State of California

California Natural Resources Agency

M e m o r a n d u m

California Energy Commission
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To: Docket Optical Unit
RE: Docket #13-IEP-1C

Date: March 13, 2013

From: Ivin Rhyne, Office Manager
Electricity Analysis Office, Electricity Supply Analysis Division
California Energy Commission

Subject: **Supplemental Information to the Energy Commission's February 19, 2013, Workshop by Malachi Weng-Gutierrez and Leon Brathwaite**

The following information responds to requests by Chairman Weisenmiller and Commissioner McAllister at the February 19, 2013, IEPR workshop on input assumptions for the electricity, natural gas, and transportation modeling sectors. The specific requests were:

1) Commissioner McAllister and Chair Weisenmiller asked that the assumed installed PV capacity embedded in the demand forecast presented at the workshop along with the assumed division between IOU and POU portions be entered into the record.
2) Chairman Weisenmiller asked that a comparison of the staff natural gas price projections with the futures market projections be entered into the record.
3) Chairman Weisenmiller asked that the sectoral price elasticities for California natural gas demand assumed in the gas model be entered into the record.

Discussion of IOU and POU disaggregation of PV Assumed in Rates

The following is a disaggregation of the *California Energy Demand 2011(CED 2011)* adopted photovoltaic (PV) installed capacity by investor-owned utilities (IOU) and publicly-owned utilities (POU). Since the forecast is based upon a variety of historic program data, there is some overlap in the POU versus IOU categories.[1] It is, therefore, impossible to completely separate IOU and POU installed capacity; however, the large majority of the overlapping installed capacity can be attributed to the IOUs and is referenced here as IOU only. The identified POU installed capacity can be associated solely with POUs. **Table 1** provides the disaggregated installed PV capacity for selected forecast years by POU and IOU categories for the three adopted *CED 2011* demand forecasts. The percentage PV provides the percent of POU and IOU installed capacity for selected forecast years.

1 Energy Commission *Revised California Energy Demand Forecast 2012-2022*, http://www.energy.ca.gov/2012publications/CEC-200-2012-001/CEC-200-2012-001-SD-V1.pdf. "For example, certain projects in the Self Generation Incentive Program have an IOU as the program administrator but are interconnected to a POU; these projects are mapped directly to forecasting zones."

Table 1: Adopted *CED 2011* Installed PV Capacity (MW)[2]

Year	High Demand		Mid Demand		Low Demand	
	POU	IOU	POU	IOU	POU	IOU
2009	-	-	55	524	-	-
2010	-	-	80	695	-	-
2016	176	1,741	180	1,797	190	1,933
***2020**	210	1,979	216	2,095	232	2,351
2022	259	2,326	268	2,522	288	2,874
Percentage PV by POU and IOU Categories						
2009	-	-	9.5%	90.5%	-	-
2010	-	-	10.3%	89.7%	-	-
2016	9.2%	90.8%	9.1%	90.9%	8.9%	91.1%
2020	9.6%	90.4%	9.3%	90.7%	9.0%	91.0%
2022	10.0%	90.0%	9.6%	90.4%	9.1%	90.9%

Source: California Energy Demand 2012–2022 Final Forecast.

* 2020 values only were presented at the February 19, 2013, workshop.

Over the forecast period, the percent distribution between IOU and POU PV installed capacity does not significantly change. Across demand forecasts, IOUs have a slightly larger market share likely due to retail rate differences across three forecasts. For example, the low demand case, associated with high rates, leads to a slightly larger IOU share of PV installations. Higher retail rates make PV more cost effective and support adoption. IOUs electricity rates are typically higher; applying a given percentage rate growth across all utilities as in *CED 2011* results in a higher absolute magnitude rate increase, so the adoption rates increase relative to that of POUs.

The IOU compound average annual growth rate from 2010 to 2022 is about 2 percent higher in the low electricity demand scenario than in the high electricity demand scenario — 12.6 percent versus 10.6 percent.[3] Similarly, POU compound average annual growth rate differences between low and high electricity demand scenarios is about 1 percent — 11.2 percent versus 10.3 percent.

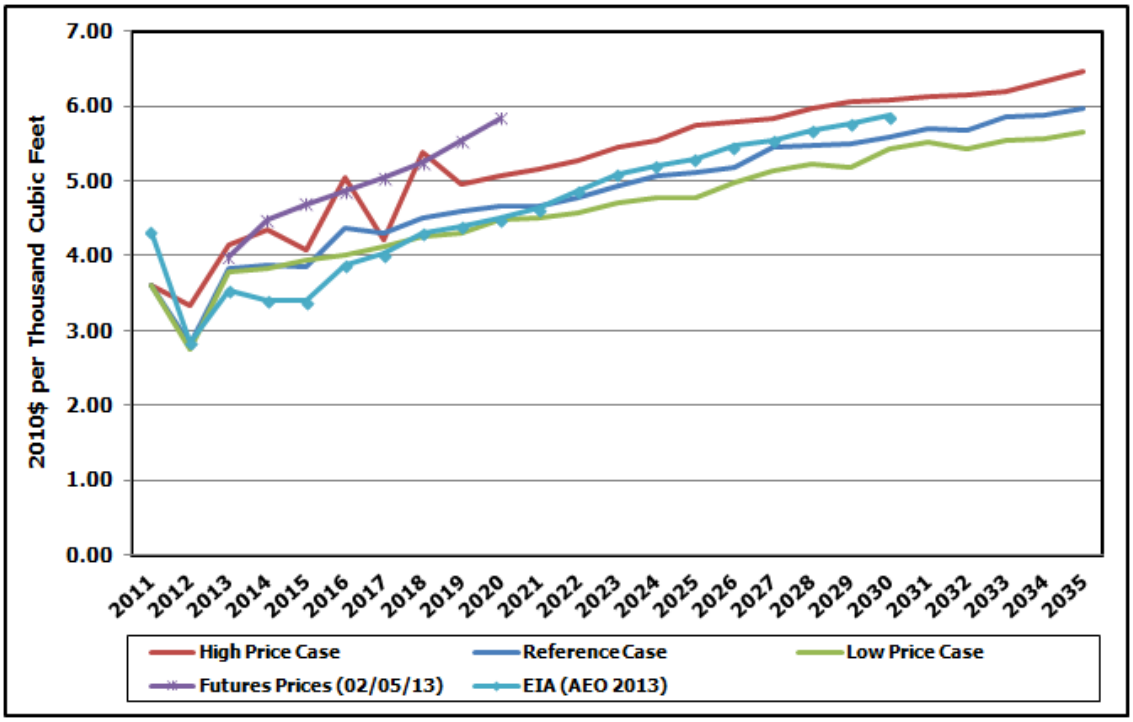
The self-generation forecast methodology and associated assumptions are detailed in Appendix B of the *CED 2011.*[4]

Discussion of Natural Gas

Figure 1 shows the preliminary natural gas price projections developed by the Energy Commission compared with the Energy Information Administration's projection. Also, staff included in **Figure 1** a natural gas futures price projection developed from trading at the Henry Hub pricing point (Trade date: 02/05/13). **Table 2** shows the annual price values used to generate **Figure 1**.

2 All values are cumulative. Reported 2009 and 2010 installed capacities are actual historic values.
3 Compounded Average Annual Growth Rate is calculated from 2010 to 2022.
4 *Revised California Energy Demand Forecast 2012–2022 Volume 1: Statewide Electricity Demand and Methods, End-User Natural Gas Demand, and Energy Efficiency.* Appendix B.
http://www.energy.ca.gov/publications/displayOneReport.php?pubNum=CEC-200-2012-001-SD-V1.

Figure 1: Price Projection Comparison



Source: California Energy Commission, Energy Information Administration, Chicago Mercantile Exchange.

Table 2 displays the data used to construct the price projections exhibited in **Figure 1.**

Table 2: Henry Hub Prices, 2010$/Mcf

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Reference Case:																									
Hub: US-Henry Hub	3.598	2.811	3.830	3.883	3.856	4.363	4.306	4.496	4.586	4.653	4.663	4.766	4.924	5.075	5.116	5.185	5.457	5.470	5.488	5.581	5.702	5.665	5.862	5.877	5.975
High Case:																									
Hub: US-Henry Hub	3.601	3.328	4.139	4.355	4.073	5.047	4.210	5.384	4.949	5.073	5.151	5.269	5.456	5.543	5.745	5.782	5.842	5.959	6.059	6.087	6.119	6.157	6.196	6.328	6.461
Low Case:																									
Hub: US-Henry Hub	3.602	2.744	3.795	3.835	3.944	4.010	4.115	4.264	4.313	4.491	4.501	4.581	4.709	4.771	4.768	4.971	5.145	5.219	5.181	5.420	5.515	5.420	5.543	5.555	5.649

Source: California Energy Commission

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
EIA Henry Hub, 2010$	4.856	4.330	2.849	3.537	3.397	3.393	3.880	4.023	4.306	4.403	4.498	4.633	4.871	5.086	5.208	5.299	5.462	5.543	5.679	5.765	5.873
Futures Price Strip, 2010$/Mcf				3.994	4.477	4.694	4.858	5.034	5.253	5.534	5.844										

Source: California Energy Commission, Energy Information Administration, Chicago Mercantile Exchange.

Price Elasticities by Sector

Table 3 shows the price elasticities by sector utilized in the North American Market Gas-Trade (NAMGas) model.

Table 3: Price Elasticity by Sector

NAMGas Model: Elasticity by Sector	
	Price
Sector	Elasticty
Residential	0.5297
Commercial	0.5331
Transportation	0.5331
Industrial	1.2365
Power Generation	0.7963

Source: Baker Institute.