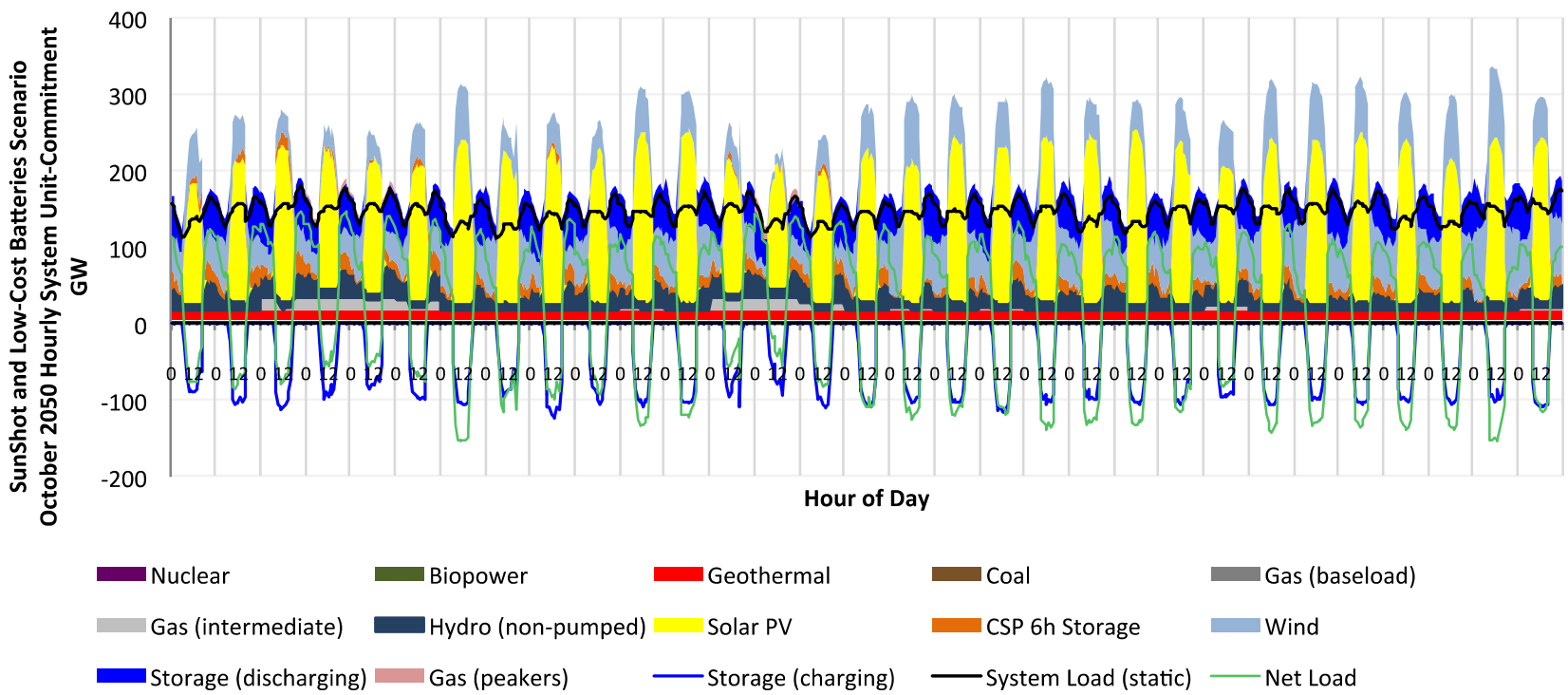


Figure 33. WECC System Hourly Unit-Commitment, SunShot and Low-Cost Batteries Scenario, October 2050.

The Role of Storage

In the results shown here, the wind energy resource exhibits large seasonal variation that requires the use of natural gas or other fuels during low-wind seasons – or of the ability to store large amounts of wind energy with low losses and shift it to other times of the year via storage with a large energy subsystem component. The scenarios explored draw from a single year of time-synchronized hourly demand and renewable output data: the historical load profile from 2006 is used to create load projections, and the wind and solar hourly resource availability data are also based on the 2006 potential in order to account for any temporal correlations between load and renewable output. Hourly wind output data for these wind sites are from the 3TIER wind power output dataset developed for the Western Wind and Solar Integration Study (3TIER 2010). Data for two more years – 2004 and 2005 – is available from 3TIER, and exhibits similar seasonal patterns.

This seasonal pattern in wind output can put stress on the system to meet demand, particularly if the periods of low availability of wind energy coincide with times of high load in the summer. If these conditions last for multiple consecutive days (or an even more extended period of time), other capacity may have to be built and run to compensate, which may be problematic from a cost and emissions perspective, or a large amount of wind energy may need to be stored during other times of the year and shifted to the times of low wind and high grid stress in the summer. Solar PV exhibits less pronounced seasonality than wind and total energy availability from it stays more similar across seasons.

Solar PV output follows a known, cyclical diurnal pattern – the sun's. The solar PV resource in the WECC, like load, exhibits an inherent periodicity at the daily timescale. This periodicity is similar across seasons: the time when the sun is not shining between sunset and sunrise is 10 to 14 hours depending on time of year in the Desert Southwest where the best solar PV resource is available. During that time, storage can be used to compensate for the lack of PV output. As a result, storage with duration of several hours providing daily arbitrage is very well suited to balance the daily variability in solar PV.

Because both load and PV output follow a daily pattern that is qualitatively similar across seasons, the net demand that must be met by other energy sources is also periodical. This recurring and predictable diurnal variability of the net load means that the availability of inexpensive storage with several hours of duration can help manage the variability of PV and thus provides a strong incentive for solar PV deployment. By building excess PV capacity above the daily peak load together with storage, the system can predictably shift the excess daytime energy to times when PV output is not available.

The availability of low-cost solar power is a main driver of storage deployment as storage devices providing daily arbitrage are well suited to balance the daily cycle in solar output. With SunShot solar costs, CSP-TES dominates, but if low-cost batteries are available, it is largely

displaces by a combination of solar PV and batteries, serving a similar function in the 2050 low-carbon grid.

In the near term, compressed air energy storage outcompetes battery storage, even if the cost of batteries is reduced to the ARPA-E target as in the *Low-Cost Batteries* scenario. While the power subsystem capacity cost is lower for batteries under the assumptions of the *Low-Cost Batteries* scenario, the energy subsystem cost remains higher than that of CAES. By 2040 in the *Low-Cost Batteries* scenario, 9 GW of CAES with 7-hour duration and 3 GW of batteries with 6-hour duration are installed. By 2050, a very large deployment of battery capacity takes place to accommodate a large build-out of renewables and a limit on the amount of natural gas that can be used due to an ever more stringent carbon cap. The battery deployment level reaches 68 GW (with 6-hour duration on average) while CAES capacity increases only slightly to 10 GW (with 11-hour duration). The difference in additional deployment of the two technologies between 2040 and 2050 suggests that the emissions from CAES are a limiting factor in how much of it can be used by the very-low-carbon 2050 power system. The batteries are used throughout the year to shift daytime solar PV energy to the nighttime. In this scenario, emissions from 10 GW of CAES in 2050 are 5 percent of the total system emissions. A large amount of CAES capacity cannot be used in a similar manner because it would entail emissions levels inconsistent with a stringent 2050 cap on greenhouse gases under the present assumptions about its characteristics.

While deployment of CSP with TES does not take place until 2040 in any of the scenarios explored here, this technology plays a crucial role in the long term as it can provide low-carbon flexibility to the power system at a range of timescales. As modeled here, solar thermal energy is more expensive on a levelized cost basis than either wind or solar PV; however, it is the timing of the energy – not the cost – that becomes the most important factor as the grid reaches very low greenhouse gas emission levels. In the *Reference* scenario, 116 GW of CSP with 6 hours of TES are installed, which help to balance both the seasonal intermittency of wind energy and the daily periodicity of solar PV. With SunShot costs in the *SunShot* scenario, CSP with storage is still the dominant solar technology: the capacity of both PV and CSP with 6h of TES increases by close to 40 percent relative to the *Reference* scenario, reaching 94 and 160 GW respectively and displacing wind.

The solar thermal resource is largest in the summer when the wind resource is limited, but is much diminished in the winter months when wind output is high. In the *Reference* scenario, for example, total electricity production from the 116 GW of deployed CSP with 6 hours of thermal storage is 38 TWh in August 2050, but only 14 TWh in December 2050. CSP is thus a good complement for wind power as it does not produce much excess energy when the wind resource is at its peak in the winter months, resulting in less curtailment and wasted electricity production, but it can help make up for the scarcity of wind energy in the summer and thus help avoid the need for additional generation capacity to be built to meet summer load.

CSP with storage is also very well suited to balance the daily cycle of PV electricity production. It stores thermal energy during the day while the sun is shining and then releases it after sunset

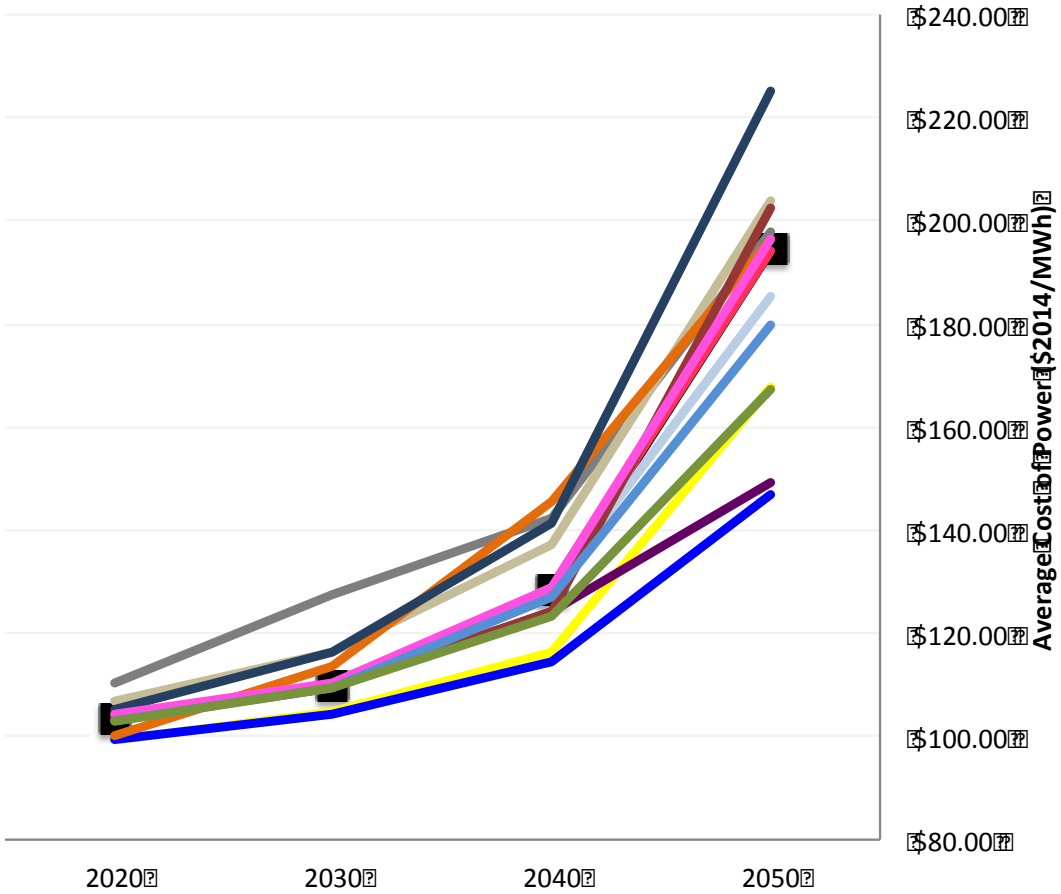
into the evening and nighttime when energy from PV is unavailable and load is usually at its daily high. This pattern is in place throughout the year. Only CSP with 6 hours of storage is modeled here; were the technology to be allowed to install thermal storage of even longer duration, it is likely that it would have additional value for the system, making it possible to dispatch energy throughout the night.

Providing additional evidence for the high value of flexibility in the decarbonized power system is that the availability of other low-cost and low-carbon sources of flexibility such as inexpensive battery technology or demand response reduces the deployment of CSP with 6h of thermal storage and instead incentivizes installation of solar PV projects. In the *Low-Cost Batteries* and *Load-Shifting* scenarios, solar PV deployment reaches 168 GW and 126 GW by 2050, a large increase from the 70 GW installed in the *Reference* scenario. In contrast, installation of CSP with 6 hours of thermal storage decreases from 120 GW in the *Reference* case to 61 GW and 89 GW in the *Low-Cost Batteries* and *Load-Shifting* scenarios respectively. In these cases, nighttime load served by CSP with TES in the *Reference* scenario can be met with PV energy stored in batteries during the day or by shifting it to the daytime when solar PV is available.

Like the availability of low-cost batteries, flexibility from load-shifting – both from demand response from thermal loads and from flexible EV charging – incentivizes deployment of solar PV. The pattern of load shifting is opposite from that in the present day when load is usually moved from the daytime peak to the nighttime when demand tends to be lower. Rather, it is nighttime, morning, and evening loads that are shifted to the middle of the day when an abundant source of carbon-free energy – solar PV – is available. This finding has implications for which loads can be most valuable as a source of flexibility to the decarbonized power system. At present, afternoon use of air-conditioning is a main target for demand response programs. However, it is loads consuming energy at other times of the day that are shifted in the 2050 (and as early as 2020), providing the most value to the system.

The sources of demand response modeled here are inherently a resource that operates within the daily timescale as most commercial and residential thermal end-uses such as heating and cooling as well as charging of EVs can only be shifted a few hours. In that sense, demand response is a resource comparable to storage with duration of several hours. Because of its diurnal availability pattern, the demand response resource can be matched well to the output of solar PV, which also exhibits daily periodicity. It therefore incentivizes deployment of PV at the expense of CSP with 6 hours of thermal storage.

System Costs



	2020	2030	2040	2050
Reference	$103.18	$110.07	$128.57	$194.43
SunShot	$99.26	$104.56	$116.32	$167.78
Low-Cost Batteries	$103.18	$110.06	$129.06	$185.14
High-Efficiency Batteries	$103.15	$110.00	$128.55	$194.13
SunShot and Low-Cost Batteries	$99.41	$104.49	$114.47	$146.69
High-Price Natural Gas	$110.19	$127.46	$142.13	$198.02
Methane Leakage	$106.83	$116.13	$137.30	$203.88
Nuclear and CCS	$103.24	$109.36	$124.41	$149.33
Limited Efficiency	$100.13	$113.38	$145.58	$196.70
High-Cost Transmission	$103.20	$109.65	$124.34	$202.50
Limited Hydro	$105.16	$116.12	$141.22	$225.03
Limited-Flexibility Hydro	$104.19	$110.37	$128.70	$196.54
Load-Shifting	$103.00	$109.38	$126.97	$179.78
Load-Shifting and Flexible EV Charging	$102.95	$109.17	$123.39	$167.50

Figure 34. Average cost of power through 2050 across scenarios. From Mileva (2014).

The 2030 Timeframe

Figure 34 shows the average system cost over time in a range of scenarios from Mileva (2014), including the six scenarios investigated here. All costs quoted in this section are in real $2014.

Through 2030, costs stay relatively constant across scenarios. The availability of SunShot solar power results in the most pronounced decrease in costs relative to the *Reference* case, from $110/MWh to $105/MWh in the *SunShot* scenario and $104/MWh in the *SunShot and Low-Cost Batteries* scenario. On the other hand, the availability of inexpensive batteries by itself does not effect substantial cost-reductions relative to the *Reference* scenario through 2030. Similarly, the availability of flexible loads results in only a small decrease in average cost, reflecting 1) the availability of sufficient flexibility that can provide services comparable to what batteries and load-shifting provide already exists within the system in the 2030 timeframe (specifically hydro and natural gas generation) and 2) the fact that batteries and load-shifting may not be able to provide the kind of flexibility most needed by the system as the times of highest stress for the grid include extended periods of low energy availability requiring storage of longer duration.

Natural gas plays a central role in the 2030 power system because of its low emissions relative to coal, which it displaces between present day and 2030, and its ability to vary output on a seasonal basis to compensate for seasonal variations in load and renewable energy availability, particularly wind, whose deployment grows in this timeframe. The cost of natural gas infrastructure and fuel are two of largest components of power system costs, comprising more than a third of system cost in almost all scenarios. If the price of natural gas is doubled relative to the *Reference* scenario or its emissions are increased due to upstream methane leakage, a fraction of the gas generation that is run in baseload mode is replaced by geothermal power and larger deployment of wind and solar PV takes place. The cost of the power system increases from $110/MWh in the *Reference* scenario to 127/MWh in the *High-Price Natural Gas* case. The latter scenario has the highest power cost in 2030: the higher natural gas price increases total fuel costs, a major component of total power cost in the 2030 timeframe, and thus total system cost in the *High-Price Natural Gas* scenario.

The 2050 Timeframe

Across scenarios, costs continue to rise through 2040 and then increase sharply by 2050 when the system must meet a stringent carbon cap of 85 percent below 1990 emissions levels.

Without major technological breakthroughs, the 2050 least-cost power system in the *Reference* scenario has costs much higher than present day, with average cost per MWh nearly doubling between 2020 and 2050, even if aggressive levels of energy efficiency are implemented. The average cost of power in 2050 in the *Reference* scenario is $194/MWh. Doubling the price of natural gas in the *High-Price Natural Gas* scenario has a negligible effect on the cost of power in 2050 because 1) the total amount of natural gas that can be used by the system is constrained by the carbon cap, 2) natural gas is very valuable to the system as it can provide flexibility on timescales ranging from the hourly to the seasonal, 3) natural gas fuel cost is a small part of system cost in this timeframe at less than 3 percent of total system cost in most scenarios.

System flexibility resources – including transmission, CAES and battery storage, and CSP with 6 hours of thermal storage – become a large component of power system cost at very low carbon levels. Low-cost flexibility is crucial to cost-containment as the power system is deeply de-carbonized through 2050. The availability of low-cost batteries or demand response push the cost of the power system down relative to the *Reference* case to $185/MWh, $180/MWh, and $168/MWh respectively in the *Low-Cost Batteries*, *Load-Shifting*, and *Flexible EV Charging* scenarios, a decrease of 5-14 percent relative to the *Reference* system. The *SunShot* scenario has even lower costs -- $168/MWh or about 14 percent lower than the *Reference* case – largely because reaching the SunShot target makes possible the cost-effective deployment of CSP with 6 hours of thermal energy storage and reduces the reliance on wind whose seasonality requires supporting infrastructure to help meet summer loads.

With the assumptions in the *Nuclear and CCS* scenario, which has the same assumptions as the *Reference* scenario but also allows the deployment of nuclear power and carbon capture and sequestration (CCS), the cost of power in 2050 is $149/MWh, 23 percent lower than in the *Reference* case. Cost estimates for nuclear power vary widely and may be substantially higher than modeled here (Bauer, Brecha, and Luderer 2012). Nuclear power also faces public acceptance challenges, so its deployment at large scale may not be politically feasible. An important finding is therefore that the *SunShot and Low-Cost Batteries* scenario has the lowest costs of all scenarios investigated here, including the *Nuclear and CCS* case. The average cost in this scenario is less than $147/MWh in 2050. The combination of low-cost solar PV and low-cost battery technology, which have a synergetic relationship on the daily timescale, allows SWITCH to design power system that meets aggressive carbon emission reduction targets while greatly containing the cost of decarbonization. Relative to the *Reference* scenario, costs in the *SunShot and Low-Cost Batteries* scenario are 25 percent lower in 2050 and also provide substantial savings in the near- and mid-term (Figure 34). While not modeled here, cost-effective long-term storage to allow for shifting wind

energy across seasons may provide additional avenues for reducing the cost of climate change mitigation in the electricity sector.

Conclusion

The State of California has put into law a requirement to reduce greenhouse gas emissions (GHG) to 1990 levels by 2020 with Assembly Bill 32 ("AB32 Scoping Plan" 2014). In addition, Executive Order S-3-05 calls for a further decline in the state's emissions to 80% below 1990 levels by 2050. In this work, I explore how the electricity sector of the entire WECC electricity sector can achieve deep GHG emission reductions in the 2050 timeframe as addressing emissions beyond California is indispensable to meaningful climate change mitigation.

A number of states in the WECC already have Renewable Portfolio Standards (RPS), which require that a fraction of electricity consumed within the state to be produced by qualifying renewable generators ("Database of State Incentives for Renewables and Efficiency" 2011). The State of California has a range of other policy targets, including a goal for storage deployment: as required by California Assembly Bill 2514, the California Public Utilities Commission has directed the state's investor-owned utilities to deploy 1.3 GW of storage by 2020, including 0.7 GW of utility-scale storage.

The results presented here indicate that focusing on decreasing solar costs is among the most effective approaches for keeping power system costs low in the near- to mid-term timeframe as the power system begins to decarbonize. Solar power may have significant cost-reduction potential and programs are in place to reach aggressive solar cost targets by 2020 ("SunShot Initiative" 2014). Wind is a more mature technology and cost-reductions are less likely ("Cost and Performance Data for Power Generation Technologies" 2012). The main driver of storage build-out in the mid-term is solar power deployment, which in turn can be driven by a rapid decline in solar costs. Cost-reductions in battery technology may not be an effective means of containing near- and mid-term power system costs as sufficient flexibility may be available to the system from less expensive natural gas, hydro, and compressed air energy storage to integrate higher levels of solar power into the grid at medium emissions levels through 2030. As the cap becomes more stringent, however, low-cost battery technology has an important advantage over CAES as it is emissions-free: in the deeply decarbonized 2050 power system, emissions are very valuable and CAES use will be limited by the carbon cap.

A central finding of the work presented here is that wind and solar PV in the WECC may have different flexibility requirements for their reliable and cost-effective integration into the power system. A key feature of the WECC wind resource is the large seasonal variation of wind output: its tendency to stay low or high for extended periods of time. Consistently low wind output in the summer can put high stress on the grid, especially if the wind energy scarcity lasts for multiple days – or even weeks – and coincides with periods of high demand. Storage with a large energy subcomponent would be required to address these energy shortage. Such very-long-duration storage is not modeled here, but could be key to reducing electricity sector decarbonization costs. Conversely, solar PV has an inherent periodicity over the diurnal timescale and exhibits synergies with storage technologies designed for daily arbitrage such as compressed air energy storage and some advanced batteries. The size of the storage energy

subcomponent required to integrate solar PV at a low cost is smaller than that for wind in the WECC.

Considering both the power subsystem component and the energy subsystem component of energy storage – i.e. the timescales over which the storage operates – is important for determining the nature of storage requirements and should be incorporated into policy goals. California's storage mandate only gives a power subcomponent GW target for storage deployment in the state. The timescales over which storage can operate are crucial to system design and reliable operation. Storage requirements should be set as part of overall system development goals as different decarbonization pathways have different flexibility needs. In the scenarios investigated here, energy shortages resulting from low wind output in the summer become a key feature of the system and driver of its costs by 2030. Storage with an energy subcomponent designed for the subhourly, hourly, or even daily timescale is not the appropriate technology to address these prolonged periods of grid stress as energy prices remain consistently high and the price differences observed during these times may be smaller than needed to justify the use of storage for arbitrage and the incurrence of storage losses.

Different storage technologies can provide different grid services, from shifting large amounts of energy over long periods of time (hours, days, or even months and seasons) to balancing the grid on much shorter timescales such as minutes or seconds. Storage policy should consider the value of each of these services – in the context of planned system development – and storage technologies' current competitiveness, setting mandates accordingly. Establishing a storage target for California would increase power system costs in the near term, but this effect is small relative to the total cost of the system. If support for *appropriate* storage technologies today helps to bring their cost down, the higher near-term cost could be counterbalanced by lower required future investment, affording a cost-effective flexibility source to the power system and making it possible to integrate higher levels of wind and solar power. As shown here, lowering the cost of storage could have widespread economic benefits and facilitate climate change mitigation.

An important question then becomes how to design policy to promote technological learning and storage cost-reductions over time. Support policy for storage deployment today should ensure that goals and performance incentives are in place to put cost pressure on system manufacturers and installers. Gradual scale-up to allow time for learning, ample opportunities to review progress, and open-information requirements to make the learning and experience of early deployers widely available are key policy features. Because storage technologies span the range of technological maturity, those that are still in the early stages of the innovation chain – and thus may not be able to compete on a cost basis with the more mature technologies yet – may benefit from R&D funding more than from deployment incentives.

Another important policy consideration is that storage is only one source of system flexibility. Fast-ramping generation, demand response, and flexible electric vehicle charging can provide comparable services and should be allowed to compete with storage on a level playing field as part of a comprehensive system flexibility portfolio. Better estimating demand response

potential and the cost of implementation programs to assess the value to the electricity sector is a crucial area of research needs. The deeply de-carbonized electricity system of the future will likely need both storage and demand response to enable deep penetration levels of renewables by providing zero-emission balancing at the lowest cost. Additionally, continued implementation of aggressive energy efficiency to slow demand growth has been shown to be crucial in containing costs and enabling deep de-carbonization of the electric power system for climate change mitigation.

Key findings include:

- In the 2030 timeframe, lowering the cost of solar technologies to the SunShot target is the main cost-reduction strategy
- Achieving the ARPA-E battery cost target has a small impact on costs in the 2030 timeframe as other sources of flexibility are available to the system, including gas generation, hydro, and CAES
- The price of natural gas is key to its utilization in the 2030 timeframe, but is not an important driver in 2050 when natural gas flexibility is of high value but its use is limited by the carbon cap
- Solar PV deployment is the main driver of CAES and battery storage deployment: its diurnal periodicity provides opportunities for daily arbitrage that these technologies are well-suited to provide
- Storage operation is very different from present day patterns – storage tends to charge during the day when solar PV is available and discharge in the evening and at night
- Similarly, the ability to shift loads to the daytime solar peak could have cost-reduction benefits for the system
- Wind output exhibits large seasonal variations; because it can remain at very low (or very high) levels for extended periods of time, it does not benefit from CAES an battery storage (operating as providers of daily arbitrage) as much as solar and instead requires storage with a large energy subcomponent
- CSP with 6 hours of thermal storage is an important component of the very-low-carbon power system but it directly competes with the combination of solar PV and batteries
- If low solar PV costs and low battery costs are achieved, the two technologies may be deployed at large-scale, displacing CSP with 6 hours of thermal storage
- The combination of SunShot solar technology and advanced battery technology has the largest impact on total storage capacity deployment in 2050
- The combination of SunShot solar PV and low-cost batteries can provide substantial savings through 2050, greatly mitigating the cost of climate change mitigation
- Policy goals for storage deployment should incorporate both the power subsystem component and the energy subsystem component of energy storage
- Storage deployment requirements should be set as part of overall system development goals as system flexibility needs will vary depending on the rest of the grid mix

- Near-term support policies for storage deployment should ensure that goals and incentives are in place to put pressure on system manufacturers and installers to reduce costs over time
- Policy should be technology-neutral and support a comprehensive portfolio of system flexibility options, allowing flexible generation, demand response, and flexible electric vehicle charging, which can provide comparable services, to compete with storage on a level playing field

References

"2008 Long-Term Reliability Assessment, 2008-2017." 2008. North American Electric Reliability Corporation.

3TIER. 2010. "Development of Regional Wind Resource and Wind Plant Output Datasets". NREL/SR-550-47676. Golden, CO: National Renewable Energy Laboratory.

"AB32 Scoping Plan." 2014. Sacramento, CA: California Air Resources Board. Accessed March 25. www.arb.ca.gov/cc/scopingplan/scopingplan.htm.

"Annual Energy Outlook." 2012. Washington, DC: United Sates Energy Information Administration.

"Arizona Public Service Wind Integration Study." 2007. Arizona Public Service Company. http://www.uwig.org/APS_Wind_Integration_Study_Final9-07.pdf.

Bauer, Nico, Robert J. Brecha, and Gunar Luderer. 2012. "Economics of Nuclear Power and Climate Change Mitigation Policies." *Proceedings of the National Academy of Sciences* 109 (42): 16805–10. doi:doi:10.1073/pnas.1201264109.

"California's Energy Future: The View to 2050." 2011. California Council on Science and Technology. http://www.ccst.us/publications/2011/2011energy.pdf.

"Contribution of Working Group III to the Fourth Assessment Report of the IPCC." 2007. Intergovernmental Panel on Climate Change.

"Cost and Performance Data for Power Generation Technologies." 2012. Overland Park, KS: Black and Veatch.

"Cost-Effectiveness of Energy Storage: Application of the EPRI Energy Storage Valuation Tool to Inform the California Public Utilities Commission Proceeding R. 10-12-007." 2013. Technical Update 3002001162. Palo Alto, CA: Electric Power Research Institute.

"Database of State Incentives for Renewables and Efficiency." 2011. Raleigh, NC: North Carolina State University. http://www.dsireusa.org/.

Denholm, Paul, Erik Ela, Brendan Kirby, and Michael Milligan. 2010. "The Role of Energy Storage with Renewable Electricity Generation". NREL/TP-6A2-47187. Golden, CO: National Renewable Energy Laboratory.

"Electricity Energy Storage Technology Options: A White Paper Primer on Applications, Costs, and Benefits." 2010. 1020676. Palo Alto, CA: Electric Power Research Institute.

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

EnerNex Corp. 2006a. "Wind Integration Study for Public Service of Colorado". Public Service of Colorado. http://www.uwig.org/CRPWindIntegrationStudy.pdf.

———. 2006b. "Final Report – 2006 Minnesota Wind Integration Study". Minnesota Public Utilities Commission.

———. 2007. "Avista Corporation Wind Integration Study". Avista Utilities. http://www.uwig.org/AvistaWindIntegrationStudy.pdf.

———. 2011. “Eastern Wind Integration and Transmission Study”. NREL/SR-5500-47078. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy11osti/47078.pdf.

“European Wind Integration Study: Final Report”. TREN/07/FP6EN/S07.70123/038509. http://www.wind-integration.eu/downloads/library/EWIS_Final_Report.pdf.

Fripp, Matthias. 2008. “Optimal Investment in Wind and Solar Power in California”. PhD, Berkeley, CA: University of California, Berkeley.

———. 2012. “Switch: A Planning Tool for Power Systems with Large Shares of Intermittent Renewable Energy.” *Environmental Science & Technology* 46 (11): 6371–78. doi:10.1021/es204645c.

GE Energy. 2005. “The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations”. The New York State Energy Research and Development Authority (NYSERDA).

———. 2006. “Ontario Wind Integration Study”. Independent Electricity System Operator (IESO) and Canadian Wind Energy Association.

———. 2007. “Intermittency Analysis Project: Final Report”. CEC-500-2007-081. California Energy Commission. http://www.energy.ca.gov/2007publications/CEC-500-2007-081/CEC-500-2007-081.PDF.

———. 2008. “Analysis of Wind Integration Impact on ERCOT Ancillary Services Requirements”. Electric Reliability Council of Texas (ERCOT).

———. 2010. “Western Wind and Solar Integration Study”. Subcontract No. AAM-8-77557-01. Boulder, CO: National Renewable Energy Laboratory.

Greenblatt, Jeffery B., Samir Succar, David C. Denkenberger, Robert H. Williams, and Robert H. Socolow. 2007. “Baseload Wind Energy: Modeling the Competition between Gas Turbines and Compressed Air Energy Storage for Supplemental Generation.” *Energy Policy* 35 (3): 1474–92. doi:10.1016/j.enpol.2006.03.023.

“Grid Energy Storage.” 2013. United States Department of Energy. http://energy.gov/sites/prod/files/2013/12/f5/Grid%20Energy%20Storage%20December%202013.pdf.

“Handbook of Energy Storage for Transmission and Distribution Applications.” 2003. Palo Alto, CA: Electric Power Research Institute.

Holttinen, Hannele. 2004. “The Impact of Large Scale Wind Power Production on the Nordic Electric System”. VTT Technical Research Center.

“Impact of Wind Power Generation in Ireland on the Operation of Conventional Plant and the Economic Implications.” 2004. ESB National Grid. http://www.eirgrid.com/media/2004%20wind%20impact%20report%20(for%20updated%202007%20report,%20see%20above).pdf.

“Impacts of Large Amounts of Wind Power on Design and Operation of Power Systems, Results of IEA Collaboration.” 2009. In Bremen, Germany. http://www.ieawind.org/AnnexXXV/PDF/Task%2025%20Paper_Bremen_final20090814.pdf.

“Integration of Renewable Resouces: Operational Requirements and Generation Fleet Capability at 20% RPS”. California Independent System Operator. https://www.caiso.com/2804/2804d036401f0.pdf.

Larochelle, Philippe. 2012. “Re: Storage Follow Up on 2/12 Energy Policy Paper”, April 25.

London Economics and Global Energy Decisions. 2007. “Structure and Performance of Six European Wholesale Electricity Markets in 2003, 2004, and 2005, Appendix I.” http://ec.europa.eu/competition/sectors/energy/inquiry/electricity_final_appendix1.pdf.

Lu, N, M.R. Weimar, Y.V. Makarov, J. Ma, and V.V. Viswanathan. 2009. “The Wide-Area Energy Storage and Management System -- Battery Storage Evaluation”. PNNL-18679. Pacific Northwest National Laboratory. http://www.pnl.gov/main/publications/external/technical_reports/PNNL-18679.pdf.

Meibom, Peter, Rudiger Barth, Heike Brand, Bernard Hasche, Derk Swider, Hans Ravn, and Christoph Weber. “All Island Grid Study, Workstream 2B, Wind Variability Management Studies.” http://www.dcenr.gov.ie/NR/rdonlyres/E812FF88-640D-4F07-BC33-B11765A03D7D/0/FinalReportforGridStudyWS2B20SEPT07.pdf.

Mileva, Ana. 2014. “Greenhouse Gas Emission Reductions, System Flexibility Requirements, and Drivers of Storage Deployment in the North American Power System through 2050”. PhD, Berkeley, CA: University of California, Berkeley.

Mileva, Ana, James H. Nelson, Josiah Johnston, and Daniel M. Kammen. 2013. “SunShot Solar Power Reduces Costs and Uncertainty in Future Low-Carbon Electricity Systems.” *Environmental Science & Technology* 47 (16): 9053–60. doi:10.1021/es401898f.

Milligan, Michael. 2003. “Wind Power Plants and System Operation in the Hourly Time Domain”. NREL/CP-500-33955. National Renewable Energy Laboratory.

Milligan, Michael, and Kevin Porter. 2008. “Determining the Capacity Value of Wind: An Updated Survey of Methods and Implementation”. NREL/CP-500-43433. Golden, CO: National Renewable Energy Laboratory.

Nelson, James H., Josiah Johnston, Ana Mileva, Matthias Fripp, Ian Hoffman, Autumn Petros-Good, Christian Blanco, and Daniel M. Kammen. 2012. “High-Resolution Modeling of the Western North American Power System Demonstrates Low-Cost and Low-Carbon Futures.” *Energy Policy* 43 (April): 436–47. doi:10.1016/j.enpol.2012.01.031.

Nelson, James H., Ana Mileva, Josiah Johnston, and Daniel M. Kammen. 2013. “California’s Carbon Challenge: Scenarios for Achieving 80% Emission Reduction in 2050”. California Energy Commission.

“Operational Costs Induced by Fluctuating Wind Power Production in Germany and Scandinavia”. 2006: GreenNet-EU27. http://greennet.i-generation.at/.

“Operational Impacts of Integrating Wind Generation into Idaho Power’s Existing Resource Portfolio.” 2007. Idaho Power. http://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/wind/Petition_ReviseAvoidedCostRates1.pdf?id=238&.pdf.

"Planning of the grid integration of wind energy in Germany onshore and offshore up to the year 2020 (DENA Grid Study)." 2005. Deutsche Energie-Agentur (DENA). http://www.dena.de/themen/thema-reg/projektarchiv/.

"Principal Aquifers of the 48 Conterminous United States, Hawaii, Puerto Rico, and the U.S. Virgin Islands." 2003. Reston, VA: United States Geological Survey. http://nationalatlas.gov/mld/aquifrp.html.

Rodriguez-Bobada, Francisco. 2006. "Study of Wind Energy Penetration in the Iberian Peninsula." In Athens, Greece.

Schoenung, Susan. 2011. "Energy Storage Systems Cost Update: A Study for DOE Energy Storage Systems Program". SAND2011-2730.

Shiu, Henry, Michael Milligan, Brendan Kirby, and Kevin Jackson. 2006. "California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis; Multi-Year Analysis Results and Recommendations: Final Report". CEC-500-2006-064. California Energy Commission.

Succar, Samir, and Robert H. Williams. 2008. "Compressed Air Energy Storage: Theory, Resources, and Applications for Wind Power". Princeton, NJ: Princeton Environmental Institute. http://www.princeton.edu/pei/energy/publications/texts/SuccarWilliams_PEI_CAES_2008April8.pdf.

"SunShot Initiative." 2014. United States Department of Energy. Accessed March 20. http://energy.gov/eere/sunshot.

"SunShot Vision Study." 2012. United States Department of Energy. http://www1.eere.energy.gov/solar/pdfs/47927.pdf.

System Advisor Model. 2014. Golden, CO: National Renewable Energy Laboratory. https://sam.nrel.gov.

Walawalker, Rahul. 2008. "The Economics of Emerging Electric Energy Storage Technologies and Demand Response in Deregulated Electricity Markets". Carnegie Mellon University.

"WECC Standard BAL-STD-0020 - Operating Reserves." 2007. North American Electric Reliability Corporation.

Wei, Max, James H. Nelson, Jeffery B. Greenblatt, Ana Mileva, Josiah Johnston, Michael Ting, Christopher Yang, Chris Jones, James E. McMahon, and Daniel M. Kammen. 2013. "Deep Carbon Reductions in California Require Electrification and Integration across Economic Sectors." *Environmental Research Letters* 8 (1): 014038. doi:10.1088/1748-9326/8/1/014038.

Williams, James H., Andrew DeBenedictis, Rebecca Ghanadan, Amber Mahone, Jack Moore, William R. Morrow, Snuller Price, and Margaret S. Torn. 2012. "The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity." *Science* 335 (6064): 53–59. doi:10.1126/science.1208365.