Achieving 50 Percent Renewable Electricity in California

The Role of Non-Fossil Flexibility in a Cleaner Electricity Grid

James H. Nelson, Ph.D.
Laura M. Wisland

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James H. Nelson is an energy modeler in the UCS Climate and Energy Program.

Laura M. Wisland is a senior energy analyst in the UCS Climate and Energy Program.

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NATIONAL HEADQUARTERS
Two Brattle Square
Cambridge, MA 02138-3780
t 617.547.5552
f 617.864.9405

WASHINGTON, DC, OFFICE
1825 K St. NW, Ste. 800
Washington, DC 20006-1232
t 202.223.6133
f 202.223.6162

WEST COAST OFFICE
500 12th St., Suite 340
Oakland, CA 94607-4087
t 510.843.1872
f 510.843.3785

MIDWEST OFFICE
One N. LaSalle St., Ste. 1904
Chicago, IL 60602-4064
t 312.578.1750
f 312.578.1751

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[EXECUTIVE SUMMARY]

One of California's leading strategies to address climate change by cutting greenhouse gas (GHG) emissions is to produce electricity from renewable resources. This strategy is a central pillar of the state's pathway to reduce GHG emissions under the California Global Warming Solutions Act of 2006 (Assembly Bill 32).

Renewables Portfolio Standard (RPS) requirements have been a driving force in the expansion of utility-scale and wholesale renewable power in the state. Under these requirements, load-serving entities—investor-owned utilities, publicly owned utilities, electric service providers, and community choice aggregators—in California must source 33 percent of their retail electricity sales from qualifying renewable energy resources by 2020.

Policy makers are now discussing how California should make deeper cuts in GHG emissions after 2020. A key strategy for achieving deeper reductions in emissions will be to deploy additional amounts of renewable energy. In his January 2015 inaugural address, Governor Jerry Brown called for the state to obtain half of its electricity supply from renewables by 2030 (Brown 2015a). In April 2015, Governor Brown also issued an executive order that directs the state to reduce GHG emissions by 40 percent below 1990 levels by 2030 (Brown 2015b). The state legislature is currently considering bills that would raise the RPS to 50 percent by 2030 and codify a statewide target for reducing GHG emissions by 2030.

Achieving economy-wide GHG targets by 2030 may require the state to deploy renewable electricity more quickly than would be required by a 50 percent RPS in 2030. Consequently, in this study we explore a 50 percent RPS in 2024.

Because wind and solar generators are driven by the weather, power from these prominent sources of renewable electricity varies over the course of each hour, day, and season. As California brings more of these resources online, operators of the electricity grid will need to find additional ways to balance supply and demand every minute of every day to manage the variability and uncertainty of renewable power.

One action that grid operators can take today to mitigate an imbalance in electricity supply and demand is to "curtail" the output of renewable facilities: that is, to send signals to renewable generators to operate below their maximum power output. Although this approach is a dependable way to balance supply and demand, it can result in a missed opportunity to take full advantage of renewable generation. Once a renewable facility is built, the cost to produce electricity from it is very low. Curtailing large amounts of renewable energy means the loss of low-cost, low GHG emission power and could raise the cost of electricity for a system that relies more heavily on renewables.

Six Key Questions

This report addresses six research questions regarding the need to curtail renewable power at a 50 percent RPS in 2024. We investigate solutions that grid operators could use to reduce renewable curtailment, GHG emissions, and the cost of producing electricity.

To explore these questions, we used the industry standard PLEXOS software to simulate hour-by-hour operation of the power system run by the California Independent System Operator (CAISO), which operates the grid used to supply roughly 80 percent of electricity demand in the state. Our model depicted the flexibility provided by individual conventional gas-fired power plants, electricity storage facilities, and advanced demand response resources in detail. We based the flexibility of the hydroelectric fleet of the CAISO system and the amount of electricity imported into the CAISO system on historical levels.

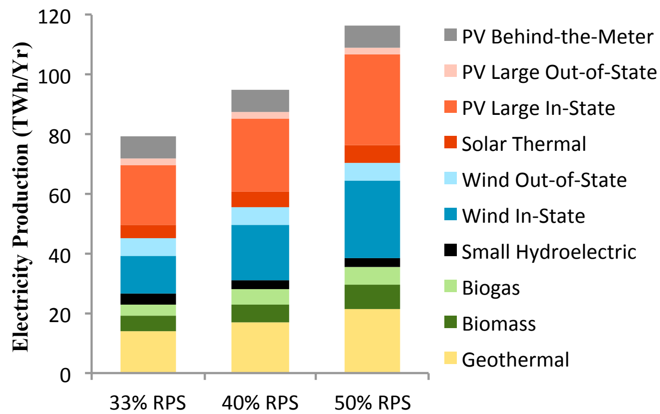
Between a 33 percent RPS and a 50 percent RPS, we added a relatively diverse mix of renewables, including solar photovoltaic (PV), solar thermal, wind, bioenergy, and geothermal facilities (Figure ES-1). We chose this resource mix because of the many benefits of portfolio diversity, but did not attempt to create an "optimal" portfolio of renewables. Our modeling did not address the capital and annual maintenance costs of renewable facilities and other resources. To simulate how load-serving entities in the state are satisfying current RPS obligations, we did not include behind-the-meter PV—that is, rooftop solar—in the RPS portfolio, and prioritized the development of in-state renewable resources.

Question 1: How do curtailment of renewables, GHG emissions, and the cost of producing electricity change as the amount of renewable energy rises to fulfill a 50 percent RPS?

Our model shows that without making additional changes to the grid, moving from a 33 percent to a 50 percent RPS reduces GHG emissions from electricity generation by 22 percent, and the cost of producing power by 20 percent. However, as the RPS rises, the model increasingly relies on renewable curtailment as a reliability tool. Curtailment reaches 4.8 percent of available renewable generation at a 50 percent RPS.

We find that renewables can provide some electricity during times of greatest need for system capacity. However, even at a 50 percent RPS, renewables cannot produce enough power to ensure a reliable electricity system during some peak periods. Our study suggests that the projected 2024 CAISO fleet of natural gas power plants will be important in ensuring that the grid has enough capacity to meet demand during peak periods.

FIGURE ES-1. **Renewable Power Production in 2024 as the RPS Is Raised**



When raising the RPS from 33 percent to 50 percent, we increased the amount of electricity produced from in-state resources, including large-scale PV, wind, biogas, biomass, and geothermal.

We did not include power from behind-the-meter PV in the calculation of RPS percentage, but we include it here for completeness. TWh = terawatt-hours.

Question 2: What are important drivers of renewable curtailment at a 50 percent RPS?

To identify reliability requirements that cause renewable curtailment, we removed two different types of such requirements—those for downward reserves and regional generation—from the 50 percent RPS base scenario in two sensitivity runs. We do not want to suggest that grid planners and operators should disregard reliability requirements when integrating higher fractions of renewable energy. Rather, we performed these sensitivity runs to highlight important areas for further analysis.

We find that 69 percent of renewable curtailment in the 50 percent RPS base scenario can be attributed to downward reserve requirements. These reserves allow the grid operator to reduce the amount of electricity generated or increase the amount of electricity demanded on the sub-hourly timescale. The grid operator needs these reserves to maintain the balance between supply and demand. Our result highlights that the grid operator could keep natural gas power plants online to provide downward reserves. Electricity produced by these power plants "crowds out" renewable generation by forcing the operator to curtail renewables to avoid a situation in which electricity supply exceeds demand.

We also find that further renewable curtailment is caused by requirements that conventional power plants—natural gas, nuclear, cogeneration, and large hydroelectric facilities—must supply 25 percent of electricity demand in each hour in specific regions within the CAISO footprint. These requirements are known as regional generation requirements.

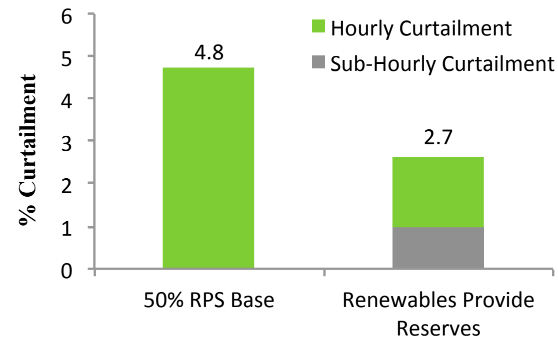
We find that together, downward reserve and regional generation requirements account for 80 percent of the curtailment of renewables at a 50 percent RPS. This indicates that to avoid crowding out renewable generation, grid planners and operators should strive to satisfy these reliability requirements with either renewable generators or resources that do not have to be online and generating.

Question 3: If renewables could contribute to reserves, how much curtailment would be eliminated?

To explore how renewables could satisfy reliability requirements, we performed a sensitivity run in which renewables could contribute to operating reserves. Our model shows that enabling wind and solar facilities to provide operating reserves would reduce curtailment of renewables by 44 percent (Figure ES-2). This approach would allow grid operators to nimbly curtail and uncurtail renewables on sub-hourly rather than hour-long intervals.

Our results suggest that enabling renewable generators to provide reserves, especially in the downward direction, could be a particularly useful and cost-effective way to reduce curtailment and GHG emissions. Policy makers who aim to deploy more renewable energy should encourage or require renewable generators to install control equipment that allows them to participate in CAISO energy and reserve markets.

FIGURE ES-2. **Renewable Curtailment in the 50 Percent RPS Base Scenario and the Renewables Provide Reserves Run**



When renewables contribute to reserves, the total amount of curtailment is reduced by 44 percent.

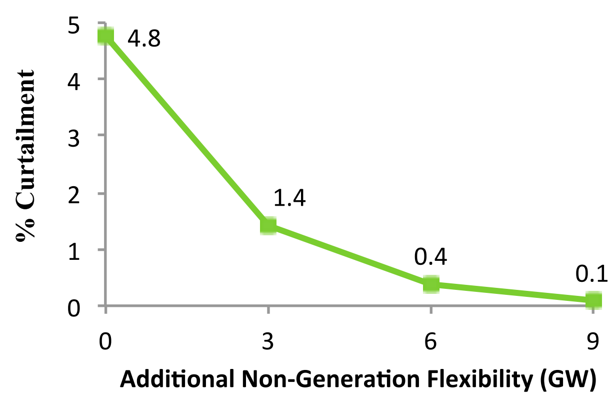
Sub-hourly curtailment is the amount of curtailment expected if renewables are operated flexibly and curtailed on a sub-hourly timescale.

Question 4: What are the benefits of relying on non-generation grid management strategies to provide operational flexibility?

To reduce curtailment of renewable generation while also ensuring a flexible electricity supply, the CAISO could expand the power system's capacity to store electricity, export more electricity to other grids, and rely on demand response that can act as either demand or supply. We refer to these three measures together as "additional non-generation flexibility."

Our model shows that deploying 3 gigawatts (GW) of non-generation flexibility reduces renewable curtailment by 70 percent—as well as GHG emissions and the cost of producing power—at a 50 percent RPS (Figure ES-3). One of the main reasons that these options reduce curtailment is that they provide online reserves without generating electricity, so grid operators do not have to curtail renewable power output. Adding even more non-generation flexibility further reduces renewable curtailment, GHG emissions, and production costs, although the marginal benefits drop.

FIGURE ES-3. **The Impact of More Non-Generation Flexibility on Renewable Curtailment**



Increasing the amount of non-generation flexibility in the CAISO power system at a 50 percent RPS reduces renewable curtailment as a share of available renewable power. The x-axis represents the deployment of equal ratios of advanced demand response, electricity storage, and net export capability.

$MMTCO_2/Yr$ = millions of metric tons of CO_2 per year. The dollar-year is 2014.

Question 5: How much can additional natural gas plant flexibility reduce the curtailment of renewables?

The ability to vary the output of natural gas power plants can help operators integrate large amounts of renewable energy into the grid. To identify which aspects of gas plant flexibility are the most valuable for reducing curtailment and GHG emissions, we dramatically increased several aspects of such flexibility in the projected 2024 CAISO natural gas fleet.

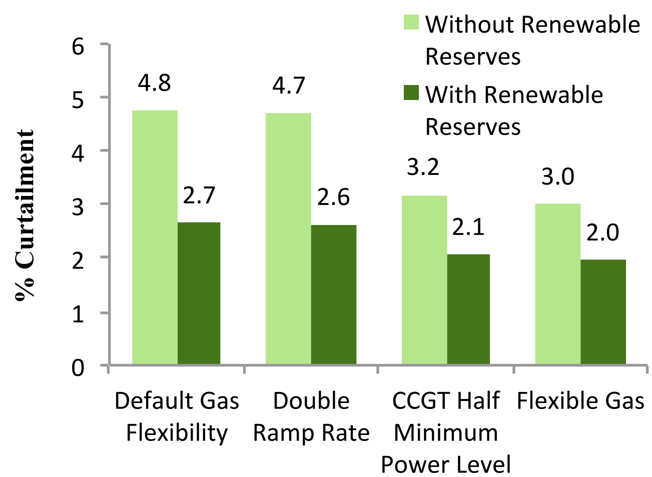
Decreasing the minimum power level—the level of output below which a generator cannot be operated when it is online and synchronized to the grid—of combined-cycle gas turbine (CCGT) power plants provides the largest benefit of any modification to the flexibility of the natural gas fleet. However, the effectiveness of this modification declines if renewable facilities are allowed to provide operating reserves (Figure ES-4).

Increasing the ramp rate—how quickly a natural gas power plant can increase or decrease output if it is already online and synchronized to the grid—does not reduce renewable curtailment significantly. This suggests that the ramping ability of the projected 2024 fleet of natural gas plants is sufficient, and that the CAISO system will not need more gas plants to meet ramping needs.

Natural gas plants face fundamental limitations as the electricity system integrates greater amounts of renewables. First, gas plants cannot contribute to some aspects of grid reliability without producing electricity, thereby crowding out renewables and causing curtailment. The second limitation is that natural gas plants cannot shift the timing and location of electricity demand or renewable electricity production. To test these limitations, we simulated an extremely flexible natural gas fleet. Even in that model run, more than half of the renewable curtailment remains, indicating that a more flexible natural gas fleet is not a silver bullet solution to challenges encountered when integrating more renewables into the grid.

Still, natural gas power plants will play important roles in meeting a 50 percent RPS in 2024. The CAISO system will still need natural gas plants to provide power and capacity when other resources are not available. Gas plants can also provide reserves at a relatively low cost throughout much of the year, allowing grid operators to integrate variable and uncertain renewable resources into the system.

FIGURE ES-4. **The Impact of Different Levels of Gas Flexibility on Renewable Curtailment**



The minimum power level of combined cycle natural gas plants is much more important than the ramp rate, start time, and other operating characteristics in reducing curtailment of renewables. "Default" gas flexibility refers to the 50 percent RPS base scenario. The Flexible Gas run simultaneously increases the flexibility of many different aspects of natural gas power plants. When renewables can provide reserves, the amount of curtailment that can be avoided by increasing the flexibility of natural gas power plants decreases.

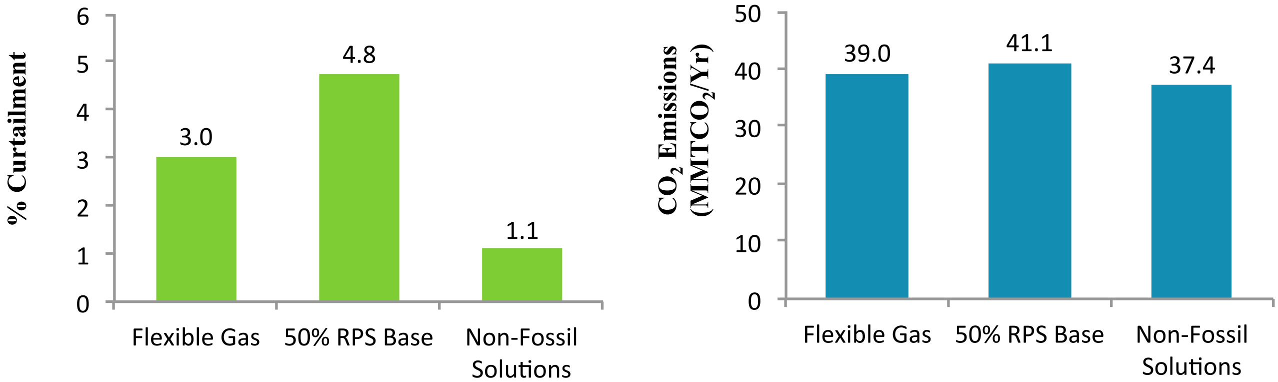
Question 6: How does more non-fossil flexibility compare with more gas plant flexibility in reducing renewable curtailment?

We modeled a mix of non-fossil options for providing flexibility that could reasonably be available by 2024 in the Non-Fossil Solutions run. In this run, we allowed renewables to provide reserves, and added 1 GW each of electricity storage, advanced demand response, and export capability to the CAISO grid.

Together these measures reduced curtailment to about 1 percent of available renewable generation—a 77 percent drop compared to the 50 percent RPS base scenario (Figure ES-5). Making the natural gas fleet much more flexible, as we did in the Flexible Gas model run, in contrast, reduced curtailment by 37 percent. The measures implemented in the Non-Fossil Solutions run also reduce GHG emissions more than a more flexible natural gas fleet.

Compared with a 33 percent RPS, raising the RPS to 50 percent and adding non-fossil flexibility solutions reduces GHG emissions from electricity generation by 27 percent, and the production cost of that electricity by 25 percent. Deploying non-fossil sources of operational flexibility along with more renewable resources allows the electricity system to extract more value from each renewable facility.

FIGURE ES-5. **Curtailment and CO_2 Emissions in the 50 Percent RPS Base Scenario, the Flexible Gas Run, and the Non-Fossil Solutions Run**



Shutting off gas power plants during times of ample renewable generation is critical to reducing GHG emissions. Increasing gas flexibility in the Flexible Gas run does not enable grid operators to shut off most CCGTs during hours in which renewable electricity is being curtailed. Relying on non-fossil solutions to provide flexibility, on the other hand, can almost eliminate electricity production from CCGTs during times of renewable curtailment.

Conclusion

To dramatically reduce GHG emissions from the power grid, non-fossil resources will need to gradually replace contributions to the flexibility and reliability of the power system now provided by natural gas plants. If this replacement does not occur, grid operators may be forced to keep natural gas plants online and producing electricity—and therefore GHG emissions—when ample power is available from renewable or zero-carbon sources. Allowing both renewable and non-generation resources to provide flexibility and reliability services to the grid will be an important step in creating a low-GHG energy system.

Electricity Reliability and the Need for Additional Renewable Energy

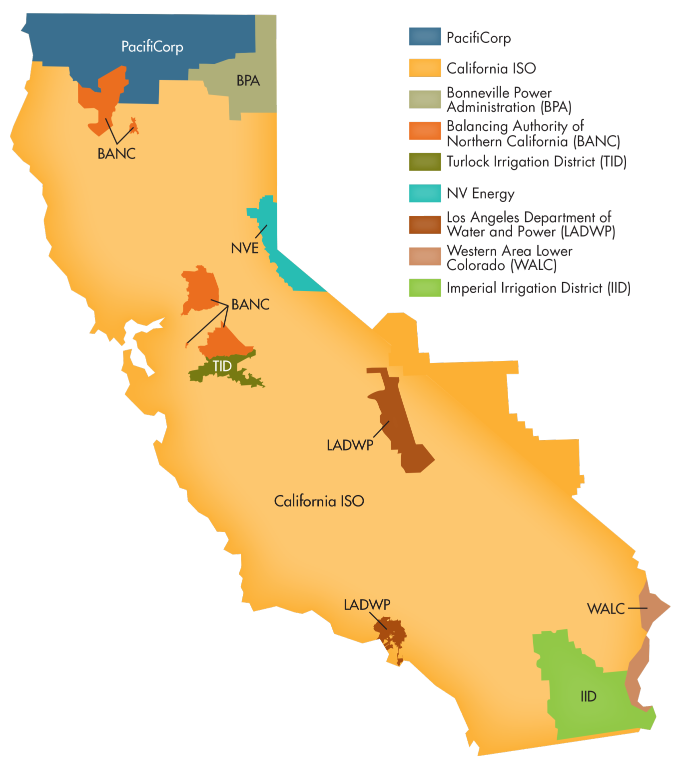
One of California's leading strategies to address climate change by cutting greenhouse gas (GHG) emissions is to produce electricity from renewable resources. This strategy is a central pillar of the state's pathway to reduce GHG emissions under the California Global Warming Solutions Act of 2006 (Assembly Bill 32).

Renewables Portfolio Standard (RPS) requirements have been a driving force in the expansion of utility-scale and wholesale renewable power in the state. Under these requirements, load-serving entities—investor-owned utilities, publicly owned utilities, electric service providers, and community choice aggregators—in California must source 33 percent of their retail electricity sales from qualifying renewable energy resources by 2020. Additional deployment of renewable electricity will be critical as the state moves to further cut GHG emissions (E3 2015; Morrison et al. 2015; Nelson et al. 2013; Wei et al. 2013a; Wei et al. 2013b; Williams et al. 2012).

Policy makers are now discussing how California should make deeper cuts in GHG emissions after 2020. For example, in his January 2015 inaugural address, Governor Jerry Brown called for the state to obtain half of its electricity supply from renewables by 2030 (Brown 2015a). In the same speech, he also called for significant cuts in GHG emissions in buildings and transportation. In April 2015, Governor Brown also issued an executive order that directs the state reduce GHG emissions by 40 percent below 1990 levels by 2030 (Brown 2015b). The state legislature is currently considering bills that would raise the RPS to 50 percent by 2030 and codify a statewide target for reducing GHG emissions by 2030.

Achieving economy-wide GHG targets by 2030 may necessitate deploying renewable electricity more quickly than would be required by a 50 percent RPS in 2030. The future composition of the state's energy system will depend on many uncertain factors, including population growth, economic growth, the cost and availability of existing and new technology, and public policy. The electricity system may need to cut emissions very quickly if other sectors of the economy are not able to reduce GHG emissions fast enough. This is

FIGURE 1. **The CAISO Footprint**



The California Independent System Operator—known as the CAISO—balances electricity supply and demand across most of the state. The map also shows other grid operators responsible for balancing supply and demand within the state.

SOURCE: CAISO N.D.

especially true because a leading strategy to reduce economy-wide GHG emissions is to electrify transportation and heating.

Balancing Electricity Supply and Demand

A reliable electricity system maintains a balance between supply and demand every second, responding to fluctuations throughout the day. Operators of the electricity grid must also quickly restore this balance in the face of a loss of a major power plant or a transmission line. If they cannot do so quickly, large-scale power outages or other reliability challenges may occur.

The California Independent System Operator (CAISO) operates the grid that meets roughly 80 percent of electricity demand in California. The CAISO footprint includes the service territories of the state's three largest investor owned utilities—Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E)—as well as several municipal utilities and a small portion of Nevada (Figure 1). With entities in other states, the CAISO also operates the Energy Imbalance Market (EIM), which helps resolve imbalances between electricity supply and demand in real time.[1]

Grid operators such as the CAISO run computer algorithms a day in advance to ensure that supply and demand will remain in balance over the course of the next day. The algorithms rely on forecasts of electricity demand, wind and solar output, and any equipment outages at power plants or transmission lines. The forecasts are typically made in hourly blocks, but grid operators make further refinements to these predictions hours and minutes ahead of a given operating window.

Despite the use of increasingly sophisticated prediction techniques, no forecast is ever 100 percent accurate. In addition, predictions cannot account for variations in supply or demand that are faster than the timescale of the predictions. For example, if a prediction is made with an hourly resolution, operators must schedule resources to ensure that the grid can meet not only the hourly prediction but also virtually all variations in supply and demand *within* the hourly operating window. The same is true for shorter operating windows, such as five-minute schedules.

Grid operators need to keep resources available to adjust the balance between supply and demand when they deviate from what is predicted or scheduled. As California brings more renewable electricity online, grid operators will need to maintain enough operational flexibility to fulfill that need. Because two of the most prominent sources of renewable electricity—solar and wind—are driven by the weather, their power output is more variable and uncertain than that of conventional power plants. Integrating larger quantities of renewable electricity into the grid requires that operators have enough flexibility to manage this variability and uncertainty while maintaining a reliable power supply. Power system flexibility does not have a single, unified definition. Rather, there are many different attributes of flexibility, each of which may be more or less important for the purposes of renewable integration (Cochran et al. 2014).

Curtailing Renewable Electricity to Ensure Reliability

One of the most straightforward ways for grid operators to balance supply and demand is to curtail the output of renewable sources of electricity. According to a report from the National Renewable Energy Laboratory (NREL), "Curtailment is a reduction in the output of a generator from what it could otherwise produce given available resources" (Bird, Cochran, and Wang 2014). Curtailing output from renewable resources allows grid operators to balance supply and demand if the electricity system has excess electricity production. This is sometimes called "overgeneration." Grid operators can also curtail renewable sources to avoid situations where inadequate flexibility could lead to unmet electricity demand.

In the absence of other measures, curtailment is a default option for maintaining reliability when a system relies more heavily on renewable sources of power. Researchers have demonstrated that as the share of renewable sources of electricity rises, curtailment can be used to avoid reliability problems relating to inadequate operational flexibility (E3 2014; Liu 2014a; Mao and Galjanic 2014a; E3 2013). Although curtailment is dependable, it can also be expensive. Once wind or solar power plants have been built, producing electricity from these facilities is very inexpensive. Curtailing large amounts of renewable energy means the loss of low-cost power and could raise the cost of a system that relies more heavily on renewables.

Still, at a 50 percent RPS, it would not make sense to eliminate all curtailment events. Curtailing renewables will sometimes be less expensive than installing infrastructure or procuring resources to avoid curtailment. Striking a balance between

[1] We did not simulate the EIM in our study.

investing in power system flexibility to avoid curtailment and using curtailment as a flexibility tool will be important when integrating more renewable electricity into the grid to fulfill a 50 percent RPS.

A recent fact sheet from the Union of Concerned Scientists discusses the reliability of the electricity system in the context of integrating more renewable energy (UCS 2015). A recent report from GE Energy Consulting provides further information (Lew et al. 2015).

The Need for "Following Reserves"

RPS policies require that a fraction of electricity demand must come from renewable sources. While RPS policies have been successful in increasing the amount of electricity generated from renewable sources, the grid needs more than just the production of electricity to maintain reliable electric service. In California, conventional power plants—mostly natural gas and hydroelectric units—have traditionally provided these other essential reliability services, known as "ancillary services." The purpose of many ancillary services is to maintain the balance of electricity supply and demand.

Though the fundamental physical requirement to maintain a balance between electricity supply and demand is similar across different regions, the way grid operators actually perform this function varies and is continually evolving. The terminology used to describe different balancing functions can also vary, so readers are encouraged to consult references for a more complete picture of this subject, such as Kirby 2014; NERC and CAISO 2013; and Ela, Milligan, and Kirby 2011.

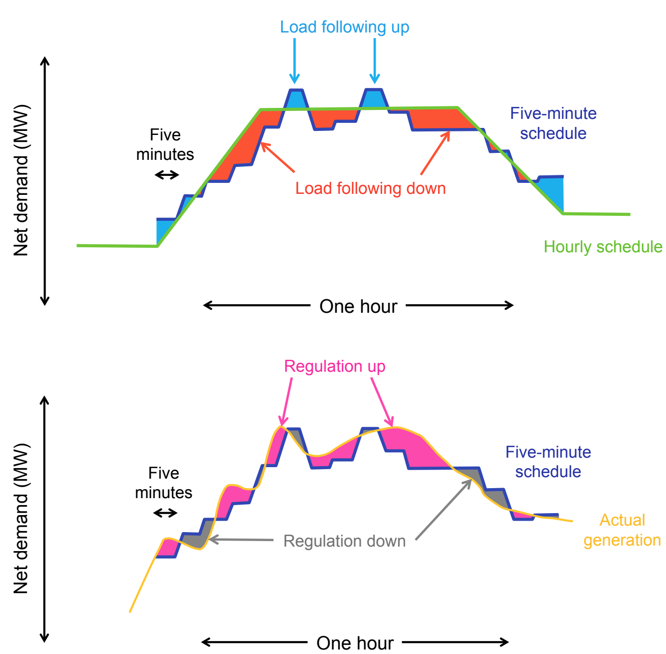
Grid operators use "following reserves"—a type of ancillary service—to fulfill sub-hourly increases and decreases in supply and demand, to correct for differences between forecasted and actual demand, and to account for fluctuations in power output from wind and solar facilities. Following reserves can be said to track a system's "net demand"—electricity demand minus the power output from wind and solar facilities. Grid operators dispatch following reserves throughout every hour of every day in response to net demand and predicted near-term conditions.

Two types of following reserves—load following and regulation—are commonly modeled in hourly production simulations. Load following ensures that grid operators have enough flexibility to bridge between schedules for hourly net demand and five-minute net demand. Regulation bridges between five-minute net demand schedules and actual second-by-second net demand. Both types of reserves must be able to move upward and downward, yielding four reserve products (Figure 2).

Following reserves are distinct from contingency reserves, which ensure that the grid can respond to a large and unexpected disturbance, such as the outage of a major power plant or a transmission line. Common examples of contingency reserves are spinning and non-spinning reserves. While contingency reserves are important to grid reliability, we will find below that their role in prompting grid operators to curtail renewable power is limited in our analysis, so we do not focus further discussion on these reserves.

CAISO operators procure some ancillary services through CAISO markets and other such services in different ways (CAISO 2014). For example, today they meet the need for following reserves through markets for both energy and ancillary services. Load following is not currently a CAISO ancillary service product. Instead, grid operators dispatch generation units on a five-minute basis through the real-time market. It is unclear whether this approach will continue to be

FIGURE 2. **Upward and Downward Following Reserves in a Power Grid**



Grid operators use load following reserves to bridge between hourly and 5-minute power schedules (top). Operators use regulation to bridge between 5-minute schedules and actual demand for electricity (bottom).

SOURCE: ADAPTED FROM MAKAROV ET AL. 2009.

adequate with higher levels of renewable energy, or whether the CAISO will need a more explicit load following ancillary services product. Load following is commonly modeled in hourly production simulations as an ancillary service (Liu 2014a; Mao and Galjanic 2014a; Ibanez et al. 2012). Regulation is currently a CAISO ancillary service product. To call on regulation reserves from electricity generators and other participating resources, grid operators send automatic signals every four seconds to increase or decrease power output.

Our Research Questions

This report addresses six questions regarding the expected need to curtail renewable sources of electricity to ensure a reliable grid with a 50 percent RPS in 2024. While we focused on the curtailment of renewables, we also calculated GHG emissions and the cost of producing electricity.

Question 1: How do curtailment of renewables, GHG emissions, and the cost of producing electricity change as the amount of renewable energy rises to fulfill a 50 percent RPS?

Question 2: What are important drivers of renewable curtailment at a 50 percent RPS?

The final four questions address grid management solutions that could reduce curtailment:

Question 3: If renewables could contribute to reserves, how much curtailment would be eliminated?

Question 4: What are the benefits of relying on non-generation grid management strategies to provide operational flexibility?

Question 5: How much can additional natural gas plant flexibility reduce curtailment of renewables?

Question 6: How does more non-fossil flexibility compare with more gas plant flexibility in reducing renewable curtailment?

Study Scope and Modeling Methodology

A 50 Percent RPS Requirement in 2024

To answer our research questions, we modeled the CAISO grid in 2024 at a 33 percent RPS, a 40 percent RPS, and a 50 percent RPS, to understand how renewable energy curtailment, GHG emissions, and electricity production costs change as more renewables are brought online. We also performed "sensitivity" runs of our model—which explored variations on the 50 percent RPS base scenario—to better understand which strategies would be most effective in reducing renewable curtailment and GHG emissions from the CAISO power system.[2]

Our focus on the year 2024 allowed our study to share many common assumptions with modeling in the 2014 Long-Term Procurement Plan (LTPP) of the California Public Utilities Commission (CPUC). The 2014 LTPP simulates the 2024 CAISO electricity grid in detail, and forms the basis for procurement authorization that the CPUC may grant to investor-owned utilities. The LTPP studies the need for operational flexibility with increased amounts of wind and solar power, and ensures safe and reliable electric power that is cost-effective for ratepayers and conforms to state policy goals.

Recent studies—including those performed as part of the LTPP—have shown that many natural gas–fired power plants can be generating electricity while ample renewable power is available, forcing grid operators to curtail production from renewables (E3 2014; Liu 2014a; E3 2013). This dynamic becomes more pronounced when the RPS rises to 40 percent or 50 percent. However, California must reduce the amount of electricity produced by natural gas power plants to meet its long-term goals for reducing GHG emissions. Our modeling identified deficiencies in the projected 2024 CAISO power system that keep fossil fuel generation online to meet essential reliability and flexibility needs, especially when ample renewable generation is available but is being curtailed. Our modeling also explored solutions to address flexibility challenges.

While our study focused on 2024, it can inform policy discussions about how California can reach 50 percent renewables by 2030. Other regions will face similar challenges as they integrate more wind and solar power into the electricity grid, so they, too, can apply many of the strategies we explored.

A Diverse Portfolio of Renewables

Between a 33 percent RPS and a 50 percent RPS, we added a relatively diverse mix of renewables: one-third wind, one-third large-scale solar photovoltaics (PV) and solar thermal, and one-third baseload renewables: geothermal, biomass, and biogas (Figure 3). In the 50 percent RPS portfolio, the total in-state installed capacity of these resources is 8.5 gigawatts (GW), 17.1 GW, and 4.3 GW, respectively. We kept the amount of small hydroelectric capacity constant at 0.7 GW. We chose this resource mix because of the many benefits of portfolio diversity, but did not attempt to create an "optimal" renewable portfolio. We assumed that wind and large-scale solar generators could be curtailed at a price of $100 per megawatt-hour (MWh). This price is a reasonable approximation of the price of power purchase agreements (PPAs).

We kept in-state large-scale hydro—which does not count toward RPS compliance—at historical levels. And we kept rooftop photovoltaics—known as behind-the-meter PV—constant at 4.6 GW. We based the amount of behind-the-meter PV on the mid-demand baseline of the California Energy Commission's (CEC's) 2024 demand forecast (CEC 2014). Consistent with current practices, we did not count behind-the-meter PV towards RPS compliance.

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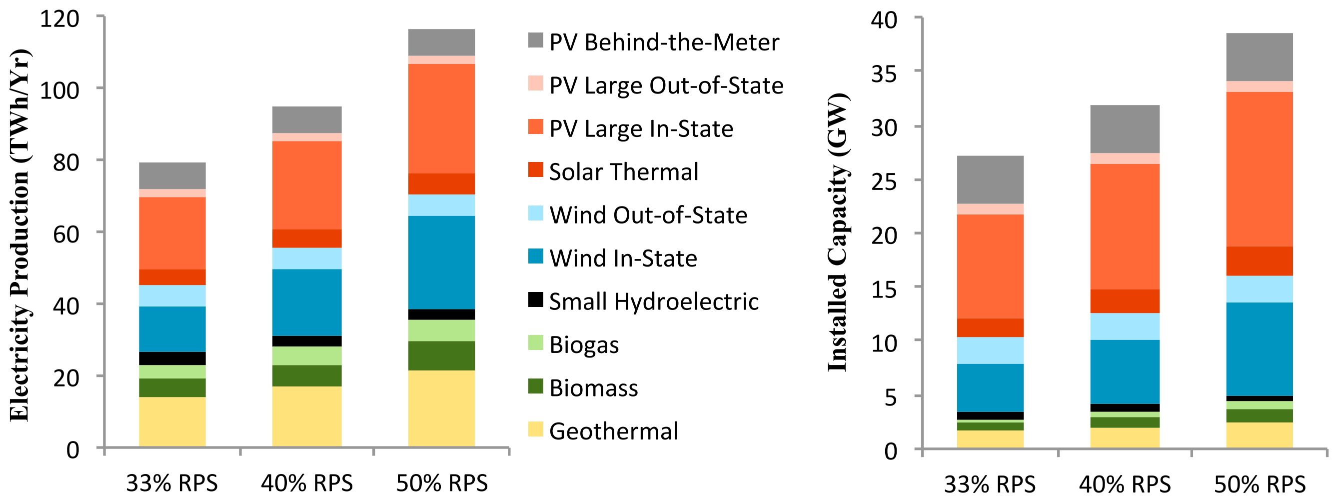
[2] CO_2 emissions are the only kind of GHG emission that we modeled.

FIGURE 3. **Renewable Power Production and Installed Capacity at Different RPS Targets in 2024**



When raising the RPS from 33 percent to 50 percent, we increased the amount of electricity produced by in-state renewable resources (left), and the installed capacity of those resources (right), which included large-scale PV, wind, biogas, biomass, and geothermal.

We did not include electricity produced from behind-the-meter PV in the calculation of RPS percentage, but we include it here for completeness. TWh = terawatt-hours.

We assumed that all incremental additions of renewables between a 33 percent and a 50 percent RPS would come from in-state resources. That means that only 7 percent of all RPS-eligible electricity production at 50 percent RPS originates from out-of-state. All else equal, increasing the geographic diversity of the renewable mix would likely decrease flexibility needs and renewable curtailment. Our scenarios are therefore relatively conservative for a given RPS requirement.

More Modeling Assumptions

To understand how the CAISO electricity grid would operate with larger fractions of renewable energy, we used the PLEXOS simulation software (Energy Exemplar n.d.), which is widely used for such studies. Table 1 summarizes what our analysis did and did not address. For more information on our methodology, see the appendix.

To simulate a wide range of conditions over which the electricity grid must function, each run of our model used more than two years—739 days, or 17,736 hours—of hourly data on wind and solar power production, electricity demand, requirements for following reserves, and generator outages. Energy and Environmental Economics (E3) generously provided these data. Although we model more than two years of data, the results represent only the year 2024. E3 paired profiles of wind and solar power production with profiles of electricity demand based on the month and the level of electricity demand.

Our model represented the flexibility of individual conventional gas-fired power plants, storage facilities, and advanced demand response resources in detail. The fleet of natural gas power plants and the operational characteristics of these plants was virtually identical to that found in the CAISO PLEXOS 2014 LTPP model (Liu 2014a), and therefore represented an up-to-date projection of the CAISO gas fleet in 2024. We modeled 42 combined-cycle gas turbine (CCGT) units with a total capacity of 15.1 GW, and 124 combustion turbine/peaker units with a total capacity of 6.7 GW. In our study, almost all the once-through cooling natural gas plants have been retired (SWRCB 2010). To be consistent with the CAISO PLEXOS 2014 LTPP model, our model replaced some of these plants with new gas units. To retain a CAISO-centric focus, our model represented gas power plants outside CAISO as a single aggregated generator that is less efficient than most CAISO peaking units. This representation caused our model to rely on natural gas power plants inside the CAISO footprint before drawing on natural gas power plants outside of the CAISO footprint.

All runs of our model included 1,325 megawatts (MW) of new electricity storage authorized by the CPUC's storage decision (CPUC 2013). In some model runs, we added even more electricity storage to the CAISO grid. All of our model runs also included 2.4 GW of conventional demand response (Liu 2014a). Conventional demand response decreases demand during periods of inadequate system capacity but cannot increase demand.

We assumed that the CAISO cannot export more electricity than it imports in any given hour, but we relaxed that assumption in model runs with additional non-generation flexibility. We restricted multi-hour increases and decreases in power output from imported electricity and CAISO hydroelectric generators to historic levels. Our model did not represent transmission constraints in detail within CAISO, although it did enforce generation requirements in specific regions of the CAISO service territory.

We simulated a middle-of-the-road electricity demand by using the CEC's "mid" demand baseline and "mid" additional achievable energy efficiency savings (CEC 2014). Consistent with the CEC's demand projection, we assumed that 2 million electric vehicles will be on the road in the CAISO region in 2024.

A complete picture of electricity costs would include generation and transmission capital costs, annual maintenance costs, and production costs. Our model quantified only production costs, including fuel costs, variable maintenance costs, the cost of permits for GHG emissions, the costs of starting up and shutting down natural gas power plants, and costs associated with calling upon demand response resources. Understanding the total cost of deploying and integrating more renewable resources would entail quantifying their capital and annual maintenance costs as well as other resources installed to increase power system flexibility. A discussion of capital and annual maintenance costs is outside the scope of our work.

Our model included six following and contingency reserve products: load following up, load following down, regulation up, regulation down, spinning, and non-spinning. We modeled each reserve as a single CAISO-wide product. For each reserve

TABLE 1. **What Our Analysis Does and Does Not Address**

Our analysis does:	Our analysis does not:
Focus on the year 2024	Simulate years other than 2024
Use industry standard software to simulate the CAISO electricity system	Simulate other sectors of the economy
Include electricity demand from 2 million electric vehicles within the CAISO footprint	Determine an optimal amount of vehicle electrification
Include a diverse portfolio of renewables	Optimize a portfolio of renewables or focus on a single renewable technology
Simulate detailed grid operations and constraints on generators and resources inside the CAISO footprint	Simulate detailed grid operations and constraints on generators and resources outside the CAISO footprint
Include generation requirements in specific regions inside the CAISO footprint	Model transmission constraints inside the CAISO footprint
Explore a variety of ways to reduce renewable curtailment	Find an optimal amount of renewable curtailment or grid flexibility
Quantify renewable curtailment, production costs, and GHG emissions from electricity production	Quantify capital and fixed costs of renewable generators or additional grid flexibility
Quantify shortfalls in generation capacity and reserves	Perform an analysis of system capacity need or loss of load expectation

product, the hourly reserve requirement (in MW) was calculated before running the PLEXOS simulation. We assumed that the CAISO must hold spinning and non-spinning reserves equal to 3 percent of electricity demand (6 percent total) during each hour (Liu 2014a; Mao and Galjanic 2014b). E3 calculated load following and regulation requirements using a methodology that is similar to the Eastern Wind Integration and Transmission Study (EnerNex 2011) and is also used in E3's REFLEX work (E3 2014; E3 2013). For more information on reserve requirements, see the appendix.

Our model builds on many recent electricity modeling studies focusing on California or the western United States. These studies include work by E3 (E3 2014; E3 2013), the CAISO (Liu 2014a), Southern California Edison (Mao and Galjanic 2014a), UCS (Nelson 2014), and NREL (Brinkman, Jorgenson, and Hummon 2014; Jorgenson, Denholm, and Mehos 2014; Denholm et al. 2013; Hummon et al. 2013). Our model most closely resembles the E3 work, which used the REFLEX production cost model. However, there are important differences between the E3 and UCS modeling, including the treatment of load following reserves.

Regional Generation Requirements

Today's electricity system has been designed to operate reliably using conventional power sources such as steam turbines, combustion turbines, and hydroelectric turbines. Conventional power plants can provide a number of services to support grid reliability, such as:

- providing voltage support and reactive power;
- providing inertia and primary frequency response/governor response;
- contributing to local and system-wide requirements for operating reserves;
- mitigating transmission congestion by providing capacity in local areas; and
- producing electricity near demand centers in case key transmission lines fail.

Non-conventional resources such as solar, wind, demand response, electricity storage, and smart grid technologies could often provide these services (Lew et al. 2015; Nelson 2014). However, today there is a lack of incentives to provide many of these services from renewable or non-generation resources. Many modeling studies have therefore made the conservative assumption that CAISO will need to keep conventional power plants, including gas-fired facilities, online and generating electricity to maintain reliability.

To be consistent with these studies, all our model runs (unless otherwise specified) included the CAISO's assumption in the 2014 LTPP that conventional power plants—natural gas, nuclear, cogeneration, and large hydroelectric—within the CAISO footprint must supply 25 percent of electricity demand in each hour (Liu 2014a). Under these assumptions, conventional power plants must also supply 25 percent of demand each hour in both the SCE's and the SDG&E's service territories. These rules are known as regional generation requirements.

Summary Tables of Model Assumptions and Results

Three tables—Table 2 through Table 4—summarize the various model runs performed in our study. Table 2 and Table 3 are found below, while Table 4 focuses on the question of natural gas power plant flexibility and is found in the section discussing research question number five.

TABLE 2. **Summary of Our Model Runs, Except Those Relating to Natural Gas Power Plant Flexibility**

Run Name	Research Question (#)	RPS in 2024 (percent)	Advanced Demand Response (GW)	Additional Storage (GW)	Maximum Net Exports (GW)	Downward Reserve Requirements Enforced?	Regional Generation Requirements Enforced?	Renewables Provide Reserves?
33 Percent RPS	1	**33**	0	0	0	Yes	Yes	No
40 Percent RPS	1	**40**	0	0	0	Yes	Yes	No
50 Percent RPS	1	50	0	0	0	Yes	Yes	No
Remove Downward Reserves	2	50	0	0	0	**No**	Yes	No
Remove Downward Reserves and Regional Generation Requirements	2	50	0	0	0	**No**	**No**	No
Renewables Provide Reserves	3	50	0	0	0	Yes	Yes	**Yes**
3 GW Additional Non-Generation Flexibility	4	50	**1**	**1**	**1**	Yes	Yes	No
6 GW Additional Non-Generation Flexibility	4	50	**2**	**2**	**2**	Yes	Yes	No
9 GW Additional Non-Generation Flexibility	4	50	**3**	**3**	**3**	Yes	Yes	No
Non-Fossil Solutions	6	50	**1**	**1**	**1**	Yes	Yes	**Yes**

All the sensitivity runs of our model built on the 50 percent RPS base scenario. Bold fields represent differences from that scenario. The first column links each model run to the most relevant research question. This table includes all of our model runs except for those relating to natural gas power plant flexibility, which are described in Table 4.

TABLE 3. **Results from All Model Runs**

Run Name	RPS-Eligible Renewable Generation Potential (TWh/Yr)	Renewable Curtailment (TWh /Yr)	Renewable Curtailment (percent of RPS-Eligible Potential)	CO_2 Emissions ($MMTCO_2$/Yr)	Production Cost ($ Billion/Yr)*
33 Percent RPS	72.2	0.07	0.10	52.4	5.84
40 Percent RPS	87.7	0.75	0.86	46.8	5.24
50 Percent RPS	109.8	5.21	4.75	41.1	4.67
Remove Downward Reserves	109.8	1.60	1.45	39.0	4.39
Remove Downward Reserves and Regional Generation Requirements	109.8	1.05	0.95	38.7	4.35
Renewables Provide Reserves	109.8	2.91	2.65	39.1	4.43
3 GW Additional Non-Generation Flexibility	109.8	1.56	1.43	38.8	4.46
6 GW Additional Non-Generation Flexibility	109.8	0.39	0.36	37.6	4.36
9 GW Additional Non-Generation Flexibility	109.8	0.09	0.08	37.0	4.31
Double Ramp Rate for Natural Gas Plants	109.8	5.16	4.70	41.1	4.66
Half Minimum Power Level for CCGTs	109.8	3.50	3.18	39.5	4.42
Flexible Gas	109.8	3.29	3.00	39.0	4.38
Double Ramp Rate for Gas Plants, with Renewable Reserves	109.8	2.88	2.62	39.1	4.43
Half Minimum Power Level for CCGTs, with Renewable Reserves	109.8	2.26	2.06	38.5	4.30
Flexible Gas, with Renewable Reserves	109.8	2.15	1.96	38.1	4.27
Flexible Gas Extreme	109.8	2.76	2.52	38.3	4.27
Non-Fossil Solutions	109.8	1.20	1.10	38.1	4.37

This table shows key results from all our model runs to allow for easy comparison.

* Production cost does not include the cost of renewable curtailment.

TWh = terawatt-hours. $MMTCO_2$/Yr = Million metric tons of carbon dioxide per year. CCGT = combined-cycle gas turbine.

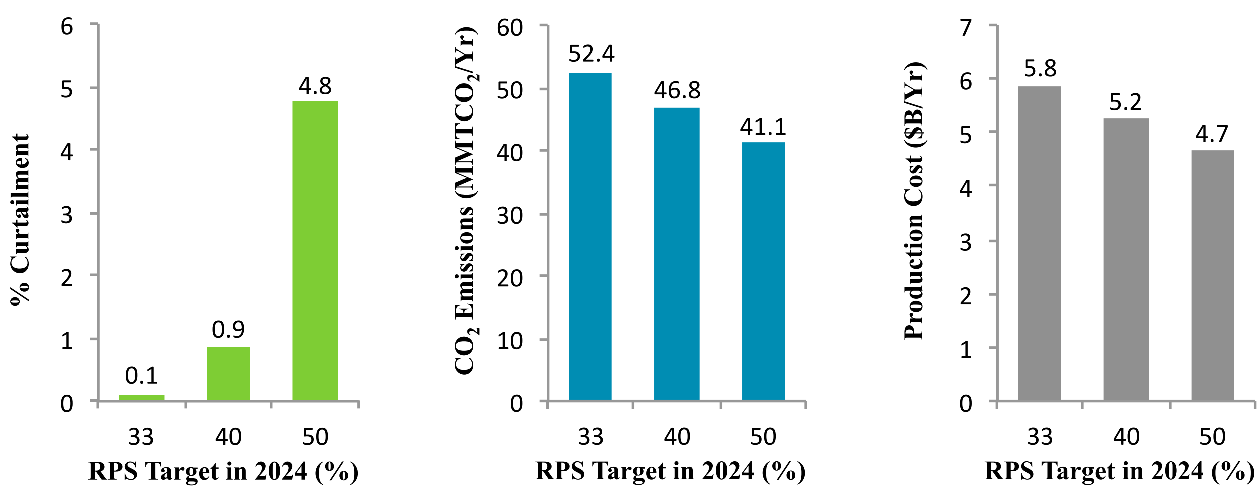
How do curtailment of renewables, GHG emissions, and the cost of producing electricity change as the amount of renewable energy rises to fulfill a 50 percent RPS?

Our model shows that without making additional changes to the grid, as California's RPS rises from 33 percent to 50 percent, renewable electricity replaces electricity generated from natural gas power plants both inside and outside the CAISO. The result is that GHG emissions fall by 22 percent, and production costs drop by 20 percent (Figure 4).

As the RPS rises, the model increasingly relies on renewable curtailment as a reliability tool. While GHG emissions and production costs drop as the RPS rises, renewable curtailment increases. In the 50 percent RPS base scenario, 4.8 percent of available renewable energy is curtailed over the course of the year, as opposed to 0.1 percent at a 33 percent RPS. Curtailment in the 50 percent RPS occurs primarily during daylight hours, especially in the spring (Figure 5).

When the RPS rises from 33 percent to 50 percent, the grid absorbs 86 percent of the incremental renewable energy, while 14 percent is curtailed. Given that integrating large fractions of renewable electricity is perceived to be difficult, 86 percent is

FIGURE 4. **Changes in Renewable Curtailment, CO_2 Emissions, and Production Cost as the RPS Rises**



Curtailment of renewables increases as the RPS rises. However, both CO_2 emissions and the cost of producing electricity drop.

$MMTCO_2$/Yr = million metric tons of CO_2 per year. The dollar-year is 2014.

impressive, especially because we did not add operational flexibility when moving from a 33 percent RPS to the 50 percent RPS base scenario. The relatively low value of 4.8 percent curtailment indicates that the CAISO's projected 2024 fleet of natural gas, hydroelectric, and storage facilities is already somewhat flexible. These findings suggest that the projected 2024 CAISO grid can accept a substantial amount of additional renewable generation. We note that the amount of curtailment in this scenario depends on the mix of renewable resources, and would likely have been higher if we had used a less diverse portfolio of renewables.

In calculating the mix of renewables for a given RPS, we assumed that zero curtailment would occur. Thus when curtailment occurs in the simulation, more renewable generation would be needed to fulfill the RPS. We did not model this dynamic explicitly, but instead explored ways to reduce curtailment and narrow the gap between the amount of renewable electricity not curtailed in the simulation and the amount required to fulfill a 50 percent RPS.

Natural gas generation and renewable curtailment occur together in 18 percent of all hours in the 50 percent RPS base scenario (Figure 6). During these hours, the amount of curtailed renewable energy could typically replace between 0 and 6 GW of electricity from gas, if the reliability services provided by natural gas facilities were provided by other sources. The coincidence of gas generation and renewable curtailment during hours 6 to 16 of a low-demand May weekend day is a near-worst case (Figure 7). In these hours, 7.2 to 13.4 GW of renewable generation is curtailed while 3.6 to 5.6 GW of electricity is generated from gas peaker and combined-cycle plants. Many of the ways that curtailment, CO_2 emissions, and production costs can be reduced depend on reducing the amount of power from natural gas facilities when ample renewable energy is available but is being curtailed to maintain grid reliability.

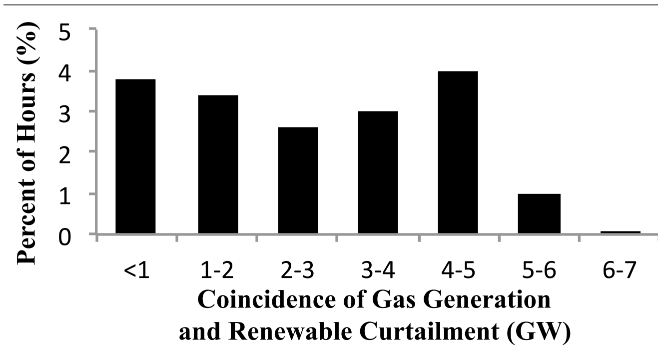
FIGURE 5. **Renewable Curtailment by Month and Hour of the Day in the 50 Percent RPS Base Scenario**

Hour of Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0	0	62	15	206	45	0	0	15	4	0	2
1	0	3	91	9	200	24	5	0	8	3	0	0
2	0	0	72	6	167	16	7	0	28	0	0	0
3	0	1	56	0	87	15	0	0	0	0	0	0
4	0	0	27	2	28	16	0	0	0	0	0	0
5	0	0	0	11	66	23	0	0	0	0	0	0
6	0	0	5	214	381	397	15	0	0	0	0	0
7	0	49	562	1407	1616	1198	192	7	112	301	41	42
8	248	452	2215	2473	2227	1458	296	59	427	1003	703	269
9	876	1134	3333	3169	2674	1587	193	55	513	1450	1227	869
10	1381	1707	4130	3727	3094	1709	155	29	547	1761	1636	1429
11	1891	2432	4874	4310	3473	1719	137	1	510	1973	2066	1968
12	2223	2732	5036	4319	3580	1702	119	0	365	1778	2181	2258
13	2029	2613	4820	4079	3448	1589	78	0	262	1459	1989	2132
14	1585	2056	4296	3427	3241	1322	48	0	163	1042	1306	1452
15	782	1176	3363	2552	2867	971	5	0	68	353	124	335
16	2	56	1232	1088	1829	572	0	0	11	0	0	0
17	0	0	0	5	276	68	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	17	0	0	0	0	0	0	0
22	0	0	0	0	79	17	0	0	0	0	0	0
23	0	0	26	59	128	31	1	0	0	0	0	0

In the 50 percent RPS base scenario, renewable curtailment occurs primarily during daylight hours, especially in the spring. This timing suggests that solar power is frequently being curtailed.

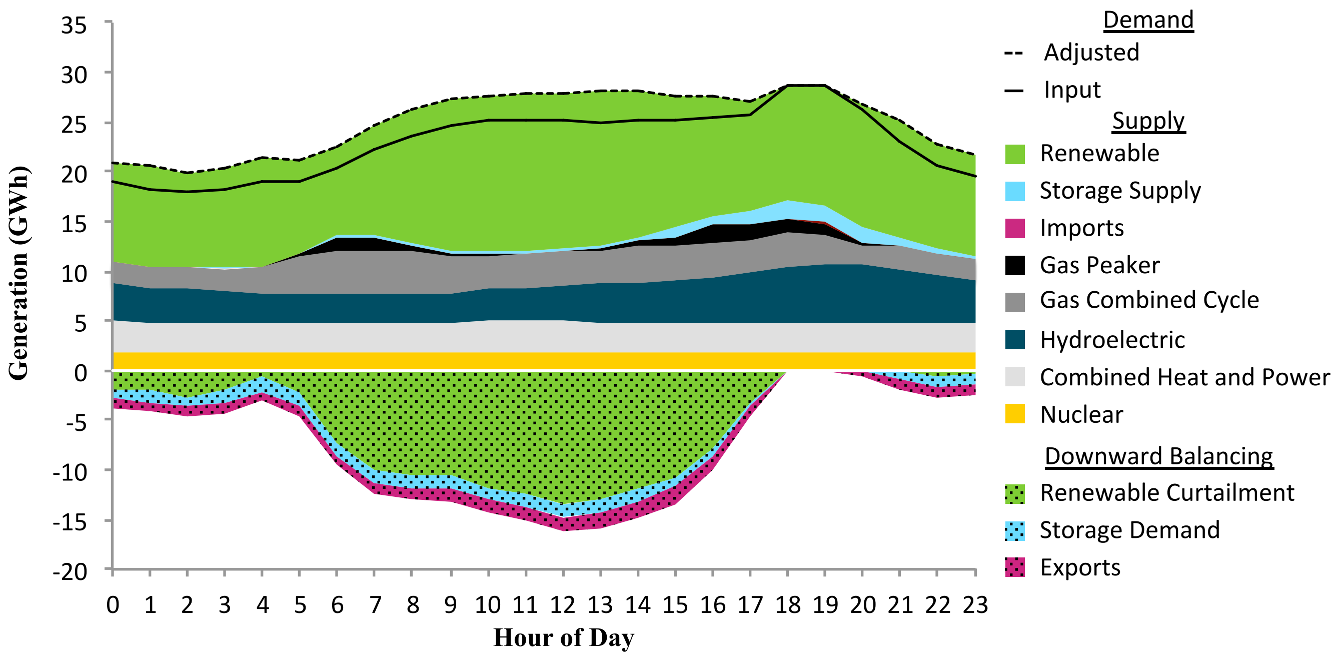
Values represent the average MW of curtailment within the CAISO footprint during a given combination of month and hour of day.

FIGURE 6. **Share of Hours When Natural Gas Generation and Renewable Curtailment Occur Together**



This figure shows the amount of power from dispatchable gas plants (peaker and CCGT) that could be replaced by curtailed renewable generation in the 50 percent base scenario. This replacement could occur if other resources were to able deliver reliability services provided by gas plants during times of renewable curtailment. Gas generation and renewable curtailment occur together during 18 percent of all hours of the year.

FIGURE 7. **Power System Dispatch on a Weekend Day in May at a 50 Percent RPS**



Renewables are curtailed during many hours in which natural gas power plants are producing electricity. Renewable curtailment is higher on this day than on the other 738 days simulated in the 50 percent RPS base scenario.

"Load" is the input load profile. "Adjusted load" includes additional demand from exported and stored power.

Deploying Additional Renewable Energy Can Count Toward the Adequacy of System Capacity, but Does Not Eliminate the Need for Natural Gas Power Plants

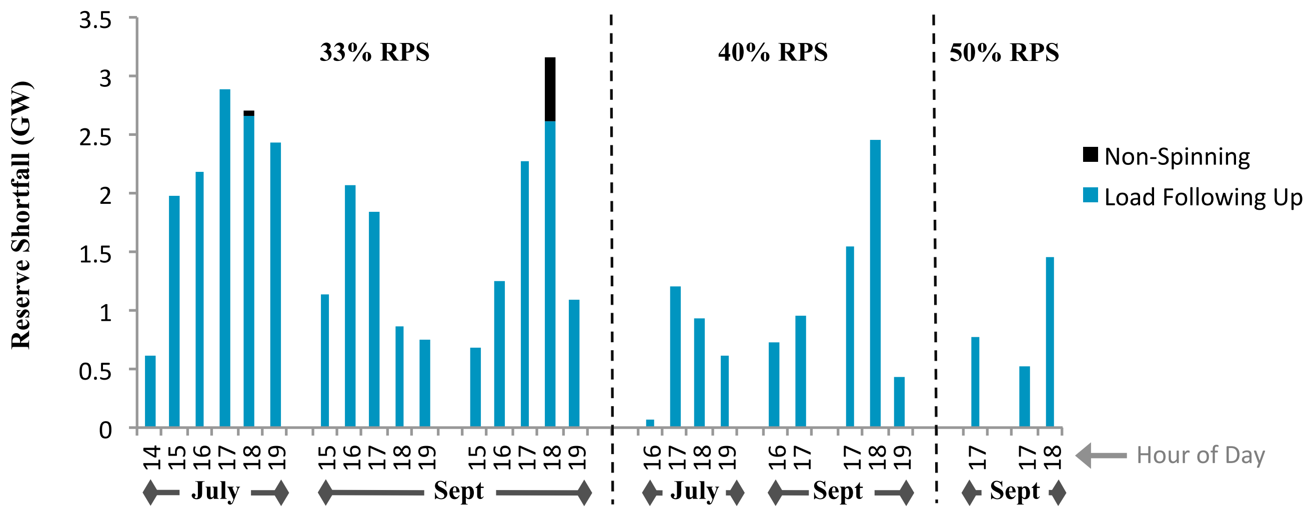
"Reserve shortfalls" occur during hours when the grid lacks enough capacity to meet reserve requirements. When more renewables are added to the system, both the frequency and magnitude of reserve shortfalls drop (Figure 8).

The fleet of conventional generators and non-renewable resources is identical in the 33 percent, 40 percent, and 50 percent RPS base scenarios, so any difference in reserve shortfall reflects changes in the fleet of renewables. Baseload renewables—geothermal, biomass, and biogas—added between the 33 percent RPS scenario and the 50 percent RPS base scenario are likely providing much of the additional "capacity adequacy," though wind and solar contribute as well. These results suggest that deploying renewable energy can support capacity adequacy—sometimes known as "resource adequacy."

We did not find reserve shortfalls or loss of load from inadequate operational flexibility. Our model curtailed renewable energy to avoid flexibility-related reserve shortfalls.

While renewables, advanced demand response, and electricity storage contribute to the adequacy of system capacity, our model could not determine whether additional capacity to meet net peak demand is needed. Traditional loss-of-load analyses calculate the probability of inadequate capacity as a number of events or hours over a 10-year timeframe, and then compare that probability to a reliability standard to determine if the system needs more capacity. The two years of hourly data simulated by our model are not enough to calculate loss-of-load frequency or expectation with ample precision. We also did not simulate how the ability to import electricity into the CAISO changes with the deployment of more renewables. A complete picture of the adequacy of system capacity would need to include a more detailed treatment of electricity imports.

FIGURE 8. **Shortfalls of Operating Reserves as the RPS Rises, by Month and Hour**



Both the frequency and magnitude of reserve shortfalls drop as the RPS rises. This indicates that adding renewable energy to the grid helps ensure that the grid has adequate resources to meet demand.

We do not observe any hours in any model run that do not have enough capacity to meet the hourly average expected demand. However, we do observe reserve shortfalls, which suggests that demand for electricity could be unmet within some operating hours.

Natural gas power plants will play an important role in meeting demand during the highest peak net demand hours through 2024. During those hours, virtually all available gas plants will be operating, with most plants running near or at their maximum output. Even in the 50 percent RPS base scenario, the fleet of CAISO resources experiences some reserve shortfalls. That means the system is operating close to the point at which additional capacity is warranted.

The retirement of thousands of megawatts of gas generation that we assumed would be available in 2024 could lead to reliability problems from inadequate system capacity during peak net demand hours. California should strive to turn down or off all possible fossil fuel generation during times of abundant renewable electricity production. However, enough power from renewable and other resources will not be available at some points during the year, and the system will need backup capacity and power from natural gas plants.

What are important drivers of renewable curtailment at a 50 percent RPS?

We removed reliability requirements from the 50 percent RPS base scenario in two sensitivity runs, to reveal the impact on renewable curtailment. We do not want to suggest that grid planners and operators should disregard reliability requirements when integrating higher fractions of renewable energy. Rather, we performed these sensitivity runs to highlight important areas for further analysis.

In the first sensitivity run, we removed downward reserve requirements: load following down and regulation down. In the second sensitivity run, we removed both downward reserve requirements and regional generation requirements. The goal in doing so was to demonstrate the implications of continuing to rely on conventional power sources to provide reliability services delivered by regional generation requirements.

We did not perform a sensitivity run in which only the regional generation requirements were removed. We observed from shadow prices that downward reserve requirements were a more stringent requirement on grid operations than regional generation requirements. Put another way, removing the regional generation requirements without removing downward reserve requirements would not have been likely to substantially change the simulation results. This is because there are few hours in the 50 percent RPS base scenario in which fulfilling downward reserve requirements does not also fulfill regional generation requirements.

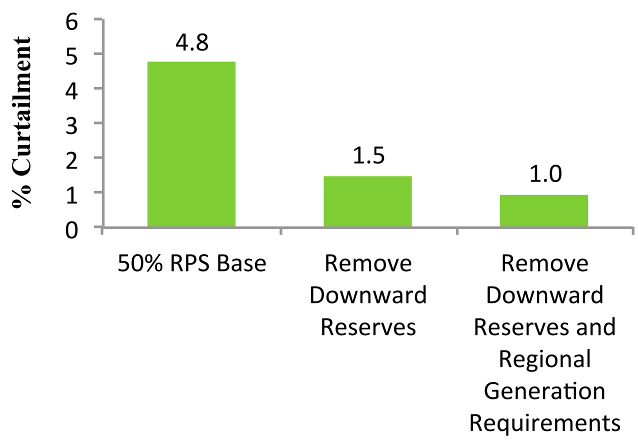
How Downward Reserves Drive Curtailment

Downward reserves are a major driver of renewable curtailment in the 50 percent RPS base scenario. When downward reserve requirements are removed, curtailment drops by 69 percent (Figure 9). GHG emissions also drop by 5.4 percent, and production costs decline by 6.0 percent.

These results highlight that our model is keeping natural gas power plants online during times of renewable curtailment to provide downward reserves. Electricity produced by these power plants "crowds out" renewable generation by forcing renewables to be curtailed to avoid an overgeneration situation. This method of providing downward reserves causes GHG emissions from natural gas power plants that could be avoided if other sources of downward reserves were available.

Grid operators and planners have typically overlooked the ability to turn down conventional power generation on the sub-hourly timescale. This omission is due to

FIGURE 9. **How Curtailment of Renewables Changes as Reliability Requirements Are Removed**



Curtailment as a share of available renewable energy drops markedly at a 50 percent RPS as requirements for downward reserves and regional generation are removed.

Reliability requirements are essential to proper grid operation. We removed requirements to show that they are important drivers of renewable curtailment.

a few factors. First, absent significant amounts of wind and solar generation, requirements for following reserves have been relatively small compared with total electricity demand. Second, conventional fossil fuel power plants could easily provide downward flexibility because they have been unlikely to operate near their minimum load during many times of the year. However, renewable energy increases the variability of net demand while also shutting off conventional generators or driving them to their minimum loading. Both of these considerations raise the importance of downward following reserves in electricity operations. Planning for adequate supplies of downward following and regulation reserves from resources that do not crowd out renewable generation will become important as the share of renewables exceeds 33 percent of retail sales.

Regional Generation Requirements Also Drive Curtailment

Regional generation requirements are a significant driver of renewable curtailment.[3] When we remove requirements for regional generation as well as downward reserves, curtailment declines by another 11 percent compared with the 50 percent RPS base scenario (Figure 9). Together, downward reserve and regional generation requirements account for 80 percent of the curtailment of renewables in the 50 percent RPS base scenario.

These findings demonstrate that to reduce renewable curtailment, grid operators will need to gradually phase out contributions to power system reliability currently made by natural gas generators, and replace these contributions with non-fossil resources. If this replacement does not occur, grid operators may be forced to keep natural gas generators online and generating electricity (and thus producing GHG emissions) when ample electricity production is available from renewable and/or zero carbon sources. Our results underscore the need to better quantify the amount of each reliability service the grid requires to meet regional reliability needs, and to determine whether renewable or non-generation resources could meet those needs. Fulfilling these needs with resources that will not crowd out renewable energy would reduce renewable curtailment and GHG emissions and enable the grid to integrate more renewable electricity.

We encourage further study of the reliability services provided by regional generation requirements. While it is beyond the scope of this study to model these reliability services in more detail, we have a few specific recommendations for further work. A recent proposal from the Electric Reliability Council of Texas to design and optimize markets for frequency response and inertia alongside markets for energy and other ancillary services can provide a starting point on which California can build (ERCOT 2013). We also recommend that grid planners and operators should incentivize or require owners of renewable and non-generation resources to provide adequate voltage support. And resource planners should consider regional generation and capacity requirements when determining the location of renewable and non-generation resources.

Curtailment from Mismatches Between Electricity Supply and Demand

Mismatches between when renewable facilities are producing electricity and when electricity is demanded on the timescale of one to many hours can also drive curtailment of renewables. For example, wind and solar facilities may produce power at relatively high output during spring weekends, when electricity demand tends to be low. If grid operators have exhausted all ways to use the wind and solar power and have also turned down all other must-run resources (such as combined heat and power, hydroelectric, nuclear, and baseload renewables) as far as possible, they will have to curtail output from wind and solar facilities.

The sensitivity run in which we removed requirements for both downward reserves and regional generation suggests that less than 1 percent of curtailment in the 50 percent RPS base scenario stems from this type of supply-demand mismatch. As we explore below, increasing the amount of demand response, electricity storage, or export capability can help resolve this type of mismatch. However, we focus on the provision of reserves because they play a more central role in curtailment of renewables in our work.

Previous sections identified factors that drive curtailment.[4] The next sections focus on potential solutions to reduce curtailment.

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[3] These results are relatively consistent with UCS testimony in the 2014 LTPP (Nelson 2014). However, see the section of the appendix to this report entitled "How Our Results Relate to UCS Testimony" for information on a few important differences between the two studies.

[4] We did not address renewable curtailment that could occur because of transmission constraints.

If renewables could contribute to reserves, how much curtailment would be eliminated?

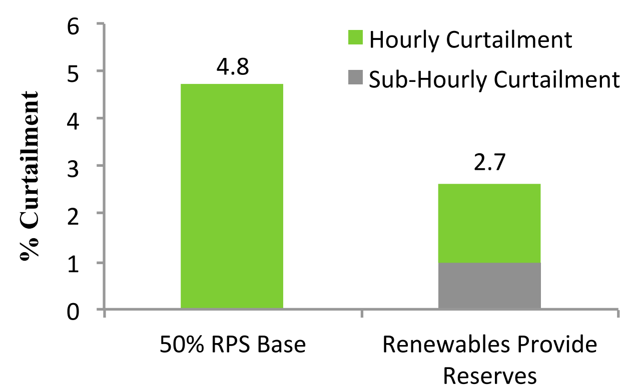
In the past, wind and solar power have largely been viewed as inflexible because of the variability and uncertainty of their fuel supply. However, recent advances in grid management have allowed operators to begin using renewable facilities to balance electricity supply and demand. Still, relying on renewables to provide flexibility or operational reserve capacity is not yet a universally accepted practice.

Research shows that solar and wind power plants can provide a variety of balancing services, if their owners have incentives to install or activate appropriate control technology (Lew et al. 2015; Morjaria et al. 2014; Ela et al. 2013). Some renewable generators currently provide bids to reduce power output into CAISO markets, allowing them to be curtailed efficiently during oversupply conditions. However, studies for the 2014 LTPP did not model renewable generators as able to contribute to any reserve products (Liu 2014a; Mao and Galjanic 2014a).

A recent report from NREL summarizes examples from grid operators outside California that use renewable energy to provide reserves or system balancing (Bird, Cochran, and Wang 2014). For example, in the territory of the Public Service Company of Colorado, wind power units can provide both downward and upward regulation. The Midcontinent Independent System Operator and the Electric Reliability Council of Texas include wind power bids in energy market operations, allowing for efficient and economic curtailment of wind facilities. These bids help fill the need for downward balancing similar to the downward load following reserves that we modeled.

As highlighted in the sensitivity run in which we removed downward reserves from the 50 percent RPS base scenario, reserve products that must be online to provide downward flexibility can cause substantial amounts of renewable curtailment. To explore the value of allowing renewable energy to provide reserves, we performed a run in which we allowed wind and solar generators to provide a maximum of 20 percent of their potential hourly power output toward reserve products. The results of that run suggest that allowing renewables to provide downward load following and regulation reserves could be particularly valuable.

FIGURE 10. **Renewable Curtailment in the 50 Percent RPS Base Scenario and the Renewables Provide Reserves Run**



When renewables contribute to reserves, the total amount of curtailment is reduced by 44 percent.

Sub-hourly curtailment is the amount of curtailment expected if renewables are operated flexibly and curtailed on a sub-hourly timescale.

Modeling Renewable Reserves

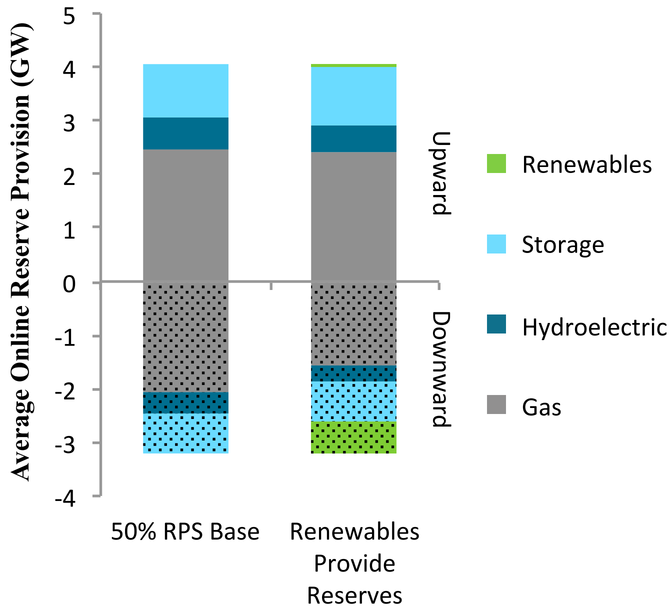
By default, we did not allow renewables to provide operational reserves. In this section we briefly describe how we modeled renewable generators providing reserves. See the appendix for more on our modeling of renewable reserves, and Tables 2 and

4 for a list of all model runs in which we allowed renewables to provide reserves.

We modeled wind and large-scale solar power facilities as bidding into reserve markets at costs consistent with a PPA price of $100 per MWh. When renewables provide upward reserves, they must be operating in a curtailed state until dispatched upward. When renewables provide downward reserves, they will be curtailed on the sub-hourly timescale when dispatched downward. Our treatment of renewable reserves determined the opportunity cost of renewables providing a reserve product based on the expected amount of curtailment and the cost of that curtailment.

We allowed wind and solar power facilities to provide reserves with up to 20 percent of their available hourly production, for two reasons. First, some renewable generators may lack the ability or adequate incentives to follow CAISO dispatch signals. Second, grid operators need to be certain that resources selected to provide reserves can respond as required. Wind and solar generators can bid only a fraction of their available production into reserve markets because of the variability and uncertainty of their output. Generators that fail to deliver the expected response when called upon by the CAISO will incur financial penalties. Renewable generators would try to minimize these penalties by bidding their reserve response conservatively into CAISO reserve markets.

FIGURE 11. **Provision of Upward and Downward Reserves, by Resource, in the 50 Percent RPS Base Scenario and the Renewables Provide Reserves Run**



When renewables contribute to reserves by economically bidding into reserve markets, they are often chosen to provide downward reserves. Renewables provide 18 percent of downward reserves and 1.5 percent of online upward reserves in the Renewables Provide Reserves run.

Online reserves in the upward direction include load following up, regulation up, and spinning. Online reserves in the downward direction include load following down and regulation down. Values represent annual averages, and may vary significantly between night and day, and seasonally.

How Allowing Renewables to Provide Reserves Reduces Curtailment and GHG Emissions

Enabling renewables to provide operating reserves reduces renewable curtailment by nimbly curtailing and uncurtailing renewables on the sub-hourly timescale rather than curtailing renewables in blocky, hour-long intervals. Curtailment in the Renewables Provide Reserves run is 44 percent less than in the 50 percent RPS base scenario (Figure 10).[6]

This result may seem counterintuitive: for renewable generation to provide downward reserves, generators must curtail their output in response to a signal from the CAISO. However, in the 50 percent RPS base scenario, if renewables are not allowed to provide reserves, then another facility, typically a natural gas power plant, will be held online and generating above its minimum power level—the level of output below which a generator cannot be operated when it is online and synchronized to the grid—to provide the downward reserve. This gas generation crowds out renewable generation and causes curtailment. That is why GHG emissions dropped by 4.8 percent when renewables provide reserves. In the Renewables Provide Reserves run, renewables provided 18 percent of all downward reserves (Figure 11).

The Renewables Provide Reserves run also showed that it could be economical for renewables to contribute to upward reserves at certain times of the year, especially during daylight hours in spring, when the supply of renewable power is large relative to electricity demand. At these times, our model often curtailed renewable generation to avoid conditions of oversupply. Instead,

[6] Curtailment in model runs in which renewables provide reserves is calculated as the sum of curtailment from hourly scheduling and that which would be expected when renewables are curtailed on the sub-hourly timescale as a consequence of providing reserves. Curtailment results from scenarios in which renewables can provide reserves therefore include both hourly and sub-hourly curtailment.

renewables could be relied upon to ramp up production if extra electricity is needed on the sub-hourly timescale. In the Renewables Provide Reserves run, renewables provided 1.5 percent of all online upward reserves, including spinning, load following up, and regulation up (Figure 11).

These results suggest that enabling renewable generators to provide reserves, especially in the downward direction, could be a particularly useful and cost-effective way to reduce curtailment and GHG emissions. Policy makers who aim to deploy more renewable energy should encourage or require renewable generators to install control equipment that allows them to participate in CAISO energy and reserve markets. For efficient provision of reserves and system balancing, renewable generators should bid their flexibility into CAISO energy and reserve markets at marginal cost. The experiences of grid operators outside California can show how to incorporate renewables into markets and dispatch them flexibly and efficiently.

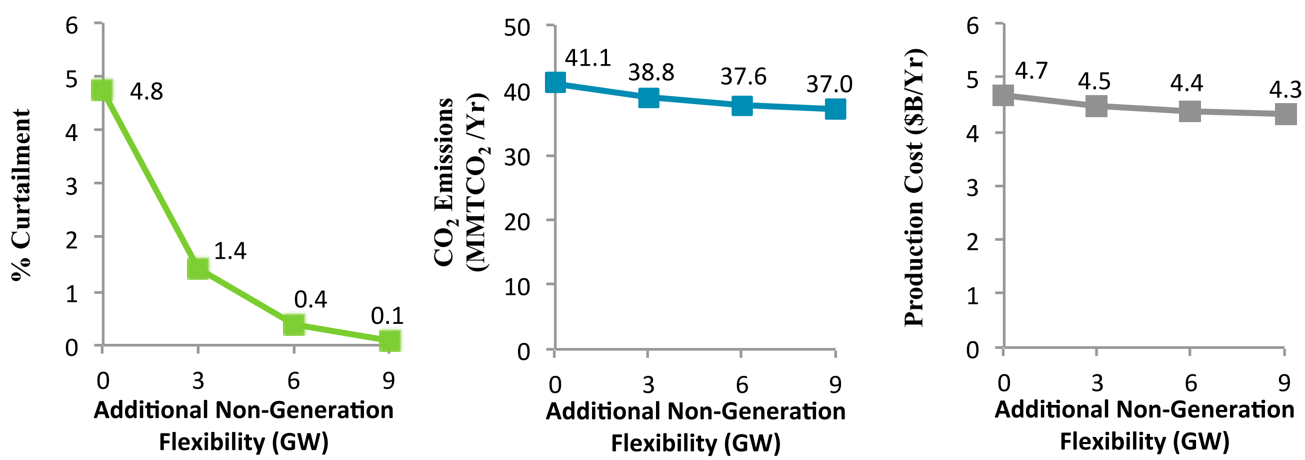
Allowing renewables to provide reserves can reduce—but likely not eliminate—the need to pursue more costly or uncertain forms of operational flexibility, and should therefore be seen as one of many tools to reduce curtailment and GHG emissions. In the next section we examine other, more frequently discussed tools to reduce curtailment and GHG emissions.

What are the benefits of relying on non-generation grid management strategies to provide operational flexibility?

To understand the degree to which deploying non–fossil fuel, non-generation sources of operational flexibility could reduce renewable curtailment, GHG emissions, and production costs, we performed several sensitivity runs on the 50 percent RPS base scenario. In these runs, which we call the "additional non-generation flexibility" runs, we added three types of such flexibility: advanced demand response, which can act as either demand or supply; electricity storage; and net electricity exports from the CAISO footprint. We added these sources of flexibility in increments of 3 GW to the non-generation resources already included in the 50 percent RPS base scenario. To show an alternative pathway to reducing renewable curtailment, we did not allow renewables to provide reserves. Near the end of the report, we present a model run that combines both pathways.

In each run with more non-generation flexibility, we increased each of the three sources of flexibility in 1 GW increments (Figure 12). The 3 GW Additional Non-Generation Flexibility run simulates a CAISO grid with 1 GW of advanced demand

FIGURE 12. **The Impact of More Non-Generation Flexibility on Renewable Curtailment, CO_2 Emissions, and Production Cost**

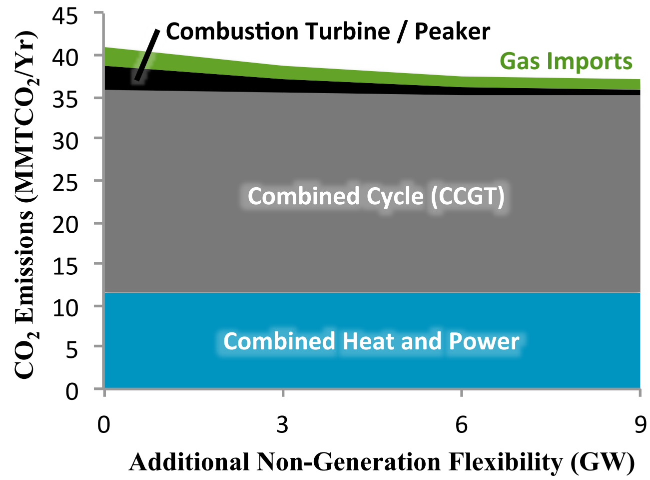


Increasing the amount of non-generation flexibility in the CAISO power system at a 50 percent RPS reduces renewable curtailment, CO_2 emissions, and the cost of producing electricity. The x-axis represents the deployment of equal ratios of advanced demand response, electricity storage, and net exports.

Zero on the x-axis represents the 50 percent RPS base scenario shown in Figure 4. $MMTCO_2$/Yr = millions of metric tons of CO_2 per year. The dollar-year is 2014.

response, 1 GW of electricity storage beyond that included in the 50 percent RPS base scenario, and the ability to export 1 GW (net) of electricity in any hour. The 9 GW Additional Non-Generation Flexibility run includes 3 GW of each of these measures. We modeled the three sources of additional non-generation flexibility in equal ratios to show how these sources could work together, but in practice many different combinations would likely work well. See the appendix for details on how we modeled each source of flexibility.

FIGURE 13. **CO_2 Emissions by Type of Natural Gas Power Plant as Non-Generation Flexibility Rises at a 50 Percent RPS**



As the amount of non-generation flexibility is increased, reductions in CO_2 emissions from gas combustion turbine/peaking power plants represent a large fraction of total reductions.

This plot is a disaggregation of the middle panel of Figure 12.

How Advanced Demand Response, Electricity Storage, and Electricity Exports Can Reduce Curtailment, GHG Emissions, and Production Costs

The first additional 1 GW tranche of each source of non-generation flexibility—3 GW in total—enables large cuts in renewable curtailment, GHG emissions, and production costs (Figure 12). Compared with the 50 percent RPS base scenario, this amount of non-generation flexibility reduces renewable curtailment by 70 percent (from 4.8 percent to 1.4 percent), CO_2 emissions by 5.6 percent (or 2.3 million metric tons of CO_2 per year), and production costs by 4.4 percent (or $205 million per year).

As we add more non-generation flexibility in the 6 GW and 9 GW runs, we see further declines in renewable curtailment, CO_2 emissions, and production costs, although the marginal benefits drop. With 9 GW of additional non-generation flexibility, renewable curtailment falls to less than 0.1 percent, occurring almost exclusively on spring weekends.

Much of the decline in CO_2 emissions is due to a reduction in generation from combustion turbine/peaking units (Figure 13). These units are less efficient but more flexible than combined-cycle gas turbines, so adding more non-generation flexibility disproportionately displaces peaking units. This suggests that adding more peaking units to the CAISO system would be less valuable as more non-generation flexibility is deployed.

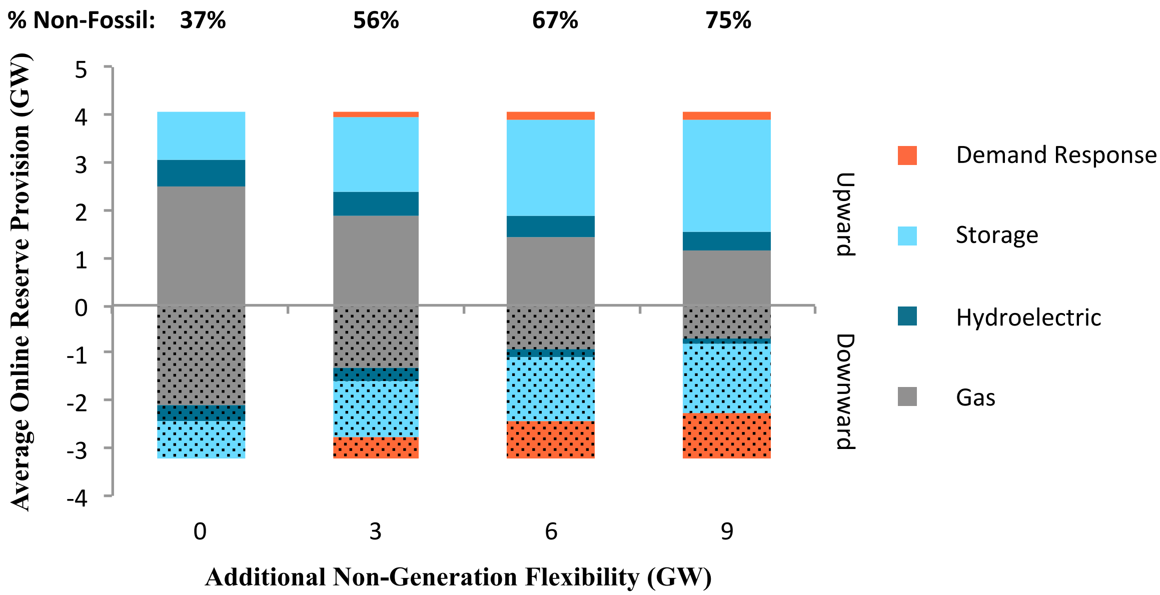
Determining the "optimal" amount of each source of non-generation flexibility would require further research. That analysis would explore tradeoffs between the capital and maintenance costs of each source of non-generation flexibility, reductions in GHG emissions, the cost of curtailing renewable generation, and many other factors.

How Reserves from Non-Generation Resources Reduce Renewable Curtailment, GHG Emissions, and Production Costs

One of the main reasons that advanced demand response and electricity storage reduce renewable curtailment, GHG emissions, and production costs is that they provide online reserves without simultaneously generating electricity.

In the case of advanced demand response, many devices and processes can provide the equivalent service while dramatically changing when they consume electricity. Consider the flexible operation of a refrigerator, an important potential source of advanced demand response. The "goal" of the refrigerator is to keep food cold by staying within a certain temperature range. If a refrigerator is in the middle of its acceptable temperature range and is not actively cooling, it could (a) not operate because its temperature is already adequate, or (b) begin cooling in response to a signal from the grid operator to increase demand, thereby providing a reserve product such as regulation down or load following down.

FIGURE 14. **Resources Providing Reserves as Non-Generation Flexibility Increases**



The share of online reserves provided by non-fossil resources grows as the amount of non-generation flexibility on the CAISO grid increases.

Online reserves in the upward direction include load following up, regulation up, and spinning. Online reserves in the downward direction include load following down and regulation down. Values represent annual averages and may vary significantly between night and day, and seasonally.

If instead the refrigerator is cooling but is within its temperature range, it could decrease electricity demand in response to a signal from the grid operator by shutting off the condenser temporarily. By doing so, the refrigerator could provide load following up, regulation up, spinning reserve, or non-spinning reserve.

Many refrigerators could be aggregated to provide grid-scale demand response in CAISO markets. This aggregation would need to occur in a way that meets operational requirements for providing reserve capacity, including sustained response over a given time window. Electricity storage devices or other forms of advanced demand response—such as electric vehicle charging, air conditioning, and water pumping—could provide reserves in an analogous manner (Dyson et al. 2014; Olsen et al. 2013).

The ability of advanced demand response and electricity storage to provide online reserves without simultaneously generating electricity contrasts with natural gas power plants and other conventional generators. These facilities must be producing electricity at or above their minimum power level to provide most operating reserves. The minimum power level of a natural gas combustion turbine or CCGT is typically 30 percent to 50 percent of its rated capacity. These plants must therefore generate a substantial amount of electricity to provide online reserves, whether or not the electricity they produce is needed.

In all three of our runs with additional non-generation flexibility, we allowed about 70 percent of the capacity of advanced demand response and electricity storage to provide following and contingency reserves. This assumption is consistent with the modeling of new electricity storage in the 2014 LTPP (CPUC 2014). Adding 3 GW of non-generation flexibility to the 50 percent RPS base scenario enabled non–fossil resources to provide more than half of all online operating reserves (Figure 14). With 9 GW of additional non-generation flexibility, non-fossil resources provided 75 percent of operating reserves.

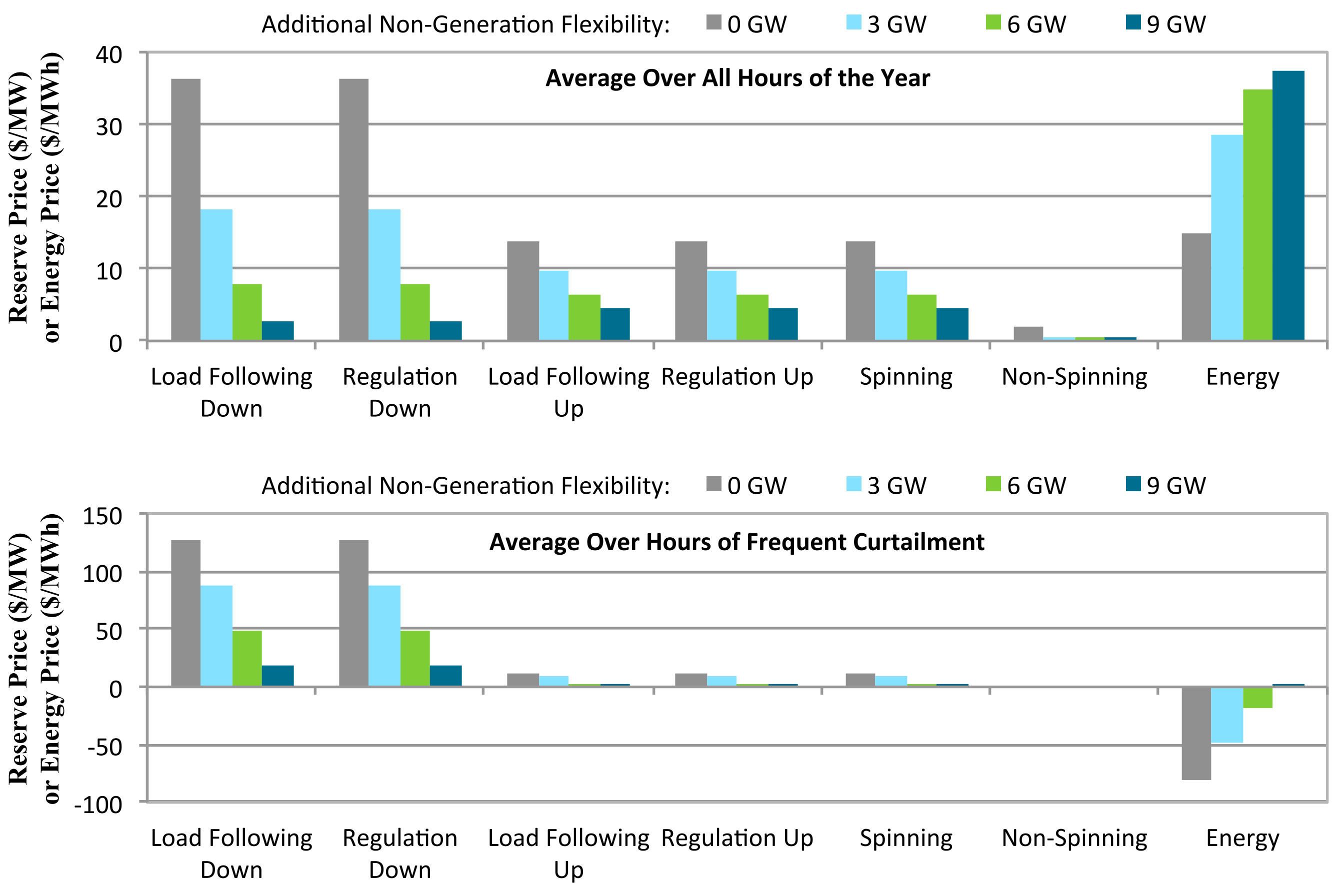
These runs imply that shifting away from the use of conventional generation to provide online reserves is an important strategy for integrating more renewable power into the grid. These results also suggest that energy storage or advanced demand response resources with a relatively small energy capacity—on the order of one to two hours—may benefit grid operations significantly by providing operating reserves.

As we increased the amount of non-generation flexibility, the share of both upward and downward reserves provided by non–fossil resources also grew (Figure 14). However, the downward reserves provided by these sources were more central to reducing curtailment than the upward reserves.

Without substantial amounts of additional non-generation flexibility, the price of downward reserves was much higher than the price of upward reserves (Figure 15). The very high price of providing downward reserves—especially during hours of frequent curtailment—shows that doing so during these hours is difficult. During hours of frequent curtailment (bottom panel, Figure 15), the price of downward reserves consistently exceeded the $100/MWh cost of renewable curtailment, suggesting that the provision of these reserves is causing curtailment. Our results suggest that downward reserves are a driving factor in renewable curtailment, and that providing enough non-fossil sources of flexibility can largely address the need for downward reserves.

Reduced renewable curtailment also means fewer hours with negative energy prices, and hence energy prices can increase due to reduced renewable curtailment (Figure 15). The price of energy in any given hour is determined by the cost of the marginal unit of electricity production, which is negative during hours of renewable curtailment. Increasing the amount of non-generation

FIGURE 15. **Average Prices of Reserves and Energy When the Amount of Non-Generation Flexibility Rises**



Without additional non-generation flexibility, downward reserves are much more costly to provide than upward reserves, especially during hours of frequent renewable curtailment. This is because downward reserves are causing substantial renewable curtailment. As the amount of non-generation flexibility increases, the amount of curtailment decreases, and the price of downward reserves drops below the price of upward reserves.

Top: These averages do not include the very limited number of hours during which reserve shortfalls occur. Bottom: Hours of frequent curtailment are 9 am to 3 pm in March, April, and May. Note the difference in y-axis scale between top and bottom.

flexibility reduces curtailment by moving renewable generation away from the margin. Energy prices rise when natural gas generators are on the margin more often and renewables are less frequently on the margin. Even though the average price of energy rose with more non-generation flexibility, the total cost of production dropped (Figure 12), because renewable energy displaced more gas generation when non-generation flexibility was increased.

Deploying More Non-Generation Flexibility Can Count Toward the Adequacy of System Capacity

Reserve shortfalls were entirely eliminated in all three runs with added non-generation flexibility, indicating that advanced demand response and electricity storage contribute to the adequacy of system capacity. With 1 GW of advanced demand response and 1 GW of added electricity storage in the 3-GW Additional Non-Generation Flexibility run, the largest reserve shortfall observed in the 50 percent RPS base scenario (about 1.5 GW) was eliminated.

As noted under question one, the 2024 CAISO power system may be operating close to the point where new system capacity is warranted, even with 50 percent renewable electricity. Deploying demand response and storage could reduce (but likely not eliminate) the need for new gas power plants in the 2024 timeframe. One remaining question is the extent to which the projected 2024 CAISO fleet of gas power plants has enough operational flexibility to integrate 50 percent renewable electricity.

[QUESTION 5]

How much can additional natural gas plant flexibility reduce the curtailment of renewables?

The ability to vary the electricity output of natural gas power plants is valuable when integrating large quantities of renewable energy into the grid. Whether the projected 2024 CAISO gas fleet is flexible enough for a grid with 50 percent renewables—or more gas flexibility would be warranted—is unclear. Previous work has suggested that there can be some benefits to increasing the flexibility of natural gas power plants at a 33 percent RPS target in California (Wärtsilä Corp. and Energy Exemplar 2014).

Understanding the most desirable attributes of natural gas power plant flexibility can help policy makers and grid operators prioritize investments. Understanding the types of additional flexibility that would not significantly reduce renewable curtailment, GHG emissions, and production costs is also important.

Models such as ours use a few different attributes to represent the flexibility of each gas power plant. Some of the most important include:

- **Maximum ramp up and maximum ramp down.** This "ramp rate," expressed in MW per minute, indicates how quickly a generator can increase or decrease power output if it is already online and synchronized to the grid.
- **Minimum power level.** Also called the minimum stable level (or the PMin), this is the level below which a generator cannot be operated when it is online and synchronized to the grid. The minimum power level, specified in MW, is typically 30 percent to 50 percent of a gas generator's maximum capacity.
- **Minimum uptime and minimum downtime.** The minimum uptime is the least amount of time that a generator must remain online and generate electricity once it has been turned on. The minimum uptimes of combined-cycle gas generators in the CAISO footprint are typically between six and eight hours. The minimum downtime is the least amount of time that a generator must be offline once it has been turned off. The minimum downtime of combined-cycle gas generators in the CAISO footprint is typically four hours. The minimum uptimes and downtimes of most combustion turbine/peaker units are two hours or less.
- **Start profile and shutdown profiles.** These are hourly sequences of output levels through which a generator must pass when either turning on or shutting down. A generator that can start and stop quickly will have relatively few start and shutdown hours. The start profiles of combined-cycle gas generators are typically zero to five hours, and their shutdown profiles are typically zero to two hours. Avoiding rapid thermal expansion and contraction in the steam cycle is an important reason for restricting how fast a combined-cycle unit can start or stop. Hourly simulations usually do not include start or shutdown profiles for combustion turbine/peaker units because they can typically start or shut down in much less than one hour.

Modeling the Flexibility of Natural Gas Plants

We performed three sensitivity runs on the 50 percent RPS base scenario to reveal the flexibility attributes of the 2024 CAISO fleet of gas power plants that would be most useful for reducing renewable curtailment (Table 4).

- In the Double Ramp Rate run, we doubled the ramp rate of each natural gas plant in the CAISO footprint relative to default assumptions.
- In the Half Minimum Power Level for CCGTs run, we reduced the minimum power level at which each CCGT in the CAISO footprint could be operated by a factor of two. While the length of time required to start or stop each CCGT did not change in this run, we modified the start and stop profiles to be consistent with lower minimum power levels.
- In the Flexible Gas run, we combined the flexibility added in the two previous sensitivities, yielding a much more flexible CAISO natural gas fleet. We also halved the minimum power level of each combustion turbine/peaker generator, reduced the minimum uptime and downtime for each CCGT to two hours (enabling it to turn on and off more quickly), and gave each CCGT only a one-hour start or shutdown profile. The MW level for each hour-long start profile was half of the unit's minimum power level.

TABLE 4. **Summary of Our Model Runs Relating to Natural Gas Power Plant Flexibility**

Run Name	Renewables Provide Reserves?	Ramp Rate for Natural Gas Plants (Percent of Base)	Minimum Power Level of Natural Gas Plants (Percent of Base)	Maximum Uptime and Downtime for Gas Plants (Hours)	Maximum Start Time for Gas Plants (Hours)
Gas Double Ramp Rate	No	**200**	100	Base	Base
Half Minimum Power Level for CCGTs	No	100	**50 (CCGT)** 100 (Peaker)	Base	Base
Flexible gas	No	**200**	**50 (CCGT)** **50 (Peaker)**	**2**	**1**
Double Ramp Rate for Gas Plants, with Renewables Providing Reserves	**Yes**	**200**	100	Base	Base
Half Minimum Power Level for CCGTs, with Renewables Providing Reserves	**Yes**	100	**50 (CCGT)** 100 (Peaker)	Base	Base
Flexible Gas with Renewable Reserves	**Yes**	**200**	**50 (CCGT)** **50 (Peaker)**	**2**	**1**
Flexible Gas Extreme	No	**400**	**25 (CCGT)** **25 (Peaker)**	**0**	**0**

All the sensitivity runs of our model built on the 50 percent RPS base scenario. Bold fields represent differences from this scenario. This table includes all of our model runs relating to natural gas power plant flexibility. Model runs not relating to natural gas power plant flexibility are described in Table 2.

We did not determine specific modifications to the plants that would yield the operational changes we modeled, or quantify the cost of the modifications. And because we focused on operational flexibility, we did not investigate modifications to gas plants that would increase their efficiency (decrease their heat rate), thereby reducing GHG emissions per unit of electricity produced.

The Most Valuable Attribute: Reducing the Minimum Power Level of Combined-Cycle Gas Turbines

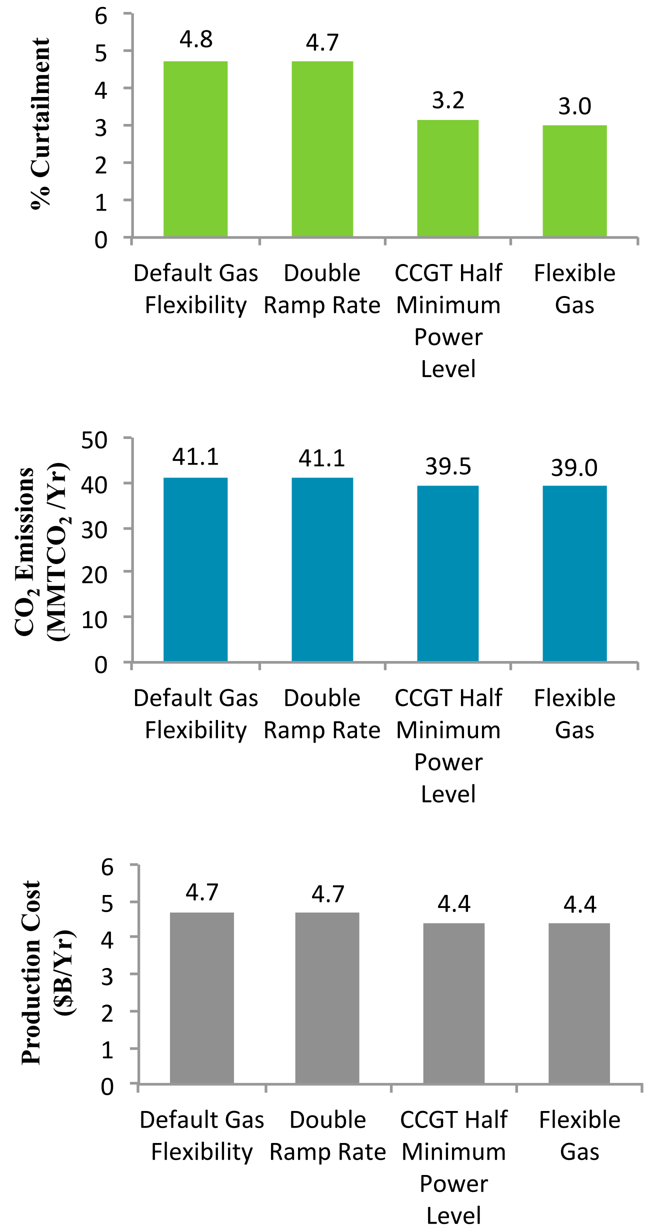
Our results show that the most important aspect of gas fleet flexibility is the minimum power level of CCGTs (Figure 16). Decreasing that level is the only modification to the gas fleet we modeled that significantly reduced renewable curtailment, GHG emissions, and production costs.

If other attributes of gas fleet flexibility, such as the ramp rate or start time, were important in reducing renewable curtailment, then the Half Minimum Power Level for CCGTs run would have shown curtailment levels closer to the 50 percent RPS base scenario than to those in the Flexible Gas run. Our results also show that the flexibility that combustion turbine/peaker gas plants can provide will be in relatively abundant supply in 2024, and that installing more of these plants to increase the operational flexibility of the grid would likely not be justified.

Increasing multiple aspects of gas fleet flexibility simultaneously in the Flexible Gas run did not meaningfully reduce renewable energy curtailment, GHG emissions, or production costs beyond that achieved in the Half Minimum Power Level for CCGTs run. This suggests that once the minimum power level of CCGTs has been reduced, obtaining more ramp rate, start-stop, or uptime-downtime flexibility from gas plants for the purpose of integrating renewable energy would not be very valuable.

Allowing renewables to provide reserves, especially downward reserves, will be a low-cost source of flexibility in many situations. We performed three more model runs that examined how the value of additional gas plant flexibility changes when renewables provide reserves. These three runs are identical to those depicted in Figure 16, except that we allowed renewables to provide reserves in the same manner as the Renewables Provide Reserves run. We found that the benefit of additional gas plant flexibility decreased when renewables could provide reserves (Figure 17). However, the minimum power level of CCGTs remained the most valuable modification to the gas fleet.

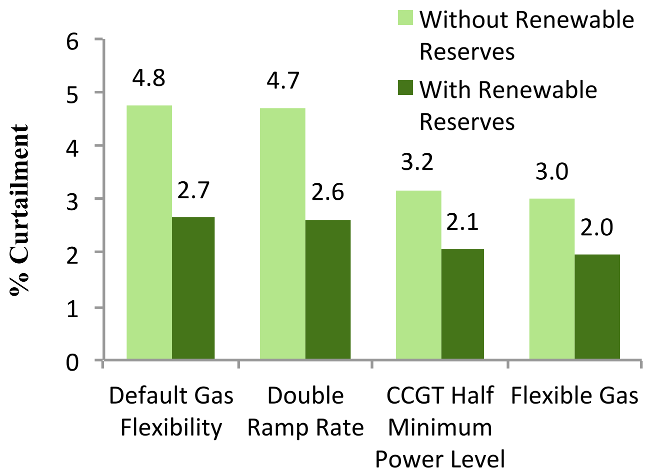
FIGURE 16. **The Impact of Different Levels of Gas Flexibility on Curtailment, CO_2 Emissions, and Production Cost at a 50 Percent RPS**



The minimum power level of natural gas plants is much more important than their ramp rate, start time, and other operating characteristics in reducing curtailment of renewables, CO_2 emissions, and production cost. Default Gas Flexibility refers to the 50 percent RPS base scenario.

In these runs, we modeled renewables as unable to provide reserves.

FIGURE 17. **Curtailment of Renewables Given Different Levels of Gas Flexibility and Ability of Renewables to Provide Reserves**



When renewables can provide reserves, the amount of curtailment that can be avoided by increasing the flexibility of natural gas power plants decreases. Lowering the minimum power level of CCGTs is the most valuable modification to the natural gas power plant fleet, regardless of whether renewables can provide reserves.

In the context of the CAISO's "Duck Chart" (CAISO 2013), our results suggest that overgeneration is a far larger concern than the ramping requirement in 2024 in the 50 percent RPS base scenario. The duck chart outlines two flexibility challenges when integrating more variable and uncertain wind and solar power into the CAISO grid: increased ramping requirements at sunrise and sunset, and the greater chance of overgeneration or renewable curtailment during daylight hours. Our results imply that increasing the ramping capabilities of the 2024 CAISO gas fleet would not reduce curtailment substantially.

Reducing the minimum power level of CCGTs to reduce curtailment, GHG emissions, and production costs comes with an important caveat related to the unit commitment process used in our model and CAISO operations. The process by which grid operators select generators to produce electricity—the least-cost unit commitment process—will provide an incentive to select CCGTs with the lowest minimum power levels (as a percentage of rated capacity) during times of renewable curtailment. Doing so will minimize curtailment while providing reserve capacity. It may be economical to retrofit or replace CCGT capacity only if the minimum power level of a retrofitted or new plant is lower than that of existing plants that are committed during times of renewable curtailment.

Grid planners will need to perform detailed studies to determine whether a proposed reduction in the minimum power level of gas plants would in fact reduce renewable curtailment. If a combined cycle generator cannot be retrofitted or replaced to have a minimum power level near that of CCGTs with the lowest minimum power level (as a percentage of rated capacity), then the retrofit may not reduce curtailment substantially. That is because the unit commitment process would not have chosen the generator either before or after the retrofit or replacement.

Further research could explore the value of additional gas fleet flexibility in the context of a less diverse portfolio of renewables than we simulated in our 50 percent RPS portfolio. A less diverse portfolio would concentrate renewable production more heavily in some hours, and change the timing and magnitude of reserve requirements. Both factors could change the value of various attributes of gas fleet flexibility. However, as we discuss in the next section, the flexibility of gas power plants will be limited whether a renewable portfolio is more or less diverse.

The Ability of Natural Gas Power Plants to Reduce Curtailment Is Fundamentally Limited

While increasing the flexibility of natural gas power plants, especially by lowering the minimum power level of CCGTs, could help reduce renewable curtailment, substantially increasing the flexibility of the gas fleet does not eliminate a large fraction of curtailment (Figure 17).

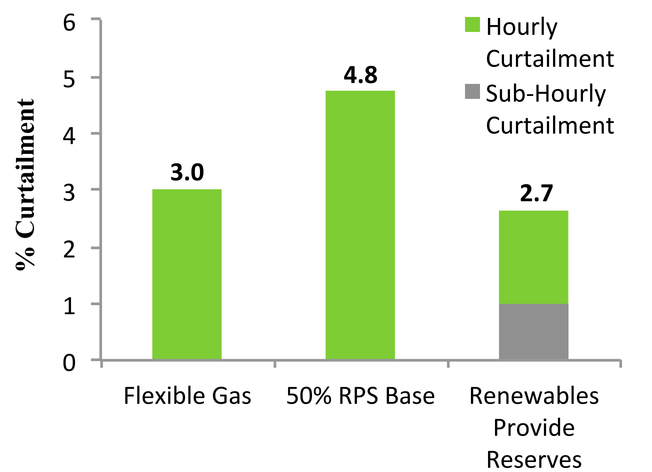
One reason is that gas plants cannot generally contribute to important forms of grid reliability—including downward following reserves, inertia/primary frequency response, reactive power/voltage support, and congestion relief—without generating electricity. Ultimately, generation from non-renewable sources that must be online to provide reliability services will crowd out renewable generation and cause curtailment.

Comparing the Flexible Gas run with the Renewables Provide Reserves run reveals that this first limitation on gas flexibility can be significant (Figure 18). Those two runs show that enabling renewables to contribute to reserves, especially downward reserves, can reduce curtailment more than increasing the flexibility of every CAISO natural gas facility. When renewables provide reserves, gas units can often be turned down or off during times of curtailment, because they are no longer needed to provide downward reserves.

Gas plants can provide some reliability services without generating electricity or burning natural gas if clutches are installed. Clutches allow the part of the power plant that generates electricity to be decoupled from the part of the plant that burns fuel and turns a turbine. Doing so allows the plant to provide reactive power and inertia without generating electricity. To the extent that it is cost effective, the installation and operation of gas plant clutches should be encouraged. However, installing clutches will not allow gas generators to provide downward following reserves or many other reliability services without producing electricity, limiting the ability of clutches to reduce renewable curtailment.

Offline gas generators that could start quickly—within an operating hour—could supply a portion of upward load following reserves, but we did not model this dynamic. The price of upward and downward following reserves in the 50 percent RPS base scenario during hours of frequent renewable curtailment suggests that downward load following reserves cause much more curtailment than upward load following reserves (bottom panel, Figure 15). Consequently, our curtailment results might not have changed appreciably if we had allowed offline gas generators to supply upward load following reserves. The starting and stopping of gas units often consumes significant amounts of fuel, so committing offline gas units to providing upward load following would entail GHG emissions.

FIGURE 18. **Curtailment in the Flexible Gas Run and the Renewables Provide Reserves Run**



A comparison of these two runs reveals that allowing renewables to operate more flexibly can reduce curtailment by an amount similar to that enabled by a more flexible natural gas fleet.

Sub-hourly curtailment is the amount of curtailment expected if renewables are operated flexibly and curtailed on a sub-hourly timescale.

A second limitation on the ability of natural gas generators to reduce renewable curtailment is that they cannot shift the location and timing of electricity demand or renewables power production. Curtailment can occur from mismatches between when electricity is needed and when renewables produce power. In our 50 percent RPS portfolio, the supply of renewable electricity exceeds the amount the CAISO grid can absorb during some hours of the year, especially during the day.

Increasing the flexibility of natural gas power plants cannot:

- move electricity generated by renewables from the daytime to the nighttime;
- move electricity demand to the daytime from the nighttime; or
- directly affect the amount of electricity that the CAISO can export.

To show the fundamental limitations of conventional generation technologies in enabling the grid to integrate large fractions of renewable energy, we performed one additional "bookend" run that included an exceptionally flexible CAISO natural gas fleet. In this run, called Flexible Gas Extreme, we did not enforce the start profile, stop profile, minimum uptime, and minimum downtime constraints of any gas generators. We also cut the minimum power level of all gas generators by three-quarters relative to the 50 percent RPS base scenario, and quadrupled their ramp rate. The fleet of CAISO natural gas power plants is unlikely to achieve this level of flexibility in practice.

In the Flexible Gas Extreme run, 2.5 percent of available renewable generation is curtailed. Despite the radical modifications to natural gas power plants, this is only a slight decrease from the 3.0 percent observed in the Flexible Gas run. Comparing the two runs reveals the diminishing returns of greater gas flexibility. The Flexible Gas Extreme run also shows that more gas flexibility alone cannot remove all renewable curtailment from the 50 percent RPS base scenario. Despite the exceptionally flexible fleet of gas plants in the Flexible Gas Extreme run, more than half of renewable curtailment remains because of the aforementioned limitations.

While a more flexible natural gas fleet should not be considered a silver bullet solution to the challenge of integrating more renewables into the grid, gas plants will play important roles in a grid with 50 percent renewable electricity. As noted above, grid operators will still need them to provide energy and capacity when other resources are not available. Gas plants can also provide reserves at a relatively low opportunity cost throughout much of the year, enabling grid operators to integrate variable and uncertain renewable resources.

[QUESTION 6]

How does more non-fossil flexibility compare with more gas plant flexibility in reducing renewable curtailment?

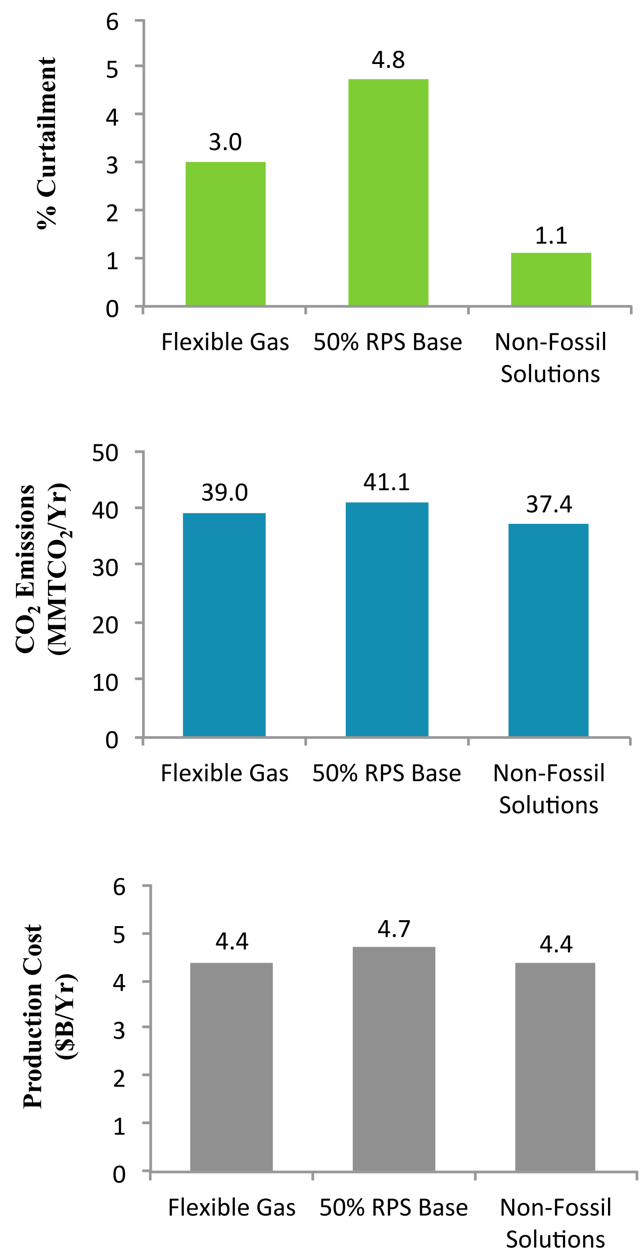
In a final model run, we combined non-fossil flexibility solutions that could reduce renewable curtailment to about 1 percent at a 50 percent RPS. In this Non-Fossil Solutions run, we included 3 GW of additional non-generation flexibility (1 GW each of electricity storage, advanced demand response, and net exports) and allowed renewables to provide reserves.

Increasing Non-Fossil Flexibility Can Reduce Curtailment More Than Making the Gas Fleet More Flexible

The Non-Fossil Solutions run reduces renewable curtailment by 77 percent relative to the 50 percent RPS base scenario, bringing the amount of renewable curtailment to 1.1 percent of renewable generation potential (Figure 19). In contrast, increasing the flexibility of the gas fleet (the Flexible Gas run) reduces curtailment by 37 percent relative to the 50 percent RPS base scenario, to 3.0 percent of renewable generation potential.

Though we did not model this, enabling non-conventional resources to contribute to regional generation requirements would further reduce curtailment, GHG emissions, and production costs. The fleet of non-conventional resources in the 2024 timeframe modeled in the Non-Fossil Solutions run could contribute to a number of specific reliability needs envisioned in the regional generation requirements (Lew et al. 2015; Morjaria et al. 2014; Nelson 2014; Ela et al. 2013). More research is needed to understand the potential of non-fossil resources to provide every operational reliability need.

FIGURE 19. **Curtailment, CO_2 Emissions, and Production Cost in the 50 Percent RPS Base Scenario, the Flexible Gas Run, and the Non-Fossil Solutions Run**

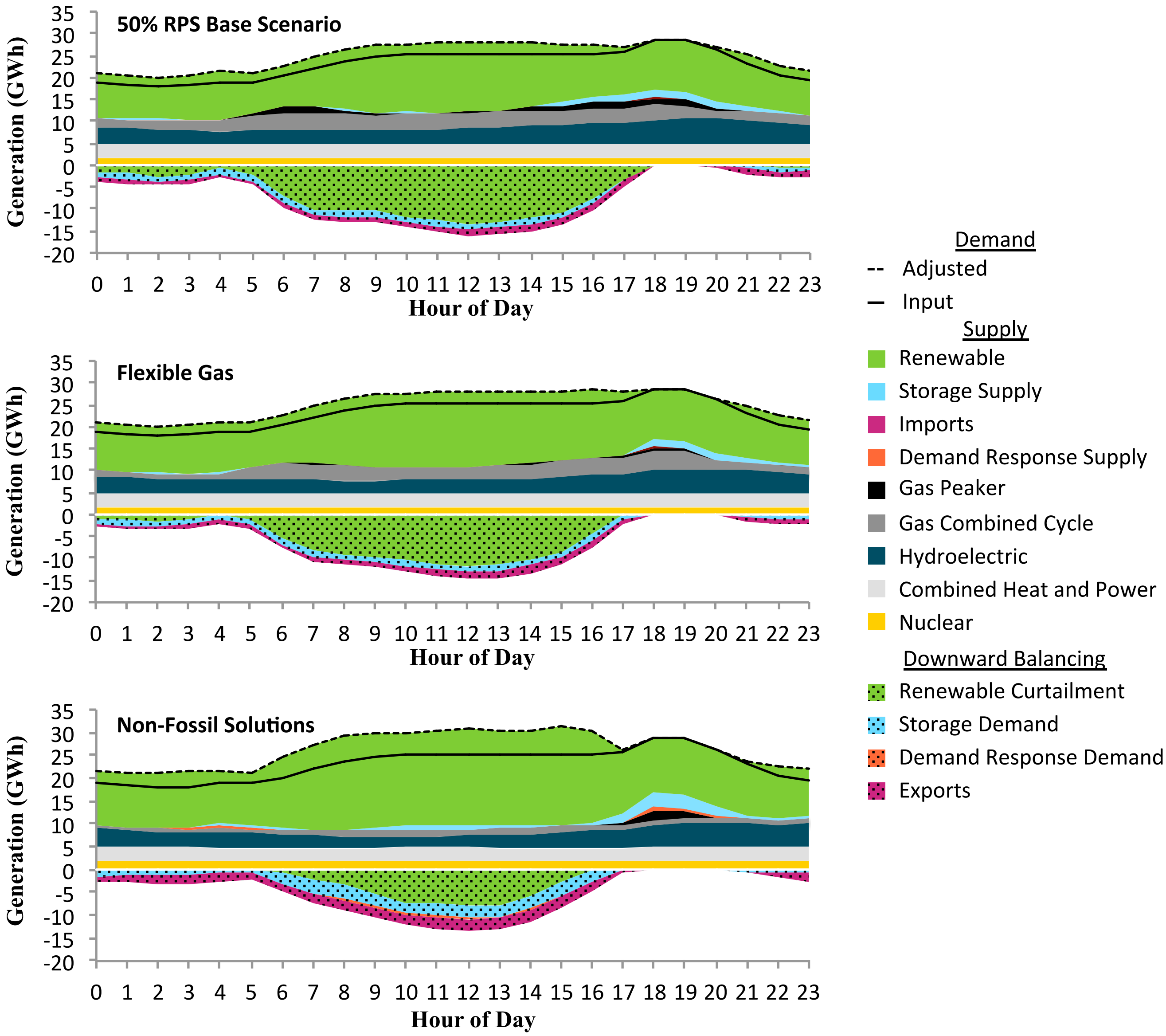


The Non-Fossil Solutions run has less renewable curtailment and CO_2 emissions than the Flexible Gas run. The production cost in these two runs is similar.

Increasing gas flexibility in the Flexible Gas run did not enable most CCGTs to be shut off during hours in which renewable electricity is being curtailed (middle panel, Figure 20). Non-fossil flexibility solutions, on the other hand, almost eliminated electricity production from CCGTs during times of renewable curtailment (bottom panel, Figure 20). Gas facilities still largely provided online reserves in the Flexible Gas run, forcing a number of gas units to remain online and generating electricity during hours of curtailment (Figure 21). In the Non-Fossil Solutions run, non-fossil resources (including renewable facilities) provided most online reserves during hours of curtailment, allowing most gas plants to be shut off.

Shutting off gas power plants during times of ample renewable generation is central to reducing GHG emissions at a 50 percent RPS. Consequently, the Non-Fossil Solutions run had lower GHG emissions than the Flexible Gas run (Figure 19). Comparing these two runs shows how non-fossil flexibility solutions could be much more effective tools for reducing renewable curtailment and GHG emissions than increasing the flexibility of the natural gas fleet.

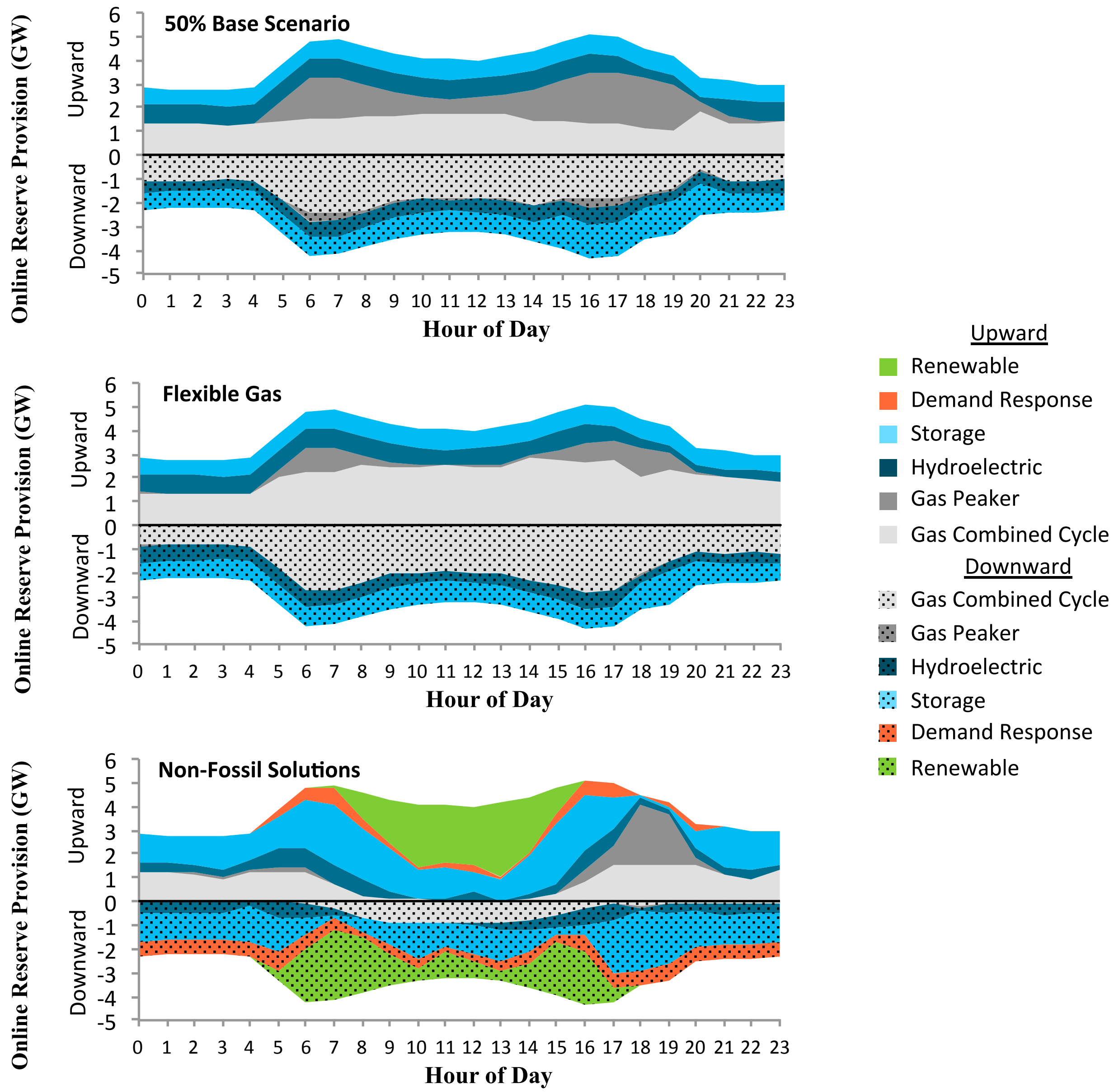
FIGURE 20. **Power System Dispatch on a Weekend Day in May in the 50 Percent RPS Base Scenario, the Flexible Gas Run, and the Non-Fossil Solutions Run**



Comparing power system dispatch in the 50 percent RPS base scenario (top), the Flexible Gas run (middle), and the Non-Fossil Solutions run (bottom) on one example day demonstrates that deploying non-fossil sources of flexibility can allow the grid operator to reduce the power output from natural gas power plants during times of renewable curtailment, whereas increasing the flexibility of natural gas power plants does not enable a similar reduction.

"Load" is the input load profile. "Adjusted load" includes additional demand from exports, electricity storage, and demand response. The three plots are for the same day and hours as in Figure 21. See the appendix for a discussion of storage acting as supply during times of renewable curtailment.

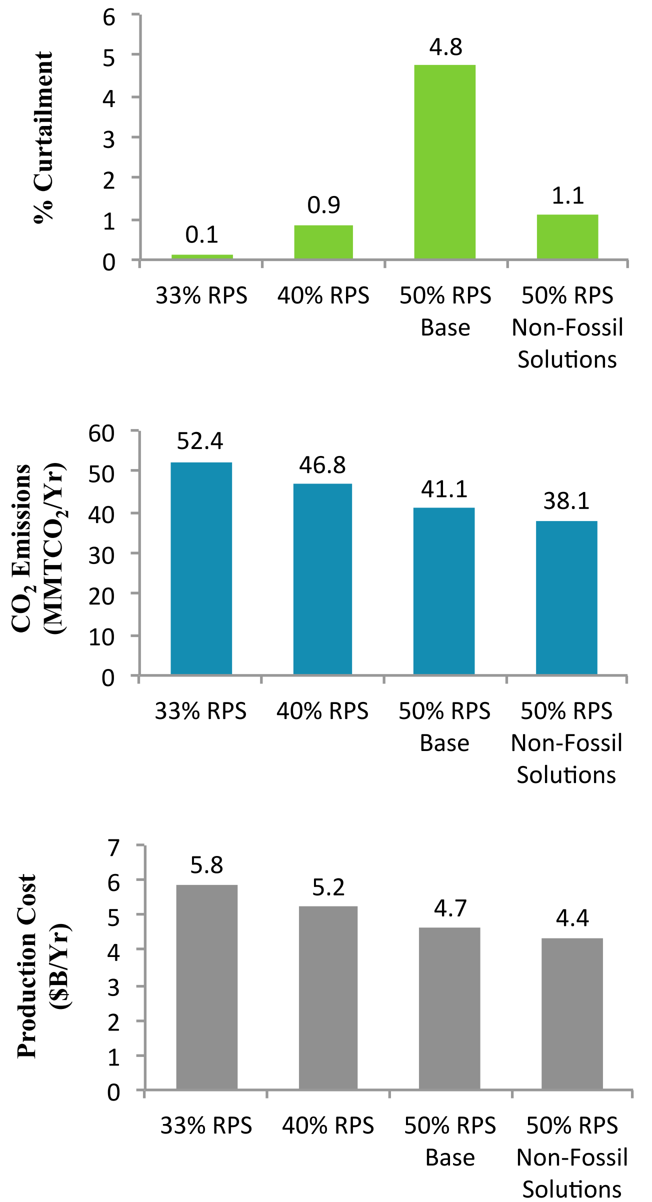
FIGURE 21. **Provision of Upward and Downward Reserves, by Resource, on a Weekend Day in May in the 50 Percent RPS Base Scenario, the Flexible Gas Run, and the Non-Fossil Solutions Run**



Comparing the 50 percent RPS base scenario (top), the Flexible Gas run (middle), and the Non-Fossil Solutions run (bottom) on one example day shows that deploying non-fossil sources of flexibility can allow the grid operator to shift away from obtaining reserves from natural gas power plants, whereas increasing the flexibility of those plants does not enable a similar shift.

More renewable curtailment occurs on this day than on any of the other 738 days simulated in the 50 percent RPS base scenario. Online reserves in the upward direction include load following up, regulation up, and spinning. Online reserves in the downward direction include load following down and regulation down.

FIGURE 22. **Curtailment, CO_2 Emissions, and Production Cost as the RPS Rises from 33 Percent to 50 Percent Without More Operational Flexibility, and at a 50 Percent RPS with Non-Fossil Solutions**



Investing in reliability services from non-fossil resources reduces the need to obtain these services from online natural gas plants. That, in turn, reduces renewable curtailment, GHG emissions, and the cost of producing electricity. The first three columns of each panel represent the same data as in Figure 4, to allow comparison with the Non-Fossil Solutions run.

To reach a 50 percent RPS, California should obtain reliability services and operational flexibility from non-fossil resources.

As California strives to make investments and reform markets to support much higher levels of renewables on the grid, policy makers must decide how to ensure a reliable future power supply. Our analysis shows the value of relying on non-fossil sources to provide reliability services at a 50 percent RPS in the CAISO footprint. Investing in reliability services from non–fossil resources reduces the need to obtain these services from online natural gas plants, reducing renewable energy curtailment, GHG emissions, and production costs. To integrate more renewable generation into the grid while curbing GHG emissions, grid planning and operations should increasingly focus on obtaining operational flexibility from non-fossil sources.

Compared with the 33 percent RPS scenario, the Non-Fossil Solutions run reduces GHG emissions from electricity generation by 27 percent, and production costs by 25 percent (Figure 22). Deploying non-fossil sources of flexibility alongside more renewable generation can allow the state to extract more value from each renewable facility. Grid operators should explore cost tradeoffs among different sources of flexibility for the power system, given the need to continually cut GHG emissions.

To reduce renewable curtailment in the 2024 CAISO power system at a 50 percent RPS, decreasing power output from conventional power plants during daylight hours appears to be much more difficult than meeting ramping requirements. Our results suggest that procuring additional peaking gas capacity would not contribute substantially to reducing renewable curtailment. Decreasing the minimum power level of natural gas combined-cycle plants appears to provide the largest benefit of any possible modification to the flexibility of the natural gas fleet. However, the effectiveness of this modification decreases if renewable generators can provide reserves, and would likely decline even more if more non-generation flexibility were deployed.

Our analysis suggests that policy makers and grid operators should focus more attention and investment on non–fossil fuel sources of flexibility than on increasing the flexibility of fossil fuel power plants. Achieving the long-term goal of dramatically reducing GHG emissions from the power sector will require a reliable electricity system with minimal electricity production from fossil-fueled power plants during periods of abundant renewable generation. Increasing the operational flexibility of renewable generators and other non-generation resources is an important step toward a low-GHG energy system.

More on Our Modeling Methodology

Electricity Demand

Our electricity demand projections for the CAISO footprint are from the CEC's demand forecast for 2014 to 2024, produced as part of its 2013 Integrated Energy Policy Report (CEC 2014). We used the CEC's "mid" demand baseline, and assumed that the additional achievable energy savings (AAEE) are achieved. The mid AAEE savings reduce CAISO electricity demand by 23 terawatt-hours (TWh) in 2024 relative to the mid demand baseline.

Consistent with CEC demand projections, CAISO-wide retail sales in our model was 218 TWh in 2024. The retail sales value does not include system losses. Additional power production must be supplied to compensate for these losses, so total demand including losses was 241 TWh. The CEC demand forecast calls this value "net energy for load." However, this should not be confused with the concept of net demand used in this report, which refers to electricity demand minus wind and solar output.

We simulated behind-the-meter PV as a supply-side resource that cannot be curtailed, and whose production does not incur transmission or distribution losses. Behind-the-meter PV provided 7.7 TWh of electricity production in 2024. Because we modeled these generators as supply-side resources, we added their production to the demand that must be met, yielding a total electricity demand of 249 TWh.

Consistent with the CEC's mid demand baseline, we assumed that 2 million electric vehicles are on the road in the CAISO footprint in 2024. Of those, 14 percent are battery-electric vehicles and 86 percent are plug-in electric vehicles. The electricity demand from these vehicles is 4.5 GWh, representing about 2 percent of total retail electricity sales.

Hourly electricity demand profiles provided by E3 were derived from historical weather data from 1950 to 2012. E3 used a neural network model to create 2024 CAISO load shapes from historical demand and weather data. E3 created the profiles by using load data from 2004 to 2012 to train a neural network regression between key weather variables and daily total electricity demand. To be consistent with the treatment of behind-the-meter PV as a supply-side resource, E3 added historical production from that resource to historical load profiles before performing the regression. E3 scaled hourly electricity demand profiles to meet CEC demand forecast values for annual energy demand and one-in-two peak demand. The CEC included demand from electric vehicles in its projections of both peak and energy, so the scaling process accounted for increased demand from electric vehicles.

The peak CAISO demand that we observed in the 17,736 hours of input data is 56.5 GW. Because we modeled behind-the-meter PV as a supply-side resource, subtracting that production from CAISO demand yields a peak demand of 53.7 GW. We did not derive these peak demand values directly from a CEC forecast, but instead pulled them directly from the hourly demand profiles provided by E3.

Renewable Generators

E3 provided RPS portfolios and hourly output from renewables for all three of our RPS portfolios: 33 percent, 40 percent, and 50 percent. E3 used version 5 of the RPS calculator to determine the amount of power produced over the course of a year by each type of renewable generator in each Competitive Renewable Energy Zone. These values are consistent with the 33 percent RPS portfolio in CAISO's 2014–2015 transmission planning process (TPP). E3 created hourly wind and solar profiles by matching the renewable sites chosen by the RPS calculator to simulated historical output data from those sites. For wind, E3 used the hourly 2004–2006 Western Wind and Solar Integration Study dataset. For both large-scale and behind-the-meter PV, E3 used the NREL's Solar

Prospector hourly insolation and weather data from 1998 to 2009 to simulate power output via the NREL System Advisor Model. The same is true for solar thermal power output, except that E3 used hourly data from 1998 to 2005.

E3 created hourly renewable output data for the 40 percent and 50 percent RPS profiles by scaling up the 33 percent RPS hourly profiles such that incremental additions of renewable energy production come from one-third solar, one-third wind, and one-third baseload renewable generators. This scaling process did not increase the diversity of renewable sites, because when additional capacity was added, new sites for renewables were not chosen. New sites would have different output profiles from the existing generation profiles. The portfolios may therefore overestimate flexibility needs because the renewable output profiles are more variable than if the incremental renewable energy had come from new sites across the state. E3 scaled up only in-state resources between the 33 percent RPS and 50 percent RPS; out-of-state resources are identical across all portfolios. Our model scheduled 70 percent of out-of-state renewable output into CAISO on an hourly basis.

We assumed that behind-the-meter PV was ineligible for RPS compliance. We kept the installed capacity of that resource within the CAISO footprint at 4.6 GW in all model runs. That figure is from the CEC's mid demand baseline for 2014 to 2024 (CEC 2014).

We allowed wind and solar facilities within the CAISO footprint to be curtailed at a price of $100/MWh. As SCE has noted, this is a reasonable cost of curtailment for modeling purposes (Mao and Galjanic 2014b). For simplicity, we do not include the cost of renewable curtailment when we report production costs (for example, the costs in the right panels of Figure 4 and Figure 12).

We did not allow imported wind and solar power to be curtailed, though we did allow it to increase export capability (see the section "Exports and the No Net Export Constraint," below). We held baseload renewables—geothermal, biomass, and biogas—at a constant level of generation for every hour of the year, not allowing them to be curtailed, although in practice many of these facilities might be curtailed or dispatched. We did not allow power from behind-the-meter PV to be curtailed. Although we inadvertently included the ability to curtail small hydropower in our study, curtailment of these facilities is not significant, so we discuss curtailment of wind and solar facilities exclusively.

Baseload renewables—geothermal, biomass, and biogas—account for one-third of the renewables added between the 33 percent and the 50 percent RPS. While all three baseload resources could technically produce more electricity in California than modeled in our study, each technology also faces a unique set of challenges. From the perspective our model, these generators are completely interchangeable. We could therefore shuffle the distribution between the three types of baseload renewables in Figure 3 and our results would remain the same, as long as total energy production from baseload renewables remained the same. The need to comply with standards for air pollutants could hamper increases in biomass and biogas power. Achieving acceptable emissions of those pollutants may require switching to gasification technology for solid biomass, for example. Questions also remain about how much bioenergy should be directed to electricity generation relative to other sectors of the economy. Our baseload mix of renewable resources is not a recommendation about how much of each technology should be developed. Rather, we simply note that baseload renewables are valuable in reducing the variability and uncertainty of power output (and associated costs) from a portfolio of renewables.

Stochastic Draws

The results from each of our model runs are based on hourly production simulations of 739 distinct days, or "draws." These days are equivalent to 24 * 739 = 17,736 hours, or 2.2 years of hourly simulation data. Each draw included a unique set of profiles for renewable output, electricity demand, following reserve requirements, and generator outages.

The draw structure is identical to that used in the E3 REFLEX model (E3 2014; E3 2013). E3 provided the wind and solar output profiles, electricity demand, following reserve requirements, and generator outages. We did not use the E3 REFLEX load following surfaces, but rather simulated load following requirements via a more traditional treatment that is similar to the CAISO 2014 LTPP PLEXOS model (Liu 2014a).

E3 enforced correlations between electricity demand, wind output, and solar output by matching the month and level of demand for each profile. As described in other sections, E3 used historical hourly weather data to create demand, wind, and solar output profiles. E3 binned the wind and solar profiles as occurring on a day with a low, medium, or high value of total energy demand. To create a large number of samples, E3 randomized the 2024 demand, wind, and solar profiles within their demand bin.

This method broadly maintains correlations between these three profiles while allowing us to simulate the CAISO grid under many unique net demand conditions.

Electricity demand is typically lower on weekends and holidays than on non-holiday weekdays. To capture this dynamic, E3 performed representative sampling of weekdays and weekends. No additional weighting of each sample was needed, as E3 used the appropriate weighting when creating the draws.

To remove edge effects from the simulation, each draw simulates three days of hourly data, but we included data only from the central day in our results. The three-day draw structure also allowed for some storage—or redispatch, in the case of hydroelectricity—of electricity between weekends and weekdays. The ability to move electricity production and consumption between weekends and weekdays is important because the largest surpluses of renewable electricity typically occur on weekends, when demand is low but renewable production is similar to that on weekdays.

E3 modeled generator outages using an exponential distribution for mean time to failure and mean time to repair. Forced outages occurred at the same rate in each month, as the timing of these outages cannot be controlled. Maintenance outages were concentrated in months for which system capacity adequacy is not a large concern.

Reserve Products and Requirements

Our model included six distinct operating reserve products (Table A1). Consistent with the CAISO PLEXOS 2014 LTPP model, we modeled each as a single CAISO-wide product. We did not model any spatial disaggregation of reserve markets.

The amount of spinning and non-spinning reserves that must be held each hour was 3 percent of CAISO electricity demand for each of these reserve products (6 percent total for both) (Liu 2014a; Mao and Galjanic 2014a). We used input demand profiles to calculate the requirement for these reserves, so the reserve requirements did not change when demand is increased or decreased via energy storage or demand response.

E3 calculated load following and regulation requirements using a methodology similar to that used in the Eastern Wind Integration and Transmission Study (EnerNex 2011). E3 used the same methodology in its REFLEX work (E3 2014; E3 2013).

Hourly forecast error and within-hour variability of load, wind, and solar both contribute to the need to hold reserves during the scheduling process. E3 calculated reserve requirements for the aggregate output of the entire CAISO fleet of wind and solar generators because the variability and uncertainty of output decreases with increasing geographic diversity. For similar reasons, E3 used aggregate electricity demand across the CAISO footprint in calculating reserve requirements. For regulation and load following, respectively, E3 assumed that 15 percent and 30 percent of the variability and uncertainty of out-of-state renewable resources are balanced by the CAISO. Our model performed day-ahead unit commitment, and therefore used day-ahead forecast error values to calculate reserve requirements. We did not perform hour-ahead or real-time unit commitment.

TABLE A1. **Reserve Products in Our Model**

Reserve Product	Average (MW)	Minimum (MW)	Maximum (MW)
Regulation Up	624	228	954
Regulation Down	624	228	954
Load Following Up	2,567	1,371	4,136
Load Following Down	2,567	1,371	4,136
Spinning	852	516	1,694
Non-Spinning	852	516	1,694

As shown in the Eastern Wind Integration and Transmission Study, deviation of load and variable generation from hourly forecasts are roughly symmetrical, and the total variability of the system can be found by summing the variances for load, wind, and solar. E3's calculations included a co-variance term, though it was found to be small. By binning load and renewable production, the variance can be calculated as a function of forecasted hourly values. This variance can then be appropriately applied during the reserve calculation so that reserves during each hour reflect likely variability and forecast error. E3's approach therefore included the dynamic that the variability and uncertainty of renewable output can be larger or smaller at different levels of renewable output. E3's methodology for calculating load following and regulation produced requirements that are symmetrical around the hourly net load forecast. For example, in every hour, the load following down requirement had the same MW value as the load following up requirement.

Renewable Reserves

Consistent with current renewable integration modeling practices and broadly consistent with current CAISO grid operations, in most runs we modeled renewables as unable to provide reserves (Table 2 and Table 4 in the main text). To show that renewable generators could provide reserve products and sub-hourly flexibility, we made reasonable, and in many cases conservative, assumptions about the participation of renewables in reserve markets.

We restricted available renewable generators to those most likely to be capable of providing reserve products. We assumed that geothermal, biomass, biogas, behind-the-meter PV, and all out-of-state renewables would not participate in reserve markets, though in reality these resources might provide some response. In each hour, we allowed 20 percent of the hourly output of large-scale wind, solar PV, and solar thermal generators ("reserve-eligible renewables") to contribute to reserve products. Three separate constraints limited 1) the total commitment of upward reserves; 2) the total commitment of downward reserves; and 3) the combined commitment of upward and downward reserves. We limited all three of these quantities to 20 percent of the forecasted hourly output of reserve-eligible renewables.

The 20 percent reserve restrictions represent two barriers to the ability of renewable generators to provide reserves. First, renewable generators need certainty that they can provide reserves. As wind and solar power have variable and uncertain fuel, these generators would likely be certain that only that a fraction of their forecasted output would be available at any given time. They would incur penalties if they failed to deliver the expected response when called upon by the CAISO. Renewable generators would try to minimize these penalties by bidding their reserve response conservatively into CAISO reserve markets. Second, only a fraction of renewable generators may be willing or able to respond to control signals from the CAISO. This second restriction could be addressed in part by requiring all new utility-scale wind and solar generators to install the hardware and software needed to participate in energy and ancillary service markets.

We modeled wind and large-scale solar facilities as bidding their flexibility into reserve markets at costs consistent with a power purchase agreement (PPA) price of $100/MWh. Under this framework, different reserve products have different opportunity costs, based on the amount of curtailment expected when a renewable generator is selected to provide a given reserve product. In the case of upward reserve products, renewables must be operating below their maximum power output (curtailed) to provide the reserve.

We assumed that renewable facilities would bid into downward following reserve markets (load following down and regulation down) at $25/MW. To provide downward following reserves, renewables could be operating at full power output, but would need to be ready to decrease their power output if their downward response was needed within the operating hour. The $25/MW value represents the dynamic that reserve-eligible renewables providing downward following reserves would be called upon to reduce their output roughly one-quarter of the time. Thus when a renewable facility provides downward following reserves, roughly 25 percent of its potential power production will be curtailed, on average.

While both upward and downward following reserves could be called upon in any given operating hour, in a statistical sense half the time the downward reserve product is not called upon because the upward reserve product is needed instead. To remain conservative, the magnitude of the reserve requirement represents a relatively large band around the net load forecast. Grid operators are therefore very unlikely to actually call upon all of the committed reserves in any hour. To determine a bid price, we assumed that when downward reserves are called upon, half would be called upon, on average. Together these two factors mean that reserve-eligible renewables providing downwardly flexible reserves would have an opportunity cost to provide the reserve of about $100/MWh PPA price * 0.5 hour downward is called * 0.5 magnitude of downward call relative to reserve requirement = $25/MW.

We assumed that renewables providing upward reserves that are called upon infrequently—spinning and non-spinning—bid into these reserve markets at their marginal cost of $100/MW, representing the cost to curtail renewable output for one hour in this study. We did not give renewables an additional bid cost or payment in PLEXOS to provide spinning and non-spinning reserves, as the model allows a generator to provide these reserves only if it has adequate ability to increase power output ("headroom"). Creating this headroom forces the model to incur the cost of curtailing renewable generation, so no additional bid cost or payment was necessary.

We took a similar approach to upward reserves that are called upon more often—load following up, and regulation up—except that, consistent with the formulation of downward following reserves, we assumed that the renewable generator would be called upon to provide the reserve one-quarter of the time it is committed to provide the reserve. For a renewable generator that is curtailed at a marginal cost of $100/MWh but is allowed to produce one-quarter of the time, this equates to a price of $75/MW for renewables to provide load following up and regulation up ($100/MWh PPA price * 1 hour – $100/MWh PPA price * 0.5 hour upward is called * 0.5 magnitude of upward call relative to reserve requirement = $75/MW).

This method assumed that when a renewable facility provides either of these reserves, 75 percent of the potential power production from the renewable would be curtailed, on average. The PLEXOS bid price for renewables providing load following up or regulation up is -$25/MW, because the cost to curtail an hour of renewable generation is included via the creation of adequate headroom on the renewable generator.

Modeling Storage

We modeled electricity storage in a manner similar to the CAISO LTPP 2014 PLEXOS model (Liu 2014a). As discussed below, one notable exception to this rule is the treatment of reserves from new electricity storage. We modeled two different types of storage plants: existing pumped hydroelectric storage (PHS) and new generic storage. We discuss the modeling of new generic storage in this section, and existing PHS in the "Hydroelectric and Pumped Hydroelectric Storage" section.

Every model run in our study included enough storage capacity to meet the CPUC storage target of 1,325 MW of new storage capacity in the CAISO territory (CPUC 2013). We modeled this storage capacity more generically than existing PHS, as it is not yet clear what form new storage devices will take. We describe the modeling parameters used for these new generic storage devices below. The one exception to the generic modeling of new storage capacity is the 40 MW Lake Hodges PHS plant in SDG&E territory. We modeled this plant as a pumped storage plant, but counted it toward the 1,325 MW storage decision. Therefore, we included at least 1,285 MW of generic storage in all model runs.

We added further generic storage capacity above 1,285 MW to model runs that included additional non-generation flexibility. We modeled this capacity by scaling up the installed capacity of these devices, as well as quantities that scale with increased capacity, such as ramp rate (as expressed in units of MW/min) and storage energy capacity. We assumed that additional storage capacity above the CPUC storage target in SDG&E territory would come from generic storage projects only. We did not add any additional PHS beyond the 40 MW Lake Hodges PHS plant.

While we modeled incremental storage additions above the 1,325 MW target as generic storage plants rather than PHS, there are similarities in how the model would represent generic storage plants and advanced PHS projects with variable-speed pumps. A detailed report from Argonne National Laboratory shows that advanced PHS in a power system with large amounts of wind power would provide significant amounts of load following down and regulation down (Koritarov et al. 2014). Generic storage projects exhibit this same behavior in our model. Incremental storage additions above the 1,325 MW target could therefore produce qualitatively similar results if advanced PHS projects were modeled instead of generic storage projects. While our study shows the benefit of additional downwardly flexible storage on the CAISO grid in 2024, further analysis would be needed to choose between procurement of advanced PHS and other storage technologies.

New Generic Storage Projects

We divided new generic storage projects into two categories: those that can provide operating reserves and those that cannot. Consistent with the CPUC storage decision, we assumed that storage is sited in three areas of the electricity system: customer side, distribution connected, and transmission connected (CPUC 2014). We assumed that all of the transmission-sited and half of the distribution-sited capacity could contribute to operating reserves, but that the rest could not. We made this division because some storage projects will likely be directly controllable by and visible to the CAISO, but some will simply respond to electricity price signals or incentives. Of the 1,285 MW of new generic storage capacity, 887 MW can provide operating reserves, while 399 MW cannot (Table A2). We modeled generic storage devices with energy capacities of two, four, or six hours relative to the device's power capacity.

Consistent with storage modeling in the CAISO PLEXOS 2014 LTPP model (Liu 2014a), generic storage devices had a round-trip efficiency of 80 percent and a charging capacity that is 4.2 percent larger than the discharge capacity of the device. The starting and ending energy in each storage device was constrained to be equal for each draw, so the device could neither reduce nor accumulate stored energy outside the three-day window simulated in each draw.

Each storage device that is able to provide operating reserves could provide all the operating reserve products we modeled: regulation up, regulation down, load following up, load following down, spinning, and non-spinning reserves. Reserve provision was subject to the usual constraints in PLEXOS that avoid double-counting reserve capacity.

One notable difference between the modeling of storage reserves in our model and the CAISO PLEXOS 2014 LTPP model is the range over which storage can provide reserves. Storage devices installed for the CPUC storage decision are generally expected to be able to switch quickly (in seconds or at most a few minutes) from charging to discharging and vice versa. These devices should therefore be able to offer double their installed power capacity in operating reserve markets.

For example, imagine that a storage device is in the process of charging at the maximum rate allowed by the device—its charging power capacity. In response to a signal from the CAISO, it should be able to not only stop charging but also to discharge up to its full power capacity until it runs out of the energy it has previously stored. From the perspective of the grid, the storage device could provide *double* its rated power capacity in reserves. However, in the CAISO PLEXOS 2014 LTPP model, and more generally in the version of the PLEXOS model that we used (version 6.208, R08 x64 edition), storage devices are restricted to provide only their rated power capacity in reserves in any given hour, not double their rated power capacity. This is because the ability to provide reserves depends on whether the pump or the generator is online, and the version of PLEXOS we used does not allow the pump and generator for storage plants to be online simultaneously.

TABLE A2. **Generic Storage Capacity Included in All Model Runs**

Utility	Hours of Storage Capacity (Hr)	Capacity Unable to Provide Reserves (MW)	Capacity Able to Provide Reserves (MW)	Maximum Reserve Provision Each Hour (MW)
PG&E	2	79.5	161	328.8
PG&E	4	79.5	161	328.8
PG&E	6	18.5	80.5	164.4
SCE	2	79.5	161	328.8
SCE	4	79.5	161	328.8
SCE	6	18.5	80.5	164.4
SDG&E	2	19.7	32.6	66.6
SDG&E	4	19.7	32.6	66.6
SDG&E	6	4.2	16.3	33.3
Total	-	**399**	**887**	**1,810**

These values do not include the 40 MW Lake Hodges pumped storage project.

We bypassed the limitation on storage reserve capacity by splitting each storage device into two separate units: one that generates electricity and one that stores electricity. The two units are connected to the same storage reservoirs. Jennie Jorgenson at NREL suggested this approach. We further extended this formulation by restricting the two units from simultaneously generating and storing electricity. This is important because the negative price on renewable curtailment used in our model would incentivize storage devices to reduce renewable curtailment via an increase in storage losses. A device that could store and release energy simultaneously could unrealistically increase storage losses without penalty. We will provide further details on the implementation of storage operating reserves in our model on request.

Advanced Demand Response

The combination of new communication and control technologies for electric loads and the deployment of variable renewable generators is likely to create new opportunities for demand-side participation in electricity markets. In California, demand response has typically focused almost exclusively on decreasing peak demand on hot summer days. In the future, concerns over renewable curtailment and grid flexibility will drive deployment of demand response devices that can voluntarily increase consumption during times of surplus electricity generation, and decrease consumption when there is a dearth of generation capacity. We call demand-side flexibility that can both increase and decrease consumption *advanced demand response* (ADR).

In our model, we simulated ADR in a generic manner, much as we simulated the generic storage projects described above. The goal was to simulate how a diverse fleet of ADR technologies could be deployed and operated. We used recent reports from Lawrence Berkeley National Laboratory and NREL to inform our formulation of ADR (Hummon et al. 2013; Olsen et al. 2013). We combined this information with the CAISO 2014 LTPP PLEXOS model formulation of generic storage devices to complete our model's representation of ADR.

Runs of our model with additional non-generation flexibility assumed a constant availability of ADR capacity: 1 GW, 2 GW, or 3 GW (see Table 2 in the main text). Demand response resources represent the aggregated participation of many different

TABLE A3. **Generic Advanced Demand Response Capacity for Model Runs That Include 1 GW of ADR**

Utility	Hours of Charge/Discharge Capacity (Hr)	Capacity Unable to Provide Reserves (MW)	Capacity Able to Provide Reserves (MW)	Maximum Reserve Provision Each Hour (MW)
PG&E	2	60	121.5	243
PG&E	4	60	121.5	243
PG&E	6	14	60.8	121.5
SCE	2	60	121.5	243
SCE	4	60	121.5	243
SCE	6	14	60.8	121.5
SDG&E	2	19.6	32.5	64.9
SDG&E	4	19.6	32.5	64.9
SDG&E	6	4.2	16.2	32.5
Total	-	**311**	**689**	**1,377**

In runs with more demand response than 1 GW, values in the three rightmost columns were increased in proportion to the installed capacity. For example, for the model run with 2 GW of advanced demand response, values in the three rightmost columns were increased by a factor of two.

sources of electricity demand, some of which are available only during certain times of the day or year. Because the availability of individual demand response devices is likely to be less than 100 percent, the installed capacity of controllable devices would need to be greater than the available capacity to operationalize the ADR resources we modeled. Estimating the availability of ADR resources was outside the scope of our study.

In the future, many demand response devices will likely have control and communication technology that will enable them to provide operating reserves. We therefore modeled some ADR capacity as able to contribute to operating reserve requirements (Table A3). Similar to generic storage, ADR resources that can provide reserves can provide double their rated capacity in reserves. This is because we assumed that resources that are able to provide reserves can ramp from full demand to full supply in five minutes or less.

In contrast to conventional demand response resources, we modeled ADR resources as load shifting rather than load shedding. ADR is therefore modeled with 100 percent efficiency, and must be energy-neutral over the course of each day. This means that when an ADR device adjusts demand in one hour, it must adjust demand in the opposite direction in other hours of the same day. To model the use-limited nature of demand response, each ADR unit can shift each unit of demand only once a day. For example, a demand response resource with 60 MW of power capacity and 2 hours of energy capacity was restricted to only 2 hours * 60 MW = 120 MWh of charging each day. As each resource must be energy-neutral over the course of a day, this also restricted discharge of the resource to 120 MWh each day.

Because the deployment of ADR technologies has to date been limited to date, the price at which customers are willing to participate in these programs is not yet fully understood. To participate in ADR programs, customers will need to receive compensation for shifting their load. Many ADR technologies will likely compensate the customer each time the load is shifted (as opposed to conferring a fixed payment each month or year for flexible use of a load). Our model therefore included a $20/MWh cost for load shifting for all ADR resources. The model also included a charge for ADR to provide reserve products of $20/MW, to compensate customers for any inconvenience or cost incurred from providing reserves. We chose these cost values to be less than the cost of renewable curtailment ($100/MWh) so ADR would in general operate to reduce renewable curtailment. While all ADR might not be available at costs lower than the cost of renewable curtailment, we focused our analysis on ADR that could reduce renewable curtailment.

Costs for using an ADR resource in this study do not include the capital or fixed costs to install or maintain the resource, and therefore do not represent the total cost of an ADR resource. Grid planners would need to consider these costs when evaluating whether to procure ADR resources.

Like generic storage, by default we did not model ADR as contributing to regional generation requirements. This modeling assumption should not be taken to mean that ADR cannot contribute to local grid reliability needs. Rather, it reflects the fact that demand response has not historically contributed to the reliability needs envisioned in the regional generation requirements.

To capture the dynamic that ADR will sometimes be unavailable, we modeled outages stochastically with the same outage parameters as generic storage devices. These outages do not capture the full range of ADR availability (devices may or may not be on, and may or may not make their capacity available for load shifting at any point in time). Rather, these outages limited the availability of ADR in a manner similar to other generators and storage devices in our model.

Conventional Demand Response

We modeled conventional demand response—whose only function is to reduce demand during times of greatest need for system capacity—as in the CAISO 2014 LTPP PLEXOS model. In total, our model included 2,390 MW of conventional demand response (Table A4). Conventional demand response was given a price of either $600/MWh or $1,000/MWh, depending on the resource. These high prices indicate that conventional demand response will be called upon only during times of extreme grid stress—generally to avoid reserve shortages or loss of load events.

TABLE A4. **Conventional Demand Response Capacity in Our Model**

Utility	Conventional Demand Response Capacity (MW)
PG&E	912
SCE	1,392
SDG&E	86
Total	**2,390**

Hydroelectric and Pumped Hydroelectric Storage

We modeled the existing CAISO hydro fleet as a single aggregated generator. We enforced energy targets for the CAISO hydro fleet for each three-day draw. To represent the seasonal availability of water, these targets varied by month. Minimum and maximum hourly output for the CAISO hydro fleet were specified by month and were limited to historical levels. To represent the distribution of hydroelectric capacity within the CAISO footprint, our model allowed 25 percent of electricity generation from the CAISO hydroelectric fleet to contribute to SCE's regional generation requirement. All electricity generation from the CAISO hydroelectric fleet was allowed to contribute to the CAISO-wide regional generation requirement.

The model enforced historical limitations on ramping the output of the CAISO hydro fleet up and down over the course of many hours (Table A5). We limited the contribution of the CAISO hydro fleet to reserve products by including maximum ramp up

TABLE A5. **Multi-Hour Limitations on the Ramp Rate of the CAISO Hydroelectric Fleet**

Hours Between Time Steps	Maximum Ramp Down (MW)	Maximum Ramp Up (MW)
1	775	742
2	1,292	1,143
3	1,704	1,410
4	2,040	1,618
5	2,304	1,841
6	2,501	2,067
7	2,690	2,290
8	2,847	2,484
9	2,956	2,678

and ramp down rates of 13.9 and 14.9 MW per minute, respectively.

Our model included existing pumped hydroelectric storage (PHS) in the CAISO footprint, simulating 1.8 GW of PHS in total. We included operational constraints on PHS units present in the CAISO 2014 LTPP PLEXOS model. PHS units were allowed to start generating only once a day, were not allowed to apply their pumping capacity to downward reserves, and could pump only near the rated capacity of the pump. Modifications to the existing pumped hydro fleet to increase flexibility while pumping may be warranted, but are not explored in this study. Our model enforced additional constraints on the Helms Pumped Storage Plant included in the CAISO 2014 LTPP PLEXOS model.

In our study, we did not allow the ability to spill energy—that is, to not generate energy with water that could be used to do so—from CAISO hydro, the CAISO's portion of Hoover Dam, and existing PHS. Our goal was to quantify the amount of renewable curtailment that would result from different levels of operational flexibility in the CAISO system. While the CAISO hydroelectric fleet does have some opportunity to spill energy, substantially increasing the amount of spillage to decrease renewable curtailment would not be desirable. Given that renewable curtailment in our model incurred a cost of $100/MWh, while hydro spill would have incurred a cost of $0/MWh, in most situations the model would have chosen to spill hydro over curtailing renewable output. This spillage could have masked the amount of renewable curtailment in a given model run, so we modeled hydroelectric generators as unable to spill energy.

We limited reserves from CAISO's portion of Hoover Dam, restricting both the total upward and total downward reserves that Hoover can provide to 254 MW.

Nuclear

Consistent with default assumptions in the 2014 LTPP, we assumed that both units of the Diablo Canyon Power Plant were operational, and that the San Onofre Nuclear Generating Station was retired (CPUC 2014). As discussed in the "Dedicated Imports" section, we modeled part of the Palo Verde Nuclear Generating Station as a dedicated import into the CAISO. Diablo Canyon contributed to the CAISO-wide regional generation requirement, but Palo Verde did not, as it is outside the CAISO footprint.

The Price of Natural Gas and Carbon

Our model included a carbon price of $23 per metric ton of CO_2 in the cost of generation from fossil fuel facilities. Natural gas prices varied over the CAISO footprint, ranging from $4.11/million BTU to $4.79/million BTU, with an average of $4.33/million BTU. Natural gas prices did not include seasonal variability. Our study used the dollar-year 2014.

Dispatchable Natural Gas Generators

In our model, the capacity, location, reserve capability, and operational flexibility of CAISO natural gas power plants is almost identical to that modeled in the CAISO PLEXOS 2014 LTPP model (Table A6) (Liu 2014a). Gas generators outside the CAISO territory are aggregated, as discussed in the "Gas Imports" section.

Modeling Heat Rate and Start Costs

In contrast to the CAISO 2014 LTPP PLEXOS model, we modeled natural gas CCGTs and combustion turbine/peaker generators with heat rate curves and optimized start costs.

The additional detail on heat rates captures the decline in generator efficiency that occurs with decreased output. This is important from the perspective of both GHG emissions and production costs, because in many hours, generators may be held at low levels of output relative to their rated capacity to provide operational reserves.

The additional detail on start costs includes the cost to start each generator while optimizing the dispatch of generation. This is important because gas generators may turn on and off frequently to balance variable renewable power. Without proper representation of start cost, our model could have overestimated gas generator starts and stops, especially for combustion turbine/peaker gas plants.

TABLE A6. **Capacity and Flexibility of the CAISO Natural Gas Fleet in Our Model**

Natural Gas Power Plant Data	Combined Cycle Gas Turbine (CCGT)	Combustion Turbine/ Peaker
Total Capacity (MW)	15,104	6,699
Average Capacity (MW)	360	54
Number of Units	42	124
Flexibility Attributes (Capacity-Weighted Average)		
Minimum Downtime (Hours)	4.2	1.9
Minimum Uptime (Hours)	7.8	2
Start Duration (Hours)	3	N/A
Shutdown Duration (Hours)	1.4	N/A
Minimum Power Level (Percent of Generator Capacity)	39.1	40.5
Maximum Ramp Rate (Percent of Generator Capacity Per Minute)	3.1	18.7

Combined Heat and Power

We modeled combined heat and power (CHP) facilities as baseload generators with efficiency, capacity, and fuel, as represented in the CAISO 2014 LTPP PLEXOS model. CHP generators in our model could not adjust their output via either the energy or reserve markets, and therefore produced at rated capacity unless the unit was experiencing a forced or scheduled outage. In total we modeled 88 units in the CAISO territory with an installed capacity of 3,726 MW. In general, CHP generators contributed to regional generation requirements. Consistent with the CASIO 2014 LTPP PLEXOS model, the only CHP generators that did not contribute to regional generation requirements were either Qualifying Facility aggregates or Existing CHP Bundles. These facilities represented 492 MW of CHP capacity, or 13 percent of total CHP capacity.

Regional Generation Requirements

Regional generation requirements are described in the “Scope and Modeling” section of the main text, and are further discussed under question 2 in the main text.

Import Capacity

We limited the capacity to import power into the CAISO to the maximum historical path flow of 13,308 MW in all hours—the same value used in recent E3 REFLEX work (E3 2013). Any upward reserves provided into CAISO markets from generators outside of the CAISO (only Hoover Dam in our study) took up a portion of this import capacity equal to the reserve provision.

As shown in the 2014 LTPP, the maximum simultaneous import capacity into CAISO can depend on the amount of non-conventional generation deployed in the CAISO system (Liu 2014a). We did not model this dependency, but note that very few hours approach this maximum import capacity, and that these are generally the same hours that experience capacity shortfalls. Large amounts of electricity imports were never observed during hours with renewable curtailment. Because our study focused on mitigating renewable curtailment, the renewable curtailment results are robust to different values of maximum import capacity.

Limits on Ramping of Imports and Exports

We did not explicitly model generation units outside the CAISO service territory, except for those discussed in the "Dedicated Imports" section. Recognizing that operational constraints exist on generators outside of the CAISO footprint, we limited the ability to ramp imports and exports up or down to historical levels (Table A7). This is a conservative assumption, because the replacement of coal-fired power plants in nearby states with more flexible natural gas power plants will likely increase the ability to adjust out-of-state generation quickly. The sum of all imports, including dedicated imports and gas imports, was limited by the ramp rates in Table A7. Multi-hour limits on ramp rates were applied across the entire range of imports and exports.

Exports and the No Net Export Constraint

Importing and exporting renewable energy can be a low-cost solution to managing the variability of renewables (E3 2014). California has traditionally imported electricity, but its experience with exporting electricity is limited. To be consistent with the CAISO 2014 LTPP PLEXOS model (Liu 2014a), we assumed that CAISO cannot export more electricity than it imports in any given hour. We relaxed this assumption of no net exports by allowing 1 GW, 2 GW, or 3 GW of net exports in model runs with additional non-generation flexibility.

TABLE A7. **Limits on Multi-Hour Ramp Rates for Power Imported into CAISO**

Hours Between Time Steps	Maximum Ramp Down (MW)	Maximum Ramp Up (MW)
1	1,206	1,241
2	1,905	1,890
3	2,384	2,299
4	2,803	2,610
5	3,089	2,802
6	3,288	2,992
7	3,402	3,126
8	3,459	3,220
9	3,462	3,266

We modeled exports as a purchaser of electricity with a bid price of $0/MWh. This allowed the CAISO to export energy during times of negative energy prices, but underestimated the potential for generators within the CAISO footprint to be paid for their power. Our model enforced limits on the ramping up and down of exports through the multi-hour ramping constraints on both imports and exports.

Dedicated Imports

We modeled three generation resources that are outside the CAISO footprint but whose power the CAISO must import for contractual or ownership reasons. In our model, each dedicated out-of-state generator reserved transmission capacity into the CAISO equal to the generator's output in a given hour.

As noted above, our model limited the ability to export power on a net basis. This means that the more electricity the model was forced to import in a given hour, the more it could export. In general there was a disincentive to export, as the price received for exported energy is taken to be $0/MWh. However, the model had an incentive to simultaneously import and export during times of negative prices. The CAISO 2014 LTPP PLEXOS model included the same import/export dynamic, as we derived the no net export assumption in our model from that model.

The first dedicated import represented SCE's share of the Palo Verde Nuclear Generating Station. We modeled 15.8 percent of Palo Verde's generation in each hour as a dedicated import into CAISO, representing a maximum capacity of 639 MW.

The second dedicated import was a share of the Hoover Dam, with a maximum import capacity of 525 MW. Hoover was allowed to provide reserves into the CAISO market subject to its operating limits. Transmission capacity into CAISO was reserved in an amount equal to the provision of all upward reserves from Hoover. Hoover generation was limited by a maximum energy constraint over the course of the three days simulated in each draw. The maximum energy from Hoover varied by month.

The third dedicated import was out-of-state renewable generation. We assumed that 70 percent of the hourly production of out-of-state renewable generation must be brought into the state via dedicated imports. In total, 70 percent of the production from an installed capacity of 2.5 GW of wind and 0.9 GW of solar PV was represented as dedicated imports. We modeled the CAISO as partially balancing the sub-hourly variability of out-of-state renewables by including those resources in the calculation of load following and regulation requirements, as discussed in the "Reserve Products and Requirements" section.

Gas Imports

All non-dedicated imports into the CAISO footprint are modeled as generic gas-fired generation. Consistent with the CAISO-centric focus of our study, choosing a relatively high heat rate for generation outside the CAISO prioritized internal resources. With a heat rate of 10,000 BTU/kWh, this generation is slightly less efficient than many combustion turbines within the CAISO, and is much less efficient than gas-fired combined-cycle generators.

Because gas imports in our model represented an aggregation of many resources outside the CAISO, generic gas imports were not subject to the same operational constraints as gas generators within the CAISO. This omission is unlikely to make a large difference in our results, as the model consistently chose in-state resources before increasing gas imports. Also, gas imports were subject to the constraints on multi-hour ramping of imports described above, which broadly represent operational constraints on gas generators outside of the CAISO. CO_2 emissions from gas imports received the same carbon price as resources within the CAISO. In our model, gas imports were not allowed to contribute to CAISO reserve products.

PLEXOS and Solver Details

We used the PLEXOS 6.208 R08 x64 edition. The model performance relative gap (MIP gap) was 0.5 percent. We used the Xpress-MP solver version 23.01.12. We used a MIP maximum time of at least one hour per three-day stochastic draw.

Relating Our Results to UCS Testimony on the 2014 LTPP Model

UCS performed a number of sensitivity runs on the 40 percent RPS in 2024 Scenario from the CAISO 2014 LTPP PLEXOS model, and submitted the results as expert testimony in the CPUC's 2014 LTPP proceeding (Nelson 2014). Those results are relatively consistent with the results in this study, but a few important differences merit discussion.

In the UCS sensitivity runs on the 40 percent RPS in 2024 Scenario, we highlighted regional generation requirements as a central driver of renewable curtailment. When preparing the testimony, we observed that the price for load following down reserves, especially during hours close to sunset, exceeded the price of renewable curtailment during many hours. This observation suggests that if renewables could contribute to operating reserves, renewable curtailment could be reduced. Because of time constraints in preparing the testimony, we were unable determine the conditions under which enabling renewables to contribute to operating reserves could reduce renewable curtailment by a substantial margin.

Subtle differences in modeling methodology and scenario construction can be important in determining the key drivers of renewable curtailment. In this study, the provision of downward reserves at a 50 percent RPS appears to be more central to renewable curtailment than enforcement of regional generation requirements.

We propose, but do not prove or show, that the relative importance of downward following reserves and regional generation requirements could change depending on key modeling assumptions. We note below a number of differences between our model and the 40 percent RPS in 2024 Scenario for the LTPP that may change the relative importance of downward following reserves and regional generation requirements in causing renewable curtailment. Because we believe that both models make a reasonable set of assumptions about the future of the CAISO grid, we believe that both of these key drivers of renewable curtailment should be better understood and addressed to reduce renewable curtailment.

Key differences between our model and the CAISO 2014 LTPP PLEXOS model and that may change the relative importance of downward following reserves and regional generation requirements include these:

- The CAISO 2014 LTPP PLEXOS model included a handful of CCGTs that are modeled as producing energy outside the CAISO footprint but that can provide operating reserves into CAISO reserve markets. We have observed that these generators frequently and disproportionally provide reserves into CAISO markets during times of renewable curtailment within CAISO. These generators are likely chosen to provide reserves because their power can be used outside the CAISO without causing renewable curtailment, and their reserve capacity can be used within the CAISO to displace reserve capacity that would otherwise have been provided by a generator inside the CAISO. Our model did not include any gas generators that can provide reserves but not energy into CAISO markets. While regional pooling of reserves will in general lower the cost of integrating variable renewable resources into the grid, the extent to which out-of-area gas resources could provide reserve capacity but not energy into CAISO markets in the 2024 timeframe is unclear. If the CAISO can expand its footprint by 2024 to include many out-of-area resources, these resources could mimic the behavior of the CCGT generators discussed here. As noted in the UCS LTPP testimony, in this situation, regional generation requirements may take priority over downward reserves. Using non-fossil resources to fulfill both downward reserves and regional generation requirements will be important to reduce coincident renewable curtailment and generation from natural gas power plants.
- The CAISO model explores a 40 percent RPS in 2024 but not a 50 percent RPS. Besides increasing the amount of renewable generation, increasing the RPS requirement can also increase requirements for following reserves because of the variability and uncertainty of renewable generators.
- Incremental additions to the CAISO model of renewables above a 33 percent RPS come mostly from solar power. Incremental additions to our model of renewables above a 33 percent RPS include equal shares of baseload renewable generation, wind power, and solar power. The difference between these two models in the mix of renewables could have important implications for renewable curtailment.
- The CAISO model does not include constraints on multi-hour ramping of power imports, whereas our model does.
- The two models differ in the methods they use to create hourly load, following reserve, wind, and solar profiles.
- The two models may differ in their treatment of hydro spillage.

Why Some Storage Devices Would Have an Incentive to Discharge During Times of Curtailment

A storage device with relatively limited capacity to store energy may have an incentive to *discharge* during times of renewable curtailment because of the negative price of curtailment used in our model and related studies. This is not a "bug" in the models but rather represents rational behavior in response to price signals.

Take the example of a storage device with 1 MW of power capacity, 2 MWh of energy capacity, and 80 percent round-trip efficiency. Further assume that the grid has enough excess renewable energy that curtailment will occur with or without the storage device during many daylight hours, such as from 10 am to 4 pm.

During these hours, the marginal price of energy is likely to be near the cost of curtailment, which is -$100/MWh in our study. If we assume that the storage device is fully discharged at 10 am, its owner gets paid $100/MWh when the device charges for two hours at its rated power capacity until it reaches its energy capacity ($200 total). At that point it cannot charge further unless it discharges.

If the device fully discharges the stored energy over the next two hours, its owner will have to pay slightly less than received for the device to charge, because it is not 100 percent efficient. The owner will therefore have to pay 2 * $100/MWh * 80 percent efficiency = $160 to discharge between noon and 2 pm. However, once the device is discharged, the owner can again get paid $100/MWh if it charges for the next two hours ($200 total), because on this hypothetical day, curtailment is still occurring between 2 pm and 4 pm. Comparing the revenue in each case shows that the owner receives more for a charge-discharge-charge cycle ($200 - $160 + $200 = $240) than for simply charging the device and waiting until marginal energy prices are positive ($200).

The same incentive does not exist when the storage device has enough capacity to charge for periods of time that are similar to the length of time during which curtailment occurs. In this case, the owner receives the most revenue from charging only, as a charge-discharge-charge cycle would take too much time to be economical. Also, if the storage device can participate in the reserve markets that are driving curtailment, the charge-discharge-charge cycle is not observed, as the owner can receive more revenue from participating in reserve markets than from a charge-discharge-charge cycle.

When contemplating how renewables could bid into energy markets, analysts should investigate perverse incentives such as these. Negative marginal energy prices could have unintended consequences that should be better understood and managed in power system operations.

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