share of U.S. venture capital investment in innovative energy technologies increased dramatically from 1995 to 2007 (see Figure 5 below).[51] The same period saw a stream of pioneering environmental policy initiatives, including energy efficiency codes for buildings and appliances, a renewables portfolio standard for electricity generation, climate change emissions standards for light-duty automobiles and, most recently, AB 32. Flows of venture capital into California are escalating as a direct result of the focus on reductions of greenhouse gas emissions. As mentioned above, California captured the largest single portion of global venture capital investment ($800 million out a total of two billion dollars) during the second quarter of 2008.

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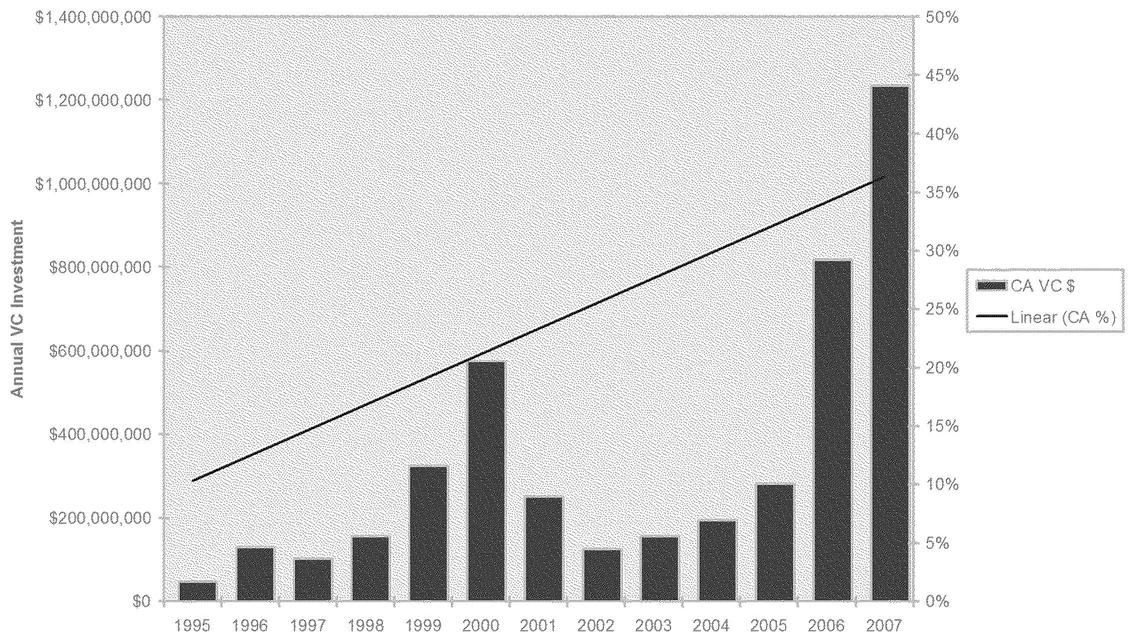
California's Growing Share of Venture Capital Investment in Energy Innovation, 1995-2007 (current $, % share)



Source: PricewaterhouseCoopers MoneyTree Report, available at: [https://www.pwcmoneytree.com].

A survey of clean technology investors by Global Insight and the National Venture Capital Association found that public policy influences where venture capitalists invest.[52] Furthermore, investments in green technology solutions produce jobs at a higher rate than

[51] Based on historical trend data for the 'Industrial/Energy' industry for California and the United States from the PricewaterhouseCoopers MoneyTree Report. https://www.pwcmoneytree.com/MTPublic/ns/nav.jsp?page=historical (accessed October 12, 2008)

[52] Clean Tech Entrepreneurs & Cleantech Venture Network LLC. *Creating Cleantech Clusters: 2006 Update*. May 2006. p.43 http://www.e2.org/ext/doc/2006%20National%20Cleantech%20FORMATTED%20FINAL.pdf (accessed October 12, 2008)

investments in comparable conventional technologies.[53] Venture capitalists estimate that each $100 million in venture capital funding, over a period of two decades, helps create 2,700 jobs, $500 million in annual revenues, and many indirect jobs.[54]

Access to capital controlled by institutional investors is also enhanced by policies that encourage early adoption of green technologies. When California-based corporations use green technologies to reduce their exposure to climate change risk, institutional investors reward them by facilitating their access to capital. The Investor Network on Climate Risk – including institutional investors with more than $8 trillion of assets under management – endorsed an action plan in 2008 that calls for requiring asset managers to consider climate risks and opportunities when investing; investing in companies developing and deploying clean technologies; and expanding climate risk scrutiny by investors and analysts.[55]

Additional capital for green technologies helps drive increased employment, both indirectly, as energy savings are plowed back into other sectors of the economy, and directly, as new green products are successfully commercialized.

McKinsey & Company projects average annual returns of 17 percent on global investments in energy productivity, and estimates the global investment opportunity at $170 billion annually through 2020.[56] Meanwhile, global investment in energy efficiency and renewable energy has grown from $33 billion to more than $148 billion in the last four years. Beyond 2020, green technologies are expected to attract investment of more than $600 billion annually.[57] In short, green technology is now a *bona fide* global growth industry.

Today, green technology businesses directly employ at least 43,000 Californians, primarily in energy efficiency and energy generation, according to a 2008 study from the California Economic Strategy Panel. Green jobs are concentrated in manufacturing (41 percent), and

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[53] Report of the Renewable and Appropriate Energy Laboratory. *Putting Renewables to Work: How Many Jobs Can the Clean Energy Industry Generate?* Energy and Resources Group/Goldman School of Public Policy at University of California, Berkeley. April 13, 2004. http://rael.berkeley.edu/old-site/renewables.jobs.2006.pdf (accessed October 12, 2008)

[54] Report prepared for the National Venture Capital Association. *Venture Impact 2004: Venture Capital Benefits to the U.S. Economy*. Prepared by: Global Insight. June 2004. http://www.globalinsight.com/publicDownload/genericContent/07-20-04_fullstudy.pdf (accessed October 12, 2008)

[55] The Investor Network on Climate Risk. *Final Report, 2008 Investor Summit on Climate Risk*. February 14, 2008. http://www.ceres.org//Document.Doc?id=331 (accessed October 12, 2008)

[56] McKinsey Global Institute. *The Case for Investing in Energy Productivity*. McKinsey & Company. February, 2008. p.8 http://www.mckinsey.com/mgi/reports/pdfs/Investing_Energy_Productivity/Investing_Energy_Productivity.pdf (accessed October 12, 2008)

[57] United Nations Environment Programme-New Energy Finance Ltd. *Global Trends in Sustainable Energy Investment 2008: Analysis of Trends and Issues in the Financing of Renewable Energy and Energy Efficiency* 2008. p.12 ISBN: 978-92-807-2939-9 http://www.unep.fr/energy/act/fin/sefi/Global_Trends_2008.pdf (accessed October 12, 2008)

professional, scientific and technical services (28 percent), with median annual earnings of $35,725 and $56,754, respectively.[58] By 2030, under a moderate growth scenario, green businesses nationwide are expected to generate revenues of $2.4 trillion, (2006 dollars), and employ 21 million Americans.[59]

As a leader in green technology development and use, California has already realized substantial economic benefits from the adoption of energy efficiency policies. State energy efficiency measures have saved enough energy over the past 30 years to avoid construction of two dozen 500-megawatt power plants. Today, California's per capita electricity consumption is 40 percent below the national average, and the carbon intensity of California's economy is among the lowest in the nation.[60]

Renewable energy, such as solar, wind, biomass, geothermal, will also bring new employment opportunities to Californians while spurring economic growth. California enjoys significant comparative advantages for renewable energy: concentrated innovation resources, a large potential customer base, key natural resources such as reliable solar and wind, and supportive regulatory programs, including the California Renewables Portfolio Standard, the Million Solar Roofs Initiative, the California Global Warming Solutions Act of 2006, and the Solar Water Heating and Efficiency Act of 2007.

Other researchers have estimated that under a national scenario with 15 percent renewables penetration by 2020, California will experience a net gain in direct employment of 140,000 jobs.[61] Because investments in green technologies produce jobs at a higher rate than investments in conventional technologies, jobs losses that occur in traditional fossil fuel industries will be more than compensated for by gains in the clean energy sector.

Furthermore, if California's renewable energy suppliers field products that are sufficiently competitive to penetrate the export market, employment and earnings dividends for the state will also increase. California renewable energy industries servicing the export market can generate up to 16 times more employment than those that only manufacture for domestic

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[58] California Economic Strategy Panel with Collaborative Economics. *Clean Technology and the Green Economy*. March 2008. P.14-15 http://www.labor.ca.gov/panel/pdf/DRAFT_Green_Economy_031708.pdf (accessed October 12, 2008)

[59] The American Solar Energy Society. *Renewable Energy and Energy Efficiency: Economic Drivers for the 21st Century*. 2007. p.39 ISBN 978-0-89553-307-3 http://www.ases.org/images/stories/ASES-JobsReport-Final.pdf (accessed October 12, 2008)

[60] California Energy Commission. *2007 Integrated Energy Policy Report*. Document No. CEC-100-2007-008-CMF. 2007. p. 3 http://www.energy.ca.gov/2007publications/CEC-100-2007-008/CEC-100-2007-008-CMF.PDF (accessed October 12, 2008)

[61] Tellus Institute and MRG Associates. *Clean Energy: Jobs for America's Future*. As cited in: Putting Renewables to Work: How Many Jobs Can the Clean Energy Industry Generate? Energy and Resources Group/Goldman School of Public Policy at University of California, Berkeley. April 13, 2004. http://rael.berkeley.edu/old-site/renewables.jobs.2006.pdf (accessed October 12, 2008)

consumption, according to a study by the Research and Policy Center of Environment California.[62]

[illegible]

As noted in several provisions of AB 32, cost-effectiveness is an important requirement to be considered in the design and implementation of emission reduction strategies. (See HSC §§38505, 38560, 38561, 38562.) AB 32 defines "cost-effective" or "cost-effectiveness" as "the cost per unit of reduced emissions of greenhouse gases adjusted for its global warming potential." (HSC §38505(d)) This definition specifies the metric (i.e., dollars per ton) by which the Board must express cost-effectiveness, but it does not provide criteria to assess if a regulation is or is not cost-effective. It also does not specify whether there should be a specific upper-bound dollar per ton cost that can be considered cost-effective, or how such a bound would be determined or adjusted over time. ARB has investigated different approaches that could be used to evaluate the cost-effectiveness of regulations and is recommending the following approach.

The estimated cost per ton of greenhouse gas emissions reduced by the measures recommended in this Plan ranges from $-408 (net savings) to $133, with all but one (the Renewables Portfolio Standard) costing less than $55 per ton. The RPS is being implemented for energy diversity purposes, not just greenhouse gas reductions, and the $133 per ton figure does not take these other benefits into account. Therefore, it should not be used as a reference to define the range of cost-effective greenhouse gas measures. These estimates are based on the best information available as ARB prepared this Proposed Plan. Updated estimates and greater certainty will be provided as the measures are further developed during the rulemaking process.

In the meantime, the current estimates provide a range illustrating the cost per ton of the mix of measures that collectively meet the 2020 target. This range will assist the Board in evaluating the cost-effectiveness of individual measures when considering adoption of regulations. The range of acceptable cost-effectiveness may change if effective lower-cost measures and options are identified. Because both the projections of "business-as-usual" 2020 emissions and the degree of reductions from any given measures may be greater or less than current estimates, the determination should remain flexible to accommodate a higher or lower estimate of cost-effectiveness. In addition, the approach must provide flexibility to pursue measures that simultaneously achieve policy objectives other than greenhouse gas emissions reduction (such as energy diversity).

The criteria for judging cost-effectiveness will be updated as additional technological data and strategies become available. As ARB moves from adoption of the Scoping Plan to

[62] Environment California Research and Policy Center. *Renewable Energy and Jobs. Employment Impacts of Developing Markets for Renewables in California.* July 2003. As cited in: Putting Renewables to Work: How Many Jobs Can the Clean Energy Industry Generate? Energy and Resources Group/Goldman School of Public Policy at University of California, Berkeley. April 13, 2004. http://rael.berkeley.edu/old-site/renewables.jobs.2006.pdf(accessed October 12, 2008)

11 avoided premature deaths attributed to emission reductions that occur in Wilmington as a result of the Scoping Plan.[72]

[illegible]

AB 32 requires ARB to "consider the overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health" (HSC § 38562(b)(6)) when developing regulations to implement the Scoping Plan. ARB conducted an initial assessment of societal benefits associated with AB 32 implementation. This section summarizes those that have been identified during development of the Scoping Plan, including diversification of energy sources, mobility, regressivity, and job creation. More detailed economic and environment/public health analyses can be found in Appendix G and H, respectively. The impact of low income households (regressivity), impacts on small businesses, and impact on jobs are described in the Economic Analysis section and Appendix G.

[illegible]

Generally, energy-related measures in this Proposed Scoping Plan are expected to result in a transformation of the State's energy portfolio, driven primarily by the Low Carbon Fuel Standard (LCFS), which addresses transportation fuel, and the 33 percent RPS, which increases renewably-produced electricity production and distribution to households and businesses.

The LCFS aims to achieve at least a 10 percent reduction in the carbon intensity of California's transportation fuels by 2020. As the State moves toward less dependence upon one source of fuel for transportation, our economy will be less at risk from significant fluctuations in fuel prices. Measures within the Scoping Plan will force energy diversification in California toward low-carbon intensive energy sources and encourage significant growth in infrastructure, capital, and investment in biofuels.

The move toward 33 percent renewables will, by definition, increase the diversification of California's electrical supply. Increased use of wind, solar, geothermal and biomass (including from the organic fraction of municipal solid waste) generation will all add to ensuring the state has a broader portfolio of energy inputs.

Based on ARB's economic analysis, the combined energy diversification and increased energy efficiency expected from implementation of the Scoping Plan is predicted to result in: a 25 percent decrease in gasoline usage (4.6 billion gallons), a 17 percent decrease in diesel fuel use (670 million gallons), a 22 percent decrease in electricity (74,000 GWh reduction) and a 24 percent reduction in natural gas (3,400 therms).

[72] See Appendix H

The cap-and-trade program, offsets, and other measures that contain market-based features may also help diversify California's energy portfolio by incentivizing the development and deployment of clean and efficient energy generating technologies.

Mobility is analyzed through multiple approaches in the Proposed Scoping Plan. Appendix C includes an analysis of a proposed measure for regional transportation-related greenhouse targets. Reductions in vehicle miles traveled (VMT) are expected to result from regional and local planning which target land use, building and zoning improvements.

As the Scoping Plan is implemented, measures that support shifts in land use patterns are expected to emphasize compact, low impact growth in urban areas over development in greenfields. Communities could realize benefits, such as improved access to transit, improved jobs-housing balance, preservation of open spaces and agricultural fields, and improved water quality due to decreased runoff. Local and regional strategies promoting appropriate land use patterns could encourage fewer miles traveled, lowering emissions of greenhouse gases, criteria pollutants and PM. More compact communities with improved transit service could increase mobility, allowing residents to easily access work, shopping, childcare, health care and recreational opportunities.

Furthermore, if open spaces and desirable locations become more accessible and communities are designed to encourage walkability between neighborhoods and shopping, entertainment, schools and other destinations, residents are likely to increase their levels of physical activity. Research shows that regular physical activity can reduce health risks, including coronary heart disease, diabetes, hypertension, anxiety and depression, and obesity. Measures in the Proposed Scoping Plan encourage Californians to use alternatives to personal vehicle travel that could result in increased personal exercise. To complement these changes, future community developments may evolve to include trails and pedestrian access to major centers. However, where compact development may increase proximity to large sources of pollution, such as high traffic arterials, distribution centers, and industrial facilities, it will be critical to analyze the anticipated and unanticipated impacts and benefits, to ensure that increases in exposure to vehicular air pollution and other toxics and particulates do not occur .

The California Environmental Quality Act (CEQA) and ARB policy require an analysis to determine the potential adverse environmental impacts of proposed projects. ARB's analysis of the potential adverse environmental impacts of the Proposed Scoping Plan is presented in Appendix J. The analysis summarizes and discusses the specific strategies in the Scoping Plan that, if adopted and implemented, will reduce greenhouse gas emissions throughout the ﬃﬄ╝├◘ – ♂∟♬☼┼

2011 IEPR

INTEGRATED ENERGY POLICY REPORT

CALIFORNIA ENERGY COMMISSION
EDMUND G. BROWN JR., GOVERNOR

CEC-100-2011-001-CMF

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Every two years, the California Energy Commission prepares an Integrated Energy Policy Report as directed by Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002). The report examines various aspects of energy supply, demand, distribution, and price and, based on these assessments, provides policy recommendations to ensure system reliability and safety, conserve resources, protect the environment, and contribute to a healthy economy.

This *2011 Integrated Energy Policy Report* provides an overview of policies that guide California's energy system and summarizes progress in implementing these policies. The report is built on a series of in-depth analyses of key aspects of the state's energy system and highlights issues that California must consider as it moves forward in meeting its energy goals. These issues fall into three general categories:

*** Ensuring that the state has sufficient, reliable, and safe energy infrastructure to meet current and future energy demand as well as the state's clean energy goals. This will involve improved forecasting

CHAPTER 2

Renewable Electricity Status and Issues

California has used renewable energy – energy from natural resources like sunlight, wind, rain, and the Earth's heat –

to help meet its electricity needs for more than a century. Renewable electricity provides many economic and environmental benefits including local jobs in clean technology and construction industries; revenues from property and sales taxes; energy independence from using local energy sources and fuels rather than imported natural gas; reduced fossil-fuel generation that has negative impacts on air and water quality; and reduced greenhouse gas emissions from the electricity sector to help meet state climate change goals. California has been a leader in expanding its consumption of renewable energy since the late 1970s when, under Governor Jerry Brown's first administration, the California Public Utilities Commission ordered utilities to establish standard offers for buying electricity from alternative suppliers ("qualifying facilities") at cost-based rates, with the price equal to the buyer's full avoided cost. By 1991, these standard contracts resulted in more than 11,000 megawatts (MW) of qualifying facilities on-line in California, about half of which used renewable resources.

Now, Governor Brown is putting forth new and expanded targets. In his Clean Energy Jobs Plan, the Governor is emphasizing the importance of investing in renewable energy as a central element of rebuilding California's economy. The Governor directed the Energy Commission to prepare a plan to "expedite permitting of the highest priority [renewable] generation and transmission projects" to support investments in renewable energy that will create new jobs and businesses, increase energy independence, and protect public health. In December 2011, the Energy Commission released the *Renewable Power in California: Status and Issues* report, which describes the current status of renewable development in California and identifies challenges to meeting the state's renewable goals. This chapter summarizes that report and outlines high-level strategies to be included in a comprehensive strategic plan for renewable energy in California that will be developed as part of the *2012 Integrated Energy Policy Report Update*.

California's Renewable Electricity Targets and Status

In 2002, the California Legislature established the Renewables Portfolio Standard (RPS) to diversify the electricity system and reduce growing dependence on natural gas. At that time, the target was to increase the amount of renewable electricity in the state's power mix to 20 percent by 2017, which was subsequently accelerated to 2010 by legislation passed in 2006. In 2011, the RPS was further revised and expanded to require that renewable electricity should equal an average of 20 percent of the total electricity sold to retail customers in California during the compliance period ending December 31, 2013, 25 percent by December 31, 2016, and 33 percent by December 31, 2020.[18] To support these RPS targets, Governor Brown's Clean Energy Jobs Plan calls for adding 20,000 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. According to a recent presentation by Michael Picker, Senior Advisor to the Governor for Renewable Facilities, resources included in the 12,000 MW goal are defined as: (1) fuels and technologies accepted as renewable for purposes of the Renewables Portfolio Standard; (2) sized up to 20 MW; and (3) located within the low-voltage distribution grid or supplying power directly to a consumer.[19] Some parties have suggested that this definition be expanded to include other low GHG-emitting resources, such as fuel cells and high-efficiency combined heat and power facilities. The Energy Commission will hold workshops during the *2012 IEPR Update* and *2013 IEPR* proceedings to discuss combined heat and power issues, and welcomes suggestions from parties on how to best ensure that the state's distributed generation and combined heat and power goals are complementary.

California appears to be on track to achieve the 20 percent average by 2013 RPS compliance period, with nearly 16 percent of statewide retail sales coming from

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18 The California Public Utilities Commission recently established procurement quantity requirements for interim years of 21.7 percent (2014); 23.3 percent (2015); 27 percent (2017); 29 percent (2018); and 31 percent (2019). Decision 11-12-020, *Decision Setting Procurement Quantity Requirements for Retail Sellers for the Renewables Portfolio Standard Program*, December 1, 2011, docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/154695.PDF.

19 Michael Picker, presentation at the December 8, 2011, California Foundation on the Environment and the Economy Energy Roundtable Summit on Distributed Generation, www.cfee.net/_documents/Picker.pdf.

Table 1: In-State Renewable Capacity and Generation (2010)

Renewable Resource	Utility-Scale Capacity (MW)	Wholesale Distributed Generation Capacity (MW)	Distributed Generation Capacity (MW)	Total Capacity (MW)	Total Generation (GWh)
Biomass	1,070	632	25	1,727	5,745
Geothermal	2,521	46	0	2,567	12,740
Small Hydro	315	1,080	0	1,395	4,441
Solar	408	149	1,070[B]	1,627	908
Wind	No data	No data	8[C]	3,027[D]	6,172
Total	4,314	1,907[A]	1,103[E]	10,343	30,005

Source: California Energy Commission

A. Sources of the data include the Energy Commission's Quarterly Fuels and Energy Report Database and POU RPS database; CPUC's IOU database (www.cpuc.ca.gov/PUC/energy/Renewables/), and CPUC staff update on installed capacity under SB 32.

B. Solar PV systems under SB1 (CPUC staff calculation for CSI, Energy Commission staff calculation for NSHP, and Energy Commission staff calculation as reported by the POUs for their portion), the Self-Generation Incentive Program (energycenter.org/index.php/incentive-programs/self-generation-incentive-program/sgip-documents/sgip-documents), and the Emerging Renewables Program (www.energy.ca.gov/renewables/emerging_renewables/).

C. Wind turbine systems in the Self-Generation Incentive Program (energycenter.org/index.php/incentive-programs/self-generation-incentive-program/sgip-documents/sgip-documents) and the Emerging Renewables Program (www.energy.ca.gov/renewables/emerging_renewables/)

D. Includes 3019 MW of utility scale and wholesale distributed generation wind capacity. California ISO data on wind projects located in the California ISO and the Energy Commission's QFER Database, energyalmanac.ca.gov/electricity/web_qfer/ for wind projects located outside the California ISO.

E. Total updated in 2011.

renewable generation in 2010.[20] In-state renewable generation represented about 75 percent of total renewable generation from more than 10,000 MW of renewable generating capacity (Table 1).[21]

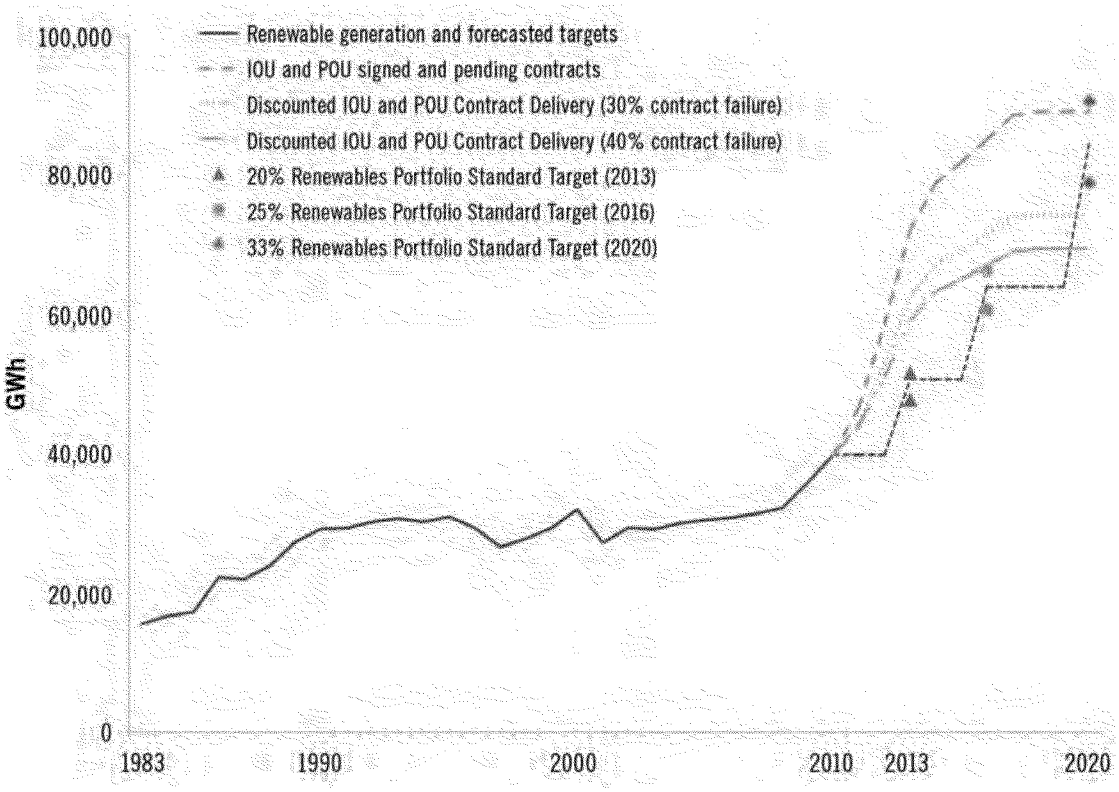
For the 33 percent by 2020 target, Energy Commission staff estimates that the state will need renewable generation in the range of 35,000 gigawatt hours (GWh) to 47,000 GWh in addition to generation expected from existing facilities. Utility contracts signed and pending to date are expected to deliver enough energy to reach the upper bound of this range if most or all of the contracted renewables are built and generating by 2020 (Figure 1).

This estimate includes a number of short-term contracts that may not be renewed, as well as existing facilities that may retire due to age or contract expiration, which could reduce the contribu-

20 Depending on the data source, total renewable generation varies between 15 and 16.5 percent of statewide retail sales from renewable generation in 2010. Procurement and generation sources include: The Power Source Disclosure Program, CPUC RPS Compliance Filings, Energy Commission RPS Tracking, and the Energy Commission's Total System Power.

21 The wholesale DG total in Table 1 was based on project size (20 MW or less) and excluded wind capacity due to lack of reliable data; the total will therefore need further refinement given the revised definition of what meets the Governor's 12,000 MW goal, to screen out projects connected at the transmission level and include wholesale DG wind capacity.

Figure 1: Renewable Generation for California and Renewables Portfolio Standard Goals



Source: California Energy Commission, *Renewable Power in California: Status and Issues*, December 2011.

Dashed orange line showing expected renewable generation does not include potential generation from electric service providers, community choice aggregators, or small multi-jurisdictional utilities which are also subject to the RPS. In 2010, renewable generation from these entities represented only about 5 percent of statewide renewable generation.

tion from existing facilities.[22] There is also risk of contract failure; data from the Energy Commission's IOU contract database indicates that since the start of the RPS program, about 30 percent of long-term RPS contracts (10 years or more) approved by the California Public Utilities Commission (CPUC) have been cancelled.

The contract failure rate increases to about 40 percent when also considering contracts that have been delayed, and, at the September 14, 2011, workshop on the draft *Renewable Power in California: Status and Issues* report, two utilities indicated that they currently assume a contract failure rate of 40 percent.[23] This suggests it would be prudent for utilities to contract for renewable generation in the range of 55,000 GWh (contract failure rate of 30 percent) to 85,000 GWh (contract failure rate of 40 percent).[24]

22 According to metrics on the California Clean Energy Future website, contracts for roughly 12,000 GWh of renewable generation will expire before 2020, www.cacleanenergyfuture.org/documents/RenewableEnergy.pdf.

23 Transcript of the September 14, 2011, Integrated Energy Policy Report workshop on the *Draft Renewable Power in California: Status and Issues* report, comments by Valerie Winn, Pacific Gas and Electric Company, (page 72) and Gary Stern, Southern California Edison (page 73), www.energy.ca.gov/2011_energypolicy/documents/2011-09-14_workshop/2011-09-14_transcript.pdf.

24 The Energy Commission acknowledges that historical contract failure rates are not predictive of future rates, which could be lower or higher.

Table 2: Preliminary Regional Targets for 8,000 Megawatts of New Renewable Capacity by 2020

Identified Transmission Line(s)	CREZ Served	Cumulative Renewable Deliverability Potential with New/Upgraded Lines (MW)	2010 Permitted Generating Capacity Associated with New/Upgrades (MW)	Additional Transmission Project Capacity (MW)
Sunrise Powerlink	Imperial North and South, San Diego South	1,700	760	940
Tehachapi and Barren Ridge Renewable Transmission Projects	Tehachapi, Fairmont	5,500	2,810	2,690
Colorado River, West of Devers, and Path 42 Upgrade	Riverside East, Palm Springs, Imperial Valley	4,700	1,825	2,875
Eldorado-Ivanpah, Pisgah-Lugo, and Coolwater-Jasper-Lugo	Mountain Pass, Pisgah, Kramer	2,450	1,470	980
Borden-Gregg	Westlands	800	145	655
South of Contra Costa	Solano	535	155	380
Carrizo-Midway	Carrizo South, Santa Barbara	900	800	100
			TOTAL	8,620

Source: California Energy Commission, *Renewable Power in California: Status and Issues*, December 2011.

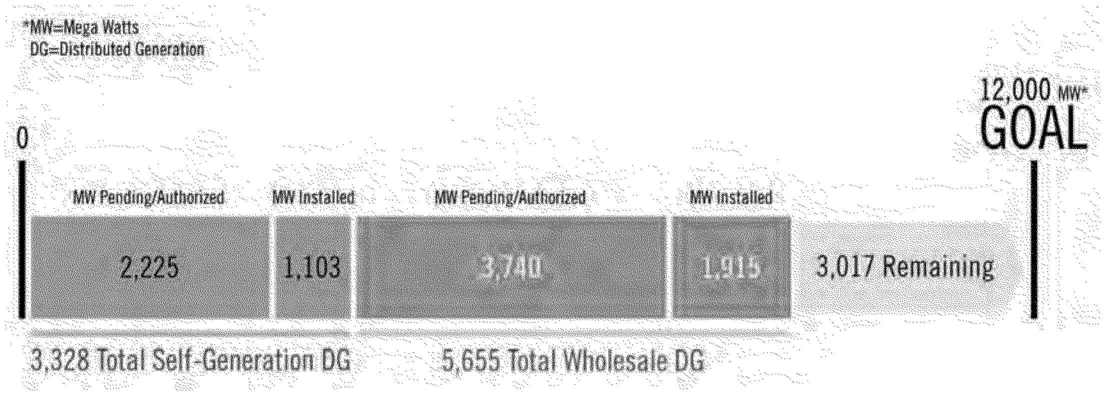
As a starting point for measuring progress toward meeting the Governor's 20,000 MW goal, the *Renewable Power in California: Status and Issues* report included preliminary regional targets for both utility-scale and localized renewable generation facilities. For the target of 8,000 MW of utility-scale renewables by 2020, Energy Commission staff identifiedrough regional targets based on new transmission lines and upgrades that have been identifiedby the California Independent System Operator (California ISO) for all of California's balancing authorities and potential renewable capacity in Competitive Renewable Energy Zones (CREZ) identifiedthrough the 2007–2010 Renewable Energy Transmission Initiative (RETI) that would be served by those lines and upgrades (Table 2).[25]

If these new lines and upgrades are permitted, built, and operating before 2020, they could allow generation from more than 16,000 MW of cumula-

25 RETI was initiated in 2007 as a joint effort among the CPUC, the Energy Commission, the California ISO, utilities, and other stakeholders. Primary goals were to identify transmission projects needed to accommodate California's renewable energy goals; promote designation of corridors for future transmission line development; and make transmission and generation siting and permitting easier. *Renewable Energy Transmission Initiative Phase 2B Final Report*, RETI-1000-2010-002-F, May 2010, www.energy.ca.gov/reti/documents/index.html.

SB_GT&S_0558310

Figure 2: Renewable Distributed Generation Capacity Counted Toward 12,000 MW Goal



Source: California Energy Commission.

"Pending" capacity refers to projects approved under existing programs and in development but not yet completely installed. "Authorized" capacity refers to capacity allocated under existing programs that is not yet approved or installed. Existing programs include the Senate Bill 32 feed-in tariff, the Renewable Auction Mechanism, the Utility Solar Photovoltaic Program, and the California Solar Initiative. The Energy Commission acknowledges that the totals presented in this figure will need further refinement; for example, not all projects deve loped under the Renewable Auction Mechanism may qualify as wholesale DG under the definition of DG presented in this report.

tive renewable capacity to flow across those lines.[26] In 2010, state and local entities issued permits for roughly 9,000 MW of new renewable capacity, about 8,000 MW of which is associated with the new lines and upgrades. This indicates that another 8,000 MW of renewable capacity could be sited in the CREZ associated with these lines in the future.

For the 12,000 MW distributed generation (DG) target, Energy Commission staff developed preliminary regional targets for localized generation (Table 3), defined for purposes of the analysis at that time as renewable DG projects 20 MW and smaller interconnected to the distribution or transmission grid. The analysis was technology neutral and included solar, biomass, geothermal, wind, fuel cells using renewable fuel, and small hydropower. The analysis also assumed that renewable DG capacity installed would count toward meeting the 12,000 MW goal. California has roughly 3,000 MW of renewable DG capacity installed and, if existing state programs to support renewable DG are fully successful, the state could add about 6,200 MW of capacity in the next five to eight years (Figure 2). More information is needed to assess the legitimacy of the targets and the targets should be periodically updated. Given the trend of declining costs for solar photovoltaic (PV) technologies, the Energy Commission believes the focus should be on developing the "low-hanging fruit" in the next few years. Meanwhile, the state should focus on reforming permitting and interconnection processes so that subsequent development of renewable DG installations can take advantage of cost reductions and improved regulatory structures in later years.

26 Written comments by Kern County and Critical Path Transmission on the draft 2011 IEPR suggested a transmission line which, if built, could potentially open up the West Mojave Desert to renewable energy development. The West Mojave Desert has been identified as an area of high solar insolation and the Energy Commission and other members of California's Renewable Energy Action Team have encouraged development there. That area also has lands with high conservation value, particularly for the Mohave ground squirrel and desert tortoise, and the Desert Renewable Energy Conservation Plan provides a forum for balancing energy and conservation needs in the area. Toward this end, the Energy Commission supports efforts by independent transmission advocates to improve access to the West Mojave and will work with agencies and stakeholders involved in the Desert Renewable Energy Conservation Plan to address development and resource conservation options.

Table 3: Proposed Preliminary Regional DG Targets by 2020

Region	Behind the Meter (all technologies) (MW)	Wholesale (MW)	Undefined(mix of behind the meter and wholesale) (MW)	Total (MW)
Central Coast	280	90	0	370
Central Valley	830	1590	0	2,420
East Bay	420	30	0	450
Imperial	50	90	0	140
Inland Empire	480	430	0	910
Los Angeles (city and county)	970	860	2170	4,000
North Bay	220	0	0	220
North Valley	120	50	0	170
Sacramento Region	410	170	220	800
San Diego	500	50	630	1,180
SF Peninsula	480	10	310	800
Sierras	30	40	0	70
Orange	420	10	40	470
Total	5,210	3,420	3,370	12,000

Source: California Energy Commission, *Renewable Power in California: Status and Issues*, December 2011.

Post-2020, additional investments in renewable generation may be needed to replace generation expected to decline over the course of the next decade, such as generation from expiring coal contracts. Generation from a number of these contracts, which currently represents about 10 percent of total generation serving California, is expected to decline by 61 percent between 2010 and 2020 due to constraints imposed by the Emission Performance Standard.[27] Remaining coal contracts are expected to expire between 2027 and 2030, which will require replacement power from a mix of renewable and thermal generation with storage to satisfy electricity needs while still meeting greenhouse gas emission reduction goals.

When signing the 2011 RPS legislation, Governor Brown indicated that the 33 percent by 2020 RPS target should be considered a floor rather than a ceiling. This is consistent with the need for additional renewable generation and other zero-carbon electricity resources to meet the state's long-term (2050) GHG emission reduction goals. Back-of-the-envelope estimates by Energy Commission staff indicate that if new renewables alone provided the zero-emission generation needed to meet electricity needs in 2050,

27 The Emission Performance Standard prohibits California utilities from renegotiating or signing new contracts for baseload generation that exceeds 1,100 lbs of carbon dioxide equivalent (CO_2e) emission per MWh. A number of contracts with coal generation facilities that exceed the Emission Performance Standard will expire within the decade and cannot be renewed with another long-term contract.

renewable generation could represent from 67 to 79 percent of total electricity sales in 2050.[28]

California's estimated renewable technical potential is 18 million MW (Table 4).[29] Although this figure does not reflect economic or environmental constraints, development of even one-tenth of 1 percent of this potential would nearly meet the Governor's 20,000 MW renewable goal. Achieving this potential will depend on the ability of project developers to secure financing, permits, transmission, interconnection, local community acceptance, and power purchase agreements.

Despite these challenges, recent trends indicate increasing market interest in renewable development. The 2009 RPS solicitation by the investor-owned utilities (IOUs) drew bids from developers offering to supply enough renewable generation to meet half of the IOUs' total electrical load in 2020, and IOUs currently have signed contracts for roughly 14,000 MW of new renewable capacity. In 2010, state and local entities issued permits for 9,435 MW of renewable capacity, and another 28,000 MW is being tracked in various

Table 4: California's Renewable Energy Potential

Technology	Technical Potential (MW)
Biomass	3,820
Geothermal	4,825
Small Hydro	2,158
Solar – Concentrating Solar Power	1,061,362
Solar – PV	17,000,000
Wave and Tidal	32,763
Wind – Onshore	34,000
Wind – Offshore	75,400
TOTAL TECHNICAL POTENTIAL	18,214,328

Source: California Energy Commission, *Renewable Power in California: Status and Issues*, December 2011.

28 The 67 percent estimate assumes that electricity demand, the number of self-generation projects, and energy efficiency programs continue to grow at current rates; increased penetration of electric vehicles; and continued operation of existing renewables, nuclear, and hydroelectric generation at the same levels in 2050 as today. The 79 percent estimate uses the same assumptions with the exception of nuclear and assumes that existing nuclear plants are not relicensed. These estimates do not consider the additional need for integration of intermittent renewables, which may require additional flexible capacity toward which fossil fuels, energy storage, and demand response could play a part. Estimates are presented for illustration only and not intended to be used for planning purposes.

29 *Technical potential* refers to the amount of generating capacity theoretically possible given resource availability, geographical restrictions, and technical limitations like energy conversion efficiencies and does not reflect economic potential (how much could be developed at cost levels considered competitive) or market potential (how much could be implemented in the market after accounting for energy demand, competing technologies, costs and subsidies, and barriers).

permitting processes.[30] The California ISO's Interconnection Queue includes about 57,000 MW of renewable capacity, and there are 450 active interconnection requests for DG systems in the Wholesale Distribution Access Tariff queue totaling about 5,200 MW.

Issues Affecting Future Renewable Development in California

The *Renewable Power in California: Status and Issues* report identified a variety of issues that will affect the amount of renewable capacity ultimately developed, including environmental, planning, and permitting; transmission; grid- and distribution-level integration; investment and financing cost; research and development (R&D); environmental justice; local government coordination; and workforce development. The report also discussed past and current efforts to address these challenges, which must be overcome to achieve California's renewable energy targets and goals.

Planning and Permitting Issues

For utility-scale renewable plants, the primary planning and permitting challenges are environmental/land use issues and fragmented and overlapping permitting processes. Renewable facilities can have a variety of environmental and land-use impacts depending on location and technology. Because the majority of new renewable development is proposed in the California desert, the *Renewable Power in California: Status and Issues* report focused on desert environmental impacts. These include impacts on sensitive plant and animal species, water supplies and waterways, and cultural resources like areas of historical or ethnographic importance. There are also land-use concerns because the majority of desert lands in California are owned by the federal government and managed for multiple uses, including recreation, wildlife habitat, livestock grazing, and open space.

In terms of the permitting process, a variety of federal, state, and local agencies have licensing authority for different types of utility-scale renewable projects. This can lead to inconsistent environmental reviews and standards and variation in the extent of environmental evaluation, interpretation of results, and mitigation requirements. The result is that developers may have to satisfy more than one set of conditions, submit duplicate information, or face delays while agencies resolve their differences.

For renewable DG facilities, widely varying codes, standards, and fees among local governments with jurisdiction over these projects are a challenge for developers trying to meet permitting requirements. In addition, developers must get permit approvals from multiple local entities like fire departments, building and electric code officials, and local air districts, which can lead to duplication and inefficiency in the permitting process. Also, many local jurisdictions do not have energy elements in their general plan or zoning ordinances to guide renewable development and may have environmental screening and review processes in place only for large-scale renewables, not DG projects.

The state's Renewable Energy Action Team (REAT) is developing the Desert Renewable Energy Conservation Plan (DRECP) to help minimize environmental impacts of renewable generation and transmission

30 California Energy Commission, see: www.energy.ca.gov/33by2020/documents/renewable_projects/REAT_Generation_Tracking_Projects_Report.pdf.

Measuring California's energy use is the essence of a much broader analysis conducted every two years as part of the *Integrated Energy Policy Report (IEPR)*. This chapter summarizes the Energy Commission staff's *Preliminary California Energy Demand Forecast 2012–2022 (CED 2011 Preliminary)*.[119] The report's analysis characterizes the effects of economic and demographic trends, human behavior, emerging technologies, state and federal policies, and California's diverse climatic and geographic landscape on current and future energy needs. The chief product of this work is the California Energy Demand (CED) forecast of electricity and natural gas consumption over the next 10 years. Staff will release a revised forecast in mid-February and expects to adopt a final version in early spring 2012.

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119 Kavalec, Chris, Tom Gorin, Mark Ciminelli, Nicholas Fugate, Asish Gautum, and Glen Sharp, *Preliminary California Energy Demand Forecast, 2012–2022*, 2011, CEC-200-2011-011SD, available at: www.energy.ca.gov/2011publications/CEC-200-2011-011/CEC-200-2011-011-SD.pdf.

Californians consumed around 272,300 gigawatt hours (GWh) of electricity in 2010. Natural gas consumption, excluding fuel for electricity generation, reached almost 12,700 million therms that same year. Forecasts of expected growth in energy demand underlie California's efforts to develop effective policy, conserve natural resources, protect the environment, and promote public health and safety while ensuring adequate energy supplies and economic growth. To that end, the Energy Commission's long-term forecast appears in many venues: as the foundation for policy recommendations to the Governor and Legislature through the *IEPR*; as a yardstick by which to measure the utilities' need for new generation resources in the California Public Utilities Commission's (CPUC) Long-Term Procurement Planning proceeding; as a reference point in the Air Resources Board's *AB 32 Scoping Plan*; as a benchmark for assessing the state's progress toward meeting its Renewables Portfolio Standard (RPS); as a baseline for estimating energy efficiency savings potential; and as input into the Energy Commission's infrastructure needs assessment.

The forecast is also used by the CPUC and the California ISO in annual resource adequacy proceedings addressing capacity needs, which depend on projected peak demand. Demand for electricity varies over time with daily, weekly, and seasonal cycles and fluctuates even within a given hour. It is generally lower at night and on weekends and holidays, with the maximum usually occurring on hot summer weekday afternoons. Expected peak demand is a critical factor in electricity and transmission planning, since it determines generation and transmission capacity requirements.

Such an analysis cannot be conducted in isolation. The Energy Commission augments its own expertise with input from other government agencies, utilities, advocacy groups, and consultants. Regular meetings of the Demand Analysis Working Group, formed by the Energy Commission in 2008, provide stakeholders the opportunity to share information, data, ideas, and methods, and to suggest changes in the existing process.

In the most recent forecast and accompanying report, *CED 2011 Preliminary*, staff incorporated stakeholder feedback on a number of important issues, including the uncertainty surrounding near-term economic conditions (which are difficult to predict) and the relative impacts of various efficiency efforts (which are difficult to measure). Staff devoted public workshops to consider all stakeholder opinions on these two issues, as they carry sufficient consequence.

Demand Forecast Results

The *CED 2011 Preliminary* forecast includes three demand scenarios: high, mid, and low. The high demand case incorporates relatively high economic/demographic growth, low electricity and natural gas rates, and low efficiency program and self-generation impacts. The low demand case includes lower economic/demographic growth, higher assumed rates, and higher efficiency program and self-generation impacts. The mid-case uses input assumptions at levels between the high and low cases.

Table 8 compares projected electricity consumption and noncoincident[120] peak demand under the three forecast scenarios. Historical and forecasted values from the previous IEPR forecast (2009) provide points of reference.

Figure 8 compares projected consumption under the three scenarios alongside *California Energy Demand 2010–2020: Adopted Forecast (CED 2009)*. Consumption grows at a faster average annual rate from 2010 to 2020 in the mid- and high-energy

120 A region's coincident peak is the actual peak for the region, while the noncoincident peak is the sum of actual peaks for subregions, which may occur at different times.

Table 8: Statewide Electricity Demand Forecast Comparison

Consumption (GWh)				
	CED 2009 (December 2009)	CED 2011 Preliminary High (August 2011)	CED 2011 Preliminary Mid (August 2011)	CED 2011 Preliminary Low (August 2011)
1990	228,473	227,586	227,586	227,586
2000	264,230	260,408	260,408	260,408
2010	280,843	272,342	272,342	272,342
2015	299,471	296,821	292,286	286,100
2020	316,280	321,268	310,462	305,932
2022	—	332,514	318,396	313,493
Average Annual Growth Rates				
1990-2000	1.46%	1.36%	1.36%	1.36%
2000-2010	0.61%	0.45%	0.45%	0.45%
2010-2015	1.29%	1.74%	1.42%	0.99%
2010-2020	1.20%	1.67%	1.32%	1.17%
2010-2022	—	1.68%	1.31%	1.18%
Noncoincident Peak (MW)				
	CED 2009 (December 2009)	CED 2011 Preliminary High (August 2011)	CED 2011 Preliminary Mid (August 2011)	CED 2011 Preliminary Low (August 2011)
1990	47,521	47,520	47,520	47,520
2000	53,703	53,703	53,703	53,703
2010*	62,459	60,455	60,455	60,455
2015	66,868	66,569	65,701	64,246
2020	71,152	72,006	69,818	68,498
2022	—	74,220	71,280	69,738
Average Annual Growth Rates				
1990-2000	1.23%	1.23%	1.23%	1.23%
2000-2010	1.52%	1.19%	1.19%	1.19%
2010-2015	1.37%	1.95%	1.68%	1.22%
2010-2020	1.31%	1.76%	1.45%	1.26%
2010-2022	—	1.72%	1.38%	1.20%

Historical values are shaded blue.

Source: California Energy Commission

*The 2011 forecasts use 2010 weather-normalized peak rather than actual to estimate growth.

Figure 8: Statewide Annual Electricity Consumption

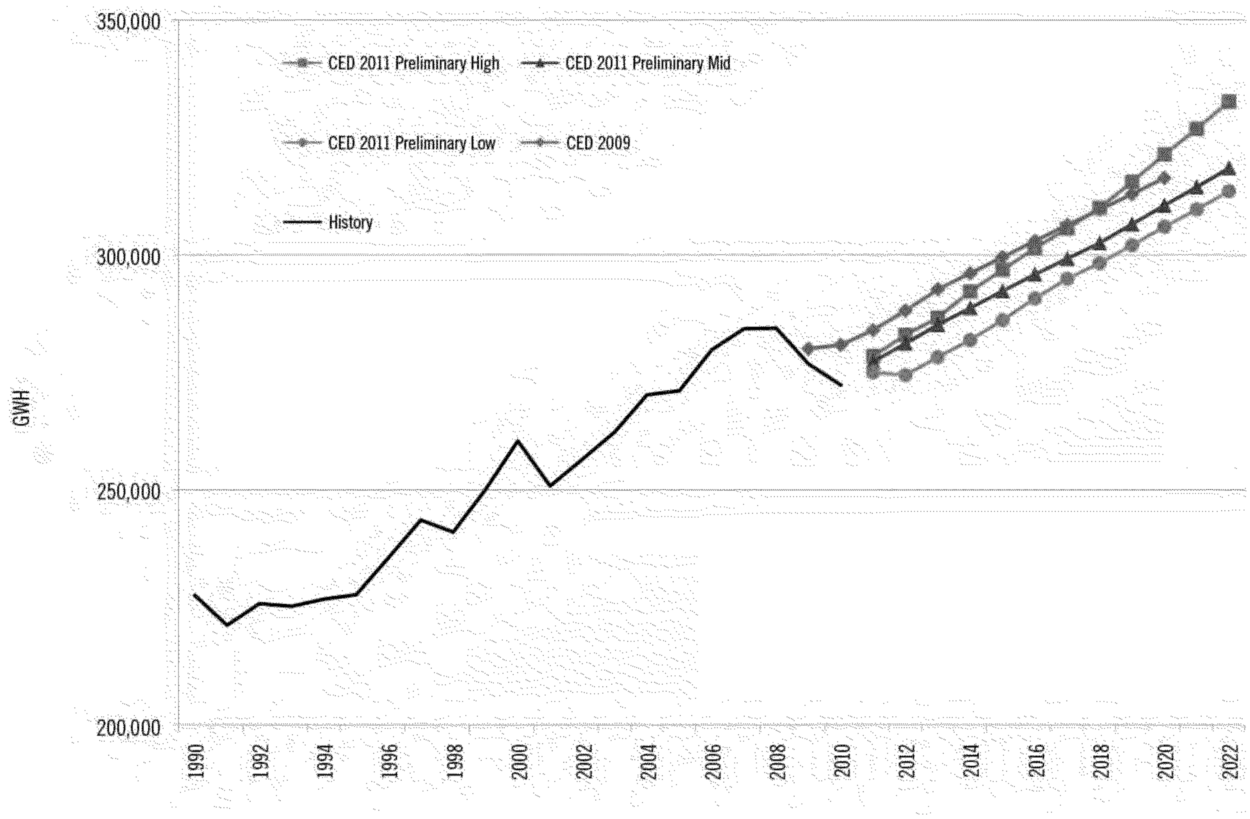
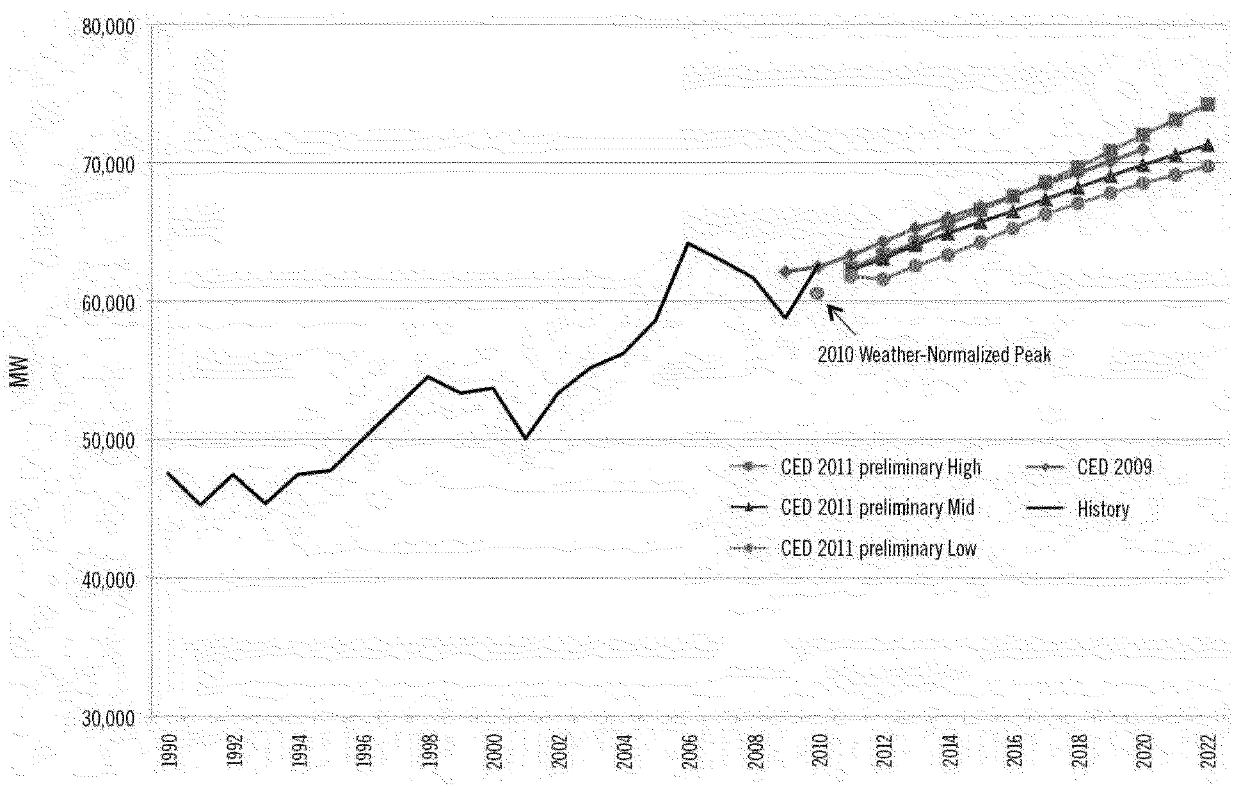


Figure 9: Statewide Annual Noncoincident Peak Demand



Source: California Energy Commission

demand cases (1.32 and 1.67 percent, respectively) compared to *CED 2009* (1.20 percent). In the low demand scenario, annual growth is higher than in *CED 2009* after 2012. Higher projected growth rates in the 2011 forecast reflect a deeper recession in 2009 than assumed as well as a very mild weather year in 2010 and therefore faster growth in reverting to expected long-term weather and economic trends. Forecast consumption reaches *CED 2009* projected levels by 2018 in the high-demand scenario and surpasses the 2020 *CED 2009* projection in the mid-case by 2022. By the end of the forecast period, California's electricity consumption is expected to reach between 313,000 and 333,000 GWh.

Consumption is the main driver for peak demand projections, so the depiction in Figure 9 of the preliminary peak forecast scenarios looks much like Figure 8. Growth in peak demand from 2010–2020, relative to a weather-normalized 2010, is faster in the high and mid cases (1.76 percent and 1.45 percent, respectively) than in *CED 2009* (1.31 percent). Statewide peak demand is projected to reach the *CED 2009* level by 2017 in the high-demand scenario and to surpass the 2020 *CED 2009* projection in the mid-case by 2022. Average annual growth rates from 2010–2020 relative to actual peak in 2010 are projected to be 1.41 percent, 1.10 percent, and 0.91 percent, respectively, in the high-, mid-, and low-demand scenarios. By 2022, peak demand is expected to reach between 69,700 and 74,200 MW.

The *CED 2011 Preliminary* natural gas forecast parallels the electricity consumption forecast. Historical data is incorporated up through 2010, and the same models are used to produce three scenarios (high-, mid-, and low-demand) under the same economic/demographic assumptions developed for the electricity forecast. Historical consumption in 2010 is higher than the value projected by *CED 2009*. Projected growth rates are higher, too, such that all three demand scenarios project greater consumption in 2020 than previously expected. By 2022, consumption is expected to reach between 13,773 million and 14,175 million therms. Table 9 compares projected natural gas consumption under the three scenarios.

Modifications to Forecast Method

Additional consumption data became available after publication of the *2009 Integrated Energy Policy Report*. The *CED 2011 Preliminary* adjusted the timeline so that 2010 is the historical base year and the forecast horizon extends to 2022, compared to 2020 in *CED 2009*. Beyond this routine adjustment, staff made several significant modifications to the *2011 IEPR* demand forecast method.

For one, staff developed the major economic sectors – residential, commercial, and industrial – by combining the Energy Commission's traditional end-use models and a new econometric approach (created by staff in 2011). Additionally, staff developed peak projections using its Hourly Electricity Load Model and a new econometric model. Staff made adjustments to results from existing models based on the econometric estimations. For example, price elasticities estimated in the residential and industrial econometric models replaced previous end-use elasticities. Recommendations from a recent evaluation of the demand model method motivated staff to develop a robust, multi-resolution modeling approach to demand forecasting.

Staff forecasted residential adoption of photovoltaic (PV) systems and solar water heaters using a predictive model rather than a trend analysis (as in previous forecasts). The new method is based on estimated payback periods and cost-effectiveness determined by upfront costs, energy rates, and various incentive levels. Staff developed scenarios using varied assumptions about electricity rates and new home construction.

Finally, *CED 2011 Preliminary* incorporates potential global climate change impacts more comprehensively. The Energy Commission demand forecasting process typically models these impacts by adjusting

Table 9: Statewide End-User Natural Gas Forecast Comparison

Historical values are shaded blue.

	Consumption (MM Therms)			
	CED 2009 (December 2009)	CED 2011 Preliminary High (August 2011)	CED 2011 Preliminary Mid (August 2011)	CED 2011 Preliminary Low (August 2011)
1990	12,893	12,893	12,893	12,893
2000	13,913	13,914	13,914	13,914
2010	12,162	12,665	12,665	12,665
2015	12,751	13,372	13,338	12,891
2020	12,997	13,832	13,789	13,552
2022	—	14,175	13,992	13,773
Average Annual Growth Rates				
1990-2000	0.76%	0.76%	0.76%	0.76%
2000-2010	-1.34%	-0.94%	-0.94%	-0.94%
2010-2015	0.95%	1.09%	1.04%	0.36%
2010-2020	0.67%	0.89%	0.85%	0.68%
2010-2022	—	0.94%	0.83%	0.70%

Source: California Energy Commission

upward the number of cooling and heating degree days in the forecast period, based on the historical ratio of degree days in the last 12 years to that of the last 30 years. The result of this adjustment is an increase in the projected amount of cooling and a decrease in heating relative to the historical period. This correction attempts to account for the likelihood of a general warming trend.

However, temperatures assumed in the peak forecast (an average of daily temperatures over a 30-year period) are not affected by the adjustment, so the forecast may not fully capture the impact on peak demand of possibly more frequent heat storm weather events, in the form of higher maximum temperatures in a given year. Therefore, using climate change scenarios for maximum temperatures developed by the Scripps Institute, staff applied these to the peak econometric model (which includes a coefficient for maximum temperature) and used the projected climate change impacts to adjust the existing end-use peak model results.

The *CED 2011 Preliminary* describes these changes, along with forecast results and modeling methodologies, in much greater detail.[121]

Energy and the Economy

Economic projections are one of the key inputs to the demand forecast. For the ***CED 2011 Preliminary*** forecast, staff examined multiple economic and demographic scenarios. The intent was to quantify the impacts from a reasonable range of assumptions

121 Kavalec, Chris, Tom Gorin, Mark Ciminelli, Nicholas Fugate, Asish Gautum, and Glen Sharp, 2011, op. cit.

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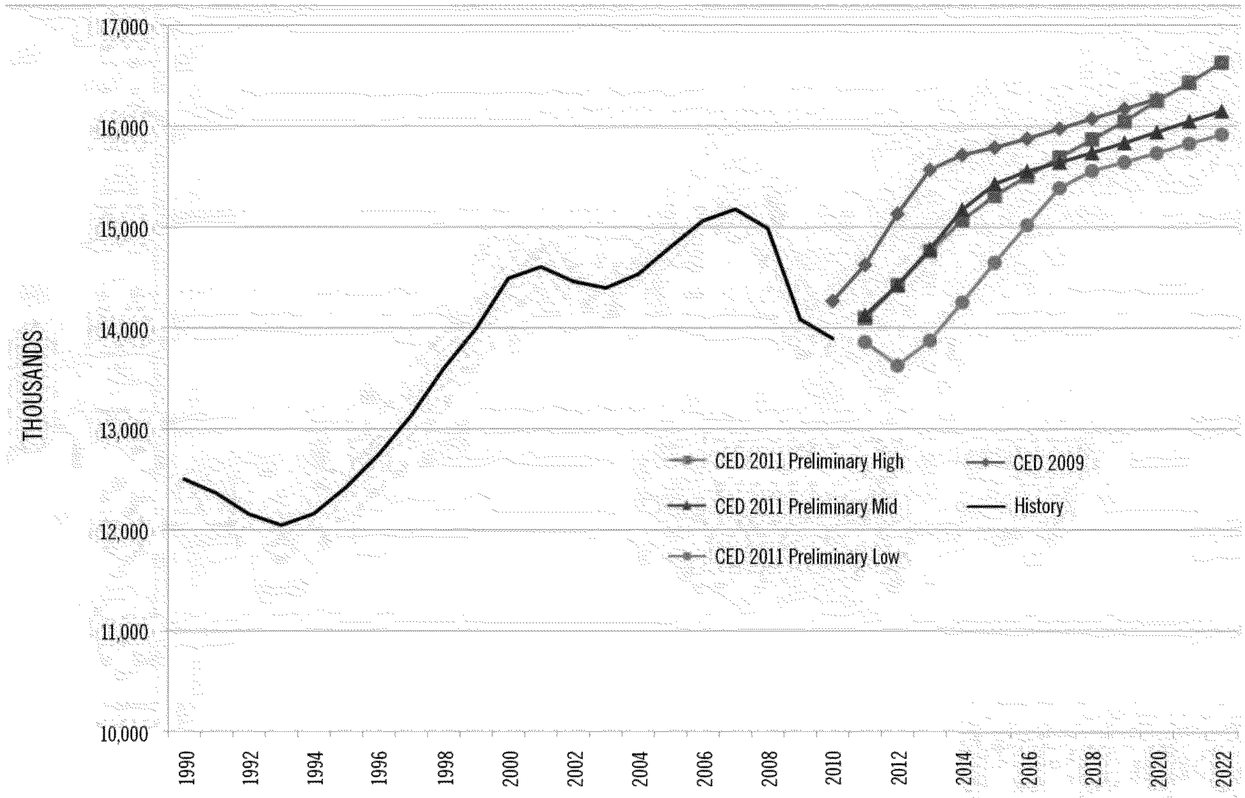
Figure 10: Statewide Employment Projections



Source: California Energy Commission

on electricity demand. Staff selected three sets of economic projections from Moody's Economy.com and IHS Global Insight. Staff chose scenarios that captured the highest and lowest projected levels of economic growth.

Figure 10 shows historical and projected levels for nonagricultural employment, a key economic driver of the commercial and industrial forecasts. A comparison of the projections illustrates consistent expectations about the future of California's economy. Each case assumes California will experience a period of rapid growth as the economy begins to recover from the 2008 crisis, followed by a return to modest long-term growth at rates similar to those seen in recent history.

The most significant discrepancy between these economic projections lies in the duration of the recession and in the timing and rate of the recovery. Energy consumption trends with employment and other economic indicators, so these transitions are important factors, particularly in characterizing energy use over the next few years. Despite a great deal of economic uncertainty surrounding the current recession (for example, when and how California will recover), the alternative scenarios show a relatively narrow band by the end of the forecast period. This narrowing tends to reduce the differences among the forecast energy scenarios later in the forecast period, all else being equal.

Traditional indicators such as employment, personal income, and population are important, but are not the only economic factors that could affect the forecast. On January 19, 2011, the Energy Commission hosted a public workshop where several expert economists, researchers, policy makers, and business owners discussed ways in which the future of Califor-

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nia's economy may deviate from its historical pattern. Staff considered some key points made during the discussion:

*** The substantial drop in housing prices may affect migration patterns, specifically increasing in-migration. It is likely that California will not experience the same pattern of depressed population growth as seen in previous recessions.

*** Changes to average home size and location may have a significant effect on demographic drivers.

*** Over the coming decade, climate change may introduce constraints on water supplies.

*** Alternative indicators, such as personal debt, may become more valuable at providing insight into energy consumption patterns.

As California's economy recovers and changes, it is critically important that the Energy Commission adapts its demand forecasting models appropriately. Staff will consider incorporating such factors in future IEPR forecasts while continuing to engage with a variety of economic and demographic experts.

Self-Generation Impacts

The *CED 2011 Preliminary* forecast includes the impacts of on-site distributed generation (DG) used in large-scale facilities and of the major incentive programs designed to promote self-generation. The forecast uses a trend analysis to project self-generation, except in the case of residential PVs and solar water heaters, where it uses a new predictive model. The incentive programs include:

*** Emerging Renewables Program (ERP): This program is managed by the Energy Commission.

*** California Solar Initiative (CSI): This program is managed by the CPUC.

*** Self-Generation Incentive Program (SGIP): This program is managed by the CPUC.

*** New Solar Homes Partnership (NSHP): This program is managed by the Energy Commission.

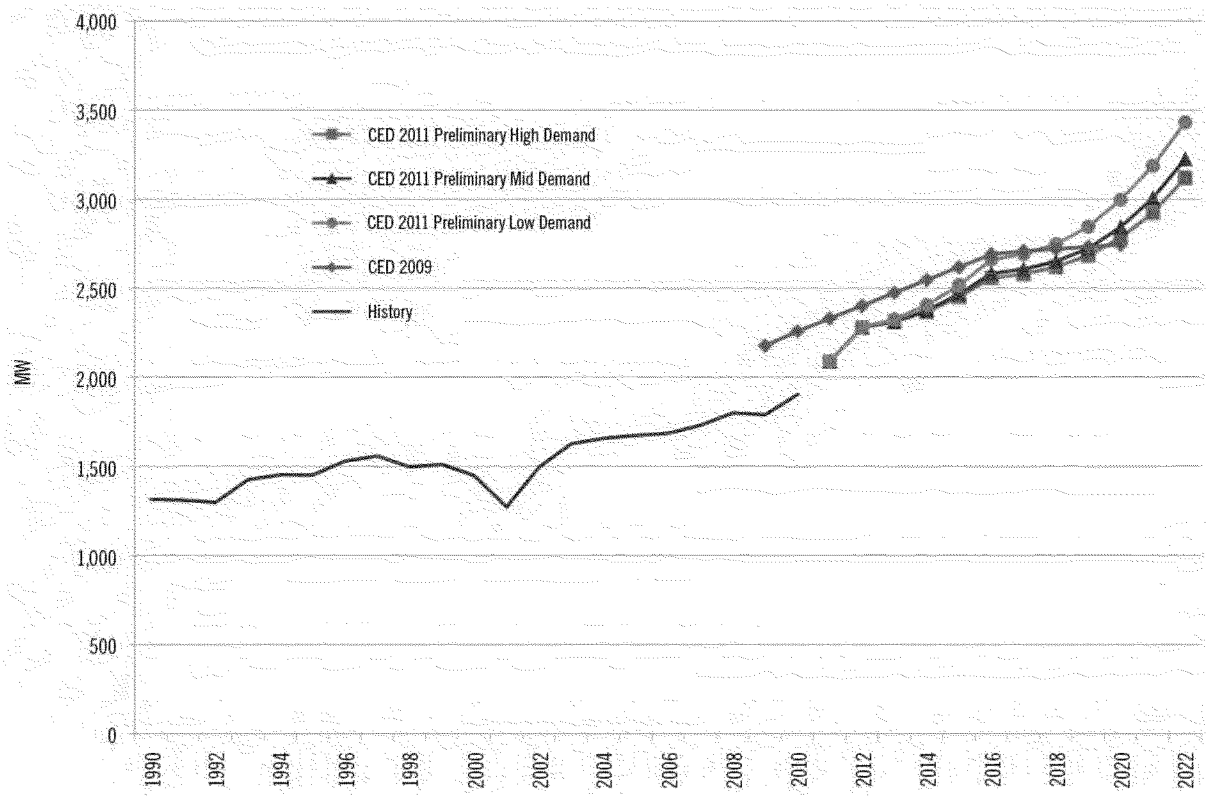
*** Utility Incentives: Administered by publicly owned utilities such as Sacramento Municipal Utility District (SMUD), LADWP, Imperial Irrigation District, Burbank Water and Power, City of Glendale, and City of Pasadena.

The general strategy of the ERP, CSI, SGIP, and NSHP programs is to encourage demand for self-generation technologies, such as PV systems, with financial incentives until the market increases and achieves economies of scale and decreases the capital costs. The extent to which consumers see real price declines will depend on the interplay of supplier expectations, the future level of incentives, and demand as manifested by the number of states or countries offering subsidies.

Figure 11 shows historical and expected peak impacts of self-generation, which are projected to reduce peak load by more than 3,000 MW by 2022. Historical impacts were revised downward because some self-generation data was found to be misclassified, so *CED 2009* projections begin well above estimates of historical impacts. Higher projections for PV peak impacts in both the residential and commercial sectors drive total self-generation peak above *CED 2009* levels by 2020 in all three scenarios. The temporary flattening of the curves after 2016 corresponds to expiration of the CSI program.

Table 10 shows historical and projected statewide electricity consumption from self-generation, and is broken out into PV and non-PV applications. For traditional combined heat and power (CHP) technologies, self-generation is assumed constant, so that

Figure 11: Statewide Peak Impacts of Self-Generation



Source: California Energy Commission

Table 10: Electricity Consumption From Self-Generation (GWh)

	1990	2000	2010	2015	2020	2022
Non-Photovoltaic Self-Generation	8,242	9,179	9,651	10,366	10,852	11,065
Photovoltaic, Low Demand	3	10	1,110	3,063	4,691	6,060
Photovoltaic, Mid Demand	3	10	1,110	2,874	4,118	5,290
Photovoltaic, High Demand	3	10	1,110	2,817	3,894	4,896
Total Self-Generation, Low Demand	8,245	9,189	10,761	13,429	15,543	17,125
Total Self-Generation, Mid Demand	8,245	9,189	10,761	13,488	14,945	16,329
Total Self-Generation, High Demand	8,245	9,189	10,761	13,429	14,716	15,924

Source: California Energy Commission

retired CHP plants are replaced with new ones with no net change in generation in the current forecast. Given the Governor's policy goals for CHP and DG and the recent qualifying facility settlement to CHP, in future *IEPRs* there will be a more comprehensive assessment of the status of CHP in California. As part of this effort, the staff will be developing scenarios for this technology for the revised forecast. Growth in non-PV self-generation comes mainly from recent increases in the application of fuel cells and other low emissions technology, projected forward.

Energy Efficiency Impacts

California's energy policy identifies energy efficiency as the "resource of first choice" for meeting California's future energy needs. As such, efficiency codes and standards, programs, and other policies play a central role in California's energy procurement and transmission plans and are a strategic element in the state's greenhouse gas emission reduction goals. Unlike other resources that are deployed to meet demand, energy efficiency reduces consumption and is therefore considered in the demand forecast, either embedded directly within the forecasting models or as an incremental effect subtracted from the model output. In both cases, staff is ensuring that the demand forecast reflects reasonable levels of efficiency from a comprehensive set of efforts expected to occur.

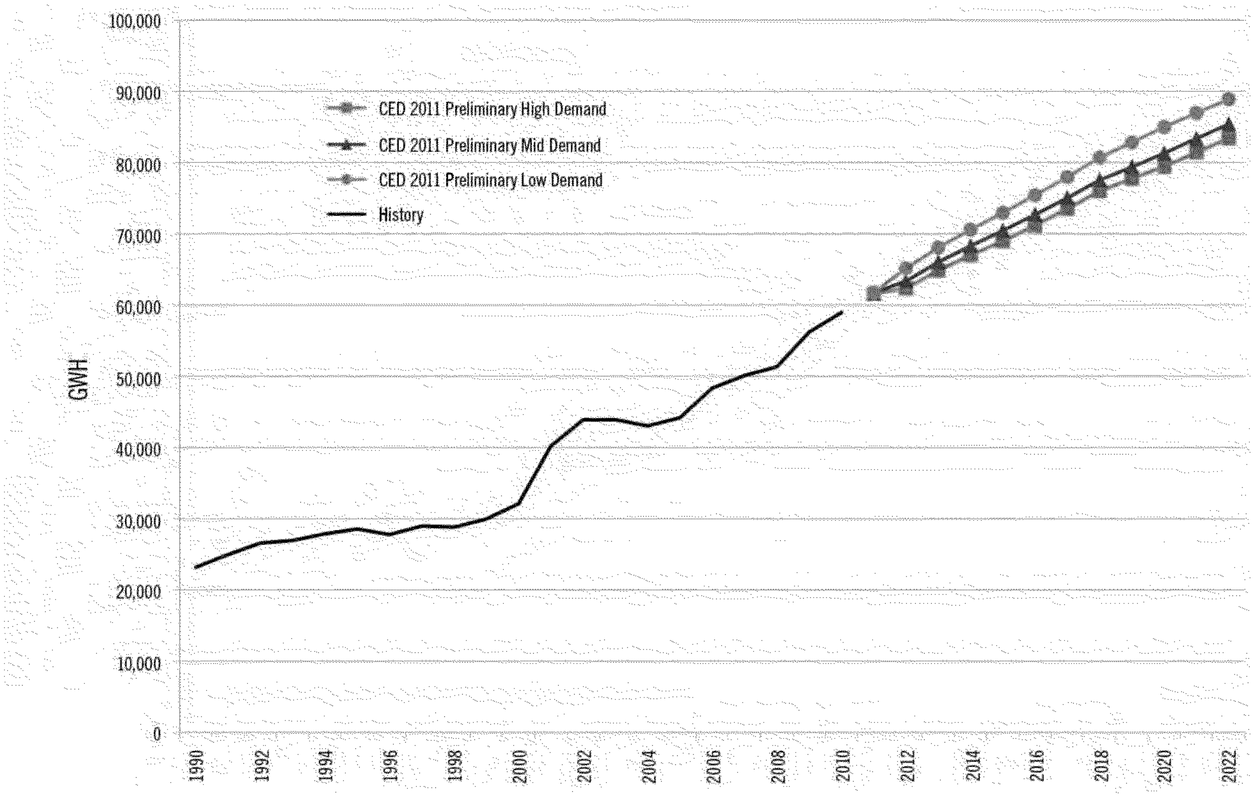
The *CED 2011 Preliminary* forecast continues the long-standing practice of distinguishing between two types of "reasonably-expected-to-occur" savings – committed and uncommitted. Committed efforts to reduce demand include authorized utility programs, finalized building and appliance standards, and other policy initiatives that have implementation plans, firm funding, and a design that can be technically assessed to determine probable future impacts. Committed savings also include price and market effects, which represent savings from rate increases and other market effects not related directly to standards and programs. These savings are incorporated directly into the forecast. Uncommitted savings – which, while plausible, have a great deal of uncertainty surrounding the method, timing, and relative impact of their implementation – are considered separately within the *CED 2011 Preliminary* analysis.

The Energy Commission developed the demand forecasting models in a way that promotes the inclusion of building and appliance efficiency standards. The models distinguish among vintages of floor space, housing, and equipment. As a new building or piece of equipment is added, the model assumes its energy use characteristics meet – at a minimum – the applicable standards. Following the effective implementation date, standards gradually affect an increasingly larger proportion of the total building and appliance stock. Each cycle of progressively tightened standards can be evaluated to determine the additional energy savings contributed from each vintage of standards by comparing model outputs.

Measuring the effects of utility programs poses a greater challenge, as customer participation is voluntary and is motivated by a complex set of interactive effects. Also, customers may replace appliances well before the end of their usefulness, and while data may be available on the efficiency of new appliances, the reference level of efficiency is often unknown for the replaced appliances.

To better measure program impacts, staff leveraged the CPUC's most recent efforts to measure utility program savings. The CPUC Energy Division's evaluation-based estimates of program savings from the 2006–2008 program cycle, as well as additional evaluation for 2009 programs, represent the most thorough and comprehensive effort to date. This unprecedented level of detailed evaluation data, however, applies only to programs implemented within the last four years. Therefore, staff modeled the uncertainty surrounding the performance of future programs using scenario analysis.

Figure 12: Statewide Committed Consumption Efficiency and Conservation Impacts



Source: California Energy Commission

Because a clear, consistent record of evaluated efficiency program achievements is not readily available,[122] there is a great deal of uncertainty around any estimate of historical program impacts. This uncertainty, along with uncertainty around attribution of savings among standards, programs, and price effects, has been the subject of debate in recent Demand Analysis Working Group meetings. Some parties have insisted that Energy Commission demand forecasts incorporate historical program impacts that are vastly underestimated and/or credit too much savings to standards and price effects, especially before 1998. A recent staff paper summarizes the positions of various parties.[123]

Staff believes that the forecasting process yields reasonable estimates of total savings but acknowledges and shares concerns voiced by stakeholders about savings attribution. Therefore, the *CED 2011 Preliminary* provides no attribution among the three sources (programs, codes and standards, and price and market effects) except for estimates of standards impacts. In other words, it provides no specific esti-

122 See discussion of EM&V requirements over time in Kavalec, Chris and Don Schultz, May 2011, *Efficiency Programs: Incorporating Historical Activities Into Energy Commission Demand Forecasts*, draft staff paper, California Energy Commission, Electricity Supply Analysis Division, CEC-200-2011-005-SD, available at: www.energy.ca.gov/2011publications/CEC-200-2011-005/CEC-200-2011-005-SD.pdf.

123 California Energy Commission, Electricity Supply Analysis Division, Chris Kavalec, *Energy Efficiency Program Characterization in Energy Commission Demand Forecasts: Stakeholder Perspectives and Staff Recommendations: Draft Staff Paper*, August 2011, CEC-200-2011-010-SD, available at: www.energy.ca.gov/2011publications/CEC-200-2011-010/CEC-200-2011-010-SD.pdf.

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mates of program and price effects. Staff will continue to work with stakeholders on these issues, with the goal of showing attribution for at least some years in future reports. Figure 12 shows total historical and projected committed efficiency savings from the three sources starting in 1990. Annual totals are relative to conditions in 1975, before the state implemented the first efficiency standards.

Beyond these committed impacts, the CPUC, Energy Commission, California Air Resources Board, and the Legislature have set efficiency goals without approval of specific program designs or authorization of actual program funding levels. Staff must consider long-term utility savings goals, future updates to Title 20 and Title 24 codes and standards, and statewide policy initiatives in determining incremental uncommitted energy efficiency impacts – impacts that are in addition those already included in the baseline forecast.

During the *2009 IEPR* cycle, at the request of the CPUC, staff began to assess the effects of incremental uncommitted energy efficiency policy initiatives. Staff included policy initiatives in the analysis similar to those originally evaluated by Itron and adopted by the CPUC in the *2008 Energy Efficiency Goals Update Report* (*2008 Goals Study*).[124] The incremental uncommitted analysis for *CED 2011 Preliminary* also relies on the *2008 Goals Study* but is updated to account for the passage of time. Therefore, some initiatives considered uncommitted in 2009 are now incorporated in the committed forecast. (Figure 12 includes estimated savings.) The newly committed initiatives include Assembly Bill 1109 (Huffman, Chapter 534, Statutes of 2007) and the 2010 Title 24 Building Code Revisions. In addition, the *CED 2011 Preliminary* extends uncommitted analysis to publicly owned utilities. The uncommitted efficiency initiatives in *CED 2011 Preliminary* include:

*** Utility programs beyond 2012, including residential, commercial, and industrial.

*** Further updates to state Title 20 and 24 standards along with updated federal appliance standards.

*** The CPUC's Big Bold Energy Efficiency Initiatives.

As in the *2008 Goals Study*, *CED 2011 Preliminary* assumed various levels of commitment to these policies to create three scenarios of uncommitted efficiency savings – high, medium, and low. By 2022, consumption in the mid-demand case would be reduced 3.3 percent if adjusted by the low savings scenario and 6.2 percent using high incremental uncommitted savings. For peak, the reductions range from 4.8 percent to 9.5 percent, higher than consumption because the end uses targeted by these initiatives tend to have higher-than-average peak-to-energy-consumption ratios.

Combining the high demand case with the low incremental uncommitted efficiency scenario and the low-demand case with the high efficiency scenario gives a range of "managed" forecasts. Statewide, adjusted consumption ranges from around 294,000 GWh to 322,000 GWh, compared to 313,000 GWh to 332,000 GWh for unadjusted consumption. For peak demand, the adjusted range is 63,000 MW to 71,000 MW, compared to the unadjusted range of 70,000 MW to 74,000 MW. In these adjusted mid- and low-demand cases, peak demand begins to drop slightly by the end of the forecast period. Peak demand in the low case drops slightly below the actual 2010 statewide (noncoincident) level.

The CPUC's new *Potential and Goals Study* is underway and is expected to be completed in late summer 2012. This schedule does not allow the study to be fully incorporated in the revised or final adopted IEPR demand forecasts, but CPUC staff intends to use interim study results to recommend changes to the incremental uncommitted efficiency impacts

124 Itron, Inc. *Assistance in Updating the Energy Efficiency Savings Goals for 2012 and Beyond*, adopted by CPUC in March 2007, www.cpuc.ca.gov/NR/rdonlyres/D72B6523-FC10-4964-AFE3-A4B83009E8AB/0/GoalsUpdateReport.pdf.

developed from the *2008 Goals Study*. Thus, the uncommitted results will likely differ in the revised and adopted IEPR forecasts compared to the preliminary.

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The California ENERGY COMMISSION

Energy Consumption Data Management System

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Energy Consumption Data Management System

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Moving Energy Storage from Concept to Reality:

Southern California Edison's Approach to Evaluating Energy Storage

Abstract:

The electric industry has pursued cost-effective energy storage for many decades. In a business traditionally constrained by the need to instantaneously match demand with supply, the potential to store generated electricity for use during more valuable periods has been long recognized. In recent years a series of factors, including technological progress, legislative and regulatory tailwinds, and new grid challenges associated with integrating variable renewable generation, have propelled energy storage to the forefront of industry consciousness. This excitement, however, does not by itself resolve the various complexities facing energy storage. Even the definition of "storage" can be confusing, as the term refers to multiple different technologies and potential uses across the electrical grid. Additionally, while these options continue to develop and emerge, there is little consensus on how their worth should be evaluated. Recognizing these challenges, this white paper offers a methodology for contextualizing and analyzing the broad and heterogeneous space of energy storage, and it ultimately identifies applications currently viewed as having the greatest potential value from Southern California Edison's (SCE) perspective. It is SCE's goal to advance the storage discussion towards the vision of a more reliable grid, with reduced environmental impacts, at overall lower costs to electric consumers.

renewable energy. The project further measured the effects of renewable variability on system operation, and then ascertained how energy storage and changes in energy dispatch strategies could improve grid performance. The white paper, therefore, was not intended to provide a holistic assessment of storage, and instead modeled the specific operational impacts associated with pre-defined renewable penetration scenarios.

Major paper conclusions include:

- The CAISO (California Independent Service Operator) control area may require between 3,000 and 5,000 MW of additional regulation/ramping services from fast (5-10 MW per second) resources in 2020. These ramping requirements are driven by longer-duration solar and wind variability.
- The short-duration volatility of renewable resource output will require additional automatic generation control (up to double current levels).
- Fast (defined as 10 MW per second) storage is two to three times more effective than conventional generation in meeting ramping requirements. Consequently, 30-50 MW of storage is equivalent to 100 MW of conventional generation.
- Energy storage may reduce the greenhouse gas emissions associated with committing combustion turbines for regulation, balancing, and ramping duty.

In summary, this report provides an analysis of renewable resource impacts on California's grid operations – particularly the changes in ramping and regulation requirements – and offers storage as a promising mitigation option. While insinuating that storage could be the most cost-effective solution for renewables integration, the authors do not thoroughly demonstrate this through full benefit-cost modeling. Additionally, the analysis is by design bounded in scope and therefore lacks the breadth of potential operational uses necessary to fully evaluate energy storage applications, even those addressing renewable intermittency, across the electric value chain.

***

In late 2009, ***EPRI*** published a report valuing specific energy storage projects and technologies.[17] Like the CEC white paper, it focused on storage's potential to provide solutions for renewables integration issues, specifically those caused by excess wind in the Electric Reliability Council of Texas (ERCOT) region. In contrast, EPRI approached its assessment through the lens of market-based analyses on four broad storage technology options: 1) Compressed Air Energy Storage (CAES), 2) Liquid Air Energy Storage (LAES), 3) bulk batteries, and 4) distributed batteries.

For each technology, the report assessed the rate of return from a potential independent investor's perspective by computing net operating incomes. These were driven primarily by the costs and revenues associated with arbitraged on and off peak energy price spreads and the market rents from offering ancillary services. The authors also assessed a broader societal benefit-cost ratio which included congestion relief and the impact on carbon

[17] Electric Power Research Institute, *Economic and Greenhouse Gas Emission Assessment of Utilizing Energy Storage Systems in ERCOT*, 1017824, Technical Update: November 2009

potential operational challenges associated with integrating large amounts of intermittent, must-take renewable energy into the electric grid.

11. Transmission system short-duration performance

Energy storage, if installed in large enough quantities, could be used to improve short-duration performance on the transmission system. This includes improving system voltage or providing capacity (fault duty) during system faults. The clearest way in which energy storage could perform this operational use is if it were to replace a device that currently improves transmission system performance (e.g., capacitor banks or Flexible AC Transmission System (FACTS) devices). If a storage device can be shown to provide one or more useful transmission services, the device could be included in a transmission planner's toolkit, and taken into consideration in the transmission planning process. Another way in which a storage device could perform this operational use is by preventing an issue causing problems on the transmission grid. For example, if extremely variable wind production was causing transmission system performance issues, and a large energy storage device firmed or smoothed this energy, it could be simultaneously providing the renewable energy smoothing / firming use while also improving transmission system performance.

12. System inertia

System inertia is provided today by large, conventional generation resources. The "spinning mass" of these devices can provide large amounts of power to the grid instantaneously in the case of a system reliability event. While storage would not do this exactly, the power electronics associated with a device could be designed such that they *simulate* system inertia by quickly discharging power onto the grid, if and when required.

13. Congestion fee avoidance

When a transmission line is congested, higher "fees" are incurred when transmitting energy. Avoiding such congestion would therefore circumvent these costs. Using an energy storage device to time-shift energy demand or supply, by transporting energy during off-peak hours and storing that energy downstream of the transmission line, would avoid such congestion and associated fees.

14. Transmission system upgrade deferral

When a transmission line or component is consistently overloaded, an infrastructure upgrade may be required. An energy storage device could be used to time-shift energy demand / supply (as per use #13, above) to avoid such problematic transmission congestion. The upgrade could be deferred until additional load growth ultimately necessitates the infrastructure improvement or if load requirements for that transmission path remain stable, energy storage could defer the upgrade more permanently.

15. Transmission system reliability

An energy storage device could be used to improve the reliability of the transmission grid in two ways. First, the energy storage device could replace a technology solution that currently improves system reliability (e.g., a Static VAR Compensator). As explained in use #11, if a storage device can be shown to provide one or more useful transmission

COMMENTS OF THE STAFF OF THE

CALIFORNIA PUBLIC UTILITIES COMMISSION

ON THE DRAFT STUDY PLAN

(FEBRUARY 21 DOCUMENT AND FEBRUARY 28 MEETING)

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March 14, 2012

Introduction

The Staff of the California Public Utilities Commission ("CPUC Staff") appreciate this opportunity to provide comments on the California Independent System Operator's ("ISO") 2012-2013 Transmission Planning Process ("TPP") Draft Study Plan ("Study Plan") dated February 21, 2012 and discussed at the February 28 stakeholder meeting. We provide the following limited comments which mainly concern the need to provide greater transparency and disclosure in some areas, and especially the need to use the latest load forecast and to both include and take into account study cases that project continuing ("incremental") Demand Side Management (DSM) and Combined Heat and Power (CHP) measures over the 10-year planning horizon.

1. 2012-2013 TPP Studies Should Use the Latest Energy Commission Load Forecast and Should Include and Take Into Account Reasonably Expected Incremental(Uncommitted)DSM and supply-and demand-sideCHP.

It is essential that planning assumptions be as up to date as possible, and for that reason the studies should be based on the current than the Energy Commission revised load forecast released on February 21, 2012, and if possible, the Energy Commission's final forecast expected to be released by the end of March. Additionally, assessment of transmission needs ten years out could be significantly influenced by which Energy Commission load forecast is used. CPUC resource planning via the Long Term Procurement Plan (LTPP) process assumes that DSM[1] and CHP[2] programs will continue and not simply terminate or "drop off a cliff" when their currently authorized funding ends. Therefore, the LTPP process "manages" CEC load forecasts to include such "incremental" CHP and DSM reasonably expected to occur. The selected values are modified downward from goals or potential study assumptions to account for uncertainty through stakeholder processes. For consistency with resource planning and to avoid a narrowly conservative picture of 10-years-out transmission needs, the ISO's 2012-2013 TPP studies should meaningfully assess scenarios that include the above incremental DSM and CHP, and should not identify major 10-year transmission needs without assessing the extent to which those needs would exist under load forecasts that include incremental DSM and CHP.

2. *The Generation Assumptions Should be Consistent with State Policy and Reasonable Expectations*

The assumptions on generation retirements only include generation units that have announced plans for retirement. A significant number of older plants are subject to the Water Resource Control Board's policy on cooling water intake structures. As such, these plants will require significant upgrades to operate past the policy's compliance dates. Many of the plant owners have indicated[3] they would repower units if they receive a long term contract and will retire the unit if they do not. Previous ISO analysis has indicated that not all the older steam generators will be needed. Assuming none of these plants retire biases the TPP analysis and provides no information on the trade-off between any needed transmission upgrades and new generation or repowers. Furthermore the retirement assumptions should be such that the generation is assumed retired consistent with current Water Resource Control Board policy compliance dates. It is important to note that to the extent these units are needed for proven reliability reasons, the Statewide Advisory Committee on Cooling Water Intake Structures is tasked with making annual recommendations to the Water Resource Control Board on any needed changes to the implementation schedule.

3. *Assumptions Underlying Local Capacity Requirements (LCR) and Once Through Cooling (OTC)/AB 1318 Studies Need to Be Clearly Explained within the Study Plan (and Ultimately within the 2012-2013 Transmission Plan), and Divergence from Planning Assumptions Used by the CPUC and CEC Should Be Justified.*

The draft 2011-2012 Plan referred to external planning materials when describing certain LCR and OTC[4] study assumptions. Combined with a more general need for greater clarity regarding assumptions for these studies, this made it difficult to assess exactly what inputs and assumptions were used.[5] This situation can complicate use and acceptance of the ISO's modeling results in other proceedings, and can impair ability to understand apparent discrepancies across different studies or projections. Therefore, CPUC Staff emphasize the need for clear documentation of LCR and OTC/AB1318[6]

[4] [illegible]

[5] [illegible]

[6] [illegible]

study assumptions, within the 2012-2013 TPP Study Plan, and ultimately within the 2012-2013 Transmission Plan itself.

4. *There Should be Sufficient Description of Any Major Transmission Additions Brought into the Base Case from the Generator Interconnection Process (GIP).*

For several years the ISO, CPUC, and other stakeholders have been pursuing the challenging goal of reducing the role of piecemeal transmission planning via the generator interconnection process and relying more strongly on holistic and transparent planning via the TPP. Recent steps in this direction include Cluster 1-4 deliverability study refinements and the TPP-GIP[7] integration initiative.

Thus, it is essential to adequately describe and analyze from a system-wide perspective any major GIP-driven transmission additions that are being imported directly into the 2012-2013 TPP base case. The ISO should explain which executed interconnection agreements result in transmission upgrades and their inclusion or exclusion from the base case and why this determination was made. Furthermore, there should be clear explanation of the correspondence between generation additions driving (or supported by) GIP-driven transmission additions and the study plan's established resource portfolios. The consequences for the Renewable Portfolio Standard (RPS) portfolios if particular GIP-driven upgrades were to be omitted should also be described.

The above information would support better understanding of the overall role of the proposed GIP-driven transmission projects. Additionally and importantly, it would inform resource planning and portfolio development.

At a minimum, the additional information that should be reported for any GIP-driven transmission facilities included in the base case includes the following.

- The physical/electrical/economic characteristics of such facilities, including voltage, transfer capability increase, endpoints, in-service date and cost.

- The MW and locations of (1) the renewable (and other) generation having signed interconnection agreements for which the GIP-driven facilities are needed and (2) separately, the amount of *additional* generation (beyond that having signed interconnection agreements) that could be accommodated by such added transmission facilities.
- Whether the added GIP-driven facilities would be needed for reliability or deliverability purposes.
- The modeled 8760-hour utilization of the added facilities under the different RPS scenarios studied. Such utilization should also be reported for other major transmission additions.

5. Methodology, Assumptions and Ultimate Planning Role for RPS Resource-Related Reliability and Deliverability Studies Need to Be Adequately Explained and Justified

This is especially important in light of the anticipated increased importance of the TPP to plan *delivery* network upgrades under TPP-GIP integration reforms. The ISO should clarify the relative roles, in upcoming studies and 2012-2013 Plan development, of on-peak deliverability studies conducted for RPS portfolios versus 8760-hour simulations of potential resource curtailment (dump energy) for those same portfolios. Furthermore, the assumed output levels (relative to maximum capacity) for wind and solar generation should be more fully and quantitatively described than in the past, particularly for major resource areas and under scenarios (and in locations) where transmission additions are identified.

It appears that for the 2011-2012 Plan development, deliverability studies set wind and solar output levels somewhere between the 50% and 20% exceedance levels[8] over the Qualifying Capacity (QC) period[9]. This suggests that the amount of transmission capacity required for deliverability under such conditions would exceed what is needed to

[illegible]

8 [illegible]

[illegible]

deliver the resources at their resource adequacy (Net Qualifying Capacity[10]) levels. This should be clarified and justified.

It is unclear, and needs to explained and taken into account when performing and interpreting studies, what should be the role of *reliability* studies conducted for RPS portfolios within the TPP. For example, are such results only informational, in that reliability network upgrades will be planned via reliability studies conducted for specific resources in the interconnection process? Similarly, the relationship between the ISO's standard TPP reliability studies for different parts of the grid (based on North American Electrical Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability criteria) versus reliability studies conducted specifically for RPS portfolios should be made clear.

For reliability and deliverability studies:

- Differences in assumed wind and solar output levels (deliverability vs. on-peak reliability studies) should be clarified,
- The assumed output of thermal generation at risk of retiring by 2022 should be clearly identified and the consequences of including versus excluding this generation in the reliability and deliverability studies should be clearly explained.

6. Key Economic Study Parameters Should be Sufficiently Documented, and Transmission Additions Identified Pursuant to Economic Study Requests Should be Eligible to Substitute for Other Transmission Additions Under Certain Circumstances.

Transmission costs can be high and can exceed estimates, especially in California and especially when encountering major siting issues. When conducting and reporting on economic congestion studies including the anticipated multifaceted Fresno/Central Valley study, as well as studies responding to study requests, the ISO should describe the source and rationale for transmission cost estimates. Assumptions and methods used to convert direct capital costs to total ratepayer costs, and to calculate various kinds of benefits

[10] [illegible]

against which costs are compared, such as summarized in Section 5.4.4 of the 2011-2012 draft Plan, should be documented and justified. Finally, given the uncertainties in both future circumstances and in appropriate selection of economic parameters, economic assessment of large potential transmission projects should be augmented with sensitivity analysis regarding key assumptions and economic parameters.

When an analysis performed for a study request identifies an efficient alternative to previously identified transmission additions[11], the ISO should evaluate which alternative produces the best value for ISO ratepayers.

7. *Major Identified "Reliability" Transmission Needs Based on N-2 (Category C) Contingencies Should be Adequately Justified*

Transmission planning studies have sometimes identified costly or difficult to permit transmission additions based on N-2 contingencies. NERC, WECC and ISO reliability and planning standards do not require avoidance of load shedding under N-2 contingencies, but provide that transmission additions to address such contingencies may be considered taking into account the specific circumstances of the contingences, consequences and mitigation. If considering major transmission additions to address N-2 contingencies, the ISO should provide substantial, transparent analysis and information regarding the contingencies and their likelihood; the magnitude, duration and costs of load shedding; and the costs and effectiveness of alternative solutions.

8. *Studies of Transmission Additions to Reduce LCR Subareas Should be Conducted*

Due to conflicting OTC requirements and local air emissions requirements, there arises the necessity to perform additional analysis related to compliance that may not just be generation retirement or repowering. Transmission improvements specifically to reduce reliance on OTC plants as well as particular locations in the transmission topology

[11] [illegible]

[illegible]

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(such as LCR subareas) are required in order to inform compliance alternatives for generating asset owners who have the choice of either retirement inside the current ISO transmission topology, repowering inside the current ISO topology, or undertaking another alternative such as refitting their water intake structures. Most importantly, transmission improvements for a future ISO transmission topology that reduce LCR requirements in sub-areas also needs to be examined, which the ISO has not addressed in a systematic manner. It is critical to be able to evaluate these tradeoffs in order to minimize ratepayer costs and make the most efficient decisions possible about future resource investment.

9. The Generation Assumptions Should be Consistent with State Policy and Reasonable Expectations

Due to conflicting OTC requirements and local air emissions requirements, there arises the necessity to perform additional analysis related to meeting reliability needs by creating options other than generation retirement or repowering. Transmission improvements specifically to reduce reliance on OTC plants as well as particular locations in the transmission topology (such as LCR subareas) are required in order to inform compliance alternatives for generating asset owners who have the choice of either retirement inside the current ISO transmission topology, repowering inside the current ISO topology, or undertaking another alternative such as refitting their water intake structures. Most importantly, transmission improvements for a future ISO transmission topology that reduce LCR requirements in sub-areas also needs to be examined, which the ISO has not addressed in a systematic manner. It is critical to be able to evaluate these tradeoffs in order to minimize ratepayer costs and make the most efficient decisions possible about future resource investment.

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Reactive Power and Importance to Bulk Power System

OAK RIDGE NATIONAL LABORATORY
ENGINEERING SCIENCE & TECHNOLOGY DIVISION

Where Does Reactive Power Come From?

- "Power" refers to the energy-related quantities flowing in the T&D network
- Instantaneously, Power is the product of voltage and current
- When voltage and current are not in phase or in synch, there are two components
  - Real or active power is measured in Watts
  - Reactive (sometimes referred to as imaginary) power is measured in Vars
  - The combination (vector product) is Complex Power or Apparent Power
- The term "Power" normally refers to active power

Why Do We Need Reactive Power

("Signatures of the Blackout of 2003",
Roger C. Dugan et. al.)

"Reactive power (vars) is required to maintain the voltage to deliver active power (watts) through transmission lines. Motor loads and other loads require reactive power to convert the flow of electrons into useful work. When there is not enough reactive power, the voltage sags down and it is not possible to push the power demanded by loads through the lines."

ESTD Engineering Science & Technology Division

UT-BATTELLE

Reactive Power Compensation Devices Advantages and Disadvantages

- **Synchronous Condensors - synchronous machines designed exclusively to provide reactive power support**
  - At the receiving end of long transmission lines
  - In important substations
  - In conjunction with HVDC converter stations.
  - Reactive power output is continuously controllable
- **Static VAR compensators – combine capacitors and inductors with fast switching (sub cycle, such as <1/50 sec) timeframe capability**
  - Voltage is regulated according to a slope (droop) characteristic

FILED

BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local Procurement Obligations.	)	Rulemaking 11-10-023 (Filed October 27, 2011)

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
SUBMISSION OF
2013 LOCAL CAPACITY TECHNICAL ANALYSIS
FINAL REPORT AND STUDY RESULTS

The California Independent System Operator Corporation respectfully submits the ISO's 2013 Local Capacity Technical Analysis Final Report and Study Results (2013 LCR Study) in accordance with the Order Instituting Rulemaking issued on October 27, 2011.

In addition, consistent with Rule 1.9, a copy of the document may be requested by telephone at 916-351-2212 or by email at apascusso@caiso.com.

Respectfully submitted,

/s/ Beth Ann Burns

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Date: May 2, 2012

2013
LOCAL CAPACITY TECHNICAL ANALYSIS

FINAL REPORT
AND STUDY RESULTS

April 30, 2012

Local Capacity Technical Study
Overview and Results

II. Executive Summary

This Report documents the results and recommendations of the 2013 Local Capacity Technical (LCT) Study. The LCT Study assumptions, processes, and criteria were discussed and recommended through the 2013 Local Capacity Technical Study Criteria, Methodology and Assumptions Stakeholder Meeting held on November 10, 2011. On balance, the assumptions, processes, and criteria used for the 2013 LCT Study mirror those used in the 2007-2012 LCT Studies, which were previously discussed and recommended through the LCT Study Advisory Group ("LSAG")[1], an advisory group formed by the CAISO to assist the CAISO in its preparation for performing prior LCT Studies.

The 2013 LCT study results are provided to the CPUC for consideration in its 2013 resource adequacy requirements program. These results will also be used by the CAISO as "Local Capacity Requirements" or "LCR" (minimum quantity of local capacity necessary to meet the LCR criteria) and for assisting in the allocation of costs of any CAISO procurement of capacity needed to achieve the Reliability Standards notwithstanding the resource adequacy procurement of Load Serving Entities (LSEs).[2]

Please note that these studies assume that SONGS will be fully operational in 2013. At the time this study was completed, SONGS was on an extended forced outage and the expected date that it would return to service was unknown. The ISO will continue to monitor the status of SONGS and reassess the 2013 LCR values, as needed.

[1] The LSAG consists of a representative cross-section of stakeholders, technically qualified to assess the issues related to the study assumptions, process and criteria of the existing LCT Study methodology and to recommend changes, where needed.

[2] For information regarding the conditions under which the CAISO may engage in procurement of local capacity and the allocation of the costs of such procurement, please see Sections 41 and 43 of the current CAISO Tariff, at: http://www.caiso.com/238a/238acd24167f0.html.

Below is a comparison of the 2013 vs. 2012 total LCR:

2013 Local Capacity Requirements

	Qualifying Capacity			2013 LCR Need Based on Category B			2013 LCR Need Based on Category C with operating procedure		
Local Area Name	QF/ Muni (MW)	Market (MW)	Total (MW)	Existing Capacity Needed	Deficiency	Total (MW)	Existing Capacity Needed**	Deficiency	Total (MW)
Humboldt	55	162	217	143	0	**143**	190	22*	**212**
North Coast / North Bay	130	739	869	629	0	**629**	629	0	**629**
Sierra	1274	765	2039	1408	0	**1408**	1712	218*	**1930**
Stockton	216	404	620	242	0	**242**	413	154*	**567**
Greater Bay	1368	6296	7664	3479	0	**3479**	4502	0	**4502**
Greater Fresno	314	2503	2817	1786	0	**1786**	1786	0	**1786**
Kern	684	0	684	295	0	**295**	483	42*	**525**
LA Basin	4452	8675	13127	10295	0	**10295**	10295	0	**10295**
Big Creek/ Ventura	1179	4097	5276	2161	0	**2161**	2241	0	**2241**
San Diego/ Imperial Valley	158	3991	4149	2938	0	**2938**	2938	144*	**3082**
Total	**9830**	**27632**	**37462**	**23376**	**0**	**23376**	**25189**	**580**	**25769**

2012 Local Capacity Requirements

	Qualifying Capacity			2012 LCR Need Based on Category B			2012 LCR Need Based on Category C with operating procedure		
Local Area Name	QF/ Muni (MW)	Market (MW)	Total (MW)	Existing Capacity Needed	Deficiency	Total (MW)	Existing Capacity Needed**	Deficiency	Total (MW)
Humboldt	54	168	222	159	0	**159**	190	22*	**212**
North Coast / North Bay	131	728	859	613	0	**613**	613	0	**613**
Sierra	1277	760	2037	1489	36*	**1525**	1685	289*	**1974**
Stockton	246	259	505	145	0	**145**	389	178*	**567**
Greater Bay	1312	5276	6588	3647	0	**3647**	4278	0	**4278**
Greater Fresno	356	2414	2770	1873	0	**1873**	1899	8*	**1907**
Kern	602	9	611	180	0	**180**	297	28*	**325**
LA Basin	4029	8054	12083	10865	0	**10865**	10865	0	**10865**
Big Creek/ Ventura	1191	4041	5232	3093	0	**3093**	3093	0	**3093**
San Diego	162	2925	3087	2849	0	**2849**	2849	95*	**2944**
Total	**9360**	**24634**	**33994**	**24913**	**36**	**24949**	**26158**	**620**	**26778**

* No local area is "overall deficient". Resource deficiency values result from a few deficient sub-areas; and since there are no resources that can mitigate this deficiency the numbers are carried forward into the total area needs. Resource deficient sub-area implies that in order to comply with the criteria, at summer peak, load may be shed immediately after the first contingency.
** Since "deficiency" cannot be mitigated by any available resource, the "Existing Capacity Needed" will be split among LSEs on a load share ratio during the assignment of local area resource responsibility.

Overall, the LCR needs have decreased by more than 1000 MW or about 4% from 2012 to 2013. The LCR needs have decreased in the following areas: Sierra, Fresno and LA Basin due to downward trend for load; Big Creek/Ventura due to downward trend for load, new transmission projects as well as load allocation change among substations. The LCR needs are steady in Humboldt and Stockton. The LCR needs have slightly increased in North Coast/North Bay, Bay Area and Kern due to load growth; San Diego due to load growth as well as deficiency increase in two small sub-areas however the total resource capacity needed for San Diego decreased slightly mainly due to changes to the WECC Regional Criteria[3] related to the definition of adjacent circuits resulting in the performance requirements for the simultaneous loss of the Sunrise Power Link and South West Power Link being classified as Category D as to compared to a category C event as well as elimination of WECC 1000 MW path rating on Sunrise Power Link. However, over the longer-term, there are expected LCR deficiencies in San Diego area due to the 2017 OTC compliance date for the Encina power plant and to the most restrictive contingency for this area limiting the pool of resources (qualifying capacity) effective in addressing the local area needs. Furthermore the San Diego local area has been expanded to include the Imperial Valley substation because the newly formed local area has higher requirements than the existing San Diego local area alone. The write-up for each Local Capacity Area lists important new projects included in the base cases as well as a description of reason for changes between 2013 and 2012 LCRs.

The ISO has undertaken an LCR assessment of the Valley Electric service area. There are no LCR needs in this new local area due to unavailability of local resources; however there are two constraints that may require local area resources in the future. Detailed results can be found in the Valley Electric section at the end of this report.

[3] TPL-001-WECC-CRT-2 System Performance Criterion – Effective April 1 2012

The ISO has undertaken a non-summer season LCR assessment of the San Diego area at stakeholder request. These results are for information purposes only and they will not be used to alter the 2013 LSE local resource allocation. The LSE local resource allocation is done based on the summer peak study as required by the ISO Tariff. Detailed results can be found at the end of the San Diego - Imperial Valley area section in this report.

III. Study Overview: Inputs, Outputs and Options

A. Objectives

As was the objective of the five previous annual LCT Studies, the intent of the 2013 LCT Study is to identify specific areas within the CAISO Balancing Authority Area that have limited import capability and determine the minimum generation capacity (MW) necessary to mitigate the local reliability problems in those areas.

B. Key Study Assumptions

1. Inputs and Methodology

The CAISO incorporated into its 2013 LCT study the same criteria, input assumptions and methodology that were incorporated into its previous years LCR studies. These inputs, assumptions and methodology were discussed and agreed to by stakeholders at the 2013 LCT Study Criteria, Methodology and Assumptions Stakeholder Meeting held on November 10, 2011.

The following table sets forth a summary of the approved inputs and methodology that have been used in the previous LCT studies as well as this 2013 LCT Study:

Summary Table of Inputs and Methodology Used in this LCT Study:

Issue:	How are they incorporated into this LCT study:
Input Assumptions:	
Transmission System Configuration	The existing transmission system has been modeled, including all projects operational on or before June 1, of the study year and all other feasible operational solutions brought forth by the PTOs and as agreed to by the CAISO.
Generation Modeled	The existing generation resources has been modeled and also includes all projects that will be on-line and commercial on or before June 1, of the study year
Load Forecast	Uses a 1-in-10 year summer peak load forecast
Methodology:	
Maximize Import Capability	Import capability into the load pocket has been maximized, thus minimizing the generation required in the load pocket to meet applicable reliability requirements.
QF/Nuclear/State/Federal Units	Regulatory Must-take and similarly situated units like QF/Nuclear/State/Federal resources have been modeled on-line at qualifying capacity output values for purposes of this LCT Study.
Maintaining Path Flows	Path flows have been maintained below all established path ratings into the load pockets, including the 500 kV. For clarification, given the existing transmission system configuration, the only 500 kV path that flows directly into a load pocket and will, therefore, be considered in this LCR Study is the South of Lugo transfer path flowing into the LA Basin.
Performance Criteria:	
Performance Level B & C, including incorporation of PTO operational solutions	This LCT Study is being published based on Performance Level B and Performance Level C criterion, yielding the low and high range LCR scenarios. In addition, the CAISO will incorporate all new projects and other feasible and CAISO-approved operational solutions brought forth by the PTOs that can be operational on or before June 1, of the study year. Any such solutions that can reduce the need for procurement to meet the Performance Level C criteria will be incorporated into the LCT Study.
Load Pocket:	
Fixed Boundary, including limited reference to published effectiveness factors	This LCT Study has been produced based on load pockets defined by a fixed boundary. The CAISO only publishes effectiveness factors where they are useful in facilitating procurement where excess capacity exists within a load pocket.

Further details regarding the 2013 LCT Study methodology and assumptions are provided in Section III, below.

C. Grid Reliability

Service reliability builds from grid reliability because grid reliability is reflected in the Reliability Standards of the North American Electric Reliability Council (NERC) and the Western Electricity Coordinating Council ("WECC") Regional Criteria (collectively "Reliability Standards"). The Reliability Standards apply to the interconnected electric system in the United States and are intended to address the reality that within an integrated network, whatever one Balancing Authority Area does can affect the reliability of other Balancing Authority Areas. Consistent with the mandatory nature of the Reliability Standards, the CAISO is under a statutory obligation to ensure efficient use and reliable operation of the transmission grid consistent with achievement of the Reliability Standards.[4] The CAISO is further under an obligation, pursuant to its FERC-approved Transmission Control Agreement, to secure compliance with all "Applicable Reliability Criteria." Applicable Reliability Criteria consists of the Reliability Standards as well as reliability criteria adopted by the CAISO (Grid Planning Standards).

The Reliability Standards define reliability on interconnected electric systems using the terms "adequacy" and "security." "Adequacy" is the ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account physical characteristics of the transmission system such as transmission ratings and scheduled and reasonably expected unscheduled outages of system elements. "Security" is the ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. The Reliability Standards are organized by Performance Categories. Certain categories require that the grid operator not only ensure that grid integrity is maintained under certain adverse system conditions (e.g., security), but also that all customers continue to receive electric supply to meet demand (e.g., adequacy). In that case, grid reliability and service reliability would overlap. But there are other levels of performance where security can be maintained without ensuring adequacy.

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[4] Pub. Utilities Code § 345

D. Application of N-1, N-1-1, and N-2 Criteria

The CAISO will maintain the system in a safe operating mode at all times. This obligation translates into respecting the Reliability Criteria at all times, for example during normal operating conditions Category A (N-0) the CAISO must protect for all single contingencies Category B (N-1) and common mode Category C5 (N-2) double line outages. Also, after a single contingency, the CAISO must re-adjust the system to support the loss of the next most stringent contingency. This is referred to as the N-1-1 condition.

The N-1-1 vs N-2 terminology was introduced only as a mere temporal differentiation between two existing NERC Category C events. N-1-1 represents NERC Category C3 ("category B contingency, manual system adjustment, followed by another category B contingency"). The N-2 represents NERC Category C5 ("any two circuits of a multiple circuit tower line") as well as requirement R1.1 of the WECC Regional Criteria[3] ("two adjacent circuits") with no manual system adjustment between the two contingencies.

E. Performance Criteria

As set forth on the Summary Table of Inputs and Methodology, this LCT Report is based on NERC performance level B and performance level C standard. The NERC Standards refer mainly to system being stable and both thermal and voltage limits be within applicable ratings. However, the CAISO also tests the electric system in regards to the dynamic and reactive margin compliance with the existing WECC regional criteria that further specifies the dynamic and reactive margin requirements for the same NERC performance levels. These performance levels can be described as follows:

Kern Area Overall Requirements:

2013	QF/Selfgen (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	584	0	584

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single) [22]	295	0	295
Category C (Multiple) [23]	483	42	525

15. LA Basin Area

Area Definition

The transmission tie lines into the LA Basin Area are:

1) San Onofre - San Luis Rey #1, #2, & #3 230 kV Lines
2) San Onofre - Talega #1 & #2 230 kV Lines
3) Lugo - Mira Loma #2 & #3 500 kV Lines
4) Lugo – Rancho Vista #1 500 kV line
5) Sylmar - Eagle Rock 230 kV Line
6) Sylmar - Gould 230 kV Line
7) Vincent - Mesa Cal 230 kV Line
8) Vincent - Rio Hondo #1 & #2 230 kV Lines
9) Eagle Rock - Pardee 230 kV Line
10) Devers- Palo Verde 500 kV Line
11) Mirage- Coachelv 230 kV Line
12) Mirage- Ramon 230 kV Line
13) Mirage- Julian Hinds 230 kV Line

These sub-stations form the boundary surrounding the LA Basin area:

1) San Onofre is in San Luis Rey is out
2) San Onofre is in Talega is out
3) Mira Loma is in Lugo is out
4) Rancho Vista is in Lugo is out

[22] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[23] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

5) Eagle Rock is in Sylmar is out
6) Gould is in Sylmar is out
7) Mesa Cal is in Vincent is out
8) Rio Hondo is in Vincent is out
9) Eagle Rock is in Pardee is out
10) Deversis in Palo Verde is out
11) Mirageis in Coachelv is out
12) Mirageis in Ramon is out
13) Mirageis in Julian Hinds is out

Total 2013 busload within the defined area is 19,300 MW with 133 MW of losses and 27 MW pumps resulting in total load + losses + pumps of 19,460 MW.

Total units and qualifying capacity available in the LA Basin area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALAMIT_7_UNIT 1	24001	ALAMT1 G	18	174.56	1	Western		Market
ALAMIT_7_UNIT 2	24002	ALAMT2 G	18	175.00	2	Western		Market
ALAMIT_7_UNIT 3	24003	ALAMT3 G	18	332.18	3	Western		Market
ALAMIT_7_UNIT 4	24004	ALAMT4 G	18	335.67	4	Western		Market
ALAMIT_7_UNIT 5	24005	ALAMT5 G	20	497.97	5	Western		Market
ALAMIT_7_UNIT 6	24161	ALAMT6 G	20	495.00	6	Western		Market
ANAHM_2_CANYN1	25211	CanyonGT	13.8	49.40	1	Western		MUNI
ANAHM_2_CANYN2	25212	CanyonGT	13.8	48.00	2	Western		MUNI
ANAHM_2_CANYN3	25213	CanyonGT	13.8	48.00	3	Western		MUNI
ANAHM_2_CANYN4	25214	CanyonGT	13.8	49.40	4	Western		MUNI
ANAHM_7_CT	25203	ANAHEIMG	13.8	40.64	1	Western	Aug NQC	MUNI
ARCOGN_2_UNITS	24011	ARCO 1G	13.8	54.28	1	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24012	ARCO 2G	13.8	54.28	2	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24013	ARCO 3G	13.8	54.28	3	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24014	ARCO 4G	13.8	54.28	4	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24163	ARCO 5G	13.8	27.14	5	Western	Aug NQC	QF/Selfgen
ARCOGN_2_UNITS	24164	ARCO 6G	13.8	27.15	6	Western	Aug NQC	QF/Selfgen
BARRE_2_QF	24016	BARRE	230	0.00		Western	Not modeled	QF/Selfgen
BARRE_6_PEAKER	29309	BARPKGEN	13.8	45.38	1	Western		Market
BRDWAY_7_UNIT 3	29007	BRODWYSC	13.8	65.00	1	Western		MUNI
BUCKWD_7_WINTCV	25634	BUCKWIND	115	0.15	W5	None	Aug NQC	Wind
CABZON_1_WINDA1	29290	CABAZON	33	11.29	1	None	Aug NQC	Wind
CENTER_2_QF	24203	CENTER S	66	18.10		Western	Not modeled Aug NQC	QF/Selfgen
CENTER_2_RHONDO	24203	CENTER S	66	1.91		Western	Not modeled	QF/Selfgen
CENTER_6_PEAKER	29308	CTRPKGEN	13.8	44.57	1	Western		Market
CENTRY_6_PL1X4	25302	CLTNCTRY	13.8	36.00	1	None	Aug NQC	MUNI
CHEVMN_2_UNITS	24022	CHEVGEN1	13.8	0.00	1	Western, El Nido	Aug NQC	QF/Selfgen
CHEVMN_2_UNITS	24023	CHEVGEN2	13.8	0.00	2	Western, El Nido	Aug NQC	QF/Selfgen
CHINO_2_QF	24024	CHINO	66	7.83		Western	Not modeled Aug NQC	QF/Selfgen
CHINO_2_SOLAR	24024	CHINO	66	0.00		Western	Not modeled	Market
CHINO_6_CIMGEN	24026	CIMGEN	13.8	25.29	1	Western	Aug NQC	QF/Selfgen

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
CHINO_6_SMPPAP	24140	SIMPSON	13.8	27.15	1	Western	Aug NQC	QF/Selfgen
CHINO_7_MILIKN	24024	CHINO	66	1.37		Western	Not modeled Aug NQC	Market
COLTON_6_AGUAM1	25303	CLTNAGUA	13.8	43.00	1	None		MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		None	Not modeled	MUNI
CORONS_6_CLRWTR	24210	MIRALOMA	66	14.00		None	Not modeled	MUNI
DEVERS_1_QF	24815	GARNET	115	1.51	QF	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25632	TERAWND	115	2.94	QF	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25633	CAPWIND	115	0.56	QF	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25634	BUCKWIND	115	1.73	QF	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	1.35	Q1	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25635	ALTWIND	115	2.50	Q2	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.59	Q1	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	2.28	Q2	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25636	RENWIND	115	0.27	W1	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25637	TRANWIND	115	6.68	QF	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25639	SEAWIND	115	2.01	QF	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25640	PANAERO	115	1.79	QF	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	1.53	EU	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	3.58	Q1	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25645	VENWIND	115	2.41	Q2	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	0.80	Q1	None	Aug NQC	QF/Selfgen
DEVERS_1_QF	25646	SANWIND	115	2.68	Q2	None	Aug NQC	QF/Selfgen
DMDVLY_1_UNITS	25425	ESRP P2	6.9	1.39		None	Not modeled Aug NQC	QF/Selfgen
DREWS_6_PL1X4	25301	CLTNDREW	13.8	36.00	1	None	Aug NQC	MUNI
DVLCYN_1_UNITS	25603	DVLCYN3G	13.8	67.15	3	None	Aug NQC	MUNI
DVLCYN_1_UNITS	25604	DVLCYN4G	13.8	67.15	4	None	Aug NQC	MUNI
DVLCYN_1_UNITS	25648	DVLCYN1G	13.8	50.35	1	None	Aug NQC	MUNI
DVLCYN_1_UNITS	25649	DVLCYN2G	13.8	50.35	2	None	Aug NQC	MUNI
ELLIS_2_QF	24197	ELLIS	66	0.00		Western, Ellis	Not modeled Aug NQC	QF/Selfgen
ELSEGN_7_UNIT 3	24047	ELSEG3 G	18	335.00	3	Western, El Nido		Market
ELSEGN_7_UNIT 4	24048	ELSEG4 G	18	335.00	4	Western, El Nido		Market
ETIWND_2_FONTNA	24055	ETIWANDA	66	0.81		None	Not modeled Aug NQC	QF/Selfgen
ETIWND_2_QF	24055	ETIWANDA	66	14.86		None	Not modeled Aug NQC	QF/Selfgen
ETIWND_2_SOLAR	24055	ETIWANDA	66	0.00		None	Not modeled Aug NQC	Market
ETIWND_6_GRPLND	29305	ETWPKGEN	13.8	42.53	1	None		Market
ETIWND_6_MWDETI	25422	ETI MWDG	13.8	10.37	1	None	Aug NQC	Market
ETIWND_7_MIDVLY	24055	ETIWANDA	66	1.54		None	Not modeled Aug NQC	QF/Selfgen
ETIWND_7_UNIT 3	24052	MTNVIST3	18	320.00	3	None		Market
ETIWND_7_UNIT 4	24053	MTNVIST4	18	320.00	4	None		Market
GARNET_1_UNITS	24815	GARNET	115	0.71	G1	None	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.25	G2	None	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.51	G3	None	Aug NQC	QF/Selfgen
GARNET_1_UNITS	24815	GARNET	115	0.25	PC	None	Aug NQC	QF/Selfgen
GARNET_1_WIND	24815	GARNET	115	0.66	W2	None	Aug NQC	Wind

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
GARNET_1_WIND	24815	GARNET	115	0.66	W3	None	Aug NQC	Wind
GLNARM_7_UNIT 1	29005	PASADNA1	13.8	22.30	1	Western		MUNI
GLNARM_7_UNIT 2	29006	PASADNA2	13.8	22.30	1	Western		MUNI
GLNARM_7_UNIT 3	29005	PASADNA1	13.8	44.83		Western	Not modeled	MUNI
GLNARM_7_UNIT 4	29006	PASADNA2	13.8	42.42		Western	Not modeled	MUNI
HARBGN_7_UNITS	24062	HARBOR G	13.8	76.28	1	Western		Market
HARBGN_7_UNITS	24062	HARBOR G	13.8	11.86	HP	Western		Market
HARBGN_7_UNITS	25510	HARBORG4	4.16	11.86	LP	Western		Market
HINSON_6_CARBGN	24020	CARBOGEN	13.8	21.46	1	Western	Aug NQC	Market
HINSON_6_LBECH1	24078	LBEACH1G	13.8	65.00	1	Western		Market
HINSON_6_LBECH2	24170	LBEACH2G	13.8	65.00	2	Western		Market
HINSON_6_LBECH3	24171	LBEACH3G	13.8	65.00	3	Western		Market
HINSON_6_LBECH4	24172	LBEACH4G	13.8	65.00	4	Western		Market
HINSON_6_SERRGN	24139	SERRFGEN	13.8	28.38	1	Western	Aug NQC	QF/Selfgen
HNTGBH_7_UNIT 1	24066	HUNT1 G	13.8	225.75	1	Western, Ellis		Market
HNTGBH_7_UNIT 2	24067	HUNT2 G	13.8	225.80	2	Western, Ellis		Market
INDIGO_1_UNIT 1	29190	WINTECX2	13.8	42.00	1	None		Market
INDIGO_1_UNIT 2	29191	WINTECX1	13.8	42.00	1	None		Market
INDIGO_1_UNIT 3	29180	WINTEC8	13.8	42.00	1	None		Market
INLDEM_5_UNIT 1	29041	IEEC-G1	19.5	335.00	1	Valley	Aug NQC	Market
INLDEM_5_UNIT 2	29042	IEEC-G2	19.5	335.00	1	Valley	Aug NQC	Market
JOHANN_6_QFA1	24072	JOHANNA	230	0.00		Western, Ellis	Not modeled Aug NQC	QF/Selfgen
LACIEN_2_VENICE	24337	VENICE	13.8	4.45	1	Western, El Nido	Aug NQC	MUNI
LAFRES_6_QF	24073	LA FRESA	66	2.55		Western, El Nido	Not modeled Aug NQC	QF/Selfgen
LAGBEL_6_QF	24075	LAGUBELL	66	10.60		Western	Not modeled Aug NQC	QF/Selfgen
LGHTHP_6_ICEGEN	24070	ICEGEN	13.8	46.55	1	Western	Aug NQC	QF/Selfgen
LGHTHP_6_QF	24083	LITEHIPE	66	1.10		Western	Not modeled Aug NQC	QF/Selfgen
MESAS_2_QF	24209	MESA CAL	66	1.06		Western	Not modeled Aug NQC	QF/Selfgen
MIRLOM_2_CORONA				2.35		None	Not modeled Aug NQC	QF/Selfgen
MIRLOM_2_TEMESC				2.49		None	Not modeled Aug NQC	QF/Selfgen
MIRLOM_6_DELGEN	24030	DELGEN	13.8	29.78	1	None	Aug NQC	QF/Selfgen
MIRLOM_6_PEAKER	29307	MRLPKGEN	13.8	43.18	1	None		Market
MIRLOM_7_MWDLKM	24210	MIRALOMA	66	4.60		None	Not modeled Aug NQC	MUNI
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	6.00	1	None	Aug NQC	Market
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	6.00	2	None	Aug NQC	Market
MOJAVE_1_SIPHON	25657	MJVSPHN1	13.8	6.00	3	None	Aug NQC	Market
MTWIND_1_UNIT 1	29060	MOUNTWND	115	7.08	S1	None	Aug NQC	Wind
MTWIND_1_UNIT 2	29060	MOUNTWND	115	2.76	S2	None	Aug NQC	Wind
MTWIND_1_UNIT 3	29060	MOUNTWND	115	2.88	S3	None	Aug NQC	Wind
OLINDA_2_COYCRK	24211	OLINDA	66	3.13		Western	Not modeled	QF/Selfgen
OLINDA_2_QF	24211	OLINDA	66	0.78	1	Western	Aug NQC	QF/Selfgen
OLINDA_7_LNDFIL	24201	BARRE	66	4.50		Western	Not modeled Aug NQC	QF/Selfgen
PADUA_2_ONTARO	24111	PADUA	66	0.91		None	Not modeled	QF/Selfgen

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
							Aug NQC	
PADUA_6_MWDSDM	24111	PADUA	66	7.70		None	Not modeled Aug NQC	MUNI
PADUA_6_QF	24111	PADUA	66	0.74		None	Not modeled Aug NQC	QF/Selfgen
PADUA_7_SDIMAS	24111	PADUA	66	1.05		None	Not modeled Aug NQC	QF/Selfgen
PWEST_1_UNIT				0.15		Western	Not modeled Aug NQC	Market
REDOND_7_UNIT 5	24121	REDON5 G	18	178.87	5	Western		Market
REDOND_7_UNIT 6	24122	REDON6 G	18	175.00	6	Western		Market
REDOND_7_UNIT 7	24123	REDON7 G	20	505.96	7	Western		Market
REDOND_7_UNIT 8	24124	REDON8 G	20	495.90	8	Western		Market
RHONDO_2_QF	24213	RIOHONDO	66	2.54		Western	Not modeled Aug NQC	QF/Selfgen
RHONDO_6_PUENTE	24213	RIOHONDO	66	0.00		Western	Not modeled Aug NQC	Market
RVSIDE_2_RERCU3	24299	RERC2G3	13.8	48.50	1	None		MUNI
RVSIDE_2_RERCU4	24300	RERC2G4	13.8	48.50	1	None		MUNI
RVSIDE_6_RERCU1	24242	RERC1G	13.8	48.35	1	None		MUNI
RVSIDE_6_RERCU2	24243	RERC2G	13.8	48.50	1	None		MUNI
RVSIDE_6_SPRING	24244	SPRINGEN	13.8	36.00	1	None		Market
SANTGO_6_COYOTE	24133	SANTIAGO	66	6.08	1	Western, Ellis	Aug NQC	Market
SBERDO_2_PSP3	24921	MNTV-CT1	18	129.71	1	None		Market
SBERDO_2_PSP3	24922	MNTV-CT2	18	129.71	1	None		Market
SBERDO_2_PSP3	24923	MNTV-ST1	18	225.08	1	None		Market
SBERDO_2_PSP4	24924	MNTV-CT3	18	129.71	1	None		Market
SBERDO_2_PSP4	24925	MNTV-CT4	18	129.71	1	None		Market
SBERDO_2_PSP4	24926	MNTV-ST2	18	225.08	1	None		Market
SBERDO_2_QF	24214	SANBRDNO	66	0.14		None	Not modeled Aug NQC	QF/Selfgen
SBERDO_2_SNTANA	24214	SANBRDNO	66	0.27		None	Not modeled Aug NQC	QF/Selfgen
SBERDO_6_MILLCK	24214	SANBRDNO	66	1.28		None	Not modeled Aug NQC	QF/Selfgen
SONGS_7_UNIT 2	24129	S.ONOFR2	22	1122.00	2	Western		Nuclear
SONGS_7_UNIT 3	24130	S.ONOFR3	22	1124.00	3	Western		Nuclear
TIFFNY_1_DILLON				5.63		Western	Not modeled Aug NQC	Wind
VALLEY_5_PERRIS	24160	VALLEYSC	115	7.94		Valley	Not modeled Aug NQC	QF/Selfgen
VALLEY_5_REDMTN	24160	VALLEYSC	115	2.00		Valley	Not modeled Aug NQC	QF/Selfgen
VALLEY_7_BADLND	24160	VALLEYSC	115	0.54		Valley	Not modeled Aug NQC	Market
VALLEY_7_UNITA1	24160	VALLEYSC	115	1.34		Valley	Not modeled Aug NQC	Market
VERNON_6_GONZL1				5.75		Western	Not modeled	MUNI
VERNON_6_GONZL2				5.75		Western	Not modeled	MUNI
VERNON_6_MALBRG	24239	MALBRG1G	13.8	42.37	C1	Western		MUNI
VERNON_6_MALBRG	24240	MALBRG2G	13.8	42.37	C2	Western		MUNI
VERNON_6_MALBRG	24241	MALBRG3G	13.8	49.26	S3	Western		MUNI
VILLPK_2_VALLYV	24216	VILLA PK	66	4.10		Western	Not modeled Aug NQC	QF/Selfgen

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
VILLPK_6_MWDYOR	24216	VILLA PK	66	0.00		Western	Not modeled Aug NQC	MUNI
VISTA_6_QF	24902	VSTA	66	0.17	1	None	Aug NQC	QF/Selfgen
WALNUT_6_HILLGEN	24063	HILLGEN	13.8	47.07	1	Western	Aug NQC	QF/Selfgen
WALNUT_7_WCOVCT	24157	WALNUT	66	3.43		Western	Not modeled Aug NQC	Market
WALNUT_7_WCOVST	24157	WALNUT	66	2.98		Western	Not modeled Aug NQC	Market
WHTWTR_1_WINDA1	29061	WHITEWTR	33	8.26	1	None	Aug NQC	Wind
ARCOGN_2_UNITS	24018	BRIGEN	13.8	0.00	1	Western	No NQC - hist. data	Market
HINSON_6_QF	24064	HINSON	66	0.00	1	Western	No NQC - hist. data	QF/Selfgen
INLAND_6_UNIT	24071	INLAND	13.8	30.30	1	None	No NQC - hist. data	QF/Selfgen
MOBGEN_6_UNIT 1	24094	MOBGEN	13.8	20.20	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24324	SANIGEN	13.8	6.80	D1	None	No NQC - hist. data	QF/Selfgen
NA	24325	ORCOGEN	13.8	0.00	1	Western, Ellis	No NQC - hist. data	QF/Selfgen
NA	24327	THUMSGEN	13.8	40.00	1	Western	No NQC - hist. data	QF/Selfgen
NA	24328	CARBGEN2	13.8	15.2	1	Western	No NQC – hist. data	Market
NA	24329	MOBGEN2	13.8	20.2	1	Western, El Nido	No NQC – hist. data	QF/Selfgen
NA	24330	OUTFALL1	13.8	0.00	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24331	OUTFALL2	13.8	0.00	1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24332	PALOGEN	13.8	3.60	D1	Western, El Nido	No NQC - hist. data	QF/Selfgen
NA	24341	COYGEN	13.8	0.00	1	Western, Ellis	No NQC - hist. data	QF/Selfgen
NA	24342	FEDGEN	13.8	0.00	1	Western	No NQC - hist. data	QF/Selfgen
NA	24839	BLAST	115	45.00	1	None	No NQC – hist. data	QF/Selfgen
NA	29021	WINTEC6	115	45.00	1	None	No NQC – hist. data	Wind
NA	29023	WINTEC4	12	16.50	1	None	No NQC – hist. data	Wind
NA	29060	SEAWEST	115	44.40	S1	None	No NQC – hist. data	Wind
NA	29060	SEAWEST	115	22.20	S2	None	No NQC – hist. data	Wind
NA	29060	SEAWEST	115	22.40	S3	None	No NQC – hist. data	Wind
NA	29260	ALTAMSA4	115	40.00	1	None	No NQC – hist. data	Wind
NA	29338	CLEARGEN	13.8	0.00	1	None	No NQC - hist. data	QF/Selfgen
NA	29339	DELGEN	13.8	0.00	1	None	No NQC - hist. data	QF/Selfgen
NA	29951	REFUSE	13.8	9.90	D1	Western	No NQC - Pmax	QF/Selfgen

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
NA	29953	SIGGEN	13.8	24.90	D1	Western	No NQC - Pmax	QF/Selfgen
HNTGBH_7_UNIT 3	24167	HUNT3 G	13.8	0.00	3	Western, Ellis	Retired	Market
HNTGBH_7_UNIT 4	24168	HUNT4 G	13.8	0.00	4	Western, Ellis	Retired	Market
New unit	29201	EME WCG1	13.8	100	1	Western	No NQC - Pmax	Market
New unit	29202	EME WCG2	13.8	100	1	Western	No NQC - Pmax	Market
New unit	29203	EME WCG3	13.8	100	1	Western	No NQC - Pmax	Market
New unit	29204	EME WCG4	13.8	100	1	Western	No NQC - Pmax	Market
New unit	29205	EME WCG5	13.8	100	1	Western	No NQC - Pmax	Market
New unit	29901	NRG ELG5	18	175	5	Western, El Nido	No NQC - Pmax	Market
New unit	29902	NRG ELG7	18	280	7	Western, El Nido	No NQC - Pmax	Market
New unit	29903	NRG ELG6	18	175	6	Western, El Nido	No NQC - Pmax	Market

Major new projects modeled:

1. 3 new resources have been modeled
2. Huntington Beach #3 and #4 have been retired
3. Del Amo – Ellis 230 kV line loops into Barre 230 kV substation
4. Recalibrate arming level for Santiago SPS

<u>Critical Contingency Analysis Summary</u>

LA Basin Overall:

The most critical contingency for LA Basin is the loss of one SONGS unit followed by Palo Verde-Devers 500 kV line, which could exceed the approved 6400 MW rating for the South of Lugo path. This limiting contingency establishes a LCR of 10,295 MW in 2013 (includes 810 MW of QF, 230 MW of Wind, 1166 MW of Muni and 2246 MW of Nuclear generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

Effectiveness factors:

The following table has units that have at least 5% effectiveness to the above-mentioned South of Lugo constraint within the LA Basin area:

Gen Bus	Gen Name	Gen ID	MW Eff Fctr (%)
24052	MTNVIST3	3	34
24053	MTNVIST4	4	34
24071	INLAND	1	32
25422	ETI MWDG	1	32
29305	ETWPKGEN	1	32
24921	MNTV-CT1	1	28
24922	MNTV-CT2	1	28
24923	MNTV-ST1	1	28
24924	MNTV-CT3	1	28
24925	MNTV-CT4	1	28
24926	MNTV-ST2	1	28
29041	IEEC-G1	1	28
29042	IEEC-G2	2	28
24905	RVCANAL1	R1	27
24906	RVCANAL2	R2	27
24907	RVCANAL3	R3	27
24908	RVCANAL4	R4	27
29190	WINTECX2	1	27
29191	WINTECX1	1	27
29180	WINTEC8	1	27
24815	GARNET	QF	27
24815	GARNET	W3	27
29023	WINTEC4	1	27
29021	WINTEC6	1	27
24242	RERC1G	1	27
24243	RERC2G	1	27
24244	SPRINGEN	1	27
25301	CLTNDREW	1	27
25302	CLTNCTRY	1	27
25303	CLTNAGUA	1	27
24299	RERC2G3	1	27
24300	RERC2G4	1	27
24839	BLAST	1	27
25648	DVLCYN1G	1	26
25649	DVLCYN2G	2	26
25603	DVLCYN3G	3	26
25604	DVLCYN4G	4	26
25632	TERAWND	QF	26
25634	BUCKWND	QF	26
25635	ALTWIND	Q1	26
25635	ALTWIND	Q2	26
25637	TRANWND	QF	26

25639	SEAWIND	QF	26
25640	PANAERO	QF	26
25645	VENWIND	EU	26
25645	VENWIND	Q2	26
25645	VENWIND	Q1	26
25646	SANWIND	Q2	26
29060	MOUNTWND	S1	26
29060	MOUNTWND	S3	26
29060	MOUNTWND	S2	26
29061	WHITEWTR	1	26
29260	ALTAMSA4	1	26
29290	CABAZON	1	26
25633	CAPWIND	QF	25
25657	MJVSPHN1	1	25
25658	MJVSPHN2	2	25
25659	MJVSPHN3	3	25
25203	ANAHEIMG	1	23
25211	CanyonGT 1	1	22
25212	CanyonGT 2	2	22
25213	CanyonGT 3	3	22
25214	CanyonGT 4	4	22
24030	DELGEN	1	21
29309	BARPKGEN	1	21
24026	CIMGEN	D1	21
24140	SIMPSON	D1	21
29307	MRLPKGEN	1	20
29338	CLEARGEN	1	20
29339	DELGEN	1	20
24005	ALAMT5 G	5	19
24066	HUNT1 G	1	19
24067	HUNT2 G	2	19
24167	HUNT3 G	3	19
24168	HUNT4 G	4	19
24129	S.ONOFR2	2	19
24130	S.ONOFR3	3	19
24133	SANTIAGO	1	19
24325	ORCOGEN	1	19
24341	COYGEN	1	19
24001	ALAMT1 G	1	18
24002	ALAMT2 G	2	18
24003	ALAMT3 G	3	18
24004	ALAMT4 G	4	18
24161	ALAMT6 G	6	18

24162	ALAMT7 G	R7	17
24063	HILLGEN	D1	17
29201	EME WCG1	1	17
29203	EME WCG3	1	17
29204	EME WCG4	1	17
29205	EME WCG5	1	17
29202	EME WCG2	1	17
24018	BRIGEN	1	16
29308	CTRPKGEN	1	16
29953	SIGGEN	D1	16
24011	ARCO 1G	1	15
24012	ARCO 2G	2	15
24013	ARCO 3G	3	15
24014	ARCO 4G	4	15
24163	ARCO 5G	5	15
24164	ARCO 6G	6	15
24020	CARBGEN1	1	15
24022	CHEVGEN1	1	15
24023	CHEVGEN2	2	15
24064	HINSON	1	15
24070	ICEGEN	D1	15
24170	LBEACH12	2	15
24171	LBEACH34	3	15
24094	MOBGEN1	1	15
24062	HARBOR G	1	15
25510	HARBORG4	LP	15
24062	HARBOR G	HP	15
24139	SERRFGEN	D1	15
24170	LBEACH12	1	15
24171	LBEACH34	4	15
24173	LBEACH5G	R5	15
24174	LBEACH6G	R6	15
24327	THUMSGEN	1	15
24328	CARBGEN2	1	15
24330	OUTFALL1	1	15
24331	OUTFALL2	1	15
24332	PALOGEN	D1	15
24333	REDON1 G	R1	15
24334	REDON2 G	R2	15
24335	REDON3 G	R3	15
24336	REDON4 G	R4	15
24337	VENICE	1	15
24079	LBEACH7G	R7	15

24080	LBEACH8G	R8	15
24081	LBEACH9G	R9	15
24047	ELSEG3 G	3	14
24048	ELSEG4 G	4	14
24121	REDON5 G	5	14
24122	REDON6 G	6	14
24123	REDON7 G	7	14
24124	REDON8 G	8	14
24329	MOBGEN2	1	14
29901	NRG ELG5	5	14
29903	NRG ELG6	6	14
29902	NRG ELS7	7	14
29951	REFUSE	D1	13
29209	BLY1ST1	1	13
29207	BLY1CT1	1	13
29208	BLY1CT2	1	13
24342	FEDGEN	1	13
24241	MALBRG3G	S3	12
24240	MALBRG2G	C2	12
24239	MALBRG1G	C1	12
29005	PASADNA1	1	10
29006	PASADNA2	1	10
29007	BRODWYSC	1	10

Valley Sub-Area:

The most critical contingency for the Valley sub-area is the loss of Palo Verde – Devers 500 kV line and Valley – Serrano 500 kV line or vice versa, which would result in voltage collapse. This limiting contingency establishes a LCR of 670 MW (includes 10 MW of QF generation) in 2013 as the generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors.

Western Sub-Area:

The most critical contingency for the Western sub-area is the loss of Serrano-Villa Park #2 230 kV line followed by the loss of the Serrano-Lewis 230 kV line or vice versa, which would result in thermal overload of the remaining Serrano-Villa Park 230 kV line.

This limiting contingency establishes a LCR of 5540 MW (includes 623 MW of QF, 6 MW of Wind, 582 MW of Muni and 2246 MW of nuclear generation) in 2013 as the generation capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units that have at least 5% effectiveness to the above-mentioned constraint:

Gen Bus	Gen Name	Gen ID	MW Eff Fctr (%)
29309	BARPKGEN	1	31
25203	ANAHEIMG	1	30
25211	CanyonGT 1	1	29
25212	CanyonGT 2	2	29
25213	CanyonGT 3	3	29
25214	CanyonGT 4	4	29
24005	ALAMT5 G	5	23
24161	ALAMT6 G	6	23
24001	ALAMT1 G	1	22
24002	ALAMT2 G	2	22
24003	ALAMT3 G	3	22
24004	ALAMT4 G	4	22
24162	ALAMT7 G	R7	22
24066	HUNT1 G	1	22
24067	HUNT2 G	2	22
24167	HUNT3 G	3	22
24168	HUNT4 G	4	22
24325	ORCOGEN	1	21
24133	SANTIAGO	1	16
24341	COYGEN	1	16
24011	ARCO 1G	1	15
24012	ARCO 2G	2	15
24013	ARCO 3G	3	15
24014	ARCO 4G	4	15
24018	BRIGEN	1	15
24020	CARBGEN1	1	15
24064	HINSON	1	15
24070	ICEGEN	D1	15
24170	LBEACH12	2	15
24171	LBEACH34	3	15
24062	HARBOR G	1	15
25510	HARBORG4	LP	15

24062	HARBOR G	HP	15
24139	SERRFGEN	D1	15
24170	LBEACH12	1	15
24171	LBEACH34	4	15
24173	LBEACH5G	R5	15
24174	LBEACH6G	R6	15
24327	THUMSGEN	1	15
24328	CARBGEN2	1	15
24079	LBEACH7G	R7	15
24080	LBEACH8G	R8	15
24081	LBEACH9G	R9	15
24163	ARCO 5G	5	14
24164	ARCO 6G	6	14
24022	CHEVGEN1	1	14
24023	CHEVGEN2	2	14
24048	ELSEG4 G	4	14
24094	MOBGEN1	1	14
29308	CTRPKGEN	1	14
24329	MOBGEN2	1	14
24330	OUTFALL1	1	14
24331	OUTFALL2	1	14
24332	PALOGEN	D1	14
24333	REDON1 G	R1	14
24334	REDON2 G	R2	14
24335	REDON3 G	R3	14
24336	REDON4 G	R4	14
24337	VENICE	1	14
29953	SIGGEN	D1	14
29901	NRG ELG5	5	14
29903	NRG ELG6	6	14
29902	NRG ELS7	7	14
24047	ELSEG3 G	3	13
24121	REDON5 G	5	13
24122	REDON6 G	6	13
24123	REDON7 G	7	13
24124	REDON8 G	8	13
29951	REFUSE	D1	12
24342	FEDGEN	1	12
24241	MALBRG3G	S3	11
24240	MALBRG2G	C2	11
24239	MALBRG1G	C1	11
29005	PASADNA1	1	9
29006	PASADNA2	1	9

29007	BRODWYSC	1	9
24063	HILLGEN	D1	6
29201	EME WCG1	1	5
29203	EME WCG3	1	5
29204	EME WCG4	1	5
29205	EME WCG5	1	5
29202	EME WCG2	1	5

There are numerous (about 40) other combinations of contingencies in the area that could overload a significant number of 230 kV lines in this sub-area and have less LCR need. As such, anyone of them (combination of contingencies) could become binding for any given set of procured resources. As a result, effectiveness factors may not be the best indicator towards informed procurement.

Ellis sub-area

The Del Amo – Ellis loop-in project along with recalibration of the Santiago SPS eliminates the LCR need for the Ellis sub-area.

El Nido sub-area

The most critical contingency for the El Nido sub-area is the loss of the La Fresa – Hinson 230 kV line followed by the loss of the La Fresa – Redondo #1 and #2 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 386 MW in 2013 (which includes 47 MW of QF and 4 MW of MUNI generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors.

Changes compared to last year's results:

Overall the load forecast went down by 470 MW resulting in 570 MW decrease in LCR.

LA Basin Overall Requirements:

2013	QF/Wind (MW)	Muni (MW)	Nuclear (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	1040	1166	2246	8675	13127

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[24]	10,295	0	10,295
Category C (Multiple)[25]	10,295	0	10,295

16. Big Creek/Ventura Area

<u>Area Definition</u>

The transmission tie lines into the Big Creek/Ventura Area are:

1) Antelope #1 and #2 500/230 kV Transformers
2) Sylmar-Pardee #1 230 kV Line
3) Sylmar-Pardee #2 230 kV Line
4) Eagle Rock-Pardee #1 230 kV Line
5) Vincent-Pardee 230 kV Line
6) Vincent-Santa Clara 230 kV Line

These sub-stations form the boundary surrounding the Big Creek/Ventura area:

1) Antelope 500 kV is out Antelope 230 KV is in
2) Sylmar is out Pardee is in
3) Sylmar is out Pardee is in
4) Eagle Rock is out Pardee is in

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[24] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[25] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

5) Vincent is out Pardee is in
6) Vincent is out Santa Clara is in

Total 2013 busload within the defined area is 4164 MW with 77 MW of losses and 355 MW of pumps resulting in total load + losses + pumps of 4596 MW.

Total units and qualifying capacity available in the Big Creek/Ventura area:

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
ALAMO_6_UNIT	25653	ALAMO SC	13.8	16.00	1	Big Creek	Aug NQC	Market
ANTLPE_2_QF	24457	ARBWIND	66	2.91	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24458	ENCANWND	66	15.09	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24459	FLOWIND	66	5.45	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24460	DUTCHWND	66	1.87	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24465	MORWIND	66	7.49	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	24491	OAKWIND	66	2.41	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28501	MIDWIND	12	2.41	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28502	SOUTHWND	12	0.88	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28503	NORTHWND	12	2.59	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28504	ZONDWND1	12	1.76	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28505	ZONDWND2	12	1.71	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28506	BREEZE1	12	0.60	1	Big Creek	Aug NQC	Wind
ANTLPE_2_QF	28507	BREEZE2	12	1.07	1	Big Creek	Aug NQC	Wind
BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	19.38	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24306	B CRK1-1	7.2	21.03	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	21.03	3	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24307	B CRK1-2	13.8	30.39	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	49.48	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24308	B CRK2-1	13.8	50.64	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	18.22	3	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24309	B CRK2-2	7.2	19.19	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	16.55	5	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24310	B CRK2-3	7.2	18.02	6	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.09	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24311	B CRK3-1	13.8	34.09	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	34.09	3	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24312	B CRK3-2	13.8	39.93	4	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24313	B CRK3-3	13.8	37.99	5	Big Creek, Rector, Vestal	Aug NQC	Market

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.09	41	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24314	B CRK 4	11.5	49.28	42	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24315	B CRK 8	13.8	23.76	81	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24315	B CRK 8	13.8	42.85	82	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24317	MAMOTH1G	13.8	91.07	1	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24318	MAMOTH2G	13.8	91.07	2	Big Creek, Rector, Vestal	Aug NQC	Market
BIGCRK_2_EXESWD	24323	PORTAL	4.8	9.35	1	Big Creek, Rector, Vestal	Aug NQC	Market
EASTWD_7_UNIT	24319	EASTWOOD	13.8	199.00	1	Big Creek, Rector, Vestal		Market
EDMONS_2_NSPIN	25605	EDMON1AP	14.4	23.27	1	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25606	EDMON2AP	14.4	23.27	2	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	23.27	3	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25607	EDMON3AP	14.4	23.27	4	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25608	EDMON4AP	14.4	23.27	5	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25608	EDMON4AP	14.4	23.27	6	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	23.27	7	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25609	EDMON5AP	14.4	23.27	8	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	23.27	9	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25610	EDMON6AP	14.4	23.27	10	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	23.26	11	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25611	EDMON7AP	14.4	23.26	12	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	23.26	13	Big Creek	Pumps	MUNI
EDMONS_2_NSPIN	25612	EDMON8AP	14.4	23.26	14	Big Creek	Pumps	MUNI
GOLETA_2_QF	24057	GOLETA	66	0.14		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
GOLETA_6_ELLWOD	28004	ELLWOOD	13.8	54.00	1	Ventura, S.Clara, Moorpark		Market
GOLETA_6_EXGEN	24057	GOLETA	66	1.17		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
GOLETA_6_GAVOTA	24057	GOLETA	66	1.41		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	QF/Selfgen
GOLETA_6_TAJIGS	24057	GOLETA	66	2.90		Ventura, S.Clara, Moorpark	Not modeled Aug NQC	Market
KERRGN_1_UNIT 1	24437	KERNRVR	66	9.03	1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28051	PSTRIAG1	18	157.90	G1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28052	PSTRIAG2	18	157.90	G2	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28053	PSTRIAS1	18	162.40	S1	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28054	PSTRIAG3	18	157.90	G3	Big Creek	Aug NQC	Market
LEBECS_2_UNITS	28055	PSTRIAS2	18	78.90	S2	Big Creek	Aug NQC	Market
MNDALY_7_UNIT 1	24089	MANDLY1G	13.8	215.00	1	Ventura, Moorpark		Market
MNDALY_7_UNIT 2	24090	MANDLY2G	13.8	215.29	2	Ventura, Moorpark		Market

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
MNDALY_7_UNIT 3	24222	MANDLY3G	16	130.00	3	Ventura, S.Clara, Moorpark		Market
MONLTH_6_BOREL	24456	BOREL	66	8.98	1	Big Creek	Aug NQC	QF/Selfgen
MOORPK_2_CALABS	24099	MOORPARK	230	6.96		Ventura, Moorpark	Not modeled	Market
MOORPK_6_QF	24098	MOORPARK	66	26.44		Ventura, Moorpark	Not modeled Aug NQC	QF/Selfgen
MOORPK_7_UNITA1	24098	MOORPARK	66	1.24		Ventura, Moorpark	Not modeled Aug NQC	QF/Selfgen
OMAR_2_UNIT 1	24102	OMAR 1G	13.8	77.25	1	Big Creek		QF/Selfgen
OMAR_2_UNIT 2	24103	OMAR 2G	13.8	77.25	2	Big Creek		QF/Selfgen
OMAR_2_UNIT 3	24104	OMAR 3G	13.8	77.25	3	Big Creek		QF/Selfgen
OMAR_2_UNIT 4	24105	OMAR 4G	13.8	77.25	4	Big Creek		QF/Selfgen
ORMOND_7_UNIT 1	24107	ORMOND1G	26	741.27	1	Ventura, Moorpark		Market
ORMOND_7_UNIT 2	24108	ORMOND2G	26	775.00	2	Ventura, Moorpark		Market
OSO_6_NSPIN	25614	OSO A P	13.2	3.63	1	BigCreek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	3.63	2	BigCreek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	3.63	3	BigCreek	Pumps	MUNI
OSO_6_NSPIN	25614	OSO A P	13.2	3.63	4	BigCreek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	3.63	5	BigCreek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	3.63	6	BigCreek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	3.63	7	BigCreek	Pumps	MUNI
OSO_6_NSPIN	25615	OSO B P	13.2	3.63	8	BigCreek	Pumps	MUNI
PANDOL_6_UNIT	24113	PANDOL	13.8	24.81	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
PANDOL_6_UNIT	24113	PANDOL	13.8	20.21	2	Big Creek, Vestal	Aug NQC	QF/Selfgen
RECTOR_2_KAWEAH	24212	RECTOR	66	1.45		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
RECTOR_2_KAWH 1	24212	RECTOR	66	0.71		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
RECTOR_2_QF	24212	RECTOR	66	5.34		Big Creek, Rector, Vestal	Not modeled Aug NQC	QF/Selfgen
RECTOR_7_TULARE	24212	RECTOR	66	1.60		Big Creek, Rector, Vestal	Not modeled	QF/Selfgen
SAUGUS_2_TOLAND	24135	SAUGUS	66	0.72		Big Creek	Not modeled Aug NQC	Market
SAUGUS_6_MWDFTH	24135	SAUGUS	66	7.50		Big Creek	Not modeled Aug NQC	MUNI
SAUGUS_6_PTCHGN	24118	PITCHGEN	13.8	19.12	1	Big Creek	Aug NQC	MUNI
SAUGUS_6_QF	24135	SAUGUS	66	0.92		Big Creek	Not modeled Aug NQC	QF/Selfgen
SAUGUS_7_CHIQCN	24135	SAUGUS	66	6.67		Big Creek	Not modeled Aug NQC	Market
SAUGUS_7_LOPEZ	24135	SAUGUS	66	5.39		Big Creek	Not modeled Aug NQC	QF/Selfgen
SNCLRA_6_OXGEN	24110	OXGEN	13.8	33.53	1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SNCLRA_6_PROCGN	24119	PROCGEN	13.8	46.16	1	Ventura, S.Clara, Moorpark	Aug NQC	Market

MKT/SCHED RESOURCE ID	BUS #	BUS NAME	kV	NQC	UNIT ID	LCR SUB-AREA NAME	NQC Comments	CAISO Tag
SNCLRA_6_QF	24127	S.CLARA	66	1.09	1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SNCLRA_6_WILLMT	24159	WILLAMET	13.8	12.63	1	Ventura, S.Clara, Moorpark	Aug NQC	QF/Selfgen
SPRGVL_2_QF	24215	SPRINGVL	66	0.25		Big Creek, Rector, Vestal	Not modeled Aug NQC	QF/Selfgen
SPRGVL_2_TULE	24215	SPRINGVL	66	0.63		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SPRGVL_2_TULESC	24215	SPRINGVL	66	0.39		Big Creek, Rector, Vestal	Not modeled Aug NQC	Market
SYCAMR_2_UNITS	24143	SYCCYN1G	13.8	57.56	1	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24144	SYCCYN2G	13.8	57.56	2	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24145	SYCCYN3G	13.8	57.56	3	Big Creek	Aug NQC	QF/Selfgen
SYCAMR_2_UNITS	24146	SYCCYN4G	13.8	57.55	4	Big Creek	Aug NQC	QF/Selfgen
TENGEN_2_PL1X2	24148	TENNGEN1	13.8	18.35	1	Big Creek	Aug NQC	Market
TENGEN_2_PL1X2	24149	TENNGEN2	13.8	18.35	2	Big Creek	Aug NQC	Market
VESTAL_2_KERN	24152	VESTAL	66	6.72	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
VESTAL_6_QF	24152	VESTAL	66	5.06		Big Creek, Vestal	Not modeled Aug NQC	QF/Selfgen
VESTAL_6_ULTRGN	24150	ULTRAGEN	13.8	34.70	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
VESTAL_6_WDFIRE	28008	LAKEGEN	13.8	5.57	1	Big Creek, Vestal	Aug NQC	QF/Selfgen
WARNE_2_UNIT	25651	WARNE1	13.8	38.00	1	Big Creek	Aug NQC	Market
WARNE_2_UNIT	25652	WARNE2	13.8	38.00	1	Big Creek	Aug NQC	Market
APPGEN_6_UNIT 1	24009	APPGEN1G	13.8	0.00	1	BigCreek	No NQC - hist. data	Market
APPGEN_6_UNIT 1	24010	APPGEN2G	13.8	0.00	2	BigCreek	No NQC - hist. data	Market
MNDALY_6_MCGRTH	29306	MCGPKGEN	13.8	47.00	1	Ventura, S.Clara, Moorpark	No NQC - hist. data	Market
NA	24326	Exgen1	13.8	0.00	S1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
NA	24340	CHARMIN	13.8	15.20	1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
NA	24362	Exgen2	13.8	0.00	G1	Ventura, S.Clara, Moorpark	No NQC - hist. data	QF/Selfgen
NA	24370	Kawgen	13.8	0.00	1	Big Creek, Rector, Vestal	No NQC - hist. data	Market
NA	24372	KR 3-1	13.8	0.00	1	Big Creek, Vestal	No NQC - hist. data	QF/Selfgen
NA	24373	KR 3-2	13.8	0.00	1	Big Creek, Vestal	No NQC - hist. data	QF/Selfgen
NA	24422	PALMDALE	66	0.00	1	BigCreek	No NQC - hist. data	Market
NA	24436	GOLDTOWN	66	0.00	1	BigCreek	No NQC - hist. data	Market

Major new projects modeled:

1. Segments of TRTP project

Critical Contingency Analysis Summary

Big Creek/Ventura overall:

The most critical contingency is the loss of the Lugo-Victorville 500 kV followed by Sylmar-Pardee #1 or #2 230 kV line, which could thermally overload the remaining Sylmar-Pardee 230 kV line. This limiting contingency establishes a LCR of 2241 MW in 2013 (includes 752 MW of QF, 381 MW of Muni and 46 MW of Wind generation) as the minimum generation capacity necessary for reliable load serving capability within this area.

The most critical single contingency is the loss of Sylmar-Pardee #1 (or # 2) line followed by Ormond Beach Unit #2, which could thermally overload the remaining Sylmar-Pardee 230 kV line. This limiting contingency establishes a LCR of 2161 MW in 2013 (includes 752 MW of QF, 381 MW of Muni and 46 MW of Wind generation).

Effectiveness factors:

The following table has units that have at least 5% effectiveness to any one of the Sylmar-Pardee 230 kV lines after the loss of the Lugo-Victorville 500 kV followed by one of the other Sylmar-Pardee 230 kV line in this area:

Gen Bus	Gen Name	Gen ID	MW Eff Fctr
24118	PITCHGEN	D1	35
24148	TENNGEN1	D1	35
24149	TENNGEN2	D2	35
24009	APPGEN1G	1	34
24010	APPGEN2G	2	34
24107	ORMOND1G	1	34
24108	ORMOND2G	2	34
24361	APPGEN3G	3	34
25651	WARNE1	1	33
25652	WARNE2	1	33

24090	MANDLY2G	2	32
29306	MCGPKGEN	1	32
24089	MANDLY1G	1	31
29004	ELLWOOD	1	31
29952	CAMGEN	D1	31
24326	EXGEN1	S1	31
24362	EXGEN2	G1	31
29055	PSTRIAS2	S2	30
29054	PSTRIAG3	G3	30
29053	PSTRIAS1	S1	30
29052	PSTRIAG2	G2	30
29051	PSTRIAG1	G1	30
25605	EDMON1AP	1	30
25606	EDMON2AP	2	30
25607	EDMON3AP	3	30
25607	EDMON3AP	4	30
25608	EDMON4AP	5	30
25608	EDMON4AP	6	30
25609	EDMON5AP	7	30
25609	EDMON5AP	8	30
25610	EDMON6AP	9	30
25610	EDMON6AP	10	30
25612	EDMON8AP	13	30
25612	EDMON8AP	14	30
24127	S.CLARA	1	30
24110	OXGEN	D1	30
24119	PROCGEN	D1	30
24159	WILLAMET	D1	30
24340	CHARMIN	1	30
25611	EDMON7AP	11	29
25611	EDMON7AP	12	29
24222	MANDLY3G	3	29
25614	OSO A P	1	29
25614	OSO A P	2	29
25615	OSO B P	7	29
25615	OSO B P	8	29
25653	ALAMO SC	1	29
24370	KAWGEN	1	28
24113	PANDOL	1	27
24113	PANDOL	2	27

29008	LAKEGEN	1	27
24150	ULTRAGEN	1	27
24152	VESTAL	1	27
24372	KR 3-1	1	27
24373	KR 3-2	2	27
24102	OMAR 1G	1	26
24103	OMAR 2G	2	26
24104	OMAR 3G	3	26
24105	OMAR 4G	4	26
24143	SYCCYN1G	1	26
24144	SYCCYN2G	2	26
24145	SYCCYN3G	3	26
24146	SYCCYN4G	4	26
24319	EASTWOOD	1	25
24306	B CRK1-1	1	25
24306	B CRK1-1	2	25
24307	B CRK1-2	3	25
24307	B CRK1-2	4	25
24308	B CRK2-1	1	25
24308	B CRK2-1	2	25
24309	B CRK2-2	3	25
24309	B CRK2-2	4	25
24310	B CRK2-3	5	25
24310	B CRK2-3	6	25
24311	B CRK3-1	1	25
24311	B CRK3-1	2	25
24312	B CRK3-2	3	25
24312	B CRK3-2	4	25
24313	B CRK3-3	5	25
24314	B CRK 4	41	25
24314	B CRK 4	42	25
24315	B CRK 8	81	25
24315	B CRK 8	82	25
24317	MAMOTH1G	1	25
24318	MAMOTH2G	2	25
24437	KERNRVR	1	22
24457	ARBWIND	1	17
24465	MORWIND	1	17
24481	MIDWIND	1	17
24483	NORTHWND	1	17

24484	ZONDWND1	1	17
24485	ZONDWND2	1	17
24458	ENCANWND	1	16
24459	FLOWIND	1	16
24460	DUTCHWND	1	16
24436	GOLDTOWN	1	16
24456	BOREL	1	15

Rector Sub-area

The most critical contingency for the Rector sub-area is the loss of one of the Rector-Vestal 230 kV lines with the Eastwood unit out of service, which would thermally overload the remaining Rector-Vestal 230 kV line. This limiting contingency establishes a LCR of 601 MW (includes 7 MW of QF generation) in 2013 as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units that have at least 5% effectiveness to the above-mentioned constraint within Rector sub-area:

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
24370	KAWGEN	1	45
24319	EASTWOOD	1	41
24306	B CRK1-1	1	41
24306	B CRK1-1	2	41
24307	B CRK1-2	3	41
24307	B CRK1-2	4	41
24323	PORTAL	1	41
24308	B CRK2-1	1	40
24308	B CRK2-1	2	40
24309	B CRK2-2	3	40
24309	B CRK2-2	4	40
24315	B CRK 8	81	40
24315	B CRK 8	82	40
24310	B CRK2-3	5	39
24310	B CRK2-3	6	39
24311	B CRK3-1	1	39
24311	B CRK3-1	2	39
24312	B CRK3-2	3	39
24312	B CRK3-2	4	39
24313	B CRK3-3	5	39
24317	MAMOTH1G	1	39
24318	MAMOTH2G	2	39
24314	B CRK 4	41	38
24314	B CRK 4	42	38

Vestal Sub-area

The most critical contingency for the Vestal sub-area is the loss of one of the Magunden-Vestal 230 kV lines with the Eastwood unit out of service, which would thermally overload the remaining Magunden-Vestal 230 kV line. This limiting contingency establishes a LCR of 801 MW in 2013 (which includes 104 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The following table has units that have at least 5% effectiveness to the above-mentioned constraint within Vestal sub-area:

Gen Bus	Gen Name	Gen ID	Eff Fctr (%)
28008	LAKEGEN	1	46
24113	PANDOL	1	45
24113	PANDOL	2	45
24150	ULTRAGEN	1	45
24372	KR 3-1	1	45
24373	KR 3-2	2	45
24152	VESTAL	1	45
24370	KAWGEN	1	45
24319	EASTWOOD	1	24
24306	B CRK1-1	1	24
24306	B CRK1-1	2	24
24307	B CRK1-2	3	24
24307	B CRK1-2	4	24
24308	B CRK2-1	1	24
24308	B CRK2-1	2	24
24309	B CRK2-2	3	24
24309	B CRK2-2	4	24
24310	B CRK2-3	5	24
24310	B CRK2-3	6	24
24315	B CRK 8	81	24
24315	B CRK 8	82	24
24323	PORTAL	1	24
24311	B CRK3-1	1	23
24311	B CRK3-1	2	23
24312	B CRK3-2	3	23
24312	B CRK3-2	4	23
24313	B CRK3-3	5	23
24317	MAMOTH1G	1	23
24318	MAMOTH2G	2	23
24314	B CRK 4	41	22

24314	B CRK 4	42	22

S. Clara sub-areas

The most critical contingency for the S.Clara sub-area is the loss of the Pardee to S.Clara 230 kV line followed by the loss of the Moorpark to S.Clara #1 and #2 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 264 MW in 2013 (which includes 65 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors.

Moorpark sub-areas

The most critical contingency for the Moorpark sub-area is the loss of one of the Pardee to Moorpark 230 kV lines followed by the loss of the remaining two Moorpark to Pardee 230 kV lines, which would cause voltage collapse. This limiting contingency establishes a LCR of 422 MW in 2013 (which includes 93 MW of QF generation) as the minimum capacity necessary for reliable load serving capability within this sub-area.

Effectiveness factors:

The generators inside the sub-area have the same effectiveness factors.

Changes compared to last year's results:

Overall the load forecast went down by 97 MW. The new Antelope 500/230 kV #1 and #2 transformers have been modeled as part of the TRTP. The overall effect is that the LCR has decreased by 852 MW. The majority of the LCR decrease is due to load allocation change within the Big Creek Ventura.

Big Creek Overall Requirements:

2013	QF/Wind (MW)	MUNI (MW)	Market (MW)	Max. Qualifying Capacity (MW)
Available generation	798	381	4097	5276

2013	Existing Generation Capacity Needed (MW)	Deficiency (MW)	Total MW LCR Need
Category B (Single)[26]	2161	0	2161
Category C (Multiple)[27]	2241	0	2241

17. San Diego-Imperial Valley Area

Area Definition

The transmission tie lines forming a boundary around the Greater San Diego-Imperial Valley area include:

1) Imperial Valley – North Gila 500 kV Line
2) Otay Mesa – Tijuana 230 kV Line
3) San Onofre - San Luis Rey #1 230 kV Line
4) San Onofre - San Luis Rey #2 230 kV Line
5) San Onofre - San Luis Rey #3 230 kV Line
6) San Onofre – Talega #1 230 kV Line
7) San Onofre – Talega #2 230 kV Line
8) Imperial Valley – El Centro 230 kV Line
9) Imperial Valley – Dixieland 230 kV Line
10) Imperial Valley – La Rosita 230 kV Line

The substations that delineate the Greater San Diego-Imperial Valley area are:

1) Imperial Valley is in North Gila is out
2) Otay Mesa is in Tijuana is out
3) San Onofre is out San Luis Rey is in
4) San Onofre is out San Luis Rey is in
5) San Onofre is out San Luis Rey is in
6) San Onofre is out Talega is in
7) San Onofre is out Talega is in
8) Imperial Valley is in El Centro is out
9) Imperial Valley is in Dixieland is out
10) Imperial Valley is in La Rosita is out

Total 2013 busload within the defined area: 4990 MW with 124 MW of losses resulting in total load + losses of 5114 MW.

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[26] A single contingency means that the system will be able the survive the loss of a single element, however the operators will not have any means (other than load drop) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

[27] Multiple contingencies means that the system will be able the survive the loss of a single element, and the operators will have enough generation (other operating procedures) in order to bring the system within a safe operating zone and get prepared for the next contingency as required by NERC transmission operations standards.

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CALIFORNIA ISO
2011/2012 TRANSMISSION PLAN

COMMENTS OF THE STAFF OF THE

CALIFORNIA PUBLIC UTILITIES COMMISSION

ON THE JANUARY 31 2011 DRAFT OF THE 2011-2012 TRANSMISSION PLAN

* * * * * * *

February 28, 2012

Introduction

The Staff of the California Public Utilities Commission ("CPUC Staff") appreciates this opportunity to provide comments on the California Independent System Operator's ("ISO") 2011-2012 Draft Transmission Plan ("Plan"), made public on January 31, 2012, and presented at the February 7, 2012 stakeholder meeting. CPUC Staff especially welcomes the ISO's focus on several 33% Renewable Portfolio Standard ("RPS") cases (alternative renewable resource portfolios) provided from the CPUC's Long Term Procurement Plan ("LTPP") proceeding. These cases included informative and perhaps unprecedented transmission analysis of a distributed renewable generation scenario including substantial, additional, solar photovoltaic resources (Environmentally-Constrained case).

CPUC Staff comments on the Plan address the following areas:

1. The Plan should contain a clear summary of key planning assumptions. This summary should establish and/or contrast the relationship between these key assumptions and corresponding assumptions being used in CPUC, California Energy Commission ("CEC"), or other statewide planning processes.
2. The transmission planning assumptions used in the Plan include less incremental, uncommitted energy efficiency; demand response; and combined heat and power than were adopted for the CPUC's Long Term Procurement Plan process. This can produce a disconnect between transmission and resource planning. The

2011-2012 Final Transmission Plan should clearly provide and describe the assumptions used, including tables with the values utilized. In addition, CPUC staff urges the ISO to use the CPUC's LTPP assumptions for these demand-side items in the 2012-2103 Transmission Plan.

3. There should be more complete justification for large reliability projects.
4. If additional large reliability projects still under study are to ultimately be included in the plan, they must first be fully explained and justified.
5. Assumptions underlying the "special reliability studies" regarding local capacity requirements ("LCR") and once through cooling ("OTC") plants need to be more clearly explained within the Plan (as opposed to citing external materials), and divergence from planning assumptions used by the CPUC and CEC should be justified.
6. Methodology and assumptions in the plan's RPS-related studies of reliability and deliverability in Chapter 4 need to be more clearly explained and justified in several respects.
7. Based on reported results of RPS portfolio reliability studies, the ISO should more fully justify the proposed new Bridgeville-Garberville 115 kV line, or select one of the lower cost and easier to site alternatives.
8. There should be fuller description and justification of major transmission additions being brought into the Plan via the generator interconnection process.
9. Key parameters in the economic studies should be more fully documented and justified.
10. The ISO should show how resources supporting proposed location constrained resource interconnection facilities ("LCRIF") designations correspond to the Plan's RPS portfolios.

Discussion

1. The Plan Should Contain a Clear Summary of Key Overarching Planning Assumptions to Establish or Contrast the Relationship with Corresponding Assumptions Being Used in CPUC, CEC, or Other Statewide Planning Processes

As addressed in prior CPUC comments, coordination between the CPUC's resource planning and the ISO's transmission planning is critically important. Much progress has been made over the last several years toward harmonizing assumptions. It is critical that the public understands that the CPUC and ISO are using the same planning assumptions when reviewing transmission and generation projects, and if any variation in assumptions occurs, those variations are clearly identified and explained. The results of the ISO's transmission planning efforts form the basis for Participating Transmission Owners applications to the CPUC for authority to build. Lack of transparency could extend the CPUC's transmission project approval process, as discovery and cross-examination are used to identify key assumptions and differences between ISO and CPUC planning assumptions and lead to avoidable regulatory delays.

ISO staff has worked with CPUC Staff and provided information on demand and supply-side assumptions, frequently beginning with specific information from the CEC and CPUC. These efforts follow the spirit of the 2010 Memorandum of Understanding between the ISO and CPUC.[1] However, in some cases, the information used by the ISO (see Section 2.3 and other sections of the Plan) has been modified from the original data, or the information is not made available to stakeholders, including the CPUC.

As the examples discussed under topic 2 (below) illustrate, more transparency is needed, and more detailed information should be provided in the Final Transmission Plan. We suggest a central table or tables summarizing key assumptions and data sources, explained in text, with appendices providing the actual assumptions and data used. It is not entirely clear what assumptions have been used across cases in the Plan. CPUC staff recommends that cases include load and resource tables that include at a minimum:

1) <u>Supply Side Resources</u>.
   a) Generation: Existing, retiring, and new generating units, each broken out on its own line.
   b) Non-generation: Demand response, combined heat and power[2] generation that is exported to the grid, and other programs at an appropriate level of geographic disaggregation (e.g., local reliability areas).

[1] Memorandum of Understanding between the California Public Utilities Commission (CPUC) and the California Independent System Operator (ISO) regarding the Revised ISO Transmission Planning Process, dated May 2010.

[2] We refer to two different types of combined heat and power (CHP). "Supply side" CHP refers to units that export energy to the grid. "Demand side" CHP refers to generation that meets onsite load but does not export energy to the grid.

2) Demand Side Resources.
   a) What demand forecast was used, including probability (e.g., 1-in-10, 1-in-2) and vintage (e.g., 2009 Integrated Energy Policy Report).
   b) Demand reductions: incremental uncommitted energy efficiency, behind-the-meter combined heat and power, and other demand side reductions (e.g. behind-the-meter solar photovoltaics) at an appropriate level of geographic disaggregation.

Including this type of detail will allow stakeholders to provide more meaningful comments on the Plan and to understand what assumptions were made. Without this information, it is uncertain what changes or applications of programs to geographic areas have been done in the modeling conducted for the Plan.

In addition, CPUC Staff makes these recommendations so that the Final Transmission Plan will be as robust a document as possible, if used as evidence in a CPUC proceeding for a Certificate of Public Convenience and Necessity ("CPCN").

2. The Transmission Planning Assumptions Include Less Incremental Energy Efficiency, Demand Response, and Combined Heat and Power than Were Adopted for the CPUC's Long Term Procurement Plan Process, Which Can Produce a Disconnect Between Transmission and Resource Planning.

The demand forecasts used in the Plan are based on the 2010-2020 California Energy Commission demand forecasts for 1-in-10 and 1-in-5 load.[3] (See generally, Section 2.3 of the Plan.) However, they do not include certain demand side reductions included for LTPP and other purposes, such as incremental, uncommitted energy efficiency programs[4] or incremental demand-side combined heat and power ("CHP"). Failure to fully account for these programs results in an increase in demand of 6,506 MW, i.e., 819 MW from the CHP forecast in the 2010 LTPP, and 5,687 MW from energy efficiency. However, there are other changes in the forecast that CPUC Staff have not been able to reproduce, leading to a higher forecast in the ISO's assumptions of approximately 4,000 MW, rather than the identified 6,500 MW. The reasons for the

[3] Plan, pp. 32-33, section 2.3.2.7, Load Forecast.

[4] Uncommitted energy efficiency are savings expected to occur, but which may not yet have specific funding or programmatic designs. This also includes future changes in codes and standards.

discrepancy are not clear. The ISO should provide more detailed discussion of the assumptions, changes, and justifications for these changes, so that stakeholders can clearly understand what assumptions are used in the ISO's models.

The ISO's December 8, 2011 presentation identified 2,581 MW of demand response and interruptible programs. The 2010 LTPP planning assumptions adopted 5,145 MW. This reflects a 50% decrease in the values associated with demand response programs, relative to the LTPP values. This derating of demand response and interruptible programs reflects a significant departure from the 2010 LTPP assumptions.

In a similar vein, CPUC Staff understands that CEC staff are also trying to reconcile assumptions about future renewable resources. In January 2012, CEC staff requested additional detail regarding assumptions made about RPS and distributed generation ("DG") resources included in the "policy" renewable scenarios for Southern California Edison's ("SCE") territory by local reliability areas.[5] This information was not provided, and CEC staff and its consultant, Navigant, attempted to estimate the RPS and DG resources in SCE's territory by local reliability area. There are significant, unexplained differences in megawatts between the installed capacity modeled in the powerflow base cases and the amounts presented in the ISO presentation of December 8, 2011 by local area.

In sum, the transmission planning assumptions used in the Plan include less incremental, uncommitted energy efficiency; demand response; and combined heat and power than were adopted for the CPUC's Long Term Procurement Plan process. The 2011-2012 Final Transmission Plan should clearly describe these differences and describe the assumptions used, including tables with the values utilized. In addition, CPUC staff urges the ISO to use the CPUC's LTPP assumptions for these demand-side items in the 2012-2103 Transmission Plan. In addition, there appear to be discrepancies regarding RPS and distributed generation resources that should be resolved and/or explained in the Final 2011-2012 Transmission Plan.

[5] Plan, p. 268, Table 4.1-12, entitled "SCE renewable generation capacity in portfolios (MW)."

3. There Should Be More Complete Justification for Large Reliability Projects

Chapter 2 of the Plan recommends certain reliability projects. The Plan recommends Board approval of the Embarcadero-Potrero project, a new 230 kV underground cable from the Potrero substation to the downtown San Francisco Embarcadero substation, providing a third line of supply to the downtown San Francisco load center. This would provide redundancy to protect against the simultaneous loss of both existing Martin-Embarcadero 230 kV circuits, a category C (N-2) contingency. The cost estimate is $130-150 million. Because this project exceeds 200 kV, the developer, PG&E, will be required to seek a CPCN from the CPUC.

The Plan states that the N-2 contingency driving the need for the project would result in an estimated 250 MW of load shedding if the proposed project were not built, and also states that, "these reliability projects [including Potrero-Embarcadero] are necessary to ensure compliance with the NERC and ISO planning standards."

However, NERC reliability standards do not require avoidance of load shedding in the event of on N-2 (Category C) Bulk Electric System contingency, but rather state with regard to such contingencies that:[6]

> *Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.*

Furthermore, the ISO's Planning Standards (June 23, 2011) state on page 6 that no <u>single</u> contingency (TPL-002 and ISO standard [g-1] [l-1]) should result in loss of more than 250 MW of load. There is no stated ceiling on load shedding for <u>double</u> contingencies, but on the same page it is stated that transmission upgrades not required by the standards, "*may be justified by eliminating or reducing load outage exposure, through a benefit to cost ratio (BCR) above 1.0 and/or where there are other*

[6] NERC Standard TPL-003-1a, approved by the Board of Trustees on February 17, 2011.

extenuating circumstances." (Emphasis added.)

The Plan describes the Category C contingencies considered to be reasons for the proposed project.[7] It discusses the project's usefulness during planned outages and during PG&E's proposed upgrade to the Embarcadero Substation, as well as the difficulty in restoring service after the N-2 outage in question. However, there should be more specific description of the *probability*[8] *and duration* of outage, and the consequent *economic loss*, to be weighed against the cost of the project, as required in the ISO's planning standards. Also, the Plan should identify alternative solutions considered, their effectiveness, and their total costs to ratepayers. Both the Plan and the PowerPoint presentation on February 7, 2012,[9] were silent on alternatives considered. Similarly, the interim solutions are not specified.[10] All of the above matters would be important in a CPCN proceeding. Note that a CPCN proceeding includes consideration of benefits and costs.[11]

ISO identified other major and costly reliability projects, such as New Bridgeville-Garberville No. 2 115 kV transmission line and the Kern PP 115 kV Area Reinforcement project. As discussed in comments under topic 7 below, information provided in conjunction with the Plan's reliability studies for RPS portfolios indicates that there may be lower cost alternatives to the Bridgeville-Garberville project that also

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[7] Plan, p. 107.

[8] Plan, p. 107, states: "Loss of Embarcadero Load." . . . The Category C contingency of the loss of the two Embarcadero-Martin 230 kV cables or a 230 kV breaker failure in the Embarcadero substation will result in the loss of the load served at the Embarcadero substation. . . . While the likelihood of the simultaneous loss of both circuits is low, the consequences of the outage are severe and require mitigation. . . ." (Emphasis added.)

[9] ISO (Bryan Fong), "Reliability-Driven Transmission Project Needs & Recommendations Greater Bay Area" in "2011/2012 ISO Transmission Plan Stakeholder Meeting," Feb. 7, 2012, PowerPoint presentation, slide 7 (entitled "Embarcadero-Potrero 230 kV Line Project").

[10] *Id.*

[11] A couple of attendees at the February 7, 2012 stakeholder meeting requested backup calculations for the Benefit / Cost ratios for certain reliability projects (especially the Embarcadero-Potrero 230 kV underground cable), and that such backup be provided in the future along with the Draft Plan. CPUC Staff agrees.

may present fewer siting issues. CPUC Staff requests that the ISO present a fuller comparison of these alternatives.

4. If Additional Large Reliability Projects Still Under Study Are to Ultimately Be Included in the Final Plan, They Must First Be Fully Explained and Justified.

The ISO is still evaluating several potential reliability projects (see Chapter 2) which could add substantially to the overall cost, including:

- Drum-Placer 115 kV line issues[12] (Sierra foothills). Various mitigations cost about $100-200 million according to the February 7th presentation.[13]

- Kern area 230 kV reinforcement (operational or infrastructure solutions).[14] The cost of alternatives was not specified in the February 7th presentation.[15]

- Morro Bay-Mesa 230 kV Line Project.[16] This project could cost close to $70 to $85 million.[17]

If any of these projects are included in the Final Plan, they should be fully explained and justified along the lines discussed under topic 3 above.

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[12] Plan, pp. 95-97.

[13] ISO (Binaya Shrestha), "Reliability-Driven Transmission Project Needs & Recommendations PG&E Central Valley Area," PowerPoint, February 7, 2012, slide 6.

[14] Plan, pp. 128-130.

[15] ISO (Abhishek Singh), "Reliability-Driven Transmission Project Needs & Recommendations San Joaquin Valley Area," PowerPoint, February 7, 2012, slides 17-18.

[16] Plan, pp. 136-137.

[17] Remarks at stakeholder meeting and ISO (Chris Mensah-Bonsu), "Reliability-Driven Transmission Project Needs & Recommendations Central Coast and Los Padres Areas," PowerPoint, February 7, 2012, slide 3.

5. Assumptions Underlying the "Special Reliability Studies" regarding Local Capacity Requirements (LCR) and Once Through Cooling (OTC) Plants Need to Be More Clearly Explained within the Plan, and Divergence from Planning Assumptions Used by the CPUC and CEC Should Be Justified.

CPUC Staff appreciates the time and effort the ISO has made in collaborating with agencies on once-through-cooled power plants and air quality issues in the Los Angeles Basin.[18] (See Chapter 3 of the Plan.) This work is critical for input into the CPUC's Long Term Procurement Plan proceeding. An adequate record is necessary by the second quarter of 2012 to inform the CPUC's stakeholders of any needs for new generation or repowering authorizations for local areas in light of the State Water Resources Control Board's policy on once-through-cooled power plants.[19] (This is CPUC Staff's rough estimate of regulatory proceeding timelines that have not yet been established.) CPUC staff requests that the ISO fully develop and complete the analysis as a supplement to the 2011-2012 Transmission Plan, if not feasible to do within the Final Plan.

The Plan refers to external planning materials for the LCR and OTC plant assumptions. These references to external documents make it difficult to assess if the tools are the same as those used in the Plan's modeling. For example, the LCR Tool has at least two different vintages publicly posted.[20] Again, this type of discrepancy leads to an increased likelihood that the ISO's modeling results will be subject to additional scrutiny in CPUC proceedings and could lead to delays in procurement authorizations for replacement or repowered generation in the local areas. CPUC Staff has been unable, to date, to identify the source of discrepancies. It would benefit all stakeholders if clear descriptions of changes and methodologies were provided. Otherwise, additional time

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[18] CPUC Staff understands that the ISO will submit testimony in CPUC Application 11-05-023 regarding total local capacity requirements in San Diego. (San Diego Gas and Electric has requested authorization to contract for three new power plants in the San Diego Local Area.)

[19] Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling, available at http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/docs/policy100110.pdf

[20] See, http://www.caiso.com/2734/2734e3d964ec0.html.

will need to be spent in the approval process as discovery and cross-examination are used to identify key assumptions, and differences between ISO and CPUC assumptions are litigated. If the Plan uses the exact assumptions as the cited external studies do, then the assumptions are transparent, and planning efforts at different agencies are in sync. However, to the extent the Plan actually relies on modified assumptions (as in the examples discussed above), there could be a disconnect between planning efforts at different agencies.

The LCR studies provide important information to the CPUC's procurement and LTPP processes; therefore, it is critical that the studies make clear where the assumptions align with the CPUC's LTPP Standardized Planning Assumptions; where they differ; and what methodologies were used to translate broad planning assumptions to the local areas. Without this type of detailed information made available, it is difficult for stakeholders to make informed recommendations to the CPUC and for the CPUC to determine whether new generation needs to be authorized.

6. Methodology and Assumptions in the Plan's RPS Resource-Related Studies in Chapter 4 Need to Be More Clearly Explained and Justified

The methodologies and assumptions for reliability and deliverability studies for RPS portfolios as described in Chapter 4 should be more clearly explained in several ways. Similarly, the interpretation of these study results for Plan purposes also needs to be more clearly explained. This is especially important in light of the anticipated increased importance of the transmission planning process ("TPP") to plan *delivery* network upgrades under TPP-GIP[21] integration reforms, to be combined with what we understand would be continuing reliance on interconnection studies to plan *reliability* network upgrades.

Thus, CPUC Staff requests that the ISO clarify and generally present in more accessible form the following aspects of the reliability and deliverability studies conducted for RPS portfolios as described in Chapter 4 of the Plan.

[21] "TPP-GIP" means Transmission Planning Process-Generator Interconnection Procedures.

- Under TPP-GIP integration reforms, it is proposed that generation-related upgrades would continue to be planned within interconnection studies rather than in the TPP. What role would the reliability studies described in Chapter 4 play in planning reliability network upgrades for new generators?

- Please explain if and how the RPS portfolio-related reliability studies described in Chapter 4 differ from the system reliability studies described in Chapter 2, beyond simply considering four different RPS resource portfolios in Chapter 4 rather than only the base case in Chapter 2. For example, were there differences in the types of contingencies considered or the types of power flow and stability analyses run, or in the assumed wind and solar output levels (see below)?

- How did major assumptions and analyses for the on-peak reliability (power flow and stability) analyses for RPS portfolios as described in Chapter 4 differ from the deliverability studies described in the same chapter for the same portfolios, particularly in terms of wind, solar and other generation output levels and in terms of outage contingencies studied?

- More specifically, please report quantitatively the assumed output levels (relative to maximum capacity) for wind and solar generation in the reliability studies described in Chapter 2, reliability studies described in Chapter 4, and deliverability studies described in Chapter 4, indicating differences across these different studies. Please provide quantitative comparisons (among the different studies and RPS cases) in the aggregate (all locations), and for at least a few major resource areas especially in the Mohave area.

- It appears that deliverability studies described in Chapter 4 set wind and solar output levels somewhere between the 50% and 20% exceedance levels over the QC period[22] (with 20% exceedance representing a level of output exceeded only 20% of the time during the QC period). Consequently, the amount of transmission capacity required for deliverability would appear to generally exceed what is needed to deliver the resources at their resource adequacy (Net Qualifying Capacity) levels, which reflect a lower level of output. This should be clarified and justified.

- Section 4.10.1.1, regarding the RPS portfolios deliverability studies, states, *"Imports are at the maximum summer peak simultaneous historical level by branch group . . . . For any intertie that requires expanded MIC, the import is the target expanded MIC value."* The Plan should clarify the

[22] The Qualified Capacity determination period, i.e., the hours between 12 p.m. and 6 p.m. during May through September.

relationship between the above summary of study assumptions and the statement on page 2 of the Executive Summary that, "*Existing inter-state transmission will have capacity made available as renewable resources displace energy from traditional resources.*"

- What thermal generation at high risk of retiring by 2021 was modeled with non-zero output in the reliability and deliverability studies? Such generation should be identified and the consequences of its inclusion versus exclusion in the reliability and deliverability studies should be clearly explained. The modeled output of such generation in the reliability, deliverability, and deliverability sensitivity (limited OTC capacity) studies should be reported.

- The overall impact on RPS portfolio deliverability of assuming limited or minimum capacity at OTC locations under the deliverability sensitivity studies should be explained more clearly.

- It is unclear if some of the instances of deliverability issues (non-deliverability of some generation) described in Section 4.10 refer to thermal generation deliverability but not significantly to RPS portfolio deliverability, despite being included in the Chapter on RPS resource studies. This should be clarified.

7. **Based on Reported Results of RPS Portfolio Reliability Studies, the ISO Should More Fully Justify a New Bridgeville-Garberville 115 kV Line, or Select Lower Cost and Easier to Site Alternatives**

Chapter 4 of the Plan states on page 292 that:

> *With additional renewable generation modeled in the environmentally constrained portfolio, overload on the Bridgeville-Garberville 60 kV line was higher than in the reliability studies. The new Bridgeville-Garberville 115 kV line would mitigate the overload under normal conditions. It would also mitigate category B and C contingency overloads and voltage concerns. If the new transmission line is not constructed, the reconductoring of the overloaded sections would mitigate the overload.*

On page 294 the Plan also identifies voltage concerns for this part of the grid in connection with some RPS resource cases, but states that, "*Additional reactive support would also mitigate the voltage deviation concerns, but it would not mitigate thermal overloads.*"

It thus appears that reconductoring plus reactive support would mitigate the thermal plus voltage issues in this part of the grid even under the environmentally constrained RPS resource case producing the greatest impacts. Thus, the CPUC Staff requests that the ISO provide a cost comparison of a new 115 kV line versus reconductoring plus reactive support. If the 115 kV line remains the proposed remedy, the Plan should more fully explain and justify it.

8. There Should be a Fuller Description of Major Transmission Additions Being Brought into the Plan via the Interconnection Process

For several years the ISO, CPUC, and virtually all stakeholders have recognized that it is inefficient to have planning (and re-planning) of major transmission upgrades supporting the State's renewable energy goals conducted piecemeal via the generator interconnection process. Because of this, we have all been seeking, and the ISO has been developing, a more holistic and transparent approach to planning such transmission.

The previous 2010-2011 plan cycle introduced substantial amounts of Large Generator Interconnection Procedures-driven ("LGIP") transmission directly into that plan, without assessing and reporting on the efficiency and utilization of those additions in the context of the overall plan. It was also unclear to what extent this LGIP transmission in the 2010-2011 plan went beyond what was needed by generators having signed interconnection agreements. CPUC Staff agrees that, as indicated in the Draft 2011-2012 Plan, the proposed LGIP-driven Pisgah-Lugo 500 kV project previously included in the 2010-2011 plan should be removed from the planning base case. This was removed due to showing very low utilization under RPS resource cases for the 2011-2012 Plan and also due to not being supported by current information on generation projects under development.

The tariff-based limitation for studying LGIP-driven upgrades specifically in the 2010-2011 transmission plan cycle[23] no longer applies in the 2011-2012 cycle, and CPUC-provided RPS resource scenarios are now being used in the TPP for the first time in the 2011-2012 plan cycle.[24] Furthermore, current reforms, including Cluster 1-4

[23] ISO tariff, Section 24.4.6.5 states, in part: "Beginning with the 2011/2012 planning cycle, Network Upgrades originally identified during the Phase II Interconnection Study or Interconnection Facilities Study Process of the Large Generation Interconnection Process as set forth in Section 7 of Appendix Y that are not already included in a signed LGIA may be assessed as part of the comprehensive Transmission Plan if these Network Upgrades satisfy the following criteria …"

[24] This is consistent with the May 2010 Memorandum of Understanding between the CPUC and ISO.

deliverability study refinements and the TPP-GIP integration initiative mentioned above, are moving us away from simply moving interconnection process-driven transmission additions directly into the Transmission Plans.

Thus, it is essential to more fully describe and assess the interconnection process-driven transmission additions that are being imported directly into the Plan. This includes LGIA-driven transmission listed in Table 1 of Executive Summary and in Table 4.3-2. Fuller disclosure is needed for understanding the role and importance of these proposed LGIA-driven transmission additions in the context of the broader plan and RPS scenarios. This should help inform development of future RPS scenarios for planning purposes, and may also help inform the procurement process.

Furthermore, Section 4.3.4 of the Plan states:[25]

> *The RPS portfolios and generator interconnection studies have considerable overlap in terms of location and generation technology. It is reasonable to assume that transmission upgrades that are in an executed LGIA would be needed to interconnect and deliver renewable generation in the RPS portfolios if the renewable generation capacity, technology and location in the portfolios correspond to that in generator interconnection studies. Therefore, some transmission upgrades in executed LGIAs were modeled in the policy-driven planning base cases based on the comparison of portfolios discussed in Section 4.1 and previous generator interconnection studies results.*

It is essential to explain more fully which "transmission upgrades in executed LGIAs" were and were not included in the Plan base case and why, including whether they were modeled for all four RPS resource cases. This should include fuller description of the megawatts and locational correspondence between the above-referenced generation having executed LGIAs versus generation in the RPS study portfolios. It should also include reporting the projected utilization (via production simulation) and cost of the LGIA-driven transmission upgrades (see below), and the consequences for the RPS portfolios, if particular LGIA-driven upgrades included in the base case were omitted.

[25] Plan, p. 272.

At a minimum, the additional information that should be reported for the LGIA-driven transmission lines (and where noted, substations) listed in Table 4.3-2 includes the following. (CPUC Staff understands that this information is partially provided in the present Plan draft.)

- The physical/electrical characteristics of the transmission line additions, including voltage, transfer capability increase and endpoints.
- The MW and locations of (1) the renewable (and other) generation having signed interconnection agreements for which this upgrade is needed, and (2) separately, the additional renewable (or other) generation that could be accommodated via this upgrade beyond the generation having signed interconnection agreements.
- The estimated in-service date and cost of the transmission line and substation additions.
- Whether the transmission line and substation additions would be needed for reliability or for deliverability purposes, for the generators having the signed interconnection agreements for which the upgrade is needed.
- The modeled 8760-hour utilization of the transmission line additions under the four RPS scenarios studied for Plan development.

With regard to the last point regarding projected 8760-hour utilization, if **any** (not just interconnection process-driven) major transmission additions are projected to have low 8760-hour utilization,[26] this calls into question the value of these projects, which needs to be explicitly justified.

9. Key Parameters in the Economic Study Should be More Fully Documented and Explained

Transmission costs can be high and can exceed estimates, especially in California and especially when encountering major siting issues. When conducting and reporting on economic congestion studies as well as studies responding to study requests, as in Chapter 5 of the Plan, the ISO should more fully describe the source and rationale for the transmission cost estimates affecting the calculated cost effectiveness of transmission solutions under study. Furthermore, assumptions and methods used to convert direct

[26] Production simulation results presented in Section 4.6 of the Plan show very low projected 8760-hour utilization for certain RPS-driven transmission projects.

capital costs to total ratepayer costs, and to calculate various kinds of benefits against which costs are compared, such as summarized in Section 5.4.4 of the Plan, should also be more fully documented and justified. Finally, given the uncertainties in both future circumstances and in appropriate selection of economic parameters, assessment of large potential transmission projects initially yielding marginal benefit-cost ratios should be augmented with sensitivity analysis regarding key assumptions and economic parameters.

If studies pursuant to a study request identify a transmission solution that could be an efficient substitute for other transmission additions that have been previously identified but not yet permitted, then the ISO should evaluate whether such a substitution (as opposed to additional on top of the previously identified transmission) would produce better value for ISO ratepayers.

10. The ISO Should Show How Resources Supporting Proposed Location Constrained Resource Interconnection Facilities (LCRIF) Designations Correspond to the 2011-2012 Plan's RPS Portfolios

Chapter 6 describes final approval for the Highwind LCRIF and the decision not to conditionally approve an Imperial Valley LCRIF. Under the ISO's tariff, final approval of a LCRIF requires demonstration that at least 60% of the proposed facility's capacity is accounted for by location-constrained resources demonstrating "interest" by meeting certain criteria, with at least 25% of the facility's capacity having to be accounted for by generators having executed interconnection agreements. For both the Highwind LCRIF and the proposed Imperial Valley LCRIF, and any future LCRIFs, the ISO should report on: (1) how resources identified as contributing to the above "interest," and (2) how total resources using the LCRIF, were it to be fully subscribed, correspond to resource quantities and locations in the RPS portfolios studied.

Thank you for your attention to these comments.

Comments submitted by e-mail to: RegionalTransmission@caiso.com

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Guidelines for Developing an Under Voltage Load Shedding (UVLS) Evaluation Program

A Technical Document
Prepared by the
Transmission Issues Subcommittee
of the
North American Electric Reliability Council

September 13, 2006

INTRODUCTION

This guideline is intended to address UVLS programs designed to prevent wide-area voltage collapse and cascading, whether the control is applied locally or by a centralized controller. Such UVLS programs are intended as a safety net to stabilize the system and prevent cascading outages for severe contingencies.

- **Locally applied UV relay schemes** — intended to protect the local load – such as large induction motors, typically on a single distribution feeder – should be recognized as interacting, but are not required to be included in the analysis of UVLS programs except as needed for coordination.
- **BPS UVLS programs** — application of UVLS systems to protect the BES from cascading and major load centers from uncontrolled voltage collapse. These systems should be included in contingency analysis, , and are of the following control types:
    - **Locally controlled** — use of local controls/relays as part of a wide-area UVLS program intended to control wider areas against voltage collapse. May be applied at the distribution, subtransmission, or transmission voltage levels.
    - **Centrally controlled** — Application of a centrally controlled wide-area UVLS program that then transfer-trips to distribution, subtransmission, or transmission stations intended to control wider areas against voltage collapse.

These guidelines were developed by the TIS based on initial drafts provided by the UVLS subgroup of the TIS and System Protection and Controls Task Force. That group's review of UVLS studies undertaken by the regions in response to NERC blackout recommendation 8b.

POWERFLOW AND DYNAMICS CASE SELECTION

Given the fact that the electric system can be most vulnerable to a system disturbance while being operated in stressed conditions, it is important to understand the response of the system under those conditions.

The analysis should be done using an appropriately stressed powerflow and associated dynamics case. Examples are summer peak, winter peak, or high transfers during off-peak periods.

Case selection should also include consideration of unit commitment to reasonably minimize inertia and reactive power supply in the area under study.

CONTINGENCY SELECTION AND EVALUATION

- BPS UVLS programs should not be used to meet the performance requirements of NERC category B contingencies.
    - For NERC category B contingencies, the application of locally applied UV relay schemes are acceptable to protect local load as described in the above introduction.
- For category C and D contingencies, the application of BPS UVLS programs should be considered as "safety nets," to avoid voltage collapse or voltage instability, and studied to ensure that they adequately perform that function.
    - For NERC category C and D contingencies, application of locally applied UV relay schemes are acceptable to protect local load as described in the above introduction.

- The application of BPS UVLS programs also should be studied to address multiple unrelated outages (extreme events) and external contingencies.

METHODS AND MODELS ANALYSIS

Generator and load responses to a system contingency play a predominant role in whether a system is stable or it collapses. Therefore, system stability cannot be determined using only steady state tools, and dynamic studies with appropriate models and controls for generators and loads are essential.

- Steady State Simulations
  - Appropriate static and dynamic load representation should be modeled. Load characteristics in general, and motor load characteristics in particular, can have a significant impact on system response following a system event. Knowing actual load characteristics in order to accurately model the load is very important in such studies. As sometimes it is difficult to get this information, it is important to examine the sensitivity of the system to a range of load characteristics. If studies show that results are sensitive to the load model used, the planner should attempt to verify actual load characteristics in the affected area. An example of a special load modeling consideration is high concentrations of high-efficiency residential air conditioning.
  - Existing special protection systems (SPS) and tap changing under load transformers (LTCs) should be modeled in the analysis.
  - As part of the steady-state analysis, powerflow simulations including PV and QV analysis should be performed.
  - Load serving or transfer capability into a given area or system should be determined under outages of various real and reactive power sources in the area.
  - Pre-contingency, post-contingency without operator or automatic device operation, and post-contingency with operator or automatic device operation cases should be analyzed.
- Dynamics Simulations
  - Appropriate static and dynamic load representation should be modeled.
  - Models and controls for generators and loads, induction motors, over excitation limiters (OELs), LTCs, flexible AC transmission (FACTS) devices, relays, existing special protection systems (SPS), etc., should be included in the dynamic model.
  - UFLS systems should be modeled in the dynamics case to assess any potential interaction with UVLS systems.

CRITERIA FOR IDENTIFYING / DETERMINING VOLTAGE STABILITY PROBLEMS

Criteria should be established and documented for evaluating/analyzing voltage stability problems. The following applicable guidelines were developed by the TIS in answer to Recommendations 7a and 13c from the NERC *August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts February 10, 2004.*

Each transmission owner or transmission planner should be responsible for establishing applicable voltage limits in its respective area, with a documented process, in accordance with NERC standards. This process should be shared with the region for review and approval. The region(s) should be responsible for facilitating the resolution of any potential conflicts in the applicable voltage limits established between adjacent transmission owners.

Examples of criteria are as follows:

a. Steady State Criteria

  - Post-contingency Power Margin (MW) of 3% to 5% from the nose point of the PV curve.
  - The post-contingency voltage at the knee point above 92% of nominal or 0.92 per unit, whichever is higher.
  - Delta V — To the extent that a Delta V criterion is used by transmission planners for screening voltage limitations, the criterion should be documented, and be based on detailed analysis and not an arbitrary rule of thumb.

  Other considerations for dynamics analysis including:

  - Design voltage criteria for nuclear plant off-site power supplies.

b. Dynamic Criteria

  Short-Term Dynamic Criteria – to determine fast voltage collapse

  - After fault clearing – Minimum of 70% of nominal voltage at any bus and not to fall below 80% for more than 40 cycles at load buses. The voltage during a fault would be expected to drop below 70%.

  Long-Term Dynamic Criteria – to determine slow voltage collapse

  - Voltage should return to at least 90% of nominal level in 10 seconds

  Other considerations for dynamics analysis including:

  - Minimum voltages at plant auxiliary buses.
  - Design voltage criteria for nuclear plant off-site power supplies
  - Large industrial motor control drop-out voltages

OTHER STUDY CONSIDERATIONS

Sensitivity studies should consider the following scenarios.

- Sensitivity analysis to tripping of severely overloaded lines should be evaluated when loading reaches a level that may result in tripping due to relay loadability limitations or conductor sag limitations
- Customer real and reactive power demand forecast errors
- Outages not routinely studied in the region of interest
- Outages not routinely studied on neighboring systems
- Unexpected generator unit trips following major disturbances
- Lower voltage line trips following major disturbances

- Variations of neighboring system's generation dispatch
- Large and variable reactive exchanges with neighboring systems
- More restrictive reactive power constraints on neighboring system generators than forecast
- Variations in load characteristics, especially in load power factors
- Risk of the next major event during a 30-minute adjustment period or an adjustment period consistent with NERC Standards
- Not being able to readjust adequately to get back to a secure state
- Increases in major transmission interface flows following major contingencies due to various factors such as undervoltage load shedding, SPS or remedial action scheme (RAS)
- On-system reactive resources not responding
- Excitation limiters responding prematurely
- Possible SPS failure
- Prior outages of system facilities
- More restrictive reactive power constraints on internal generators than planned
- Neighboring system voltage profile for the operating condition (the higher the voltage on the neighboring system in the pre-contingency case, the higher the contingency voltage will be in the area under study).

RECOMMENDED DOCUMENTATION

The following are the recommended documentation and reporting for UVLS investigations:

- Description of screening studies to identify voltage stability challenged areas.
- Description of undervoltage scenarios identified by the screening studies.
    - Contingency type studied (e.g., C1 or D2).
    - Pre-event conditions studied including degree of system stress (e.g., large generator outage, high transfer levels, high load levels, poor load power factor, etc.).
    - Long-term vs short-term voltage collapse.
    - Amount and location of load at risk.
    - Applicable voltage stability criteria.
- Description of analysis used to study the event.
    - Regional method for simulating cascading event scenarios (was/was not) developed and used.
    - Cases used in the analysis.
    - PV/QV analysis methods.
    - Consideration of thermally overloaded and tripped lines.
    - Dynamic analysis (short-term voltage collapse events)
    - Load modeling sensitivities.

- Verification of operational security of any automatic regulating device(s) employed to prevent voltage collapse that require(s) station service for proper operation.
    - Can the device(s) survive the event(s) threatening voltage collapse and provide mitigation as modeled?
    - Is the station service adequate to keep the device(s) on line through the studied event(s)?
- Description of each UVLS scheme determined to be feasible and beneficial in preventing voltage collapse.
    - General locations, order, and amount of load to be shed.
    - Type of UVLS controls – centralized or distributed.
    - Is the application of UVLS a temporary or long-term mitigation?
- "Next Steps," with estimated schedule.
- Summary of studies that support each UVLS scheme.
- Overview of interaction between each UVLS scheme with UFLS and other protection schemes (regional and inter-regional, as appropriate), and an overview of the level of effort required to assess coordination between these various schemes and to mitigate any miscoordination.

Sciencexpress Research Article

The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity

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Reducing greenhouse gas emissions 80% below 1990 levels by 2050 is the subject of vigorous policy debate but there has been little physically realistic modeling of the energy and economic transformations required. We analyzed the infrastructure and technology path required to meet this goal in a specific economy (California), using detailed modeling of infrastructure stocks, resource constraints, and electricity system operability. We find that technically feasible levels of energy efficiency and decarbonized energy supply alone are not sufficient. Rather, widespread electrification of transportation and other sectors is required. Decarbonized electricity becomes the dominant form of energy supply, posing challenges and opportunities for economic growth and climate policy. The transformation demands technologies that are not yet commercialized and coordination of investment, technology development, and infrastructure deployment.

Pacala and Socolow proposed a way to stabilize climate using existing greenhouse gas (GHG) mitigation technologies, visualized as interchangeable, global-scale 'wedges' of equivalent emissions reductions (*1*). Subsequent work has produced more detailed analyses, but none combines the sectoral granularity, physical and resource constraints, and geographic scale needed for developing realistic technology and policy roadmaps (*2–4*). We addressed this gap by analyzing the specific changes in infrastructure, technology, cost, and governance required to decarbonize a major economy, at the state/provincial level that has primary jurisdiction over electricity supply, transportation planning, building standards, and other key components of an energy transition.

California is the world's sixth largest economy and 12th largest emitter of GHGs, its per capita GDP and GHG emissions are similar to those in Japan and Europe, and its policy and technology choices have broad relevance nationally and globally (*5*, *6*). California's Assembly Bill 32 (AB32) requires the state to reduce GHG emissions to 1990 levels by 2020, a reduction of 30% relative to business as usual assumptions (*7*). Previous modeling work we performed for California's state government formed the analytical foundation for the state's AB32 implementation plan in the electricity and natural gas sectors (*8*, *9*). California has also set a target of reducing 2050 emissions 80% below the 1990 level, consistent with the IPCC emission trajectory for a 450 ppm carbon dioxide equivalent (CO_2e) stabilization path that avoids dangerous anthropogenic interference (*10*). Working at both time scales, we found a pressing need for methodologies that bridge the analytical gap between planning for shallower, near-term GHG reductions, based entirely on existing commercialized technology, and deeper, long-term GHG reductions, which will depend substantially on technologies that are not yet commercialized.

We used a stock-rollover methodology that simulated physical infrastructure at an aggregate level, and built scenarios to explore mitigation options (*11*, *12*). Our model divided California's economy into six energy demand sectors and two energy supply sectors, plus cross-sectoral economic activities that produce non-energy and non-CO_2 GHG emissions. The model adjusted the infrastructure stock (e.g., vehicle fleets, buildings, power plants, and industrial equipment) in each sector as new infrastructure was added and old infrastructure was retired, each year from 2008 to 2050. We constructed a baseline scenario from government forecasts of population and gross state product, combined with regression-based infrastructure characteristics and emissions intensities, producing a 2050 emissions baseline of 875 Mt CO_2e (Fig. 1). In mitigation scenarios, we used backcasting, setting 2050 emissions at the state target of 85 Mt CO_2e as a constrained outcome, and altered the emissions intensities of new infrastructure over time as needed to meet the target, employing seventy-two types of physical mitigation measures (*13*). In the short term, measure selection was driven by implementation plans for AB32 and other state policies (table S1). In the long term, technological progress and rates of introduction were constrained by physical feasibility, resource availability, and historical uptake rates rather than relative prices of technology, energy, or carbon as in general equilibrium models (*14*). Technology penetration levels in our model are within the range of technological feasibility for the U.S. found in recent assessments (table S20) (*15*, *16*). We did not include technologies expected to be far from commercialization in the next few decades, such as fusion-based electricity. Mitigation cost was calculated as the difference between total fuel and measure costs in the mitigation and baseline scenarios. Our fuel and technology cost assumptions, including learning curves, are comparable to those in other recent studies (tables S4, S5, S11, and S12, and fig. S29) (*17*). Clearly, future costs are very uncertain over such a long time horizon, especially for technologies that are not yet commercialized. We did not assume explicit lifestyle changes (e.g., vegetarianism, bicycle transportation) which could have a significant effect on mitigation requirements and costs (*18*); behavior change in our model is subsumed within conservation measures and energy efficiency.

In order to ensure that electricity supply scenarios met the technical requirements for maintaining reliable service, the model featured an electricity system dispatch algorithm that tested grid operability. Without a dispatch model it is difficult to determine if a generation mix has infeasibly high levels of intermittent generation. We developed an electricity demand curve bottom-up from sectoral demand, by season and time of day. Based on the demand curve, the model constrained generation scenarios to satisfy in succession the energy, capacity, and system balancing requirements for reliable operation. The operability constraint set physical limits on the penetration of different types of generation, and specified the requirements for peaking generation, on-grid energy storage, transmission capacity, and out-of-state imports and exports for a given generation mix (table S13 and figs. S20 to S31). It was assumed that over the long run California would not "go it alone" in pursuing deep GHG reductions, and thus that neighboring states decarbonized their generation such that the carbon intensity of imports was comparable to California in-state generation (*19*).

Electrification required to meet 80% reduction target. Three major energy system transformations were necessary to meet the target (Fig. 2). First, energy efficiency had to improve by at least 1.3% yr^{-1} over 40 years. Second, electricity supply had to be nearly decarbonized, with 2050 emissions intensity less than 0.025 kg CO_2e/kWh. Third, most existing direct fuel uses had to be electrified, with electricity constituting 55% of end-use energy in 2050, compared to 15% today. Results for a mitigation scenario including these and other measures are shown in Fig. 1. 28% of emissions reductions relative to 2050 baseline emissions came from energy efficiency; 27% from decarbonization of electricity generation; 14% from a combination of energy measures including smart growth, biofuels, and rooftop solar photovoltaics (PV); 15% from measures to reduce non-energy CO_2 and non-CO_2 GHGs; and 16% from electrification of existing direct fuel uses in transportation, buildings, and industrial processes. Table 1 shows changes from 2010 to 2050 in primary and end use energy and emissions by sector and fuel type for the baseline and mitigation cases, along with per capita and economic intensity metrics.

The most important finding of this research is that, after other emission reduction measures were employed to the maximum feasible extent, there was no alternative to widespread switching of direct fuel uses (e.g., gasoline in cars) to electricity in order to achieve the reduction target. Without electrification, the other measures combined produced at best 2050 emissions of 210 Mt CO_2e, about 50% below the 1990 level. The largest share of GHG reductions from electrification came from transportation, in which 70% of vehicle miles traveled—including almost all light duty vehicle miles—were powered by electricity in 2050, along with 20% from biofuels and 10% from fossil fuels. Other key applications for fuel switching occurred in space and water heating and industrial processes. Figure 3A shows that even with aggressive EE keeping other demand growth nearly flat, fuel-switching to electricity led to a doubling of electricity generation by 2050. "Smart charging" of electric vehicles was essential for reducing the cost of electrification, by raising utility load factors and reducing peak capacity requirements through automated control of charging times and levels (Fig. 3B).

In the electricity sector, three forms of decarbonized generation—renewable energy (RE), nuclear, and fossil fuel with carbon capture and storage (CCS)—each has the potential to become the principal long-term electricity resource in California, given its resource endowments. All currently suffer from technical limitations and high cost relative to the conventional generation alternative, natural gas, so it is not obvious which if any of these will dominate in the long run. Therefore, we built separate high RE, high nuclear, and high CCS scenarios that met the target, plus a mixed case. Because these technologies have very different operating characteristics—CCS, when commercialized, is expected to be dispatchable; nuclear is baseload; and the most abundant RE resources (wind and solar) are intermittent—they also have very different needs for supporting infrastructures, including capacity resources, high-voltage transmission, and energy storage. Figure 3C shows the generation scenarios. The high RE case has the highest requirements for installed capacity, transmission, and energy storage; the high nuclear case requires the largest export market for excess generation, along with an expansion of upstream and downstream nuclear fuel cycle infrastructure; and the high CCS case requires construction of CO_2 transportation and storage infrastructure. In addition, water, land use, and siting issues are quite different for each of these options. Residual electricity sector carbon emissions in 2050 came primarily from combustion of natural gas for peaking generation and CCS. CCS fleet-average carbon storage efficiency in 2050 was 90%, but new CCS units were required to reach 98% efficiency. Within the western grid of which California is part, all existing conventional coal plants were retired at the end of their planning lives of 30 years.

Some studies suggest that 100% of future electricity requirements could be met by renewable energy, but our analysis found this level of penetration to be infeasible for California (*20*, *21*). We found a maximum of 74% renewable energy penetration despite California's high renewable resource endowment, even assuming perfect renewable generation forecasting, breakthroughs in storage technology, replacement of steam generation with fast-response gas generation, and a major shift in load curves by smart charging of vehicles. Using historical solar and wind resource profiles in California and surrounding states, the electricity system required 26% non-renewable generation, from nuclear, natural gas, and hydro, plus high storage capacity to maintain operability. It would be possible to forecast higher penetration in cases with a higher resource base and/or much lower energy demand, for example due to lower population growth or lower economic growth.

Unprecedented energy efficiency, limited contribution from biofuels. The rate of EE improvement required to achieve the target and enable feasible levels of decarbonized generation and electrification—1.3% yr^{-1} reduction relative to forecast demand—is less than the level California achieved during its 2000-2001 electricity crisis (*22*), but is historically unprecedented over a sustained period. This level is, however, consistent with the upper end of estimates of long-term technical EE potential in recent studies (*23*, *24*). In our model, the largest share of GHG reductions from EE came from the building sector, through a combination of efficiency improvements in building shell, HVAC systems, lighting, and appliances. EE improvements were complemented by other measures to reduce new energy supply requirements for electricity, transportation, and heating. EE in combination with on-site distributed energy resources in the form of solar hot water and rooftop PV reduced the net consumption of grid-supplied electricity and fuels in new residential and commercial buildings to zero by 2030 (*25*). Structural conservation in the form of "smart growth" urban planning to reduce driving requirements was responsible for 5% of total emission reductions in 2050.

Biofuels, while essential because not all transportation can be electrified, made only a modest 6% contribution to the 2050 emissions reduction when feedstocks were constrained to be carbon neutral, produced in the U.S., and limited to California's consumption-weighted proportional share of U.S. production (*26*–*28*). This feedstock was sufficient to provide 20% of transportation fuels in the form of cellulosic ethanol and algal biodiesel, assuming these technologies achieve commercialization (fig. S15). In our model, biofuel feedstocks were dedicated to the production of transportation fuels as their highest-valued economic use, and these fuels allocated to applications for which electrification is not a practical option, such as long-haul freight trucking and air travel. A small amount of biomethane was used in power generation.

In the baseline forecast, 2050 emissions of non-energy CO_2 (e.g., from cement manufacturing) and non-CO_2 GHGs (e.g., methane and nitrous oxide from agriculture and waste treatment, and high global warming potential (GWP) gases used as refrigerants and cleaning agents) were 145 Mt CO_2e, more than the entire economy-wide target of 85 Mt CO_2e. Compared to CO_2 emissions from energy sectors, scientific understanding of long-term mitigation potential for these sectors is poorly developed (*29*–*32*). Nevertheless, it was clear that if these emissions were not abated, the 2050 target could not be met. We modeled mitigation based on extrapolating California's AB32 implementation plan for 2020 (*7*), in three broad areas. Agricultural and forestry measures contributed 48 Mt CO_2e of reductions, cement-related measures contributed 8 Mt CO_2e, and industrial and other measures contributed 62 Mt CO_2e, for a total reduction of 116 Mt CO_2e below the 2050 baseline, which maintained the current share of non-energy/non-CO_2 in overall emissions.

There is evidence that the three key energy system transformations identified here are broadly generalizable to developed economies. A recent report on 80% GHG reductions in the EU found similar transformations were required, including electrification of transportation and buildings (*33*). In other studies where reductions rely on energy efficiency and generation decarbonization but not electrification, lower GHG reduction levels were achieved. For example, in a recent IEA study of technology paths in OECD countries as a whole, the most aggressive scenario had a 2050 reduction of about 50% below 1990 levels, with a 6% contribution from electrification (*34*). The consistency among these results is predictable, in that developed economies broadly share the same challenges for reaching deep reduction targets—the need to virtually eliminate fossil fuel use in electricity supply and in final consumption, especially in vehicles and buildings.

Infrastructure deployment and technology investment require coordination. In contrast to Pacala and Socolow, we found that achieving the infrastructure changes described above will require major improvements in the functionality and cost of a wide array of technologies and infrastructure systems, including but not limited to cellulosic and algal biofuels, CCS, on-grid energy storage, electric vehicle batteries, smart charging, building shell and appliances, cement manufacturing, electric industrial boilers, agriculture and forestry practices, and source reduction/capture of high-GWP emissions from industry (*35*).

Not only must these technologies and systems be commercially ready, they must also be deployed in a coordinated fashion to achieve their hoped-for emission reduction benefits at acceptable cost. For example, switching from fuels to electricity before the grid is substantially decarbonized negates the emissions benefits of electrification; large-scale deployment of electric vehicles without smart charging will reduce utility load factors and increase electricity costs; without aggressive energy efficiency, the bulk requirements for decarbonized electricity would be doubled, making achievement of 2050 goals much more difficult in terms of capital investment and siting. Figure 3D shows the impact of aggressive EE on three key metrics of decarbonized electricity supply: generating capacity, energy storage, and miles of high-voltage transmission line. For the mixed generation case, achieving the 2050 target with baseline levels of EE raised the requirement for annual construction of decarbonized generation from a very formidable 3.7 GW yr^{-1} to a practically unachievable 7.0 GW yr^{-1}, and the requirement for new transmission from 400 to 960 miles yr^{-1}.

Our model shows a net mitigation cost to California relative to the baseline of 0.5% of gross state product (GSP) in 2020, 1.2% in 2035, and 1.3% in 2050 ($65 billion or $1200 per capita) (Fig. 4 and fig. S34). The transportation sector bore the highest share of these costs, reflecting the cost of fleet electrification. These results are highly sensitive to both measure costs and fuel price assumptions; using the upper value of the EIA long-term crude oil price forecast makes net mitigation costs negative (fig. S12). Cumulative net costs from 2010 to 2050 were $1.4 trillion. The average cost of carbon in 2050 was \$90/t CO_2e, while the highest average cost by measure type was \$600/t CO_2e for electrification measures (*36*). Because mitigation measures reduce fuel use by investing in energy efficient infrastructure and low carbon generation, a much higher percentage of energy cost will go to capital costs; our model indicates a cumulative investment of $400-500 billion in current dollars (figs. S35 and S36) for electricity generation capacity in the mitigation case, a factor of about ten higher than the baseline case (*37*).

The transition to an energy efficient, low-carbon, electrified infrastructure thus requires mobilizing investment and coordinating technology development and deployment on a very large scale over a very long time period. How best to achieve this is an active debate over the relative roles of markets, government, carbon pricing, R&D policy, regulation, and public investment (*38*). Many consider carbon pricing the key to achieving efficient investment and providing incentives for consumer adoption, while others argue that carbon pricing is insufficient, and requires complementary policies to address market failures, public goods, and coordination problems (*16*, *39*, *40*). Some make the specific case that pollution pricing is effective in encouraging technology adoption, but not technological innovation (*41*, *42*). Others are concerned that the venture capital model is mismatched with the scale and timeline of investment required for an energy transformation (*43*) and with the risks created by the need for multiple technologies to achieve commercialization in parallel (*44*). These concerns have led to calls for novel public-private partnerships to address investment failures through government absorption of private capital risk (*43*), and to address coordination and sequencing through industry-government roadmapping (*45*).

Electricity's role in future energy costs and climate policy. The second model result deserving special attention is the expanded role of electricity, which increases from 15% to 55% of end-use energy, essentially switching places with petroleum products, which fall from 45% to 15% (Table 1). If electricity does become the dominant component of the 2050 energy economy, the cost of decarbonized electricity becomes a paramount economic issue. Our results show that generation mixes dominated by renewable, nuclear, and CCS, in the absence of cost breakthroughs, would have roughly comparable costs, raising the present average cost of electricity generation by a factor of about two, a result also noted by other researchers (*17*). These findings indicate that minimizing the cost of decarbonized generation should be a key policy objective. By some estimates, aggressive R&D policies could reduce the cost of low-carbon generation in the U.S. from 2020 to 2050 by about 40% or $1.5 trillion (*17*).

For electrified transportation, the inherently higher efficiencies of electric drive trains would still allow a net reduction in fuel costs even with electricity prices doubled and oil prices at $100/barrel, as well as shifting cash flows away from foreign oil imports toward domestic purchases of electricity. On the other hand, electrification of direct fuel uses will increase residential, commercial, and industrial sector costs, especially for heating, emphasizing the need for energy efficiency and design of new infrastructure in these sectors to minimize lifecycle costs. Because much of the required technology and infrastructure for the energy-system transformation is not yet commercialized, comparative lifecycle costs are highly uncertain. However, because decarbonized generation technologies are dominated by capital costs and insensitive to oil and natural gas price volatility, an electrified economy would have a long-term cost stability that could lower investment risk and make the optimal level of energy efficiency more certain (*46*). Even varying measure costs from one-half to twice the nominal values in the mitigation scenario produced no more variation in overall energy system costs than did varying crude oil prices in the baseline scenario over the range in the EIA's long-term forecast (fig. S12).

The climate policy community has proposed a suite of policies to complement carbon pricing (e.g., EE and RE standards, R&D support) that reflect not only economic and technology goals but also sociopolitical considerations such as equity, local initiative, and adaptability (*16*). The central role of electricity in our results suggests the importance of electricity sector governance as a tool of climate policy, but this has received relatively little attention until recently (*47*). Although some argue that regulation impedes innovation and increases implementation costs (*43*), state-level electricity regulation has existing tools for pursuing many climate policy goals, through both market mechanisms and direct regulation: requirements that utilities procure renewable generation, limit carbon intensities, and implement customer energy efficiency and distributed energy programs; and set rates that encourage conservation and electric vehicle charging, internalize pollution costs, and allocate the costs of these policies equitably (*7*, *48*). Given the political challenges of achieving comprehensive federal climate legislation, it is worth further exploring decentralized electricity governance as a climate policy mechanism.

Assuming plausible technological advances, we find that it is possible for California to achieve deep GHG reductions by 2050 with little change in lifestyle (although the potential for lifestyle change deserves further study). The logical sequence of deployment for the main components of this transformation is energy efficiency first, followed by decarbonization of generation, followed by electrification. This transformation will require electrification of most direct uses of oil and gas. In California no single generation technology, RE, nuclear, or CCS, can be used to decarbonize all electricity; a mixed generation portfolio is required. If it is true that the low-carbon path features electricity, then the question is how best to mobilize investment and coordinate R&D and infrastructure roll-out to achieve this end, and what climate policy modalities will be most effective. If the oil economy is replaced by the electric economy, it is instructive to consider the implications of the price of a decarbonized kWh replacing the price of a barrel of oil as a benchmark for the overall economy.

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Acknowledgments: The authors would like to thank the anonymous reviewers. The early modeling work was carried out with partial support from Hydrogen Energy International. The contributions of MST were supported by the Director, Office of Science, Office of Biological and Environmental Research, Climate and Environmental Science Division, of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231 to Lawrence Berkeley National Laboratory.

Supporting Online Material

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Materials and Methods
SOM Text
Figs. S1 to S36
Tables S1 to S22
References

13 May 2011; accepted 3 November 2011
Published online 24 November 2011;
10.1126/science.1208365

Fig. 1. Emission reduction wedges for California in 2050. (above) Measures grouped into seven "wedges" reduce emissions from 875 Mt CO_2e in the 2050 baseline case to 85 Mt CO_2e in the mitigation case. In the 2020 model results, the wedge contributions are consistent with implementation plans for California's policy objectives (AB32) for 2020. (below) Reductions by wedge are shown for the 2030 and 2050 mitigation cases, in Mt CO_2e and as a percentage of total reductions. The top three contributions are from energy efficiency (28%), electricity decarbonization (27%), and electrification of direct fuel uses (16%). For each wedge, the types of measures included and key assumptions are shown.

Fig. 2. The three main energy system transformations required to reduce GHG emissions 80% below 1990 levels by 2050 in California. End use energy efficiency (EE) must be improved very aggressively (annual average rate 1.3% y^{-1}), electric generation emissions intensity must be reduced to less than 0.02 kg CO_2e/kWh, and most direct fossil fuel uses in transport, buildings, and industry must switch to electricity, raising the electricity share of end-use energy from 15% today to 55% in 2050. Both economics and the current state of technology development suggest a staged deployment in large-scale infrastructural transformation. Without aggressive levels of EE, the scale of decarbonized generation required to simultaneously replace fossil plants and meet both existing and newly electrified loads would be infeasible. Until high levels of electricity decarbonization are achieved, emission benefits from electrification would be limited. Without electrification, constraints on the other measures would limit total reductions to about 50% below 1990 levels.

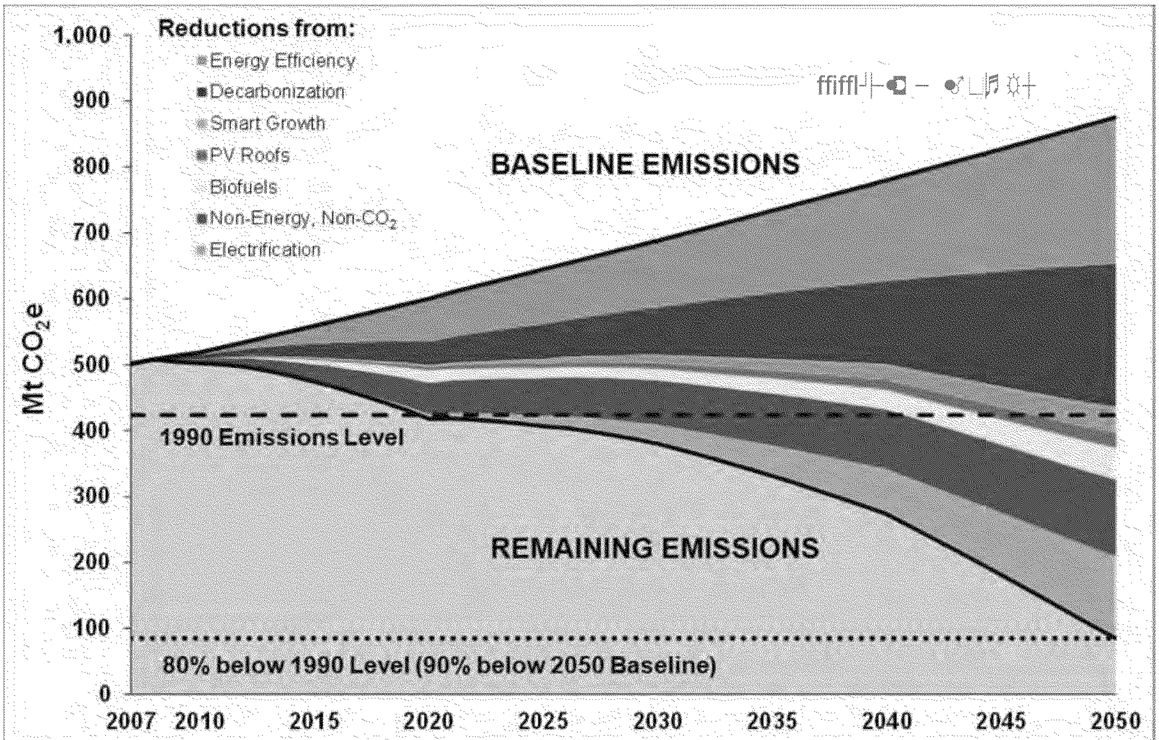
Fig. 3. Electricity consumption, load profiles, and fuel mix in baseline and mitigation scenarios. (**A**) In the mitigation case, aggressive end-use efficiency flattens baseline load growth. However, electrification of transportation adds a major new load, so that 2050 consumption is similar in both cases. (**B**) Smart-charging of electric vehicles flattens the average daily load curve, reducing capacity requirements. (**C**) In the 2050 baseline scenario, load growth is met primarily with natural gas generation. Four mitigation scenarios are shown with different fuel mixes, constrained by California's existing fuel mix and policy requirements (e.g., 33% renewable portfolio standard, continued licensing of existing nuclear generation). The "mixed" case, which contains all three generation types, yields the results discussed in this paper and shown in Figs. 1 to 3. (**D**) New capacity requirements for each generation fuel mix are shown for generation, transmission, and energy storage. Without aggressive EE, new capacity requirements increase by roughly a factor of two. The high renewables case has higher new capacity requirements than the high CCS and high nuclear case; however, high renewables does not have the CCS case requirements for CO_2 transmission and storage capacity, nor the nuclear case requirements for upstream and downstream nuclear fuel cycle facilities.

Fig. 4. Mixed case net cost by mitigation type in 2020, 2035, and 2050. For each year shown, the left hand column shows incremental mitigation costs in excess of baseline costs, and the right hand column shows incremental savings relative to baseline fuel costs. "Other" mixed case costs include measure implementation costs not associated with energy efficiency, electrification, generation decarbonization, or biofuels. "Other" savings include jet fuel and natural gas purchases for

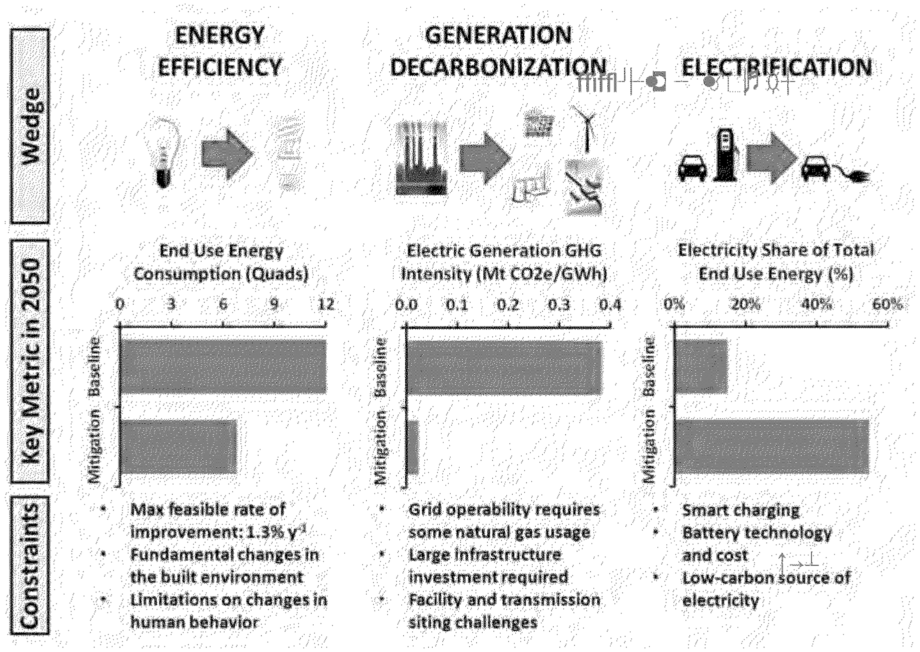
direct use (e.g., heating). Net costs are $15 billion dollars in 2020, $45 billion dollars in 2035, and $65 billion dollars in 2050. This is equivalent to $320 per capita or 0.5% of the statewide GSP in 2020, $910 per capita or 1.2% of the statewide GSP in 2035, and $1,200 per capita or 1.3% of the statewide GSP in 2050.

Table 1. Primary and end use energy and emissions by sector and fuel type in 2010 and 2050. The numerical difference between primary and end use energy is due to conversion and other losses. Sources for population and economic data are given in the supporting online material.

	Energy consumption (EJ)					Emissions (Mt CO_2e)		
	2010	2050 Baseline	2050 Mitigation	2010 (%)	2050 Mitigation (%)	2010	2050 Baseline	2050 Mitigation
Primary energy consumption and emissions, by sector								
Residential	1.60	2.56	0.52	18%	8%	71.3	117.1	5.4
Commercial	1.68	2.60	0.94	19%	14%	70.9	114.5	10.0
Industrial	1.41	1.39	0.96	16%	14%	67.4	67.3	6.4
Petroleum	0.81	0.82	0.58	9%	9%	46.7	47.5	5.6
Agriculture	0.34	0.52	0.21	4%	3%	16.3	27.1	1.0
Transportation	2.86	5.67	3.60	33%	53%	189.4	374.1	45.0
Non-energy, non-CO_2 GHG emissions						56.4	127.8	11.4
Total all sectors	8.70	13.56	6.81	100%	100%	518.4	875.4	84.8
Primary energy consumption and emissions, by fuel type								
Direct fuel use								
Natural gas	2.73	3.40	0.38	31%	6%	148.9	185.1	20.5
Gasoline	2.09	4.36	0.13	24%	2%	135.9	283.4	8.3
Diesel	0.73	1.23	0.39	8%	6%	50.2	84.7	26.6
Jet fuel	0.04	0.08	0.04	0%	1%	3.3	6.0	3.4
Biomethane and biofuels	0.00	0.00	0.73	0%	11%	0.0	0.0	0.0
Total direct fuel use	5.59	9.06	1.67	64%	25%	338.3	559.2	58.8
Electric generation (primary)								
Natural gas (non-CCS)	1.45	2.90	0.01	17%	0%	72.1	135.3	0.4
Coal (non-CCS)	0.49	0.49	0.00	6%	0%	43.2	43.2	0.0
Fossil fuel w/ CCS	0.00	0.00	2.18	0%	32%	0.0	0.0	10.6
Nuclear	0.30	0.26	0.74	3%	11%	0.0	0.0	0.0
Renewables and hydro	0.71	0.66	2.04	8%	30%	0.4	0.4	0.8
Other	0.16	0.18	0.16	2%	2%	8.0	9.6	2.9
Total electric generation	3.11	4.49	5.14	36%	75%	123.7	188.4	14.7
Non-energy, non-CO_2 GHG emissions						56.4	127.8	11.4
Total all fuel types	8.70	13.56	6.81	100%	100%	518.4	875.4	84.8
End-use energy consumption and emissions, by fuel type								
Total direct fuel use	5.59	9.06	1.67	85%	45%	338.3	559.2	58.8
Electricity (end-use)	0.98	1.63	2.03	15%	55%	123.7	188.4	14.7
Direct fuel use + electricity	6.57	10.69	3.70	100%	100%	462.0	747.6	73.4
Non-energy, non-CO_2 GHG emissions						56.4	127.8	11.4
Total end use by fuel type	6.57	10.69	3.70	100%	100%	518.4	875.4	84.8
Intensity metrics								
CA population (millions)	38.8	56.6	56.6					
Per capita energy use rate (kW/person)	7.1	7.5	3.8					
Per capita emissions (t CO_2e/person)	13.3	15.5	1.5					
Energy intensity ($/GJ)	$249	$383	$762					
Economic emissions intensity (kg CO_2e/$)	0.239	0.169	0.016					
Electric emissions intensity (kg CO_2e/kWh)	0.42	0.39	0.02					



Wedge Category:	Emissions Reduction Mt CO_2e (% of Total) 2030	2050	Types (and Numbers) of Measures Used	Key Attributes in 2050
Energy Efficiency	102 (33%)	223 (28%)	Building EE (18); Vehicle EE (9); Other EE (6)	Improve energy efficiency 1.3% per year on average for 40 years
Electricity Decarbonization	72 (23%)	217 (27%)	High renewables, high nuclear, high CCS, and mixture of the three	Meet 90% of generation requirement with CO_2-free sources. Equivalent decarbonization in each scenario.
Smart Growth	13 (4%)	41 (5%)	Reductions in vehicle miles traveled (VMT) (6)	VMT reduced in light duty vehicles (LDV) by 10%; freight trucks 20%; other transportation 20%
Rooftop PV	8 (3%)	21 (3%)	Residential and commercial PV roofs (2)	Rooftop PV displaces 10% of electricity demand by 2050.
Biofuels	18 (6%)	49 (6%)	Transportation biofuels: ethanol, biodiesel, biojet fuel (9); Residential, commercial, industrial biomethane (3)	By 2050, biomethane displaces 2% of natural gas use in buildings, and biofuels displace 10-20% of petroleum-based fuels for vehicles
Non-Energy, Non-CO_2	67 (22%)	116 (15%)	Cement, agriculture, and other (3)	Non-fuel, non-CO_2 GHG emissions reduced 80% below baseline
Electrification	29 (9%)	124 (16%)	Transportation electrification (9); Other end-use electrification (5)	75% of LDV gasoline use displaced by PHEVs & electric vehicles; 30% of fuel use in other transport sectors electrified; 65% electrification of non-heating/cooling fuel use in buildings; 50% electrification of industrial fuel uses
Baseline Case Emissions	688	875		
Mitigation Case Emissions	380	85		
Total Reduction	308	791		



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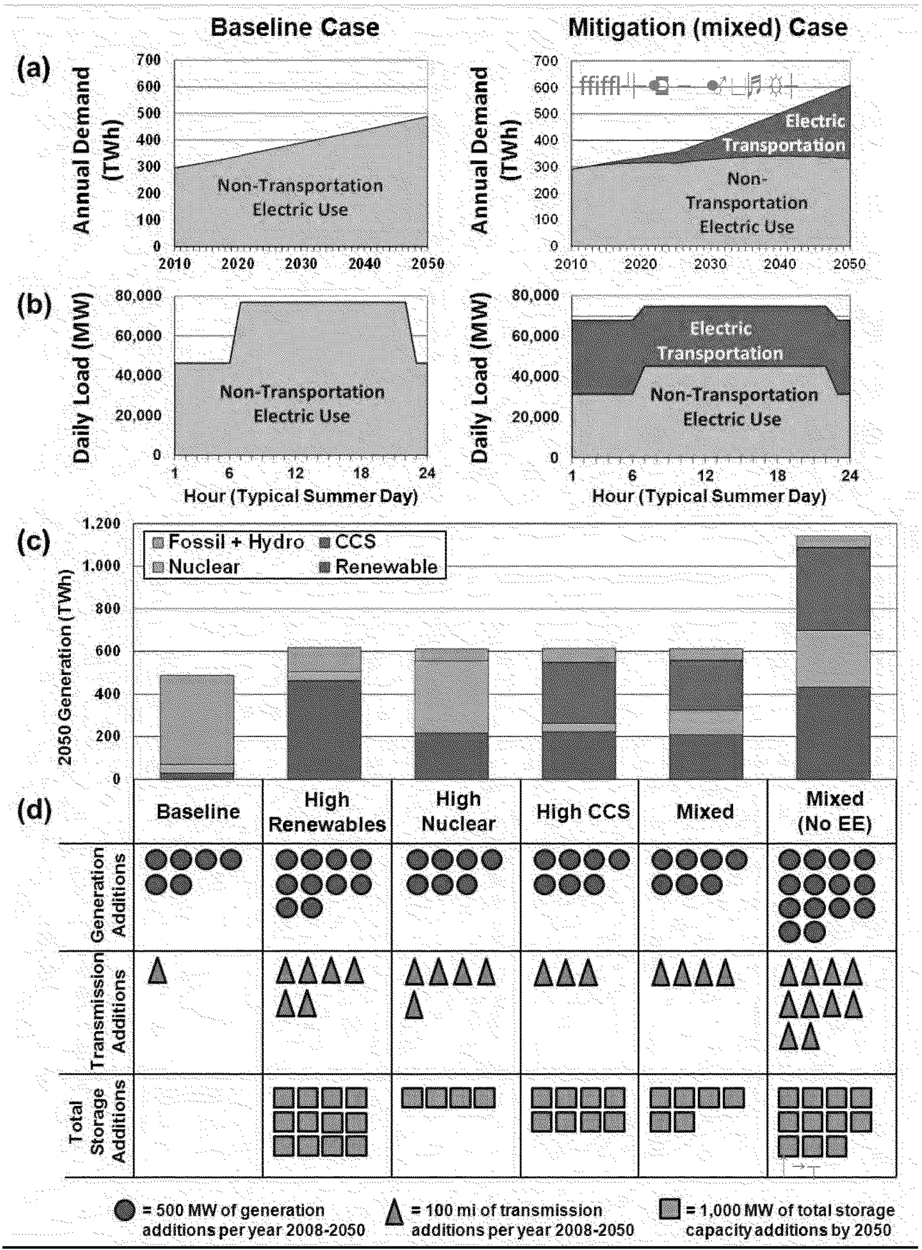
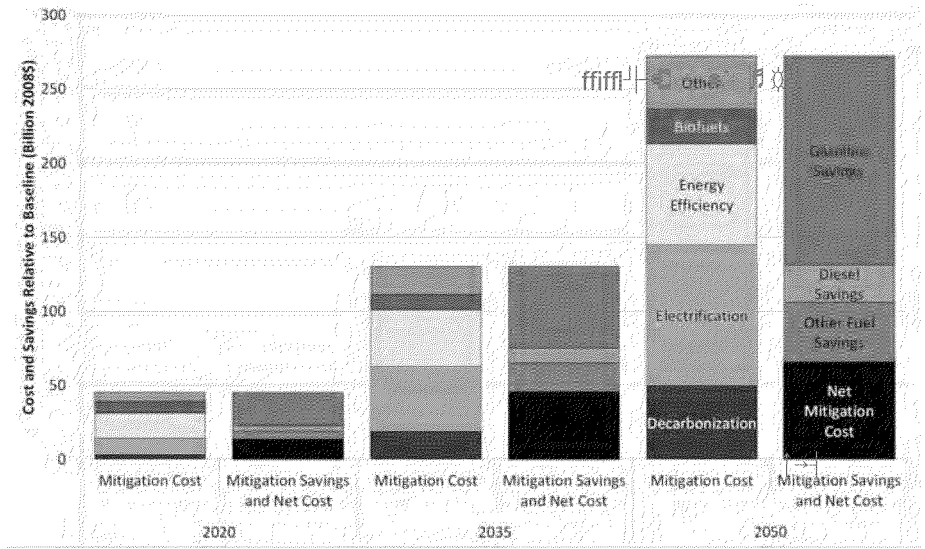

Baseline Case
Mitigation (mixed) Case
(a)
Annual Demand (TWh)
Non-Transportation Electric Use
Electric Transportation
Non-Transportation Electric Use
(b)
Daily Load (MW)
Hour (Typical Summer Day)
Non-Transportation Electric Use
Electric Transportation
(c)
2050 Generation (TWh)
Fossil + Hydro
CCS
Nuclear
Renewable
(d)
Baseline
High Renewables
High Nuclear
High CCS
Mixed
Mixed (No EE)
Generation Additions
Transmission Additions
Total Storage Additions
= 500 MW of generation additions per year 2008-2050
= 100 mi of transmission additions per year 2008-2050
= 1,000 MW of total storage capacity additions by 2050



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Docket:	**A.11-05-023**
Witness:	**Jaleh Firooz**
Exhibit No.:	

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.	Application 11-05-023 (Filed May 19, 2011)

PREPARED DIRECT TESTIMONY OF JALEH FIROOZ

ON BEHALF OF

THE CALIFORNIA ENVIRONMENTAL JUSTICE ALLIANCE

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

May 18, 2012

TABLE OF CONTENTS

INTRODUCTION

My testimony addresses and evaluates the local area need analyses performed by the California Independent System Operator (CAISO) and San Diego Gas & Electric Company (SDG&E) in Application 11-05-023. My testimony discusses the appropriateness of underlying reliability criteria and assumptions used for establishing the need. In addition, my testimony explores whether all feasible alternatives have been investigated and provides recommendations for next steps in evaluation of the need.

Before discussing my comments related to SDG&E's and CAISO's testimony, I will summarize my experience and qualifications.

I began my career working for the San Diego Gas and Electric Company (SDG&E) for twenty five years. At SDG&E, I worked in the engineering department, in grid operations, transmission operations and planning, resource planning, power procurement and regulatory affairs. I am familiar with the CAISO market rules, planning procedures and operational protocols. I was one of the key participants in California's electric industry restructuring process which took place in the 1995 through 1998 period. This restructuring process led to the formation of the CAISO in 1998. After leaving SDG&E, I worked for a wind resource development company in California for a year.

I have performed numerous transmission and resource planning analyses during my career. These analyses include determining the economic and operational feasibility of a 500 MW pumped storage hydro project along with a 500 kV transmission line. Recently I performed an analysis of the CAISO's proposed 2010/2011 transmission plan where, based on power flow studies, I determined that two of PG&E's proposed 500 kV transmission lines in the San Joaquin Valley are not needed. The CAISO consequently changed their initial determination of "need" in their 2010/2011 transmission plan, classified the project as "to be looked at in a future planning cycle." Most recently, I completed analysis of the need for generation at the location of the existing Redondo Beach power plant for the California State Coastal Conservancy. The existing Redondo Beach power plant uses Once Through Cooling (OTC) technology and is subject to the State Water Resources Control Board's requirements for the use of ocean water for cooling. My analysis evaluated whether Local Capacity Requirements for the LA basin and the western LA basin sub-area actually required that there be generation at the Redondo Beach location.

I published a paper in 2010 discussing problems with transmission planning in California funded by UCAN. I also published an article in the Natural Gas and Electricity journal on the same topic.

I am a registered Profession Electrical Engineer in CA with over 30 years of experience in the electricity industry. I have a BS in Electrical Engineering and an MBA in Finance. My resume is attached.

In this proceeding, CAISO provided two sets of testimony: original testimony on March 9, 2012, and supplemental testimony on April 6, 2012. The original testimony included testimony from

Robert Sparks discussing the Local Capacity Requirement (LCR) and from Mark Rothleder discussing renewable integration needs. Mr. Sparks' original and supplemental testimony discusses both the San Diego LCR area as well as the Greater Imperial Valley-San Diego LCR area.

The San Diego LCR area is the most limiting LCR area. Although the Greater Imperial Valley-San Diego LCR area has a higher LCR than the San Diego LCR area, the availability of existing dependable generation at Imperial Valley substation means it is easier to satisfy the Greater Imperial Valley-San Diego LCR area. The San Diego LCR area has the higher deficiency and is therefore the focus of this testimony.

My testimony mainly addresses the ISO's identified requirements for year 2021 since that is higher than the previous years. If it is shown that there is no capacity shortfall in the year 2021, then it can safely be assumed that there would not be any in earlier years. This assumption is premised on applicable solutions being implemented prior to when the need arises.

In my evaluation, I have found that several aspects of the CAISO's analysis and assumptions are questionable and inconsistent. In particular, later in my testimony, I demonstrate that use of 2500 MW as the limit for the South of Songs (Path44) is not appropriate. In addition, the CAISO's application of the Path 44 limit to the Greater Imperial Valley-San Diego LCR area, and not to the San Diego LCR area, is inconsistent.

I. Summary and Recommendations

My testimony shows that the probabilities of the contingency events used to calculate the need in San Diego are very low. Furthermore, it shows that if these contingency events did happen there are many other mitigating options available. These options follow the commission's loading order, are more economical, are less detrimental to the environment, and allow time for other more desirable resources to be developed. In contrast, the options recommended by the applicant remove the incentive for other alternative resources by making a costly twenty year commitment to fossil-fired generation. The alternatives, and their impact on the San Diego LCR area deficiency determined by the CAISO, are shown on the table below. My testimony also points out that the CAISO's renewable integration requirements do not require that new flexible generating capacity be built in the San Diego LCR area.

My testimony raises serious concerns regarding the adequacy of the CAISO's analysis and validity of its results.

The testimony shows that based on the CAISO's data, SDG&E's analysis showing an LCR deficiency in the San Diego area is not valid. It is therefore recommended that the CPUC (1) reject the applicant's request for approval of the three contracts and, (2) ask the CAISO to study the options listed in my testimony and for any options not accepted by the CAISO, provide a reason why they should not be implemented.

Table 1: Summary of Results

Year 2021 Local Capacity Requirement (LCR) Deficiency		Traject. Scenario (NQC MW)	Env Scenario (NQC MW)	ISO Base Scenario (NQC MW)	Time Scenario (NQC MW)
Sparks' April 6, 2012 Supplemental Testimony	**"OTC" deficiency (San Diego area LCR deficiency)**	**730 (a)**	**300 (a)**	**630 (a)**	**540 (a)**
Options Counting Toward LCR Deficiency					
Firooz Testimony	Retain Encina gas turbine	14 (b)	14 (b)	14 (b)	14 (b)
Firooz Testimony	Extend leases for Cabrillo II gas turbines	173 (c)	173 (c)	173 (c)	173 (c)
Anderson Testimony	Estimated NQC from Demand Response	219 (d)	219 (d)	219 (d)	219 (d)
Anderson Testimony	Uncommitted Energy Efficiency	175 (d)	175 (d)	175 (d)	175 (d)
Anderson Testimony	Additional Demand-Side CHP	17 (d)	17 (d)	17 (d)	17 (d)
Firooz Testimony	Load drop allowed for N-1-1 contingency condition (reduces LCR)	370 (e)	370 (e)	370 (e)	370 (e)
	Surplus/(Deficiency)	**238**	**668**	**338**	**428**
Other Possible Options Counting Toward LCR Deficiency					
Firooz Testimony	Remove the 2.5% margin added to the load 5749 x .025 = 144 MW	144	144	144	144
Firooz Testimony	Phase Shifter to control loop flow through CFE (negates CFE's need to trip parallel path into San Diego area)	543 (f)	561 (f)	585 (f)	565 (f)
SDG&E's Proposal to add Synchronous Condensers	Adds dynamic reactive support that mitigates voltage collapse thereby reducing LCR	?	?	?	?
Firooz Testimony	Path 44 rating obsolete (studies show flows above 2500 MW do not result in reliability standard violations)	?	?	?	?
Firooz Testimony	New 500 kV transmission line connecting San Diego area to SCE system (parallel to Path 44); reduces San Diego area LCR	500-1000 (g)	500-1000 (g)	500-1000 (g)	500-1000 (g)
Powers Testimony	Resources Not Taken Into Account in CAISO's Calculations including Uncommitted EE, DR, CHP, Energy Storage, Additional Distributed Generation	513 (h) 1000 (i)	513 (h) 1000 (i)	513 (h) 1000 (i)	513 (h) 1000 (i)

(a) Bottom row of first table in Robert Sparks' April 6, 2012 supplemental testimony.
(b) Table 2.8-1 of the CAISO Board-approved 2011-2012 Transmission Plan. EA GT 14 MW
(c) Table 2.8-1 of the CAISO Board-approved 2011-2012 Transmission Plan. Kearny GT1 = 15 MW, Kearny 2AB (Kearny GT2) = 55 MW, Kearny 3AB (Kearny GT3) = 57 MW, Miramar GT 1 = 17 MW, Miramar GT 2 = 16 MW, El Cajon GT = 13 MW.

(d) Table 1 of Rob Anderson's April 27, 2012 supplemental testimony. These are overly conservative values used to show that there is no need. The Testimony of Bill Powers describes why these assumptions are not reasonable. Using the CPUC's recommended numbers from the 2010 LTPP, which are reasonable, these values would be higher. *See* Bill Powers' Testimony.
(e) See note marked "**" for the top row of the table in Robert Sparks' April 6, 2012 supplemental testimony
(f) Table 4.9-4 of the CAISO Board-approved 2011-2012 Transmission Plan
(g) Estimate based on studies conducted for the Sunrise Powerlink
(h) According to Bill Power's Testimony, CAISO failed to account for: 544 MW of EE, which is 369 MW more than SDG&E, 302 MW of DR, which is 83 MW more than SDG&E, 64 MW of incremental CHP, which is 47 MW more than SDG&E, and over 14 MW of energy storage currently planned and much more is underway.
(i) Bill Powers also estimates that the SDG&E area will install significantly more PV in ranges up to 1000 MW of additional PV by 2020.

II. CAISO Testimony

A. What Is "Reliability" and How Is it Measured?

Before discussing the details of CAISO's testimony, it is important to establish what "reliability" is and how it is measured because "reliability" is the main justification for spending money on and inflicting environmental damage for new infrastructure. It is inarguable that although higher reliability margins should, in theory, lower the risk of brown-outs or black-outs, it is statistically impossible to eliminate the possibility altogether. Unexpected things can always happen no matter how much money is spent and infrastructure is developed. Mindless pursuit of greater reliability margins is ultimately an exercise in waste and is not just and reasonable for ratepayers. Inevitably, hard judgments must be made as to how much reliability margin is enough.

Federal regulations require that the transmission grid be planned and operated in accordance with reliability criteria developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC). These criteria generally specify that the grid must be capable of accommodating the outage of any one element of the grid (N-1) without loss of load and the loss of two common elements (N-2) (*e.g.,* two circuits on the same set of towers) without uncontrolled load loss. Local balancing authorities may impose stricter criteria, and the CAISO has done so by implementing the requirement that the CAISO grid must also be capable of accommodating the outage of one generator followed by the outage of a transmission element (G-1/N-1) without loss of load or, in the current proceeding, outage of a transmission element followed by the outage of another transmission element (N-1/N-1; also referred to as N-1-1) without loss of load. This criterion establishes the amount of generating capacity that the CAISO requires load serving entities in the San Diego area to place under contract (local capacity requirements) in order to ensure that there will be enough dependable capacity available to serve all forecast loads. These contracts impose costs on San Diego area consumers because the import constraints that result from the application of the G-1/N-1 reliability criteria limits competition among the local generators and therefore the incentive to negotiate lower contract prices.

What is not specifically described in these reliability criteria are the system conditions under which the applicable contingencies are to be applied. Typically, utilities and balancing authorities assume stressed system conditions such as one-year-in-ten peak load conditions. As mitigation measures, these standards permit the use of pre-contingency generation redispatch, generator dropping and, for some less likely contingency conditions (N-2 outages), controlled load drop. These operating procedures add little or no rate base and are usually the last mitigation options to be considered by IOUs, if they are considered at all. From the CAISO's perspective operating procedures such as load drop are a desirable *backstop* to new transmission or new in-area generation, but are not substitutes for new infrastructure even where the backstop is equally or more reliable. For example, a load drop is more reliable than a generating unit that may not be available at the time it is needed.

B. The Probability of the Identified Reliability Criteria Violations

While not specifically prescribed by any criteria, common practice is to apply these reliability criteria for system conditions that are believed to be "stressed." For planning purposes, the CAISO typically applies its reliability criteria to system conditions that assume peak loads are at one-year-in-ten levels, i.e., a peak load that has a 10% probability of being exceeded in any year. The logic for using one-year-in-ten load levels in planning studies is that mitigation for reliability criteria violations at this load level will provide a reliability margin for more probable system load conditions.

Whether the resulting probabilities are sensible, however, has never been seriously questioned. It is instructive to perform some simple calculations to get a sense of how likely these events actually are. Roughly speaking, any single transmission element has a forced outage rate of about 1% or less. A generator on average may have a forced outage rate on the order of 5%. The probability of an overlapping G-1/N-1 event occurring in the same hour of the year is therefore about 5% x 1% or 0.05% (0.01 x 0.05 = 0.0005). On an expected basis this amounts to a little over 4 hours per year (8760 x .0005).

The probability of an overlapping N-1/N-1 or N-1-1 event occurring in the same hour of the year is therefore about 1% x 1% or 0.01% (0.01 x 0.01 = 0.0001). On an expected basis this amounts to a little over 52 minutes per year (8760 x .0001).

The CAISO, however, applies this over-lapping contingency to a peak load condition that is not "expected;" i.e., a peak load that, on a probabilistic basis would only be exceeded one year out of ten. Applying the over-lapping contingency to a peak load condition that has a one-year-in-ten probability of occurrence, the overall probability of the simulated condition is reduced further. To keep the calculations simple, assume that contingency-based system constraints are reached in 200 peak load hours (20 hot days with 10 high load hours each day) in any given one-in-ten-year heat wave. The probability of encountering a load level at which contingency-based system constraints are reached would then be 0.228% (.1 x 200/8760) = .00228

The combined probability of a G-1/N-1 overlapping outage occurring during any one of these peak hours would be .0005 x .00228 = .000001 or about 0.0001% in any given year. This is equivalent to about 30 seconds in a year or 6 minutes in a ten year period. The combined probability of an N-1/N-1 (N-1-1) overlapping outage occurring during any one of these peak hours would be .0001 x .00228 = .000000228 or about 0.00002% in any given year. This is equivalent to about 7 seconds in a year or a little more than a minute in a ten year period.

Adding the effect of using conservatively-rated transmission lines; e.g., using ambient air temperatures that significantly *exceed* the air temperature that would exist during a one-year-in-ten peak load condition; shrinks the likelihood of actually encountering these limiting conditions even further. Notably for this proceeding, the CAISO is using another 2.5% margin on top of the one-year-in-ten load forecast; i.e., in the CAISO's LCR analysis, forecast one-year-in-ten forecast loads are increased by 2.5%.

Although WECC[1] recommends the 2.5% margin (102.5% of load) be used for category C contingency voltage studies there is no mention of applying this margin on top of a one-year-in-ten peak load condition. The one-year-in-ten peak load condition is already about 10% higher than the highest expected peak load in any given year.

> "For load area studies, the load in the area of interest should be modeled based on the load forecast normally used for planning that area. (For the purpose of developing an extended P-V curve, base case can be developed at less than 100%.)"

The WECC does not provide guidance as to what load forecast is "normally used for planning;" this is a subjective determination made by planning entities such as the CAISO.

In my experience long term resource planning was done using a one-year-in-two (expected) load forecast plus 10% adder to provide an installed capacity cushion to account for unexpected generator outages and load forecast error at time of peak. Later, the cushion was raised to 15% to 17%. The LCR analysis, which is based on a one-year-in-ten load forecast, is only binding for the upcoming year. According to the CAISO tariff, longer term LCR estimates which are the main subject of this proceeding are informational and not binding.[2] For example, section 40.3.1 of the CAISO tariff (Local Capacity Technical Study) states,

> "On an annual basis, pursuant to the schedule set forth in the Business Practice Manual, the CAISO will, perform, and publish on the CAISO Website the Local Capacity Technical Study. The Local Capacity Technical Study shall identify Local Capacity Areas, determine the minimum amount of Local Capacity Area Resources in MW that must be available to the CAISO within each identified Local Capacity Area, and identify the Generating Units within each identified Local Capacity Area."

1. Is Procurement for this Highly Improbable Event Just and Reasonable?

The G-1/N-1 or N-1-1 reliability criteria, which establishes the local capacity requirements for certain load pockets—such as the San Diego area—are being applied for conditions which, for all practical purposes, will never happen. Yet, billions of dollars are planned to be spent to address these highly improbable study conditions. In this situation, it is important to ask how

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[1] Guide to WECC/NERC Planning Standards I.D: Voltage Support and Reactive Power Approved by TSS March 30, 2006; Summary of WECC Voltage Stability Assessment Methodology, July 11, 2001.

[2] 40.3 Local Capacity Area Resource Requirements For SCs For LSEs

much consumers are willing to pay to protect against an unlikely event. Is procurement for this highly improbable event just and reasonable?

To answer this, it is necessary to estimate both the probability and the consequences of these events. While probabilistic approaches to reliability have been around for many years, they are currently not being used in short-term LCR analyses. Here, where CAISO is using a prediction for the year 2021, this type of approach should be scrutinized to determine whether it is appropriate. Under CAISO's current deterministic approach to contingency analysis, every conceivable N-1, G-1/N-1 and N-1-1 overload must be mitigated regardless of its probability, consequence, and cost. If probabilistic contingency analysis were adopted, proponents of new infrastructure would need to provide, not only the contingency condition that creates the overload, but also an estimate of the probability with which the contingency will occur and an assessment of what the consequences of the contingency condition will be to electric grid users. With this information, an informed decision could be made as to whether the costs of the proposed project, or the costs of any feasible alternatives, would be offset by the consequences of the overload given its likelihood of occurrence.

C. Comparison of CAISO's and WECC/NERC's Outage Criteria

1. Is CAISO's Reliability Criteria More Stringent for the Same Contingencies?

Yes. NERC and WECC reliability criteria permit load drop for G-1/N-1 outages and for N-1-1 outages, the CAISO does not. CAISO reliability standards specifically preclude load drop as mitigation for G-1/N-1 contingencies. CAISO witness Sparks indicates that the CAISO has determined it would not be "prudent" to rely on load drop in the San Diego area as mitigation for N-1-1 contingencies.

The CAISO's more stringent reliability criteria could cost consumers billions of dollars in contract costs -- the cost of new generation to meet LCRs with effectively no measurable increase in grid reliability. As a general matter, it does not make sense for California to have more stringent reliability criteria than the rest of WECC. This increases costs and puts load serving entities within the CAISO balancing authority at competitive disadvantage to other balancing authorities, both inside and outside of California. If there are special circumstances where more stringent reliability criteria may be required, those need to be brought up on an exceptional basis and justified rather than being the rule. Changing the CAISO's existing reliability criteria to match that of NERC/WECC would only require action by the CAISO. Approvals from WECC, NERC or FERC do not appear to be necessary.

2. Does the Use of Probability Lower Reliability in California?

Not approving procurement for highly improbably contingency criteria would not lower reliability in California at any reasonably measurable level. The CAISO would still meet all applicable NERC and WECC reliability requirements and would be on par with the reliability standards of all other balancing authority areas. Where a project sponsor or regulatory authority believes existing NERC or WECC reliability criteria are not adequate, or that the assumptions and/or methodology for implementing those criteria are not sufficiently conservative to address the contingency event of concern, the project sponsor or regulatory authority should be required to:

1. Assess the probabilities associated with the contingency based on ten years of relevant historical outage data.

2. Identify the consequences of the contingency event (e.g., amount and duration of uncontrolled load loss, economic impacts of such load loss, public safety concerns).

3. Provide a justification for applying more conservative reliability criteria than required by WECC and NERC.

3. Does Considering the Probability of the Outage Result in Lower Reliability?

No, since to be true it has to be assumed that all contingencies are equally inconvenient and harmful for consumers. The reality is that different contingencies have significantly different consequences. A probability-based reliability approach would result in higher consumer and environmental welfare than the current deterministic criteria since (i) capital would be spent on contingencies where the combination of probability and consequence would otherwise provide the worst outcome for consumers, and (ii) capital would not be spent on contingency events that result in minor consumer inconvenience.

III. Other Solutions and Options for Meeting the Capacity Need

A. Load Drop and its Ramifications

1. Does CAISO allow load drop as a mitigating solution?

Question 15 of CEJA's Second Set of Data Requests to the CAISO asked the following:

> "Does NERC, WECC, and/or CAISO reliability criteria prevent the use of controlled load drop for an N"1"1 transmission contingency? If so, where is this criteria documented? If not, what threshold does the CAISO use to determine when controlled load drop is acceptable mitigation and when it is not? Are there any limits on the amount of controlled load drop which is acceptable?"

The CAISO responded:

> "The ISO is required by NERC TPL 003 to plan its network so that it can be operated to supply projected customer demands for N"1"1 events regardless of their probability. NERC Transmission Planning Standards allow the use of controlled load drop depending on system design and expected system impacts. However, with all generation available at full capacity, the ISO would operate this generation to avoid the need to shed load for the Sunrise/IV"Miguel overlapping outage event. For the San Diego area, the ISO does not consider it acceptable to rely on load shedding to mitigate the category C outage of N"1"1 because there is no suitable Special Protection System designed or in place at this time. Further, the ISO decision to plan its system to operate available generation to ensure

stable operation of the system following the loss of Sunrise and IV"Miguel without reliance on an Special Protection Scheme is to minimize the risk of cascading outages due to disturbances on the grid and unreliable system conditions such as those that have occurred too frequently in recent years in the San Diego area. Load shedding would be utilized to address scenarios with reductions in resource availability due to generation outages that occurred prior to, during or after a Sunrise/IV"Miguel overlapping outage event."

2. Is the CAISO's reason for not allowing load drop in the San Diego area reasonable?

No. First the CAISO's initial statement above is not correct. As stated earlier, the NERC and WECC do allow the use of controlled load drop—with appropriate levels of triggering redundancy and review by potentially affected neighboring balancing authorities—under the G-1/N-1 and N-1-1 outage conditions.

Second, based on the reports published by the CAISO and FERC on recent San Diego area outages (April 1, 2010 and Sept 8, 2011), the outages were caused by either operator error[3] and/or by a lack of visibility and coordination among Balancing authorities.[4]

As mentioned earlier, although higher reliability margins should, in theory, lower the risk of brown-outs or black-outs, it is statistically impossible to eliminate this possibility altogether. A better and far more efficient use of capital would be to prevent errors by improved training, and by improved coordination and communication among balancing authorities. In contrast, building in higher reliability margins through new infrastructure imposes tremendous costs on consumers and the environment. This consumes capital that could otherwise be efficiently deployed to reduce California energy prices, thereby reducing cost of products and putting more money in consumers' pockets. More money in consumers' pockets translates into more job creation within California. Efficient use of capital results in a net gain in employment; inefficient use of capital has the opposite effect.

B. Incorrect Retirement Assumptions

1. Do you agree with the CAISO's and SDG&E's retirement assumptions for the Cabrillo II generating resources?

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[3] *See* Power Grid Operator Admits Mistakes In Shutoff, San Diego Union-Tribute (April 6, 2010) http://www.utsandiego.com/news/2010/apr/06/power-grid-operator-admits-mistakes-san-diego-shut/. ISO issued a statement after the shutoff: "The ISO said yesterday that was a big mistake. It shouldn't have allowed the plant, in Otay Mesa, to shut down. And that shouldn't have led to the intentional blackout."

[4] *See* FERC/NERC April 27, 2012 Report on September 8, 2011 Outage, https://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf. FERC/NERC's report found that the outage was due to transmission operator and a balancing authority error, lack of visibility and lack of coordination. Based on the facts of this outage, the most sensible and cost-effective solution is to improve operator training, enhance inter-balancing authority coordination and provide for greater electric system visibility; not to build more generation and/or transmission infrastructure.

No. The Cabrillo II generating resources are comprised of inland gas turbines. They are not Once-Through-Cooling (OTC) units and therefore are not subject to the State Water Resources Control Board (SWRCB) policy on the use of OTC technology. Accordingly, they are not subject to any mandatory retirement or retrofit requirements. Mr. Anderson's testimony explains the component of the line in his table called "Other Retirements":

> "This line includes the retirement of the existing 35 MW unit at the Wellhead Escondido site in 2012 and the retirement of 188 MW of existing peakers at the end of 2013 when their land leases end. The MW are older combustion turbines that were built in the early 1970's. They have heat rates of approximately 16,000 BTU/kwhr and limited operating hours."

The fact that these units are relatively "old" and comparatively inefficient does not require their retirement. SDG&E's response to question 10 of CEJA data request #3 suggests that the assumed retirement of these units is driven by SDG&E's own decision to not renew the land leases for the physical locations of these units. The expiration of the land leases does not mean that the leases cannot, or should not, be renewed; and SDG&E has provided no economic or legal justification for refusing to renew these leases. The Cabrillo II units are existing resources that are rarely operated and therefore contribute little to air emissions, yet provide 188 MW of Resource Adequacy counting rights. In addition, these resources are "flexible" in that they can be started quickly and respond to CAISO dispatch instructions. SDG&E has not explained why extending the lease for these resources would not be a far more economical way of providing generating capacity in the San Diego area than SDG&E's proposal to construct entirely new Product 2 resources. This question is particularly relevant since, as was pointed out earlier in this testimony, the locational need is for capacity in anticipation of a very low probability event; not for energy. Therefore, we should expect these units to run rarely and for very short durations. For this reason the units' inefficient heat rates should not be a major concern. Similarly, the existing Encina gas turbine (14 MW) and the existing Wellhead Escondido gas turbine (35 MW) are not OTC units and no reason has been provided as to why they have to be retired.

C. Dynamic Reactive Support

SDG&E submitted four projects in the CAISO's 2011 – 2012 Transmission Planning Process (TPP) to install synchronous condensers at the Mission, Penaquitos, Sycamore Canyon and Talega 230 kV substantions. Each of these projects proposed to install +/- 240 MVar of dynamic reactive support at the respective substations to address the anticipated need for reactive sources in the area. The CAISO stated in the ISO Board-approved 2011/2012 transmission plan that:

> "The reliability assessment performed by the ISO did not identify any issues that can be mitigated by these upgrades. These upgrades can solve an expected issue of reactive source-sink availability if and when the Encina plant retires …..Hence, the ISO has identified these projects as potential solutions for voltage stability. The need will be evaluated in future planning cycles as the generation retirement issue gathers some clarity."

Question 14 of CEJA's Second Set of Data Requests to CAISO asked:

> "Has the ISO modeled these projects to determine if they could resolve the voltage stability problem indicated as the limit by the ISO in the LCR analysis described in Mr. Sparks' April 6, 2012 testimony? If not, does the ISO have a plan to do this analysis? If so when? If not, when?"

The CAISO's response was as follows:

> "Under these assumptions, the San Diego import limit is approximately 3,850 MW to 3,700 MW but approximately 700 MVAr of reactive support would be needed at the Sycamore, Talega and Mission 230 kV substations to mitigate unacceptable voltage deviations under applicable planning contingencies."

Question 11 of CEJA Second Set of Data Requests to SDG&E asked:

> "On page 206 of the 2011-2012 Transmission Plan, CAISO states that SDG&E submitted four projects to install synchronous condensers at four substations. Please explain the cost and purpose of these condensers and why SDG&E proposed them."

SDG&E responded as follows:

> "SDG&E proposed four 230 kV-connected synchronous condenser installations (three preferred locations at Mission, Penasquitos, and Talega substations and one alternate location at Sycamore Canyon substation) as a part of the 2011/2012 CAISO Transmission Planning Process. .....The approximate cost for each installation is $65 million to $85 million, depending on location."

It appears that the possible need for reactive support was originally observed by SDG&E. The CAISO's 2011/2012 Transmission Planning study then showed that these reactive supply sources can "mitigate unacceptable voltage deviations" under the planning contingencies. It therefore seems prudent to study the addition of these reactive support devices in lieu of the proposed gas turbines to determine if the LCR need can be reduced or eliminated. The costs of all three synchronous condensers (about $200 million in capital costs which equates to annual levelized revenue requirement of about $40 million/year for twenty years or about 552.6 million[5] present value for 60 years[6]) is lower than the estimated lower range cost of 450 MW of proxy gas turbines at $200 kW-yr for twenty years with present value of about $1.2 billion for 60 years.[7]

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[5] See work papers in Appendix A

[6] 60 year is chosen for comparison later on with a transmission line which has 60 year life

[7] This estimate is conservatively in the lower end of the proxy-gas turbine cost range given by the CEC.

D. Additional Import Through CFE

Table 4.9-4 in the CAISO Board-approved 2011-2012 Transmission Plan shows imports into the San Diego area as determined by the CAISO's policy-driven need assessment for the San Diego area in year 2021. According to the accompanying discussion in the 2011-2012 Transmission Plan, the worst contingency is the G-1/N-1 outage of the Otay Mesa combined cycle plant followed by the outage of the 500 kV ECO-Miguel line. Figure 4.9-2 shows that for this contingency, the 230 kV loop through the Comision Federal de Electricidad (CFE) balancing authority—which is parallel to the Imperial Valley-ECO-Miguel and Imperial Valley-Suncrest-Sycamore Canyon lines—remains intact. Table 4.9-4 indicates that this loop delivers between 543 MW and 585 MW of power (depending on the renewable resource scenario) into the San Diego area.

This analysis highlights the significance of the CFE loop in maximizing the amount of imports into the San Diego area under contingency conditions. If, in the event of contingencies on the 500 kV lines between Imperial Valley substation and the San Diego area, CFE's Special Protection Scheme does not operate to open the U.S.-Mexico tie between Imperial Valley and La Rosita substations and the U.S.-Mexico tie between Tijuana and Otay Mesa substations, an additional path into the San Diego area is available to support post-contingency imports. According to the CAISO's analysis, this path can carry a significant amount of power. Hence, it is worth considering measures that could negate the need for CFE to operate its Special Protection Scheme to protect its facilities from post-contingency loop flows.

One option that can be used to control flows on the CFE loop, is the installation of phase shifting transformers. The phase shifters could be installed on the U.S. side of the border and operated so as to limit post-contingency loop flow through the CFE system to levels that would not require CFE to operate its Special Protection Scheme. Assuming the costs of phase shifting transformers are in the $50 million range, assuming the CFE loop accommodates post-contingency imports into the San Diego area of about 500 MW, and assuming this import translates into a megawatt-for-megawatt reduction in San Diego area LCR, the option of installing phase shifting transformers may be far more economical and much less environmentally disruptive than SDG&E's proposed Product 2 generating resources.

E. Transmission Options

1. **Have all other alternatives to the PPTA for meeting San Diego LCRs been examined by either SDG&E or CAISO?**[8]

No. One of the alternatives not considered is the Talega-Escondido/Valley-Serrano Interconnect Project[9] (TE-VS proposed transmission line). This proposed transmission project is currently in the CPUC's CPCN process. Although CEJA does not support this transmission line at this point in time, CEJA nevertheless acknowledges that this 500/230 kV transmission project would

[9] The TE-VS Interconnect Project is sometimes associated with the Lake Elsinore Advanced Pumped Storage (LEAPS) project.

connect the Edison 500 kV system (Valley – Serrano) to SDG&E's 230 system (Talega-Escondido)—roughly parallel to the south of SONGS path—and could potentially reduce LCRs in the San Diego area.

In his original testimony filed March 9, 2012, Mr. Sparks responded to the following question:

> "Are there any feasible transmission mitigation solutions that can meet the 650 MW to 950 MW need?"
>
> "As described above, the constraint driving these needs is the transmission system limitations between the SCE and SDG&E systems south of SONGS. During studies of the Sunrise Powerlink, the ISO studied transmission options to increase the transmission capability between these two systems in order to further reduce local generation needs in San Diego. However, the scope of the upgrades needed to meet a 650 MW to 950 MW need was essentially a new 500 kV line connecting the SDG&E system to the SCE system."

Mr. Sparks' testimony seems to indicate that the CAISO believes new transmission between SCE and SDG&E—such as the TE/VS Interconnect Project—could meet a LCR deficiency in the SDG&E LCR area of 650 MW to 950 MW. Our preliminary rough estimate of the annual levelized carrying charge for a $700 million transmission investment would be $105 million per year ($700 x .15) for 58 years.[10] It is assumed that the capacity charges paid by customers in a CPUC-authorized PPA will cover the fixed costs of the new generation that will built as part of the PPA. The CEC's estimate of fixed costs associated with new peaking gas turbines is 200-$300/kW-yr.[11] Using this proxy, the levelized annual carrying charges for 450 MW of gas turbine capacity would be roughly about $90 million to $135 million/year (450,000 x 200 = $90 million, 450,000 x 300 = $135 million) for 20 years. This value ignores any cost of transmission network upgrade that may be required to allow full deliverability of the energy from these gas turbines to the load. Considering the much longer life of the transmission line (58 years), the effective cost for the gas turbines is going to be higher since the proposed contracts are only for 20 years; the gas turbines would have to be replaced twice; one contract in year 21 and another in year 41.

In addition, since the thermal rating of the TE-VS line is definitely over 1000 MW, it is possible that simultaneous imports into the San Diego area would increase by over 1000 MW under the same N-1-1 contingency condition considered in this proceeding. The addition of the TE/VS Interconnect Project might therefore provide more than twice the capacity benefit of the 450 MW of proposed PPAs. It would appear that a transmission alternative could be less costly than the PPAs proposed by SDG&E.[12]

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[10] An annual levelized carrying charge factor of 15% is a rule of thumb for a 60 year transmission project with an authorized rate of return of about 8.5%.

[11] *See* Comparative Costs of California Central Station Electricity Generation, California Energy Commission 200-2009-017, available at http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SD.PDF.

Note that there are other ISO approved reliability upgrade projects such as "Southern Orange County Reliability Project" proposed by SDG&E and approved by the CAISO in their 2010/2011 Transmission Plan last year but may not have met the CAISO's regulatory approval criteria for inclusion into the study model. Once this project or similar projects in the ISO interconnection process are approved it is expected that the reliability concerns identified will improve.

IV. Is There a Renewable Integration Need for New Capacity Inside the San Diego Area?

No. According to CAISO's response to question 6 of CEJA's First Set of Data Requests, it is clear that no locational need has been established for flexible resources. Specifically, CEJA asked the CAISO:

> "Is any portion of the CAISO's overall renewable integration resource need identified in Mr. Rothleder's testimony required to be inside the San Diego LCR area? If yes, please explain why and indicate the amount."

The CAISO responded:

> "The ISO's renewable integration studies have not focused on precise locational needs to date. The process for determining the need for renewable integration needs within LCR areas is to first identify the local capacity needs following traditional local capacity technical study methodologies, and assume that these needs are met by flexible generation. Then, renewable integration studies would be performed to determine if additional flexible generation is needed beyond the local capacity needs met by flexible generation."

To cover any possible system-wide flexibility need to integrate renewable resources , according to the CAISO's Dec 8, 2011 presentation on the CAISO's 2011/2012 Transmission plan[13], 4853 MW of new flexible conventional generation is already scheduled to come on line prior to year 2021.[14]

V. CAISO's Analysis and Data

1. Is testimony provided by the CAISO in this proceeding adequate to justify their recommendation that the three PPTAs and/or the Encina repower be approved?

No. In its testimony, the CAISO has provided the end results of three series of complex analyses without discussing or providing much of the underlying data. One result is the determination of the minimum dependable generation needed within the San Diego area (the Local Capacity

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[13] http://www.caiso.com/Documents/Presentation%20-%2020112012_TransmissionPlanningProcessDec8_2011.pdf, slide 7

[14] This is pointed out to illustrate the number of sources that the utilities are planning to construct in California. CEJA does not believe that many of these facilities are necessary.

Requirement or "LCR") to avoid any reliability standard violation based on a set criteria that identifies maximum imports assuming the worst contingency (outage) scenario under an extreme weather condition. The second deficiency is failure to perform or include a resource analysis to determine if the sum of existing and planned resources including Energy Efficiency (EE), Demand Response (DR), Combined Heat and Power (CHP) and Distributed Generation (DG) is adequate to meet the identified need. The third deficiency is a failure to determine the best solution for meeting the asserted LCR deficiency.

The amount of data and information presented, including the answers provided to data requests during discovery, is grossly inadequate relative to the cost and the duration of the commitment that customers and the environment will have to make if the three PPTAs and/or the Encina repower project are built. The present value of the fixed costs associated with 450 MW of generic gas turbines is over $1.2 to $1.8 billion based on the CEC's estimate of the annual levelized fixed carrying costs associated with new peaking gas turbines ($200-$300/kW-yr).[15] Considering the magnitude and duration of the economic and environmental commitments that are at stake, a more comprehensive set of data is required for the Commission and interveners to determine and verify the reasonableness of the CAISO's analysis, underlying assumptions and conclusions.

The only data presented in Mr. Sparks' testimony are the LCRs for the San Diego area and the associated "OTC" shortfall for the four RPS scenarios considered. As backup, the CAISO testimony references several different technical analyses performed outside this proceeding. However, there are no specific references to any tables or pages in these long and involved analyses. This should be found unacceptable because the set of underlying assumptions are not available for scrutiny *in this proceeding*; neither are they adequately described in the referenced technical analysis.

Despite FERC order 1000's recommendation to facilitate the broader participation of stakeholders, and unlike CPUC proceedings, CAISO stakeholder processes do not have an intervener compensation mechanism. As such, stakeholder discussions are dominated by the IOUs and generation developers; these entities have no incentive to objectively question CAISO input assumptions and or results.

2. **Are there inconsistencies in the CAISO's data that makes you believe that the CAISO's analyses need further scrutiny?**

Yes. The CAISO has failed to provide adequate data in this proceeding to demonstrate that any of the three sets of analyses have been performed properly, and has failed to explain observed inconsistencies. The CAISO's results show inconsistencies between the years as well as between the different contingencies and scenarios. For example, it was observed that the 2013 and 2021 LCR results provided in the April 6, 2012 supplemental testimony of Robert Sparks are

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[15] *See* Comparative Costs of California Central Station Electricity Generation, California Energy Commission 200-2009-017, available at http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SD.PDF.

inconsistent.[16] These inconsistencies were pointed out to the CAISO during the April 17, 2012 workshop and during the discovery period (question No. 16 of CEJA's second set of data requests).

Specifically, it was observed that compared to the 2021 LCR case, the 2013 LCR case has an additional 1100 MW of flexible generation available (mainly the Encina plant), and about 537 MW of lower load (5749 MW in 2021 versus 5212 MW in 2013).[17] Nevertheless, the CAISO's 2013 case still shows voltage collapse for the same contingencies taken in the 2021 case. This is especially troubling, since according to the LCR table in Mr. Sparks' testimony, 300 MW to 700 MW of additional "OTC" generation could mitigate the voltage collapse problem in the 2021 case yet the additional 1100 MW of generation in 2013 and lower loads (compared to 2021) does not solve the claimed voltage problem in 2013.

The CAISO provided the following answer[18] to the above inconsistency:

> "There are major differences between the 2013 and 2021 base case models. The largest difference is the addition of approximately 20,000 MW of installed renewable generation capacity. With this generation producing with[in] San Diego, and all around the San Diego area, the usage of the transmission system changes substantially. These differences explain the difference in system performance between the 2013 and 2021 base case models."

The above answer does not provide a reasonable explanation for the inconsistency described above. The addition of 20,000 MW of renewable generation in 2021 compared to 2013 does not explain why there is voltage collapse in 2013. The output from 20,000 MW of renewables outside the San Diego area in year 2021 simply replaces the type of imports flowing into the San Diego area, not the amount. It would be expected that with higher in-area generation resources and lower loads in 2013 (compared to 2021), there should be no problem in avoiding a voltage collapse condition. The 1100 MW of additional flexible generation in 2013 should result in lower overall generation dispatch within the San Diego area, thereby providing greater dynamic reactive capability in the San Diego area to mitigate voltage problems in the 2013 case relative to 2021. Neither does the lack of 42 MW of DG within the San Diego area in the 2013 case explain why voltage collapse occurs at the comparatively low levels of imports into the San Diego area.

Without any explanation, it can only be concluded that there is a problem with the CAISO's power flow cases; the results of these cases cannot be trusted.

3. Were other unexplained discrepancies observed?

Yes. Another discrepancy observed and questioned involves the comparison of two different contingencies for the same year for each of the four RPS scenarios. The G-1/N-2 and N-1-1

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[16] 2021 LCR results are shown on page 3 and 2013 results are shown on page 5 of Mr. Sparks's April 6, 2012 supplemental testimony.
[17] CAISO Response to Reqeust No.DRA-CAISO-04 Part c.
[18] CAISO Response to Request No 16 of CEJA's Second Set of Data Requests.

contingencies shown in the table on page 3 of Mr. Sparks' April 6, 2012 supplemental testimony are basically the same except for the G-1 (the outage of the Otay Mesa combined cycle plant). This is because the same two lines (ECO-Miguel and Imperial Valley-Suncrest) are considered out in both contingency scenarios and once the second line is tripped (either simultaneous with, or after, the first line) the cases are basically identical: the end-state transmission configuration is the same, and available generation in both cases is maxed out since, according to the ISO, both cases show a generation shortage. Therefore, the only difference between the two cases after the outages is the availability or unavailability of the Otay Mesa combined cycle plant. However, in one case (the G-1/N-2 contingency), the ISO results show that there is no voltage collapse as the voltage collapse is mitigated by dropping 370 MW of load.[19] But in the second case (the N-1-1 contingency), voltage collapse still occurs even though there is an additional 604 MW of generation available compared to the G-1/N-2 case (i.e., we should expect to see voltage collapse in the case with the lower generation and not the other way around).

For the "ISO base" RPS scenario, the CAISO's results show that in the case without the Otay Mesa combined cycle generation (the G-1/N-2 contingency case) 604 MW of additional generation is needed to solve the reliability concern once the two lines are out. However, for the same "ISO base" RPS scenario with 604 MW of Otay Mesa combined cycle generating capacity available, almost the same (630) MW of additional generation is needed to resolve the reliability concern after the same two lines are out. If 370 MW of load drop can achieve a solution in the first case, why doesn't the addition of 604 MW of generation in the second case also achieve stability?

The ISO's "response"[20] to this discrepancy does not explain this inconsistency:

> "The study results provided by the ISO in its testimony include the N-1-1 outage with Otay Mesa, and indicates that this outage results in adequate system stability performance."

We suggest that until these discrepancies are resolved or explained, it is not prudent to commit to the large magnitude and long duration investments that are the subject of this proceeding. Due the limited resources of CEJA and the limited time in this proceeding, we were not able to evaluate the power flow cases in detail. CEJA recommends that, at the very least, the CPUC does detailed analysis of the cases before relying on these studies due the number of discrepancies described earlier.

Notwithstanding the above, our analysis shows that even assuming the CAISO's LCR analysis is correct there are better ways to meet this requirement than the IOUs' and ISO's business-as-usual approach of building more fossil fueled power plants. These better ways follow the CPUC loading order, are most cost effective, and are environmentally superior to the proposed peakers. These solutions will allow development of additional EE, DR, renewable and nonrenewable CHP and renewable and non-renewable DG.

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[19] According to Mr. Sparks' April 6, 2012 supplemental testimony, "load curtailment of approximately 370 MW was simulated to achieve stability under G-1/N-2 contingency."
[20] CAISO Response to Request 17 of CEJA's Second Set of Data Requests.

VI. SDG&E's Testimony: Does It Appropriately Establish the Capacity Need?

1. Is the 3500 MW import assumption made by SDG&E in its LCR analysis a realistic import limit into the San Diego area with the Southwest Powerlink and/or Sunrise Powerlink out of service?

Mr. Sparks' April 6, 2012 supplemental testimony and the table provided by the CAISO in response to question 12(a) of DRA's Second Set of Data Requests to SDG&E[21] show the forecast load and the LCR with segments of the Southwest Powerlink and Sunrise Powerlink out of service under the four different RPS scenarios. The CAISO load assumptions and LCR results are summarized in the table below. Accordingly, as shown in the table, subtracting LCRs from the forecast load implies between 3230 MW and 3369 MW of imports into the San Diego area depending on the RPS scenario.

2021	Load MW	Trajectory MW	Envir. MW	ISO Base MW	Time MW
1 in 10 Load	5749	5749	5749	5749	5749
1in 10 Load + 2.5%	5893	5893	5893	5893	5893
N-1-1 LCR		2646	2524	2663	2553
Import = Load - LCR		3247	3369	3230	3340

According to the CAISO, following the outage of a segment of the Southwest Powerlink and a segment of the Sunrise Powerlink, a CFE-controlled Special Protection Scheme (SPS) would trip the path from CFE into the San Diego area.[22] This means that between 3230 MW and 3369 MW of imports would flow into the San Diego area through the remaining south of SONGS lines (Path 44). This conclusion is further reinforced based on the CAISO's assumption in its testimony[23] that the SONGS separation scheme is going to be removed such that more than 8000 Amps (3187 MW)[24] could flow on Path 44 after the outage of one segment of the Southwest Powerlink and one segment of the Sunrise Powerlink.

Further evidence that more than 2500 MW can, and does, reliably flow over Path 44 can be seen in the information provided by the CPUC[25] during, and just prior to, the San Diego outage of September 8, 2011. Immediately following the outage of the Hassayamp-North Gila over 3000 MW of power was flowing on Path 44 with only cautionary concern flagged.

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[21] A second set of data requests show the LCR identified by the CAISO for 2021 under N-1-1 contingency conditions.

[22] See the discussion regarding allowing flow through the CFE balancing authority area under contingency conditions.

[23] Mr. Sparks' April 6, 2012 Supplemental Testimony at page 4: "this assumed the 8000 Amp limit due to the SONGS separation scheme is removed from being a binding constraint."

[24] CAISO Response to Request 2 of CEJA First Set of Data Requests.

[25] CPUC briefing called "CPUC briefing _Sept 8 2011 SDGE blackout (s).pdf".

2. How does SDG&E establish a need for the PPA capacity?

Based on the assumptions provided in Mr. Anderson's testimony (load and resource table shown on page RA-5), the transmission capability into San Diego area is 3500 MW. According to this table, Mr. Anderson has calculated that there would be a capacity "Need" in San Diego starting with 488 MW in year 2018 and increasing to 721 MW in 2021.

The major assumptions in the table are a higher one-year-in-ten load forecast from the CEC staff, existing and proposed resource assumptions, and the "Transmission Capability" which Mr. Anderson explains below came from Mr. Strack's testimony:

> "The San Diego-area need calculation determines how much additional generation capacity must be obtained to meet grid planning criteria under N-1/G-1 conditions. This criterion is explained in the testimony of SDG&E Witness Strack."

3. Is the import limit of 3500 MW assumed by SDG&E correct?

According to the Mr. Strack's testimony of April 27, 2012, page JS-8:

> "Studies conducted by SDG&E in connection with the Sunrise Powerlink proceeding indicate that aggregate imports into the San Diego area with the Otay Mesa combined cycle plant out of service can be at least 3,500 MW and it would still be possible to readjust the system and survive the subsequent outage of the 500 kV Imperial Valley-Miguel line. (A 3,500 MW simultaneous import level represents a 1000 MW increase above the 2,500 MW limit that exists prior to the energization of the Sunrise Powerlink.) Mr. Anderson's testimony indicates that this level of imports translates into a San Diego area LCR of 3,026 MW."

However, as is explained above, the 2500 MW import limit is no longer valid. According to the CAISO's analysis, a minimum of 3230 MW of imports is possible in 2021 with the outage of a portion of the Southwest Powerlink and the 500 kV Imperial Valley-Suncrest line (Sunrise). According to Mr. Strack's testimony the addition of Sunrise in 2013 will add a 1000 MW to the existing simultaneous import limit of 2500 MW. Given the CAISO's numbers, the simultaneous import limit into San Diego area should also go up by 1000 MW with Sunrise in service. Accordingly, the new import limit should be 4230 MW (3230 MW +1000 MW). This would be about 730 MW higher than the 3500 MW limit shown on Mr. Anderson's table.

4. Is SDG&E's analysis and the conclusions shown in Mr. Anderson's testimony still valid given a higher rating for the south of SONGS path as discussed above?

No. Assuming all the other assumptions in Mr. Anderson's table are correct (which Bill Power's testimony refutes), the 3500 MW transmission limit should be increased from 3500 MW to 4230 MW or a 730 MW increase in years 2013 through 2021. Increasing the transmission capability number in Mr. Anderson's table by 730 MW (4230 MW – 3500 MW), the "Capacity (Need) Surplus" numbers shown at the bottom of Mr. Anderson's table would all change to surpluses through 2021 with the SDG&E's assumed loads and resources. The new numbers are shown in the table below:

MW	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
SDG&E Capacity (Need) Surplus	1025	473	401	320	233	(488)	(569)	(647)	(721)
Increased Import limit (4230 - 3500)	730	730	730	730	730	730	730	730	730
SDG&E Capacity (Need) Surplus	1755	1203	1131	1050	963	242	161	83	9

Accordingly SDG&E's conclusion that "SDG&E has found a need for a substantial amount of new generation, a portion of which can be provided via these PPTAs"[26] is not valid.

4. Re rating of path 44

As is discussed elsewhere there is strong evidence that the flows over Path 44 have and can exceed 2500 MW when one segment of the Southwest Powerlink is out of service. As shown earlier, based on the CAISO's supplemental testimony, flows as high as 3200 MW can be accommodated over path 44. Consider Mr. Sparks' original testimony:

> "The most limiting contingency in the San Diego area is described by the outage of the 500 kV Sunrise Powerlink and Southwest Powerlink (SWPL) overlapping with an outage of the Otay Mesa combined-cycle power plant (603 MW). The limiting constraint for this contingency is the South of SONGS Separation Scheme. The ISO is working with the PTOs to investigate modifying this scheme and reducing the LCR needs by up to approximately 300 MW."

Mr. Sparks' testimony indicates that once the separation scheme is removed, flows on path 44 could increase by 300 MW over the separation scheme limit of 3187 MW. Accordingly flows as high as 3487 MW (3187 MW + 300 MW) over Path 44 may be possible under contingency conditions provided any voltage problems are resolved.

It is recommended that a path flow study be conducted to establish more realistic and workable limits on the south of SONGS path (Path 44). The current limits were established by WECC more than 20 years ago, are now obsolete, and probably do more harm than good. Another reason why this path needs to be studied and rerated as soon as possible – before committing billions of dollars of consumers money and imposing environmental costs based on ancient

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[26] Prepared Supplemental Testimony of Robert Anderson on Behalf of San Diego Gas & Electric Company, A.11-05-023, at p. RA-2 (April 27, 2012).

limits – is that SCE has proposed a transmission upgrade project in the Ellis substation area.[27] The original path flow studies identified transmission in the Ellis substation as the limiting element that established the Path 44 ratings. According to the CAISO's response to question 8[28] of CEJA data request # 1, the CAISO has approved SCE's proposed upgrades in the Ellis substation area with an in service data of 2013.

CONCLUSION

Since applying the CAISO numbers to the SDG&E's assumptions shows no deficiency in the SDG&E case for years 2013 through 2021, we can ignore SDG&E's deficiency calculation. We also showed that there is no need for the capacity inside San Diego LCR area to integrate renewable resources. Therefore, the deficiency reported by the CAISO can be met without the proposed PPAs; better options are available.

We want also to note that, as was discussed above, there are unexplained discrepancies and inconsistencies in the CAISO's results, and there is inadequate data to check the accuracy of the CAISO analysis which makes us leery of the results and concerned about making long and costly commitments on behalf of ratepayers.

Even if we assume that the CAISO calculations are correct. There are viable options available to either reduce the Local Capacity Requirements or meet the requirement through means that are more cost-effective, less environmentally detrimental, and that generally follow the Commission's loading order. In general, if long term commitments for new fossil-fired generation are made early in the game, there remains no incentive to pursue other options.

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[27] *See* CEJA's First Set of Data Requests to CAISO, question 8: "proposed for summer 2013 and presented by SCE during 2011/2012 ISO Transmission Plan Stakeholder Meeting No. 2 on September 29, 2011 ("Loop Loop the Del Amo-Ellis 230 kV into Barre Sub").

[28] *See* CAISO response to CEJA's First Set of Data Requests to CAISO, question 8.

Appendix A

Annual Inflation Rate for Capital Investments:	2.5%							
Assumed Discount Rate:	8.5%							
Installed Gas Turbine Capacity	450	MW						
	Instant Cost	Fixed O&M						
	2009$	2009$						
Table 22	$/kW	$/kW-year						
100 MW Conventional Simple Cycle Gas Turbine:	1231	17.4	Table 22					
	$123.1	million						
Table 1	$/kW-year							
Levelized Annual Carrying Charge for 100 MW Conventional Simple Cycle Gas Turbine	252.53	Table 1						
Levelized Annual Carrying Charge for 100 MW Conventional Simple Cycle Gas Turbine:	$25.3	million/year						
Levelized Annual Carrying Charge Rate for Conventional Simple Cycle Gas Turbine:	20.5%							
Levelized Annual Carrying Charge Rate for a Transmission Line:	15.0%	Rule of thumb						
Conventional Simple Cycle Gas Turbine	$/kW-year		Year:	1	2	3	4	5
High: Levelized Annual Carrying Charge for Conventional Simple Cycle Gas Turbine:		300		$135.0	$135.0	$135.0	$135.0	$135.0
Discounted Annual Carrying Charges				$124.4	$114.7	$105.7	$97.4	$89.8
		Present Value:	[redacted]	millions				
	$/kW-year							
Low: Levelized Annual Carrying Charge for Conventional Simple Cycle Gas Turbine:		200		$90.0	$90.0	$90.0	$90.0	$90.0
Discounted Annual Carrying Charges				$82.9	$76.5	$70.5	$64.9	$59.9
		Present Value:	[redacted]	millions				
Talega Escondido/Valley Serrano (TE/VS) Interconnect Project								
Installed Cost:	$700.0	million		$105.0	$105.0	$105.0	$105.0	$105.0
Discounted Annual Carrying Charges				$96.8	$89.2	$82.2	$75.8	$69.8
		Present Value:	[redacted]	millions				
Synchronous Condesers	$/kW-year							
Installed Cost:	$200.0	million		$41.0	$41.0	$41.0	$41.0	$41.0
Discounted Annual Carrying Charges				$37.8	$34.9	$32.1	$29.6	$27.3
		Present Value:	[redacted]	millions				

6	7	8	9	0	1	2	3	4	5	6	7	8	9	0
$135.0	$135.0	$135.0	$135.0	$135.0	$135.0	$135.0	$135.0	$135.0	$135.0	$135.0	$135.0	$135.0	$135.0	$135.0
$82.7	$76.3	$70.3	$64.8	$59.7	$55.0	$50.7	$46.7	$43.1	$39.7	$36.6	$33.7	$31.1	$28.7	$26.4
$90.0	$90.0	$90.0	$90.0	$90.0	$90.0	$90.0	$90.0	$90.0	$90.0	$90.0	$90.0	$90.0	$90.0	$90.0
$55.2	$50.8	$46.9	$43.2	$39.8	$36.7	$33.8	$31.2	$28.7	$26.5	$24.4	$22.5	$20.7	$19.1	$17.6
$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0
$64.4	$59.3	$54.7	$50.4	$46.4	$42.8	$39.4	$36.4	$33.5	$30.9	$28.5	$26.2	$24.2	$22.3	$20.5
$41.0	$41.0	$41.0	$41.0	$41.0	$41.0	$41.0	$41.0	$41.0	$41.0	$41.0	$41.0	$41.0	$41.0	$41.0
$25.1	$23.2	$21.4	$19.7	$18.1	$16.7	$15.4	$14.2	$13.1	$12.1	$11.1	$10.3	$9.4	$8.7	$8.0

21	22	23	24	25	26	27	28	29	30
$221.2	$221.2	$221.2	$221.2	$221.2	$221.2	$221.2	$221.2	$221.2	$221.2
$39.9	$36.8	$33.9	$31.2	$28.8	$26.5	$24.4	$22.5	$20.8	$19.1
$147.5	$147.5	$147.5	$147.5	$147.5	$147.5	$147.5	$147.5	$147.5	$147.5
$26.6	$24.5	$22.6	$20.8	$19.2	$17.7	$16.3	$15.0	$13.8	$12.8
$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0
$18.9	$17.4	$16.1	$14.8	$13.7	$12.6	$11.6	$10.7	$9.9	$9.1
$67.2	$67.2	$67.2	$67.2	$67.2	$67.2	$67.2	$67.2	$67.2	$67.2
$12.1	$1.2	$0.3	$9.5	$8.7	$8.1	$7.4	$6.8	$6.3	$5.8

31	32	33	34	35	36	37	38	39	40	
$221.2	$221.2	$221.2	$221.2	$221.2	$221.2	$221.2	$221.2	$221.2	$221.2	$221.2
$17.6	$16.3	$15.0	$13.8	$12.7	$11.7	$10.8	$10.0	$9.2	$8.5
$147.5	$147.5	$147.5	$147.5	$147.5	$147.5	$147.5	$147.5	$147.5	$147.5	$147.5
$11.8	$10.8	$10.0	$9.2	$8.5	$7.8	$7.2	$6.6	$6.1	$5.6
$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0
$8.4	$7.7	$7.1	$6.6	$6.0	$5.6	$5.1	$4.7	$4.4	$4.0
$67.2	$67.2	$67.2	$67.2	$67.2	$67.2	$67.2	$67.2	$67.2	$67.2	$67.2
$5.4	$4.9	$4.6	$4.2	$3.9	$3.6	$3.3	$3.0	$2.8	$2.6

41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	
$362.5	$362.5	$362.5	$362.5	$362.5	$362.5	$362.5	$362.5	$362.5	$362.5	$362.5	$362.5	$362.5	$362.5	$362.5	$362.5	$362.5	$362.5	$362.5	$362.5
$12.8	$11.8	$10.9	$10.0	$9.2	$8.5	$7.8	$7.2	$6.7	$6.1	$5.7	$5.2	$4.8	$4.4	$4.1	$3.8	$3.5	$3.2	$2.9	
$241.7	$241.7	$241.7	$241.7	$241.7	$241.7	$241.7	$241.7	$241.7	$241.7	$241.7	$241.7	$241.7	$241.7	$241.7	$241.7	$241.7	$241.7	$241.7	
$8.5	$7.9	$7.2	$6.7	$6.1	$5.7	$5.2	$4.8	$4.4	$4.1	$3.8	$3.5	$3.2	$3.0	$2.7	$2.5	$2.3	$2.1	$2.0	
$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0	$105.0		
$3.7	$3.4	$3.1	$2.9	$2.7	$2.5	$2.3	$2.1	$1.9	$1.8	$1.6	$1.5	$1.4	$1.3	$1.2	$1.1	$1.0	$0.9		
$110.2	$110.2	$110.2	$110.2	$110.2	$110.2	$110.2	$110.2	$110.2	$110.2	$110.2	$110.2	$110.2	$110.2	$110.2	$110.2	$110.2	$110.2	$110.2	
$3.9	$3.6	$3.3	$3.0	$2.8	$2.6	$2.4	$2.2	$2.0	$1.9	$1.7	$1.6	$1.5	$1.3	$1.2	$1.1	$1.1	$1.0	$0.9	

Appendix B

Jaleh Firooz, P.E.

Resume

SUMMARY

- Transmission and energy expert with strong leadership and excellent technical and analytical skills. Experienced in renewable resource and transmission development, interconnection, transmission regulatory policy, competitive wholesale energy markets and market design. Licensed professional electrical engineer, project manager with MBA, and more than 25 years of utility and consulting experience in the following areas:Transmission planning, CAISO generation interconnection policies and contracts
- Renewable energy projects development
- State and FERC regulatory policy related to electricity markets and renewable energy development
- Resource planning, economic and reliability evaluation of generation and grid expansion projects, production cost analysis and power flow simulation models
- California Independent System Operator (CAISO) market design and markets
- Wholesale trading, offer preparation, power contract negotiations, and portfolio risk optimization

EXPERIENCE

Advanced Energy Solutions Consulting Company 12/2005 - 4/2008 and 2/2009-Present

Provide consulting services in the areas of project development, regulatory policy, economic analysis, CAISO markets, transmission interconnection expansion, offer preparation, and rates.

- Provided interconnection and regulatory consulting to a client opposing a 500 kV transmission project. Won the argument with the CAISO, resulted in re-categorization of the line from "needed" to "to be looked at in the future".
- Consulted to a large developer for a 500 MW generation and 500 kV high voltage transmission project. Performed economic and reliability analysis. Prepared RFP to hire other vendors and consultants. Identified CAISO day-ahead, real-time, and ancillary services market opportunities for the project under current and future market designs. Filed testimony with the FERC. Intervened on behalf of the project in CPCN application at the CPUC.
- Provided interconnection, regulatory, economic analysis, and rate support to renewable generation developers and environmental groups .Provided expert testimony
- Published two papers and an article in the Natural Gas and Electricity journal related to transmission planning issues in CA. Analyzed the need for a Once-Through Cooling power plant.

First Wind Energy

Director of California Business Development, Regulatory, and Transmission 4/2008 – 2/2009

- Responsible for CA prospecting, site selection and evaluation, wind resource evaluation, securing land interests, permitting, environmental studies, coordinating interconnection studies, and participating in the projects economic evaluation, design and construction.
- Developed a market assessment and strategic plan for wind development in CA and Baja Mexico. Prospecting in five different counties in Southern, Central, and Northern CA, and re-permitting BLM ROW grants. Initiated discussions with prospective land owners and put together lease option agreements to start negotiations for met tower placement and long term site control. Manage CA regulatory issues related to wind development, including CAISO generation interconnection procedures, Renewable Energy Transmission Initiative (RETI), AWEA, and

CalWEA. Involved in exploring potential power sales opportunities with CA municipal and Investor Owned Utilities.

San Diego Gas and Electric Company (1981 – 2006)

<u>Regulatory Affairs (FERC Regulatory Manager), 2003 – 12/2005</u>

- Analyzed market and transmission related proposals and rules by regulators and market participants. Identified their impacts and recommended courses of action to senior management. One such policy recommendation identified more than $50 million per year in cost savings.
- Managed the development of collaborative policy and strategic positions related to transmission interconnection protocol and energy markets. Wrote position papers and developed regulatory filings by working with business units, attorneys and corporate leadership to meet the company's business and strategic objectives. A key catalyst in a more than $30 million Existing Transmission Contract (ETC) settlement with the CAISO.
- Promoted SDG&E policy by participating in regulatory proceedings and stakeholder meetings and provided regulatory and policy intelligence and guidance.
- Developed SDG&E's "capacity market" proposal and presented it in regulatory proceedings.
- Key participant in the economic evaluation of new transmission projects and upgrades.
- Revised and filed SDG&E's Wholesale Distribution Tariff (WDT).

<u>Electric & Gas Procurement Dept (Portfolio Manager), 1998- 2003</u>

- Initiated and managed wholesale power trading for SDG&E's portfolio of generation and contract resources. Generated more than $60 million in profits through trades over a two year period.
    - Developed and managed the front, middle, and back office activities in support of trading activities.
    - Managed and optimized the portfolio by recommending hedging strategies to maximize value and reduce risks.
    - Built relationships with buyers, sellers and brokers in the market and structured new energy products for sale.
- Managed the development of several RFPs and successfully negotiated and signed power purchase agreements.
- Negotiated and signed several $40 million long-term deals resulting in millions of dollars of customer cost savings.
- Managed the CAISO related activities, participated in the CAISO and SDG&E market related policy and operational stakeholder discussions, evaluation and decision making.
- Managed the development and implementation of the energy and ancillary services bid optimization program including supplier evaluation, selection, and purchase of software. The software was used to generate over $120 million in revenues annually.
- Led efforts to develop a forecasting model for market prices, with a cost saving of $3 million per year.
- Evaluated and purchased a probabilistic production cost model. Proposed a procurement PBR and incentive mechanism for load forecasting and other procurement activities.
- Led SDG&E's settlement and policy dispute resolution efforts with the CAISO, a $50 million project. Successfully negotiated and resolved more than $10 million in disputes.
- Developed resource plans and made procurement recommendations using production cost simulation modeling.

Strategic Planning and Projects (Senior Engineer/Senior Analyst), 1995 – 1998

- Participated in, and managed interface with, the CAISO energy markets/systems.
- Participated in the development of strategic plans for SDG&E to restructure the electricity market in California.
- Represented SDG&E and was a key participant in the development of rules and protocols for bidding, scheduling, and operation of a competitive electricity market in California.
- Co-managed the development and purchase of the Power Exchange computer and CAISO metering and data acquisition systems including hiring consultants, writing specs, evaluating vendors, and developing project schedules.
- Led the technical evaluation of the vendors' proposals.

Power Control Operations and Power Contract Department, 1987 – 1995

(Power Contracts Administrator/Power Control Project Manager)

- Successfully managed a $20 million project and over 50 people in the purchase of a new Energy Management Computer System (EMS)
  - Organized project teams, hired consultants and additional staff, developed the Request for Proposal, evaluated proposals, participated in vendor selection, signed the contract, and managed vendor performance against contract commitments. .
  - Managed the project schedule, budget, and training.
  - Oversaw software and data base development, testing and training of the staff.
- Evaluated, recommended and negotiated power and transmission purchase/sale contracts for SDG&E worth $25-40 million.
- Managed the design, purchase, and installation of Remote Terminal Units (RTU) to transmit real-time data to the SDG&E control center.
- Supervised operators' daily implementation of power contract terms and conditions.

Other tasks performed and projects managed – Principal and Senior Engineer 1981-1995

- Directed the efforts of teams to study transmission system reliability using power flow analysis. Identified transmission system deficiencies and recommended short and long term solutions.
- Performed complex studies of power purchase/sale proposals and alternatives.
- Developed an operating plan using an hourly probabilistic production cost program.

EDUCATION

B.S. Electrical Engineering, Wichita State University, Cum Laude
M.B.A. - Finance Major, San Diego State University, Dean's Honor Roll
Certificate - Negotiation Skills, University of California San Diego (UCSD)
Completed more than 20 management, leadership, team building, communication, computers, economics, risk management, and other technical courses offered by SDG&E
PROFESSIONAL REGISTRATION Registered Professional Engineer in the state of California.