PACIFIC GAS AND ELECTRIC COMPANY
Long-Term Procurement Plan 2010 OIR-Track I
Rulemaking 10-05-006
Data Response

PG&E Data Request No.:	ED/IOU-PGE-006		
PG&E File Name:	LTPP 2010 OIR TI_DR_ED/IOU-PGE-006-Q01		
Request Date:	July 21, 2011	Requester DR No.:	N/A
Date Sent:	July 29, 2011	Requesting Party:	Energy Division
IOU Witness:	Various	Requester:	Kevin Dudney

QUESTION 1

Energy Division requests that the Joint IOUs perform an additional analysis of the transmission actually needed for each of the seven scenarios in order to **provide a revised version of Table 42[1] showing different transmission costs for the different scenarios**. This analysis should seek to describe the actual transmission costs associated with the different generation portfolios of the different scenarios. The costs of transmission projects already permitted by the CPUC may be included in all of the scenarios, but the cost of projects that require but have not yet received CPUC approval should be included in only those scenarios under which they would be heavily used, according to the transmission inputs and assumptions in the 33% RPS Calculator. In order to support the revised Table 42, the IOUs should provide documentation from the Evaluation Metrics Calculator (EMC) demonstrating the calculations used and the different assumptions between the different scenarios. At a minimum, this documentation should include:

- A copy of the values used on the newTx tab[2] of the EMC for each scenario, and
- A short narrative description of the reasoning for the specific transmission lines/costs selected for each scenario.

ANSWER 1

The CAISO is ultimately responsible for identifying new transmission projects needed to reliably operate a grid containing resources required to meet a 33% RPS requirement. As stated in the Joint IOU Supporting Testimony, Exhibit IOU-1, the transmission facilities needed and identified by the CAISO did not vary among the four scenarios studied by the CAISO in its March 24, 2011 Draft 2010/2011 Transmission Plan: a High

[1] Page A-68 of Appendix A of the Joint IOU testimony.

[2] Specifically rows 17 and greater

Utilization scenario, a High Distributed Generation (DG) scenario, a High Out-of-State scenario, and a Hybrid scenario. Please see Section 5.1.6 (beginning at p 253) in the CAISO board approved 2010-2011 transmission plan for the CAISO assessment of the renewable delivery potential for each of its proposed LGIP transmission lines under each of these renewable portfolios.

The CAISO's 2010-2011 transmission plan seeks to directly address the question of what transmission to build given the uncertainty in the composition of the renewable generation portfolio. The CAISO's plan is based on a "least regrets" approach, which the CAISO defines as:

"[A general least regrets approach] is intended to balance the objective of developing sufficient transmission to meet the 33% renewable energy target with the potentially competing objective of minimizing the exposure of transmission ratepayers to potential stranded investment due to under-utilized transmission, in the context of significant uncertainty about the timing and location of new renewable resources. The approach entails distinguishing, based on the best available information about new resource development, between needed transmission facilities that present relatively low risk of under-utilization versus ones that should be reconsidered in a later planning cycle when there is greater certainty about the resources that will use the facilities."

Notwithstanding, the IOUs, their consultant E3, and the CPUC Energy Division (CPUC ED) held a conference call on July 27, 2011 during which CPUC ED requested E3 to examine the effect of excluding the costs of specific transmission lines in each of the CPUC-Required Scenarios upon the costs to ratepayers. Figure 1 shows the transmission lines that were included in the LTPP results filed by the IOUs on July 1, 2011 (based on the CAISO transmission plan) and the lines that the CPUC ED requested E3 to exclude from the updated calculation.

Figure 1. Summary of the transmission line costs included in the Evaluation Metrics for the CPUC-Required Scenarios as modeled in the IOU's LTPP filing and as specified by the CPUC ED.

	Tx Assumptions Used in IOU LTPP Filings				Tx Assumptions as Specified by CPUC Energy Division			
Transmission Project*	Trajectory	Environmental	Cost	Time	Trajectory	Environmental	Cost	Time
Sunrise Powerlink	x	x	x	x	x	x	x	x
Tehachapi Transmission Project	x	x	x	x	x	x	x	x
Colorado River - Valley 500 kV Line	x	x	x	x	x	x	x	x
Eldorado - Ivanpah 230 kV Line	x	x	x	x	x			
Borden Gregg Reconductoring	x	x	x	x		x		
South of Contra Costa Reconductoring	x	x	x	x	x	x	x	
Pisgah - Lugo	x	x	x	x	x			
West of Devers Reconductoring	x	x	x	x				
Carrizo Midway Reconductoring	x	x	x	x	x	x	x	x
Coolwater - Lugo 230 kV Line	x	x	x	x				
Mirage - Devers 230 kV Reconductoring (Path 42)	x	x	x	x				

An 'x' indicates that the cost of the specified project was included in the CSA revenue requirement

For each of the CPUC-Required Scenarios, annual and NPV revenue requirements were recalculated excluding the lines as specified in Figure 1 from the calculations. The effect of removing these lines from the calculation of the revenue requirement is shown in Figure 2 on the next page.

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Figure 2. Impact of the exclusion of specified transmission projects (as requested by the CPUC ED) on the annual and NPV revenue requirements for the Combined Service Area.

	Revenue Requirement Using Tx Assumptions Used in IOU LTPP Filings				Differences in Revenue Requirement Due to Removing Tx Projects per the CPUC Energy Division's Request			
Period	Trajectory	Environmental	Cost	Time	Trajectory	Environmental	Cost	Time
NPV, 2011-2020	$ 256,645	$ 256,976	$ 255,614	$ 256,835	$ (511)	$ (1,133)	$ (1,150)	$ (1,220)
NPV, 2011-2030	$ 423,491	$ 426,343	$ 420,487	$ 422,301	$ (1,106)	$ (2,275)	$ (2,280)	$ (2,386)
2011	$ 30,422	$ 30,417	$ 30,435	$ 30,430	$ (1)	$ (4)	$ (4)	$ (4)
2012	$ 32,537	$ 32,528	$ 32,558	$ 32,552	$ (2)	$ (22)	$ (22)	$ (22)
2013	$ 33,474	$ 33,475	$ 33,501	$ 33,502	$ (5)	$ (68)	$ (68)	$ (82)
2014	$ 34,453	$ 34,509	$ 34,473	$ 34,537	$ (22)	$ (89)	$ (89)	$ (102)
2015	$ 35,673	$ 35,387	$ 35,536	$ 35,949	$ (47)	$ (139)	$ (139)	$ (152)
2016	$ 35,879	$ 35,772	$ 35,737	$ 36,120	$ (102)	$ (232)	$ (232)	$ (244)
2017	$ 36,371	$ 36,380	$ 36,116	$ 36,429	$ (153)	$ (291)	$ (298)	$ (310)
2018	$ 36,446	$ 36,708	$ 36,271	$ 36,492	$ (153)	$ (288)	$ (294)	$ (306)
2019	$ 37,008	$ 37,190	$ 36,489	$ 36,702	$ (153)	$ (285)	$ (291)	$ (303)
2020	$ 37,280	$ 37,809	$ 36,761	$ 36,965	$ (149)	$ (279)	$ (285)	$ (297)
2021	$ 36,877	$ 37,409	$ 36,364	$ 36,562	$ (147)	$ (274)	$ (280)	$ (291)
2022	$ 37,212	$ 37,747	$ 36,704	$ 36,895	$ (144)	$ (269)	$ (275)	$ (286)
2023	$ 37,590	$ 38,128	$ 37,087	$ 37,272	$ (141)	$ (264)	$ (270)	$ (281)
2024	$ 37,872	$ 38,414	$ 37,375	$ 37,553	$ (139)	$ (259)	$ (265)	$ (276)
2025	$ 38,444	$ 38,988	$ 37,970	$ 38,126	$ (136)	$ (255)	$ (260)	$ (271)
2026	$ 39,036	$ 39,698	$ 38,649	$ 38,791	$ (134)	$ (261)	$ (256)	$ (266)
2027	$ 39,718	$ 40,461	$ 39,339	$ 39,471	$ (131)	$ (270)	$ (251)	$ (261)
2028	$ 40,413	$ 41,150	$ 40,042	$ 40,165	$ (129)	$ (269)	$ (247)	$ (257)
2029	$ 41,250	$ 41,871	$ 40,756	$ 40,870	$ (134)	$ (267)	$ (242)	$ (252)
2030	$ 42,169	$ 42,630	$ 41,770	$ 41,620	$ (143)	$ (266)	$ (267)	$ (247)

All costs expressed in millions of 2010 dollars