Stage 1 GHG Calculator Changes
February 29, 2008

Overview

This document compiles comments made by parties and agency staff on the Stage 1 Greenhouse Gas (GHG) Calculator and the CPUC's "Administrative Law Judges' Ruling Requesting Comments on Modeling-Related Issues" (CFT/JOL/k47 11/9/2007)[1].

This document proposes changes to the Stage 1 model in response to comments and summarizes those comments which will not be incorporated into the revised model. Many of the comments will be accommodated by changing the GHG Calculator, or through sensitivity analysis on an input assumption. However, some of the comments cannot or will not be addressed for a variety of reasons. Some comments suggest making changes to the model which we do not believe would result in substantive changes to the results, are inconsistent with the model's methodology or provide results outside of the scope of the model's designed function of modeling the impact of GHG policy on California consumers' rates and costs. We have tried to prioritize those changes that affect key drivers on the results in 2020. We have also tried to provide clarifications when comments incorrectly interpreted the documentation or referenced materials that were out of date.

Next Steps

The goal of this document is to provide a common platform for discussion of proposed Stage 1 model changes with interested stakeholders. While not comprehensive, we have tried to address all of the substantive comments received to date in this document. Once these revisions to the Stage 1 model have been completed, we hope to hold a workshop on the revised results prior to the April 17th scoping workshop at CARB. If necessary, we intend to schedule a conference call or conference calls to work through modeling issues on specific topics as needed in response to the planned approach.

In addition, the team is developing a written description of the modeling changes necessary for the 'Stage 2' model to accommodate an energy deliverer approach as described in the Proposed Decision of President Peevey in the "Interim Opinion on Greenhouse Gas Regulatory Strategies" mailed on February 8th, 2008.

The comments we received that pertain to issues we plan to address in the Stage 2 modeling effort will be summarized in the 'Stage 2' document; this includes comments on the trading of GHG permits, offsets and allocation or auction of GHG permits in the electricity sector.

[1] A slightly revised version of the Stage 1 GHG modeling documentation was included as Attachment A in the "Administrative Law Judges' Ruling Extending Comment Deadlines and Addressing Procedural Matters" (CFT/JOL/jt2 11/30/2007). The GHG model and associated documentation were also posted by Energy and Environmental Economics, (E3) on their website (at http://www.ethree.com/cpuc_ghg_model.html).

Sources of Comments

This section lists the parties which have provided comments to E3 that are considered in this document:

1. Parties' to R.06-04-009/07-OIIP-01 Comments on Modeling-Related Issues: January 4th, 2008
- Alliance for Retail Energy Markets (AReM)
- California Municipal Utilities Association (CMUA)
- Center for Energy Efficiency and Renewable Technologies (CEERT)
- Division of Ratepayer Advocates (DRA)
- Energy Producers and Users Coalition and the Cogeneration Association of California (EPUC/CAC)
- Green Power Institute (GPI)
- Independent Energy Producers Association (IEP)
- Kenneth C. Johnson, Private Citizen
- Los Angeles Department of Water and Power (LADWP)
- Natural Resources Defense Council and the Union of Concerned Scientists (NRDC/UCS)
- Northern California Power Agency (NCPA)
- Pacific Gas and Electric Company (PG&E)
- PacifiCorp
- Sacramento Municipal Utility District (SMUD)
- San Diego Gas & Electric Company and Southern California Gas Company (SDG&E)
- Solar Alliance
- Southern California Edison Company (SCE)
- Southern California Public Power Authority (SCPPA)
- Western Power Trading Forum (WPTF)

2. Parties' to R.06-04-009/07-OIIP-01 Reply Comments on Modeling-Related Issues: January 18th, 2008
- California Municipal Utilities Association (CMUA)
- Division of Ratepayer Advocates (DRA)
- Energy Producers and Users Coalition and the Cogeneration Association of California (EPUC/CAC)
- Los Angeles Department of Water and Power (LADWP)
- Natural Resources Defense Council, Union of Concerned Scientists, and the Green Power Institute (NRDC/UCS/GPI)
- Pacific Gas and Electric Company (PG&E)
- PacifiCorp
- Sacramento Municipal Utility District (SMUD)
- Southern California Edison Company (SCE)
- Southern California Public Power Authority (SCPPA)
- Western Power Trading Forum (WPTF)

3. CPUC Energy Division Staff

4. CEC Staff

5. Informal stakeholder communication (phone, email, meetings)
- Burbank Water and Power, consultant for
- Energy Producers and Users Coalition/Cogeneration Association of California (EPUC/CAC)
- Glendale Water and Power
- Los Angeles Department of Water and Power (LADWP)
- Natural Resources Defense Council (NRDC)
- Northern California Power Agency (NCPA)
- Pacific Gas and Electric (PG&E)
- Sacramento Municipal Utility District (SMUD)
- San Diego Gas and Electric (SDG&E)
- Union of Concerned Scientists/Center for Energy Efficiency and Renewable Technologies (UCS/CEERT)

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A. *Proposed Changes to Stage 1 Model*

The following list describes the changes that E3 proposes to make to the Stage 1 GHG model in response to stakeholder comments. The second section of this document outlines the variables around which we propose to do sensitivity analysis. The final section responds to comments which, for various reasons explained below, will not be incorporated into the next revision of the model.

1. Allow users to change coal contract expiration dates

Proposed Change: We plan to add additional functionality that will allow users of the GHG calculator to be able to change the contract expiration dates, by year, for key out-of-state coal contracts. This added ability will be used to do sensitivity analysis and will not influence the base case. Our base case will assume that existing contracts run through their existing contract expiration dates. Note that terminating contracts early will not in itself change the WECC generator dispatch. Out-of-state coal plants will be assumed to continue to sell power to non-California regions if economic, and in this case the associated greenhouse gas emissions from the coal plants will be assigned to the non-California west.

Comments: This change is being made in response to the opening comments filed by SDG&E (p. 7), NCPA (p. 10), NRDC/UCS (p. 2) and CEERT (p. 17), which requested modeling the termination of contracts. In their reply comments, PacifiCorp, (p. 4) supported NRDC/UCS's assertion that retirement and repowering of high GHG emitting generators is a valid emission reduction strategy. In their reply comments, SCPPA, p. 8 argued that breach of coal contracts should not be considered a valid emissions reduction measure, as that would result in a bond default on the part of the utility.

2. Modeling of combined heat and power (CHP) generation

CHP will be added as a low carbon resource to the GHG Calculator. Modeling of CHP will involve three principle changes to the GHG calculator.

Proposed Change #1: The first change will be to add the ability for users to increase or decrease the amount of <u>new</u> CHP developed in California. Two types of CHP units will be modeled: small CHP (<5MW) and large CHP (>5MW) developed in California. Both of these resources will include assumptions about the thermal/electric split between fuel consumption and GHG emissions, cost, performance and penetration rate. These assumptions are still under-development. We plan to use the CEC forecast of new CHP in the November 2008-2018 Load Forecast for the 'Business as usual' reference case, and the 'Base Case" from the CEC's 2005 CHP market potential study in our 'Aggressive policy' reference case. The model will allow more or less CHP to be specified in the target cases.

Comments: In their opening comments, SDG&E (p. 7), PG&E (p. 23) and EPUC/CAC, (p. 2-3) requested that CHP be included as a resource in the model. Stakeholders had varying opinions about how to model CHP, as well as how much CHP generation to include in the business-as-usual and aggressive policy reference cases.

For example, PG&E, (p. 24) argued that the CEC's CHP market potential study, "needs to be updated and modified," and that the Aggressive Market Access case of CHP market potential in the state is especially suspect. In contrast, the EPUC/CAC, (p. 3) argued that the Aggressive Market Access case for CHP market potential should be used in the aggressive policy reference case of the GHG calculator, and that CHP should be added consistent with the California Energy Action Plan II's preferred loading order (EPUC/CAC, p. 2-3).

Proposed Change #2: The second major change will improve the way existing CHP is modeled. This will be done in three steps;

1. Identify existing CHP units in the TEPPC database used in PLEXOS
2. Add missing units that are not in the database
3. If data becomes available on the fleet average CHP capacity factors in California, we will adjust operating pattern of CHP units to be 'must run' in PLEXOS at a capacity factor consistent with known operations of large units (note this will probably be done on an average basis since individual unit data is not available). Absent better data, we plan to assume an 85% capacity factor for new large CHP units in the PLEXOS dispatch.

Comments: EPUC/CAC, (p.12) pointed out that the TEPPC database does not include all large in-state CHP generators. EPUC/CAC has provided informal feedback to E3 identifying, to the best of their ability, their client's existing CHP units in the TEPPC database.

Proposed Change #3: The third major change is to adjust accounting for emissions between the electricity sector and thermal use according to an appropriate accounting rule. Which accounting rule will be applied for determining the thermal electric split of CHP units is still being decided, pending guidance from the CPUC, CEC and ARB.

Comments: PG&E (reply comments, p. 9), argues that most CHP capacity in the state, "are subject to PURPA efficiency requirements that are lower than the efficiency of currently available CCGT technology …Specifically, emissions from CHP generation should be compared to emissions from the combination of new gas fired CCGT plus a new gas fired boiler." EPUC/CAC in their reply comments state that, "while EPUC/CAC agree that the model must make assumptions [about how to model CHP], PG&E's recommendations should not be blindly adopted without further technical examination…"

Comments: On-site load can reduce transmission losses and avoid transmission investment; and costs of CHP serving on-site load are not passed on to ratepayers. (EPUC/CAC, p. 2)

Response: The GHG Calculator does include the benefit of reduced transmission losses from new CHP because energy from CHP units is assumed to reduce retail sales, which also reduces transmission and distribution losses, ultimately resulting in reduced system generation. The model will not, however, directly model avoided transmission investment. However, transmission investment savings will materialize to the extent that (1) supply resources that have transmission costs do not need to be procured, and (2) the retail non–generation revenue requirements decline with reductions in retail sales. The

linkage between sales and non-generation revenue requirements is a user input that can be changed to model this sensitivity. In order to model the CHP costs, the model will divide that energy that is provided to the grid and that consumed on-site. Energy sold to the grid by the CHP generator will be a cost to the LSEs, and energy consumed behind the meter will reduce retail sales and will not be a cost.

3. Improved User-friendliness of the GHG Calculator

Proposed Change: E3 will work to improve the user-friendliness of the GHG calculator by adding some explanation directly into the spreadsheet, and by simplifying some of the outputs on the main tab.

Comments: A number of stakeholders, including SCE, (p. 6), NRDC/UCS, (p. 20), SMUD, (p. 7), and WPTF, (p. 7), suggested that the GHG calculator tabs be re-formatted to make the calculations easier to follow, and to make the purpose of the other tabs, besides the main tab, more obvious.

Proposed Change: E3 plans to add a 'recording' function to the GHG calculator, which will capture some of the key variables in a user-defined GHG scenario, each time the 'record' button is hit. These variables will be stored on another tab in the calculator, to allow comparison of these key outputs over different user-defined scenarios.

Comments: This change is being made in response to Green Power Institute's (GPI, p. 6) request that multiple GHG scenarios be comparable on a single sheet.

Proposed Change: E3 plans to add a simplified 'cost override' capability on the main tab, which will enable stakeholders to more easily test alternative scenarios with different resource cost assumptions.

Comments: This change is being made in response to comments from SCPPA, (p. 15) and SDG&E (p. 8) expressing concern about the difficulty of changing key cost assumptions in the GHG calculator.

Proposed Change: In the effort to improve the user-friendliness of the model, we are making the renewable energy resource supply curves easier to adjust and more transparent. However, we are not sure yet whether we can reasonably integrate resource ranking directly in the GHG Calculator. If not, it will be up to the parties to specify their own zonal resource order, if desired, which will require independent analysis.

Comments: This change is being made in response to comments from SCPPA, (p. 14) requesting the ability to perform resource ranking of renewable energy directly in the GHG calculator.

4. PLEXOS verification of results

Comment: Verify the results of the GHG calculator in the Plexos Solutions production simulation model, and document the outcome. (SCE, p. 29) Test the feasibility of wind expansion scenarios in Plexos. (SCPPA, p. 9, WPTF, p. 3, 6)

Response: To the extent that resources are available during the final report, we will run Plexos with a final target case to cross-check the feasibility of the dispatch and the emissions levels.

5. Additional functionality to choose RPS allocation to Load Serving Entities (LSEs)

Proposed Change: The GHG calculator will include a capability for the user to define the renewables portfolio standard (RPS) level that each LSE achieves by 2020. This functionality will override the default assumption that each LSE achieves the same RPS percentage of their retail sales.

Comments: SMUD, (p. 4) suggested that the GHG calculator account for Green Power Pricing programs. SMUD pointed out that this could be achieved in SMUD's case by increasing SMUD's renewable energy in 2020 by 3% to 23% (SMUD, p. 4). The additional flexibility to choose RPS targets by LSE helps to address SMUD's green power pricing concern. E3 does not plan to explicitly model the impacts of green power pricing programs however.

6. Changes to pumping load

Comment: "Not all pumping loads can be reduced to zero at the time of the peak load. A more realistic assumption would be to assume that pumping load drops by 50% (SCE, p. 13).

Response: After consulting with the CEC, we learned that the CEC's annual peak forecast for the pumping load of the Department of Water Resources, the Metropolitan Water Department and the Central Valley Project (WAPA) represents their average hourly load during the summer peak period, defined as mid-June through mid-September, 1- 6 PM. This means that the pumping load peak forecast does not require additional adjustment. In the revised version of the GHG model, no adjustment to CEC's forecast of the pumping load will be made.

7. Updated wind integration costs

Proposed Change: E3 will add the ability for the user of the GHG calculator to adjust wind integration costs more easily.

Comments: Stakeholders submitted varying views regarding the wind integration costs assumed in the reference cases of the GHG calculator. While WPTF argued that the estimates are too low, (p. 4), SCE argued that the costs are about right but that the methodology for calculating costs should be altered, (p. 26-27), and NRDC/UCS (p. 10-11) and CEERT (p. 37) argued that the costs are too high. In general, the GHG calculator allows users to change costs in order to create a user-defined scenario. However, E3 agrees that the calculator should be set-up to more easily allow users to change the wind integration cost assumptions.

Proposed Change: E3 will recalculate the wind integration cost function, replacing the Idaho Power and Avista study numbers used previously, with the stipulated values that the Idaho PUC approved in its settlement stipulations for Idaho Power and Avista on February 20, 2008. In addition, E3 also accepts NRDC's criticism that the slope of E3's regression analysis is steeper than the slopes of most individual studies, resulting in integration costs that are typically lower than the individual study results for lower levels

of wind penetration and higher than the individual study results at higher levels of wind penetration. In recognition of the fact that the GHG analysis is more interested in accurate estimates of costs for high levels of wind penetration than for low levels of wind penetration, E3 has changed regression analysis technique (including a y-intercept in the regression). This results in a reduction of the average slope from 0.3 to approximately 0.1. Figures 1 and 2 below show the results of the new analysis.

Comments: This change is being made in response to comments suggesting changes to the wind intermittency costs made by SMUD, (p. 8), NRDC/UCS (p. 10-11), CEERT, (p. 32-34).

Figure 1. Old and New Wind Integration Costs in $/MWh of Wind Energy Generated, as a Function of Wind Penetration

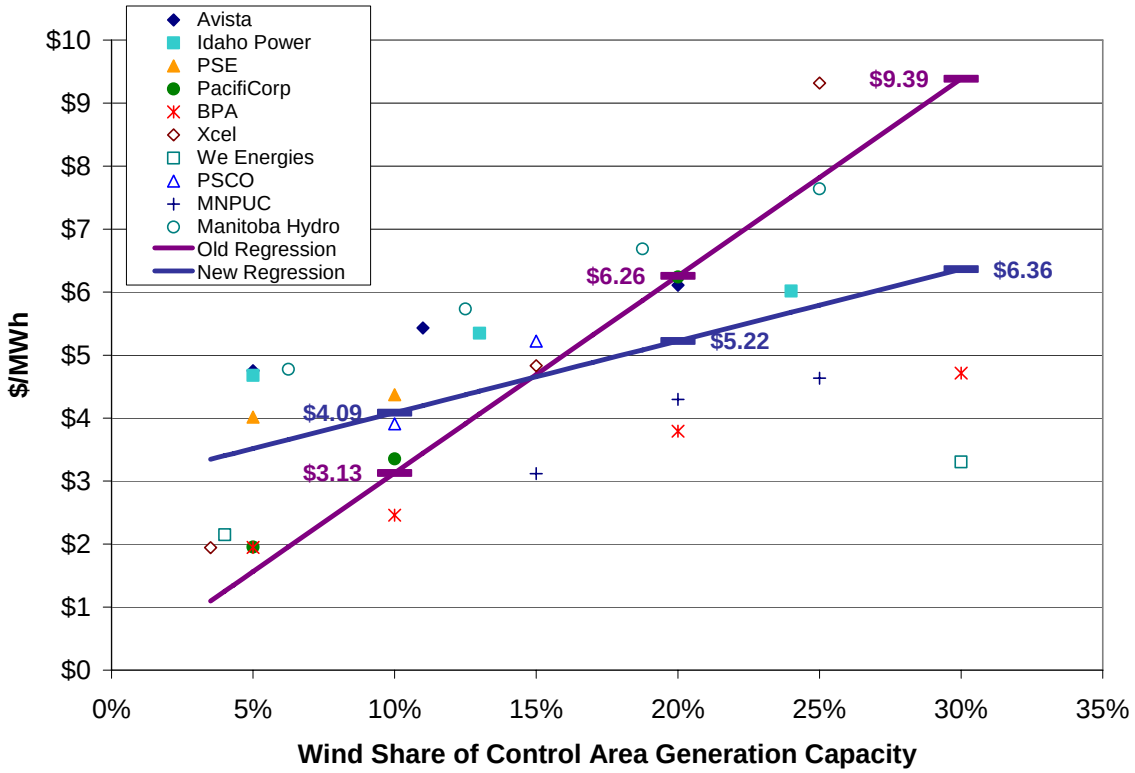
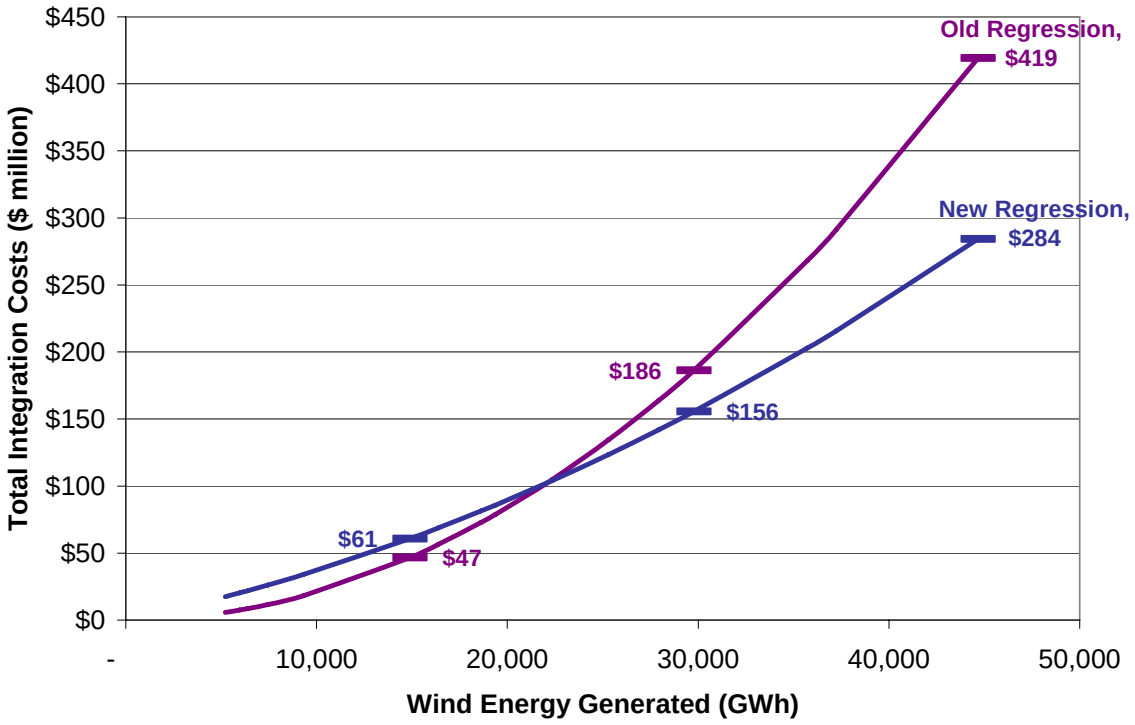


Figure 2. Old and New Total Wind Integration Costs for 50,000 MW Control Area



8. Disaggregate drivers of transmission costs

Proposed Change: E3 will clarify in the calculation how we separate network costs due to load growth from transmission costs due to additional renewable energy build-out. We believe that all of the transmission cost estimates in California are incremental with the possible exception of Tehachapi and Imperial. In these cases, both Tehachapi and Imperial are present in the reference and target cases and the network transmission costs net out. Therefore, an adjustment to the incremental costs will not change the results.

Comments: This clarification is being made in response to comments by CEERT, (p. 37) and NRDC/UCS, (p. 14). CEERT, (p. 37) suggests that the incremental cost of Tehachapi is actually only $900 M.

9. Updated forecast of solar photovoltaic (PV) installation

Proposed Change: The inputs to the GHG Calculator will reflect municipal utilities' solar PV installations as forecast in the CEC's revised November 2007 load forecast. In the aggressive policy reference case additional solar PV, to reach the 3,000 MW of solar PV goal, will be allocated to LSEs based on the ratios of current solar PV installations.

Comments: This change is being made in response to comments from SMUD, (p. 1, 5, 7), and NCPA, (p. 7) and SCE, (p. 18-19), which correctly pointed out that the E3 model should have reflected municipal utilities' solar PV installations.

10. Updated financing assumptions

Summary: SCE suggested modifying the financing assumptions to include a consideration of situations where the book life of a generator is not equal to the actual asset life, to include preferred stock in financing assumptions, as well as other suggestions in Attachment A of their opening comments (SCE, p. 15 & Appendix A). The CEC staff also suggested a change to the IPP equity rate, as described below. The following responses summarize which financing assumptions we plan to adjust.

Proposed Changes:

IOU Preferred stock in finance structure: To better match California IOU assumptions, we propose adding a preferred equity tranche to the IOU capital structure. This is treated as deductible for tax purposes but like equity for regulatory/ratings purposes, therefore the tax gross-up calculation will include preferred stock. Since preferred equity rates are about equal to debt rates, the inclusion of preferred equity will have the effect of lowering the utility WACC.

IOU Deferred taxes: We propose adjusting the rate base for deferred taxes to match California IOU treatment.

IOU debt cost: To better match California IOU assumptions, we propose changing the debt rate to match the average rate currently allowed by the CPUC, rather than the average balance sheet debt rate.

IPP equity rate: We plan to change the equity rate to 15.7% (was 15.8%), consistent with CEC staff comments. This change will slightly increase the debt rate to 7.93% while maintaining the CEC-recommended asset return of 10.26%.

11. Updated load forecast

Proposed Change: The CEC's November 2007 load forecast (CEC-200-2007-015-SF2) will now be the starting point for the GHG calculator load forecast. Previously, the load forecast used the CEC's October 2007 forecast. In addition, users of the GHG calculator will now have the ability to adjust the loss factors applied to the retail sales in order to estimate greenhouse gas savings from improved grid efficiency. Finally, the renewables portfolio standard calculation, California solar photovoltaic program, behind-the-meter combined heat and power (CHP) and energy efficiency achievements will now be applied to the retails sales forecast excluding pumping load.

12. Improved data on generator assignment to LSEs

Proposed Change: E3 is adjusting the generator assignments to LSEs based on the stakeholder information we have received on generator assignment. In addition, we are adding another category of State 'Water Agencies' that includes the California Department of Water Resources (DWR), the Central Valley Project / WAPA, and the Metropolitan Water Department (MWD). This change will mean that the Water Agencies emissions are not allocated to an LSE and the Water Agencies load will not be applied to the Renewable Portfolio Standard (RPS) requirement calculation.

Proposed Change: E3 is working with LSEs to correct the assignment of generators' emissions to LSEs based on contractual agreements or LSE ownership of a generator.

Comments: We have received feedback on generator assignment thus far from SMUD, LADWP, PacifiCorp, PG&E, Burbank Water and Power, Glendale Water and Power and SDG&E. SCE comments, (p. 12-13) that, "SCE has reviewed the [E3 generator assignment] database and at this time offers no specific changes to the assumptions regarding generation assignments made by E3. SCE's review of the generation assignments indicates that E3 is assuming that the majority of the assignments in year 2008 continue into 2020. SCE comments that this assumption is very broad based, e.g. most of contracted transactions effective in year 2008 are probably not extended through 2020. As such, SCE believes that the existing assumptions, as a whole, are best left as is and that making changes that reflect only SCE's perception are inappropriate."

SDG&E (p. 8) expressed concern that the TEPPC list of generators is missing small renewable resources and Qualifying Facilities, which will skew LSE results. It is true that most small sources of generation (under ~5 MW) are not included in the TEPPC database.

13. Updates to energy efficiency assumptions

Proposed Next Step: The energy efficiency supply curves used in the GHG calculator rely on energy efficiency data from studies produced by Itron in 2006 for the investor owned utilities and for SMUD. Itron has been contracted to update the data, and a 2007 version of their California energy efficiency potential study is expected to be released soon. E3 will review the 2007 ITRON energy efficiency study results, if they are released in time for the new data to be incorporated. If the results of the new 2007 study vary significantly from current assumptions used in the 2006 study, we hope to include the new results.

Comments: This proposed next step is based on communication with ITRON and a comment from PG&E, (p. 8-11). PG&E writes (p. 10) that, "E3 should use the 2007 Itron Potential Study for its GHG modeling. Results should be considered interim until the new Itron study, after being publicly reviewed and evaluated, replaces the current assumptions."

Proposed Next Step: E3 has been, and will continue to, work closely with the CEC on determining how the energy efficiency embedded in the CEC's forecast relate to, and compare with, the energy efficiency potential data used in the GHG calculator.

Comment: NRDC/UCS (p. 8) suggested that we work with the CEC to better understand how much energy efficiency is embedded in the load forecast.

14. Electricity and natural gas sectors: updated emissions benchmarking

Comment: SCPPA and SCE stated that E3 should use the most recent CARB emissions inventory to verify GHG calculator emissions output. (SCPPA, p. 14-15, SCE, p. 29)

Proposed Change: E3 plans to incorporate the adopted November 19th, 2007 CARB emissions inventory numbers in the revised GHG model, as an estimate of the electricity and natural gas sectors' proportional sector share of GHG emissions to meet the 1990

baseline target. E3 notes that the final CARB emissions inventory was not yet available when the Stage 1 model v.1b results were released on November 16th, 2007.

15. Updated biomass and biogas heat rates

Comment: "The heat rate E3 has assumed for biomass seems extremely low and the heat rate it has chosen for biogas seems extremely high" (SCE, p. 21).

Proposed Change: E3 relies, to the extent possible, on cost characterizations from the Energy Information Administration (EIA). However, after reviewing alternative sources, E3 agrees that EIA's heat rate assumptions for biomass plants are flawed. E3 has therefore substituted heat rates and capacity factors from the CEC's Cost of Central Station Generation model for the EIA values. Specifically, E3 used the CEC's landfill gas technology (heat rate of 11,566 Btu/kWh, 85% capacity factor) for the "Biogas" category and CEC's "Direct Combustion with Stoker Boiler" (heat rate of 15,509 Btu/kWh, capacity factor of 85%) for the "Biomass" category.

16. Updated wind capacity factors

Comment: NRDC (p. 11-12) and CEERT (p. 35-36) take exception to the 10% wind on-peak capacity factor applied in the model. CEERT recommends the application of the Effective Load Carrying Capacity (ELCC) based approach to compare capacity provided by variable output and conventional resources. "Studies performed for the CEC using this approach to calculate the capacity contribution of California wind resources to the state electric system have found the ELCC of California wind to be in the mid-20% range" (CEERT, p. 35-36). PG&E, on the other hand, states that the analysis in the PG&E 2006 LTPP showed that, "on average, the actual output received during the peak hour in summer months for [existing wind generation] ranges between 0.3% and 7% of wind installed capacity…Therefore, E3's assumption that wind resources operate at a 10% capacity factor seems too high" (PG&E reply comments, p. 7).

Proposed Change: E3 recognizes that, on further analysis of currently available studies, its assumption of 10% on-peak availability for wind is too conservative of an assumption, and agrees with NRDC and CEERT that a higher on-peak availability is warranted for California wind resources. We have therefore changed the value to 20%. E3 notes that other analyses performed have resulted in higher values based on Loss-of-Load Probability ("LOLP") calculations using data from existing California resources. For example, the Intermittency Analysis Project finds on-peak Effective Load Carrying Capability ("ELCC") values of 24-39% of nameplate. However, these studies did not include the period in late July 2006 in which record peak demands and low wind generation were experienced across the WECC. For example, the Northwest Power and Conservation Council finds that "during the extreme heating event of July 24, 2006, the regional wind fleet as a whole generated at 5 to 10 percent of nameplate capacity."[2] The Council recommends that the "Northwest Resource Adequacy Forum (NWRA Forum) should reassess its 15 percent pilot sustained wind capacity value." E3 expects that a newer analysis would result in a value closer to 20% for California wind resources' on-peak capacity.

[2] Northwest Power and Conservation Council, Northwest Wind Integration Action Plan, March, 2007, p. 18.

Comment: NRDC writes (p. 13) that, "…the wind capacity factor assumptions in the E3 model should be increased to be more consistent with the assumptions found in recent sources of wind capacity factor data." Both CEERT (p. 37) and NRDC (p. 11-13) argue that the average capacity factors for wind resources used in the E3 model are too low.

Proposed Response: CEERT and NRDC recommend using capacity factors from the NREL/AWEA Wind Vision report. However, the final report has not yet been made publicly available, so E3 is unable to verify the capacity factors that are claimed for that report. E3 did review a number of public sources of capacity factors. E3's 34% value for a Class 5 wind resource is identical to the value assumed in the CEC's Cost of Generation study. Also, the Northwest Power and Conservation Council currently assumes a 32% capacity factor for wind projects located in the Inland Northwest. This is lower than E3's assumed value for a Class 5 resource and close to E3's assumed 31% for a Class 4 resource. However, EIA's Annual Energy Outlook assumes 45% for Class 6, 40% for Class 5 and 34% for Class 4 in 2010, closer to the NREL values. In light of this, and the comments received, E3 has increased its average capacity factors for wind, so that the capacity factor for a Class 5 resource is now 37%. This results in the following capacity factors for Class 3 – 7 wind resources:

Class 3: 29%
Class 4: 34%
Class 5: 37%
Class 6: 40%
Class 7: 44%

17. Documentation improvements and clarifications

Stakeholders provided a number of comments suggesting ways to improve and clarify the documentation of the GHG calculator. These comments will either be incorporated into the documentation provided in the final GHG calculator report, or are clarified below.

Comment: Many stakeholders requested additional detail on the operating conditions of the electric generation units from the TEPPC WECC database, such as data on must run units, ramp rates, minimum run times, etc. (SDG&E, p. 6, PacifiCorp, p. 21, IEPA, p. 2, PG&E, p. 35)

Response: The operating data of the generators in the TEPPC WECC database is publicly available to members of the WECC. However, the WECC asks that this information not be distributed without their permission. Therefore, stakeholders that are interested in getting more information about the operating conditions of specific electric generators should obtain this information directly from the WECC.

Comment: SCE (p. 7) requested documentation of how the SSG-WI database was been modified for use in Plexos. SCE also requested clarification of the meaning of "PS."

Response: "PS" is an abbreviation for Plexos Solutions, the project team member responsible for the production simulation model used to provide input data to E3 on the dispatch of generators in the WECC. Plexos Solutions, in working with any database for its production simulation model, makes modifications to the database to clean it up for use in the model. We do not believe that documenting all of the small database

adjustments to the SSG-WI data which were required to run Plexos would result in significantly improved transparency to the modeling effort.

Comment: DRA, (p. 4) requested setting up a process to describe how and when the TEPPC data is updated.

Response: E3 and Plexos Solutions use the TEPPC data which the WECC first released in October 2007 and which since has been revised and refined. E3 and Plexos Solutions will use the most up-to-date version of this database whenever possible, such as when the Stage 1 results are revised. The WECC will continue to revise and update this data in its own stakeholder process and therefore E3 does not believe we need to have a parallel process with the same goals. Information about these revisions is available from the WECC.

Question: SCPPA, (p. 12) asked what energy efficiency measures underlie the energy efficiency supply curves. WPTF (p. 6) asked if the empirical data on energy efficiency support the energy efficiency supply curves used in the model.

Response: The data underlying the energy efficiency supply curves used in the GHG model, for all LSEs excepting SMUD, is available on the website of the consulting firm Itron, which produced the data and the supporting energy efficiency potential study: http://www.itron.com/pages/news_articles_individual.asp?nID=itr_008890.xml. The supporting documentation is presented in the Itron 2006 report "California Energy Efficiency Potential Study," available at the same website. The SMUD energy efficiency data was also produced from a similar energy efficiency potential study produced by Itron in 2006. This report, and the supporting energy efficiency data for SMUD, was obtained directly from the utility.

Comment: PG&E suggested that E3 revise the energy efficiency methodology documentation to reflect the switch from measuring the GHG emission savings from net energy efficiency to gross energy efficiency and other changes to the methodology. (PG&E, p. 10)

Response: In the final report the documentation of the energy efficiency methodology will be updated to reflect the latest treatment of net and gross energy efficiency and the most energy efficiency recent numbers employed in the GHG calculator.

Question: SCPPA asked if the wind costs shown in Table CA-3, p. E155 include the cost of firming resources and transmission. (SCPPA, p. 12)

Response: No, the costs in the table specified are busbar costs, and do not include firming or transmission costs.

Comment: SCE asked that E3 explain how transmission losses were treated in the GHG calculator. (SCE, p. 6)

Response: In-state transmission losses are used only to estimate retail sales from the CEC's net energy to load forecast, the loss factor is assumed to be constant at 1.077. In the next version of the GHG calculator, loss factors will vary by LSE, based on the CEC's estimate of loss factors by control area, and the retail sales forecast will be used along with the loss factors, to calculate the load needed for generation. Out-of-state transmission losses, for new transmission, vary by the location and size of the transmission line. These assumptions can be found in the GHG calculator on the "Supply

Curves" tab, column D. Out-of-state transmission loss factors feed into the calculation of new resource build-out costs for resource ranking purposes and also influence the amount of energy delivered into California from new transmission lines (calculated on the "SpecGen" tab of the GHG calculator).

Comment: SCE asked that E3 explain how generation subtractions were done in the GHG calculator (SCE, p. 7).

Response: See Appendix A of the ALJ ruling, section 5, "Ensuring Sufficient Resources to Meet Loads." E3 is happy to answer more specific questions related to generator subtractions.

Comment: SCE asked that E3 document emission rates by fuel type used in the GHG calculator and by Plexos Solutions (SCE, p. 7).

Response: This information will be more thoroughly documented in the final report. Currently, the emissions rates by fuel type used in the GHG calculator and in Plexos Solutions are available on the E3 website, on the spreadsheet titled "Generator Data and Generator Ownership/Contract Assignments to LSEs."

Question: SCE asked if, in the "California Resource Zones" section of Attachment A, renewable resource potential estimates are incremental or total to renewables already developed. (SCE, p. 28)

Response: Renewable resource potentials reported in the "California Resource Zones" section are incremental to currently developed renewable energy.

Comment: SCE stated their belief that 16,000 MW of surplus generation in 2020 is too high (As quoted in write-up "Ensuring Sufficient Resources to Meet Loads") (SCE, p. 13).

Response: It is not clear exactly what number SCE is referring to in this particular comment, however, in general, we plan to maintain the existing methodology which assumes the 2008 reserve margins are maintained through 2020.

Comment: LADWP states that it is not well explained how LSEs are attributed emissions when they have excess generation. (LADWP, p. 6-7)

Response: The model assigns the Plexos incremental CO2 emission rate to any balancing energy (positive or negative). So if an LSE has excess specified GWh, the model reduces their total CO2 emission using the excess GWh times the Plexos incremental CO2 emission rate.

Question: SMUD asked how an LSE's load is met, and at what point renewable energy is added to meet load. (SMUD, p. 4)

Response: An LSE's load is met by basically following California's loading order. First, energy efficiency and other behind-the-meter resources are applied to the LSE's load forecast. Then, renewable energy is added until the LSE has met its RPS target. After this any user-input conventional generation is added. The GHG Model then performs an energy balance by adding or subtracting CCGT units to meet the baseload energy needs, and using the cost and emissions from the Plexos marginal units to balance the energy requirements by TOU period. Finally, the model performs a capacity balance by adding

or subtracting existing or new capacity to meet the residual summer peak demand for each LSE.

Comment: PG&E asked that E3 create a handbook explaining how to perform sensitivity analyses (PG&E, p. 35), and GPI and IEPA asked how to build an entire scenario using all variables (GPI, p. 7, IEPA, p. 3)

Response: E3 will provide documentation explaining how to perform sensitivity analyses within the project resource constraints.

Comment: NCPA pointed out that EE targets are not set by the CEC for the POUs, but by POU governing bodies pursuant to AB 2021. (NCPA, p. 6-7)

Response: E3 acknowledges this error in the E3 energy efficiency documentation. The fact that POU's set energy efficiency targets pursuant to AB 2021 will be reflected in the final report.

Comment: SCE asked how transmission ratings and nomograms are treated in the WECC database. (SCE, p. 12)

Response: This information is available to members of the WECC through the TEPPC WECC database documentation.

Comment: PacifiCorp asked that E3 create matrices showing E3's modeling assumptions compared to key assumptions used in utility IRPs: electricity load growth, fuel supply and price curves (particularly natural gas price and supply curves), energy efficiency supply curves, new generation build costs, emission control costs, nuclear and hydro re-licensing, and environmental regulatory policy constraints. (PacifiCorp, p. 22)

Response: The utility IRPs contain numerous LSE-specific assumptions, have different vintages, may not be available publicly for all LSEs, and are not consistent across utilities. In order to develop a regional model that includes all of the LSEs, a consistent set of assumptions has been made and documented. While some detail may be lost, we believe that our approach provides reasonable results for the GHG policy decisions being addressed in R.06-04-009.

Comment: WPTF wrote that, "No specific documentation is provided on the development of the target cases…As a result, it is not possible to discern, for example, the difference between E3's "target" case and the Aggressive Policy Reference case, which show comparable levels of GHG emissions" (WPTF, p. 6).

Response: The target case and reference cases were developed based on a series of assumptions created by E3 or directed by the CPUC/CEC. The Aggressive Policy Reference Case assumes that 100% of economic energy efficiency potential is achieved statewide, whereas the E3 'target case,' which is based on a modification of the Business-as-Usual reference case, assumes that 75% of economic energy efficiency potential is achieved. These differences in energy efficiency assumptions mean that the two cases require different levels of renewable energy to be developed to meet the model's GHG and RPS targets. The total GHG emissions level from the two cases is similar because the Aggressive Policy Reference case meets the "proportional sector GHG target" for the electricity and natural gas sectors, as does the "target" case. If additional documentation is required, E3 will try to clarify any remaining confusion about this issue.

Comment: NRDC, UCS and CEERT all disagreed with the use of the terms 'firming penalty' and 'firming cost.' NRDC/UCS, (p. 13) suggested instead the use of the term 'capacity value adjustment.' In an informal communication with CEERT, the term 'system balancing' cost was suggested as an alternative to 'firming penalty.'

Response: E3 will change the 'firming penalty' language.

Comment: For its wind integration costs, SCE notes that E3's write-up on "Modeling Costs of Integrating Wind Resources" "describes a series of hypothetical scenarios that seem inconsistent" (SCE, p. 26-27).

Response: E3 acknowledges that the example of total wind integration provided in the integrating wind resources write-up contained a computational error, and accepts SCE's recommended revision as the correct way to calculate the values for the example used in the write-up.

B. *Sensitivity Analysis*

A number of comments have to do with numerical assumptions in the GHG Calculator, rather than the methodology used to compute the results. E3 proposes to address most of the comments on numerical input assumptions through sensitivity analysis. This will be done in two ways. First, we will make it easier for parties to make adjustments to key input variables in the GHG Calculator, as described above. Second, in the report on results (tentatively scheduled for release in May 2008) E3 will include a sensitivity analysis to key drivers. We are not sure that all of the comments discussed below will materially affect the results or will be included in the final report, however, with the revised model we will evaluate the range of sensitivities to major input assumptions and report the results where the results materially impact the findings.

Proposed Change: Sensitivity analysis will entail adjusting key input variables and a discussion of the resulting impacts on key output variables. E3 does not plan to assign "probabilities to cost distributions" as suggested by IEPA, (p. 4) as such an analysis is not readily compatible with the GHG calculator's methodology and approach. The following suggestions for sensitivity analysis were presented in stakeholder comments:

a. Energy efficiency program costs: a) marginal incentive payments to get 100% of economic energy efficiency potential, and b) lower administrative costs. (NRDC/UCS, p. 8-9)

b. Renewable energy technology costs, to examine the impact of future market transformation, (SMUD, p. 9, Solar Alliance, p. 5), or future renewable energy technology cost increases. (IEPA, p. 4)

c. Worst-case and best-case scenarios to better estimate the upper limit on potential carbon compliance cost impacts on customer rates. (PacifiCorp, p. 23)

d. Load uncertainty. (PG&E, p. 4, 7, 8)

e. Energy efficiency, renewable energy and transmission availability. (WPTF, p. 2)

f. Price of natural gas, potentially other fuel costs. (NRDC, p. 15-16, UCS/CEERT, informal communication 12/6/2007)

g. All output metrics for reducing emissions from electricity and natural gas sectors to get back to 1990 levels and 29% below 2020 BAU levels. (NRDC/UCS, p. 18)

Cost and resource potential assumptions for renewable energy

The following stakeholder comments relate to criticisms of the costs and generation potential associated with the renewable resources modeled in the GHG calculator. These comments are presented in two categories; those inputs parties felt are too optimistic and those that parties felt were too pessimistic.

Comments suggesting that cost and resource potential assumptions are too optimistic:

a. Renewable potential supply curves are overly optimistic, not feasible. (PG&E, p. 4-5)

b. Cost assumptions for all types of generators are too low. (SCE, p. 19-20)

c. The supply curve for wind is overly optimistic – 160,000 MW of wind at $60/MWh or less is not realistic. (SCE, p. 10)

d. Integration and firming costs for wind are good, intermittency analysis does not account for high wind penetration rates, especially in the Plexos dispatch. (SCE, p. 10-11)

e. Concentrating Solar Power costs are too low – capital costs are 25% higher. (SMUD, p. 8)

f. Wind integration costs are overly optimistic. (WPTF, p. 4)

g. Biomass fuel costs (Section 9) look too low. (IEPA, p. 3-4)

h. Geothermal cost assumptions are too low. (SCE, p. 21-22)

i. Wind speeds associated with National Renewable Energy Laboratory wind classes look too high. Wind costs looked low. (SMUD, p. 8)

Stakeholder comments suggesting that cost and resource potential assumptions are too pessimistic:

a. Apply wind capacity factors used in the DOE-AWEA 2007 Wind Vision report. (CEERT, p. 37)

b. Wind integration costs should be $5-6/MWh, not $6.26-$9.39/MWh. Use higher wind capacity factors. (NRDC/UCS, p. 10-11)

c. PV market prices should decline below $8/W. (Solar Alliance, p. 5)

d. Firming penalty is too high. (CEERT, p. 35-36)

e. Municipal solid waste gasification means statewide biomass potential is 4,700 MWe, rather than 600 MW. (SCE, p. 21)

f. The nameplate capacity of a wind farm should not necessarily determine the rated capacity of new transmission – avoid underutilizing transmission lines by building transmission 20% less than nameplate capacity. (NRDC/UCS, p. 15)

Load forecast, energy efficiency, DR and solar photovoltaic (PV) assumptions

The following list notes stakeholder comments suggesting that the load forecast, or other distributed resource assumptions are too optimistic:

a. California Solar Initiative (CSI) numbers are too aggressive, 3,000 MW is not possible by 2020. Solar PV costs should be higher at $9 - $10/W. (SCE, p. 18-19) PG&E, (p. 12-13) also felt that CSI costs are too low, they are currently above $9/W, and argued that the PV market transformation case is too optimistic.

b. The demand response goal of 5% is not attainable (NCPA, p. 8, SCE, p. 19). Use the demand response forecast in the IOUs Long-term Procurement Plans. (SCE, p. 19)

c. The CEC's load forecast is too low for LADWP. (LADWP, p. 11)

d. Achieving 100% energy efficiency economic potential is unrealistic unless building/equipment/appliance standards savings are included. (SDG&E, p. 9)

e. The energy efficiency (EE) potential is overestimated in both the business-as-usual and aggressive policy reference cases. EE costs are higher as well: incorporate cost of decay, cost for early retirement or inefficient measures, and total customer costs. (PG&E, p. 5-6, p. 8-11)

f. The business-as-usual reference case load growth forecast should increase with population growth. 100% economic EE is not achievable – use historic trends in consumption as a guide for consumption in the reference case. (CEERT, p. 12)

The following list notes stakeholder comments suggesting that the distributed resource assumptions are too pessimistic:

a. The solar PV cost assumptions are too expensive (Solar Alliance, p. 5)

b. Wind integration costs should be $5-6/MWh, not $6.26-$9.39/MWh. (NRDC/UCS, p. 10-11)

c. Municipal solid waste gasification means statewide biomass potential is 4,700 MWe, rather than 600 MW. (SCE, p. 21)

d. Nameplate capacity of wind farm should not necessarily determine the rated capacity of new transmission – avoid underutilizing transmission lines by building transmission 20% less than nameplate capacity. (NRDC/UCS, p. 15)

C. *Suggestions and Comments That will Not be Included*

The following comments either were determined to fall outside the scope of this modeling effort or which are difficult to incorporate into the current modeling framework. Explanations and responses for these decisions are provided below.

18. Analysis of criteria pollutants

Comment: In their reply comments, NRDC/UCS/GPI, (p. 2-3) noted that, "E3 should provide access to information on changes in emissions at generating units, or at least at the regional level, given the health and environmental impacts on local populations."

Response: While we agree that criteria pollutant emissions are an important policy issue, we do not agree that this GHG model is the appropriate platform to perform an analysis of criteria pollutant emissions. A thorough and useful analysis of criteria pollutant emissions would require a detailed look at emissions within specific load pockets and air quality control areas. The GHG model is not designed to produce results at that level of detailed, generator-specific output. The GHG calculator utilizes generator output data from the Plexos production simulation model run at the 'zonal' level: a much higher level of aggregation than a "nodal" configuration, which could produce results at the level of detail needed for an analysis of criteria pollutants. We do not run Plexos at the nodal level because this would require making too many detailed assumptions about the Western region's generator and transmission topography in 2020 to be reasonably accurate. Even at the regional level, we do not believe that criteria emissions results of the model will be useful. By leaving the criteria pollutant analysis to another forum, we seek to avoid creating a false perception of precision regarding criteria pollutants in this GHG model.

19. Financing Assumptions

Comment: SCE suggested modifying the financing assumptions to include a consideration of situations where the book life of a generator is not equal to the actual asset life, to include preferred stock in financing assumptions, as well as other more detailed comments in the Appendix A of their comments (SCE, p. 15 & Appendix A).

Response: The summary below describes those suggestions related to financing assumptions which we do not plan to incorporate.

IPP Tax assumptions: No change proposed. Adding state-specific tax rates applicable to IPP-owned assets would not substantively change the results of the analysis but would be computationally complex.

Section 199 Manufacturers deduction: No change proposed. This deduction is limited to 50% of W2 wages paid by the taxpayer. Because the company holding the asset often does not retain employees, it is unclear how this deduction could be implemented on a global basis.

Book life and Contract life: No change proposed. We assume IOUs will rate base assets (30 years) and IPPs will project finance contracted assets over the life of an off-take contract (20 years). We agree that this may overstate the costs of IOU assets that could be financed over longer lives than 30 years, but believe that an IPP contract term of 20 years is realistic. We believe none of the assets have shorter actual asset lives.

Sunset dates before 2020 for certain credits and incentives: No change proposed. Rather than attempting to predict tax incentives available in 2020, the model assumes that the state-level SEP and property tax incentives would no longer be available in 2020, nor would federal incentives with cumulative capacity limitations. Other federal tax benefits are assumed to be permanently available at 2008 levels.

Comment: In an informal communication with Burbank Water and Power, they suggested incorporating municipal financing for new resources into the model. AReM, (p. 3-4) also suggested modeling different financing options for IOUs, POUs and ESPs.

Response: The base case model results describe costs of assets held by IPPs, while IOU, POU or other forms of ownership may be run as a sensitivity case. In this way the model avoids the difficult and controversial task of attempting to designate which resources will be developed under which types of financing structures. Ultimately, we do not believe that the financing structure of new generation projects is a key driver in the analysis.

20. Changes to fuel prices

Comment: Fuel price forecasts should be compared to the 2008 EIA Energy Outlook and "depending on the results, E3 should consider revising its assumptions regarding the 2020 price of each fuel, specifically the assumption that all fuel prices should be increased by the same ratio as the ratio between the 10/4/07 MPR natural gas price and the SSG-WI natural gas price." (PG&E, p. 40)

Response: There are many fuel forecasts by different agencies with different vintages, biases, and methods. We plan to continue to use the MPR forecast developed by the CPUC as the base case, and adjust fuel prices as a sensitivity to accommodate the range in other forecasts.

21. Vary demand response (DR) assumptions by LSE

Comments: NCPA (p. 8) requested that the amount of DR be adjustable to allow DR impacts to differ between utilities.

Response: While this is not a difficult change to make in the model, we do not believe that differing levels of DR are a key driver in the results of the analysis. Further, we do not have information on LSE-specific plans for DR for all of the LSEs. Therefore, we plan to maintain the current approach for a single DR percentage by LSE.

22. Changes to solar thermal and geothermal assumptions

Comment: Additional types of geothermal facilities should be included in the model, given that some technologies have higher fugitive GHG emissions, or higher volatile organic chemicals (VOC) emissions than other technologies. Concentrating solar thermal is most commonly a hybrid facility, using some natural gas combustion. In addition, "SCE recommends making storage a variable in the model and creating an option for inserting a Concentrating Solar Plant ("CSP") without storage and/or adjust the hours of storage." Include small-scale distributed solar on warehouse rooftops, commercial buildings or multi-family housing developments" (SCE, p. 21-23). The Solar Alliance

suggests the deployment of Utility Scale Solar more widely across WECC. (Solar Alliance, p. 3-4)

Response: In an improvement to the model, we are leaving 'blank' rows for parties to define their own additional resources such as more geothermal technologies, or additional types of solar thermal or utility scale PV. However, we do not have the resources to model the wide range of potential and emerging renewable resource types more specifically than they have already been defined.

23. Additional suggestions to change energy efficiency assumptions

Comment: "Contrary to E3's model, energy efficiency potential estimates should not assume…that the same aggressive growth rate for energy savings from IOU programs between 2008 – 2016 will continue for 2016 – 2020" (PG&E, p. 6-10).

Response: Given the uncertainties surrounding future rates of energy efficiency adoption, E3 believes that a reasonable assumption is to maintain a constant rate of energy efficiency savings through 2020, and then use sensitivity analysis to evaluate higher and lower energy efficiency penetration levels.

Comment: "Accurate and reasonable costs and potential for [customer energy efficiency] CEE within the service territories of the POUs should not be based on the closest IOU, as is done in the E3 analysis. E3 should update these assumptions based on the POUs' possible lower cost and higher potential relative to the more mature IOU programs." (PG&E, p. 11)

Response: E3 is not aware of a more up-to-date public resource estimating the POUs' cost-effective energy efficiency potential than the AB 2021 filings. In the absence of other publicly available data on the POUs' cost and potential for energy efficiency, E3 has no basis on which to create a different set of assumptions for POUs. E3 thinks it reasonable to rely as much as possible on the AB 2021 filings, and to make other assumptions, such as assumptions about energy efficiency costs, based on available IOU data.

Comment: "For the natural gas sector, given that the only change in GHG emissions comes from increased efficiency, equipment/appliance standards as well as building standards should be included under energy efficiency. The model could also include some energy alternatives such as solar water heating and biomethane as part of the supply of GHG reductions in the natural gas sector" (SDG&E, p. 7). NRDC/UCS (p. 5) also mentioned in their comments related to the CPUC staff working paper that solar thermal for water and space heating as a replacement for natural gas, as well as the use of biomethane, should be considered as emission reduction measures for natural gas.

Response: These are useful suggestions; however, given the February 8th, 2008 CEC/CPUC Proposed Interim Opinion recommending against the inclusion of the natural gas sector in a cap and trade program we do not plan to add more GHG reduction measures for natural gas. There are a number of uncertainties surrounding the use of biomethane in particular, since it is not yet clear which sector of the California economy would be credited with the GHG emission reductions from the use of biomethane. The

exclusion of these emission reduction measures from the model of course, does not preclude their consideration by the California agencies in any policy decisions.

Comment: NRDC/UCS "recommend that a substantial effort be placed on developing an analysis of the [WECC] regional energy efficiency resource." "While it would be possible to simulate [WECC] regional energy efficiency programs in the E3 model by reducing the demand growth rates, this would fail to capture the cost savings of those programs, and in any case, would not be based on an assessment of the potential for efficiency gains" (NRDC/UCS, p. 9).

Response: The E3 GHG calculator does not attempt to estimate the costs of GHG policies, energy efficiency programs, or any other costs for states or regions outside of California. Therefore, simply allowing users of the GHG calculator to adjust the load forecast for the other Western regions, to reflect the impact of energy efficiency on the load forecast, captures the same effect that a more detailed analysis of the energy efficiency resource in the Western region would.

Comment: "…The reference case recommends LSE load forecasts that are an extrapolation of CEC information out to 2020. These forecasts are not accurate. The CEC forecast contains errors in its assumptions regarding the amount of available energy efficiency. In addition, the amount of energy efficiency assumed by the CEC is inconsistent with that used by other WECC entities and therefore biases the forecast to be significantly too low when compared to the other areas." (SCE, p. 14-15)

Response: E3 relies on the CEC's load forecast because it is the most comprehensive and detailed publicly-available load forecast for California. To the extent that users of the GHG calculator disagree with the CEC's load forecast, they can perform sensitivity analysis around the California and rest of WECC region load forecasts.

Comment: Include an estimate for other states to have demand response, if cost-effective. (SCE, p. 13)

Response: While other states do have demand response programs, we do not feel that these programs are likely to be a key driver of the model's results and therefore would not justify the resources required to incorporate them into the model.

Comment: Modify the list of generators to include EIA plant name and CEC plant number. (PG&E, p. 35)

Comment: E3 does not have the necessary information to modify the list of generators from the TEPPC WECC database to include all of the EIA plant names and the CEC plant numbers.

24. Price elasticity response in the model

Comment: "For both [natural gas and electricity] sectors, the impact of overall cost of GHG emissions reduction measures should be considered. As prices increase, there is an elasticity response in energy conservation and further energy efficiency measures may become cost effective" (SDG&E, p. 7). The inclusion of a price elasticity of electricity demand was also suggested in informal communications with the CEC.

Response: We do not plan to include a price-elasticity effect on electricity or natural gas consumption in the model. This is for several reasons. First, the overall order of magnitude is small. Consider a 30% rate increase, which is a large amount. With an elasticity of -0.1 (a common result of elasticity studies), this effect would decrease consumption by 3%. We believe that this difference is small enough to be contained within the prediction error of the CEC's load forecast. Second, the price response to electricity varies greatly by customer class and rate tier. Capturing the complexity of electricity price response by customer class and tier is beyond the scope of this project. Third, the model does allow a sensitivity analysis with respect to load growth, so a sensitivity analysis can be done with lower (or higher) loads without an explicit price elasticity effect. Finally, our understanding is that the Energy 2020 model that the consulting firm ICF is using for the Air Resources Board modeling work includes significant attention to price elasticity, so this is probably the better tool to use to evaluate the price elasticity of electricity demand effect.

25. Additional suggestions on renewable energy assumptions

Comment: "…E3 includes Class 3 wind sites within California. Such sites should not be included in the model…because the industry does not generally consider them economically viable. Additionally, E3's model assumes that a current, mainstream wind turbine to be rates at 2.5 MW. While recent installations of up to 3.0 MW have started within the past year, 1.5 MW is the most common size" (SCE, p. 20).

Response: Class 3 wind is included as a resource in California because there is a possibility it will be developed under some scenarios, however, its higher costs make it unlikely that it would be built in a least-cost AB 32 compliance scenario. As for the size of new wind installations assumed in the model, E3 expects that most new wind projects coming on-line between now and 2020 are likely to be in 2.5 MW size range, despite the fact that the most common size for past projects is 1.5 MW.

Comment: Allow user to adjust the Environmental Exclusions for new wind resource development. The current 50% exclusion for Department of Defense land is too low. (SCE, p. 21) "Land area exclusions seem to be too restrictive…Sacramento's summertime solar resource rivals that of the Mojave region, and there are likely other areas in California whose solar resource during Spring, Summer and Fall months is exceptional. Alternative filter approaches should be considered to account for the fact that energy prices and the solar resources are both more important during the summer months. Further, exclusions for locations of 1% or greater slope seems restrictive as most solar siting studies we have seen put that value at 2% or greater as the balancing point for costs" (SMUD, p. 8).

Response: As mentioned, in the effort to improve the user-friendliness of the model, we are making the resource zone supply curve easier to adjust and more transparent. While this will not extend to allowing users to adjust the land or environmental exclusions, stakeholders may perform their own resource assessment with different environmental and slope exclusions, in order to specify their own resource potential by zone as well as the order in which resources are developed by zone.

Comment: "Analysis should verify minimum load conditions that affect the ability of the electric sector to absorb large amounts of intermittent renewable generation in the areas where these resources are developed or if insufficient transmission is in place to access and deliver this energy to load centers. Alternatively, where system integration is unavailable, storage costs, to the extent they may be reasonably estimated based on future technologies, should also be added to all intermittent renewables costs to take into account the lack of system integration." (PG&E, p. 5).

Response: Such an analysis of minimum load conditions is beyond the scope of this project. However, between the model's current estimates of firming and integration costs, we believe that all renewable integration costs are reflected in the current model without the need for storage costs.

26. Concern about emissions factor of unspecified electricity

Comment: Since unspecified power cannot be traced from generator to load, the emissions profiles for LSEs will be flawed. Using generic power pool emissions factor is not acceptable. (SCE, p. 8)

Response: The GHG calculator relies on the CPUC's "Interim Opinion on Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector," issued 9/7/2007 to determine how out-of-state unspecified emissions are treated. An emissions factor of 1,100 lbs/MWh is applied to unspecified electricity imports in the GHG calculator. This input assumption however can be modified by the user of the GHG calculator to test alternative scenarios. In the next version of the model, E3 plans to allow users of the GHG calculator to adjust the unspecified imports emissions factor for the Northwest and the Southwest regions independently. In-state unspecified emissions are assigned the average CO2 emissions of either Northern or Southern California generation from the Plexos dispatch.

27. PLEXOS Solutions related concerns

Comment: LADWP and SMUD dispatch differently than the CAISO. (LADWP, p. 10) PLEXOS should rely on utility resource plans for generator assumptions, rather than the least-cost dispatch model. (LADWP, p. 3-5)

Response: We plan to continue with the assumption that in the long-run generators are dispatched on the economic merit order. In addition, the TEPPC WECC database is constructed based on utility resource plans.

Comment: The WECC database may not be most accurate database available. "A more accurate alternative might be achieved with the purchase of a different database." (SCE, p. 12)

Response: E3 plans to continue to rely on the WECC TEPPC database. The benefits of this database are that it is publicly available, and is the result of input from many utilities across the WECC.

Comment: Run the Plexos model nodally. (SCPPA, p. 16, WPTF, p. 10)

Response: Despite initial plans of the project, we do not plan to run Plexos in a nodal mode for 2020. The current Plexos model uses more than 20 zones in the WECC which

we feel is adequate for the type of analysis that E3 is doing. The primary reason E3 no longer plans to do a nodal analysis is that even with the substantial cost and time invested to do the analysis nodally, the additional information that will be gained would be of limited worth, given the large number of assumptions required to develop a nodal 2020 run. This effort would only demonstrate how one possible system might operate in 2020. Our focus is to be able to model a range of possible target scenarios quickly and easily rather than focus in detail on a single scenario.

28. Concern about other structural assumptions

Comment: "…the E3 model does not account for the effect of increased reliance on preferred resources on reducing natural gas prices. Instead, the model assumes that natural gas prices are unchanged between the reference and the target cases, even though natural gas demand may be much lower in the target case." (NRDC/UCS, p. 17)

Response: Given the huge uncertainty around any long-term natural gas forecast, E3 is of the opinion that this uncertainty overshadows the possible natural-gas price forecasts which may result from different levels of demand for natural gas in the scenarios.

Comment: "E3 assumes that the entire state of California will reach 20% [RPS] by 2020 based on the various policy goals established by municipal utilities…it is important to note that municipal utilities are not regulated by the CPUC and therefore, may not have the same incentive to reach their goals as regulated entities. Accordingly, E3 should consider reducing the "20% by 2020" assumption. (SCE, p. 18)

Response: As other stakeholders have pointed out (SCPPA, p. 6-7. LADWP, p. 12, CMUA, p. 2-4, NCPA, p. 4, SMUD, p. 1-4) municipal utilities are required to implement and enforce RPS targets, and some municipal utilities have set more aggressive RPS targets than the IOUs are obliged to meet. Therefore, E3 does not intend to change the model's assumption that the state will meet 20% RPS by 2020 in the business-as-usual reference case.

Comment: SMUD suggested that E3 consider CARB's Native Load designation rules. (SMUD, p. 4)

Response: E3 does not believe that accounting for this rule in the GHG model would materially change the modeling results.

Comment: PacifiCorp states that the model does not account for PacifiCorp's $4 billion transmission investment plans to connect Wyoming to Utah, Idaho, Oregon and the desert Southwest. (PacifiCorp, p. 20-21)

Response: The planned transmission assumptions used in the GHG calculator come from the TEPPC 2017 database. To the extent that PacifiCorp participated in the development of the TEPPC 2017 database, their planned transmission investments will be reflected.

29. Concern about the aggregation of LSEs in the model

Comment: A number of stakeholders expressed concern that the disaggregation of cost and GHG impacts by LSE was not granular enough in the GHG calculator. PacifiCorp (p. 22-23) noted that the California-portion of the PacifiCorp utility should not be grouped together with the "Northern other" largely municipal utilities. PacifiCorp points out that

their rate impacts due to GHG legislation are likely to be higher than the investor-owned utilities and the publicly owned utilities. Southern California Edison, (p. 18), NCPA, (p. 2, 6) and SCCAPA, (p. 14, 16) all expressed concern that grouping the smaller utilities into the "Northern other" and "Southern other" categories makes it impossible to measure individual rate impacts or emission reduction strategies for these utilities. The Alliance for Retail Energy Markets (AReM, p. 2) expressed concern that the model did not explicitly model Direct Access customers given that Energy Service Providers typically have higher procurement and energy costs than IOUs or POUs. Finally, the Western Power Trading Forum (WPFT, p. 8) suggested that the model should calculate rate impacts for non-LSE market participants.

Response: We understand that the current level of disaggregation in the model, dividing all of the LSEs in the state into seven groups, is not detailed enough to answer all of the questions parties might have about the impacts of GHG reductions. However, we do not intend to change the number of LSEs, or their definition, in the Stage 2 model. There are several reasons we do not plan to do this. First, this would take considerable additional costs and time, second, it would be difficult to incorporate each individual LSEs' resources, and lastly it would then be difficult to evaluate the overall results from a statewide impact perspective. We believe that the current level of aggregation provides enough information to make the necessary policy decisions in the ARB scoping plan. We understand that individual LSEs may need to do their own analysis on the individual impact to their LSE of various AB 32 scenarios, as NCPA has done.

30. Clarifications

Comment: "It appears that E3 has utilized reports prepared by the investor owned utilities ("IOUs") that include the energy efficiency savings from building standards and appliance codes in their estimates of energy efficiency potential. POUs generally do not include energy efficiency savings available from applying building codes and standards…The treatment of savings that might be available from applying building standards and appliance codes should be consistent between IOUs and POUs" (SCPPA, p. 8).

Response: The estimates of energy efficiency economic potential for the Investor Owned Utilities rely on the 2006 study prepared by Itron, "California Energy Efficiency Potential Study." To the best of our knowledge, this report does not include energy efficiency savings from building standards and appliance codes. On page 7 of the Executive Summary, the report states, "Savings are net of known changes in standards, in the sense that they change the base measure and incremental savings in years when standards change."[3] It may be true that the IOU and POU accounting methods for economic potential of energy efficiency are not exactly the same, however, we do not believe that the treatment of standards and codes is driving such differences.

Comment: California shouldn't be allowed to import large hydro to count towards its Renewable Portfolio Standard. (SCE, p. 17)

[3] The 2006 Itron study referenced here is available on-line at:
http://www.itron.com/pages/news_articles_individual.asp?nID=itr_008890.xml

Response: Large hydroelectric generation (larger than 30 MW) is not counted towards the California RPS in the model.

Question: "E3 seems to conclude that the Pacific Northwest (including Utah) region is the only area adding any significant amount of combined cycle generating turbine ("CCGT") technology." (SCE, p. 14)

Response: The Pacific Northwest is not the only zone to add significant new natural gas fired generation in 2020. To determine the total additions of new CCGT by zone in 2020, one must add the amount of new CCGT added by the TEPPC database, shown in Table 2 of the write-up "Ensuring Sufficiency Resources to Meet Loads," to the amount of new CCGT shown in Table 4 of the same document that shows additional resources added by E3 when doing load and resource balancing.

Comment: It is incorrect to assume coincidence of peak load throughout the WECC. (SCE, p. 14)

Response: Plexos was run using the non-coincident peak forecasts, not assuming coincidence of peak load throughout the WECC. The GHG Calculator has a 95% coincidence factor that is only used for the capacity balance calculations when a user enters a custom load forecast.

Comment: 500 kV line costs should be closer to $50 million, not $26 million. Explain the source of the $1600/MW rule of thumb metric from transmission costs. Disclose 'system upgrade costs' for transmission. How are system upgrade costs treated for large, new nuclear or conventional resource additions? The 10% of transmission capacity for wind is not reasonable because of congestion costs. (SCE, p. 24).

Response: The source of all of the transmission cost assumptions are documented on the E3 website and in Attachment A of the ALJ's ruling on modeling-related issues. We do not use the $1600/MW rule of thumb in the analysis. The 10% of transmission capacity availability for wind is only applied to out-of-state resources, which are not used in the reference cases.

Comment: LADWP takes issue with the conclusion of the model that LADWP will build 6,600 MW of new conventional coal (LADWP, p. 10).

Response: We assume that the source of this comment is derived from Table 2 of the E3 model document #5, "Ensuring Sufficient Resources to Meet Loads." The table shows that 6,592 MW of new coal is added to the entire WECC between 2008 and 2020. This assumption is based on the TEPPC database. These new coal resources are not assigned to California, nor are they assigned to LADWP.

Comment: SMUD (p. 7) and SCE (p. 14) disagree with the assumption of applying 0% demand response to the POUs in 2020 (SCE, p. 14, SMUD, p. 7).

Response: While this 0% demand response assumption for POUs was erroneously reported in the original E3 model documentation, this description of demand response was corrected in the "Corrections to Stage 1 Documentation" document, p. 3. Currently, 5% demand response is applied to all POUs and IOUs in 2020 in the GHG calculator reference cases.

Comment: SCE (p. 18) states that the E3 model incorrectly reports the CEC load forecast numbers.

Response: This seems to be a misperception based on the assumption that we used the CEC load forecast for the entire SCE service territory in the SCE load forecast. In reality, for SCE, the load forecast only considers SCE's bundled customers. The remaining, non-bundled load in SCE's service territory is applied to the "Southern Other" category. While this methodology of assigning load to SCE will not change in the next version of the model, the overall load forecast used in the revised model will change, as outlined in the section of this document describing updates to the load forecast.

Comment: PG&E suggests that E3 should not assume technological breakthroughs for energy efficiency. (PG&E, p. 6)

Response: E3 does not make assumptions about technological breakthroughs in energy efficiency beyond what may be reported in POU AB 2021 filings. E3 excludes the category of emerging technology energy efficiency potential from the IOU and the SMUD 2006 Itron data on energy efficiency potential.

Comment: The model is limited by its lack an estimate of congestion costs. (WPTF, p. 6)

Response: The Plexos least-cost dispatch model is subject to transmission constraints between zones. Re-dispatch costs to alleviate transmission congestion are included in the model.

Comment: "In Issue Papers #28 "Cost of Integrating Wind Resources" and 29 "Firming Cost", it is not clear whether it was assumed that the cost of integrating wind would include the firming cost or whether that was solely used for the cost ranking process. It is recommended that the firming penalty only be used for the resource selection process if that is not the case already….The expectation that the integration costs ought to be linear with penetration also does not seem consistent with industry expectations" (SMUD, p. 8).

Response: Wind firming and integration are separate categories of costs. "Firming" is used only in resource ranking and selection process to reflect the fact that resources such as wind do not provide firm, dependable capacity for meeting peak demands. Integration costs are calculated based on the overall level of wind resources selected. While unit ($/MWh) integration costs increase linearly with penetration, total wind integration costs increase geometrically with penetration. E3 believes that this consistent with industry expectation as indicated in the various studies that E3 researched.

Comment: The use of uniform emissions rate by fuel type is inaccurate. (SCE, p. 30)

Response: GHG emissions from generators depend both on the emissions rate, by fuel type, as well as the heat rate of the generator and the amount that the generator is dispatched in the model. Emissions will therefore vary by generator even though the emissions rate by fuel type is uniform.