**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans	R.13-12-010 (Filed December 19, 2013)

COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON THE ENERGY DIVISION'S DECEMBER 18, 2013, WORKSHOP MATERIALS

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Pursuant to the schedule identified by the December 19, 2013, e-mail ruling of the assigned Administrative Law Judge (ALJ), Pacific Gas and Electric Company (PG&E) provides these comments on the materials presented by the Energy Division at the December 18, 2013, workshop on planning assumptions and scenarios for use in the California Public Utilities Commission's (Commission) 2014 long-term procurement plan (LTPP) proceeding and the California Independent System Operator's (CAISO) 2014-2015 Transmission Planning Process (TPP), as well as related materials subsequently posted on the Commission's website.[1/]

PG&E provides responses to the ten questions posed by the assigned ALJ in the December 19, 2013, Ruling, as well as several general comments.

Due to the timing of the issuance of the proposed planning assumptions and scenarios over the holiday season and the relatively short amount of time provided to review posted materials, PG&E was unable to complete a full review of all materials prior to the submission of these comments. PG&E encourages the Commission to provide additional opportunities to provide feedback on the proposed planning assumptions and scenarios. In the 2012 LTPP, many months of discussion occurred before a decision was adopted on assumptions and scenarios.[2/] While it may not be necessary to provide the same amount of discussion on planning

1/ On December 11, 2013, various materials supporting the December 18, 2013, workshop, including the Summary of Renewable Portfolio Standard (RPS) Portfolios, the Scenario Matrix, and a Planning Assumptions and Scenarios document, were posted. Ten questions to be addressed in parties' comments were also circulated by the ALJ on December 19, 2013, along with the supporting materials. On December 26, 2013, various materials supporting the December 18, 2013, workshop, including the Scenario Tool, an updated Scenario Matrix, an updated Summary of RPS Portfolios, Workshop Slides, and an updated Planning Assumptions and Scenarios document were posted. On December 31, 2013, materials supporting the Renewable Portfolio Standard's Calculator were posted. These materials are located at: http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm and http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/2012+LTPP+Tools+and+Spreadsheets.htm.

2/ The first Energy Division staff workshop on scenario planning in the 2012 LTPP occurred over a two-day period on April 11-12, 2012. Energy Division staff's straw proposal on LTPP planning standards was then issued on May 10, 2012. Several workshops and opportunities to comment were provided before a ruling on standardized planning assumptions was issued on June 27, 2012. On August 2, 2012, Energy Division staff issued their straw proposal on 2012 LTPP scenarios. Again, several workshops were held and opportunities to comment were provided before a decision adopting assumptions and scenarios was issued.

assumptions and scenarios in this LTPP, some additional time is warranted given the complexity of these topics.

I. ANSWERS TO QUESTIONS POSED BY THE ASSIGNED ALJ

1. Is the current range of scenarios sufficient to cover current policy issues facing the CPUC?

Section 3, "Preliminary Scoping Memo," of the Order Instituting Rulemaking for the 2014 LTPP recognizes that one of the issues to be addressed in this LTPP is to "'[i]dentify CPUC-jurisdictional needs for new resources to meet local or system resource adequacy (RA), operational flexibility, or other requirements and to consider authorization of IOU procurement to meet that need."[3/] PG&E believes that the high load and the trajectory scenarios are the best scenarios to run, as they will provide a reasoned basis for the Commission to evaluate incremental resource needs and consider any necessary procurement authorization based on current regulatory policy. PG&E makes the following two recommendations regarding adjustments to the high load and trajectory scenarios:

1. For the scenarios, given the significant reduction of firm southwest imports of coal into the CAISO through the planning horizon, imports should be reduced from the current default of 13,396 megawatts (MW) (identified in Scenario Tool as "ISO available import") of availability to the more conservative value of 10,350 MW (identified in Scenario Tool as "CEC net interchange").[4/]
2. For the high load scenario, the assumptions for hydropower generation should represent "dry" conditions in order to fully evaluate potential stress on the system

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3/ R.13-12-010, p. 8.

4/ The current version of the Scenario Tool (ScenarioTool2014inExcelv1.xlsx) includes three options for Imports: 1) ISO max import; 2) ISO available import; and 3) CEC net interchange. Based on the Proposed Planning Assumptions and Scenarios document, the CAISO available import capability for loads in its control area assumption is the current default value for all scenarios (*See* "Attachment Planning Assumptions and Scenarios for use in the CPUC 2014 Long-Term Procurement Plan Proceeding and CAISO 2014-15 Transmission Planning Process," p. 17). PG&E recommends that the default value be modified to CEC net interchange.

under high load conditions. The CAISO and the Commission should work with stakeholders to determine specific values of hydropower used in the high load scenario.

Parties should be allowed to present their own analysis based on alternative scenarios. This will help the Commission make an informed decision that takes into consideration the range of factors that parties consider important.

On a broader level, the proposed scenarios cannot provide the Commission with sufficient information to evaluate long-term energy policy issues such as the comparison of alternative pathways to achieve greenhouse gas (GHG) reduction in the state. For example, there are trade-offs between obtaining additional reductions in GHG emissions via increasing the levels of electricity generated from qualifying renewable sources of power beyond the current 33 percent level, versus obtaining GHG reductions via promoting electrification across other emitting sectors in California. In addition, there are trade-offs inherent in using technologies that can offer only limited near-term reductions, such as fossil fueled topping-cycle combined heat and power (CHP).[5/]

If the Commission chooses to evaluate these broader policy topics in this LTPP, a broader analytic framework will be necessary, one that has the explicit objective of evaluating how to obtain GHG emissions reductions at lower cost, and with less reliability and operational flexibility impacts, than the policy alternatives represented by scenarios currently being proposed. In order to evaluate this trade-offs, it will be necessary to identify and develop metrics associated with each policy issues.

2. ***Are there any technical errors in the proposed scenarios, scenario tool, or RPS Calculator? For any identified errors, please be very specific in your comments including the location of the error and the correct value, including the source for the***

5/ In California, the electric grid continues to become cleaner due to Assembly Bill 32 and other related policies. As a result, fossil fueled topping-cycle CHP is unlikely to be useful as a GHG reduction measure in California post-2020. PG&E supports affordable bottoming-cycle and renewable-fueled CHP and recognizes that these CHP configurations can reduce GHG emissions.

revised value. If appropriate, please provide a revised spreadsheet showing any corrected values. Some example questions to consider in identifying factual errors are:

At this time, PG&E has only been able to conduct a preliminary review of the various supporting materials provided with the proposed planning assumptions and scenarios documentation, including the Scenario Tool and the RPS Calculator. PG&E will continue to review these materials, and will bring any material, technical errors to the attention of the Energy Division if identified.

a. Are any resources counted twice or inappropriately left out of the analysis?

The Scenario Tool does not display the MW of "Additional RPS Resources" needed to maintain the 33 percent target for the years 2025-2034 under any scenario.[6/] While the Proposed Planning Assumptions and Scenarios document describes a method to forecast these RPS additions,[7/] without seeing the results it cannot yet be determined that the methodology will be implemented appropriately.

b. Are any numbers cited in the proposed scenarios or spreadsheets inaccurate relative to the intended sources?

Not that PG&E is aware of at this time.

c. Are there any errors in the renewable generation project data in the 33% RPS Calculator?

Not that PG&E is aware of at this time. However, PG&E does include recommendations related to values included in the RPS Calculator in Section II.E of these comments.

3. Should Diablo Canyon be assumed online or retired in the Trajectory case?

Diablo Canyon Power Plant should be assumed online in the trajectory scenario.

4. Is the treatment of energy storage for capacity value reasonable?

PG&E has no objection to assuming that the transmission-level storage targets adopted in

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6/ Scenario Tool, "Supply Individual Assumptions" tab, rows 68-73.

7/ *See* "Attachment Planning Assumptions and Scenarios for use in the CPUC 2014 Long-Term Procurement Plan Proceeding and CAISO 2014-15 Transmission Planning Process," p. 15.

D.13-10-040 are available and presumably counted as capacity in power flow studies in 2024, and that 425 MW for distribution-connected storage and 200 MW of customer-side storage will not count as capacity in power flow studies. However, as PG&E described in its recent 2012 LTPP Track 4 reply brief, it should not be the end of the matter to simply assume the existence and effectiveness of a not-yet-existing resource that has yet to be fully evaluated. To the extent that the 2014 LTPP analysis assumes the existence and effectiveness of *any* resources that do not yet exist, the actual development of these assumed resources should be tracked, and mid-course corrections made as necessary to ensure that the needs are actually met, and the electric system operates reliably.

If recent LTPP proceedings provide a guide, the Commission and the parties will not have the time or the resources to conduct interim-year analysis. Therefore, the interim-year assumptions for storage are probably not particularly important for the purposes of this proceeding. PG&E notes, however, that they assume very aggressive development of storage resources.[8/] Related, the Proposed Planning Assumptions and Scenarios document does not capture D.13-10-040 completely accurately. While D.13-10-040 sets a procurement target of 700 MW of transmission-connected storage by 2020, the full amount of these MW need not be installed and delivered to grid until the end of 2024.[9/]

5. ***For existing resources that do not have announced retirement dates, Staff may assume a resource retires based on facility age. Facility age is calculated from Commercial Online Date (COD), but the COD may not be available for some resources. If no COD is available, is it reasonable to assume the resource does not retire within the planning***

8/ If interim year assumptions do have a significant effect on the analysis here, then the Energy Division's proposal should be modified. Given that it could take several years for a storage technology to begin delivery after contract solicitation and approval, the storage targets should be assumed to be achieved in a more gradual fashion with a relatively larger amount of resources coming online in the later years closer to 2024 to meet the end-of-2024 delivery targets.

PG&E also notes that the Proposed Planning Assumptions and Scenarios document misstates D.13-10-040 when it states that the maximum size of storage projects that count towards the target is 50 MW. This limitation only applies to pumped storage projects. Non-pumped storage projects may exceed 50 MW.

9/ D.13-10-040, Appendix A, p. 1.

horizon? If not, please provide an alternate methodology and justification from a public data source as needed.

PG&E is comfortable with the process used in the 2012 LTPP. There, for existing resources that do not have announced retirement dates, additional public information on ccommercial onine dates was used, where available, to supplement information available from the Master CAISO Control Area Generating Capability List to determine potential retirements based on facility age. If no commercial online date is available for a resource, it is reasonable to assume that the resource does not retire within the planning horizon.

6. ***How should the capacity value of energy storage, demand response, and demand side resources (PV, CHP) be allocated to small geographic regions and/or busbars and how should the capacity value be adjusted to account for locational and operational characteristics uncertainty?***

Current LTPP modeling techniques for analyzing system reliability or operational flexibility do not use assumptions about the location of resources within "small geographic regions and/or busbars." Nor is it clear that such refinements are needed.

However, for TPP studies, the location (busbar level) and the characteristics of the resources are required to assess the reliability impact and to meet the Western Electricity Coordinating Council/North American Electric Reliability Corporation (WECC/NERC) modeling requirements. The location and the characteristics of the resource will greatly determine the impact of the resource on the local capacity needs and therefore different capacity values and sensitivities should be considered. The different capacity values and sensitivities should be based upon the technology types and their performance characteristics. For example, since the impact of storage will be different in charging (acts as a load) and discharging (acts as a generator) modes, the sensitivity should look at the different modes of operation. For TPP-related assumptions, PG&E's recommendation is to keep the technical modeling and assumptions development at WECC and CAISO and work through the existing CAISO stakeholder process.

7. ***Decision 13-10-040 established storage goals for each of three categories – transmission, distribution, and customer-side of the meter – but does not specify the***

function(s) to be provided. Should storage modeling be focused on deep multi-hour cycling to support operational flexibility or rapid cycling for ancillary services? How should the production profile of each category of storage identified in the CPUC Storage Target Decision be modeled – as a fixed profile or as a dispatchable resource?

PG&E is not able to answer this question at this time. At this time it is not known which storage projects will be offered or selected as a result of the storage targets established by D.13-10-040. Projects offered in solicitations are generally selected based on net cost, taking into account both costs and benefits. As noted above, the actual development of new resources should be tracked, and mid-course corrections made as necessary to ensure that their contribution in meeting the system needs are accounted for when better information becomes available.

8. ***Should incremental small PV and small CHP on the customer side of the meter be modeled as demand-side load reduction or supply side generation? How should the production profile of each resource type be modeled? Should the same modeling convention be used in all 2014 LTPP and 2014-15 TPP studies or may specific studies make this decision in a manner best suited to the topic being studied?***

Ideally, small behind the meter CHP should continue to be modeled as a reduction to load, but small behind the meter PV (both embedded and incremental) should be modeled as a supply resource. Therefore, for system reliability and operational flexibility need studies in the 2014 LTPP, PG&E recommends modeling small behind the meter PV as a supply resource in order to better account for the impact of increased intra-hour variability of net load created by intermittent PV generation added to the customer side of the meter.

However, since power flow studies require the resources be modeled at the busbar level, unless the location and the resource characteristics are available, PG&E recommends modeling the small behind the meter PV for local reliability studies by subtracting the expected PV generation for the study hour from the load. This approach is consistent with the California Energy Commission's (CEC) current load forecast methodology.

9. ***Is the forecast of incremental small PV (beyond what is embedded within the IEPR forecast) on the demand side reasonable? If not, please provide an alternate forecast and justification from a public data source as needed.***

PG&E does not object to the Energy Division's proposal to not include incremental small

PV in the trajectory or high load scenarios. Nor does PG&E object, for the purposes of the 2014 LTPP and 2014-2015 TPP, to the Energy Division's proposal to include incremental small PV, on the demand-side, for the proposed high DG and expanded preferred resources scenarios as well as the base TPP policy and economic studies scenarios.

However, PG&E notes that Energy Division could support a scenario with higher demand-side PV. By 2020, the forecast of incremental small PV on the demand side being proposed by the Energy Division is substantially lower than the "5% NEM Cap Scenario" in a recent report by Energy+EnvironmentalEconomics (E3 Report).[10/] Also, as noted in the California Energy Demand (CED) Final Staff Report, the residential PV adoption model underlying the Integrated Energy Policy Report (IEPR) forecasts do not capture the strong economic incentives for small demand-side PV provided by tiered and time-of-use residential rates nor the potential impact of zero net energy policies.[11/]

Also worthy of noting regarding the solar PV assumptions, the peak demand impact factor assumed for demand-side PV in the Scenario Tool (47% of nameplate capacity) is higher than what other public documents support.[12/]

10. Is the forecast of incremental CHP on the demand side and the supply side reasonable for the scenarios that include those forecasts? If not, please provide an alternate forecast and justification from a public data source as needed.

PG&E concurs with the Energy Division's proposal to begin with the base assumption of

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10/ The 5% NEM CAP case in the E3 Report projects 2,566 MW in 2020 in PG&E's service territory compared to 1,943 MW in the CEC's Low Demand (High PV). *See* the "Forecast" Tab in the E3 NEM Summary Public Model http://www.cpuc.ca.gov/NR/rdonlyres/AD52FE7A-E283-4AB8-BCB2-87DF56D7443B/0/E3NEMSummaryTool.xlsm case for the PG&E Planning Area (which is approximately 10% larger than PG&E's service territory).

11/ *See* "California Energy Demand 2014-2024 Final Forecast,", Volume I , Appendix B, p. B-14. Located at: http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC-200-2013-004-SF-V1.pdf

12/ For example, the 2010 California Solar Initiative Impact Evaluation Report included a 70th Percent Exceedence analysis which showed that South-facing fixed tilt PV systems had a value around 33% of nameplate capacity, lower than the values for West-facing and tracking systems. pp. 6-13. Located at: http://www.cpuc.ca.gov/NR/rdonlyres/E2E189A8-5494-45A1-ACF2-5F48D36A9CA7/0/CSI_2010_Impact_Eval_RevisedFinal.pdf.

zero new supply-side CHP in all scenarios except the expanded preferred resources scenario. With respect to the expanded preferred resources scenario, the Energy Division proposes to include some new supply-side CHP. As previously stated, the expanded preferred resources scenario cannot provide the Commission with sufficient information to evaluate long-term energy policy issues. A broader analytic framework would be necessary to measure the reliability, cost, and environmental trade-offs of various alternative paths to achieve GHG reductions. To the extent that the Commission decides to provide a broader analytical framework to analyze alternative policy scenarios, PG&E does not object to the inclusion of some new supply-side CHP in the expanded preferred resources scenario. However, the amount should be reduced from what is proposed by the Energy Division.

The Energy Division proposes to use "high" incremental CHP assumptions in the expanded preferred resources scenario. As is discussed in the Proposed Planning Assumptions and Scenarios document, the high estimate used by the Energy Division is derived from the "high case" market penetration from a 2012 report prepared by ICF International.[13/] As stated in previous comments to the CEC, the 2012 ICF report overestimates the potential for CHP in California.[14/] Therefore, PG&E recommends that the ICF "medium case" estimate be used for the high incremental CHP assumption in the expanded preferred resources scenario. PG&E's proposal is similar to what was approved in the 2012 LTPP assumptions for supply-side CHP.[15/]

With respect to demand-side CHP, PG&E supports using the 2013 IEPR demand forecast

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13/ *See* "Attachment Planning Assumptions and Scenarios for use in the CPUC 2014 Long-Term Procurement Plan Proceeding and CAISO 2014-15 Transmission Planning Process," pp. 11, 13.

14/ In summary, ICF based its potential analysis on usage patterns and business type, but ignored fundamental physical barriers, such as space limitations or age of the building. PG&E comments - Winn, V. J. (2012), "2012 Integrated Energy Policy Report Update: Combined Heat and Power: Comments of Pacific Gas and Electric Company on Combined Heat and Power in California." Located at: http://www.energy.ca.gov/2012_energypolicy/documents/2012-02-16_workshop/comments/Pacific_Gas_and_Electric_Company_Comments_2012-03-12_TN-64134.pdf.

15/ R.12-03-014, "Assigned Commissioners Ruling on Standardized Planning Assumptions," pp, 17–18.

of non-PV self-generation resources as the starting point.[16/] These estimates are realistic and represent business-as-usual growth of demand-side CHP resources in California. Similar to PG&E's comments above, use of the 2012 ICF CHP report for assumed incremental demand-side CHP overstates the potential growth for new CHP resources. Therefore, PG&E recommends that the "Low Incremental CHP" assumption be removed for scenarios 1c (Base – TPP Policy Studies), 1d (Base – TPP Economic Studies), and 4 (High DG). Further, for the expanded preferred resources scenario PG&E recommends that the "High Incremental CHP" currently reflected in that scenario be replaced with values derived from the "medium case" of the ICF report. PG&E's proposal is similar to what was approved in the 2012 LTPP assumptions for demand-side CHP.[17/] Additionally, the capacity factor assumed for demand-side CHP resources should be adjusted to reflect real world performance of CHP units observed in the Self-Generation Incentive Program (SGIP) data.[18/]

II. GENERAL COMMENTS

A. The Trajectory And High Load Scenarios Should Be Given The Highest Priority

PG&E recommends that the trajectory and high load scenarios be given the highest priority as those two scenarios will provide the most useful information regarding likely resources needs in 2024.

16/ *See* "California Energy Demand 2014-2024 Final Forecast," Volume I , Table 10, pp. 40-41. Located at: http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC-200-2013-004-SF-V1.pdf.

17/ R.12-03-014, "Assigned Commissioners Ruling on Standardized Planning Assumptions," pp, 17–18.

18/ Evaluation reports on the SGIP found that the operational capacity factor of small CHP installed under SGIP were well below the level of performance expected based on manufacturer's specifications. "Self-Generation Incentive Program Eleventh – Year Impact Evaluation Report." Located at: http://www.cpuc.ca.gov/NR/rdonlyres/EC6C16C5-9285-4424-87CF-4A55B0E9903E/0/SGIP_2011_Impact_Eval_Report.pdf.

B. The Results Of Track 1 And Track 4 Of The 2012 LTPP, As Well As D.13-03-029, Should Be Reflected In The 2014 LTPP Analysis

It is unclear what amount and type of resources the Energy Division is proposing to include in the various proposed scenarios for authorized resources from D.13-02-015[19/] (Track 1 of the 2012 LTPP) or D.13-03-029[20/] (San Diego Gas and Electric Company Local Capacity Requirement Decision). Nor is it clear what amount and type of resources the Energy Division is proposing to include for any procurement authorization resulting from the pending Track 4 of the 2012 LTPP, even though Track 4 demonstrates an additional several thousand MW of incremental local capacity reliability need beyond the resources authorized in D.13-02-015 and D.13-03-029. Assumptions for recent procurement authorization are not discussed in the Proposed Planning Assumptions and Scenarios document.

However, the Scenario Tool does include an option for "Authorized Procurement" of new resources. The default value is zero with options for "2012 LTPP Track 1" and "2012 LTPP Track 1 + Track 4." Both of the non-zero options include 1,400 MW of additional resources beginning in 2022. Given that the default value of "Authorized Procurement" of new resources is zero MW, PG&E assumes that this is Energy Division's current proposal.

PG&E disagrees with this approach. The Energy Division should make more reasoned assumptions about anticipated resources based upon the applicable Commission decisions. For example, in the 2012 LTPP the CAISO completed preliminary analysis for Track 2 (system needs) that included 1,050 MW of new local capacity generation for Southern California Edison Company (SCE) (1,000 MW of gas-fired resources and 50 MW of storage resources) and 343

19/ D.13-02-015 ordered SCE to procure 1,400 to 1,800 MW of local generation capacity (at least 1,000 MW and up to 1,200 MW of gas-fired resources, 50 MW of storage resources, and 150 MW to 600 MW of preferred resources) in the Los Angeles basin local reliability area by 2021 and 215 to 290 MW of local generation capacity in the Moorpark sub-area of the Big/Creek/Ventura local reliability area by 2021. *See* D.13-02-015, pp. 130-131.

20/ D.13-03-029 determined a local capacity requirement need and directed SDG&E to procure 298 MW of local generation capacity beginning in 2018. *See* D.13-03-029, p. 27.

MW of new gas-fired local generation capacity for San Diego Gas & Electric Company (SDG&E).[21/]

PG&E recommends that these amounts be included in the 2014 assumptions, as well as additional amounts to meet the maximum procurement authorization for Track 1 of the 2012 LTPP and anticipated procurement values for Track 4 of the 2012 LTPP. Once a decision is approved for Track 4 of the 2012 LTPP, those assumptions can be updated, if necessary.

Consistent with Energy Division's proposal to include anticipated energy storage resources, the planning assumptions should be modified to reflect the authorized, and anticipated to be authorized, procurement amounts from the 2012 LTPP and D.13-03-029. As PG&E noted above, that should not end the inquiry into whether or not these resources are actually procured and meet the identified needs. The Commission should continue to track the development of the authorized procurement to ensure that it is occurring in a timely manner, or to develop alternative plans as appropriate.

It does not make sense to analyze system needs in the 2014 LTPP by assuming that SCE and SDG&E do not meet their previously identified local capacity requirements needs in a timely manner.

C. Path constraints between zones or "bubbles" within the CAISO should be modeled and accounted for in the operating flexibility studies

PG&E recommends that path constraints between zones or "bubbles" represented in the operating flexibility studies be modeled and accounted for in unit commitment and economic dispatch and use of energy and ancillary services within the CAISO grid. This will allow the CAISO to examine both the capability to move ancillary services from one "bubble" to another and the need for minimum fossil generation in each "bubble" during low net load hours to ensure that the system has the necessary ability to respond to forced outages and the intermittency of wind and solar generation in each zone or bubble. Without sufficient flexible generation

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21/ R.12-03-014, "Energy Division Workshop – Operating Flexibility Modeling," April 24, 2012, p. 16.

committed in low load spring periods, the result may be an unreliable system in each bubble, and potential over-generation conditions may be masked. With unit commitment and dispatch from operating flexibility studies, CAISO can then examine the system's ability to respond to voltage and reactive power system operating requirements, forced outages, and the intermittency of wind and solar generation.

D. If The Expanded Preferred Resources Scenario Is Analyzed, It Should Reflect A Higher Value For Demand Response

As stated above, the two scenarios with the greatest value for informing the LTPP needs assessment are the trajectory scenario and the high load scenario. To the extent that the Commission also conducts additional studies that include the expanded preferred resources scenario, PG&E proposes an additional modification beyond the changed CHP assumptions discussed above. Specifically, PG&E proposes that an incremental amount of demand response, equal to 10 percent of the amount of demand response reflected in the trajectory scenario, be reflected in the expanded preferred resources scenario.

This is consistent with the expanded preferred resource scenario's treatment of energy efficiency, where a higher value is assumed compared to the trajectory scenario. This recommendation is also in alignment with the IEPR Final Draft Report, which suggests that higher amounts of demand response may be achieved.[22/]

E. Depending On The Purposes It Is Used For, The RPS Calculator Should Be Updated

1. The Levelized Cost Of Energy Values Should Be Updated For All Technologies

PG&E appreciates the Energy Division staff's efforts to update the levelized cost of energy (LCOE) values for solar technologies to reflect most current prices. However, since

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22/ *See* "2013 Integrated Energy Policy Report, Final Lead Commissioner Report," December 2013, pp. 5-6. Located at: http://www.energy.ca.gov/2013publications/CEC-100-2013-001/CEC-100-2013-001-LCF.pdf.

LCOE values for other generation resource technologies were not updated in this version of the RPS Calculator, PG&E is concerned that portfolio costs may be skewed if applied to other proceedings. Therefore, PG&E recommends that the RPS Calculator be updated to include most current LCOEs for all technologies in order to accurately reflect current market prices for energy and capacity.

2. Project Details Should Be Included In The PRS Calculator

The current version of the RPS Calculator lacks Renewable Auction Mechanism (RAM) project details seeking interconnection to the transmission system, and instead, accounts for the RAM program prior to determining a RPS net short. Although this methodology does capture the MW, in order to account for actual projects in the CAISO's TPP, PG&E encourages the Energy Division to include all project details in the portfolios created by the RPS Calculator. This level of portfolio detail would inform the CAISO's TPP to ensure appropriate capacity is available for projects seeking interconnection to the transmission system.

3. The RPS Calculator Should Reflect A Distribution Cost For Projects Connected At The Distribution Level

PG&E notes the omission of distribution costs in the RPS Calculator. PG&E recommends that distributed generation RPS resources include a distribution cost, consistent with the fact that transmission-level projects shown in the RPS Calculator include transmission costs.

F. An Additional Round Of Comments On Planning Assumptions And Scenarios Is Appropriate

As discussed at the beginning of these comments, more time should be committed to developing the planning assumptions and scenarios for the 2014 LTPP. Therefore, PG&E proposes that an additional iteration of comments on the proposed planning assumptions and scenarios be added. Under PG&E's recommended approach, the Energy Division would evaluate and consider the points raised in this round of comments, and then circulate a revised set of planning assumptions and scenarios. A second round of comments would follow before adoption of the final planning assumptions and scenarios.

G. Parties Should Be Given The Opportunity To Present Analysis Based On Alternative Scenarios

In its December 18, 2013 presentation, the Energy Division indicated that the assigned Commissioner would issue a ruling on January 31, 2014, adopting planning assumptions and scenarios. Parties should not be limited to consideration of the scenarios set forth in the assigned Commissioner's ruling. Parties should be given the opportunity to present analysis based on alternative scenarios. This will ensure that the Commission has available to it the full range of analysis that the parties to the proceeding consider to be relevant and important.

Respectfully Submitted,

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