Review and Sign-Off Sheet for E-mail-Only Notices

Directions: *Insert text of e-mail message below. Designate which list server lists this will be sent to and the date by which it needs to be sent. (Please allow five business days for review.) Print this page and send around for review. After review and sign-offs are completed, send final version of text along with names of list servers to WEBWORK. The Web Team will confirm with you that message has been sent out.*

List Servers:	energypolicy	Date to send out e-mail:
		January 14, 2014

See http://www.energy.ca.gov/listservers/index.html for names of list servers.

Subject line:

Proposed Changes to Final Lead Commissioner Report – 2013 Integrated Energy Policy Report

Text of Message to be Sent

On January 15, 2014, the Energy Commission will consider adopting the 2013 Integrated Energy Policy Report. The Final Lead Commissioner Report was posted on December 20, 2013. Additional proposed changes to the report reflect corrections, clarifications, and public comments received on the final report for consideration at the January 15 business meeting. The summary of proposed changes can be found at: http://energy.ca.gov/2013_energypolicy/.

Originator:	Office Manager:	Division Chief:	Media & Public Communications:	Executive Office:
Date:	Date:	Date:	Date:	Date:

Summary of Proposed Changes to *2013 Integrated Energy Policy Report* Final Lead Commissioner Report

For Consideration at the January 15, 2014 California Energy Commission Business Meeting

Page numbers refer to the report posted on December 20, 2013. The December 20^{th} version shows edits in underline-strikeout. The edits proposed below assumes that all changes to the December 20^{th} draft have been accepted. Added text is shown in underline; ~~deleted text shown in strikeout.~~

Executive Summary, page 1, first paragraph:
…The state's economy, environment, and public health depend on reducing greenhouse gas emissions by using less energy, ~~electrifying~~ de-carbonizing the transportation system, and producing ~~power~~ energy both sustainably and with lower overall greenhouse gas emissions.

Executive Summary, page 1, second paragraph:
…The state's "Loading Order" is a guiding policy which places energy efficiency (using less energy to do the same job) and demand response (~~using less~~ modifying energy usage when needed for optimal grid operation) as top priorities for meeting California's energy needs…. California also has a goal of making all new buildings zero-net-energy – essentially combining energy efficiency measures and renewable ~~power~~ energy generation so that a building can produce as much ~~power~~ energy as it uses annually – by 2020 for homes and 2030 for businesses….

Executive Summary, page 8 first paragraph:
…Average annual electricity demand growth from 2012–2024 is expected to range from ~~0.78~~ 0.88 to ~~1.56~~ 1.82 percent. Peak demand growth is expected to range from ~~0.88~~ 0.97 to ~~1.82~~ 1.92 percent. Combining the mid demand case for both demand and additional achievable energy efficiency, the annual electricity demand growth from 2012–2024 is expected to average 0.2 percent, and annual peak demand growth is expected to average 0.4 percent for the investor owned utility service territories which is remarkably flat considering the anticipated economic expansion and population growth.

Executive Summary, page 8, second paragraph:
…Challenges include the local nature of reliability needs, the difficulty and uncertainty of forecasting load and additional achievable energy efficiency at specific locations, and the difficulty estimating daily load-shape impacts. Thus, it is prudent at this time to use a combination of the mid base case forecast and the low mid~~mid-low~~ additional achievable energy efficiency scenario for local studies in these planning processes.

Chapter 1 (Energy Efficiency), page 23, second paragraph:
The adoption of this definition will enable the Energy Commission to update the California Building Energy Efficiency Standards for 2016 and 2019 with clear orientation toward the upcoming ZNE targets for low‐rise residential buildings (three stories or fewer) in 2020 and nonresidential buildings in 2030. At the same time, the Energy Commission intends to make any needed changes to the definition through ongoing discussion with stakeholders and analysis of key issues identified later in this section.

Chapter 1 (Energy Efficiency), page 25, first paragraph:
…The graphic also shows a “ZNE Ready” level to represent a home with the energy efficiency improvements that sufficiently reduce demand so that the addition of onsite renewable ~~power~~ energy production could achieve ZNE (the “ZNE Ready” level assumes that the onsite renewable energy production is not actually installed).

Chapter 1 (Energy Efficiency), page 28, first paragraph:
~~Under AB 2021, POUs are directed to provide an annual report to the Energy Commission on energy efficiency investments, programs, expenditures, cost-effectiveness, and results; and provide an independent evaluation of reported energy savings. The Energy Commission is to report on utility progress in the biennial *Integrated Energy Policy Report*.~~ Under Public Utilities Code Section 9505, POUs are directed to identify all potentially achievable cost-effective electricity efficiency savings and establish annual targets for energy efficiency savings and demand reduction for the next 10-year period.

Chapter 1 (Energy Efficiency), page 30, fourth paragraph:
…~~Cost-effectiveness is difficult to compare between POUs and IOUs because of the differences in their regulatory, financing, and revenue structures and the lack of data about cost-effectiveness inputs for individual POUs.~~ Interpretation of the results of the cost-effectiveness analysis is challenging among POUs and IOUs because of the differences in their regulatory and financial structures and lack of data about cost-effectiveness inputs for individual POUs.

Chapter 1 (Energy Efficiency), page 31, 2nd paragraph:
The Energy Commission is committed to encouraging and assisting the POUs in their EM&V efforts as a means to increasing energy efficiency effectiveness. In 2010, the Energy Commission developed an EM&V guide to clarify the reporting requirements needed to improve EM&V studies and reports. These guidelines included how and when to apply the framework of evaluation criteria. Some POUs indicated that size, diversity in customer base, and program types made the “one-size-fits-all” approach outlined in the guidelines impractical. As a result of utility feedback, the Energy Commission is revising the ~~EM&V~~ guidelines. In 2014, staff will publish revised EM&V~~guidance~~ guidelines designed to better meet the needs of the POUs, improve the transparency of the methods used to develop program savings estimates, and improve overall credibility of the reported energy savings. ~~The Energy Commission is committed to encouraging and assisting the POUs in their EM&V efforts as a means to increasing energy efficiency effectiveness.~~

Chapter 1 (Energy Efficiency), page 36, 8th paragraph under recommendations

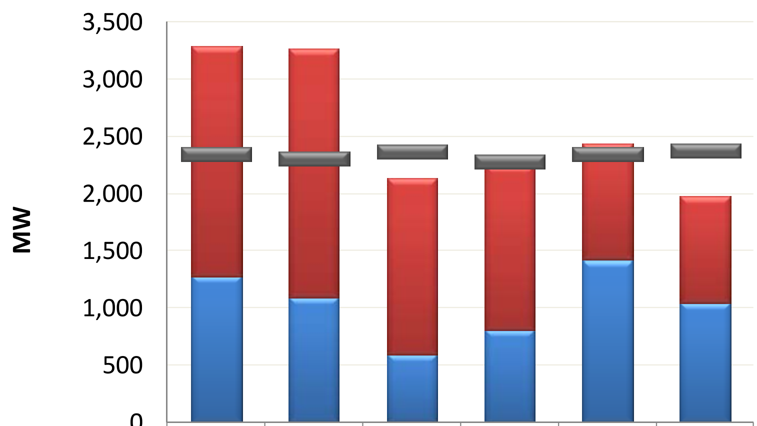
Improve evaluation, measurement, and verification (EM&V). The Energy Commission aims to complete the EM&V guidelines early in 2014 for the publicly owned utilities to use in their next EM&V cycle to increase confidence and ensure independent verification~~; the publicly owned utilities should subsequently complete development of an EM&V program tracking system within 12 months~~.

Chapter 2 (Demand Response), page 38, first paragraph:

…DR—essentially ~~reducing electricity use or shifting it to another period~~ the modification of energy usage due to market, grid, or pricing signals—provides many benefits including a more efficient electric system with lower overall system costs, reduced need for new power plants and transmission infrastructure, and more control by customers over their electric bills.

Chapter 2 (Demand Response), page 42, Figure 3:

Figure 3: IOU Demand Response 2008-2013*



	2008	2009	2010	2011	2012	2013
Emergency	2,007	2,172	1,544	1,428	1,010	924
Price-Responsive	1,287	1,095	589	814	1,420	1046
5% Target	2,345	2,302	2,368	2,277	2,342	2,371

*DR resource accounting methods were standardized in the Load Impact Protocols decision, D.08-04-050. The IOUs began using those methods for the 2010 forecast year.

Chapter 2 (Demand Response), page 45, second paragraph:

In November of 2013, the CPUC and SCE held a workshop to discuss proposals for SCE's "~~Living~~ Preferred Resources Pilot." The goal of this process is to develop a comprehensive, accelerated approach to assembling preferred resources (including efficiency and demand response resources), energy storage, and other advanced technologies in the area of SCE's territory most affected by the SONGS shutdown. The assembled approaches are intended to be followed closely and modified as necessary to increase the effectiveness of the pilot.

Chapter 2 (Demand Response), page 45, third paragraph:
…As of June 2013, the California ISO had developed two products for DR participation, the Participating Load product and the Proxy Demand Resource product, and has been seeking approval from FERC of a third, the Reliability Demand Response Resource product ~~program~~, since May 2011.

Chapter 2 (Demand Response), last paragraph on page 45 continued to page 46:
…The California ISO expects that further integration of DR into wholesale markets will increase competition, promote efficiency, and reduce costs.~~, and has instituted a stakeholder process to develop a *Demand Response and Energy Efficiency Roadmap*.~~To achieve this expectation, the CAISO initiated a stakeholder process to develop a *Demand Response and Energy Efficiency Roadmap*, intended to help guide future technical and policy efforts to expand DR resources. The *Roadmap* was published in December of 2013. (See Appendix C and sidebar below for summaries of the roadmap.)

Chapter 2 (Demand Response), page 46, last paragraph:
… At the end of 2012, the IOUs had ~~just~~ 250 megawatts (MW) of dispatchable load using OpenADR.

Chapter 3 (Bioenergy), page 60 paragraph below Table 3:
…However, some facilities retired due to various factors including unfavorable economic conditions, ~~and~~ unsuccessful attempts to amend power purchase agreements, and operational challenges.

Chapter 3 (Bioenergy), page 71, second paragraph:
The statutory and regulatory landscape for biomethane projects is undergoing a number of changes. For example, the RPS no longer allows biomethane delivered through the natural gas pipeline to be eligible as a renewable resource unless the project provides environmental benefits to California….*

*Assembly Bill 2196 (Chesbro~~Skinner~~, Chapter 605, Statutes of 2012)~~.~~ allows for the grandfathering of some existing biomethane contracts. Under AB 2196, "Any procurement of biomethane delivered through a common carrier pipeline under a contract executed by a retail seller or local publicly owned electric utility and reported to the Energy Commission prior to March 29, 2012, and otherwise eligible under the rules in place as of the date of contract execution shall count toward the procurement requirements established in this article, under the rules in place at the time the contract was executed, including the Fourth Edition of the Energy Commission's Renewables Portfolio Standard Eligibility Guidebook, provided that those rules shall apply only to sources that are producing biomethane and injecting it into a common carrier pipeline on or before April 1, 2014."

Chapter 3 (Bioenergy), page 74 first paragraph:
…For example, while there is little debate that AB 1900 will benefit development of biomethane in California, some have raised concerns regarding the ~~increased~~ new costs to meet new biomethane pipeline quality standards.

Chapter 3 (Bioenergy), page 75 last paragraph:
Pipeline safety is another issue for biomethane. Utilities have said that it is imperative to monitor and test biomethane going into their pipelines. While utilities have limited experience injecting biomethane into their pipelines, they still lack data, especially for interconnections into low- demand pipelines….

Chapter 3 (Bioenergy), page 77 last recommendation:

Support research and development for pipeline biomethane injection. The EnergyCommission should continue research, development, and demonstration of biogas-to – biomethane technologies and projects that inject biomethane into California's natural gas pipelines in consultation with California Public Utilities Commission and other state agencies. The priority should be research that satisfies CPUC's AB 1900 rulemaking needs and provides needed data identifying constituents of concern for additional feedstock sources not identified in the California Air Resources Board and Office of Environmental Health Hazard Assessment staff report *Recommendations to the California Public Utilities Commission Regarding Health Protective Standards for the Injection of Biogas into the Common Carrier Pipeline*….

Chapter 4 (Electricity), page 82, first paragraph (and page 83, third paragraph):
More details are available in the *California Energy Demand Final Forecast 2014-2024* (*CED 2013*).**

** http://www.energy.ca.gov/2013_energypolicy/documents/#~~12112013~~reportsnomeeting.

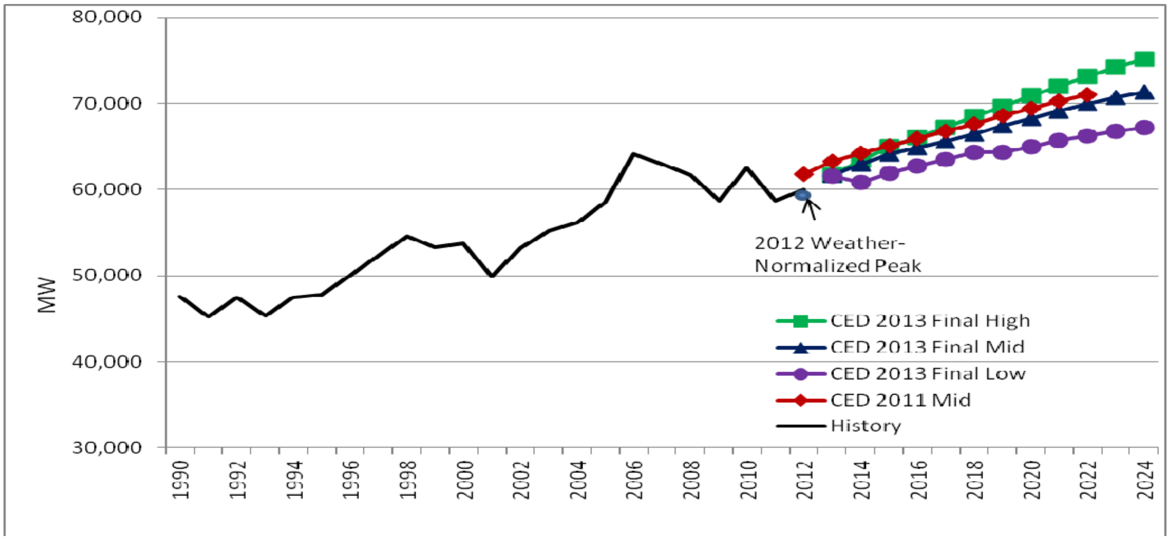
Chapter 4 (Electricity), page 84, Table 6: Comparison of Statewide Energy Demand Scenarios:

Consumption (GWh)				
	CED 2011 Mid Energy Demand	**CED 2013 Final High Energy Demand**	**CED 2013 Final Mid Energy Demand**	**CED 2013 Final Low Energy Demand**
1990	227,586	227,576	227,576	227,576
2000	261,381	260,399	260,399	260,399
2012	281,347	280,561	280,561	280,561
2015	291,965	291,307	287,104	280,314
2020	310,210	316,874	305,218	294,056
2024	--	337,713	321,734	308,277
	Average Annual Growth Rates			
1990-2000	1.39%	1.36%	1.36%	1.36%
2000-2012	0.62%	0.62%	0.62%	0.62%
2012-2015	1.24%	1.26%	0.77%	-0.03%
2012-2022	1.20%	1.56%	1.12%	0.72%
2012-2024	--	1.56%	1.15%	0.79%
Noncoincident Peak (MW)				
	CED 2011 Mid Energy Demand	**CED 2013 Final High Energy Demand**	**CED 2013 Final Mid Energy Demand**	**CED 2013 Final Low Energy Demand**
1990	47,546	47,543	47,543	47,543
2000	53,700	53,702	53,702	53,702
2012	--	59,931	59,931	59,931
2012*	61,796	59,811	59,811	59,811
2015	65,036	~~64,221~~ 64,914	~~63,413~~ 64,093	~~61,221~~ 61,872
2020	69,418	~~70,121~~ 70,905	~~67,550~~ 68,293	~~64,306~~ 65,001
2024	--	~~74,278~~ 75,124	~~70,495~~ 71,283	~~66,445~~ 67,175
	Average Annual Growth Rates			
1990-2000	1.22%	1.23%	1.23%	1.23%
2000-2012	1.18%	0.90%	0.90%	0.90%
2012-2015	1.72%	~~2.40~~ 2.77%	~~1.97~~ 2.33%	~~0.78~~ 1.14%
2012-2022	1.38%	~~1.91~~ 2.03%	~~1.46~~ 1.57%	~~0.92~~ 1.03%
2012-2024	--	~~1.82~~ 1.92%	~~1.38~~ 1.47%	~~0.88~~ 0.97%
Historical values are shaded. Weather normalized: *CED 2013 Final* uses a weather-normalized peak value derived from the actual 2012 peak for calculating growth rates during the forecast period				

Chapter 4 (Electricity), page 85, second paragraph:
…Actual peak demand in 2012 was lower than projected in the *CED 2011* mid case, reflecting slower economic growth than was predicted in 2011. ~~There is little growth in~~

~~all three scenarios from 2012-2013, a result of efficiency improvements in 2013, price effects, and low economic growth.~~ By 2022, the new mid case is almost 4 percent below the previous. With smaller price effects over the forecast period and higher population growth, the *CED 2013* high case reaches the *CED 2011* mid case level by 2022.

Chapter 4 (Electricity), page 86, Figure 5: Statewide Annual Noncoincident Peak Demand: (replaced figure with updated version)



Chapter 4 (Electricity), page 87, second paragraph:

…Staff converted simulated daily averages for each weather station to degree days and temperature indices for each planning area by weighting each climate zone either by estimated number of air conditioners (temperature and cooling degree days) or population (heating degree days).[1]

[1] Heating and cooling degree days measure the difference between daily average temperature and a reference temperature (for example, 65 degrees) summed over all days in a given year. An average temperature below the reference temperature adds to heating degree days and an average above the reference adds to cooling degree days.

Chapter 4 (Electricity), page 92, second paragraph:

… This combination is also referred to as a "managed" demand forecast.

The next two tables give several examples of managed forecasts. Table X1 shows the *CED 2013* mid baseline forecast of electricity deliveries for the combined IOU service territories, along with two managed versions of the forecast that have been adjusted by the low-mid AAEE and the mid AAEE savings scenarios, respectively. Similarly, Table X2 shows the mid baseline peak demand forecast for the same territories along with managed forecasts that take into account low-mid and mid AAEE savings. While forecasts of electricity deliveries assume normal weather, separate peak forecasts must be made for normal (1-in-2) and extreme (1-in-10) weather, as such variations are considered in transmission planning and grid reliability studies.

Table X1: Baseline and Managed Forecasts of Electricity Deliveries for PG&E, SCE, and SDG&E Combined Service Territories

	Mid Baseline (GWh)		
	No AAEE	Low Mid AAEE	Mid AAEE
2012	192,766	192,766	192,766
2013	191,888	191,554	191,357
2014	193,496	192,937	192,565
2015	195,913	193,903	192,886
2016	198,018	194,552	192,567
2017	200,444	195,504	192,696
2018	202,655	196,841	193,041
2019	205,446	198,450	193,919
2020	208,254	200,209	194,996
2021	211,015	201,914	195,920
2022	213,752	203,552	196,790
2023	216,224	204,754	197,258
2024	218,535	205,836	197,545

Table X2: Baseline and Managed Forecasts of Peak Demand for PG&E, SCE, and SDG&E Combined Service Territories

	Mid Baseline 1-in-2 (MW)			Mid Baseline 1-in-10 (MW)		
	No AAEE	Low Mid AAEE	Mid AAEE	No AAEE	Low Mid AAEE	Mid AAEE
2013	45,040	45,040	45,040	48,999	48,999	48,999
2014	45,976	45,922	45,889	50,017	49,958	49,922
2015	46,887	46,480	46,322	51,006	50,562	50,391
2016	47,467	46,703	46,340	51,637	50,805	50,410
2017	48,078	46,953	46,427	52,302	51,077	50,505
2018	48,738	47,349	46,587	53,017	51,505	50,677
2019	49,426	47,719	46,789	53,766	51,908	50,897
2020	50,108	48,114	47,024	54,505	52,335	51,150
2021	50,739	48,453	47,172	55,193	52,706	51,314
2022	51,338	48,750	47,270	55,842	53,026	51,417
2023	51,869	48,935	47,249	56,420	53,226	51,394
2024	52,357	49,079	47,176	56,947	53,381	51,313

Chapter 4 (Electricity), page 92, Table 9: Consumption and Peak Demand by Climate Zone:

	PG&E					SCE				LADWP	
	1	2	3	4	5	7	8	9	10	11	12
	Consumption (GWh)										
2013	4,924	10,273	31,572	38,477	24,387	6,373	38,616	28,187	26,579	8,503	16,553
2024	5,546	12,299	37,751	43,531	27,572	7,692	42,549	32,437	31,824	9,356	18,806
Avg. Growth 2013-2024	1.09%	1.65%	1.64%	1.13%	1.12%	1.72%	0.89%	1.29%	1.65%	0.87%	1.17%
	Peak Demand (MW)										
2013	~~970~~ 984	~~2,395~~ 2,429	~~7,135~~ 7,236	~~7,098~~ 7,199	~~5,318~~ 5,394	~~723~~ 740	~~8,356~~ 8,550	~~5,431~~ 5,558	~~7,379~~ 7,551	1,715	4,066
2024	~~1,088~~ 1,104	~~2,884~~ 2,924	~~8,666~~ 8,789	~~8,095~~ 8,209	~~5,886~~ 5,969	~~935~~ 957	~~9,355~~ 9,576	~~6,268~~ 6,416	~~8,857~~ 9,066	1,915	4,630
Avg. Growth 2013-2024	1.05%	1.70%	1.78%	1.20%	0.93%	2.36%	1.03%	1.31%	1.67%	1.01%	1.19%

Chapter 4 (Electricity), page 93, third paragraph:
…Therefore, agency leadership recommends using the mid AAEE forecast scenario for system-wide and flexibility studies for the upcoming 2014-2015 LTPP and TPP cycles. Because of the local nature of reliability needs and the difficulty of forecasting load and additional achievable energy efficiency at specific locations and estimating their daily load-shape impacts, using the low mid~~mid-low~~ AAEE scenario for local studies is more prudent at this time.

Chapter 6 (Nuclear), page 161, second paragraph:
…Within two years of permanently ceasing operations, SCE must submit to the NRC and state officials a detailed plan (known as a Post-Shutdown Decommissioning Activities Report) that spells out specific decommissioning activities and schedules, cost estimates, and potential environmental impacts.[346] ~~SCE anticipates Units 2 and 3 decommissioning activities to commence in mid-2015.~~

Chapter 6 (Nuclear), page 168, third paragraph:
…The scope of Phase 2 evidentiary hearings,[368] ~~scheduled for~~ held October 2013, will include determining the value(s) of San Onofre assets in rate base, and which of these assets should be removed from rate base pursuant to Public Utilities Code Section 455.5.[369] A Phase 2 decision is anticipated in ~~February~~ 2014.

Chapter 7 (Natural Gas), page 183, last paragraph:

While future CHP development is expected in both the commercial (for example, big box retail and restaurants) and industrial (such as food processing and water treatment) sectors, Energy Commission staff analysis allocated the shift in natural gas demand from the power generation sector to generation for CHP in the industrial sector. ~~CHP is assumed to be topping-cycle CHP.~~~~[137]~~

Chapter 7 (Natural Gas), page 186, second paragraph:

However, PG&E informed the CPUC and stakeholders in July 2013, ~~however,~~ that its 2011 request ~~application presenting “traceable, verifiable and complete” records and therefore requesting approval to increase the operating pressure~~ to restore operating pressure on Line 147 in San Carlos to 365 pounds per square inch gauge (psig) had in fact been based on inaccurate information about the pipeline. PG&E reduced the pressure on Line 147 to 300 psig, and the CPUC asked in a Show Cause Order why it should not rescind all of the orders it had approved to restore operating pressures. At the Show Cause Order hearing, PG&E indicated that the pipelines were safe as they all underwent pressure tests and explained the impact of reducing operating pressures on all of the lines whose pressures had since been restored would be to curtail natural gas service to power plants, noncore customers on the San Francisco Peninsula, and core customers in San Francisco’s Financial District this winter should we experience cold temperatures that are expected to occur once in every ten years.

PG&E’s errata explained that the information it filed in October 2011 in support of its request to lift operating pressure restrictions on ~~these pipelines~~ Line 147 was erroneous in part. With respect to Line 147, information ~~Information~~ contained in PG&E records—developed as part of the pipeline records validation process ordered by the CPUC after the San Bruno explosions—showed that ~~these pipelines~~ certain segments of the pipeline contained double submerged arc welds or were seamless and had joint efficiency factors of 1.0. PG&E argued that this justified an MAOP of 365 psig. Based on ~~this~~ the October 2011 representation by PG&E, the CPUC granted permission to raise the MAOPs of the lines to no more than 365 psig in December 2011.”

The errata revealed that PG&E had learned upon completing a repair resulting from a routine leak inspection and from subsequent investigations that as many as six segments of Line 147 actually are early vintage pipe or have single submerged arc welds, implying a joint efficiency factor of 0.8, which effectively reduces the pipeline’s MAOPs to 330 psig from the approved 365 psig. ~~The implications from a pipeline safety perspective are clear.~~ The pipeline specifications errors are troubling in light of the significant effort to assure that PG&E understands what pipe is in the ground and its condition before restoring higher operating pressures. Due to PG&E’s admitted error, ~~the pipelines~~ Line 147 received approval to operate at pressures that are higher than the recommended MAOP. PG&E noted in the errata that it has reduced the operating pressures to safe levels, but the pipeline had been approved to operate at a higher pressure in December 2011 and PG&E’s errata was not filed for another 18 months. PG&E reduced pressure on the line in late October 2012 after identifying the erroneous pipeline characteristics, about 9 months prior to filing its errata, but the nature of the erroneous information, the length of time the pipeline operated at the higher pressure based on that ~~false~~ information, and the way this situation came to light undermines the public's confidence that the gas system is safe. Based on both the length of time it took PG&E to file the errata ~~—18 months—~~and the fact that the information contained in the errata was substantive, ~~led~~ the CPUC ~~to~~ ordered PG&E to appear at a hearing and show cause why it shouldn't be sanctioned for violating Rule 1.1 of the Commission's Rules of Practice and Procedure. Rule 1.1 states that any person who transacts business with the CPUC agrees to "never mislead the Commission or its staff by an artifice or false statement of law or fact."[393] The Show Cause Order also asks PG&E to show why all of the CPUC orders approving PG&E requests to restore operating pressures arising out of the post-San Bruno effort to verify pipeline features and maximum allowable operating pressures should not be rescinded until "competent demonstration that PG&E's natural gas system records are reliable." On December 19, 2013, the CPUC granted permission to operate the line at 330 psig, and fined PG&E $14.35M for violations of Rule 1.1.

Chapter 7 (Natural Gas), page 189, third paragraph:
…This delivery requirement, known as the Southern System Minimum (SoSysMin), refers to the minimum amount of gas flowing supply needed to serve customers located in SoCalGas' Southern Zone (the Imperial Valley, portions of Riverside and San Bernardino Counties, and San Diego County). ~~that must be delivered through the pipeline at Ehrenberg to serve all load in the SDG&E gas service area.~~ The SDG&E service area is in SoCal Gas' Southern Zone, which receives the majority of its gas through Ehrenberg from the El Paso Natural Gas south mainline. There are smaller pipeline interconnects between SoCal Gas's Northern System and Southern System, but the capacity is too small to deliver to all loads and they create bottlenecks. Consequently, on days when the gas deliveries at Ehrenberg are insufficient to serve all load in the Southern System, SoCal Gas has permission from the CPUC to go into the market and purchase the additional gas needed to meet that load. ~~more gas for delivery on the El Paso Natural Gas south mainline to make up the deficiency.~~ Without this permission, SoCal Gas is allowed to purchase gas only for its core customers, which, given the current gas delivery reductions at the Ehrenberg receipt point, would result in curtailments for noncore customers, including electric generators, along the southern system.

Chapter 7 (Natural Gas), page 190, second paragraph:
Since the shutdown of San Onofre, the SoSysMin has risen from an annual average of 420 MMcf/d in 2011 to 520 MMcf/d in 2012. SoCal Gas had to purchase additional gas to meet this rising SoSysMin on more than 100 days during the past 12 months. These purchases usually take place later in the day when there is a higher likelihood that there will not be enough gas available for purchase, which could lead to curtailments. ~~SoCal Gas is exploring options to solve this issue, which include a minimum percentage of gas that shippers would have to deliver to the Ehrenberg receipt point or a new pipeline that would connect SoCal Gas's northern system to its southern system.~~ SoCal Gas, during 2013, explored options such as requiring all shippers to deliver a minimum percentage of gas at Ehrenberg or building new facilities. On December 20, 2013, SoCal Gas and SDG&E filed an application at the CPUC to recover the $628 million cost to build a new

pipeline, running approximately from Adelanto to Moreno, and associated compression. If approved, the new facilities, known as the "North-South Project," will connect SoCal Gas' northern system to its southern system. The new facilities will allow Sempra's gas customers to continue to have gas delivered into northern system receipt points instead of using Ehrenberg. It will also provide a path from storage facilities to the southern system.

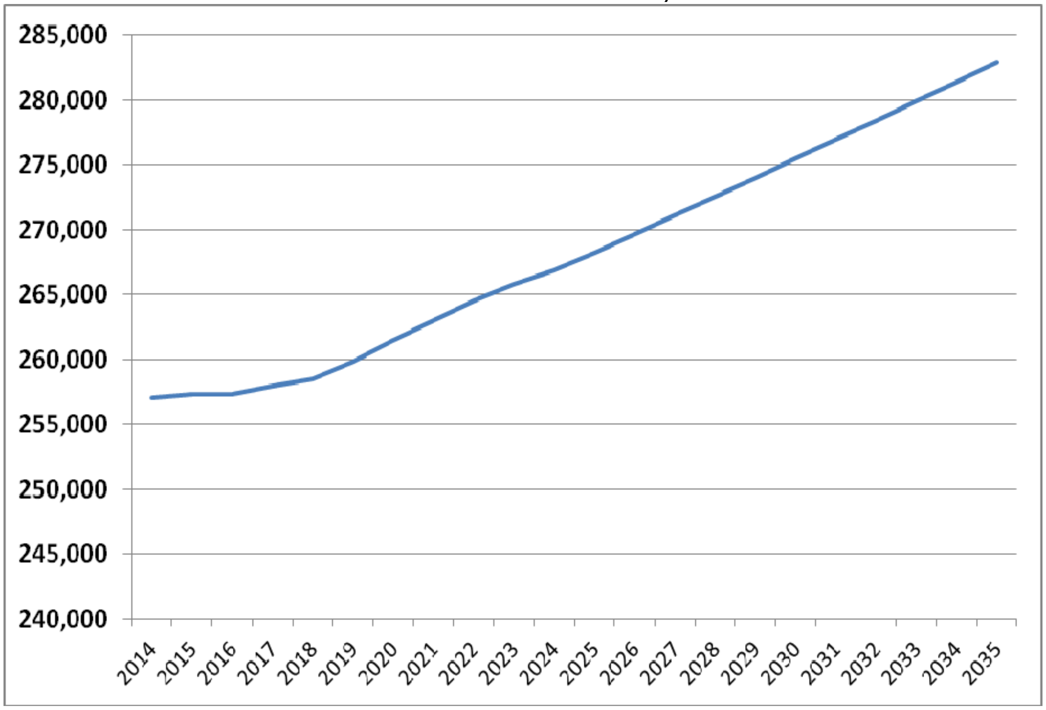
Chapter 7 (Natural Gas), page 190, last paragraph:
…California has 13 underground natural gas storage facilities with a total working gas inventory of 335 Bcf as of 2011. As shown in Figure 19, storage inventory ~~capacities~~ in 2012 rose in the winter and spring by up to 24 percent compared to 2011 on the heels of a warmer-than-usual winter and lower-than-usual demand.

Chapter 8 (Transportation) page 223, second paragraph:
One automaker in the United States produces a dedicated natural gas passenger vehicle, but four others have developed dual-fueled gasoline/natural gas concept cars and may bring them to market in limited production within the next three years. In addition, SoCalGas is currently working with a major new home production builder to optionally install natural gas Home Refueling Appliances as part of a ZNE project in Lancaster, California.

Chapter 9 (Climate Change) page 238, last paragraph
…The LBNL study indicates that by the end of the century, under certain climate scenario assumptions, energy supplies would need to increase by nearly 40 percent to meet increased demand from climate change and offset lower capacity of thermal generating plants and substations, assuming no technology advancements or population changes. ~~This assumes the climate scenario is superimposed on the current electricity infrastructure with no technology advancements or population changes.~~

Chapter 9 (Climate Change) page 244, revision to Figure 38

Figure 38: California Energy Demand Final 2013 Forecast and Extrapolation to 2035, RPS Eligible Retail Sales, GWh



Chapter 9 (Climate Change) page 246, first paragraph and also the title of Table 23

Table 23 shows California's RPS-eligible renewable portfolio as of year-end 2013~~2012~~. Slightly more than 35 percent of this energy, 15,200 GWh, comes from resources that came on-line in 2012 and 2013.

Table 23: California's RPS Portfolio, December 2013~~2012~~

Chapter 9 (Climate Change) page 253

Table 26: Capacity Needed to Provide 24,000 ~~24,008~~ GWh of Energy, Selected Renewable Technologies

Technology	Capacity Factor	Required MW
Distributed Solar	24%	~~10,784~~ 11,366
Central Station Solar	28%	~~9,244~~ 9,743
Wind	32%	~~8,088~~ 8,525
Geothermal	80%	~~3,235~~ 3,410
Biomass/Biomethane	85%	~~3,045~~ 3,209