2012 IEPR
UPDATE

INTEGRATED ENERGY POLICY REPORT UPDATE

CALIFORNIA ENERGY COMMISSION
EDMUND G. BROWN JR., GOVERNOR

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The *2012 Integrated Energy Policy Report Update* is dedicated to

CARLA J. PETERMAN

Energy Commissioner
January 2011 – December 2012

With gratitude for her leadership and dedication in developing the 2012 IEPR Update as well as her significant contributions to California energy policy in the areas of renewable energy, alternative transportation fuels and technologies, and natural gas.

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Preface

Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002) requires the California Energy Commission to prepare a biennial integrated energy policy report that contains an assessment of major energy trends and issues facing the state's electricity, natural gas, and transportation fuel sectors and provides policy recommendations to conserve resources; protect the environment; ensure reliable, secure, and diverse energy supplies; enhance the state's economy; and protect public health and safety (Public Resources Code § 25301[a]). The Energy Commission prepares these assessments and associated policy recommendations every two years, with updates in alternate years, as part of the *Integrated Energy Policy Report*. Preparation of the *Integrated Energy Policy Report* involves close collaboration with federal, state, and local agencies and a wide variety of stakeholders in an extensive public process to identify critical energy issues and develop strategies to address those issues.

Abstract

The *2012 Integrated Energy Policy Report Update* includes additional information on five topics that were originally raised in the *2011 Integrated Energy Policy Report*. These topics include: (1) the Energy Commission's adopted electricity and natural gas demand forecast for 2012–2022; (2) the outlook for and trends in the natural gas market; (3) the potential for increased development of combined heat and power facilities; (4) an assessment of electricity infrastructure needed in Southern California to provide sufficient and reliable power; and (5) suggested actions to support renewable development and help California meet its Renewables Portfolio Standard target of 33 percent renewable electricity by 2020.

KEYWORDS

California Energy Commission, California Independent System Operator, California Public Utilities Commission, combined heat and power, distributed generation, electricity, electricity demand, electricity infrastructure, hydraulic fracturing, natural gas demand, natural gas pipelines, renewable, Renewable Action Plan, Renewables Portfolio Standard

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Table of Contents

List of Tables and Figures

EXECUTIVE SUMMARY

As the ninth largest economy

in the world, California depends on having reliable, safe, and affordable supplies of energy. State government plays an essential role in energy planning and development to meet California's energy needs while protecting public health, promoting a healthy economy, conserving natural resources, and preserving environmental quality. Every two years, the California Energy Commission issues an *Integrated Energy Policy Report (IEPR)* that provides forecasts of energy supply and demand along with evaluations of the most current and pressing energy issues facing the state. These forecasts and assessments form the basis for long-range energy policies and planning to guide the future of California's energy system.

Throughout the *IEPR* development process, the Energy Commission works closely with a variety of state, local, and other agencies. Specific agencies – including the California Public Utilities Commission, the Division of Ratepayer Advocates, the California Air Resources Board, the California Independent System Operator, the Department of Water Resources, and the Department of Transportation – are in turn required by statute to "carry out their energy-related duties and responsibilities based upon the information and analyses contained in the report." This requirement ensures that consistent information is used among all parties to develop energy policies and decisions affecting the state.

In the year following publication of the biennial *IEPR*, the Energy Commission publishes an energy policy review that provides updated information on topics raised in the biennial *IEPR*. The main element of this *2012 IEPR Update* is the Energy Commission's Renewable Action Plan, which identifies actions to help California achieve its Renewables Portfolio Standard target of 33 percent renewables by 2020 and support potentially higher targets in the future.

The *2012 IEPR Update* also provides a status report on the following activities that were initiated during the *2011 IEPR* proceeding and either continued or completed during 2012:

- The Energy Commission's electricity and natural gas demand forecast for 2012–2022, which was adopted in June 2012.
- Reports on the natural gas market outlook and trends, which were finalized in 2012.
- An assessment of market potential for and barriers to increased development of combined heat and power facilities to meet the Governor's goal of 6,500 megawatts of combined heat and power by 2030.
- An ongoing assessment of electricity infrastructure in Southern California needed to meet future electricity demand and provide reliable service.

Renewable Action Plan

Background

California's "loading order" of energy resources was established in 2003 in the state's first *Energy Action Plan*. Energy efficiency and demand response are the preferred means of meeting growing energy needs, followed by renewable resources, distributed generation, and combined heat and power applications, and finally by clean and efficient fossil-fired generation. The loading order has been instrumental in California's success as a clean energy leader.

The *2012 IEPR Update* focuses on the renewable component of the loading order. California's Renewables Portfolio Standard requires renewable electricity to equal an average of 33 percent of the total electricity sold to retail customers in California by December 31, 2020. To support this target, Governor Jerry Brown's Clean Energy Jobs Plan called for adding 20,000 megawatts (MW) of new renewable capacity by 2020, including 8,000 MW of large-scale wind, solar, and geothermal as well as 12,000 MW of localized generation close to consumer loads.

As noted in the *2011 IEPR*, renewable energy can improve California's energy independence by using local energy sources and fuels rather than imported natural gas, which is susceptible to supply shortages and price spikes. Investments in renewable energy can also provide economic and job benefits. Further, increasing the amount of renewable resources in California's electricity portfolio benefits the environment by reducing fossil-fuel generation and helping to achieve the state's greenhouse gas emission reduction goals. However, moving from a century-old system dominated by fossil fuels to a system with increasing amounts of renewable resources presents substantial challenges, which were described in detail in the *Renewable Power in California: Status and Issues* report that was published as part of the *2011 IEPR*.

In addition to identifying challenges, that report described California's success with renewable resources to date. In 2010, the state had more than 10,000 MW of installed renewable capacity which provided nearly 16 percent of total retail sales of electricity. Of that amount, about 3,000 MW represents distributed generation, and there is an additional estimated 6,000 MW of distributed generation either under development or authorized under existing

programs. The report also noted that, as of May 2011, enough renewable generation appeared to be either on-line or under contract to meet the Renewables Portfolio Standard target for 2020.

The *Renewable Power in California: Status and Issues* report also described some of the many successful efforts to promote renewable energy in California. Thanks in large part to programs such as the California Solar Initiative, the Emerging Renewables Program, the Self-Generation Incentive Program, and the New Solar Homes Partnership, California leads the nation in solar installations with more than 137,000 solar projects totaling roughly 1,450 MW. The California Public Utilities Commission has made great strides in reforming interconnection processes to streamline interconnection of smaller renewable projects. The state's Renewable Energy Action Team – established in 2008 and composed of the U.S. Department of the Interior Bureau of Land Management, the U.S. Fish and Wildlife Service, the California Department of Fish and Wildlife, the Energy Commission, the California Public Utilities Commission, and the State Lands Commission – is a model for successful coordination between agencies and continues to streamline and expedite permitting of renewable energy projects in California.

The report proposed five overarching strategies to guide the state in its efforts to increase renewable electricity generation. These five strategies were the foundation for the Renewable Action Plan developed as part of the *2012 IEPR Update*:

1. Identifying and prioritizing geographic areas for renewable development.

2. Evaluating costs and benefits of renewable projects.

3. Minimizing interconnection costs and time at both the transmission and distribution levels.

4. Promoting incentives for projects that create in-state jobs and economic benefits.

5. Promoting and coordinating existing financing and incentive programs for critical stages in the renewable development continuum.

Overall Approach

The recommendations in the Renewable Action Plan are meant to advance a renewable-centric generating portfolio that minimizes cost and risk while maximizing economic, social, and environmental benefits. In 2010, natural gas-fired power plants provided more than 40 percent of California's electricity. Increasing the amount of renewable generation will diversify the portfolio of generating resources and reduce risks to ratepayers. Renewable resources can also provide a hedge against natural gas price spikes or shortages, along with other benefits like reduced greenhouse gas emissions, and economic and job growth.

The actions in the plan will also position California for higher renewable goals post-2020. This is consistent with statements by Governor Brown that the 33 percent by 2020 RPS target should be considered a floor and not a ceiling and with the need for a higher percentage of renewable electricity resources to meet the state's long-term (2050) greenhouse gas emission reduction goals.

The Renewable Action Plan focuses on actions that are not undertaken by the market, can be influenced by the state, and are feasible within agencies' purviews, with an emphasis on "no regrets" actions that will provide a significant return in terms of greenhouse gas emission reductions. Actions are also focused on maximizing the value of existing programs rather than on recommending new programs or incentives.

Action items are loosely grouped by the overarching strategy and challenge they are intended to address. That said, many of the actions are interconnected to some extent, meaning that successful

implementation of some actions may mitigate the need for others. Also, several goals of the Renewable Action Plan – reducing costs, securing the benefits of renewables, creating jobs, and promoting economic development – will be affected by all of the actions regardless of category. For example, actions to aid renewable integration, reduce permitting time by identifying the best locations, or improve technology performance through research and development will also reduce costs. Similarly, actions to promote renewable development will ultimately promote job creation and economic development as projects are built and placed into operation.

A theme running through the Renewable Action Plan is the need to improve and expand California's electricity planning efforts. Energy planning is not simply a question of engineering and how to plan for and integrate more renewable resources. It is also about economic and equity issues that will require increased involvement by a large and diverse group of stakeholders. In addition, with the push for increased amounts of localized generation, local government officials and residents will need to become more involved. Long-term planning also provides the policy certainty needed by the market to encourage new investments and focus future investments in clean technology innovation.

California needs to broaden its electricity planning to include the distribution system as well as generation and transmission. Focusing on distribution system planning will promote integration of demand-side supply and consumption strategies and technologies including energy efficiency, demand response, and electrification of the state's vehicle fleet. With the Governor's goal of 12,000 MW of distributed generation by 2020, distribution planning needs to be modernized and made more transparent.

As California increases its use of renewable electricity generating resources, there are major planning challenges associated with moving from a generating fleet largely composed of dispatchable resources, which can be ramped up or turned off on demand, to one that includes large amounts of intermittent resources that cannot. Integrating these resources will require a combination of complementary resources. While flexible natural gas plants can provide the services needed to operate the electric grid safely and reliably, it is important to also have a range of alternative and complementary options such as energy storage and demand response. Electricity planners need to incorporate and consider carefully how to develop a role and market for these supporting technologies.

During the development of the Renewable Action Plan, two foremost issues arose related to using natural gas plants to integrate intermittent renewable resources. First, ensuring that natural gas plants can be called on when needed will require better harmonization between the increasingly interdependent electric and natural gas markets. Second, there is still much uncertainty about the number, size, and operating characteristics of natural gas plants needed to help integrate large amounts of intermittent renewable resources. Analyses must consider many variables with differing degrees of uncertainty, including:

- The effect of increased energy efficiency on electricity demand, how much reduced demand could lessen the amount of renewable energy needed to meet the 33 percent renewable target that is based on retail sales, and the potential contribution of demand response to resource adequacy needs.

- The number of electric vehicles deployed to help meet California's goals to reduce the carbon intensity of transportation fuels and increase the use of alternative fuels.

- The construction of transmission projects to bring renewable energy to market.

- The timing and likelihood of retirement or repowering of fossil plants that use once-through cooling.

- The continued operation or relicensing of the state's nuclear power plants.

- The ultimate mix of renewable resources, how much of that mix is baseload versus intermittent, and where it is located.

- The success of investments in the smart grid – an electric grid that uses computer intelligence and networking to allow all components of the grid to both "talk" and "listen," thereby improving operations, maintenance, and planning – that can aid renewable integration and reduce the need for backup generating facilities.

- The effect on electricity demand of population growth, economic recovery, and climate-related factors, as well as the impact of climate change on electricity-generating resources like hydroelectric which often depend on snowpack.

A major challenge California must address is how to fund the clean energy investments that are critical to the long-term security, stability, and economic welfare of California. The reality is that California's public sector alone cannot provide enough funding for the long-term investments needed to reach the state's renewable energy goals for 2020 and beyond. The state will need to leverage federal and private funding and build on investments made through utility procurement programs, the American Recovery and Reinvestment Act of 2009, and the private sector.

In addition, California must continue to fund cutting-edge research, development, and demonstrations that are required to produce the next generation of clean energy technologies. Targeted research and development can reduce the costs and environmental impacts of renewable technologies, help create new businesses and jobs, and attract investment capital to the state.

The ultimate cost and rate impacts of California's 33 percent Renewable Portfolio Standard remain highly uncertain. As California works to achieve its renewable energy goals, actions to promote those goals must send the appropriate price signals to help shape investments and influence behavior. At the same time, rate design must be fair, sustainable, and have some type of mitigation measures for those who are disadvantaged. Actions should also lower the cost of renewables and reduce impacts on electric rates. Along with technology costs, renewables face other costs related to integration, permitting, and interconnection that can affect retail rates. Additionally, the many benefits of renewable energy have yet to be fully quantified. Electricity procurement processes must fully consider both costs and benefits so that renewable price signals reflect the all-in cost of generation and service. Actions to promote renewable energy must also ensure that the costs and benefits of renewable development are fairly distributed. California's energy system has disproportionately affected many of the state's disadvantaged communities, which may not be in line to receive many of the benefits of increasing renewable development throughout the state.

Finally, because the renewable energy market is complex and dynamic, it will be important to monitor and report on progress toward achieving the actions identified in the Renewable Action Plan and to identify course corrections as needed. This will not only keep decision makers and stakeholders apprised of the progress that is being made, but will also help to identify outstanding, new, or unexpected issues and areas where regulatory assistance may be needed. For example, as the renewables market continues to scale up, further focus on consumer protection may be needed. The Energy Commission therefore proposes to hold an annual workshop under the direction of its Lead Commissioner for Renewables to highlight progress made on the various actions contained in the plan and to seek input on additional actions that may be needed to maintain forward momentum.

Specific Actions to Advance Renewable Energy

Based on workshop discussions, written comments, and the considerations discussed above, the Energy Commission puts forward the following actions to advance California's renewable industry and achieve its renewable goals. While each action is important, emphasis should be on actions that create a foundation for further efforts or that are especially timely to take advantage of current opportunities. Within this framework, Table E-1 identifies the 10 top priority actions. Implementation will require leadership across a wide variety of actors including the Governor's Office, energy agencies, regional and local governments, the Labor Workforce Development Agency, and electric utilities.

To identify and prioritize geographic areas for renewable development, utilities, the California Public Utilities Commission, the Energy Commission, local and regional governments, and the Governor's Office of Planning and Research should work together to identify preferred renewable development zones for distributed generation and renewable generation in general, with an initial focus on identifying preferred renewable zones in the Central Valley. This work aims to align local government land-use planning and utility planning processes more closely. The Energy Commission should also broaden its planning efforts beyond 2020 to explore renewable targets higher than 33 percent as the state moves toward the 2050 goal to reduce greenhouse gas emissions 80 percent below 1990 levels. California must also continue its efforts to deploy renewable energy on state property and expand the effort to deploy renewables at elementary, middle, and high schools and in areas of Southern California that need additional energy supplies.

Actions to maximize the benefits of renewable energy include modifying procurement practices to develop a higher-value portfolio that includes not just lower-cost projects but also those that provide integration services, reduce the risk of forest fires that damage transmission lines, encourage investment in disadvantaged communities, create jobs in California, and provide value to the state as a whole. The state also needs to reevaluate its residential electricity rate structure to more equitably spread any new costs going forward. Moreover, as the state electrifies the transportation sector to reduce air pollution, the Energy Commission and others need to ensure that electric vehicle charging infrastructure is designed to capture renewable benefits, for example by encouraging charging during times of high wind and low load. Last, developing more transparent and publicly available data on renewable generation costs will help support ongoing analyses needed to monitor and further develop renewable policies.

Actions needed to minimize interconnection and integration costs and time must address both the transmission and distribution systems. On the transmission side, consistent use of the Energy Commission's environmental analysis for in- and out-of-state resources in transmission planning can improve the efficiency and effectiveness of the process. Actions are also needed to streamline transmission line development to ensure timely interconnection of new renewable facilities. On the distribution side, California must begin a dialogue on developing a more transparent and integrated distribution planning process to advance strategic deployment of distributed generation and reduce interconnection costs. Also, new protections and control systems are required to avoid damage to the distribution system as distributed generation penetration increases. The Energy Commission should develop a more disaggregated demand forecast to support a comprehensive distribution planning process and identification of preferred locations for renewable development. To support these efforts, the state should develop a statewide data clearinghouse to make renewable generation planning information clear and readily available to state, local, utility, and industry planners.

Integrating increasing levels of intermittent resources will require greater operational flexibility. To ensure sufficient capacity is available to integrate

Table E-1: Priority Actions – Renewable Action Plan

Action	Lead Agencies/Actors
Strategy 1 : Identify Preferred Geographic Areas for Renewable Development	
Action 2: Identify renewable energy development zones	Energy Commission, regional/local governments, Governor's Office of Planning and Research, Renewable Energy Action Team, utilities
Strategy 2: Maximize Value Through Appropriate Assessment of Benefits and Costs	
Action 5: Modify procurement practices to develop a higher value portfolio	California Public Utilities Commission
Action 6: Revise residential electricity rate structures	California Public Utilities Commission
Strategy 3: Minimize Interconnection and Integration Costs and Requirements	
Action 9: Consider environmental and land-use factors in renewable scenarios	Energy Commission, California Public Utilities Commission, California Independent System Operator
Action 12: Develop a dialogue on distribution planning and opportunities for a more integrated distribution planning process	Energy Commission
Action 16: Develop a forward procurement mechanism	California Public Utilities Commission, California Independent System Operator
Action 17: Define clear tariffs, rules, and performance requirements for integration services	California Public Utilities Commission, California Independent System Operator
Strategy 4: Economic Development With Renewable Energy	
Action 20: Better align workforce training to needs	Labor Workforce Development Agency, California Workforce Investment Board, Division of Apprenticeship Standards, Employment Development Department
Strategy 5: Research and Development and Financing	
Action 25: Promote research and development for renewable integration	Energy Commission
Action 28: Support long-term extension of federal tax credits	Office of the Governor

Source: California Energy Commission

intermittent resources, the California Public Utilities Commission should consider developing a forward procurement mechanism that allows all resources – demand response, energy storage, distributed technologies, and natural gas facilities – to compete. To foster the development of integration services, the California Independent System Operator should develop a comprehensive package of products, tariffs, rules, and protocols that allow automated demand response (in which electrical systems or appliances automatically reduce consumption in response to price or emergency signals), energy storage, and other distributed technologies to provide needed integration services. California should also support advancement of integration services on a regional level. Finally, the Energy Commission and the California Public Utilities Commission will need to work with the Federal Energy Regulatory Commission to ensure that the state's natural gas infrastructure can support the integration services that natural gas facilities will need to provide in the electricity market.

Meeting California's renewable goals will require a well-trained workforce to meet the evolving needs of the renewable industry. Although several workforce training efforts are underway, further work is essential to better align these efforts with industry needs. Also, the Workforce Investment Board should develop a clearinghouse to improve connections between workforce, employers, and education providers to promote participation in the clean energy economy, including outreach to encourage the participation of inner-city communities, poor rural communities, and veterans. The Governor's Office of Business and Economic Development should support renewable energy technology innovation and development through the state's innovation hub initiative.

Research and development are crucial to lower installation and maintenance costs, improve technology performance of existing technologies, promote innovative technologies, address the challenge of integrating intermittent resources, and advance proactive siting of renewable technologies to avoid permitting delays and impacts to environmentally sensitive areas. Research and development for existing technologies should include enhancing synergistic combinations of renewable technologies that can be co-located in a region as well as efforts to advance California's *Bioenergy Action Plan*. Research and development are also needed for innovative technologies that are "on the horizon" and hold promise to help meet the state's renewable goals.

Finally, the lack of available financing for early stages of project development and capital needed in later stages of early commercial development can result in lost opportunities for technology advancement and economic development. Under the leadership of the Governor's Office of Business and Economic Development, the state should create an interagency clean energy financing working group to better coordinate and leverage existing clean energy financing programs and increase public awareness of available programs. The state should also support a long-term extension of federal tax credits to attract investment in renewable development and explore the effectiveness and impacts of the property tax exclusion for solar energy systems, which expires in 2016. Lastly, the Energy Commission should modify the Clean Energy Business Financing Program and the Energy Conservation Assistance Account Program to provide loans more effectively to renewable developers and provide technical assistance and low-interest financing to local and public entities.

Electricity and Natural Gas Demand Forecast

Accurate forecasts of energy demand are crucial to identifying the new power plants, transmission lines, natural gas pipelines, and other energy infrastructure that are the key elements of providing reliable, affordable energy to California residents and businesses.

Every two years, the Energy Commission forecasts electricity and natural gas demand over a 10-year period. The forecast is used in a variety of energy planning venues, including the California Independent System Operator's transmission planning studies and the California Public Utilities Commission's electricity procurement planning process.

The Energy Commission released a preliminary forecast for 2012–2022 as part of the *2011 IEPR*, with the final forecast adopted by the full Energy Commission in June 2012. The forecast included three scenarios representing high, medium, and low energy demand. Final results showed that average annual growth in demand for electricity ranged from 1.03 percent to 1.69 percent from 2010 to 2022, with peak demand growing by 1.0 percent to 1.91 percent over the same period. Natural gas demand (not including natural gas needed for electricity generation) is expected to increase by an annual average of between 0.58 percent and 0.81 percent.

Natural Gas Trends and Outlook

California depends on natural gas to meet many of its energy needs – including heating, cooking, industrial processes, natural gas vehicles, and power plants – but continues to import nearly 90 percent of the natural gas it uses from out of state. This dependence makes it essential for California to keep abreast of natural gas market trends at state, national, and global levels.

In May 2012, the Energy Commission released two staff reports, the *2011 Natural Gas Market Assessment: Outlook* and the *2012 Natural Gas Market Trends.* Among the variety of issues impacting natural gas markets in the future, four issues, discussed in more detail in Chapter 2, are of highest significance:

- The potential effect on natural gas supplies and prices in California from activities to limit hydraulic fracturing or "fracking" – injecting water under high pressure into the ground to release natural gas in shale deposits – because of environmental concerns.

- The increase in natural gas demand at the national level due to a shift from coal to natural gas-fired generation, and potential increased demand in California from the use of natural gas plants to integrate renewables and increased use of natural gas as a vehicle fuel.

- The need for better coordination between the electric and natural gas industries as the national power fleet relies increasingly on natural gas and as more natural gas plants are used to integrate renewables.

- The potential rise in natural gas prices from pipeline safety enhancements made in response to the September 2010 San Bruno explosion and the potential downward pressure on prices from recent additions of pipeline capacity across the country that is creating more competition.

Combined Heat and Power Potential and Barriers

Combined heat and power, also known as cogeneration, is the efficient production of both electricity and heat from a single fuel source. California has more than 8,500 MW of combined heat and power facilities, and the California Air Resources Board set a target for 4,000 MW of additional capacity by 2020 as an important strategy to reduce greenhouse gas emissions. In addition, Governor Brown has called for adding 6,500

MW of new combined heat and power by 2030. A recent assessment of technical and market potential funded by the Energy Commission concluded that there is more than 14,000 MW of additional combined heat and power that could be developed, but policies implemented under current and emerging regulations will not be sufficient to achieve the market penetration needed to meet the Air Resources Board's targets.

Barriers to increased development of combined heat and power include disincentives under current cap-and-trade rules; cost and regulatory complexity of interconnection rules; costly nonbypassable, departing load, standby, and demand charges; expensive metering requirements; and lack of eligibility for net energy metering.

Electricity Infrastructure Assessment

The *2011 IEPR* highlighted the importance of reliable, affordable, and safe electricity infrastructure –power plants, transmission lines, distribution wires, and control systems – to meet California's growing energy demand. Determining what infrastructure will be needed involves balancing many factors, including complying with environmental regulations and maintaining reasonable and fair energy costs. This can be challenging, particularly in Southern California, which is facing a perfect storm of unique issues that include the potential retirement of a large number of fossil power plants that use once-through cooling, lack of available emission credits to allow replacement plants to be built, the outage since January 2012 at the San Onofre Nuclear Generating Station, and policies to electrify combustion sources in the Los Angeles Basin to improve air quality that could end up increasing electricity demand.

As part of the *2012 IEPR Update*, the Energy Commission held a forum in Los Angeles to examine electricity infrastructure challenges. Participants included the Energy Commission, the California Public Utilities Commission, the California Air Resources Board, the California Independent System Operator, the South Coast Air Quality Management District, and a variety of energy stakeholders and public participants. The forum discussed the many analytic studies being conducted by various agencies that will provide the information decision makers need to determine what generating facilities or transmission lines should be built and where.

In addition, the forum discussed some potential solutions to infrastructure challenges in Southern California. One solution included developing a contingency plan in case the San Onofre Nuclear Generating Station is not available in the summers of 2013 and 2014, as well as a longer-term plan for what would be needed to replace the nuclear facilities permanently. In the meantime, the energy agencies developed and implemented a plan for summer 2012.

The Energy Commission intends to continue its ongoing assessment of electricity infrastructure needs and will work with other agencies to incorporate results of their studies into its analysis. There is also a need for "refreshed" studies that take into account the outage at San Onofre and its effect on future infrastructure needs.

In addition, the analysis will consider the potential vulnerability of California's energy supply and demand infrastructure to the effects of climate change. These include higher temperatures that will increase electricity demand for air conditioning and reduce the efficiency of power plants and transmission lines; reduced snowpack that will affect the amount of hydropower generation; sea level rise, which could affect numerous coastal power plants and substations; and extreme events like wildfires that can damage transmission lines and potentially cause blackouts.

CHAPTER 1

Electricity and Natural Gas Demand Forecast

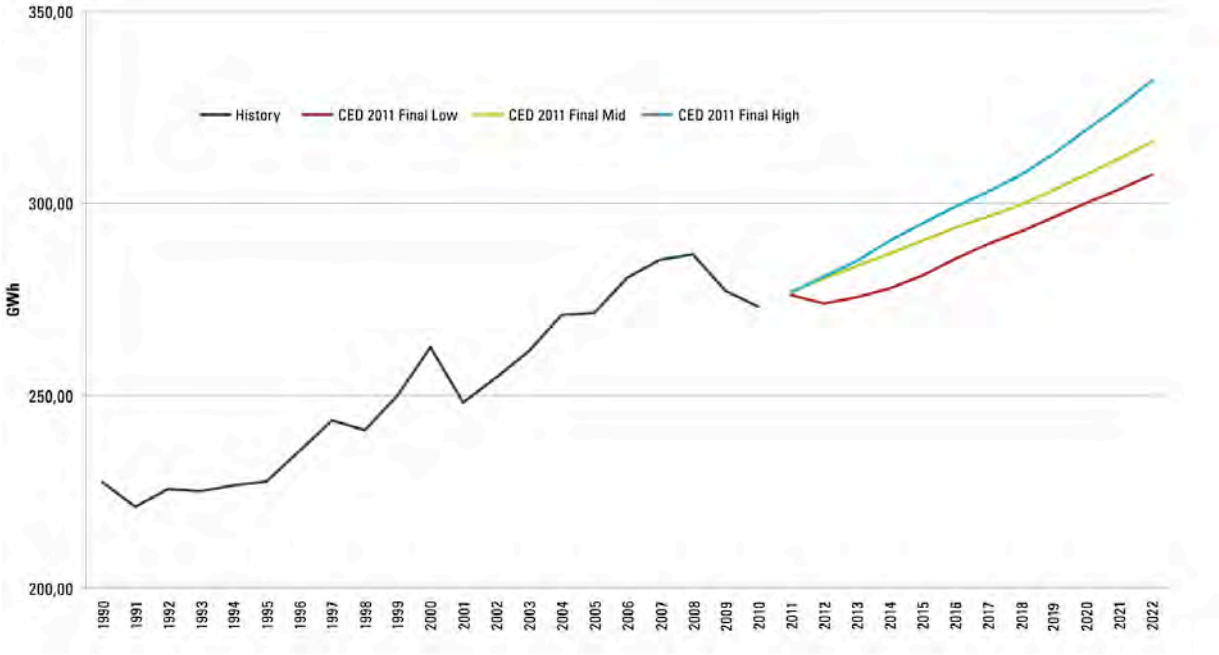
Forecasts of future demand

for electricity and natural gas are essential to ensuring that California builds the power plants, transmission lines, and natural gas pipelines needed to provide reliable and affordable energy to its residents, businesses, and industries. Every two years, the California Energy Commission analyzes current energy trends, customer behavior, government policies, and emerging technologies and provides a forecast of electricity and natural gas consumption and demand for the next 10 years. The Energy Commission's electricity demand forecast is used in many venues, including the California Independent System Operator's transmission planning studies and the California Public Utilities Commission's (CPUC) electricity procurement planning process.

Updates to the Preliminary Forecast

During the *2012 IEPR Update* proceeding, Energy Commission staff finalized the preliminary forecast prepared during the *2011 IEPR* proceeding to include updated or additional information related to:

Figure 1: Statewide Annual Electricity Consumption



Source: *California Energy Demand, 2012–2022 Final Forecast, Volume 1*, June 2012.

- Historical electricity consumption and peak demand data for 2011.
- Electricity savings from 2011 television efficiency standards.
- Peak demand savings from certain demand response programs.
- Economic and demographic projections.
- Forecasts of light-duty electric and natural gas vehicles.
- Electrification at ports[1] and other sources in Southern California.
- Potential effect of climate change on electricity demand; although the analysis was not comprehensive and did not capture the impact on peak demand, it is the first time that climate change impacts have been included at any level in the forecast.

Forecast Results

The *California Energy Demand 2012–2022 Final Forecast* was adopted by the Energy Commission in June 2012.[2] The forecast included scenarios for high, mid, and low energy demand with varying assumptions about economic and demographic growth, electricity

1 Port electrification refers to replacing internal combustion sources with electricity to power berthed ships and cargo handling equipment like tractors, trucks, and cranes.

2 California Energy Commission, *California Energy Demand, 2012–2022 Final Forecast, Volume 1: Statewide Electricity Demand and Methods, End-User Natural Gas Demand, and Energy Efficiency,* June 2012, http://www.energy.ca.gov/2012publications/CEC-200-2012-001/CEC-200-2012-001-CMF-V1.pdf.

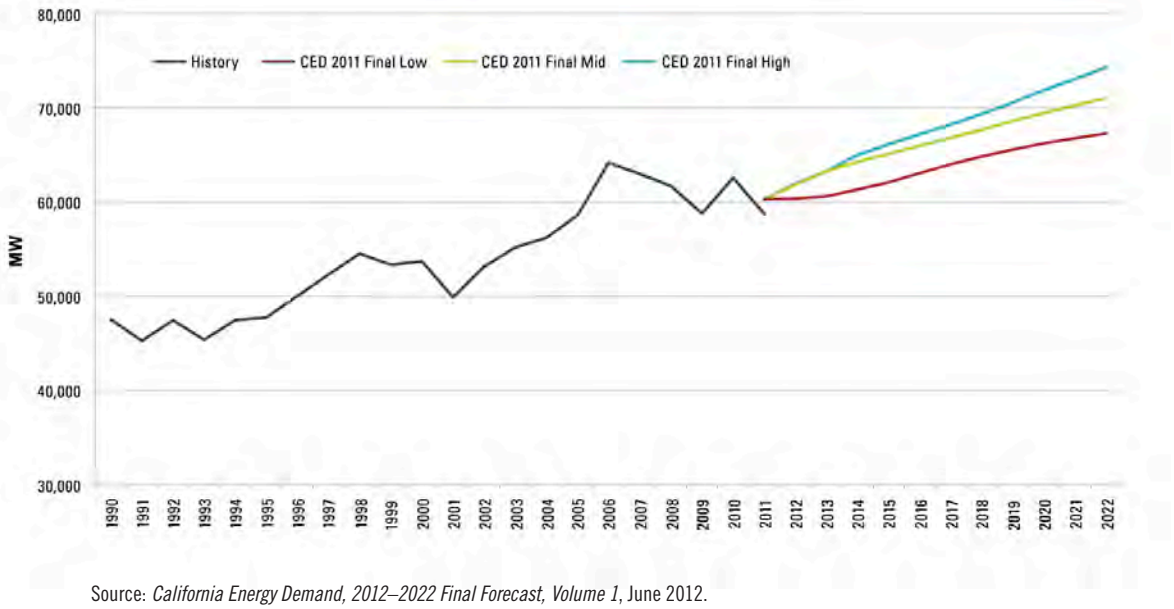
Table 1: California Statewide Historical and Projected Electricity and Natural Gas Demand

Electricity Consumption (Gigawatt hours)			
	High Energy Demand	*Mid Energy Demand*	*Low Energy Demand*
2000	261,381	261,381	261,381
2010	273,103	273,103	273,103
2015	297,509	291,965	283,011
2020	322,760	310,210	301,535
2022	333,838	318,071	308,677
Annual Average Growth Rates			
2000–2010	0.44%	0.44%	0.44%
2010–2015	1.73%	1.34%	0.72%
2010–2020	1.68%	1.28%	1.00%
2010–2022	1.69%	1.28%	1.03%
Electricity Noncoincident Peak (megawatts)			
2000	53,700	53,700	53,700
2011	58,737	58,737	58,737
2011*	60,310	60,310	60,310
2015	65,950	65,036	61,791
2020	71,701	69,418	65,884
2022	74,049	70,946	66,916
Annual Average Growth Rates			
2000–2011	0.82%	0.82%	0.82%
2011–2015	2.33%	1.93%	0.72%
2011–2020	1.97%	1.58%	1.05%
2011–2022	1.91%	1.50%	1.00%
Natural Gas Consumption (million Therms)			
2000	13,913	13,913	13,913
2010	12,774	12,774	12,774
2015	13,265	13,503	12,877
2020	13,648	13,961	13,588
2022	13,929	14,075	13,688
Annual Average Growth Rates			
2000–2010	-0.85%	-0.85%	-0.85%
2010–2015	0.76%	1.12%	0.16%
2010–2020	0.66%	0.89%	0.62%
2010–2022	0.72%	0.81%	0.58%

*Weather normalized: *CED 2011 Final* uses a weather-normalized peak value derived from the actual 2011 peak for calculating growth rates during the forecast period

Source: *California Energy Demand, 2012–2022 Final Forecast, Volume 1*, June 2012. Historical values are shaded

Figure 2: Statewide Annual Noncoincident Peak Demand



Source: *California Energy Demand, 2012–2022 Final Forecast, Volume 1*, June 2012.

and natural gas rates, and effects of energy efficiency programs and self-generation. Results from the final forecast (Table 1 and Figures 1 and 2) are similar to and slightly lower than those in the preliminary forecast, indicating that Californians will consume between 308,677 and 333,838 gigawatt hours (GWh) of electricity per year by 2022, compared to 2010 consumption, which was 273,103 GWh. This reflects an annual average growth rate of between 1.03 and 1.69 percent. For natural gas, the annual growth rate is expected to be between 0.58 and 0.81 percent, with customer demand ranging from 13,688 million (MM) therms to 14,075 MMtherms, compared to 2010 consumption, which was 12,774 MMtherms.

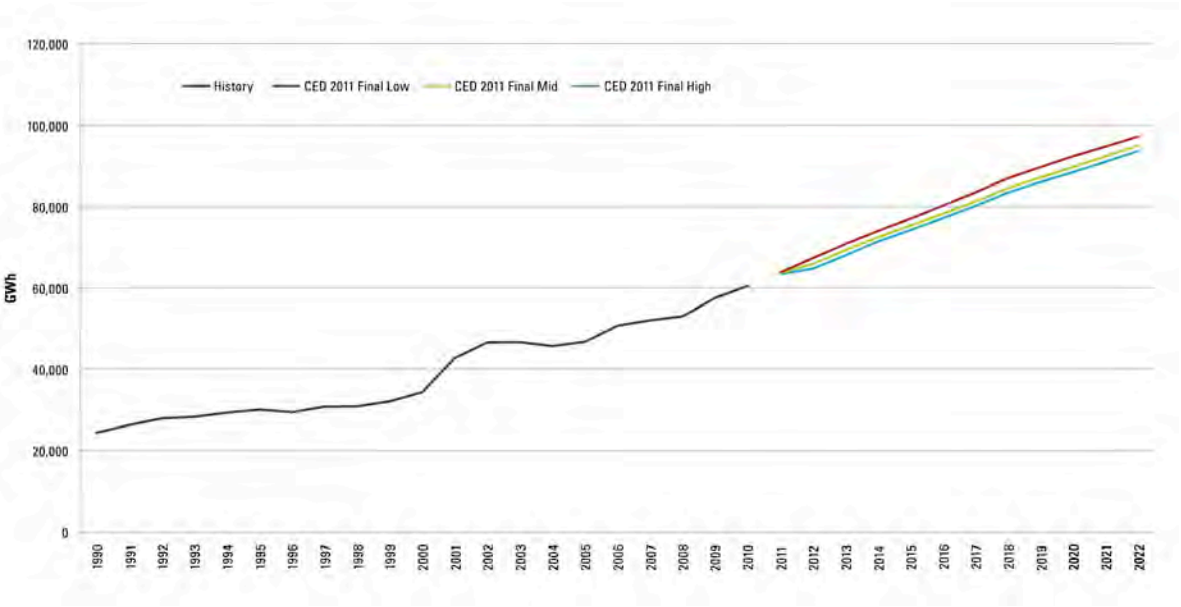
Energy Efficiency in the Forecast

A major topic of discussion in the past several *IEPRs* has been how the Energy Commission's forecast accounts for energy efficiency and conservation savings. Energy planners need accurate projections of these savings to determine the amount of new electricity generating capacity that will be required to meet future demand. Since 1985, the Energy Commission's practice has been to split savings that are reasonably expected to occur into two categories. "Committed" energy efficiency includes utility and public agency programs; codes and standards; initiatives that have been authorized, have firm funding, and a clear program design; and price and other market effects. "Uncommitted" efficiency represents savings from programs or policy initiatives that have not yet been implemented or funded but are reasonably expected to occur.

Figure 3 shows estimates of historical and projected committed consumption savings impacts that are included in the forecast, which include programs, codes and standards, price, and other effects.

The *California Energy Demand 2012–2022 Final Forecast* did not include uncommitted, or incremental, efficiency savings impacts. In July 2012, the Energy Commission provided preliminary estimates

Figure 3: Total Statewide Committed Consumption Efficiency and Conservation Impacts



Source: *California Energy Demand, 2012–2022 Final Forecast, Volume 1*, June 2012.

of incremental savings to the CPUC for use in its procurement processes. These estimates were based on a May 2012 study of efficiency potential conducted by Navigant Consulting, Inc. The CPUC is scheduled to complete its efficiency goals study, which is an extension of the May 2012 study, by summer of 2013. The Energy Commission will then provide an updated assessment in summer 2013 of uncommitted efficiency impacts that reflects the results of that study.

Recommendations

- Changes in the magnitude and frequency of extreme weather events as a result of climate change will affect future energy demand in California. This could in turn require increased investments in new energy infrastructure. To aid electricity system planning, the Energy Commission, beginning with the *2013 IEPR*, will expand and refine its analysis of the potential effects of climate change not only on electricity consumption and peak demand, but on temperature distribution and the relationship between "normal" and "extreme" peak demand.

- The Renewable Action Plan (Chapter 5) emphasizes the importance of location-specific electricity demand data to support better distribution system planning and geographic renewable development zones for distributed generation. As part of the *2013 IEPR*, the Energy Commission will provide additional demand forecast results by climate zone to supplement the usual planning area level forecasts. This is an initial step in the process of evaluating methods to further disaggregate the forecast.

- State mandates and targets for more zero-emission vehicles, combined heat and power facilities, and distributed generation facilities will influence future electricity demand and consumption. The Energy Commission should begin an effort to reflect more comprehensively uncertainty surrounding the demand forecast, particularly regarding the interaction and implementation of California's policies for zero-emission vehicles, combined heat and power, and distributed generation.

CHAPTER 2

Natural Gas Trends and Outlook

California continues to rely on

natural gas, 88 percent of which comes from out of state, to meet many of its energy needs. In 2010, natural gas power plants provided 42 percent of the state's electricity; coincidentally, natural gas used for electricity generation also represented 42 percent of total statewide natural gas demand. Other natural gas users include the industrial sector (29 percent), residential sector (20 percent), commercial sector (8 percent), and natural gas vehicles (1 percent).[3]

During 2011, Energy Commission staff assessed the future outlook for natural gas and released a draft report in September 2011 as part of the *2011 Integrated Energy Policy Report*. The final *2011 Natural Gas Market Assessment: Outlook* was published in May 2012, along with a companion document, *2012 Natural Gas Market Trends,* which outlined the recent trends in natural gas supplies, demand, prices, and infrastructure that were used in the outlook analysis.[4] Each report covered a wide variety of issues that will affect natural gas markets, with the most significant issues summarized below.

3 *2010 California Gas Report*, http://www.pge.com/pipeline/library/regulatory/downloads/cgr10.pdf.

4 *2011 Natural Gas Market Assessment: Outlook*, May 2012, http://www.energy.ca.gov/2011publications/CEC-200-2011-012/CEC-200-2011-012-SF.pdf; and *2012 Natural Gas Market Assessment: Trends,* May 2012, http://www.energy.ca.gov/2012publications/CEC-200-2012-004/CEC-200-2012-004.pdf.

Hydraulic Fracturing

Hydraulic fracturing or "fracking" is the process of pumping high-pressure fluid, mostly water and sand with chemicals added to improve the flow, into the ground to fracture the rock and allow oil and gas to be pumped out. Natural gas production from shale formations in the United States is transforming the natural gas market, with shale gas now comprising roughly 34 percent of total gas production in the United States. The use of fracking to recover natural gas has increased available supplies and lowered prices but has also raised environmental concerns due to the millions of gallons of water and the chemicals used in the process. Because more than half of new wells use this technique to stimulate production, any activity that could limit its use – for example, moratoria on new development, regulatory restrictions, or increased mitigation costs – would have a significant impact on gas production in the United States. This in turn could lead to increased costs and reduced natural gas supplies for California.

Fracking has been used in California for more than 30 years.[5] FracFocus.org, a website created by the oil and gas industry on which companies are encouraged to voluntarily post information about their wells, showed 401 fracked wells in California as of September 2012. While much of the fracking in California is for oil production, the environmental challenges are similar to those for natural gas production and there appears to be interest from the oil and gas industry to increase the use of fracking in California using new technology.[6]

As noted in the *2011 IEPR*, Energy Commission staff continues to monitor activities to evaluate the potential impacts of fracking. At the federal level, the United States Environmental Protection Agency is conducting a study on the effects of fracking on drinking water and groundwater.[7] A first progress report was released in December 2012, with a final draft report expected in 2014.[8] In addition, in May 2012 Department of the Interior Secretary Ken Salazar released proposed rules for fracturing undertaken on federal and Native American lands.[9] In California, the Department of Conservation's Division of Oil, Gas, and Geothermal Resources in March 2012 requested all California energy companies to disclose where they conduct fracking operations and what chemicals they inject into the ground.[10] In addition, in December 2012, the department released a pre-rulemaking discussion draft of regulations governing hydraulic fracturing.[11] The Energy Commission will monitor each of these efforts to determine what effects they may have on the availability and price of shale gas and any consequences on the natural gas market.[12]

5 California Department of Conservation, Division of Oil, Gas & Geothermal Resources, http://www.conservation.ca.gov/dog/general_information/Pages/HydraulicFracturing.aspx.

6 Mercury News, "California releases first-ever fracking regulations," December 18, 2012, http://www.mercurynews.com/science/ci_22219233; "But now the oil industry is looking at a dramatic expansion into Monterey shale, a huge geologic formation that extends through much of the Central Valley into San Benito and Monterey counties."

7 U.S. Environmental Protection Agency, *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*, November 2011, http://www.epa.gov/hfstudy/index.html.

8 U.S. Environmental Protection Agency, *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources: Progress Report,* December 2012, http://www.epa.gov/hfstudy/pdfs/hf-report20121214.pdf.

9 U.S. Department of the Interior press release, "Interior Releases Draft Rule Requiring Public Disclosure of Chemicals Used in Hydraulic Fracturing on Public and Indian Lands," May 14, 2012, http://www.blm.gov/wo/st/en/info/newsroom/2012/may/NR_05_04_2012.html.

10 Department of Conservation, March 28, 2012, ftp://ftp.consrv.ca.gov/pub/oil/Notice_to_Operators/NTO%20Fracking%203.28.12.pdf.

11 http://www.conservation.ca.gov/dog/general_information/Pages/DDraftHFRegs.aspx.

12 Each of these efforts applies to both oil and natural gas fracking activities.

Natural Gas Demand Trends

Despite continued population growth, over the past decade residential and commercial demand for natural gas has remained relatively flat in both the United States and California. The one exception is in the electric generation sector, which in the United States has increased 82 percent from 1997–2010.[13] Demand has increased as a result of major investments in natural gas power plants throughout the nation over the last decade due to federal air quality regulations that require significant retrofits to coal facilities, many of which are reaching the end of their design lives. Natural gas plants also typically have lower capital, operation, and maintenance costs than coal-fired or nuclear power plants, making them an attractive choice for new power plants. The national shift from coal to natural gas may also accelerate due to current low prices for natural gas. With natural gas prices lower than Central Appalachian coal prices since the beginning of 2012, there is increased pressure to switch from coal to natural gas for power generation.

In contrast to the rest of the United States, natural gas demand in California's electric generation sector has risen only slightly. This is due in part to the success of energy efficiency, conservation, and renewable energy policies. Going forward, the state's aggressive renewable electricity goals will affect the role of and demand for natural gas in the electricity system. Natural gas plants will be an important element of integrating high levels of variable renewable resources, like wind and solar, into the electric grid while maintaining grid reliability, although these plants are likely to be operated very little.

California is also seeing growing demand for natural gas as a transportation fuel in response to greenhouse gas emission reduction targets, volatile oil prices, air quality standards, the state Low Carbon Fuels Standard, and the federal Renewable Fuels Standard. New investments are being made through the Energy Commission's Alternative and Renewable Fuels and Vehicle Technology Program for natural gas vehicles and fueling stations, which could potentially increase demand for natural gas in the transportation sector.

Electric and Natural Gas Industry "Harmonization"

As the natural gas and electric industries become more interdependent, it is increasingly important to improve coordination between pipeline delivery of natural gas and electric system operation. For example, natural gas is typically scheduled or "nominated" for delivery far in advance of when electricity dispatch decisions are made. In addition, as natural gas plants are increasingly used to integrate renewable resources, they will need the ability and flexibility to ramp up or down quickly in response to system needs. However, if the natural gas needed to do so was not requested hours in advance, then the generator is actually burning natural gas in the system as line pack[14] or taking another user's supply, which can have ripple effects throughout the system.

Recent studies by the American Public Power Association, the Massachusetts Institute of Technol-

13 U.S. Energy Information Administration, *Natural Gas Monthly,* February 2012, Tables 12, 13, 14, 15, and 16.

14 *Line pack* is the ability of a natural gas pipeline to store small quantities of gas on a short-term basis by increasing the operating pressure of the pipe. Pipelines use line pack to help manage load fluctuations on the system, building it up when demand is low and drawing it down when demand increases.

ogy, and the National Petroleum Council highlight the differences between the natural gas "day" and the electricity day, and the fact that using natural gas to address renewable intermittency further magnifies the need for harmonization.[15] To address the renewable integration issue, entities will need the ability to nominate and receive natural gas in short time increments to better match real-world operating conditions. Currently, natural gas utilities in California allow intraday nominations (two for Pacific Gas and Electric Company and three for Southern California Gas Company) in addition to day-ahead nominations. However, they do not guarantee delivery of natural gas to power generators. As the state moves ahead to fulfill the 33 percent renewable mandate, rules and protocols need to be revisited to better meet the needs of ratepayers and ensure that California's natural gas and electricity industries can work in tandem to meet renewable generation goals.

Pipeline Safety and Reliability

Delivery of natural gas to meet customers' needs, including electricity generators, depends on a safe and reliable network of natural gas pipelines. Two pipeline issues that may affect natural gas prices going forward are (1) planned pipeline safety enhancements in the wake of the September 2010 explosion in San Bruno, California, of a high-pressure natural gas transmission pipeline system owned by Pacific Gas and Electric Company, and (2) additional pipeline capacity that is becoming available for California, in particular the Ruby Pipeline that has been delivering additional gas from the Rockies since 2011.

After the San Bruno pipeline explosion, the CPUC ordered the gas utilities to submit pipeline safety enhancement plans to improve the natural gas transportation system in the state.[16] In December 2012, the CPUC approved Pacific Gas and Electric Company's 2012–2014 Pipeline Safety Implementation Plan, which authorized rate recovery for $299 million in increased revenue and is expected to increase PG&E's rate for residential core service by 1.5 percent.[17]

Recent additions of pipeline capacity across the country have allowed access to new shale gas supplies and created more competition between supply and demand regions, putting downward pressure on prices. Additional pipeline capacity available for California's use has resulted in more pricing competition and could mean lower natural gas rates for California consumers. However, there is also the potential for natural gas pipeline owners/operators to abandon or reduce delivery capacity to California in the future, which could interfere with the ability of natural gas power plants to provide integration services to support renewable generators. As recommended in the Renewable Action Plan (Chapter 5), California needs to monitor natural gas supply and pipeline activities throughout the country that may affect the availability and deliverability of natural gas to California.

15 *Implications of Greater Reliance on Natural Gas for Electricity Generation*, American Public Power Association, July 2010; Moniz, et al., *Future of Natural Gas, Interim Study*, MIT, 2010, p. 65; and *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources,* National Petroleum Council, September 2011, http://www.npc.org/Prudent_Development.html.

16 *2011 Natural Gas Market Assessment: Outlook*, May 2012, page 117, http://www.energy.ca.gov/2011publications/CEC-200-2011-012/CEC-200-2011-012-SF.pdf.

17 CPUC, "CPUC Approves Pipeline Safety Plan for PG&E; Increases Whistleblower Protections," press release, December 20, 2012, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M040/K531/40531580.PDF.

Recommendations

- The Renewable Action Plan (Chapter 5) emphasizes the importance of natural gas pipeline infrastructure to support integration of renewable resources. Because renewable integration could increase the variability of gas demand throughout the day, consideration of the natural gas infrastructure needed to support renewable integration should include the availability and flexibility of natural gas storage as well as the intrastate natural gas transmission and distribution systems. To ensure that natural gas power plants can be called on when needed to support renewables, the Energy Commission and the CPUC should monitor and participate in Federal Energy Regulatory Commission proceedings related to (1) natural gas supply and pipeline development activities that may impact California and (2) natural gas-electricity market harmonization.

- The Energy Commission, the CPUC and the California Independent System Operator should examine the adequacy of existing rules and protocols to deliver natural gas to power plants that back up renewable energy technologies.

CHAPTER 3

Combined Heat and Power Assessment and Barriers

California's electricity mix

includes more than 8,500 MW of combined heat and power (CHP) facilities. CHP, also known as cogeneration, is the production of electricity and heat from a single fuel source such as natural gas, biomass, biogas, coal, waste heat, or oil. CHP facilities improve energy efficiency and reduce greenhouse gas emissions because they can yield more energy from the same amount of fuel by producing both electricity and usable heat or cooling. Because much of the energy that is produced is typically used on-site, CHP is a localized generation technology (although not always renewable) that may also reduce the need for new transmission and distribution infrastructure. Of particular interest given recent extreme weather events, CHP can also improve the reliability of the electric system. During the massive power outage on the East Coast after Hurricane Sandy, a small number of facilities including hospitals, universities, and some residential buildings were able to keep their power, heat, and critical equipment running because they had CHP systems.[18]

The California Air Resources Board's *Climate Change Scoping Plan* identified CHP as an important strategy to reduce greenhouse

18 "How CHP Stepped Up When the Power Went Out During Hurricane Sandy," theenergycollective, December 7, 2012, http://theenergycollective.com/aceee/153346/how-chp-stepped-when-power-went-out-during-hurricane-sandy.

gas emissions in the electricity sector and included a target of 6.7 million metric tons carbon dioxide (CO_2) equivalent reduction from increased CHP use.[19] In 2010, Governor Brown's Clean Energy Jobs Plan reaffirmed the importance of developing more CHP projects due to their higher efficiency and contribution to reducing greenhouse gas emissions and called for 6,500 MW of new capacity by 2030.[20]

In December 2010, the California Public Utilities Commission (CPUC) approved California's Qualifying Facility and Combined Heat and Power Program Settlement, which established a CHP framework for the state's investor-owned utilities.[21] The settlement established a near-term target of 3,000 MW of CHP for entities under the jurisdiction of the CPUC, although this target includes not just new CHP, but capacity from renewal of contracts due to expire in the next three years. The CPUC has also adopted a settlement agreement that includes reforms to the Rule 21 interconnection process to provide a clear, predictable path to interconnection of distributed generation while maintaining the safety and reliability of the grid.[22]

California's two largest publicly owned utilities, the Los Angeles Department of Water and Power (LADWP) and the Sacramento Municipal Utility District (SMUD) will also play a critical role in helping California achieve its CHP policy goals. LADWP has 161 MW of CHP capacity and, in its *2010 Power Integrated Resource Plan*, indicated its intent of "developing CHP target goals to incorporate CHP generation in its future resource mix."[23] In written comments submitted for the February 2012 IEPR workshop on CHP, LADWP stated that it "is pursuing other more cost effective and amenable alternatives over CHP in its service territory…"[24] while also "currently re-assessing the CHP technology and potential for its service territory and planning to include more robust CHP goals in the 2012 Integrated Resource Plan." However, LADWP's *2012 Power Draft Integrated Resource Plan* does not mention CHP.[25]

Currently installed CHP capacity in SMUD's territory is 464 MW, although that could decrease with the closure of the Sacramento Campbell Soup facility which used a 160-MW CHP system. In 2010, SMUD held a request for offers under its feed-in tariff that was made available to solar and CHP resources larger than 5 MW. The program reached its 100-MW limit with solar projects with no CHP projects applying before the limit was reached. SMUD has indicated it is open to receiving "unsolicited offers" for CHP projects and will work with developers although there

19 California Air Resources Board, *Climate Change Scoping Plan: A Framework for Change,* December 2008, http://arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm. Under certain assumptions this level of reduction may be reached by the addition of 4,000 MW of new clean, efficient combined heat and power generation.

20 Governor Jerry Brown, see: http://www.jerrybrown.org/Clean_Energy.

21 California Public Utilities Commission, *Decision Adopting Proposed Settlement,* Decision 10-12-035 issued December 21, 2010, http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/128624.PDF.

22 California Public Utilities Commission, *Decision Adopting Settlement Agreement and Revising Distribution Level Interconnection Rules and Regulations – Electric Tariff Rule 21 and Granting Motions to Adopt the Utilities' Rule 21 Transition Plans,* Decision 12,09-018 issued September 20, 2012, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M028/K168/28168335.pdf.

23 https://www.ladwp.com/ladwp/faces/ladwp/aboutus/a-financesandreports/a-fr-reports?_adf.ctrl-state=f2ot2p0m5_92&_afrLoop=264244427045000; the *2011 ICF Market Assessment* placed LADWP's installed CHP capacity at 294 MW, Resource Plan notes 265 MW, LADWP workshop filing notes a reduction to 161 MW because of a refinery closing.

24 Comments from the Los Angeles Department of Water and Power to the California Energy Commission's Staff Workshop on Combined Heat and Power, March 9, 2012, http://www.energy.ca.gov/2012_energypolicy/documents/2012-02-16_workshop/comments.

25 Los Angeles Department of Water and Power, *2012 Power Draft Integrated Resource Plan*, October 5, 2012.

is no guarantee that developers will be eligible for the price or terms offered in the feed-in tariff.

The Energy Commission has long supported and recommended proactive CHP policies in past *IEPR*s. Following up on recommendations in the *2011 IEPR,* the *2012 IEPR Update* proceeding included evaluation of CHP technical and market potential, barriers to future development, and the implications of the CPUC's Qualifying Facility Settlement Agreement, although it is still too early to see any definitive results from the settlement. After a February 2012 public workshop to take public comments on new estimates of CHP technical and market potential, the Energy Commission released an ICF International consultant report in June 2012 that assesses the current CHP market in California.[26] This was followed by a staff white paper released in September 2012 that outlines barriers to CHP development raised in the workshop and potential strategies to achieve California's CHP goals.[27] Highlights from these documents are provided below.

Technical and Market Potential

The ICF International report identified about 8,500 MW of active CHP throughout the state and more than 14,000 MW of technical potential for additional CHP that could be developed at existing industrial, commercial, institutional, and multifamily residential sites. Much of the potential for new development is concentrated in systems smaller than 20 MW.

The report also analyzed market penetration of new CHP facilities over 20 years (2011–2030) under three scenarios with different policy implementation assumptions. Under all three scenarios, CHP development will fall short of the Air Resources Board's GHG emissions reduction target. However, the medium and high scenarios show that additional CHP market penetration can be achieved with policy measures such as extension of the Self-Generation Incentive Program, higher payments, cap-and-trade allowance costs for CHP fuel consumption, elimination of nonbypassable charges currently applied to CHP,[28] a 10 percent state investment tax credit, and reduced capital costs from technology, installation, and interconnection improvements.

Barriers to Combined Heat and Power Development

The future for CHP in California appears promising, with much of the foundation already in place to achieve CHP goals. The Governor has expressed support for CHP by establishing a statewide target of 6,500 MW. Utilities and the California Independent System Operator are working toward reducing long wait list queues for interconnection. The Rule 21 Settlement has been approved by the CPUC, and utilities are finishing their first solicitation under the Qualifying Facility Settlement Agreement. The CPUC's Self-Generation Incentive Program, after excluding CHP for nearly five years, is once again accepting

26 ICF International, *Combined Heat and Power: Policy Analysis and 2011 – 2030 Market Assessment,* June 2012, http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf.

27 California Energy Commission, *A New Generation of Combined Heat and Power: Policy Planning for 2030*, staff white paper posted for public comment on September 11, 2012, http://www.energy.ca.gov/2012_energypolicy/documents/index.html.

28 Nonbypassable charges are any of several types of charges applied to all customer billings in a given region whether they receive service from a local utility or from a competitive supplier. These charges can include fees for public purpose programs, transition charges, access charges, and nuclear decommissioning funds, among others.

applications. Assembly Bill 1613 contracts for up to 5 MW and 20 MW projects were approved by the CPUC in December 2011,[29] and contracts for facilities up to 500 kilowatts were approved in mid-2012.[30]

However, barriers remain to achieving the CHP goal by 2020. Primary challenges identified in the February 2012 IEPR workshop on CHP include:

- Cap-and-Trade: Current cap-and-trade rules provide a disincentive for facilities to invest in CHP since the regulations do not provide allowances for the shift in emissions that occurs from reduced grid use to increased onsite generation. Cap-and-trade rules will also affect existing facilities that do not have the ability to pass compliance costs onto the end user of the electricity.

- Interconnection: Current interconnection rules do not accommodate distributed, small-scale generators that wish to export some or all of their electricity. The CPUC has a proceeding underway to examine reforms needed to these rules, but in the interim the process represents substantial cost and regulatory complexity for small CHP developers.

- Nonbypassable and Departing Load Charges: Customers who serve their own electric loads or who purchase electricity from customer generators like CHP facilities must still pay fees to the investor-owned utilities for public purpose programs, investments made on customers' behalf prior to the restructuring of the electricity industry in 1996, Department of Water Resources bonds issued during restructuring, and nuclear decommissioning funds. These charges can increase the cost of CHP investment.

- Standby and Demand Charges: Utilities charge fees to customer generators even if no electricity is provided to the utility. These fees are intended to cover a utility's investment in infrastructure and generation needed to provide power if a customer has to shut down unexpectedly or needs additional electricity to meet its performance requirements.

- Metering Requirements: Meters are necessary but can also impose a financial burden on developers. Meter costs are especially burdensome for smaller generators because they represent a larger percentage of total project cost.

- Net Energy Metering (NEM): CHP facilities are not eligible for net energy metering unless they use biogas or are a fuel cell. NEM facilities must be sized to meet their annual load and can "feed back" electricity to the grid during times of high generation and low demand. These facilities qualify for a fast-track interconnection process, while a CHP facility with the same generation and feed-back profile must follow a more traditional timeline that is more expensive.

Recommendations

- The Energy Commission should revisit and update its CHP technical assessments in late 2013/early 2014 for the CPUC's use in the 2014 Long Term Procurement Plan proceeding. The assessment should include evaluation of the potential effects of cap-and-trade on CHP before its full implementation in 2015 as well as progress toward addressing other barriers.

29 Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007) required the Energy Commission to establish technical criteria for CHP eligibility for CPUC and publicly owned utility programs, and the CPUC to establish a standard tariff for purchase of excess electricity from eligible CHP systems.

30 CPUC approval letter for PG&E: http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4071-E.pdf; SCE: http://www.sce.com/NR/sc3/tm2/pdf/2676-E.pdf and http://www.sce.com/NR/sc3/tm2/pdf/2676-E-A.pdf; and SDG&E: http://regarchive.sdge.com/tm2/pdf/2317-E-A.pdf.

- Agencies with jurisdiction over interconnection processes (Rule 21, the Wholesale Distribution Access Tariff, and Generator Interconnection Procedures) should evaluate their requirements with the goal of easing the process of interconnection at facilities that expand their generation capabilities.

- The Energy Commission and CPUC should continue to track, analyze, and report to the Governor and Legislature on the progress of the Qualifying Facility Settlement Agreement, Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007), and programs of both the investor- and publicly owned utilities to encourage new CHP.

CHAPTER 4

Electricity Infrastructure Assessment

California's energy decision

makers must balance the need for a reliable electricity system with the need to comply with environmental regulations and maintain reasonable and equitable energy costs for Californians. As the state's energy policy and planning agency, the Energy Commission is in a unique position to explore challenges to and opportunities for transformation of California's energy infrastructure, particularly the electricity system. One of the overarching themes of the *2011 IEPR* was the importance of sufficient, reliable, affordable, and safe energy infrastructure to meet California's growing energy demand. The *2011 IEPR* focused on electricity infrastructure needs in Southern California, given the unique challenges in that part of the state, and the *2012 IEPR Update* continues the exploration of those challenges.

Factors Affecting Electricity Infrastructure Needs in Southern California

Southern California is unique in the number and intensity of forces that influence the need for electricity infrastructure development. These are summarized in Table 2 and discussed below.

Once-Through Cooling

The *2011 IEPR* discussed the impact of the State Water Resources Control Board's (SWRCB) policy on once-through cooling (OTC), in which water is pumped from the ocean, estuaries, rivers, or lakes to cool steam turbines and then returned to its source. This policy induces the retirement of aging steam boiler generators along California's coastline and in the San Francisco Bay/Delta. Most of the Southern California OTC facilities have 2020 dates for compliance with the policy, with the exception of the El Segundo (2015) and Encina (2017) plants. Los Angeles Department of Water and Power plants have a staggered schedule with some units replaced in 2013–2015 but others not repowered until 2029.

Compliance dates for California's two nuclear power plants that use OTC – the San Onofre Nuclear Power Plant (SONGS) operated by Southern California Edison (SCE) and the Diablo Canyon Power Plant operated by Pacific Gas and Electric Company (PG&E) – are 2022 and 2024, respectively. However, the OTC policy contains provisions for the nuclear power plants that require SCE and PG&E to undertake special studies to investigate alternatives for the facilities to meet the OTC policy requirements. An independent third party with engineering experience with nuclear plants is conducting these studies, which are being overseen by a review committee composed of agencies from the Statewide Advisory Committee on Cooling Water Intake Structures, including the Energy Commission, the environmental community, and staff from SWRCB and the regional water boards. Studies are scheduled for completion by October 1, 2013, and will be used by SWRCB to evaluate whether to modify the OTC policy based on the nuclear plants' ability to achieve compliance, including the costs and environmental impacts.

Emission Reduction Credits

Extremely tight emission reduction credit markets in Southern California are hindering construction of replacement facilities for OTC plants that retire. Access to credits in the South Coast Air Quality Management District's (SCAQMD) internal bank is fundamental because a portion of retired OTC capacity must be replaced with quick-response modern gas-fired power plants that will require credits to be built.[31] However, as agencies evaluate the need for emission credits to ensure reliable electricity supplies, they must also consider the serious human health impacts from air pollution.[32]

31 Northern California is already well on its way to identifying likely replacement facilities for its OTC units because construction there is not impeded by emission reduction credit markets. California Clean Energy Future, *Progress Report for OTC*, http://www.cacleanenergyfuture.org/otc-phase-out.html.

32 Transcript of Energy Commission Lead Commissioner Workshop on Electricity Infrastructure Issues in California, June 22, 2012, comments by Angela Johnson Meszaros (Law Offices of Angela Johnson Meszaros), pp. 265–266: "We can't have thousands of people dying because they breathe….The public health epidemic that's caused by air pollution is too severe for us to not deal with these issues correctly and directly."

Table 2: Forces Influencing Southern California Infrastructure Development

Force	Effect
State Water Resources Control Board policy on once-through cooling in power plants	New generation sources needed to replace plants that retire as a result of policy.
Ability of South Coast Air Quality Management District to implement its power plant permitting rules	Scarcity of commercial offsets makes generators dependent on South Coast Air Quality Management District's offset exemption and internal bank credits.
San Onofre Nuclear Generating Station outage	New generation sources needed to assure local reliability and replace lost energy production; transmission upgrades and synchronous condensers needed to replace lost energy production and maintain system voltage levels.
South Coast Air Quality Management District policy for electrification of combustion sources in the Los Angeles Basin	New generation sources needed to satisfy increased electrical load.
Climate change	Increased electrical loads, reduced generation and transmission efficiency, increased need for new generation sources.
Renewables Portfolio Standard	Additional and flexible generation and transmission upgrades needed to support intermittent resources like wind and solar.
State demand-side policies such as energy efficiency and demand response	Reduced electricity usage and reduced need for new power plants but increased uncertainty regarding timing/ amounts.
Numerous single-purpose agencies	Need agreement from multiple agencies for necessary infrastructure to be built.

Source: California Energy Commission

San Onofre Nuclear Generating Station Outage

SONGS has been idle since January 2012 when a tube break in one of the generators released traces of radiation. Due to a design defect in the steam generators, Unit 3 will be idled for several years, and Southern California Edison must demonstrate to the Nuclear Regulatory Commission that Unit 2 will be safe to operate within its mitigation measures. In addition to the loss of 2,200 MW of generating capacity, the outage has revealed how much the San Diego area depends on the grid stabilization qualities of SONGS to enable imports from other areas.

Electrification of the Los Angeles Basin

In 2011, SCAQMD adopted an energy policy likely to result in expanded electrification of combustion sources as a way to meet stronger air quality standards. In late 2012, the agency adopted its first air quality management plan under that policy. The plan includes an energy chapter highlighting the needs for fuel switching toward electricity, increased renewable generation and greater use of energy efficiency, and planning coordination among SCAQMD and various state agencies. The Energy Commission's June 2012 adopted demand forecast includes the electricity demand consequences of some near-term control measures, but implementation of further measures will increase electricity demand more than was projected in that forecast. Some portion of this increased load will require additional power plant development within the Los Angeles Basin itself.

Climate Change

As a result of climate change, California is becoming warmer and drier. Energy planning needs to incorporate measures to adapt to climate change effects on the energy system. These may include:

- Higher peak demand.
- Lower power plant and transmission line efficiency during peak periods.
- Changes in the amount and timing of hydroelectric power generation from altered rainfall and snowfall patterns.
- Increased sea level rise during winter storms, which could affect coastal plants.
- More frequent and severe wildfires, which may affect transmission lines.[33]

Renewables Portfolio Standard

While California is committed to meeting the 33 percent by 2020 Renewables Portfolio Standard, the ultimate location and mix of technologies for actual projects are uncertain. These factors will affect what and where complementary infrastructure will need to be built, including transmission to bring generation to load centers and dispatchable resources to firm up intermittent renewables.

33 California Natural Resources Agency and California Energy Commission, *Our Changing Climate 2012 – Vulnerability & Adaptation to the Increasing Risks from Climate Change in California,* July 2012, http://www.energy.ca.gov/2012publications/CEC-500-2012-007/CEC-500-2012-007.pdf.

Demand-Side Policies

Demand-side policies include energy efficiency programs, demand response measures (including automated demand response),[34] behind-the-meter distributed generation, and combined heat and power programs. Pursuing the goals outlined in these policies will have a major impact on the amount and type of infrastructure needed for the bulk power system. The technologies and behavioral changes implicit in these policies may have much shorter lead times than building the additional transmission lines and central station power plants that the policies would displace. When these policies are at the stage of goals or targets, as opposed to firmly funded programs, or when they depend on voluntary participation, there can be a wide range of alternative effects that are reasonably likely to occur. This requires some guesswork about what proportion of demand-side policy goals should be considered certain when making decisions about necessary bulk system infrastructure additions with long lead times.

Competing Institutional Influences

Southern California has more decision makers overseeing various pieces of the electricity infrastructure than any other region in California. Southern California Edison (SCE) is the largest single utility in the region and is regulated by the California Public Utilities Commission (CPUC). There are also many smaller municipal utilities located within the Southern California portion of the California Independent System Operator (California ISO) balancing authority area that are governed by their own local governing boards with their own methods for satisfying statewide laws or energy policies. The Los Angeles balancing authority area, which is operated independently of the California ISO, includes the nation's largest municipal utility, the Los Angeles Department of Water and Power (LADWP), and two other small public utilities. SCAQMD is the air pollution control agency for all of Orange County and the urban portions of Los Angeles, Riverside, and San Bernardino counties and faces more challenges any other local air district in California in achieving compliance with the federal Clean Air Act. The agency has substantial authority to implement control measures that shift fuel-based combustion processes into alternative technologies that increase demand for electricity. SCAQMD and the California Air Resources Board (ARB) have begun an unprecedented visioning effort to coordinate their development of the next *State Implementation Plan* for stationary and mobile emission sources, and to address both air emission standards and GHG goals.[35] Finally, many of the generating plants required to comply with the SWRCB's OTC policy are located in Southern California.

Energy Agency Coordination

In June 2012, the Energy Commission held a forum in Los Angeles on Southern California electricity infrastructure challenges. This forum included not only commissioners from the Energy Commission, but the California Public Utilities Commission and management from the ARB, the California ISO, and SCAQMD. The forum began the important conversation among these decision makers about potential

34 Demand response programs offer incentives for users to voluntarily and temporarily reduce their electricity usage when demand exceeds supply.

35 Air Resources Board and South Coast Air Quality Management District, *Vision for Clean Air: A Framework for Air Quality and Climate Planning,* http://www.arb.ca.gov/planning/vision/vision.htm.

solutions and included presentations by agency staff, energy stakeholders, and the public on the various decision-making processes underway that will affect energy infrastructure decisions. Among the solutions discussed at this forum was developing a contingency plan not only for longer-term uncertainties about the availability of California's nuclear plants, but for the potential that one or both SONGS units will not be available in the summers of 2013 and 2014. The Energy Commission, CPUC, California ISO, and ARB have developed and implemented a plan for the summer of 2012 and are committed to developing a longer-term contingency plan. The California ISO has also committed to assessing by 2013 the reliability implications of either sustained outages or an inability to extend the operating licenses of all California nuclear power plants.

California has a variety of environmental regulations and policies that affect the electricity system, including the SWRCB's once-through cooling policy, increasingly stringent air emission regulations (particularly in Southern California), electrification of the transportation system to reduce air quality impacts, and the ARB's regulations to reduce statewide greenhouse gas emissions as part of Assembly Bill 32, the Global Warming Solutions Act (Núñez, Chapter 488, Statutes of 2006). Energy efficiency, demand response, renewables, and zero-energy vehicles will contribute to California's air quality goals, but market forces can also be an important complement to regulatory requirements. Within this context, the CPUC has started investigating potential reforms to its retail rates. There is also a coordinated effort among the CPUC, Energy Commission, and ARB to address the current wholesale market structure that both provides limited pricing signals to encourage multiyear investments in the existing generation fleet and challenges the financial viability of existing generation without long-term power purchase agreements.

Important Analytic Studies

Several important multiyear studies have been or will soon be completed that affect the estimates of need for various types of electricity infrastructure and/or the ability of existing regulatory mechanisms to permit and construct such facilities. The studies described below were meant to assist resource procurement decisions but do not reflect the implications of the outage at SONGS.

Local Capacity Requirements in Southern California

Local capacity requirements define the minimum amount of generating capacity that must be available within the boundaries of areas with inadequate transmission to serve loads under extreme peak conditions. In late 2011, the California ISO released its technical assessment results on the implications for OTC facilities to satisfy local capacity requirements in 2021. The assessment used four renewable portfolios since the location of renewable facilities – whether central renewables such as wind or distributed facilities such as photovoltaics – is important in determining how much existing OTC capacity must be replaced in local areas by fast-response, gas-fired generation resources (or their functional equivalent). The range of replacement requirements depended on two factors: the degree of urbanized local capacity development, and where the new generation interconnected to the grid.

The California ISO examined the Los Angeles Basin, San Diego, and Ventura/Big Creek areas that were previously established as distinct load pockets and whose load must be satisfied to ensure reliability. As shown in Table 3, the results of the California ISO's analysis indicate that in all three load pockets, the 2021 local capacity requirements are substantially

Table 3: California ISO Analysis of Range of OTC Capacity Replaced to Satisfy Local Capacity Area Requirements

Local Area	Existing OTC Capacity (MW)	2021 Range for CPUC-Derived RPS Scenario (MW)			
		ISO Base Case	Trajectory	Environmentally Constrained	Time Constrained
Los Angeles Basin	4926	2424 - 3834	2370 - 3741	1870 - 2884	2460 - 3896
Big Creek/Ventura	1930	430	430	430	430
San Diego	960	211 - 630	311 - 730	0 - 300	121 - 540

Sources: For San Diego, California ISO, Presentation on San Diego Local Capacity Needs, CPUC Workshop: Application of SDG&E for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center, and Quail Brush Power, April 17, 2012, slide 35. For or other areas, California ISO, 2011/12 Transmission Plan, Table 3.3-1, p. 216.

lower than the almost 8,000 MW of existing OTC capacity. It is critical to note, however, that these analyses presume that both SONGS units are operational.[36]

LADWP has also conducted OTC repowering analyses for its facilities that show that the transmission system configuration essentially requires that all of the roughly 3,900 MW of existing OTC capacity must be maintained as either existing steam boilers or repowered units at the same locations. LADWP's current OTC compliance schedule calls for its OTC capacity to be repowered by 2029, with replacement capacity being fully air-cooled and using no ocean water.

36 The California ISO's analyses were released in early December 2011, well before the SONGS outages were experienced or the California ISO had conducted mitigation studies for summer 2012. The California ISO released its studies for summer 2013 on August 20, 2012, and the results were reviewed in a stakeholder meeting on August 27, 2012. See *2013 Local Capacity Technical Analysis, Addendum to Final report and Study Results, Absence of San Onofre Nuclear Generation Station (SONGS).* The California ISO board approved moving forward with conversion of Huntington Beach Units 3 and 4 into synchronous condensers at the September 12–13 Board meeting. Long-term studies of OTC replacement without SONGS are being conducted as part of the ISO's 2012/13 Transmission Planning Process, with initial results expected in December 2012.

Capacity Requirements and Criteria Pollutants

Assembly Bill 1318 (V. Manuel Pérez, Chapter 285, Statutes of 2009) directs the ARB to work with the Energy Commission, the CPUC, the California ISO, and the SWRCB to (1) determine the amount of capacity needed to assure reliability in Southern California and (2) assess whether it would be possible to permit this amount of capacity while satisfying SCAQMD's criteria pollutant permitting requirements for power plants located in the South Coast Air Basin (SCAB).

The Energy Commission and the ARB conducted a joint workshop in February 2011 that discussed the agencies' study plans, and the ARB expects to release a draft report in the spring of 2013. The AB 1318 (Pérez, Chapter 285, Statutes of 2009) analysis builds off the OTC assessments prepared by the California ISO and LADWP but adds to those assessments by examining scenarios with higher energy efficiency, combined heat and power development, and increased distributed generation penetration. The California ISO analysis used a scenario with the greatest local distributed generation penetration (thus the smallest need for conventional power plants)

and found that the amount of OTC replacement in the Los Angeles Basin decreased from a range of 1,870 MW to 2,884 MW to a range of 1,042 MW to 1,677 MW.[37] LADWP assessed a milder reduction in load from further energy efficiency efforts and found no reduction in the need for repowering its OTC facilities at their current capacity.

The California ISO and other entities are studying the development of additional highly flexible capacity to ensure energy deliveries and reliability when intermittent renewable resources are not producing at expected output. A September 2011 settlement agreement among the parties to the CPUC's 2010 Long-Term Procurement Plan (LTPP) rulemaking established that the California ISO's analyses as of that date were incomplete justification for procurement authorizations. However, the California ISO is continuing to assess the need for additional capacity in excess of local capacity requirements within the SCAB for renewable integration purposes as well as the number of hours per year that those capacity additions would be expected to operate.[38] To the extent that additional studies show that some proportion of resources needed for renewable integration should be located south of Path 26 – SCE's transmission interconnection to Northern California and the Pacific Northwest – then the Los Angeles region may need to find air credits for additional resources. The California ISO is finalizing plans to study this issue as part of the CPUC's 2012 LTPP rulemaking and study results are now expected in summer 2013.

In their compliance plans filed at the SWRCB in April 2011, generators identified repowering as the preferred method to satisfy OTC requirements to reduce ocean water use. The plans rely on SCAQMD's Rule 1304(a)(2), which allows a project developer to be exempt from providing offsets for new combined cycle or advanced combustion turbine power plants that replace old steam boilers. While the generator may be exempt under air district rules, to satisfy federal New Source Review requirements[39] SCAQMD itself must "retire" credits from its internal bank of retired emissions using provisions of its Rule 1315.

At the June 22, 2012, forum in Los Angeles, SCAQMD reported that commercial emission reduction credits for PM10,[40] the pollutant with the tightest market, continue to cost in excess of $100,000 per pound per day and are too scarce to support the level of power plant development identified in either the California ISO or LADWP studies. The SCAQMD representative at the forum also acknowledged the challenge of permitting enough generating capacity to assure reliability given the constraints of satisfying mandated air quality standards.[41] Another challenge

37 The California ISO analysis was completed in January 2012, just as the SONGS facilities were shutdown. As it became clear that SONGS units would not return to service in the near future, the ARB decided to revise its analysis using more current assumptions about SONGS' operation. The California ISO is still studying local capacity requirements without SONGS and the ARB expects to obtain this analysis and release a draft AB 1318 report in spring 2013.

38 California ISO, Renewable Integration Study Advisory Team Conference Call, May 9, 2012, slide 16.

39 On July 24, 2012, U.S. EPA and SCAQMD were sued in Federal District Court (Case 12-72358) by Communities for a Better Environment and California Communities Against Toxics over SCAQMD's Rule 1315. How this lawsuit may affect power plants already under construction, in the licensing pipeline, or in the developmental stage is unknown.

40 Particulate matter larger than 10 microns.

41 Transcript of Energy Commission Lead Commissioner Workshop on Electricity Infrastructure Issues in California, June 22, 2012, comments by Dr. Barry Wallerstein (South Coast Air Quality Management District), pp. 191: "And the chart that I showed about the offsets shows we don't have that solved. There's a problem there that needs to be addressed. It isn't just a power plant issue, it is potentially a much bigger issue. But we certainly need, with the long lead time necessary for power plants, to be able to ensure that there are adequate offsets for the power plants that need to be built."

identified by the environmental justice representative at the forum was the need to provide a clear vision of how infrastructure development in local communities fits into the broader statewide plan.[42]

Nuclear Power Replacement

The *2011 IEPR* reiterated a recommendation made in the *2007 IEPR* for the California ISO to study the reliability implications of unexpected nuclear power plant shutdowns. This proved to be somewhat prescient, since in early 2012 SONGS experienced steam generator problems, and both of its units were shut down. The units cannot be restarted until the Nuclear Regulatory Commission (NRC) approves a diagnosis of the problem and its solution.[43] The CPUC is preparing to conduct a proceeding under Public Utilities Code Section 455.5 to examine the extent to which the SONGS outage implies that the remaining capital investment ought to be removed from rate base, thus reducing shareholder earnings,[44] and has created an interagency task force to assist in the investigation.

To prepare for a summer 2012 peak season without SONGS, an interagency group studied and developed plans for various contingencies. There are no reliability issues for the California ISO system as a whole because there is surplus capacity above conventional planning standards. However, there are problems specific to Southern California, especially Orange and San Diego counties. Measures identified to mitigate the situation in the event of prolonged hot weather or unexpected power plant or transmission line outages included returning Huntington Beach Units 3 and 4 to service,[45] accelerating the completion of the interconnection of the Del Amo – Ellis transmission line to the Barre substation, completion of the Sunrise Powerlink, instituting a flex alert in which Californians are asked to immediately conserve electricity, and implementing new demand response programs. As 2012 unfolded and SONGS was unable to return to service, these measures were implemented.

At the June 22, 2012, IEPR forum, the California ISO presented its plan for summer 2013 – 2014 reliability studies, with an assessment of the likely problems and proposed solutions expected by the end of August. Several options implemented for summer 2012 cannot be continued in 2013 and 2014, in particular using Huntington Beach Units 3 and 4 to generate power. These units were no longer able to generate power as of October 31, 2012, under the terms of the air permit allowing the new 500 MW Walnut Creek facility in the City of Industry to begin operating in June 2013.[46] In November 2012, the Energy Commission approved the conversion of Units 3 and 4 from steam generators to synchronous

42 Ibid, comments by Angela Johnson Meszaros (Law Offices of Angela Johnson Meszaros), p. 262: "What we need to be able to have is a vision and a plan so when you come to a community that you're asking to host a facility, you can explain why, why it's there, how it fits into a bigger picture, what it means for the broader horizon, what it means for people's communities more broadly."

43 At the time this report was released, there was no firm return-to-service date for SONGS Unit 2 or 3.

44 Public Utilities Code Section 455.5 authorizes the CPUC to eliminate the value of any facility that is nonoperational for more than nine months from consideration in establishing rates for an electrical corporation and reduce the rates for that corporation accordingly.

45 Huntington Beach 3–4 were retired in December 2011 as an implementation of SCAQMD's Rule 1304(a)(2) exemption from offsets for the Walnut Creek power plant in northwestern LA County. In effect, HB 3–4 capacity was shutdown to allow Walnut Creek capacity to be permitted. Given their location in the grid, HB 3–4 were uniquely able to both replace some SONGS capacity for the LA Basin and to enable imports into the San Diego region. California ISO studies show that next to SONGS itself, the Huntington Beach site is the next best location for grid-stabilizing generation to allow maximum imports into the San Diego area.

46 SCAQMD's Rule 1304(a)(2) exempts a new facility from provision of offsets when equal or greater capacity of old power plants with steam boilers is retired provided that the new capacity uses advanced gas turbine technology.

condensers to provide voltage support to the grid and satisfy a portion of the reactive power capabilities lost during the outage of the SONGS units.[47]

In addition to the Walnut Creek facility, the El Segundo and Sentinel projects are expected to begin operation during 2013.[48] Additional steps to balance reliability needs include reconfiguring transmission circuits at the Barre-Ellis substation and installing static reactive support (shunt capacitors[49]) at the Johanna and Santiago substations.[50] These additions, coupled with the plan to convert Huntington Beach Units 3 and 4 into a synchronous condenser, help reduce contingency and voltage concerns in the San Diego and Los Angeles Basin local capacity areas. Further efforts to build demand response program capability and reduce load through efficiency and combined heat and power resources, especially in state buildings and on military installations, are key ingredients for the SCE and San Diego summer 2013–2014 program.[51]

For San Diego, a major uncertainty is the reliability implications of the necessary high reliance on the import capabilities of the new Sunrise Powerlink transmission line in Imperial and San Diego counties without the stabilizing influences of SONGS. San Diego's recently permitted Carlsbad and Pio Pico plants have not yet started construction so at best they could not be operational until 2014 unless aggressive construction is pursued. The California ISO has identified grid reliability concerns under summer load conditions in the San Diego, southern Orange County, and Los Angeles Basin areas in the absence of SONGs, including reduction of San Diego's import capability by about 350 MW.[52]

The California ISO's 2013 Local Capacity Requirement Addendum analyses of the San Diego area shed new light on the interactions between San Diego and the Los Angeles Basin. Although the new Sunrise Powerlink Transmission line allows greater imports into the San Diego area, the relative lack of generating capacity in the San Diego area creates reliability concerns (voltage instability) with various combinations of simultaneous transmission and generator outages. The actions outlined above to install reactive capacity in southern Orange County reduce some of the voltage instability concerns in San Diego and allow moderation of the initial anticipated increases in local capacity requirements to some extent. Reducing capacity requirements in San Diego, however, creates new issues in the Los Angeles Basin. The California ISO proposes to rely on increases in demand response

47 Converting a steam boiler turbine generator into synchronous condenser requires cutting the turbine shaft, installing an electric motor to spin the generator, and advanced electronic controls to enable the unit to produce or absorb reactive power as needed in the local area. No fuel is used, and thus the requirements of SCAQMD for the units to surrender their emission permits could be satisfied.

48 The Sentinel Project is located in unincorporated Riverside County.

49 Shunt capacitors installed in transmission and distribution networks help increase transmission capability, reduce losses, and improve power factors.

50 Barre, Ellis, Johanna, and Santiago substations are transmission-level substations in Orange County connecting 220 kilovolt lines roughly in a line from Northwest to Southeast.

51 Millar, Neil, *Briefing on Summer 2013 Outlook – SONGS Mitigation Planning,* [California ISO] Board of Governors Meeting, General Session, September 13–14, 2012.; *2013 Local Capacity Technical Analysis, Addendum to the Final Report and Study Results, Absence of San Onofre Nuclear Generating Station (SONGS),* August 20, 2012.

52 "Reduction of San Diego's import capability by about 350 MW due to an overlapping outage of Sunrise Powerlink 500 kV line, followed by the loss of the Imperial Valley – Miguel 500kV line segment of the Southwest Powerlink. This reduction in import capability into San Diego is due to the lack of dynamic voltage support that the San Onofre units would otherwise be providing to support the level of import into San Diego under this contingency condition. Huntington Beach Units 3 and 4 provide the necessary voltage support beyond that already being provided by Huntington Beach Units 1 and 2 to enable import levels that are necessary to serve loads in the San Diego area." California ISO, *August 2012 Significant Event CPM Designation Report*, page 2, http://www.caiso.com/Documents/August2012SignificantEventCapacityProcurementDesignationReport.pdf.

program capacity in the early portions of summer 2013 and on commercial operation of the El Segundo repower and the Sentinel power plant later in the summer to resolve these newly emerged Los Angeles Basin issues.[53]

The California ISO is now studying shutdowns at SONGS and the Diablo Canyon Power Plant consistent with one of the two recommendations in the *2011 IEPR*. This study will examine an interim year to determine what will be needed to assure reliability if there are unexpected outages at either or both nuclear facilities, and will evaluate what generation and transmission infrastructure would be needed to permanently replace the nuclear facilities from a reliability perspective. This study is expected to be completed in early 2013. The California ISO will provide an in-depth report to the Energy Commission as part of the *2013 IEPR* proceeding and to the CPUC as part of the 2012 Long Term Procurement Plan rulemaking and the 455.5 investigation.

Another analysis related to potential shutdown of the nuclear facilities is being conducted by the Rocky Mountain Institute (RMI), which reported the preliminary results at the June 22, 2012, forum. RMI's privately funded report to achieve 50 percent renewables with no nuclear facilities in Southern California by 2030 is one of several that have recently emerged from federal energy labs, consulting firms, or advocacy groups examining high renewable futures.[54] RMI's analyses are not capable of addressing detailed operational requirements but show that nuclear shutdown scenarios have only a modest incremental cost in the long term when planning and procurement efforts can smoothly accommodate higher levels of renewable penetration without nuclear power production.

The contrast between the RMI study results predicting minor incremental costs for a nonnuclear, high-renewable future and the "near emergency" nature of the summer 2012 energy agencies' effort illustrates the difference between careful planning to replace infrastructure versus eleventh-hour struggles to deal with unplanned contingencies. The *2011 IEPR* recommendation that the California ISO conduct a study on nuclear replacement was intended to acquire the information needed to allow prudent planning for nuclear replacement. Instead, the unforeseen contingency of both SONGS units being out of service for a summer forced all agencies into the near-term operational time horizon, underscoring the need for significant improvements in collective energy planning efforts.

Planning and Procurement in the Face of Uncertainty

In addition to the unique or critical uncertainties affecting Southern California, there are others that affect all of California. Many of these relate to the preferred resources in the state's "loading order," which calls for reducing energy demand through energy efficiency and demand response programs and meeting remaining demand first with renewable and combined heat and power facilities followed by clean fossil generation. Assumptions about energy demand in the future, the amount and type of future demand reduction from energy efficiency and demand response programs, and the ultimate mix of renewable technologies that will be used to meet California's RPS targets are some of the many variables that feed into electricity infrastructure assessment and planning.

53 California ISO, *Addendum to the Final Report and Study Results*, pp. 4–5.

54 National Renewable Energy Laboratory, *Renewable Electricity Futures Study,* 2012, http://www.nrel.gov/analysis/re_futures/.

Table 4: Key Electricity Planning Uncertainties

Variable	Uncertainty Influencing Planning Assumptions
Demand	
Base demand forecast	+/- 5 percent to reflect range of economic and demographic growth Increased intensity of electricity use from process electrification Increased electricity use and different load shapes from transportation electrification and climate change
Incremental energy efficiency	Impacts of programs not included in the base forecast but compatible with adopted energy efficiency goals
Customer-side generation (rooftop PV, CHP)	"Guesstimates" of energy and peak demand reduction from programs to encourage customer adoption
Price response from market-based tariffs	Assumptions whether/when CPUC can create such tariffs given SB 695 (Kehoe, Chapter 337, Statutes of 2009) and estimates of impacts
Supply	
Demand response programs	Range from existing program capabilities up to 10 percent of base peak demand. Estimates of automated demand response are 0.9 GW on a hot summer day and 0.18 GW on a cold winter night; with increased use in commercial and industrial facilities that could double to 2.07 GW and 0.421 GW, respectively.*
OTC power plant retirement	Distribution of retirement dates centered on official OTC compliance date for each steam plant
Other power plant retirement	Range of assumptions for retirement of other aging power plants
Conventional resource additions in the pipeline	Alternative scenarios using different assumptions about development milestones like signed/approved contracts, permits, and others
Utility-scale renewables needed to satisfy 2020 RPS target	Alternative scenarios of the mix of technology and locations emerging over time
Distributed generation	Increased uncertainty of load/supply at the bulk system level as less information is available to the system operator implies that the system operator will need to operate more conservatively or that improved communications will be needed.
Supply-side CHP	Alternative consequences for the QF settlement at the CPUC
Performance change for existing resources	Climate change effects including reduced efficiency of air-cooled facilities due to higher temperatures, changes in timing and amount of hydroelectric output, and increased danger of wildfires near critical transmission infrastructure; catastrophic outages like SONGS
Imports/Exports	Potential for fewer imports as California becomes more self-sufficient; availability of lower-cost renewables in other parts of the Western interconnection
Other	Effects of cap-and-trade program

* Watson, David S. et al, *Fast Automated Demand Response to Enable the Integration of Renewable Resources*, LBNL-5555-E, June 2012.

Source: California Energy Commission

Key Uncertainties

Table 4 lists key variables and the range of planning assumptions that might be considered in infrastructure assessments. In any planning assessment, one of the initial steps is to develop an expected range of values for a long list of variables. The analysis can exhaustively evaluate the consequences of every combination of variables or define a selected set of scenarios with values chosen in some internally consistent manner that may also follow a particular theme, such as a low-GHG future. The current challenges are to determine which metrics to assess, how to fine tune the assumptions across studies that use these assumptions in different ways and toward different ends, and how to better synchronize the schedules of the various studies so there is logical progression from one study to the next and findings from one study can be used as input into subsequent studies and proceedings.

After assessing a range of different possible outcomes based on the assumptions in each scenario in terms of cost, reliability, and other metrics, the question is how to make an informed decision about which and how many resources to procure. CPUC staff identified the concept of "deliverability risk assessment" in the 2008 Long-Term Procurement Plan rulemaking that essentially balances the policy-based goals for preferred resource development against the threat to reliability if such goals are not achieved on the desired time schedule.[55] The Energy Commission endorses this concept but recognizes the difficulty of balancing these competing goals given different missions and responsibilities.

55 California Public Utilities Commission, *Energy Division Straw Proposal on LTPP Planning Standards*, R.08-02-007, Phase 1, July 2009, p. 27.

Other Supply Uncertainties

Operation of existing generating resources cannot be taken for granted. Calpine's Sutter natural-gas fired facility near Yuba City, California, is at risk of retirement due to the inadequate revenue streams currently available for merchant plants without contracts. The threatened closure of the facility is also contributing to the California ISO's efforts to seek tariff changes at the Federal Energy Regulatory Commission that would allow payments to "at risk" generators needed for reliability within the next five years. This issue is the result of basic market design issues.[56]

Procurement Decision-Making

The CPUC has directed investor-owned utilities to implement programs for preferred resources. If these programs perform as expected, most calculations of resource addition needs indicate that total resources will exceed the standard planning reserve margin of 15–17 percent of expected peak demand many years into the future. There are still unique requirements, however, that cannot be satisfied even if preferred resources are achieved at expected levels. Examples include (1) resources needed in specific geographic areas to satisfy local capacity needs, (2) resources with particular operating characteristics to integrate renewables, or (3) resources designed and operated to stabilize the grid and alleviate transmission limitations. Assessments of projected supply and demand balances could indicate more than enough total generating capacity but not enough resources to meet one or more of these specialized needs. In addition, although there is general conceptual agreement about the need for flexible generating resources, there is no

56 California ISO, *Flexible Capacity Procurement Phase 1: Risk of Retirement,* September 5, 2012, p. 12. See http://www.caiso.com/Documents/SecondRevisedDraftFinalProposal-FlexibleCapacityProcurement.pdf.

concurrence regarding amounts or specific performance characteristics. Procurement may need to be targeted toward resources with specific performance require-ments, such as highly flexible combined cycle and combustion turbines.

Although all generation project development timelines – from planning studies to an operational facility – are lengthy, there are important differences in the amount of time needed, depending on whether permitting activities precede or follow approval of a contract (Figure 4).

The overall project development timeline is significantly reduced if a project developer chooses a path where permitting precedes contract approval and is able to obtain a permit in time to submit a bid into the request for offer (RFO) process, with construction beginning two years earlier in Version B than in Version A.[57] Some of the steps in each path could be expedited to move more quickly if developers uniformly followed one path or another, but in reality developers use both paths. Because it is unlikely that developers could be required to exclusively use one path or the other, there is a considerable range in the amount of lead time from RFO announcement to on-line generation, depending on the success of projects already in the permitting steps. Repowering projects creates additional complications, especially when the existing capacity must be on-line even while new capacity is being developed within the overall facility footprint.[58] In addition, projects can easily require even more time to achieve commercial operation, and particularly controversial projects may ultimately have to be abandoned.

As a result of extensive multiagency coordination in the development by the SWRCB of the OTC policy, it is unlikely that reliability will be threatened when infrastructure needed to enable OTC compliance falls behind schedule.[59] If there is not enough replacement capacity on-line to allow for the timely retirement of OTC plants in Southern California, the energy agencies can petition the SWRCB to allow existing units to operate beyond their current compliance deadlines until replacement infrastructure is operational.

At the June 22, 2012, forum, the California ISO highlighted the need to examine transmission system upgrades in the urbanized Los Angeles area, which was echoed in written comments submitted by Pacific Gas and Electric Company (PG&E) and SCE.[60] There has been little attention paid to potential transmission upgrades within load centers that could reduce local capacity requirements. Reducing local capacity requirements could increase the flexibility to put additional generating capacity in areas with less disruption. It would also reduce the potential for market power than can occur when limited numbers of existing power plant owners can respond to utility procurement opportunities. Creating alternative transmission routes would also lessen the vulnerability of transmission lines to fires, which may increase in the future as a result of climate change-induced weather

57 In Version B of the chart, a project would need to have submitted an Application for Certification to the Energy Commission by the fourth quarter of 2011 and obtained a permit within an average of 18 months to have a completed permit when bidding into an IOU RFO initiated in the second quarter of 2013.

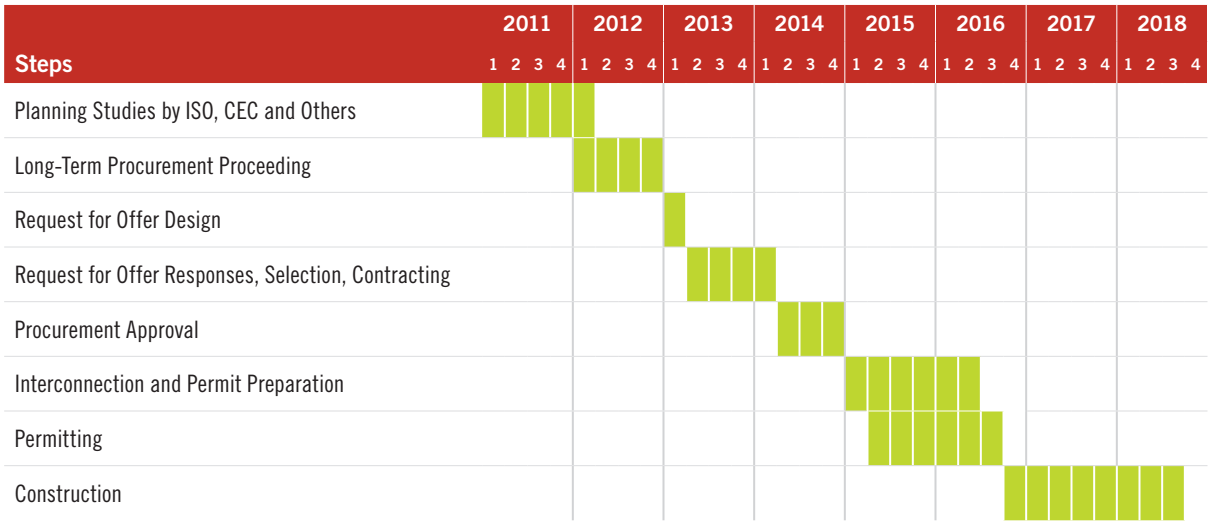
58 For example, in its generator implementation plans submitted to the SWRCB, AES requests that it be allowed to split compliance dates into unit-specific groups reflecting phased repowering on its geographically constrained sites. For Alamitos, AES proposed three phases: 2020, 2022, and 2024. Even for the smaller facilities of Redondo Beach and Huntington Beach, AES proposed two phases with four or more years between phases.

59 State Water Resources Control Board, Resolution No. 2011-0033, July 19, 2011, p. 000441, Sections 1H and 1I. http://www.waterboards.ca.gov/board_decisions/adopted_orders/resolutions/2011/rs2011_0033att.pdf.

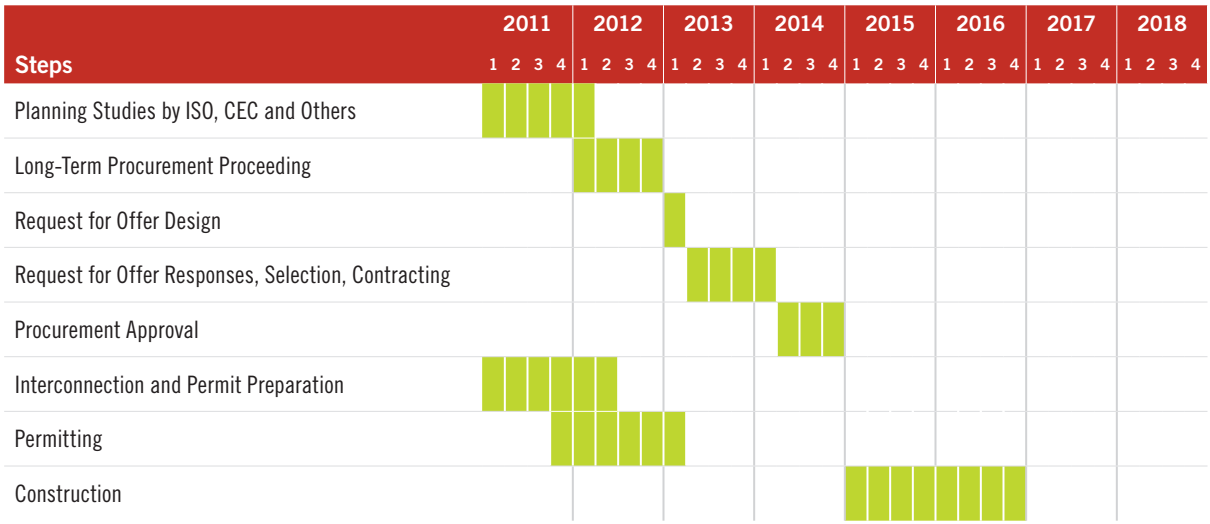
60 Comments of PG&E on Electricity Infrastructure Issues in California, July 13, 2012, page 5; comments by SCE on Lead Commissioner Workshop on Electricity Infrastructure Issues in California, July 13, 2012, Appendix: Response to Question 3.

Figure 4: Generation Project Development Timeline

Version A: Permitting Follows Contract Approval



Version B: Permitting Precedes Contract Approval



Source: California Energy Commission

patterns.[61] However, given the complexity of transmission permitting, the timeline for major projects can be much longer than generation projects, with SCE assuming eight years for even relatively minor projects.

Recommendations

Although the June 22 forum largely confirmed the directions already established by current studies, some new issues did surface. Testimony at the forum and subsequent events highlight the importance of SONGS and the need to examine how to maintain a reliable system without one or both SONGS units in both the near and long term. Recommendations are provided below; many of these infrastructure challenges and opportunities as they relate to renewable energy are also discussed further in Chapter 5.

- Contingency Planning for San Onofre Nuclear Generation Station Outage in the Summers of 2013 and 2014: Concurrent with release of this report, the energy agencies will have completed a summer 2013/2014 assessment and will be taking actions accordingly. The Energy Commission will participate in assessments of years 2013 and 2014 and in the development and implementation of mitigation measures to maximize reliability.

- CPUC Investigation of SONGS Outage: At the beginning of November 2012, the CPUC initiated an investigation under Public Utilities Code Section 455.5 regarding whether SONGS is "used and useful." The Energy Commission will participate in the CPUC's investigation.

- Long-Term Analyses of SONGS and Diablo Canyon Replacement: The California ISO's nuclear facility reliability study will consider the impact of extended nuclear outages on transmission system reliability. The Energy Commission staff and CPUC's Energy Division have submitted comments to the California ISO on its draft study plan, and the California ISO plans to submit a report to the Energy Commission's *2013 IEPR* proceeding and to the appropriate CPUC proceedings. By itself, a reliability study is insufficient to understand the alternatives to the long-standing presumption that the nuclear facilities will continue producing power until their current licenses expire. Other studies are needed to assess factors beyond grid reliability, including asset valuations, environmental impacts of GHG emissions, AB 32 compliance, flexible generation requirements, planning reserve margins, rate impacts, and gas system impacts. The California ISO's assessment should be reviewed in the *2013 IEPR* proceeding, along with any credible nuclear replacement studies, as input for policy decisions concerning reserves needed to address nuclear facility outages and the amount, type, and costs of infrastructure to replace these facilities. As soon as the assessment is received, the Energy Commission will conduct a public workshop to review the assessment and frame further discussion for the *2013 IEPR* proceeding.

- Refresh of OTC and Air Emissions Issues: The analysis of replacement for OTC facilities undertaken by the California ISO with input from the CPUC and Energy Commission, and the compliance plans of specific generators submitted to the SWRCB in April 2011, presume that SCAQMD's Rule 1304(a)(2) can be relied upon to the full level of existing OTC capacity. Both OTC and AB 1318 assessments rely upon studies that assumed both units of San Onofre are operating. The California ISO's nuclear replacement study will reveal much about what is needed to replace that facility while assuring reliability.

61 California Natural Resources Agency and California Energy Commission, *Our Changing Climate 2012 – Vulnerability & Adaptation to the Increasing Risks From Climate Change in California,* July 2012, http://www.energy.ca.gov/2012publications/CEC-500-2012-007/CEC-500-2012-007.pdf.

The proposed ARB process to complete the AB 1318 project should provide an opportunity for this topic to be fully discussed, options to be considered, and follow-up activities to be identified. At a minimum, the *2013 IEPR* proceeding should track this topic and, if appropriate, the Energy Commission should promote additional analyses and implementation efforts.

Additional refreshed assessments will be needed to examine OTC compliance schedules and the volume of fossil power plants that must be located in the SCAB in light of SONGS replacement studies. These studies should be undertaken by the California ISO in early 2013, and the Energy Commission should continue to provide technical support as it has in the past.

Energy Commission staff will provide support to SWRCB's Statewide Advisory Committee on Cooling Water Intake Structures to help develop recommendations to the SWRCB for compliance date changes for OTC facilities by March 31, 2013.

- Targeted Procurement Decision in 2012: Since the OTC assessments and the foundational analyses to be integrated into AB 1318 all show some need for local capacity area resource additions even without the San Onofre issues, it makes sense for the CPUC to proceed with its plans to provide procurement authorization to SCE and SDG&E despite uncertainty about the reliability consequences of the SONGS shutdown. Failing to do so risks either failing to satisfy reliability standards or inducing SWRCB to delay OTC compliance dates for some Southern California OTC facilities. Two proposed decisions related to A.11-05-023[62] at the CPUC have been issued and are awaiting consideration, one that rejects the Pio Pico, Quail Brush, and Escondido power purchase agreements and one that authorizes only the Escondido power purchase agreement. Both proposed decisions would authorize local capacity procurement but require SDG&E to refile with different specific projects. In R.12-03-014 (the 2012 LTPP rulemaking) a proposed decision would authorize SCE to procure 1,215 MW – 1,490 MW of conventional gas-fired capacity and additional amounts of preferred generating resources for local capacity purposes. Neither proceeding incorporated into its procurement authorization any increase in need due to the shutdown of SONGS units should the shutdown prove to be permanent. The CPUC should find a procedural mechanism to authorize both SDG&E and SCE to procure replacement capacity that would be operational in a timely manner.

- Formal Capacity Planning Assessments: In CPUC D.10-06-018, the CPUC decided to continue the resource adequacy program's reliance on bilateral contracting for capacity rather than adopting a policy for a centralized capacity auction mechanism by the California ISO.[63] On the question of whether a central capacity market would address the actual issues expected in the future, the CPUC raised key concerns about local capacity requirements and specialized renewable integration resources.[64] Further, the CPUC, Energy Commission, and California ISO needed to improve coordination among their electricity planning processes. Recent reports of low market clearing prices and low capacity factors for gas plants, the Sutter situation, and other evidence suggest that California's market design is incomplete. To provide

62 California Public Utilities Commission, Application of San Diego Gas & Electric Company (U 902 E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center, and Quail Brush Power.

63 Bilateral contracts are contracts negotiated between two parties with customized terms and conditions that are mutually acceptable, whereas a centralized market sets the price for all market participants based on matching of supply and demand for a uniform product that may not fully satisfy the needs of all participants.

64 California Public Utilities Commission, D.10-06-018, p. 60: "While a centralized auction approach may be well-suited to achieving system reliability, it is less clear that this is true for satisfying local capacity across multiple capacity areas. Moreover, it is not necessarily the most effective way to develop and trade specialized capacity in order to both meet the State's environmental goals of and satisfy the CAISO's operational needs."

the flexible capacity in the amounts and with the characteristics the California ISO believes are needed, the California ISO is proposing that the CPUC modify its resource adequacy program to shift to a multiyear forward obligation and that the market better reflect the distinction between the value of different operational capabilities.

Recognizing that developing a formal multiyear forward capacity or capabilities market is very complex and will require several years to put in place, the California ISO has proposed to eliminate "risk of retirement" by providing compensation to existing generators that the California ISO judges to be required in a future year but that have no contract in the near future.

The Energy Commission will continue to work with the CPUC and the California ISO to improve coordination among the electricity planning processes in California, particularly the hand-offs across these processes. The three agencies should work to not only maintain the good working relationships demonstrated in the San Onofre responses, but to further enhance them.

The CPUC should consider either opening a new proceeding or using the existing resource adequacy rulemaking to evaluate allowing utilities to participate in a forward procurement mechanism. Such a mechanism could be developed by either the CPUC or the California ISO with stakeholder input with the goal of developing consensus on possible solutions, followed by evaluation of appropriate institutional roles.

CHAPTER 5

Renewable Action Plan

California's Renewables

Portfolio Standard (RPS) was established in 2002 with the goal of diversifying the electricity system and reducing growing dependence on natural gas. The current RPS target calls for increasing the amount of renewable electricity in the state's power mix to 33 percent by 2020. To support the RPS target, Governor Brown's Clean Energy Jobs Plan called for adding 20,000 megawatts (MW) of new renewable capacity by 2020, including 8,000 MW of large-scale wind, solar, and geothermal resources and 12,000 MW of localized renewable generation close to consumer loads and transmission and distribution lines.[65]

This Renewable Action Plan responds to direction in Governor Brown's plan for the Energy Commission to prepare a plan to "expedite permitting of the highest priority [renewable] generation and transmission projects." The intent was to support investments in renewable energy that will create new jobs and businesses, increase energy independence, and protect public health. The Renewable Action Plan builds on the *Renewable Power in California: Status and Issues* report, which was published under the *2011 Integrated Energy Policy Report* (*IEPR)* proceeding. That report discussed challenges that will affect the amount of renewable capacity ultimately

65 http://www.jerrybrown.org/Clean_Energy.

developed, described past and current efforts to address those challenges, and identified five overarching strategies as the basis for future action. These strategies included:

- Prioritizing geographic areas for renewable development.
- Evaluating costs and benefits of renewable projects.
- Minimizing interconnection and integration costs and time.
- Promoting incentives for projects that create in-state jobs and economic benefits.
- Promoting and coordinating existing financing and incentive programs for critical stages in the renewable development continuum.

During the *2012 IEPR Update* proceeding, Energy Commission staff developed a set of recommended actions related to each of these strategies based on discussions in public workshops and comments submitted by stakeholders from various communities, industries, and state and local agencies throughout California.[66]

The following sections provide recommendations for each of the five strategies and for monitoring and reporting progress in the future. The section for each strategy includes a discussion of the challenges addressed by the recommendations and suggests actions, implementation steps, and timelines for each recommendation. Each recommendation also identifies the lead agency or agencies that will be responsible for working with supporting agencies to:

- Create a plan for moving each action forward.
- Coordinate assignment of tasks needed to complete the action.
- Develop timelines for completion of tasks.
- Establish communication between agencies to monitor status, report on progress and timelines, raise issues needing resolution, resolve conflicts, and recommend revisions to actions as needed based on future market or regulatory changes.

66 Summaries of Renewable Action Plan workshops are provided in the Appendix beginning on page A-1.

Strategy 1: Identify Preferred Geographic Areas for Renewable Development

Identify and prioritize geographic areas in the state for both renewable utility-scale and distributed generation development. Priority areas should have high levels of renewable resources, be located where development will have the least environmental impact, and be close to planned, existing, or approved transmission or distribution infrastructure. Prioritization should also include increasing efforts between state and local agencies to coordinate local land-use planning and zoning decisions that ease the siting and permitting of renewable energy-related infrastructure.

Challenges and Opportunities

- The location of a utility or distributed generation renewable energy project can have a significant effect (negative or positive) on the cost and speed of both utility interconnection and local government permitting processes. Unfortunately, most renewable project developers will not know the nature of the effect until

after they have invested time and money due to a lack of baseline environmental data and the lack of a local comprehensive land-use planning process or a transparent distribution planning process.

- Piecemeal siting of renewable projects makes it difficult to anticipate or evaluate cumulative environmental, electrical system, and other consequences of development. A more comprehensive planning process will help provide effective protection and conservation of sensitive habitats and key agricultural areas as well as potential system upgrade needs, for example, while allowing for the appropriate development of renewable energy projects.

- Local governments typically have permitting authority for many types of renewable projects, and some have expressed interest in creating land-use plans to promote renewable energy development. Although Kern County and a handful of other local governments have developed land-use plans for renewable energy, many local governments do not have the data and resources to develop land-use plans that aid renewable energy development.

- Utility distribution planning and local government land-use planning are not coordinated to plan for future growth in electricity demand (load). For example, a utility can pull local government planning permits for new residential, commercial, or industrial development and plan new or upgraded distribution systems to accommodate anticipated load growth. Distribution planning, however, occurs for new supply (generation) on a case-by-case basis through an onerous and uncoordinated distribution interconnection process. Developing renewable energy zones would provide utilities with increased certainty about where new generation projects will be built.

- Transparent utility system and land-use information is needed to improve coordination of utility system and land-use planning. A wealth of utility system data is currently available but is not centrally located and can be difficult to find. Utility system data gaps and availability need to be addressed while avoiding creation of duplicative reporting processes.

Recommendations

1. Incorporate Distributed Renewable Energy Development Zones Into Local Planning Processes

Preferred renewable distributed generation (DG) development zones should be identified and incorporated into utility distribution system investment plans and local government planning processes. Zones should prioritize development within the existing built environment followed by development on lands with negligible environmental or habitat value (for example, marginal or salinity-impacted agricultural land). Priority should also be on areas near existing or planned electric system infrastructure, particularly in areas where DG could be beneficial to the electricity system, and recognize that land use implications vary depending on the size and type of the DG facility. The effort should build on experience gained during the Renewable Energy Transmission Initiative (RETI) process, the Desert Renewable Energy Conservation Plan (DRECP), and Renewable Auction Mechanism mapping activities, and include a pilot project within each utility to evaluate diverse geographic areas. SCE's study assessing the impacts of increasing deployment of local energy resources into its distribution system[67] should also be considered when developing a method to identify DG development zones. Identifying DG zones will be an iterative process as new DG development within identified zones may prompt the need to for reassessment. The aim is to develop a process that can be replicated by local jurisdictions

67 Southern California Edison, *The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System*, May 2012.

throughout California to analyze the suitability of areas for DG and place priority on developing those areas. This supports the overall goal of cost effectively maximizing the benefits of renewable DG.

Actions/Implementation Steps:

- The Energy Commission and the California Public Utilities Commission (CPUC) should work with each investor-owned utility to establish pilot working groups to (1) create maps identifying DG renewable energy development zones and (2) demonstrate how improved coordination between utility infrastructure planning and land-use planning can build markets that better support high penetrations of renewable DG. The pilot effort should represent diverse built and geographic environments and incorporate relevant work already completed or in progress. Where possible, the DG zones should target areas where system upgrades and modernization are anticipated, and could allow for increased penetration of DG resources. Interested publicly owned utilities are also encouraged to work with the Energy Commission to identify DG renewable energy development zones in their service areas.

- The CPUC should require that in future general rate cases utilities provide cost and benefit analysis of investments being requested to accommodate DG resources in each DG zone. Approved DG investments should be communicated to local governments to inform land use decisions, and the energy agencies should recognize these areas in the CPUC's Long-Term Procurement Plan proceeding, the California ISO's Transmission Planning Process, and the RPS procurement process. The analysis should be in a stand-alone document that is readily available for public review.

- The Energy Commission will coordinate with the CPUC, utilities, and interested local jurisdictions in each pilot effort to develop renewable energy overlay maps that can be used by local planners. The Energy Commission will lead the following actions to develop the maps:

    - Identify preferred development zones with minimal environmental or habitat value, located in or near load centers and near existing or planned electric system infrastructure, and with minimal permitting and interconnection costs. Land-use types considered for inclusion in development zones within each pilot program area will vary from urban to suburban and from rural to industrial.

    - Consider areas of high unemployment and communities that are disproportionately burdened by environmental pollutants. Consider using the California Communities Environmental Health Screening Tool (CalEnviroScreen) that is under development at the California Environmental Protection Agency (Cal/EPA) and uses existing environmental, health, and socioeconomic data to compare the cumulative impacts of environmental pollution on the state's communities.[68]

    - Establish an effective and transparent process for identifying preferred development zones that can be replicated throughout the state.

    - Determine data needs for identifying renewable distributed generation zones. This includes data related to land use and the environment, utility interconnection/infrastructure, and economic/workforce development.

68 For further information, see http://oehha.ca.gov/ej/cipa073012.html.

- Evaluate the effectiveness of zones to expedite development and reduce costs by monitoring the permitting, interconnection, and construction of renewable DG projects in each zone. From this analysis, lessons learned can be applied to the development of subsequent DG zones.

- Consider the zones in the ongoing analysis and updates of regional soft targets for deploying DG. These soft targets break down the overall 12,000 MW DG target into county-specific goals.

- Incorporate the results of the Energy Commission's disaggregated demand forecasts into development of DG zones.[69]

- The state may consider, as appropriate, developing incentives (financial and nonfinancial) or revising existing incentives (financial and nonfinancial) to encourage development in DG zones.

- Support the Governor's Office of Planning and Research (OPR) drafting of guidelines for developing local government general plan elements (implementation of Government Code Section 65040.2) related to renewable energy, which OPR plans to include in the *2013 General Plan Guidelines*.

- OPR, in coordination with the Energy Commission, should work with DG stakeholders to develop a best practices manual for local governments and developers to advise planning, permitting, and development of DG and related infrastructure. The manual should describe strategies – including health and safety considerations – for integrating a variety of DG renewable technologies into land-use plans, zoning codes, and building codes.

Lead: Regional/local governments, OPR, CPUC, and Energy Commission.

Date Complete: By the end of 2014.

2. Identify Renewable Energy Development Zones

Renewable energy overlay zones that identify preferred areas for all sizes and technology types of renewable energy projects should be developed in coordination with local governments and incorporated into local planning processes. This is a higher-level mapping effort to identify areas suitable for renewable development from both land use/environmental and utility system perspectives than discussed in Recommendation 1 (Incorporate Distributed Renewable Energy Development Zones Into Local Planning Processes). Recommendation 1 establishes a process to identify the best places to install DG that can be replicated elsewhere in California and would likely focus initially on relatively small areas, potentially within renewable energy development zones.

Renewable energy development zones should prioritize development within the existing built environment followed by lands with negligible environmental or habitat value (for example, marginal or salinity-impacted agricultural land) and that are in areas near existing or planned electric system infrastructure. The zones should build on the "smart-from-the-start" approach to encourage siting of renewable projects in low-conflict areas and impaired agricultural lands as a strategy to accelerate renewable development and protect vital natural resources.[70] The zones should include consideration of the effects of development on the environment and electrical system, including development of the transmission and distribution systems, areas with high unemployment, and

69 For further information on the disaggregated demand forecast, see Strategy 3.

70 Defenders of Wildlife, *Smart from the Start, Responsible Renewable Energy Development in the Southern San Joaquin Valley*, http://www.defenders.org/sites/default/files/publications/smartfromthestartreport12_print.pdf.

disadvantaged communities that are identified by Cal/EPA as required by Senate Bill 535 (De León, Chapter 830, Statutes of 2012).[71] Zones should also include consideration of increased penetration of electric vehicles (EV) and the development of required EV infrastructure. The effort should build on experience gained during RETI and the DRECP and initially focus on the Central Valley. The Central Valley is experiencing a high volume of permitting and interconnection requests, primarily from PV projects that pose significant land use and environmental challenges, as well as electric system challenges caused by circuits that were originally designed to serve minimal rural loads. This is also an area that has experienced widespread economic disadvantages. Additionally, the Central Valley provides an opportunity to capitalize on repurposing retired agricultural lands, such as lands in Westlands Water District, for renewable energy development. The Renewable Energy Development zones should be developed in coordination with the DG zones in Recommendation 1 (Incorporate Distributed Renewable Energy Development Zones into Local Planning Processes).

Actions/Implementation Steps:

- The Energy Commission will coordinate with utilities and interested local jurisdictions to create and identify renewable energy overlay maps that cities and counties can easily include in their comprehensive plans and utilities in their infrastructure plans. The Energy Commission will lead the following actions using the best available science to develop the necessary elements of overlay maps:

- Identify data and other resources needed to map renewable energy development zones.

- Collaborate with the United States Environmental Protection Agency (U.S. EPA) and the Cal/EPA to incorporate RE-powering America's Land sites (for example, brownfield and other contaminated lands) into overlay maps.[72]

- Collaborate with the Department of Conservation Farmland Mapping and Monitoring Program to identify areas with site characteristics that meet the criteria of Senate Bill 618 (Wolk, Chapter 596, Statutes of 2011) that would be suitable for renewable energy development.

- Collaborate with Cal/EPA on using CalEnviroScreen, a method for identifying disadvantaged communities based on pollutant exposure, environmental effects and susceptibility, and socioeconomic factors.

- Collaborate with environmental justice and workforce development stakeholders and the Employment Development Department (EDD) to identify areas for development that can provide environmental and workforce benefits to disadvantaged communities.

- Collaborate with the U.S. Department of Defense, U.S. Department of the Interior Bureau of Land Management, and Native American tribes to identify potential lands for renewable energy development within their authority to incorporate into mapping efforts.

71 Senate Bill 535 requires the Cal/EPA to identify disadvantaged communities, "… based on geographic, socioeconomic, public health, and environmental hazard criteria, and may include, but are not limited to, either of the following: (a) Areas disproportionately affected by environmental pollution and other hazards that can lead to negative public health effects, exposure, or environmental degradation. (b) Areas with concentrations of people that are of low income, high unemployment, low levels of homeownership, high rent burden, sensitive populations, or low levels of educational attainment.

72 http://www.epa.gov/oswercpa/.

- The Energy Commission will implement the grant program in Section 25619 of the Public Resources Code.[73] The Energy Commission will use the information gathered to help grant recipients develop or revise rules and policies that will facilitate renewable energy development.

- The CPUC should evaluate the appropriate way to consider renewable zones in the RPS procurement Requests for Offers (RFO).

- Utilities and local governments should incorporate into land-use planning research products related to renewable energy siting and mapping.

- Local/ regional governments and utilities should incorporate the results of the Energy Commission's disaggregated demand forecasts into their respective planning efforts.[74]

Lead: Energy Commission, regional/local governments, OPR, Renewable Energy Action Team (REAT), and utilities.

Date Complete:

- By the end of 2013, complete mapping.

- Include maps and disaggregated demand forecasts in local and regional planning processes on an ongoing basis.

3. Conduct 2030 Analysis

Energy Commission staff will conduct a scenario-driven analysis to assess the implications of likely or possible developments beyond the current 2020 planning horizon to evaluate generation resource requirements through 2030, recognizing the substantial uncertainties with planning for the more distant future. Possible developments include interest in setting targets to increase the RPS beyond 33 percent,[75] having a backstop plan if the state's nuclear facilities cannot extend their operating licenses, maximizing DG development on military facilities, displacing direct and indirect coal imports into California, targeting disadvantaged communities as identified by Cal/EPA and areas with high unemployment, and providing energy to electrify the industrial and transportation sectors to reduce GHG emissions. The analysis will include evaluation of what is needed to achieve a 40 or 50 percent renewable energy goal, including the potential need for complementary resources, such as dispatchable renewable and flexible gas-fired resources and storage. California recognizes the value of regional out-of-state resources and must also look more closely at regional solutions to meet future needs.

Planning for 2030 will help the state control costs as it transitions its energy infrastructure to meet the 2050 goal to reduce GHG emissions to 80 percent below 1990 levels. This analysis will also help determine if actions, or inaction, undertaken over the next five years might limit the options available in 2030 and help the state identify practical steps toward achieving its vision for the future.

73 Section 25619(b) states: "The [Energy] commission shall provide up to seven million dollars ($7,000,000) in grants to qualified counties for the development or revision of rules and policies, including, but not limited to, general plan elements, zoning ordinances, and a natural community conservation plan as a plan participant, that facilitate the development of eligible renewable energy resources, and their associated electric transmission facilities, and the processing of permits for eligible renewable energy resources."

74 For further information on the disaggregated demand forecast, see Strategy 3.

75 Governor Jerry Brown, signing statement, Senate Bill X1-2 (Simitian, Chapter 1, Statutes of 2011): "While reaching a 33% renewables portfolio standard will be an important milestone, it is really just a starting point – a floor, not a ceiling." April 12, 2011, http://gov.ca.gov/docs/SBX1_0002_Signing_Message.pdf.

Actions/Implementation Steps:

- The Energy Commission staff will develop a report that analyzes implications of current trends in procurement, increasing the RPS, having a backstop plan if the state's nuclear facilities cannot extend their operating licenses, maximizing DG development on military facilities, displacing direct and indirect coal imports into California, disadvantaged communities as identified by Cal/EPA and areas with high unemployment, and providing energy for electrified transportation over 2020 – 2030 for generation resource needs beyond the current planning horizon. The analysis will provide a foundation for developing an interim 2030 RPS target as the state moves toward its 2050 GHG emission reduction goals. The analysis will be largely scenario-driven, using techniques that incorporate risk and are appropriate in situations of deep uncertainty.

Lead: Energy Commission.

Date Complete: 2014.

4. Continue Development of Renewable Energy on Government Property

The state, led by OPR, should continue to develop renewable energy on state property as agreed upon in a memorandum of understanding between the Energy Commission, the Departments of General Services, Corrections and Rehabilitation, Transportation (Caltrans), Water Resources, and Fish and Wildlife, the California State Lands Commission (CSLC), and the University of California. This work will help the state achieve the goals in Executive Order B-18-12,[76] including reducing grid-based energy purchases for state-owned buildings by at least 20 percent by 2018; requiring all new state buildings and major renovations designed after 2025 to be constructed as zero net energy; and achieving zero net energy for 50 percent of the square footage of existing state-owned buildings by 2025.

A barrier to installing renewable DG on state properties is that many state buildings are financed with lease revenue bonds, requiring notification and approval of the bond owners before development on the property can proceed. For utility-scale generation, parcels managed by the CSLC hold the greatest potential for development; however, many of the land parcels are scattered throughout the DRECP area, so consolidating specific properties would advance both environmental protection and development opportunities. Finally, the effort to deploy renewables on state property should be broadened to include government-owned, K-12 schools. Deploying renewables on K-12 schools can reduce energy costs, provide a mechanism for deploying renewable DG in disadvantaged communities as identified by Cal/EPA in coordination with the requirements of SB 535, and areas with high unemployment, and inspire an interest in clean energy in the next generation.

Actions/Implementation Steps:

- The Department of General Services, Department of Finance, and State Treasurer's Office should jointly develop a standardized method for addressing bond requirements, including notifying bond holders, to expedite renewable DG installations on properties financed with state revenue bonds.

- Under Assembly Bill 982 (Skinner, Chapter 485, Statutes of 2011), CSLC is required to execute a land exchange with the federal agencies to consolidate state lands for the advancement of renewable energy projects and environmental protection, consistent with the DRECP. Under state law, the CSLC is also required to consult with the Department of Fish and

76 Executive Order B-18-12, April 25, 2012, http://gov.ca.gov/news.php?id=17508.

Wildlife to identify areas for land swaps. The REAT agencies have been discussing potential opportunities with the CSLC in the DRECP area. Opportunities for land swaps include CSLC parcels located on or surrounded by lands that are not suitable for energy resource development, such as national parks, national monuments, and other sensitive lands.

- When OPR and state agencies identify opportunities to deploy renewables on state property, a priority should be deployment in generation-constrained areas in Southern California affected by the outage of the San Onofre Nuclear Generating Station. This supports the Energy Commission's efforts to evaluate a range of options to address the outage, including energy efficiency, demand response, and combined heat and power.

- The Energy Commission's Bright Schools, Energy Partnerships, and Energy Financing Programs should provide financial and technical assistance to make energy efficiency upgrades and install renewable DG at California schools.[77]

Lead: OPR.

Date Complete:

- Standardized lease revenue bond procedures: By June 2013.

- Land swap: By the end of 2013.

- Increase deployment of renewable DG on schools: in 2013 and ongoing.

77 For further information, refer to Recommendation 32 (Develop Marketing Outreach Plan for Energy Conservation Assistance Account Programs) under Strategy 5.

Strategy 2: Maximizing Value Through Appropriate Assessment of Benefits and Costs

Evaluate the cost of renewable energy projects beyond technology costs – including costs associated with integration, permitting, and interconnection – and their impact on retail electricity rates. This evaluation shall be coupled with a value assessment that could potentially lead to monetizing the various system and nonenergy benefits attributable to renewable resources and technologies, particularly those benefits that enhance grid stability and reduce environmental and public health costs.

Challenges and Opportunities

Current processes for infrastructure planning and resource procurement should do a better job of maximizing portfolio value and diversifying risk. Examples of areas where renewable benefits can be further realized include the following:

- Improved processes to identify preferred locations where renewable projects can reduce costs. For example, connecting renewable projects to the transmission and distribution system at the best locations will reduce interconnection costs and locating projects in preferred renewable energy development zones will reduce permitting costs.

- Developing a variety of technologies can create a more attribute-based, diversified portfolio to minimize risks and realize cobenefits. For example, woody

biomass projects strategically located to reduce fire load can reduce the risk of wildfires that damage transmission and distribution lines and strengthen electric system reliability and public safety. Also, using dairy and food processing waste can reduce environmental costs, odors, and solid-waste handling costs while expanding resource diversity. Renewable projects under development as a result of investor-owned utility procurement are predominately solar without storage,[78] and the first Renewable Auction Mechanism (RAM) results were nearly entirely PV with 11 of the 13 contracts (122 MW of a total 140 MW) representing solar PV projects.[79] A study by Lawrence Berkeley National Laboratory concluded that with increasing penetrations, the value of solar without storage declines due to a drop in capacity and energy value as peak energy demand shifts.[80] Although the analysis includes a narrow set of benefits, it suggests that there are broad variations in the value of different technologies at different penetration levels. Planners and policy makers should consider differences in the economic value among renewable technologies when analyzing costs and benefits of renewable energy.

- There is a lack of "green collar" employment opportunities and renewable projects in disadvantaged communities in urban and rural areas. Further deployment of renewable technologies in such areas can help increase employment opportunities. Also, the state must explore making subsidies available to ensure that disadvantaged and low-income communities most impacted by the effects of air pollution can participate in the electrification of the transportation system and realize its benefits.

- Many studies provide levelized cost of generation evaluations but do not adequately document how key assumptions were derived and how assumptions can lead to widely varying cost estimates. Identifying key cost drivers and the extent to which these are affected by innovation or scale is essential for developing actions that will shape those drivers and reduce the costs of renewable development.

- Currently, valuation of renewable resources does not include integration costs such as incremental ancillary service needs (for example ramping, regulation) or capacity-related services provided by renewable resources.[81] This prevents the procurement of even a "least direct costs" portfolio.

- California's current residential rate design – in which the per-kilowatt-hour rate increases as electricity consumption rises – is intended to drive efficiency but does not fully capture the fixed cost of providing electricity service. As a result, as energy efficiency and distributed generation increase, more of these fixed costs will be spread amongst a smaller ratepayer base.

- California must begin to consider the effects of changes in electricity demand and the generation fleet during the period from 2013 – 2022 on future efforts to further reduce GHG emissions and environmental impacts from the energy sector. Current planning

78 California Public Utilities Commission's investor-owned utility contract database. As of September 6, 2012, of approved and in development, about 6,366 MW of 10,815 MW represent solar without storage. http://www.cpuc.ca.gov/PUC/energy/Renewables/.

79 California Public Utilities Commission, *Renewables Portfolio Standard Quarterly Report*, 1st and 2nd quarters of 2012, http://www.cpuc.ca.gov/NR/rdonlyres/2060A18B-CB42-4B4B-A426-E3BDC01BDCA2/0/2012_Q1Q2_RPSReport.pdf Page 9.

80 Mills, Andrew and Ryan Wiser, Ernest Orlando Lawrence Berkeley National Laboratory, *Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California,* June 2012, http://eetd.lbl.gov/EA/EMP.

81 For a definition and examples of ancillary services, please see *Renewable Energy in California, Status and Issues* report, December 2011, http://www.energy.ca.gov/2011publications/CEC-150-2011-002/CEC-150-2011-002-LCF-REV1.pdf, p. 102.

efforts and studies focused on 2022 and 2050 do not prepare the state for interim renewable targets to achieve the 2050 GHG emission reduction goals.

Recommendations

5. Modify Procurement Practices to Develop a Higher Value Portfolio

The utilities and the CPUC should adopt changes to procurement practices for utility-scale generation and DG to develop a higher-value portfolio. The first step is to develop an evaluation approach to minimize the overall risks and maximize the overall value of the renewable portfolios. For the investor-owned utilities, this could be initiated through the CPUC's efforts to reform its least-cost best-fit methodology as part of the RPS proceeding.[82] Procurement decisions should consider an expanded suite of renewable energy benefits, including RPS-eligible facilities that can provide integration benefits, reduction in forest fires that threaten public health and safety and damage transmission lines, reduced transmission and distribution costs, investment in disadvantaged communities, and creation of California jobs. The Energy Commission also encourages the publicly owned utilities to consider actions to develop a higher value portfolio as discussed below.

Actions/Implementation Steps

- The CPUC's efforts to evaluate the RAM and feed-in tariff projects should identify the extent to which projects are located in areas identified by utilities as having low costs for transmission and distribution, and encourage a minimum percentage of investment in disadvantaged communities or areas with high unemployment. The CPUC should consider changes to the RAM selection criteria based on its findings.
- The CPUC should consider evaluating the locational costs and benefits of DG and develop standard methods to determine the locational value of DG. This assessment should draw on experience gained in identifying distributed renewable energy development zones as discussed in Recommendation 1 (Incorporate Distributed Renewable Energy Development Zones Into Local Planning Processes).
- More broadly, to the extent ratepayer benefits can be identified, the valuation of individual RPS projects by the CPUC and publicly owned utilities should consider:
  - Integration benefits.
  - The capability of the project to provide other services needed for reliability.
  - Interconnection costs.
  - Integration costs, recognizing and supporting the CPUC and investor-owned utility efforts already underway to assess and incorporate integration costs into the evaluation of renewable projects.
  - Geographic diversity to help reduce the effects of intermittent resources.
  - Technology diversity.
  - Forest fire risk reduction. In addition to the public safety and air quality impacts of forest fires, ratepayers are paying for power outages during wildfires and infrastructure damage, as well as settlement costs from wildfires started by transmission lines.[83]

82 CPUC, Amended Scoping Memo and Rulemaking of Assigned Commissioner, Rulemaking 11-05-005, September 12, 2012, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M027/K801/27801308.PDF.

83 Transcript of Energy Commission Lead Commissioner Workshop on Identifying and Prioritizing Geographic Areas for Renewable Development in California, May 10, 2012, Christine Nota, U.S. Forest Service, p. 86.

- Exploration of an appropriate minimum percentage of investment in disadvantaged communities that bear a disproportionate burden from air pollution, disease, or other effects from burning fossil fuel in coordination with SB 535.[84]

- Job creation by showing a preference for technologies manufactured in California to the extent appropriate.

- The Energy Commission encourages publicly owned utilities or the California Municipal Utilities Association to provide an annual summary report on their procurement practices that explains how they ensure benefits are captured for California ratepayers.

Lead: CPUC and publicly owned utilities.

Date Complete:

- Evaluate RAM projects: late 2013.

- Incorporate integration costs in procurement by the end of 2013.

- Consider modification of procurement criteria: spring 2014.

- Publicly owned utility annual summary report on RPS procurement practices: late 2013.

6. Revise Residential Electricity Rate Structures

Residential electricity rate structures need to be re-evaluated to reflect the evolving nature of the electric system while ensuring that infrastructure investments are recovered through equitable pricing. The Energy Commission supports the CPUC's proceeding R.12-06-013, *Order Instituting Rulemaking on Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations*.[85] As California works to achieve its loading order preferences for energy efficiency, demand response, and renewable generation, actions are needed to send the appropriate price signals to help shape investments and influence behavior while making sure that rate design is equitable, sustainable, and has some form of mitigation measures for those who are disadvantaged.

Actions/Implementation Steps:

- Through the CPUC's proceeding on residential rate structures, the Energy Commission supports the development of a revised rate design that equitably spreads any new costs, including infrastructure costs, across all customers and retains the incentive for efficiency. While residential rate design is the first priority, commercial and industrial rate design may also need to be reevaluated in the future.

Lead: CPUC.

Date Complete: Ongoing.

7. Improve Transparency of Renewable Generation Costs

To improve understanding of key cost trends and drivers in California's growing renewable portfolio and to support distribution planning, the Energy Commission will evaluate and improve its data collection efforts to track publicly available information on the costs of

84 SB 535 requires that when the Department of Finance develops a three-year investment plan for funds collected from cap and trade, 25 percent must be allocated to projects that provide benefits to disadvantaged communities and a minimum of 10 percent must be allocated to projects located within disadvantaged communities.

85 California Public Utilities Commission, *Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations,* Rulemaking 12-06-013, June 28, 2012, http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/169782.PDF.

recently built renewable projects, particularly smaller projects. The analysis should focus on identifying cost trends and providing foundational data for analysis of renewable development costs and build on information provided by the CPUC to the Legislature[86] and data provided by agencies such as the United States Energy Information Administration, the National Renewable Energy Laboratory, and other national laboratories.

Actions/Implementation Steps:

- The Energy Commission will coordinate with local, state, and federal agencies to identify which cost data are already publicly available and what additional information is needed to support distribution planning. The Energy Commission will examine the data overlaps between various local, state, and federal agencies to streamline collection and presentation of data where possible.

- The Energy Commission will work with the CPUC, utilities, the California ISO, customers, and developers to develop a framework to prepare transparent estimates of the system costs of renewable DG, including both wholesale DG and DG that serves on-site load (self-generation). For this analysis, levelized costs of small DG will be developed along with system costs that include network upgrades.

Lead: Energy Commission.

Date Complete: Late 2013.

8. Strengthen Links Between Transportation and Clean Electrification

As the state integrates energy policy for the transportation and electric sectors to account for the increase in EV and hybrid vehicles, policies and programs should place a priority on efficiently electrifying the transportation system consistent with Executive Order B-16-2012[87] and as envisioned in the *2012 ZEV Action Plan*.[88] Targets in the Executive Order include deploying 1.5 million zero-emission vehicles in California by 2025, transforming personal transportation so that virtually all vehicles in the state are zero-emission by 2050, and ultimately reducing transportation sector greenhouse gas emissions by 80 percent below 1990 levels. In deploying zero-emission vehicles, emphasis should be placed particularly in disadvantaged communities that bear a disproportionate burden from air pollution, disease, or other effects from burning fossil fuels to help ensure that they realize the benefits that can be achieved with transportation electrification.

Further, programs to encourage charging EVs during times of low electric load and high wind generation can help improve the value of wind energy in California's electricity portfolio. Transportation electrification programs should use research findings to employ demand response programs to minimize peak charging and to provide potential ancillary services such as using the battery storage capacity of EVs to supply the grid – "vehicle-to-grid" services.

Actions/Implementation Steps:

- The *Investment Plan for the Alternative and Renewable Fuel and Vehicle Technology Program* (ARFVTP) should continue to support the deployment of EVs, hybrid vehicles, other alternative fuel vehicles and infrastructure, and goods movement using EVs and hybrids, particularly in communities that are disproportionately impacted by air pollution from the transportation sector. Prioritization may include

86 Senate Bill 836 (Padilla, Chapter 600, Statutes of 2011) requires the CPUC to report annually to the Legislature starting in February 2012 on costs of all electricity procurement contracts for eligible renewable resources and all costs for utility-owned generation approved by the CPUC.

87 http://gov.ca.gov/news.php?id=17472, March 2012.

88 *2012 ZEV Action Plan, A Roadmap Toward 1.5 Million Zero-emission Vehicles on California Roadways by 2025*, Governor's Interagency Working Group on Zero-emission Vehicles, Draft Version for Public Comment, September 2012. This report was drafted by an interagency team convened by the Governor's Office.

funding incentives for EV charging infrastructure in multiunit dwellings, funding to help demonstrate and commercialize zero- and near zero-emission trucks along urban corridors, and comprehensive regional planning for areas with particularly high air quality issues. The ARFVTP should consider providing preference points for projects in disadvantaged communities or economically depressed areas in coordination with SB 535 requirements.

- The Energy Commission will include representatives from the environmental justice community on the advisory committee for the *2013–2014 ARFVTP Investment Plan*.

- The Energy Commission will work with the Air Resources Board (ARB), the California ISO, the CPUC, utilities, and other state and local agencies to develop greater links between planning efforts for renewable energy, the distribution system, and zero-emission vehicles. The United States Department of Defense (U.S. DOD) has the most aggressive vehicle-to-grid demonstration effort in the nation. Through its 100-percent Electric Vehicle Base Initiative, the U.S. DOD will begin converting its nontactical vehicles from fossil fuel to electricity starting at the Los Angeles Air Force Base.[89] This EV conversion will involve the local utility, the California ISO, Lawrence Berkeley National Laboratory, and the ARFVTP.[90] Utilities in the state should conduct other vehicle-to-grid fleet demonstrations, building on lessons learned from the Los Angeles Air Force Base vehicle-to-grid demonstration.

89 "Staff Sgt. Richard Williams, Los Angeles AFB to replace general purpose vehicle fleet with PEVs and PHEVs," press release, http://www.af.mil/news/story.asp?id=123270249, August 31, 2011.

90 Lawrence Berkeley National Laboratory was competitively selected by the U.S. DOD to perform the "vehicle-to-grid" conversion, analysis, data collection, and reporting. The ARFVTP is providing cost share for the project.

- The Energy Commission will work with the California ISO, the CPUC, utilities, and other state agencies as they develop and publish the vehicle-to-grid roadmap for California as part of Governor Brown's *2012 ZEV Action Plan*.

Lead: Energy Commission.

Date Complete: By the end of 2013.

Strategy 3: Minimize Interconnection and Integration Costs and Requirements

Develop a strategy that minimizes integration costs and requirements at both the distribution level (such as use of remote telemetry and other smart grid technologies) and the transmission level (such as improved forecasting, the development of a western-wide energy imbalance market, and procurement of dispatchable renewable generation), and that strives for cost reductions and improvements to integration tools and technologies, including storage, demand response, and the best use of the state's existing natural gas-fired power plant fleet.

Challenges and Opportunities — Interconnection

- Environmental and land-use factors are underused in renewable resource scenarios and should be further incorporated into the California ISO's Transmission Planning Process and the CPUC Long Term Procurement Plan Proceeding (LTPP).

- The Imperial Valley is rich in renewable energy resources and has been both historically, and because of the recent recession, an area with high unemployment and economic challenges. But renewable development remains slow. Renewable resources in the Imperial Irrigation District (IID) service territory may be at a competitive disadvantage with resources connecting directly to the California ISO due to several factors, including differences in the allocation of costs for transmission upgrades and wheeling costs among others. The Federal Energy Regulatory Commission (FERC) report on the Arizona-Southern California outages on September 8, 2011, identified significant issues from multiple transmission operators across the region, including IID, associated with contingency planning, situational awareness, and reliance on protection schemes that point to the potential need for system upgrades, particularly in light of possible generation additions in the Imperial Valley.[91]

- The time needed to license, plan, and build major transmission facilities is often much longer than the time required to license and build a power plant. This disparity can impede the development of renewable resources in California. Better alignment of these time frames could reduce the possibility that generators would be stranded and help ease the timely interconnection of renewable generators to the grid.

- Challenges with permitting transmission lines in California include fragmented and overlapping permitting processes, inconsistent environmental analyses, and inadequate consideration of regional and statewide benefits. Many of these challenges have been or are continuing to be addressed at the planning level, but the Energy Commission's planning-level expertise should be leveraged further.

- Lack of comprehensive distribution system planning is expected to result in interconnection delays, lost opportunities to deploy DG strategically, and increased costs.

- California's DG procurement programs trigger market-driven solicitations and the selection of DG projects that require interconnection, consistent with the intent of the procurement programs. Interconnecting these projects could benefit from taking a more systematic approach.

- A challenge with increasing levels of DG is that the electricity system is designed to move electricity in one direction: from the transmission system to substations and finally to consumers. New protection and control systems are required to avoid damaging the system in the event that DG exceeds local demand and flows backward into circuits or substations. Additionally, storage may promote increasing levels of DG deployment if cost-effective options are available.

- PV inverters need to be able to respond to system conditions to maintain grid reliability. The primary functions of inverters for PV power are converting the direct current generated from sunlight into alternating current used by the distribution grid and basic real power delivery. However, PV inverters that have other inherent control capabilities are successfully being used in Europe for managing power and improving power quality. As more PV DG is installed in California, successful management of these resources requires better inverters to provide fast and flexible control of their output current.

- There is still substantial uncertainty about the total system costs of California's goals and targets for renewable DG. At the same time, California is rapidly accumulating knowledge and experience from the development and interconnection of DG projects. These data need to be systematically collected and assessed.

91 http://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.

- Utilities need detailed and accurate modeling and analysis of grid power flow and system performance to understand the effects of DG. Few tools are commercially available to perform integrated transmission and distribution modeling.

Challenges and Opportunities – Integration

- Intermittent renewable resources like wind and solar increase the minute-to-minute and hourly variability of the electric system. They are difficult to forecast and cannot be dispatched on command, and their generation pattern may not match system load. In addition, going forward the system will no longer be able to rely on current excess capacity and special rules for intermittent renewable resources. Integrating intermittent resources will require increased operational flexibility and market mechanisms that align with these new technical operating requirements to ensure that enough fast-response and flexible resources are made available.

- Maintaining reliable operation of the electric system with high levels of intermittent resources will require integration services including regulation to follow real-time ups and downs in generation output, voltage, or frequency; ramping generation to follow swings in wind or solar generation; spinning reserves that are standing by and ready to connect to the grid; replacement power for outages; and strategies to deal with overgeneration conditions. It will also require complementary fast-response generation, energy storage, and demand response that can be turned up or down as needed, as well as increasingly sophisticated controls and new market designs.

- Deploying 12,000 MW of DG will require the addition of features to the distribution system to absorb voltage fluctuations and intermittency. New types of distribution equipment are being introduced that could support increased deployment of DG by allowing utilities to manage voltage fluctuations, intermittency, and reverse power flow.[92]

Recommendations – Transmission Interconnection

9. Consider Environmental and Land-Use Factors in Renewable Scenarios

The Energy Commission will ensure that environmental and land-use information developed through the DRECP and other relevant sources is incorporated into renewable resource scenarios used in the CPUC's LTPP proceeding and the California ISO's Transmission Planning Process. Environmental and land-use factors should be included for potential in-state and out-of-state renewable resources. The Energy Commission maintains an extensive database on proposed renewable projects in California and is developing a database on out-of-state projects. Using its environmental and land-use expertise, the Energy Commission will continue to develop its in-state and out-of-state renewable project databases. These data should be collected and maintained through a transparent, public process that provides opportunities for stakeholder involvement.

Actions/Implementation Steps:

- Hold a public workshop to discuss the goals and scope of this effort, data needs, possible sources of publicly available data, gaps in available information, any data collection issues (including timing needed for inclusion in the CPUC 2014 LTPP process), and possible options. Closely coordinate this effort with the OIR suggested in Recommendation 14 (Create a Statewide Data Clearinghouse for Renewable Energy Genera-

92 Gridco Systems, Comments on the Final 2012 IEPR Update (Docket No. 12-IEP-1A), February 7, 2013, http://www.energy.ca.gov/2012_energypolicy/documents/index.html#02132013.

tion Planning). Based on staff analysis and workshop findings, and in coordination with the CPUC, California ISO, and OPR, the Energy Commission will continue to develop and maintain a public, transparent, and useful database of environmental and land-use attributes of both in- and out-of-state renewable resources.

- Determine interim products based on outcome of public workshop.

- Provide input on environmental and land-use attributes of out-of-state renewable resources and associated transmission lines to CPUC in support of the 2014 LTPP process, in coordination with the WECC's Transmission Expansion Planning Policy Committee.

Lead: Energy Commission, CPUC, and California ISO.

Date Complete:

- Hold a joint Siting Committee/Electricity Lead Commissioner workshop in second quarter 2013.

- Determine interim steps.

- Provide updated database of in-state and new out-of-state renewable resources to CPUC by July 2013.

10. Monitor Status of California ISO-Approved Transmission Projects to Ensure Timely Completion

To meet RPS targets, California must continue to develop the transmission required to deliver remote renewable generation to load centers. In cases where transmission projects have been identified and approved through the California ISO Transmission Planning Process or Generator Interconnection Procedures, utilities, state and federal agencies, and the CPUC must make appropriate progress on the environmental analysis and licensing of these projects. If progress on these projects slows or there are indications that the project may not be licensed, then the state should take appropriate action to get projects back on track or seek solutions that appropriately mitigate the root cause of any obstacles or barriers to transmission project implementation. If these measures are unsuccessful, the state should consider alternative solutions, including but not limited to supporting independent transmission projects that can deliver renewable energy to California load centers.

Actions/Implementation Steps:

- Develop milestones for each of the critical transmission projects and evaluate the capability of current tracking efforts to monitor progress toward meeting these milestones.

Lead: Energy Commission, California ISO, CPUC, and utilities.

Date Complete: Implement milestones and tracking process in September 2013. Track progress through monthly coordination calls.

11. Streamline Transmission Permitting in California

To reduce the amount of time needed to license, plan, and build major transmission facilities in California that can support the 33 percent RPS and higher goals in the future, the Energy Commission and the CPUC should jointly develop a process that will reduce the time required to bring these transmission projects online. Typically, the routing and environmental analyses for these major types of transmission facilities do not begin until the California ISO determines they are needed. These can occur about the same time as the renewable generators that require the transmission are ready to start construction. Transmission can therefore lag behind the generators by three or more years. Options to help the timely development of transmission projects include a programmatic CEQA review program for transmission facilities, completing the environmental component of a Certificate of Public Convenience and Necessity for policy-driven transmission facilities

prior to the California ISO finding of need, or leveraging the Energy Commission's environmental expertise to reduce analysis time without compromising quality.

Actions/Implementation Steps:

- As a first step, the Energy Commission will hold a workshop in 2013 to vet options to promote the timely approval of in-state transmission projects needed to support renewable development. The discussion should include timelines for implementing any options proposed.

- Develop milestones for each of the critical transmission projects and track the progress toward meeting these milestones.

Lead: Energy Commission, CPUC, and investor-owned utilities.

Date Complete:

- Hold workshop in the second quarter of 2013.

- Implement workshop recommendations (to be determined).

- Implement milestones and tracking process in 2013. Track progress through monthly coordination calls.

Recommendations – Distribution Interconnection

12. Develop a Dialogue on Distribution Planning and Opportunities for a More Integrated Distribution Planning Process

Building on recommendations in the *2007 IEPR*, the Energy Commission, the CPUC, the California ISO, local governments, environmental stakeholders, and utilities should work together to build transparency into distribution planning. Distribution planning should integrate information on increasing quantities of DG while maintaining reliability, controlling costs, and reducing emissions. Information about investments in distribution infrastructure is not readily available to the public nor is there public transparency in the distribution planning process of each utility. Because the transmission and distribution systems were designed on the premise that generation would flow from utility-scale generation to the distribution system, integrating increasing amounts of generation at the distribution level requires that both planning processes and system infrastructure be modernized.

Actions/Implementation Steps:

- The Energy Commission, the CPUC, utilities, and the California ISO should begin to explore how to better coordinate and integrate DG procurement programs, the LTPP, smart grid deployment plans, transmission planning, and other planning processes to build transparency into distribution planning. The goal is development of a modern and smart distribution network that can actively accommodate high levels of DG. A first step is to identify a forum to better understand how each utility does distribution planning.

- As part of the dialogue, the agencies and utilities should consider providing additional information on the existing grid such as improved interconnection maps and searchable databases, including information from smart meters.

- The Energy Commission will hold a workshop to consider SCE's study on *The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System* which developed a framework for evaluating utility costs associated with interconnecting high levels of DG.

- The Energy Commission will disaggregate its demand forecast to support development of a more integrated and transparent distribution planning process. (See Recommendation 13, Disaggregate the Energy Commission's Demand Forecast).

- Utilities throughout the state should use advanced analysis and modeling tools to accurately and openly assess the systemwide impacts of DG and the use of energy storage. Within three to five years, California's utilities should use state-of-the art analysis and modeling tools that provide high-level and accurate circuit detail to ensure efficient interconnection of renewable generation and energy storage.

Lead: Energy Commission.

Date Complete:

- Early analytical efforts to study systemwide impacts of distributed generation will be achieved by mid-2013.

- Broader acceptance and adoption of methods will begin 2013–2015.

13. Disaggregate the Energy Commission's Demand Forecast

The Energy Commission will evaluate methods to further disaggregate its demand forecast beyond the current planning area level to provide stakeholders with location-specific demand data. As a first step, the Energy Commission will provide additional demand forecast results by climate zone to supplement the usual planning area level forecasts, as discussed in Chapter 1. Increased geographic granularity in the demand forecasts will contribute to better planning for DG procurement, utility infrastructure, and renewable DG development zones. Improved understanding of local government loads will also help inform the development of regional soft DG targets.

Actions/Implementation Steps:

- The Energy Commission will discuss the level of suitable demand forecast granularity for Energy Commission, CPUC, and California ISO planning and assessments.

- The Energy Commission will explore what data and resources are needed for further disaggregation of its biannual demand forecast. Protocols and guidelines for transferring customer-specific data from utilities to the Energy Commission to support more disaggregated, location-specific end-use analysis should be included.

- The Energy Commission will begin work on further disaggregation in the demand forecast as part of the *2013 IEPR* process.

Lead: Energy Commission.

Date Complete: By the end of 2013.

14. Create a Statewide Data Clearinghouse for Renewable Energy Generation Planning

The state should create a statewide data clearinghouse for renewable energy generation planning. Renewable developers, utilities, system operators, and state and local planners need a centrally located source of data, information, and resources to help coordinate land-use planning with utility system planning at both the distribution and transmission levels. Collected data will also provide a foundation for the Energy Commission's identification of renewable development zones and for its development of a regionally disaggregated demand forecast. Data should include detailed, nonconfidential information about existing energy generation projects, existing and planned transmission and distribution systems, location-specific demand data, and geographic areas for preferred renewable energy development. Geographic Information System data that protects customer confidentiality and proprietary information should be made publicly available to allow ready access to the most up-to-date information. The Energy Commission will

closely coordinate this effort with the CPUC's proposal to create an energy data center to make aggregated customer energy usage data available.[93]

Actions/Implementation Steps:

- The Energy Commission will open an Order Instituting Informational Proceeding (OII) to investigate what publicly available data currently exist, what additional data are needed, how data collection can be streamlined, and what is needed for the data clearinghouse to provide value. Areas to investigate include:
  - With an initial focus on the areas identified for developing maps for renewable DG and renewable energy development zones, data that may currently exist and additional data needed to identify preferred site characteristics (such as resource potential, electric system, habitat value, brownfields or chemically or physically impaired lands, farmlands, economic development areas, and local demand) for renewable energy development as discussed in Recommendations 1 (Incorporate Distributed Renewable Energy Development Zones Into Local Planning Processes) and 2 (Identify Renewable Energy Development Zones).
  - Data needed to support Recommendation 13 (Disaggregate the Energy Commission's Demand Forecast).
  - Data needed to support a database of out-of-state renewable resources as discussed in Recommendation 9 (Consider Environmental and Land Use Factors in Renewable Scenarios).
  - Data on distribution system costs and operational profiles to support analysis and advanced modeling techniques for distribution system planning as discussed in Recommendation 7 (Improve Transparency of Renewable Generation Costs) and Recommendation 12 (Develop a Dialogue on Distribution Planning and Opportunities for a More Integrated Distribution Planning Process).

Lead: Energy Commission.

Date Complete: By the end of 2013.

15. Enable Deployment of Advanced Inverter Functions for Volt-Var[94] and Frequency Management

As California installs more distributed PV, successful integration and management of these new resources will require inverters that are able to provide fast and flexible control of output current. Over the next two years, the CPUC should undertake an inquiry to establish new inverter requirements in utility procurement and interconnection programs for wind and solar PV resources. The CPUC should also consider and determine what operational communication and control technologies are necessary for these resources to provide greater visibility and respond to dispatch instructions from both utilities and the California ISO.

Actions/Implementation Steps:

- The CPUC should incorporate new inverter requirements and requirements for operational communication and control technologies for wind and solar photovoltaics into California procurement programs and utility interconnection processes no later than December 2014.
- The Energy Commission will work with the CPUC to convene a working group to develop agreement on a range of autonomous inverter functions that would

93 California Public Utilities Commission, *Energy Data Center Briefing Paper*, September 2012, http://www.cpuc.ca.gov/puc/emergingissues.

94 Voltage and volt-ampere reactive.

respond to local system conditions via preset parameters. These functions would be specified by utilities and would not require new standards. The working group should include utilities, the National Renewable Energy Laboratory, the National Institute of Standards and Technology (NIST), inverter manufacturers, the Electric Power Research Institute, and interested utilities from other states and have a deadline to determine which functionalities should be recommended for inclusion in new inverters in California.

- The working group should support pilot tests and simulations on the agreed-upon autonomous preset controls to validate the effectiveness of improving efficiency and increasing system reliability through their deployment.

- Once validation and simulations are completed, the working group will submit a report to the CPUC Phase 2 rulemaking (R.11-09-011) that outlines its findings and recommendations. Because these inverter-based functionalities are already widely incorporated into inverters used in Germany, Spain, and Italy, this effort should build on the European experience.

- The CPUC should establish and integrate new inverter requirements in California into procurement programs and interconnection processes as soon as practically possible.

- Share with NIST and IEEE standards committees' operational experience using autonomous systems. This data and operational experience can be used by these organizations to accelerate movement toward developing the necessary standards that will move from autonomous controls to utility real-time monitoring, communications, and control of DG resources.

- The CPUC, in collaboration with the utilities, the Energy Commission, and the California ISO, should determine if tariff changes or regulation modifications are needed to allow PV DG generators to provide distribution-level ancillary services to utility system operators as increased operational communication and control technologies are approved.

Lead: CPUC.

Date Complete:

- New inverter requirements should be incorporated into California procurement programs and interconnection processes by December 2014.

- By the end of 2015, PV DG generators should be able to provide ancillary services to the California ISO.

Recommendations – Grid-Level Integration

16. Develop a Forward Procurement Mechanism

To ensure sufficient flexible capacity to integrate intermittent renewable resources, the state should develop a forward procurement mechanism for three to five years ahead. A multiyear mechanism is necessary to provide sufficient revenue streams to ensure that flexible capacity resources are available when needed. This mechanism should identify necessary attributes and be designed so that all resources – demand response (DR), energy storage, and distributed technologies, as well as natural gas power plants – are allowed to compete on a level playing field with appropriate consideration of the loading order and cost-effectiveness. The mechanism should use competitive solicitations to foster innovation and lower costs to consumers. Also, the mechanism should complement the CPUC's existing LTPP process for new capacity.

Actions/Implementation Steps:

- By early 2013, the CPUC should consider opening a new proceeding (or use its existing Resource

Adequacy Rulemaking [R-11-10-023]) to allow utilities to participate in such a procurement mechanism.

- Either the CPUC or the California ISO could develop such a procurement mechanism, but at this time California needs a timely solution to address shortcomings in its wholesale markets. It is time for the stakeholders to develop a consensus of possible solutions and then work through the appropriate institutional roles.

Lead: CPUC and California ISO.

Date Complete: By the end of 2014.

17. Define Clear Tariffs, Rules, and Performance Requirements for Integration Services

To fully leverage automated demand response, energy storage, and other distributed technologies in providing renewable integration services, the state should establish a forward procurement mechanism that allows all technologies to participate. In addition to encouraging third-party aggregators, designing metering and telemetry requirements, speed of response, and other participation rules to accommodate the unique features of auto-DR, energy storage, and other distributed technologies will be essential to achieving their participation in integrating renewables.

Actions/Implementation Steps:
To allow direct participation for all technologies:

- By late 2013, the CPUC should release a decision in R. 07-01-041 authorizing third-party aggregators for all types of DR, energy storage, and other distributed technologies to participate in California ISO wholesale energy and ancillary services markets.

- By late 2014 (within a year from a CPUC decision on third-party aggregators), the California ISO should conduct a stakeholder process and have final tariffs and rules for energy storage participation in ancillary services markets to submit to FERC for approval.

An interim step to allow storage to participate as DR:

- By early 2013, the CPUC should amend its earlier decision in A-11-03-001 and authorize third-party aggregators for projects that are permanent load-shifting storage.

- By early 2014 (within a year from a final decision in the CPUC decision on energy storage as permanent load shifting), the California ISO should have final tariffs and rules allowing for permanent load shifting energy storage participation as DR in energy and ancillary services markets to submit to FERC for approval.

To develop a comprehensive package of tariffs, rules and protocols for renewable integration:

- By early 2014, the CPUC should implement rules for determining technology-neutral resource adequacy valuation methods for all distributed resources.

- By early 2014, the California ISO should identify and propose a plan to eliminate barriers to ensure that all resources capable of providing flexible resource adequacy capacity may participate in the California ISO's wholesale energy and ancillary services markets.

- By the end of 2014, the tariffs, rules, products, and protocols necessary to establish this procurement mechanism should be ready for adoption.

Lead: CPUC and California ISO.

Date Complete: By the end of 2014.

18. Provide Regional Solutions to Renewable Integration

To take advantage of near-term, low-cost renewable integration solutions throughout the West, California needs to promote regional efforts to expand subhourly dispatch and intrahour scheduling, promote dynamic transfers between balancing authorities, improve reserves management, access greater flexibility in the dispatch of existing generating plants, and improve wind and solar forecasting.

Actions/Implementation Steps:

- Promote expansion of subhourly dispatch and intrahourly scheduling and foster standardization of intrahourly scheduling among Western balancing authorities.

- Conduct an energy imbalance market (EIM) study to identify opportunities for dispatching generation and transmission resources across balancing authorities within California, including investor-owned utilities, publicly owned utilities, and the California ISO, to take advantage of the full diversity of load and generation. An EIM could increase the efficiency and flexibility of system operations to integrate higher levels of wind and solar resources and to provide reliability benefits by coordinated balancing across the state.

- Participate in regional efforts to explore the costs and benefits of regulated utilities participating in EIMs, such as the proposal to use the California ISO software, or some adaptation of it, to explore EIM opportunities in the West. Studies are underway to explore EIM use in Nevada, parts of which are now a member of the California ISO, and by the NorthWest Power Pool.

- Commission an independent evaluation of the costs, benefits, and impacts of extended pilots on the need for reserves (especially for regulation) as well as the estimated equipment and labor costs of transitioning to subhourly dispatch and intrahourly scheduling.

- Complete transmission provider calculations of dynamic transfer limits to help identify which lines are most restrictive for dynamic transfers and determine the priority for transmission system improvements to alleviate restrictions on dynamic transfers.

- Request the Western Electricity Coordinating Council (WECC) Variable Generation Subcommittee to analyze dynamic reserve methods to help with wind and solar integration and equip more existing conventional generating facilities with automatic generation control.

- Participate in the United States Department of Energy and Western Area Power Authority (WAPA) initiative "Defining the Future" to identify ways to transition to a more resilient and flexible grid that will increase coordination among system operators and take advantage of clean energy resources in the West.

- Analyze the potential for retrofitting existing, less-flexible generating facilities and develop appropriate incentives or market mechanisms to encourage generating plant owners to invest in increased flexibility.

- Support government and private industry efforts to improve the foundational models and data that are incorporated into variable generation forecasting models and encourage the expanded use of variable generation forecasting by balancing authorities.

Lead: California ISO should work with a regional entity such as the WECC, the Western Interstate Energy Board, or the Western Governors' Association.

Date Complete: By the end of 2014.

19. Ensure Adequate Natural Gas Pipeline Infrastructure

To ensure that natural gas power plants can be called on when necessary to integrate renewable resources, the Energy Commission and the CPUC will need to work with FERC to ensure adequate natural gas pipeline infrastructure and to better align electricity and natural gas markets.

Actions/Implementation Steps:

- Monitor (and participate in, if necessary) FERC proceedings in which natural gas pipeline owners/operators are seeking to abandon or reduce delivery capacity to California.

- Monitor natural gas supply and pipeline development activities throughout the country and internationally that can impact the availability and deliverability of natural gas to California.

- Monitor (and participate in, if necessary) FERC proceedings dealing with natural gas-electricity harmonization issues. California should support efforts and help identify solutions that will allow the two industries to better coordinate operations.

- Participate in a regional study initiated in October 2012 by the Western Interstate Energy Board and Western Governors' Association to examine critical interactions between the electricity and natural gas systems related to the deliverability and potential vulnerabilities of providing adequate natural gas supplies for electricity generation in the West.

Lead: Energy Commission and CPUC.

Date Complete: By the end of 2014.

Strategy 4: Economic Development With Renewable Energy

Promote incentives for renewable technologies and development projects that create in-state jobs and support in-state industries, including manufacturing and construction. In implementing this strategy, the state should evaluate how current renewable energy policies and programs are affecting in-state job growth and economic activity and identify which renewable technologies rely on supply chains that provide the best opportunities for California businesses and create high-wage jobs for California residents.

Challenges and Opportunities

- Further work is necessary to ensure that a well-trained workforce is available to support California's renewable policy goals. As investment in the clean economy continues to expand, there is a need for a coordinated approach to workforce training at the state and local levels that is closely aligned with economic development planning and labor demand. Although there are a number of workforce training programs in place, some have low placement rates. This is partly due to slower than anticipated growth in DG, renewable energy project delays, and employer hesitation to hire in this fragile economy, but stakeholder feedback also indicates the need for programs to be more closely aligned with industry needs.

- Expiration of federal stimulus funding for workforce development may make it difficult for community colleges, labor unions, trade associations, and other training providers to continue their clean energy training curricula in the future.

- Disadvantaged communities have suffered disproportionately from the negative effects of electricity generation but have not yet seen concrete benefits from the clean energy economy.

- It is difficult for innovators and entrepreneurs to manufacture cost-effectively in California. However, recent experience in the wind industry indicates that under the right circumstances, companies building projects in California will buy components from California manufacturers.

Recommendations

20. Better Align Workforce Training to Needs

The California Workforce Investment Board (CWIB) should create strategic workforce partnerships among state energy, labor, and education agencies and foster capacity building to ensure that training meets industry needs for the deployment of current and innovative renewable technologies.[95] An area of emphasis should be on creating pathways to utility jobs, including meeting the current need for skilled electrical workers. A successful model is the clean energy partnership academies established by Senate Bill X1 1 (Steinberg, Chapter 2, Statutes of 2011). The program, which serves primarily at-risk students, focuses on preparing 9–12 grade students for careers in energy and water conservation, renewable energy, pollution reduction, and similar technologies.

Actions/Implementation Steps:

- CWIB, through its Green Collar Jobs Council,[96] in consultation with the Energy Commission, the EDD, the CPUC, the ARB, the Department of Industrial Relations, the Employment Training Panel, the Department of Education, the Governor's Office of Business and Economic Development (GO-Biz), and the Community Colleges Chancellor's Office should develop policy guidance and strategies to provide ongoing technical assistance to education and training providers to help them incorporate new energy technologies, policies, and standards into their programs and curricula. With CWIB direction, EDD should develop necessary guidance and administrative support for the activities listed above.

- As part of this effort, CWIB, in consultation with the Energy Commission, the EDD, the CPUC, the ARB, the Department of Industrial Relations, Division of Apprenticeship Standards, the Employment Training Panel, the Department of Education, GO-Biz, and the Chancellor's Office, should work with providers to ensure quality standards and industry value of any renewable energy certification programs.

- The Energy Commission and CWIB should enter into a Memorandum of Understanding to formalize these roles and responsibilities. In addition, the agencies identified above should establish an interagency work group to perform the staff work necessary to develop guidance and strategies.

Lead: CWIB, Labor Workforce Development Agency, Division of Apprenticeship Standards, and EDD.

Date Complete: Ongoing.

21. Enhance Linkage Between Clean Energy Policies, Workforce, and Employers

Create a clearinghouse for clean energy workforce and economic development to strengthen links between education, training, labor organizations, and employers, placing a priority on communities with high unemployment. A primary goal of the clearinghouse is building connections between the workforce, education providers, and industry to ensure that industry

95 95 *Capacity building* generally refers to a process to increase the skills, infrastructure, and resources of individuals, organizations, and communities.

96 http://www.cwib.ca.gov/sc_green_collar_jobs_council.htm.

needs are met and to provide high-wage career pathways for clean energy jobs. Also, the clearinghouse should develop, recommend, and support policies and programs that allow inner-city disadvantaged youth, impoverished rural communities, low-wage workers, long-term unemployed workers, and veterans to participate in the clean energy workforce.

Actions/Implementation Steps:

- Collaborate with energy, organized labor, and education agencies at both the state and federal levels as well as with utilities, industry, and other stakeholders to develop the clearinghouse. This clearinghouse will provide research and technical assistance on best practices and policy analysis for clean energy occupations. The agencies will work closely with renewable energy employers, labor, utilities, and industry associations to identify and address workforce needs and participate in job forums coordinated by the clearinghouse.

- Procure research and technical assistance services to conduct regional based analysis regarding key barriers and strategic opportunities regarding the workforce needs of California's clean energy industry sectors.

- Support upgrades to and promote awareness of the EDD CalJobs/labor exchange system. Upgrades should include a comprehensive listing of California clean energy jobs that highlights opportunities in areas of the state with high unemployment.

- To accomplish these actions, the agencies should identify potential funding sources and the estimated funding needed to launch the clearinghouse. The Energy Commission will collaborate with the other lead agencies to secure funding and develop a solicitation for establishing the clearinghouse.

Lead: CWIB, EDD, Energy Commission, CPUC, local workforce investment boards, California Community Colleges Chancellor's Office, Department of Education, UC and CSU systems, and Division of Apprenticeship Standards.

Date Complete: 2013–2014.

22. Support the Innovation Hub (iHub) Initiative at the Governor's Office of Business and Economic Development

Under the leadership of Go-Biz, the Energy Commission will provide the state's 12 regional iHubs with the information and assistance each needs to discover, launch, and scale innovative renewable energy technologies in California.

Actions/Implementation Steps:

Go-Biz should lead the following activities with support from the Energy Commission:

- Survey the state's 12 regional iHubs to determine their level of interest and expertise in renewable energy technologies, need for information, and interest in collaboration. Share the information obtained from the initial iHub survey throughout the network.

- Identify other entities such as manufacturers, project manufacturers and developers, venture capitalists, economic development agencies, colleges and universities, workforce developers, disadvantaged communities, and economically depressed communities that want to be part of an information-sharing, capacity-building network.

- Regularly consult with the iHubs and others and conduct regular roundtables, conference calls, and webinars for network members.

- Identify and consider implementing best practices to support innovative technology development that have been tested in other states. For example, the New York State Energy Research and Development Authority's (NYSERDA) Clean Energy Business Incubator

Program[97] makes executive-level mentoring available to early stage clean energy companies[98] and conducts hands-on workshops to help technology innovators analyze technology, market, and business considerations before entering the pre-seed or funding stage.[99]

- Provide information and technical assistance to iHubs and others as requested.

Lead: GO-Biz.

Date Complete: By the end of 2013.

Strategy 5: Research and Development and Financing

Promote and coordinate existing state and federal financing and incentive programs for critical stages including research, development, and demonstration; precommercialization; and deployment. In particular, the state should maximize the use of federal cash grants and loan guarantee programs by prioritizing the permitting and interconnection of California-based renewable energy projects (and their associated transmission or distribution infrastructure) vying for federal stimulus funds.

97 Clean Energy States Alliance Announces Winners of 2012 State Leadership in Clean Energy Awards, press release, http://www.cleanenergystates.org/about-us/news/newsitem/cesa-announces-winners-of-2012-state-leadership-in-clean-energy-awards, October 15, 2012.

98 NYSERDA's Entrepreneurs-in-Residence programs http://www.htr.org/nyserda_entrepreneurs_in_residence_program.asp.

99 NYSERDA's Pre-Seed Workshop, http://www.psw-ny.com/about.php.

Challenges and Opportunities – Research and Development

- High overall system cost, including installation and maintenance costs, remains one of the major barriers to widespread use and commercialization of renewable energy technologies. Existing and innovative renewable energy technologies are also challenged by issues related to reliability, maintainability, and durability.

- Several studies and analyses have demonstrated potential synergistic benefits of co-located technologies. These benefits include addressing intermittency, reducing transmission requirements, and reducing costs associated with permitting, environmental impact mitigation, installation, power production coordination, and operation.[100] Further work is needed to implement results of the studies and analysis, identify opportunities, investigate integration and operational challenges, and demonstrate the benefits.

- Broadening the portfolio of renewable energy technologies will better position California to increase renewable resources beyond 33 percent of the state's electricity mix. Advancements in innovative technologies can help the state meet its clean energy policy goals. However, there is little financial incentive for private companies to invest in research and develop-

100 Example studies include: (1) Glassley, W.; Kleissl, J., van Dam, C.P. (2011), *California Renewable Energy Forecasting, Resource Data and Mapping*, Appendix C: Identification of Areas within the Los Angeles Basin and Salton Sea Trough with Potential for Integrated Renewable Energy Projects, Part 1. Regents of the University of California: Basic Ordering Agreement, Contract Number 500-99-013, BOA-99-248-R. (Unpublished Contractor Report) and (2) Stoutenburg, E.D. and Jacobson, M. Z. (2011), *Reducing Offshore Transmission Requirements By Combining Offshore Wind And Wave Farms*, Peer-Reviewed Technical Communication, IEEE Journal Of Oceanic Engineering, http://ieeexplore.ieee.org/xpls/abs_all.jsp?arnumber=6032718&tag=1.

ment (R&D) for innovative technologies that are most beneficial to society because there is no certainty of return on their investment.

- The intermittency of many renewable resources results in widely variable electricity generation; such high intermittency can cause major problems for grid operators, including potentially costly outages.

- Locating facilities in sensitive areas has resulted in costly delays and uncertainty in the environmental review and permitting process. Little information is available on environmental baselines and specific effects on many habitats and species in areas where projects will be developed. Methods to evaluate potential environmental consequences from certain developments are not well-considered, and it can be time-intensive and costly to perform the extensive environmental surveys and scientific studies to gather the information needed to determine environmental baselines and assess impacts. Also, mitigation techniques for species and habitat effects associated with renewable development remain largely untested and suitable compensation land acreage can be difficult to acquire. An example of an advancing technology for which there is little information on potential environmental impacts is offshore wind.

Challenges and Opportunities – Financing

- New technologies and strategies often do not have the performance data needed to attract venture capital investment. Seed funding is necessary for demonstration, deployment, and market facilitation and to generate publicly available performance data.

- Lack of funding during early stages of project development can affect the success of a renewable project. During the later stage of early commercial development, significant capital is needed to finance projects and demonstrate the viability of a project at scale. The high risk for return on investment in both of these precommercialization phases deters private investment.

- Renewable development financing goes through boom-and-bust financing cycles largely due to uncertain and sporadic federal and state financing incentives. The state has tremendous innovation and business capacities that require sustained initiatives to reap the full benefits of the entire renewable supply chain.

Recommendations – Research and Development

23. Advance R&D for Existing and Co-located Renewable Technologies

Public research funding should support R&D to improve existing renewable energy technologies and infrastructure. R&D activities should include, but not be limited to, initiatives that reduce installation and maintenance costs and improve reliability, maintainability, durability, efficiency, and overall performance. Some potential research areas that can reduce costs include development of methods and technologies that will make cost-effective environmental compliance and permitting easier; improvements in materials, manufacturing, and installation strategies; improved locations and operations; and controls and integration technologies.

Research should develop ways to expand installed generation capacity and advance various existing generation and enabling technologies for solar, biomass, wind, geothermal, and small hydro. As discussed in the *2012 Bioenergy Action Plan,*,[101] R&D on biomass energy should include the development

101 O'Neill, Garry. 2012. *2012 Bioenergy Action Plan*. California Energy Commission, http://www.energy.ca.gov/bioenergy_action_plan/.

of community-scale bioenergy facilities; address challenges to developing anaerobic digesters in dairy and other animal facilities, wastewater treatment facilities, and other processing facilities that generate sufficient organic wastes; environmental impact assessment, mitigation, and performance improvements of thermochemical conversion technologies; and barriers to biomethane use including biogas quality, biogas cleanup technology, and standards. R&D efforts should also enhance the capability for synergistic combination of renewable technologies as an option for sites and regions that have the potential for co-located resources and that can promote development of localized hybrid or multiple energy technology installations. Further, the Energy Commission will continue working with other agencies, stakeholders, universities, and private institutions to coordinate R&D efforts aimed at improving existing renewable energy technologies.

Actions/Implementation Steps:

- Research proposals should be evaluated through a publicly vetted process. Also, the state should leverage cofunding opportunities and collaborate with its state, federal, university, and other partners to ensure that R&D efforts funded by the state do not duplicate other efforts.

- The Energy Commission will publish research results on its website and make the information available to renewable energy technology developers, generators, integration service providers, grid system operators, regulatory agencies, policy makers, and research groups as appropriate for implementation or follow-up activities.

Lead: Energy Commission.

Date Complete: Ongoing.

24. Advance R&D for Innovative Renewable Technologies

Public research funding should support and provide funding for R&D that will advance innovative renewable energy technologies and provide an avenue for bringing those technologies closer to commercialization. This recommendation includes support to applied R&D projects that will assess the potential of renewable energy technologies on the horizon to contribute to the state RPS goals. Projects should also provide data and tools to advance the development and support market facilitation of these innovative renewable energy technologies. The recommendation also supports creating opportunities for research, development, and demonstration initiatives to verify technical, economic, and environmental performance of innovative technologies and several capacity and market scales. Advanced technologies in the area of biomass conversion, offshore wind, concentrating solar power and other solar technologies, small hydro, geothermal, and renewable energy integration and controls are among those that could potentially be supported under this recommendation.

Actions/Implementation Steps:

- Research proposals should be evaluated through a publicly vetted process. Also, the state should leverage cofunding opportunities and collaborate with its state, federal, university, and other partners to ensure that R&D efforts funded by the state do not duplicate other efforts.

- The Energy Commission will publish research results on its website and make the information available to renewable energy technology developers, generators, integration service providers, grid system operators, regulatory agencies, policy makers, and research groups as appropriate for implementation or follow-up activities.

Lead: Energy Commission.

Date Complete: Ongoing.

25. Promote R&D for Renewable Integration

R&D activities to better integrate intermittent generation into the grid should be continued to account for increasing solar, wind, and other renewable energy generation. Research should include improvement of forecasting capabilities and models for solar and wind, existing grid technologies, grid flexibility, expansion of smart grid technologies, and development of microgrids. Research should also address technology advancements that can firm intermittent renewables, including energy storage, generation technologies with multiple fuel capabilities, and co-locating renewable resources to develop cost-effective options for controllable renewable generation.

Actions/Implementation Steps:

- Research proposals should be evaluated through a publicly vetted process. Also, the state should leverage cofunding opportunities and collaborate with its state, federal, university, and other partners to ensure that R&D efforts funded by the state do not duplicate other efforts.

- The Energy Commission will publish research results on its website and make the information available to renewable energy technology developers, generators, integration service providers, grid system operators, regulatory agencies, policy makers, and research groups as appropriate for implementation or follow-up activities.

Lead: Energy Commission.

Date Complete: Ongoing.

26. Support R&D for Proactive Siting of Renewable Projects

Public research funding should be increased for applied R&D to reduce, resolve, and anticipate environmental barriers to renewable energy deployment in California. R&D should focus on new technology designs, scientific studies, and decision-support tools for proactive siting to avoid impacts to environmentally sensitive areas and permitting delays. Environmental analysis should support identification of preferred areas for renewable development such as in the San Joaquin Valley. Also, methods should be developed, evaluated, and implemented to determine proactively potential environmental consequences prior to full-scale deployment of offshore wind. The Energy Commission will continue to work with other agencies and stakeholders involved in environmental impact assessment and mitigation to determine critical research needs and leverage research funds and expertise when possible.

Actions/Implementation Steps:

- Research proposals should be evaluated through a publicly vetted process. Also, the state should leverage cofunding opportunities and collaborate with its state, federal, university, and other partners to ensure that R&D efforts funded by the state do not duplicate other efforts.

- The Energy Commission will publish research results on its website and make the information available to renewable energy technology developers, generators, integration service providers, grid system operators, regulatory agencies, policy makers, and research groups as appropriate for implementation or follow-up activities.

Lead: Energy Commission.

Date Complete: Ongoing.

Recommendations – Financing

27. Create an Interagency Clean Energy Financing Working Group

Create an interagency working group of agencies involved in clean energy financing to improve coordination and leveraging of existing clean energy financing

programs, better leverage private capital, increase public awareness of financing options, and consider new financing programs. The working group should include GO-Biz, the California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA), the California Pollution Control Financing Authority (CPCFA), the Energy Commission, the CPUC, the ARB, the California Public Employees Retirement System (CalPERS), the California State Teachers Retirement System (CalSTRS), and other applicable state financing entities.

Actions/Implementation Steps:

- Under the leadership of GO-Biz, entities including CAEATFA, CPCFA, the Energy Commission, CPUC, ARB, CalPERS, CalSTRS, and other applicable state financing authorities should enter into a memorandum of understanding to form an interagency working group to promote financing opportunities for renewable energy development in California.

- The interagency financing working group should assess the current suite of financing programs, consumer and industry access, and awareness of existing financing programs. The working group should explore opportunities to leverage private capital as well as potential funding sources for financing programs including cap-and-trade auction revenues. Also, each organization should assess its current regulatory and statutory authority related to financing to identify opportunities to advance existing or new renewable energy financing products. The working group should meet regularly to exchange information about programs, propose modifications to existing programs to enhance their effectiveness, and consider development of new programs as necessary.

- The working group should collaborate with the CPUC to build upon the CPUC's and investor-owned utilities' experience in ongoing efforts to develop, design, and implement new energy efficiency financing products.[102]

Lead: GO-Biz.

Date Complete: Ongoing.

28. Support Extension of Federal Tax Credits

The state should support federal legislation that would allow a long-term extension of federal tax credits for renewables. The tax credit programs are critical to project delivery, job creation, business attraction, and deployment of innovative technologies. The Investment Tax Credit, the Production Tax Credit, and the Manufacturing Tax Credit (48[C]) are valuable tools in financing renewables in California. Federal tax credits have been critical to helping the state attract new companies, develop renewable projects, and meet renewable goals. Project developers in California indicate that without these credits, projects would have been scaled back or would not have been developed. Extending existing tax credits and creating new incentives can help move the economy forward while advancing renewable energy and energy efficiency technologies.[103] Toward that end, the American Taxpayer Relief Act of 2012, signed by President Obama in January 2013, includes a one-year extension of the federal Production Tax Credit for certain types of renewable facilities, including wind, geothermal, landfill gas, trash, marine, and hydrokinetic facilities as well as certain closed- and open-loop biomass and hydropower facilities that begin construction before January 1, 2014. However, to provide market certainty for investors, a longer-term approach

102 The financing products are being developed in response to the CPUC's Decision: *Providing Guidance on 2013–2014 Energy Efficiency Portfolios and 2012 Marketing, Education, and Outreach*. Rulemaking 09-11-014, Decision 12-05-015.

103 For example, see Senator Jeff Bingaman's proposal S.3352 on industrial efficiency incentives http://www.govtrack.us/congress/bills/112/s3352.

is needed. According to the American Wind Energy Association, "Uncertain federal policies have caused a 'boom-bust' cycle in U.S. wind energy development for over a decade."[104] For the Investment Tax Credit, the United States Partnership for Renewable Energy Finance noted in its July 2012 report that the credit has enabled financing mechanisms that generate a positive return for the federal government. The report further indicates that these investment structures accounted for more than 63 percent of the residential installations in California in the first quarter of 2012.[105]

Actions/Implementation Steps:

- The Energy Commission and other state agencies should support the Governor's Office's leadership in working with the California Congressional delegation to support federal legislation to extend federal tax credits for a longer term.

Lead: Governor's Office.

Date Complete: Federal legislation 2013–14.

29. Study the Effectiveness and Impacts of the Property Tax Exclusion

The current construction property tax exclusion for solar energy systems is set to expire in 2016. While project developers have identified the property tax exclusion as an important mechanism to reduce project costs, its effects on local government must also be considered. To avoid the boom-and-bust cycles experienced as a result of federal tax credit reauthorization and instead provide greater market certainty, California should conduct a careful evaluation of the effectiveness and impacts of the tax exclusion well in advance of the 2016 expiration date.

Actions/Implementation Steps:

- The Energy Commission, Franchise Tax Board, State Treasurer's Office, California Assessors' Association, and local government stakeholders should assess the effect of Section 73 of the California Revenue and Taxation Code in meeting RPS, DG, and economic development goals.

- The Franchise Tax Board should lead an analysis of potentially expanding the new construction property tax exclusion to other renewable technologies and potentially targeting specific areas identified as prime areas for renewable development as identified through efforts identified in Strategy 1. Any assessment of the benefits of new construction exclusion must also quantify the cost of lost property tax revenues to cities, counties, and education.

- Pending results of the assessment above and by the end of 2013, the Franchise Tax Board should recommend whether to introduce legislation that would reauthorize or potentially otherwise amend Section 73.

Lead: Franchise Tax Board.

Date Complete: By the end of 2013.

30. Modify the Clean Energy Business Financing Program (CEBFP)

The CEBFP is a loan program for eligible clean technology manufacturers that was created under the American Recovery and Reinvestment Act of 2009. A revolving loan fund was created for manufacturers of energy efficiency, renewable energy, and biogas technologies for low-interest loans. The CEBFP needs to be modified to address more current loan terms, update the program, and identify loan management

104 American Wind Energy Association, "Congress extends wind energy tax credits for projects that start in 2013," January 1, 2013, https://www.awea.org/newsroom/pressreleases/congressextendswindptc.cfm.

105 *Paid In Full: An Analysis of the Return to the Federal Taxpayer for Internal Revenue Code Section 48 Solar Energy Investment Tax Credit (ITC)*, US Partnership for Renewable Energy Finance, July 2012

options. About $18 million in loan principal will be received once the current loan portfolio is repaid. By late 2014, sufficient funds should be repaid (approximately $10 million) to allow reopening the program for new applications. The loan principal has the potential to grow in value when managed prudently and can provide a source of funding for commercial companies along the entire renewable supply chain.

Actions/Implementation Steps:

- The Energy Commission will conduct a public workshop on newly proposed CEBFP guidelines to solicit feedback on the program's future development. After receiving public input, the Energy Commission will develop final guidelines to manage and market the CEBFP.

Lead: Energy Commission.

Date Complete: Conduct workshop early 2014.

31. Develop Marketing Outreach Plan for Energy Conservation Assistance Account Programs

The Energy Commission administers the Energy Financing Program, Bright Schools, and Energy Partnerships, which provide low-interest financing and technical assistance primarily to local public entities. These programs are funded by the Energy Conservation Assistance Account. The Energy Financing Program helps local entities achieve energy cost savings, mainly through installation of energy efficiency measures. Few local entities use the Energy Financing Program to finance renewable energy projects due to requirements for energy payback periods that do not accommodate the longer payback periods that are typical of renewable installations. The Bright Schools and Energy Partnership Programs provide technical assistance to local entities to identify cost-effective energy efficiency and renewable opportunities in planned and existing facilities. In general, this technical assistance consists of energy audits, feasibility studies, and reports. The Bright Schools and Energy Partnership Programs reopened in November 2012 after a suspended period due to Energy Commission workload issues associated with American Recovery and Reinvestment Act activities. Using a marketing outreach plan, the Energy Commission will reach out to K-12 public schools and local entities to promote efficiency and renewable opportunities.

Actions/Implementation Steps:

- The Energy Commission will work with the Department of Finance and other stakeholders to explore allowing longer payback periods for loans and offering grants in lieu of loans for the Energy Financing Program. These changes may require legislative action.

- The Energy Commission will work with the Department of Finance, the Department of Education, and other stakeholders to develop and implement a plan to reach out to local entities to market the Bright Schools, Energy Partnership, and Energy Financing Programs with the goal of increasing renewable projects on local public facilities.

- The Energy Commission will monitor and analyze the number of technical assistance applications for renewable projects received through the market outreach plan process.

Lead: Energy Commission.

Date Complete: Develop plan in 2013.

Monitoring and Reporting

Recommendation

32. Evaluate Progress to Plan

Implementing the recommendations within this Renewable Action Plan will require effective and creative leadership, adequate resources, and accountability among all involved participants. To support these objectives and achieve the goals of this plan, it will be essential to monitor and report on progress made on the various actions in the plan to maintain forward momentum and identify and address new or unexpected issues that may arise over time.

Action/Implementation Step:
The Energy Commission proposes to hold an annual workshop under the direction of its Lead Commissioner for Renewables to highlight progress on the Renewable Action Plan and to seek input on changes needed to the plan to reflect the dynamic and changing nature of the renewable electricity market.

Lead: Energy Commission.

Date Complete: Beginning in early 2014 and continuing annually thereafter**.**

As the first step in implementing the strategies identified in the *Renewable Power in California: Status and Issues* report, the Energy Commission held seven public workshops to seek input from experts, stakeholders, and the public on topics related to each strategy. A brief summary of each workshop is provided below.[106]

Identifying and Capturing Benefits From Renewable Generation

This workshop was held on April 12, 2012, and discussed public benefits associated with renewable energy generation, how well existing state and local policies capture those benefits, and suggestions for improvements.

Some of the main points from workshop presentations and discussions include the following:

- Benefits of renewable generation fall into four broad categories: environmental benefits, such as slowing climate change or improving air quality; system benefits, such as deferred transmission and distribution costs and reduced line losses by increasing

BENEFITS WORKSHOP PRESENTERS AND PANELISTS
CAL FIRE
California Air Resources Board
California Center for Sustainable Energy
California County Planning Directors Assoc.
California Environmental Justice Alliance
California Independent System Operator
Clean Coalition
Clean Energy States Alliance
Communities for a Better Environment
E3 Consulting
Independent Energy Producers Assoc.
Los Angeles Dept. of Water & Power
National Renewable Energy Laboratory
Pacific Gas and Electric Company
San Diego Gas & Electric Company
Sempra Utilities
Southern California Edison
U.S. Department of Food and Agriculture
U.S. Environmental Protection Agency
Union of Concerned Scientists
University of California/Berkeley
University of California/Irvine

106 Agendas, presentations, transcripts, and public comments for each workshop are available at http://www.energy.ca.gov/2012_energypolicy/documents/index.html.

distributed generation;[107] economic benefits, such as advancing overall economic growth or creating jobs; and diversity benefits, such as providing a hedge against natural gas price spikes or shortages.[108]

- Discussions of renewable benefits should include electrification of the transportation sector.[109]

- Adding renewables can provide broad air quality benefits but does not necessarily displace local fossil plants. Because power plants that provide local reliability and support the grid must continue to operate, adding renewables locally may actually displace fossil generation located many miles away.[110] Policy makers must also balance the benefits of renewable generation with the need for reliable electricity, particularly the need for flexible generating capacity in local areas.[111]

- Any attempt to quantify the benefits of renewables needs to recognize that all renewable technologies are not alike. Each technology has different attributes, costs, and benefits, depending on technology and location. In addition, as energy markets and the economy change over time, so will the perception of which characteristics are most desirable.

- Decision makers need to be cautious about adding too much complexity to renewable procurement programs in an effort to accommodate every technology.[112]

- It will be very difficult to quantify some renewable benefits with accuracy or precision, so decision makers should not delay moving forward with clean energy policies because benefits and costs aren't fully quantified. The focus should be on quantifying renewable benefits that have limited uncertainty.[113]

- A major challenge is to translate quantitative information into effective and transparent procurement decisions. Several parties suggested incorporating renewable benefits into current procurement processes through adders for specific benefits, including adders to reflect: differences in health impacts; different benefits and costs based on geographic location; the value of converting biomass or biogas waste into a fuel; and displacement of transmission and distribution upgrades.[114] However, others noted that this could lead to developers tailoring their bids based on the adder rather than bidding their actual costs.[115]

- Equity is essential. Ratepayers should not be the sole payers for renewables that provide benefits to the broader population like energy security or economic development. Also, renewable benefits should be distributed fairly throughout society and in particular to communities that have historically suffered disproportionately negative impacts from the use of fossil energy.

107 Written comments submitted by Tom Casten to Docket 11-IEP-1D, March 5, 2012: "Studies by Carnegie Mellon/MIT professor Marija Ilich and her doctoral candidates have shown how to cut line losses in half by generating about 10% of total power with DG, and shown how each megawatt-hour of DG could displace 1.2 to 1.5 MWhs of CG [centrally generated] generation."

108 Transcript of Energy Commission Lead Commissioner Workshop on Evaluating and Capturing Benefits of Renewable Energy for California, April 12, 2012, comments by Warren Leon (Clean Energy States Alliance), pp. 32–33.

109 Ibid, comments by Margaret Mann, National Renewable Energy Laboratory, p. 90; James Nelson, UC Berkeley, p. 92; Laura Wisland, Union of Concerned Scientists, pp. 246–247.

110 Ibid, comments by Arne Olson, Energy and Environmental Economics, pp. 26–27.

111 Ibid, comments by Heather Sanders, California ISO, p. 91.

112 Ibid, comments by Steven Kelly (IEPA), p. 210.

113 Ibid, comments by Warren Leon (Clean Energy States Alliance), p. 67; Steven Kelly (IEPA), p. 208.

114 Ibid, comments by Ben Machol (U.S. EPA), p. 91; Shana Lazerow (Communities for a Better Environment), p. 91; Bill Snyder (CAL FIRE), p. 128; Craig Lewis (Clean Coalition), p. 265.

115 Ibid, comments by Marc Ulrich (SCE), p. 182.

- Energy policies and planning in California are fragmented and need to be better coordinated.[116] Before proposing new policies, the state should consider the costs and benefits of the various programs and mandates already in place. There is also a need for better coordination with local planners and between locals and utilities.

Identifying Priority Geographic Areas for Renewable Development

The May 10, 2012, workshop included three panel discussions on preferred characteristics of priority areas for renewable development, regional strategies to identify priority geographic areas, and development of local goals to build toward the 12,000 MW goal for distributed generation.

Highlights from the workshop include:

- Preferred characteristics: Near existing transmission lines with available capacity should be first priority,[117] followed by mechanically disturbed lands that are no longer supporting natural habitats, including the urban core, brownfields, and land that has been identified as drainage or chemically impaired and no longer suitable for agriculture.[118] Other preferred

116 Ibid, comments by Steve Weissman (UC Berkeley), p. 123–124; Marc Ulrich (SCE), p. 259; Laura Wisland (Union of Concerned Scientists), p. 276; Aaron Johnson (PG&E), p. 278.

117 Transcript of Energy Commission Lead Commissioner Workshop on Identifying Priority Geographic Areas for Renewable Development, May 10, 2012, comments by Noah Long (NRDC), p. 41; comments by Michael Wheeler (Recurrent Energy), pp. 65–66.

118 Ibid, comments by Noah Long (NRDC), p. 40–41.

GEOGRAPHIC AREAS WORKSHOP PRESENTERS AND PANELISTS

Alameda County
Butte County/California County Planning Directors Association
California Environmental Justice Alliance
California Farm Bureau Federation
Center for Energy Efficiency and Renewable Technologies
County of Sonoma
Defenders of Wildlife
Energy and Environmental Economics Inc. (E3)
Environment California
Governor's Office of Planning and Research
Interstate Renewable Energy Council
Inyo County
Los Angeles Dept. of Water and Power
Natural Resources Defense Council
Pacific Environment
Pacific Gas and Electric Company
Recurrent Energy
Sacramento Municipal Utility District
Southern California Edison
U.S. Environmental Protection Agency
UC Berkeley, Center for Law, Energy and the Environment
United States Environmental Protection Agency
United States Navy
Yolo County

areas are those where development can serve other strategic goals like job creation, or "hot spots" where existing generators are being retired and additional local generation is needed.[119] Conversely, pristine or environmentally sensitive sites should be avoided. In particular, a California Farm Bureau Federation representative suggested that Williamson Act land, with the exception of marginally productive or physically impaired land that qualifies for Williamson Act contract rescission under Senate Bill 618 (Wolk, Chapter 596, Statutes of 2011), prime agricultural land, and unique farmland should be excluded from consideration for development. High-quality resource potential is also a key characteristic.[120]

- There was general support for developing overlay maps to identify preferred geographic areas for development, but there was concern that such mapping exercises would create a land rush and artificially inflate property values.[121] Another suggestion was that developing "go, no-go" criteria for preferred areas to develop and for areas that should not be developed would be more politically palatable than developing maps.[122]

- Areas such as West Mojave, Central Valley, and, to some extent, the Imperial Irrigation District are desirable from a policy perspective because they have good resource potential, include already disturbed lands, and suffer from high unemployment. The Westlands Water District is an example of an area with high resource potential, strong developer interest, contaminated land that is no longer useable for agriculture, proximity to existing transmission, and high unemployment. Policy makers must grapple with what additional level of investment should be made to expand transmission access to such areas given that the state is expected to meet its 33 percent RPS target through already approved transmission projects. Consequently, these areas are not being selected through the transmission planning process without an additional policy preference overlay.[123]

- Potential cobenefits of community-scale woody biomass facilities include improved forest and watershed health; forest fire reduction; reduced net carbon emissions through replacement of fossil fuels; and social benefits in rural communities. In addition to the public safety and air quality impacts of forest fires, ratepayers are paying for power outages and infrastructure damage caused by wildfires, as well as for settlement costs from wildfires started by transmission lines.[124] Woody biomass supply correlates well with available transmission infrastructure and with rural areas that are economically depressed.

- There is a disconnect between county planning and utility planning, and better coordination is needed.[125] For example, with better coordination, planning efforts could identify a community's preferred areas for development that are also favorable locations to interconnect on the distribution grid.

- Counties are short-staffed and, in many cases, need additional funding to be able to use the land-use planning tools already developed and available to them. Developing overlay maps was estimated to cost a

119 Ibid, comments by Jeffrey Russell (UC Berkeley), p. 76.

120 Ibid, comments by Ryan Drobek (CEERT), p. 60.

121 Ibid, comments by Michael Wheeler (Recurrent Energy), p. 69; John Gamper (California Farm Bureau), p. 148; Ethan Elkind (UC Berkeley), p. 176.

122 Ibid, comments by Ethan Elkind (UC Berkeley), p. 181.

123 Ibid, comments by Noah Long (NRDC), pp. 41–42; comments by Daniel Kim (Westlands Water District), pp. 110–112; comments by Chair Robert Weisenmiller (Energy Commission), p. 45; Randy Howard (LADWP), p. 37.

124 Ibid, comments by Christine Nota (U.S. Forest Service), pp. 85–86.

125 Ibid, comments by Noah Long (NRDC), p. 97; Jeffrey Russell (UC Berkeley), p. 98.

county on the order of $100,000 to $250,000. Counties also need access to information to develop overlays and land-use plans along with statewide sharing of information on wildlife and environmental concerns.[126] More consistent siting criteria in counties throughout the state would help reduce permitting costs.[127]

- A regional, comprehensive environmental analysis – something like the DRECP process but not necessarily as extensive – will help expedite the permitting process, preserve sensitive habitat, identify mitigation opportunities, and address cumulative impacts that are difficult to identify in a piecemeal permitting process.[128]

- The Energy Commission staff proposed a method for developing regional "soft targets" for installing 12,000 MW DG by 2020 statewide. The proposal puts forward county-specific targets weighted by a county's relative share of electricity consumption, number of low- and moderate-income households, and number of unemployed workers. The California Environmental Justice Alliance representative suggested that another consideration to include is the Environmental Justice Screening Methodology, which identifies areas of high cumulative impact from pollution sources and high social vulnerability. There was general agreement that the targets should remain "soft."

126 Ibid, comments by Noah Long (NRDC), p. 43.

127 Ibid, comments by Michael Wheeler (Recurrent Energy), p. 70.

128 Ibid, comments by Kim Delfino (Defenders of Wildlife), pp. 155–156.

Interconnection of Renewable Projects in California

This workshop, held on May 14, 2012, discussed transmission planning scenarios, generator interconnection processes at the transmission and distribution system levels, and near-term tools and approaches to address interconnection challenges.

Highlights of the workshop include the following:

- The CPUC and Energy Commission have jointly proposed four renewable resource portfolios for use in the California ISO's 2012–2013 transmission planning process. Several parties expressed concern about using a cost-constrained portfolio as the base case and argued for using the portfolio that gives preference to projects with executed power purchase agreements and completed applications for environmental permits.[129] Other parties expressed concern about insufficient involvement of stakeholders in developing and vetting the resource scenarios.[130]

- There was general agreement about the importance of reducing the number of renewable projects in the California ISO's interconnection queue to reduce costly delays to developers as well as increased costs to consumers from overbuilding transmission for projects in excess of what is needed to meet the 33 percent RPS target. Utilities also cited resource concerns with the additional engineering staff needed

129 Transcript of the Energy Commission Lead Commissioner Workshop on Interconnection of Renewable Projects in California, May 14, 2012, comments by Carl Silsbee (SCE), p. 72 ; Jason Yan (PG&E), p.78 ; Kristin Burford (Large Solar Association), p. 141; Chris Ellison (Pathfinder LLC/Zephyr LLC), p. 142 ; V. John White (CEERT), p. 291.

130 Ibid, comments by David Miller (CEERT), p. 102–103.

INTERCONNECTION WORKSHOP PRESENTERS AND PANELISTS
BrightSource Energy
California Independent System Operator
California Institute for Energy and Environment
California Municipal Utilities Assoc.
California Public Utilities Commission
Center for Energy Efficiency and Renewable Technologies
Clean Coalition
DNV and Associates
Electric Power Research Institute
Imperial Irrigation District
Large Solar Association
National Renewable Energy Laboratory
New Power Technology
Pacific Gas and Electric Company
Pathfinder/Zephyr
Sacramento Municipal Utility Association
San Diego Gas & Electric Company
Silverado Power
Southern California Edison
United States Navy

to conduct interconnection studies and process interconnection requests.[131] Many parties acknowledged that integrating the transmission planning and interconnection processes will reduce the size of the queue. Others suggested strategies such as an economic ranking process with only the most cost-effective projects moving forward.[132]

- Most parties agreed that much progress has been made in improving interconnection at the distribution level as a result of the CPUC's Rule 21 tariff reform. Utilities' stated objective was to make interconnection fast, accurate, and fair while appropriately considering customer costs and reliability, which will be increasingly challenging as DG penetration increases.[133] Several parties expressed a need for additional studies on the screens used to determine whether projects can be fast-tracked, particularly the screen that requires additional studies if PV interconnected to a circuit exceeds 15 percent of peak load on that circuit.[134]

- There is a need for more granular data about PV performance in the field and about the operation of the distribution system itself, as well as connection between models of the transmission and distribution systems to fully understand the effects of increased PV penetration on individual circuits and on the system as a whole.[135] Studies are underway to identify data gaps, add monitoring equipment, and look at individual and combined impacts of actual projects based on current data.[136] Another study is being explored to work with utilities to add 25 percent or more penetration of DG at a single substation that is balanced with storage, demand response, and curtailment.[137] Parties noted the need for improved sharing of results of current research activities.

131 Ibid, comments by David Berndt (SCE), p. 171; Valerie Winn (PG&E), p. 182.

132 Ibid, comments by Tony Braun (California Municipal Utilities Association), p. 95.

133 Ibid, comments by David Berndt (SCE), p. 222; Valerie Winn (PG&E), p. 223.

134 Ibid, comments by Michael Coddington (NREL), pp. 213–214.

135 Ibid, comments by Peter Evans (New Power Technology), p. 237; Dr. Sasha Von Meier (California Institute for Energy and Environment), p. 242.

136 Ibid, presentation by Dr. Sasha Von Meier (California Institute for Energy and Environment), p. 242–249.

137 Ibid, comments by Craig Lewis (Clean Coalition), pp. 259–260.

Renewable Energy Costs and Retail Rate Impacts

The May 22, 2012, workshop discussed renewable cost estimates, projections, and key drivers; how costs are considered in renewable procurement; and rate design issues including cost considerations and using rate design to address cost impacts.

Main points from workshop presentations and discussions include the following:

- It is essential that renewable cost studies are transparent about the assumptions used so that policy makers can compare different studies, recognize the key cost drivers in each study, and understand which variables they can influence to push costs toward the lower end of the ranges.[138]

- Utilities noted that renewable procurement is based not just on cost but on the total value of the project.[139] Value, however, appears to mean something different depending on one's perspective. Utilities and the California Public Utilities Commission characterized value as how well a project meets the needs of the utility portfolio (baseload, peaking, when a project will come on-line);[140] others described value as elements like resource diversity, fossil fuel displacement, reduced greenhouse gas emissions, or capturing other cobenefits.[141]

- While cost-effectiveness remains a paramount consideration, cost-containment strategies can be problematic given that cost caps may be interpreted by the market as a price floor rather than a ceiling. Cost-containment mechanisms appear to work best when they are used as a release valve on policy stringency when costs are higher than expected.[142] It was also noted that when implementing cost containment, clarity, stability, and ease of administration are key elements.[143]

COST/RETAIL RATE WORKSHOP PRESENTERS AND PANELISTS
Aspen Environmental Group
Black & Veatch
California Public Utilities Commission
Climate Policy Initiative
CPUC Division of Ratepayer Advocates
Greenlining
Los Angeles Department of Water & Power
Pacific Gas and Electric Company
Sacramento Municipal Utility District
San Diego Gas & Electric
Southern California Edison
University of California Energy Institute

138 Transcript of Energy Commission Lead Commissioner Workshop on Renewable Energy Costs and Retail Rate Impacts, May 22, 2012, comments by Dr. Richard McCann (Aspen Environmental Group), p. 27.

139 Ibid, comments by Carl Silsbee (SCE), p. 71; David Lewis (PG&E), p. 77; William Walsh (SCE), p. 79.

140 Ibid, comments by William Walsh (SCE), p. 80; Jim Tracy (Sacramento Municipal Utility Association), p. 81; Jason Simon (CPUC), p. 86.

141 Ibid, comments by Dr. Richard McCann (Aspen Environmental Group), p. 30.

142 Ibid, comments by Brendan Pierpont (Climate Policy Initiative), p. 87.

143 Ibid, comments by Valerie Winn (PG&E), pp. 127–128.

- The renewable market appears to be becoming increasingly competitive, with increased numbers of responses to solicitations and a general trend of decreased costs, but some parties noted it is impossible to tell if that trend will continue because there is still too much uncertainty in the market.[144] Other parties noted that the mandate to purchase renewable energy makes the market a seller's market.

- Utilities and some other parties indicated they would like to see integration costs considered in utility valuations to help quantify differences between technologies, for example between solar photovoltaic and solar thermal facilities.[145]

- California's current rate design – in which the per kilowatt hour rate increases as electricity consumption rises – is disconnected from the actual cost of providing service. As a result, any cost increases as a result of the 33 percent Renewables Portfolio Standard (RPS) mandate will likely fall on those already paying the highest rates.[146] Conversely, utilities suggested that the costs associated with net energy metering (NEM) programs are borne disproportionately by those in the lower tiers.[147] Some parties suggested that California needs to address rate design to spread any new costs to customers equitably;[148] others emphasized that not all customers are energy savvy enough to take advantage of complex rate designs.[149] Moreover, renewable policies are not the only cause of rate pressure; other factors like distribution and infrastructure upgrades and safety investment also drive rate increases.

- It is unclear at this time what the rate impacts of California's renewable energy policies will be, but parties suggested that rates will continue to rise over time as contracted projects are built and begin generating[150] and as utilities make new investments in both renewable and fossil fuel projects. One utility suggested that rates could go even higher if natural gas prices go up, since for many utilities natural gas prices have more impact on rates than renewables.[151]

Jobs and Renewable Energy

The workshop on jobs and renewable energy held on May 30, 2012, discussed methods to quantify renewable energy jobs, the effectiveness of current workforce training programs, the benefits of coordinating training with local economic development activities, California's competitive advantages and disadvantages in creating renewable energy jobs, and strategies used in other states.

Highlights of the workshop include the following:

- Many clean energy policies and programs were in large part established before the economic recession and were not specifically designed to create jobs. Efforts to measure job effects from renewable energy development may therefore be premature since it is not clear what California's job creation goals are and whether those goals should influence program design or continuation.[152]

144 Ibid, comments by David Lewis (PG&E), pp. 89–90; William Walsh (SCE), pp. 92–93.

145 Ibid, comments by William Walsh (SCE), p. 100.

146 Ibid, comments by Amrit Singh (PG&E), p. 150.

147 Ibid, comments by Tom Brill (SDG&E), p. 159

148 Ibid, comments by Amrit Singh (PG&E), pp. 151–152.

149 Ibid, comments by Stephanie Chen (Greenlining), p. 201.

150 Ibid, comments by Chloe Lukins (Division of Ratepayer Advocates), p. 184.

151 Ibid, comments by Jim Tracy (SMUD), pp. 210–211.

152 Transcript of Energy Commission Lead Commissioner Workshop on Jobs and Renewable Energy, May 30, 2012, comments by Dr. Carol Zabin (UC Berkeley), pp. 38–39.

JOBS WORKSHOP PRESENTERS AND PANELISTS
California Environmental Justice Alliance
California Environmental Protection Agency
California Labor Federation
California Public Utilities Commission
California Senate Office of Oversight and Outcomes
California Workforce Investment Board
Center for Energy Efficiency and Renewable Technologies
Clean Energy Group
College of the Desert
Communities for a Better Environment
Environmental Health Coalition
enXco
Gossamer Innovations
Governor's Office of Business and Economic Development
Kern Economic Development Corporation
MRG & Associates
National Renewable Energy Laboratory
Optony, Inc.
Resources for the Future
Sacramento Metropolitan Utility District
San Bernardino Community College District
Sierra Nevada Conservancy
Solar City
University of California Berkeley

- Policy makers need to clearly understand assumptions used in models to estimate job creation and economic impacts of renewable energy. In addition, models need the ability to include long-term effects that are unforeseen but could be major game changers.[153]

- Several parties suggested that energy agencies can provide the most value by setting standards for job training, skill needs, and work quality to send clear signals to the workforce training community as to what is needed and to ensure that ratepayers receive clear value for dollars invested in workforce training.[154]

- Workshop participants generally agreed that workforce training needs to be driven by industry requirements with a clear connection to California businesses.[155] In addition, because the renewable industry is dynamic and constantly improving, closer ties to industry partners are important so that training organizations can keep up with current needs. Apprenticeship training programs can provide important partnerships between business and labor to allow workers to stay current on the evolving needs of industry. These programs, as well as career academies and other work-based learning, also provide the hands-on training and practical experience that is a high priority for most employers.[156]

153 Ibid, comments by Dr. Richard McCann (Aspen Environmental Group), p. 115.

154 Ibid, comments by Dr. Carol Zabin (UC Berkeley), p. 39; Nicole Capretz (Environmental Health Coalition/California Environmental Justice Alliance), p. 164; Ben Foster (Optony, Inc.), p. 223.

155 Ibid, comments by Javier Romero (California Workforce Investment Board), p. 123; Nicole Capretz (CEJA), p. 128; Lisa Paulo (CPUC), p. 133.

156 Ibid, comments by Javier Romero (California Workforce Investment Board), p. 123; Susan Wheeler (SMUD), pp. 143–144; John Brauer (California Labor Federation), p. 126.

- Environmental justice advocates stated they have yet to see the promise of the green economy materialize for disadvantaged communities. In many cases, there is still a disconnect between workforce training programs and the private sector.[157] Their experience indicates that many contractors are not even aware of job training programs and therefore don't seek out program graduates to hire. Advocates also echoed the need for better coordination between employers and training programs because trained workers are finding that their skill sets don't match employer needs. To leverage renewables to provide economic development in EJ communities, it was suggested that California should use an Environmental Justice Screening Tool when making decisions about preferred locations for renewable development and should develop policies that allow for development of small solar in inner-city and rural communities. Others pointed out the need to get more capital into these communities, perhaps by working with community development finance institutions that finance low-income housing projects or through municipal bonding authority.[158]

- California enjoys many competitive advantages in clean energy job creation and economic development, including clear and aggressive clean energy policies, a commitment to innovative technologies, the variety and amount of renewable resources, and a growing trained workforce. However, there are also challenges, including anticipated reduction in federal clean energy support between now and 2014 and environmental regulations that may discourage new businesses from locating in California.

- Bringing clean energy manufacturing jobs to California is a key element of sustainable economic development. Other states are studying clean energy supply chains to determine the size of industry clusters and how to support them better through incentives, policies, and procurement requirements.[159] Another suggestion to support in-state manufacturing was to include that as a requirement for a renewable facility's permit or power purchase agreement, or providing a higher incentive for projects that use locally sourced equipment.[160]

- Financing also remains a major barrier to renewable development, and further coordination is needed among local, state, and federal agencies providing clean energy financing. A high-level economic development strategy could include manufacturing grants, bonding authority, and supply chain support.

Renewable Research and Development, American Recovery and Reinvestment Act, and Financing

The June 6, 2012, workshop discussed the role of and support mechanisms for emerging renewable technologies with the potential to contribute toward the Renewables Portfolio Standard; the current status of renewable project finance and what creative financing mechanisms may be available; and the status of California renewable energy projects that received funding through the American Recovery and Reinvestment Act of 2009.

157 Ibid, comments by Nicole Capretz (Environmental Health Coalition/California Environmental Justice Alliance), pp. 128–129.

158 Ibid, comments by Lewis Milford (Clean Energy States Alliance), p. 194.

159 Ibid, comments by Lewis Milford (Clean Energy States Alliance), p. 229.

160 Ibid, comments by Mark Tholke (enXco), p. 222; Commissioner Carla Peterman, p. 225.

R&D/FINANCING WORKSHOP PRESENTERS AND PANELISTS
BrightSource
California Alternative Energy and Advanced Transportation Financing Authority
California Clean Energy Fund
Chadbourne and Parke, LLP
Clean Energy Group
CleanPath
DBL Investors
Electric Power Research Institute
Ellison, Schneider & Harris LLP
Galati/Blek LLP
Infrastructure Bank
ITRON
NextEra
Pattern Energy
REVision Consulting, LLC
TerraGen Energy
UC Davis California Geothermal Energy Collaborative
UC Davis California Small Hydro Collaborative
UC Irvine National Fuel Cell Research Center

Key takeaways from the workshop included the following:

- A study by the Electric Power Research Institute evaluated the contribution of renewables toward California's 80 percent GHG emission reduction goal for 2050. The study concluded that meeting electricity needs with renewables will require improvements in cost and performance on the generation side and more grid flexibility – including energy storage at the bulk and distributed scales, flexible loads, smart grid, and more flexible gas turbines.

- Policy drivers like the Renewables Portfolio Standard do not drive emerging technologies. Research and development (R&D) continue to be essential to reduce costs and improve performance of renewable technologies, develop the smart grid of the future, and advance innovative technologies that will contribute toward California's clean energy targets, but there has been significant underinvestment in energy-related R&D for decades. There is also a major gap between development of technologies and full commercialization (the "Valley of Death").

- Different renewable technologies face different barriers. Examples:

  - Solar photovoltaic (PV) technologies need improved communication between inverters and meters, identification of ideal locations, and evaluation of how to couple solar technologies with energy efficiency and demand response.

  - Geothermal heat pumps, although not an emerging technology, still face barriers to widespread penetration with the biggest challenges being upfront cost, securing financing, and permitting.

  - Fuel cells are an emerging technology that can play an important role due to their high fuel-to-electricity conversion, low criteria pollutant emissions, continuous production of power, and ability to provide renewable integration services.

  - Offshore wind faces challenges from the structure of California's coastline, which drops off sharply, so there is a need for R&D in deepwater technologies. Using such technologies will also allow turbines to be installed farther out, which may reduce visual impacts and concerns. There is also significant potential for offshore wave energy, but additional R&D investments are needed to reduce the currently high costs seen in pilot-phase plants.

For all offshore renewables, R&D are needed to test technologies, examine environmental effects, and look at the lifecycle implications. As interest in these technologies grows, it will be important to consider future impacts now to avoid unforeseen impacts such as those seen with migratory birds from wind development in the Altamont Pass.

- California needs to develop innovative ways to finance clean energy projects, particularly given expected reductions in clean energy subsidies at the federal level. Suggestions included:

  - Municipal bond financing: One party noted that the amount of municipal bond financing available nationwide in only the first three months of 2012 was $80 billion, and that the renewable industry needs to figure out how to take advantage of that funding source. However, another party noted that the bond market is facing difficulties because government borrowers have budget issues. It may also be difficult for smaller projects to access the bond market, which could be addressed by pooling small projects together.

  - Efficacy insurance: Several parties noted the value of efficacy insurance, which provides funds to pay debt service costs in the event a project doesn't meet the technical performance required by its contract. This tool can be helpful in lowering interest rates and encouraging growth of venture investment by reducing the cost of capital and making it more accessible for technologies that aren't field proven or considered mature by mainstream debt providers.

  - Identifying opportunities for co-location of technologies; increased investment in gas clean-up systems to support fuel cells that use renewable fuel and to allow introduction of biogas into natural gas pipelines; using existing oil and gas platforms for deepwater offshore renewables; and developing a financing authority to deal with DG projects under 1 MW in size.

- In terms of assistance that California can provide, parties identified the need for sound, consistent, and long-term energy policies to foster growth and provide market certainty. There was also a suggestion that sales tax credits, tax exclusions, and property tax exemptions could provide real value.

- Of the nine solar thermal projects licensed by the Energy Commission that applied for ARRA funding, three are under construction, one will begin construction in 2013, and five were unsuccessful in moving forward. In the panel discussion, participants emphasized that early planning is the key to successful projects, particularly given the uncertainty over time from radical changes in permitting, availability of federal funds, procurement policies, and transmission studies. The state can provide real value by clearly identifying areas where developers should not site a project, as is being done through the Desert Renewable Energy Conservation Plan process. Similar to the financing discussion, parties noted the need for consistent energy policies, as well as better translation of policies into actual implementation at the project level.

Renewable Integration Costs, Requirements, and Technologies

The final Renewable Action Plan workshop was held on June 11, 2012, and participants discussed integration issues associated with increased renewable penetration, the operational characteristics of natural gas

plants needed to support renewable integration, and the potential for demand response and energy storage to provide integration services.

Highlights of discussions in the workshop include the following:

- Characteristics needed to support increased renewable penetration at the transmission level include fast ramping (up or down), low minimum loads, and ability to provide regulation, inertia, or frequency/voltage response. Modifying California's existing fleet of gas-fired resources is likely the "low-hanging fruit" for providing the flexible capacity needed to support renewable integration.[161] Current market mechanisms and power purchase agreements do not provide compensation for the value of investments in those modifications;[162] however, the California ISO has introduced a flexible ramping product to compensate resources that provide this service.[163]

- Parties generally agreed that the focus should be on what products are needed rather than on specific technologies. Meeting those product needs will require a suite of resource alternatives, and there need to be market mechanisms that allow those resources to compete equitably to provide the necessary services. The California ISO's flexible capacity product will help, but several parties agreed on the need for a long-term market tool like an attribute-based forward procurement requirement.[164] Many parties also identified the need for proper allocation of integration costs, with utilities favoring those costs being allocated to the entity causing the need for integration.[165]

- Integrating renewables at the distribution level will require new standards, protection, and control systems to prevent backflow that can damage the electric system. Work is also needed on identifying the

INTEGRATION WORKSHOP PRESENTERS AND PANELISTS

A123
AES Southland
BrightSource
California Energy Storage Alliance
California Independent System Operator
California Public Utilities Commission
Calpine Corporation
Enbala
EnerNOC
KEMA
Lawrence Berkeley National Laboratory
National Renewable Energy Laboratory
Pacific Gas and Electric Company
PJM
Siemens
Target
Turbine Air Systems

161 Transcript of the Energy Commission Lead Commissioner Workshop on Renewable Integration Costs, Requirements, and Technologies, June 11, 2011, comments by Mark Smith (Calpine), pp. 88–89; comments by Lori Bird (NREL), p. 57.

162 Ibid, comments by Mark Smith (Calpine), p. 91: "So you can see that, without an incremental payment of some kind, without an incremental investment of some sort, further investments will not be recovered or could not be recovered."

163 Ibid, comments by Mark Rothleder (California ISO), pp. 34, 82–83.

164 Ibid, comments by Mark Rothleder (California ISO), pp. 83–84; comments by Mark Smith (Calpine), pp. 92 and 96; comments by Todd Strauss (PG&E), pp. 212–213; comments by Jim Eyer (California Energy Storage Alliance), p. 226.

165 Ibid, comments by Justin Kubassek (SCE), p. 284; comments by Todd Strauss (PG&E), p. 215.

best locations for distributed generation, determining cost responsibility for distribution system upgrades, evaluating standardization needed around control and communication interfaces, streamlining interconnection and permitting processes, and upgrading inverter standards.[166]

- A report by the Western Governors' Association identified options for addressing integration challenges at the transmission level, including:[167]
  - Allowing generators to schedule output over shorter time intervals to reduce the amount of regulating reserves needed to integrate renewables.
  - Expanding the use of dynamic transfers in which generation is moved from the balancing area where it physically resides and controlled by the receiving balancing area.
  - Establishing an energy imbalance market to allow balancing areas to use regulation across a larger area and access cost-effective resources for balancing.
  - Improving forecasting of renewable generation and encouraging geographic diversity of renewables.
  - Encouraging demand response by allowing third-party demand response aggregators.
- Equipment manufacturers are developing new plant designs that can provide the flexibility needed to support renewable integration. New plants will be more efficient, able to move from low to high load, have low cost of generation and low emissions, and ramp up and down quickly. A challenge, however, is getting developers to select these technologies.[168] From the developers' perspective, challenges include finding the right combination of project site, plant design, and attributes.[169]
- Demand response programs can provide some of the attributes needed to integrate renewables. However, utilities identified barriers that need to be addressed to have demand response at the scale needed for renewable integration.[170] These barriers include consumer participation and education, better understanding of how to incorporate third-party aggregators and vendors, and making demand response visible to the California ISO. Other parties noted the value of third-party aggregators,[171] particularly for companies who participate in DR programs but are not energy experts,[172] and expressed the need for policy clarity in California as to who would run the DR market and whether third-party aggregators would be allowed. It was also emphasized that customer considerations are key, since demand response must be worth their while and not harm their underlying businesses.[173]
- Energy storage can complement demand response and natural gas plants to provide integration services. Storage solutions that were discussed

166 Ibid, comments by Dr. Ben Kroposki (NREL), pp. 73–74.

167 Ibid, comments by Lori Bird (NREL), pp. 50–57.

168 Ibid, comments by Dr. Bonnie Marini (Siemens), pp. 110–111.

169 Ibid, comments by John Kistle (AES), p. 120.

170 Ibid, comments by John Hernandez (PG&E), pp. 173–174.

171 Ibid, comments by Lori Bird (NREL), p. 56.

172 Ibid, comments by Anthony MacDonald (Target), p. 185.

173 Ibid, comments by Rick Counihan (EnerNOC), p. 196–197.

included community energy storage, batteries, pumped hydroelectric, and molten salt thermal storage for solar facilities. Parties stated that economies of scale and manufacturing will bring down costs, and that regulatory frameworks are needed to allow monetization of storage benefits.[174] The CPUC's energy storage proceeding will be an important forum for addressing storage issues.

- The California ISO stated it is working on changing its markets to accommodate both demand response and energy storage products, and that telemetry, visibility, and control are important components to provide certainty that these products will respond when instructed by the California ISO.

174 Ibid, comments by Charlie Vartanian (A123), pp. 249–250; comments by Jim Eyer (California Energy Storage Alliance), p. 236–237; comments by Bill Keese (Eagle Crest Energy), p. 281.

APPENDIX B: ACRONYMS

ARB	California Air Resources Board
ARFVTP	Alternative and Renewable Fuel and Vehicle Technology Program
Cal/EPA	California Environmental Protection Agency
California ISO	California Independent System Operator
CalPERS	California Public Employees' Retirement System
CalSTRS	California State Teachers' Retirement System
CEBFP	Clean Energy Business Financing Program
CEQA	California Environmental Quality Act
CHP	combined heat and power
CPUC	California Public Utilities Commission
CSLC	California State Lands Commission
CSU	California State University
DG	distributed generation
DR	demand response
DRECP	Desert Renewable Energy Conservation Plan
EDD	Employment Development Department
EIM	energy imbalance market
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
GO-Biz	Governor's Office of Business and Economic Development
GWh	gigawatt hour(s)
IEPR	Integrated Energy Policy Report
iHub	innovation hub
IID	Imperial Irrigation District
IOU	investor-owned utility
LADWP	Los Angeles Department of Water and Power
LTPP	Long-Term Procurement Plan
MM	million
MW	megawatt(s)
NEM	net energy metering
NIST	National Institute of Standards and Technology
NYSERDA	New York State Energy Research and Development Authority
OIR	Order Instituting Rulemaking
OPR	Governor's Office of Planning and Research
OTC	once-through cooling
PG&E	Pacific Gas and Electric
PGE	Portland General Electric
PV	photovoltaic
R&D	research and development

RAM	Renewable Auction Mechanism
REAT	Renewable Energy Action Team
RETI	Renewable Energy Transmission Initiative
RMI	Rocky Mountain Institute
RPS	Renewables Portfolio Standard
SCAB	South Coast Air Basin
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison Company
SONGS	San Onofre Nuclear Generating Station
SWRCB	State Water Resources Control Board
UC	University of California
U.S. DOD	United States Department of Defense
U.S. EPA	United States Environmental Protection Agency
WECC	Western Electricity Coordinating Council