**ACC 2020 Update Draft Resolution Post-Webinar Questions**

**Questions submitted by San Diego Gas & Electric**

1. Which IEPR forecast is E3 using for each utility transmission load growth analysis?

E3 used the ***CED 2019 Baseline Forecast - LSE and BA Tables Mid Demand Case - CORRECTED Feb 2020*** forecast for the load growth analysis. The 1-in-10 forecasts were used for determination of IOU peak.

1. What DER types are being excluded from each utility’s forecast for their counterfactual analysis?

Table 2, showing precisely which DER energy and capacity resources are removed in the No New DER case, is on page 5 of the ACC documentation.

1. Did E3 use SDG&E’s coincident DER quantities in determining the number of counterfactual overloads?

E3 used SDG&E’s coincident DER forecasts in determining the number of counterfactual overloads.

1. The load forecast used for calculating marginal transmission costs should reflect an earlier vintages of the CEC’s IEPR load forecasts.  For example, for year 2021 peak-load growth-driven transmission expenditures, the load forecast developed by the CEC five years earlier (in 2016) should be used to account for the fact that utilities/CAISO makes commitments for capital expenditures well in advance in order to account for permitting/construction lead times.

This is a suggestion for changing the ACC, not a question, and should be included in comments.

1. The load forecast used for calculating marginal transmission costs should be the CEC’s 1-in-10 load forecast, not 1-in-2 load forecast, since utilities typically use extreme weather conditions when identifying peak-load growth-driven expenditures.

This is a suggestion for changing the ACC, not a question, and should be included in comments.

1. SDG&E does not believe it is appropriate to use Expected Unserved Energy (EUE) to allocate marginal transmission costs to individual hours of the year.  EUE values reflect not only load levels, but also planned and unplanned generator maintenance outages.  These outages have no relationship to transmission needs; e.g., adding Behind-The-Meter (BTM) resources that are operational during hours with relatively high planned and/or unplanned generator maintenance outages would not necessarily avoid any transmission that is added for peak-load growth.   Instead, SDG&E suggests the use of thresholds targeted at the highest load hours of the year; e.g., allocating marginal transmission costs to the twenty highest load hours of the year.

This is a suggestion for changing the ACC, not a question, and should be included in comments.

1. The method for calculating the transition year values for distribution deferral costs seems off. On p. 56 of the ACC documentation, it shows how the transition should theoretically work.

However, on p.62 you can see that they are using the calculated PG&E value for SCE and SDG&E as well to calculate values for the transition years. It doesn’t make sense why they wouldn’t just use our values.



In the actual ACC, you can see SDG&E is set to SCE, which is the case for all the rows except PG&E CZ1.



PG&E CZ1 is the only cell in this row that has an actual calculation.

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This has been corrected in version 1b.

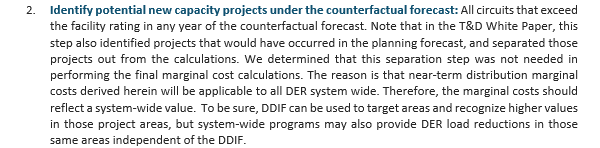
**Questions submitted by Southern California Edison**

1. Did the Publicly Owned Utility load removed from the SCE IEPR forecast values when the counterfactual analysis (IEPR without DER) was performed?

The POU load was not removed from the forecast when the analysis was performed.

1. It seems that the assets already overloaded in the GNA is not excluded in the counterfactual forecast as described in step 2 of Method 1 for avoided distribution cost.

The observation is correct. As stated on page 46 of the ACC documentation:

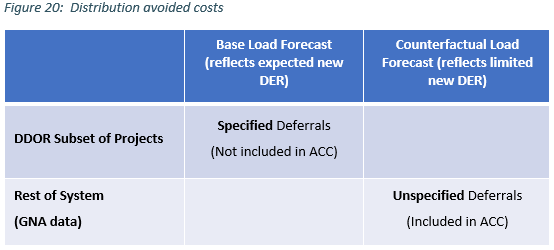


As mentioned in the documentation, change from the Method 1 presented in the Staff Proposal was necessitated by the need to develop a system average marginal distribution capacity cost that would apply to DER regardless of the location of the DER.

Method 1 was developed based on the framework and discussion put forth in the White Paper. The White Paper placed a strong focus on the additional projects, the unspecified projects, that would have been required absent the forecasted DER load reductions.

“All circuits that are above 100% loading are considered overloaded. However, only circuits that are overloaded in the counterfactual forecast, and not in the actual planning forecast are counted as deferred by non-targeted DEF growth (DER growth that is embedded in the forecast).” (White Paper, p. 13)

This separation of projects identified under the actual planning forecast (specified projects) from the unspecified projects was maintained in Method 1, but results in the Method 1 costs not being representative of the entire utility system. This is clearly presented in Figure 20 from the Staff Proposal that states that the unspecified deferral values represent distribution avoided costs for the “Rest of the System” and not the entire utility system.



This approach of limiting the avoided costs to just reflect the “rest of system” is meant to avoid double counting, but inadvertently led to undervaluation of DER in Method 1. Indeed, the White Paper explicitly recognizes that system-wide, or non-targeted, DER can provide both specified and unspecified value.

“Non-targeted DERs will have some unspecified deferral value, but depending on their location may also have some specified deferral value.” (White Paper, p. 5)

Hence, we concluded that Method 1 did not allow us to carry out the analysis specified in the White Paper, and determined that is was therefore appropriate to modify Method 1. The ACC’s use of both specified and unspecified projects in the calculation of the system-wide marginal distribution capacity cost corrects the Method 1 error of excluding the value that non-targeted DER can provide by reducing loads in specified project areas.

**Questions submitted by Pacific Gas and Electric**

# General Model Setup

1. Figure 2 on p. 3 of the documentation shows the ACC structure. It shows RESOLVE modeling of the RSP is used for the GHG value. Please confirm that this is a mistake, and that the No New DER RESOLVE case informs the GHG value.

Yes, this is a mistake in the documentation. The GHG Value in the ACC is in fact taken from the No New DER RESOLVE case.

1. Figure 2 on p. 3 of the documentation shows the ACC structure. Why does the RESOLVE modeling of the RSP inform the long-run GHG intensity of the grid, while all other GHG calculations rely on No New DER case?

The RSP case is used to reflect the actual IRP procurement plan for achieving target GHG reductions. The ACC assumes that portfolio rebalancing will be done based on actual procurement plans rather than for a counterfactual No New DER case.

1. In the v1a ACC ‘Dashboard Viewer’ tab – Month-Hour average tables from AQ31:BB84 are not set up to change dynamically with dashboard selections, can this be updated for the final version?

This has been corrected in version 1b.

1. In the v1A ACC ‘Dashboard Viewer’ tab – Annual averages from G8792:P8792 don’t match the columns of hourly data in columns G:P.

This has been corrected in version 1b.

# No New DER

1. Table 2 on p. 5 shows the No New DER sales forecast buildup. PG&E’s understanding of Additional Achievable PV is that it’s based on CEC Title 24 Codes & Standards requirements for new home construction. Since this growth will happen regardless of CPUC programs, should this forecast remain in the counterfactual No New DER load growth scenario?

The IEPR documentation does not contain any reference to how much of the IEPR DER forecast was related to codes and standards vs. other reasons (e.g., natural customer adoption). Absent such documentation, we kept adoption at 2019 levels. It is not possible to revise the No New DER case and re-run SERVM for the 2020 ACC at this point.

1. At the workshop, ED explained that No New DER was intended to evaluate the counterfactual elimination of utility programs. Energy efficiency programs recognize that there is some naturally occurring energy efficiency that is not the result of the program incentives, so the impacts are adjusted using a net-to-gross ratio. Did the No New DER case also include a similar net to gross adjustment to make sure naturally occurring DERs were included in the forecast? Was any adjustment made to ensure this?

The DER MW and MWh in the IEPR forecast were removed in the No New DER case. No net to gross adjustment was made to the forecasted quantities shown in the IEPR tables. We are not immediately familiar with what, if any, net to gross assumptions were made in developing the forecasts included in the IEPR.

# Energy Prices

1. Energy prices still appear to be too flat over the day, even with the “scarcity adjustments”. Differentials between peak and super off-peak are lower in SERVM forecast for every year 2020-2026 than they were in 2018 or 2019. [PG&E will provide a spreadsheet showing this comparison to historical data by Monday, May 11.]

This is a suggestion for changing the ACC, not a question, and should be included in comments.

1. Has E3 considered defining scarcity adjustments separately by hour of the day? This would probably yield much more accurate price shapes in terms of emulating duck curve effects. Decision would appear to allow this enhancement, since it does not get into details of the methodology. [PG&E will provide a spreadsheet implementing hourly scarcity adjustments and comparing forecasts to historical data by Monday, May 11.]

E3 does believe that scarcity adjustments have a more direct link with Implied Marginal Heat Rate (IMHR) than hours. High IMHR hours directly signifies the market is struggling to meet demand, and is more prone to market irrationality and "scarcity events". Low IMHR hours on the other hand are not well captured by SERVM production simulation and is a gap needing to be bridged with some post-processing. Hours may also an effective indicator for market condition, but not as direct as IMHR. For hours, if we only differentiate by hour of the day (1-24), we probably lose some granularity as a summer noon and winter noon could be very different. If we assign different coefficients for hour by month (576) or hour of the year (8,760) the improved accuracy may be a result of ‘over-fitting’ and an overly broad re-adjustment of SERVM outputs.

1. Energy prices also appear to be much higher than expected in late 2020s; by 2030 the heat rate is above 8500 about 60% of the time.  How could this happen with all the extra solar coming in and little additional load? [This appears to be related to the scarcity adjustments as implemented in current model. See Q2.]

We have some question about whether this difference is due to actual results, or different assumptions made by PG&E in their spreadsheet. We believe that some of the differences may be because the NO New DER case is more balanced than the RSP, because of the large changes in the BTMP V and EE, with the result that low prices and curtailment in the middle of the day are not happening. We also agree that some of this may be the result of the scarcity pricing adjustment. We will continue to look into this to better understand it.

1. There is much less curtailment (prices = 0) than expected or shown in other analyses by PG&E or E3 (e.g. E3 [report](https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf) that showed the value of letting renewables provide regulation rather than be curtailed). Can E3 provide full dispatch from SERVM of all resources for a high-renewables spring day as well as a hot summer day so all parties can better see what is going on? There was a chart displayed during Friday’s presentation comparing no new DER to RSP; having the detailed dispatch behind that chart would be very illuminating.

The file “RSP and No DER SERVM Detailed Dispatch Data Weeks 15 and 35.zip” includes 4 files with detailed SERVM outputs, each with 1 week of output data; 1 spring week and 1 summer week for each of the No New DER and the RSP cases. Week 15 includes the data for April 12, 2030 (hours 2425 to 2448), which is the sample day used in the chart that was displayed in the workshop. For summer prices, Week 35 is included (August 25 – 31, 2030). August 29th (hours 5761 to 5784), in particular, has a high system peak and high prices. The RSP and No DER SERVM Detailed Dispatch Data Weeks 15 and 35.zip is available on the E3 file site in the ‘SERVM Dispatch’ folder and will be added to the CPUC website soon.

1. Slides 18 and 19 of the Energy, AS, and Capacity Webinar deck show that while there were at least 1379 curtailment hours in 2019, the SERVM results used in the 2020 ACC show only 82 curtailment hours in 2020 and 233 hours in 2030. Does this gap between 2019 actuals and 2020/2030 forecasts indicate that SERVM may not be accurately forecasting how much curtailment will occur in the future?

The SERVM production simulation model is modeling a counterfactual No New DER case. The No New DER Resource portfolio includes a different resource mix than the actual portfolio in 2019. In addition, the RESOLVE modeling of the No New DER portfolio allows an optimal selection of supply side resources to meet load and GHG constraints. It appears the No New DER supply side portfolio results in less curtailment.

SERVM, like any production simulation model, does tend to over optimize dispatch relative to the real-world, and this may result in less curtailment in modeled results than in actual historical data.

1. PG&E is concerned that forcing the price floor to zero is unrealistic – RT and even DA prices do indeed get below zero, though almost never anywhere near -300. A price floor of -15 would be more realistic; recent data from the last few days in CAISO support this.  Answer provided during workshop mentioned GHG as considering these negative prices; could E3 provide a more detailed written explanation?

This works under the assumption that negative pricing is indicative of renewable curtailment, and is driven by the negative price of a Renewable Energy Credit. Negative prices are assumed to be the difference between the marginal generation costs (zero for renewable generation) and the premium of delivering incremental renewable energy. In the IRP proceeding, the GHG emissions target was more stringent than the RPS target, so it is projected to become the main driver of negative pricing. Since the RPS target will no longer be binding, negative prices will no longer be driven by REC value, but will be driven by the cost premium of reducing marginal emissions. That price signal is represented by the GHG Adder field in this cycle of the ACC; if marginal emissions are below the annual target, there will be an emissions credit for increasing load in those hours. This is similar to today’s REC-driven framework, in which increasing load in renewable curtailment hours allows incremental delivery of REC-eligible generation, and providing that benefit.

1. Ancillary services forecast prices in 2020 (and beyond) are significantly less than those experienced in 2018-2019 (about 80% lower for spin, and 70% lower for regulation). This is the case in all forecast years, even 2020 (before significant energy storage penetration). This may be a good candidate for implementing a scarcity adjustment for A/S, or perhaps a simple multiplier to get forecasts closer to recent historical data. [PG&E will provide a spreadsheet showing this comparison to historical data by Monday, May 11.]

E3 acknowledges that the AS price forecasts from SERVM are lower than historical prices. We note that there isn’t as clear of a signal on implied marginal heat rate for spinning reserve and regulation markets. The AS markets will also undergo a change in the 2020s as energy storage saturates the market, thus driving down AS market prices.

1. Modeling reg up and reg down as half of SERVM’s “regulation” price is unrealistic and also could reduce EGM – should have high Reg Up prices during peak, high Reg Down prices during mid-day. PG&E appreciates E3 recognizing this issue in the workshop. An easy way to fix this would be to apportion Reg Up/Reg Down based on heat rate, with high heat rates putting most or all of the Regulation price into Reg Up, low heat rates putting it into Reg Down. [PG&E will provide a spreadsheet implanting a proposed solution by Monday May 11.]

This is a suggestion for changing the ACC, not a question, and should be included in comments, but we appreciate PG&E providing this spreadsheet for our analysis.

1. A/S prices after 2030 do not follow their CAGR formula – if you copy down the formula from the first row, the values in other rows change. See cells starting Q6 on tab AS Values of the SERVM Prices spreadsheet.

This has been corrected in version 1b.

1. A/S Procurement tab does not make sense – uses 0.9% of energy value from when spin price was 16% of energy prices (2018), but spin price is only 2.3% of energy price in 2020 and it uses the same 0.9% of energy value.  Considered minor since this is still a small number, and spin price should be higher anyway which would reduce the impact of this methodological inconsistency. PG&E suggests using A/S value data from 2019 (which was hard-coded rather than calculated) instead of 2018 as the starting point for this calculation; this would reduce the impact of the inconsistency further.

This has been corrected in version 1b.

1. Scarcity price calculations appear to assume a VOM cost of $1/MWh, not $0.25.  This leads to a number of instances where the scarcity price uses the wrong “bucket”.  And sometimes a zero heat rate translates to a price of $1, sometimes $0.25. A fairly minor error with little impact, but should still be corrected. See for example cell AU21 on tab Scarcity Pricing Adjustment; which appears to have a value that comes from the wrong “ratio bucket”. See also cells AU1959-AU1965, where scarcity price is sometimes $1 and sometimes $0.25. [PG&E can provide further detail if necessary; SERVM Prices spreadsheet is too large to email.]

This is a suggestion for changing the ACC, not a question, and should be included in comments.

1. On p. 11 of the ACC documentation, E3 identifies two use-cases for SERVM real-time and ancillary services prices: 1) to determine the net CONE of battery storage for marginal generation capacity costs and 2) to estimate revenues that could be earned by dispatchable DERs in wholesale CAISO markets. D.20-04-010 at p. 73 states that dispatchable grid services should not be included in this major update to the ACC. Can ED/E3 please clarify where this second use case was identified and in which proceedings the RT and AS value streams should be used?

The real-time energy prices and ancillary service prices are made available for valuing dispatchable DERs in specific resource proceedings (e.g., Demand Response, SGIP energy storage). They are not included in the ACC itself. The hourly prices are provided in the SERVM Results spreadsheet.

1. The “Changing Avoided Cost Paradigm” slide that appears in several of the webinar decks state that the 2020 ACC is intended to capture that “Solar and Storage are the Marginal Resources for Energy and Capacity.” Does this imply that the combined marginal energy, GHG, and capacity costs (or benefits) of adding (or subtracting load) which approximately matches the profile of a solar generator should approximately equal the marginal cost of a equivalent amount of solar generation in RESOLVE?

In the ACC, any DER shape that is similar to solar generation will have similar avoided costs. The ACC used SERVM production simulation prices of resource portfolios from RESOLVE and these prices are not necessarily set with solar generation as the marginal resource. The ACC value will not necessarily be similar to the marginal cost of solar generation in RESOLVE, which is a capacity expansion, not a production simulation model.

1. What is the marginal reduction in GHGs provided by 1 MW of FTM and BTM solar in 2030 in RESOLVE in the “No New DER” case, respectively? How does this compare to the marginal reduction in GHGs provided by 1 MW of FTM and BTM solar in model year 2030 in the 2020 ACC? If this analysis is not possible to do, conceptually should the marginal emission reductions from the same resource addition be similar in the two models? If they are not similar (based on either the quantitative or qualitative assessment), why not?

Conceptually in RESOLVE, the marginal GHG emissions impact of adding 1 MW of FTM or BTM solar with the same production shapes would be the same, except for accounting for losses. Because GHG intensity is based on retail sales, there will be a difference for BTM resources that reduce retail sales (the denominator) vs. IFM resources that add generation (the numerator).

# Transmission and Distribution

1. **This Question was submitted prior to the T&D workshop, but please confirm this has been addressed:**  On p. 48 of the ACC documentation, Staff calculates a short-term value for PG&E of $14.49/kW-yr (page 48). In the table summarizing the distribution MCs by year used in the model, the year 1 PG&E value is instead $45.36/kW-yr (page 62). The SCE and SDG&E year 1 values also do not match the short-term values on p. 48, but are much closer (~26 vs. ~24 for SCE, 3.39 vs 3.66 for SDG&E). How did Staff arrive at the $45.36/kw-yr for PG&E?

$14.49 is the correct number. The value on page 62 and in the ACC were incorrect due to clerical error. This has been corrected in version 1b. The small variations noted in the second part of the question are due to simple cost escalation. The tables in the ACC documentation have been updated to make the nominal years for the costs clear.

1. **This Question was submitted prior to the T&D workshop, but please confirm this has been addressed:** On the ‘Distribution’ tab of the ACC model, there appears to be an error in the interpolation between near-term GNA-based costs and long-term GRC-based costs. The 2025 ‘Transition Year’ from cells D28:O28 are all copied from the formula in cell D28, and are therefore the same value for all of PG&E’s climate zones and for SCE and SDG&E.

This has been corrected in version 1b.

# Natural Gas ACC

1. In the v1a version of the Gas ACC on the ‘Emissions’ tab, CO2/ton costs are ~104/ton nominal in 2030 and increase linearly (see row 20). D.20-04-010 states that the Gas ACC should use the same GHG adder as the electric model (OP 3). Can E3 confirm where the Gas ACC figures come from?

This has been corrected in version 1b.

# High Global Warming Potential Gases (methane and refrigerant leakage)

1. What is the reasoning behind not applying the leak adder for the replacement of a gas appliance with an appliance of better efficiency appliance? Wouldn’t higher efficiency appliances leak less?

Some recent academic studies suggest that certain higher efficiency gas appliances actually leak more, not less, than their lower efficiency counterparts. For example, see <https://doi.org/10.1021/acs.est.9b07189>. Given this uncertainty, we have elected to only apply the BTM adder to measures that remove a gas appliance from a home.

1. What is the basis for the adder of residential applications? Is it Eric Fischer’s study?

Yes, it is based on the residential behind-the-meter methane leakage included in the CARB GHG inventory (0.89 MMT in 2017), which is based on the 2018 Fischer study, [“Natural Gas Methane Emissions from California Homes”](https://ww2.energy.ca.gov/2018publications/CEC-500-2018-021/CEC-500-2018-021.pdf).

1. The upstream leakage factor of 5.57% is static over the entire ACC forecast horizon. Should this factor change as more all-electric new developments are built and the gas distribution system is phased out over time? As noted in the documentation at pp. 68-69, the adder is meant to capture the long-run impacts of fewer gas end-uses, should the changing overall size of the gas system be factored in to this long-run average?

The leakage factor is a percentage of GHG emissions, not an absolute value, so this would reflect that the magnitude of leakage will change over time as the size of the gas distribution system decreases.

# SERVM Inputs

1. On the ‘IRP and Fuel Cost Inputs’ tab, the monthly price shape from cells C7:N7 average out to 105%, not 100%.

This has been corrected in version 1b.

1. Please provide the SERVM outputs from the RSP case for comparison to the SERVM outputs from the previously provided No New DER case.

“RSP and No DER SERVM Detailed Dispatch Data Weeks 15 and 35.zip” includes 4 files with detailed SERVM outputs, each with 1 week of output data; 1 spring week and 1 summer week for each of the No New DER and the RSP cases. Week 15 includes the data for April 12, 2030 (hours 2425 to 2448), which is the sample day used in the chart that was displayed in the workshop. For summer prices, Week 35 is included (August 25 – 31, 2030). August 29th (hours 5761 to 5784), in particular, has a high system peak and high prices. This file will be posted on the CPUC website and is currently available in the SERVM dispatch folder on E3’s website at <https://www.ethree.com/cpuc-acc-downloads-page/>

**Questions submitted by Solar Energy Industries Association and Vote Solar**

Questions refer to pages and sections in the *2020 ACC Model Documentation*, as well as to various spreadsheets of the draft 2020 ACC model.

**Section 4 – Natural Gas Avoided Costs**

1. Please specify which version of the CEC IEPR gas forecast for electric generators (EGs) was used in the SERVM modeling. For example, was it a draft or final version of the CEC IEPR gas forecast? Specifically, we refer to the CEC IEPR spreadsheet source of the IEPR Mid-case annual average fuel prices excluding carbon costs, shown on row 11 of the “IRP and fuel Costs Input” tab of the “2020 ACC SERVM Prices v1a” spreadsheet (i.e. $4.30 per MMBtu in 2020, in 2016$, etc).

For consistency, the gas prices in the ACC are taken from the Sys – Fuels tab in the RESOLVE Scenario Tool 2020-03-23 starting in Cell J69, available at <https://www.cpuc.ca.gov/General.aspx?id=6442459770>

**Section 5 – Avoided Cost of Energy**

1. The “Energy” tab of the 2020 ACC Electric Model has NP-15 and SP-15 scarcity-adjusted energy prices that we believe should be in nominal dollars, because the avoided costs calculated in the 2020 ACC are in nominal $. However, the hardwired scarcity-adjusted energy prices in the “Energy” tab are taken from the “Scarcity Price wo Carbon” tab of the “2020 ACC SERVM Prices v1a” spreadsheet, which is in 2016 $. It appears that the “Energy” tab should have been populated from the “Scarcity Price wo Carbon Nom” tab of the “2020 ACC SERVM Prices v1a” spreadsheet, which is in nominal $. Is this an error?

This has been corrected in version 1b.

1. At the May 7 webinar, Jan Grygier of PG&E said that they would be forwarding a revised implementation ofthe IMHR tranche methodology that is used in the scarcity scaling process for determining avoided energy prices. Can you provide the workpapers for that PG&E revision? This is particularly important given the lack of reply comments, as parties will be unable to comment on any PG&E revision proposed in opening comments.

Energy Division has decided to allow replies to comments, and requests that PG&E include this information, if possible, in their comments.

1. The “2020 ACC SERVM Prices v1a” spreadsheet does not appear to show the formulas used for the scarcity price adjustments to the SERVM-derived heat rates, as the resulting scarcity-adjusted SERVM prices are hardwired. Is there a version of this spreadsheet with the intact formulas for the scarcity pricing adjustments, or with the macro that was used to do the adjustments? If the scarcity price adjustments were done separately, can you provide the separate spreadsheet(s) used?

The equation for implied marginal heat rate is included in Section 5.1.1 of the ACC documentation. The scarcity scaling functions in Section 5.1.3 of the ACC documentation were develop with a python script. To implement these factors, the implied marginal heat rate is just multiplied by the scarcity scaling factor for the appropriate tranche in Table 5. This step is also implemented in a python script.

**Section 7 – Avoided GHG Emissions**

1. There was confusion in the E3 presentation on May 8 on whether the draft 2020 ACC is using GHG Adder values from the No New DER case or the Reference System Plan case. Please clarify the results of your review of this. We believe that page 38 of D. 20-04-010 requires use of the GHG Adder values from the No New DER case, and that the GHG Adder values in the draft 2020 ACC actually are, correctly, from the No New DER case, but please confirm this.

This was a misstatement in the Webinar. The values in the ACC are correct and are from the No New DER case, consistent with the ACC documentation and D.20-04-010.

**Section 9 – Transmission Avoided Capacity Cost**

1. PG&E and SDG&E appear to have excluded significant capacity-related projects from their transmission investment data. PG&E’s calculation includes only six of 73 capacity-related projects, because only projects that can be deferred with less than a certain demand reduction (stated as 5% to 10%) are categorized as deferrable (A. 19-11-019, PG&E Testimony [PG&E-2], Chapter 4, p. 4-4, Table 4-1). The SDG&E calculation omits certain projects “deemed too large to be deferred” (ACC Documentation, p. 41).
   1. Can parties obtain and review the data on the excluded capacity-related projects, as well as details on the reasons for the exclusions? SEIA and Vote Solar observe that the IOUs already make public project-specific data on expected transmission additions, including cost ranges, in their AB 970 filings. The only additional data that might be needed in addition to what is already public in AB 970 reports is the size of the demand reduction necessary to defer each project. Any demand reduction used to exclude transmission projects as non-deferrable should be greater than the demand reduction from the amount of forecasted DERs. For example, since DERs can result in much more than just the 5% to 10% change in demand that PG&E uses to determine whether a project is deferrable, we need data on how many more transmission projects would be deferrable with the larger changes in demand that DERs can produce.

Data on projects excluded by the IOUs was not provided in the data they provided to Energy Division. Energy Division requests that PG&E and SDG&E include this information, if possible, in their comments.

* 1. Question 9 below asks whether the use of PG&E’s marginal transmission cost data from the ongoing A. 19-11-019 complies with D. 20-04-010. Given this open question, we would request the above PG&E transmission project data from both A. 19-11-019 and the “most recently complete [GRC Phase 2] proceeding,” which would be A. 16-06-013.

Information from A.16-06-013 was not provided to Energy Division or E3. To determine the comparable transmission marginal costs for PG&E from the earlier proceeding, parties can refer to the 2019 Avoided Cost Calculator

**Section 10 – Distribution Avoided Capacity Cost**

1. Are the workpapers from each utility’s Grid Needs Assessment available, such that parties can understand where Energy Division / E3 derived the data used in this first implementation of Method 1 for unspecified distribution avoided costs? We would be happy to review aggregate data without project-specific costs, to avoid confidentiality issues.

The tables for distribution avoided capacity costs in the ACC report are fully documented with sources and equations. Workpapers beyond that level of detail cannot be provided because of confidentiality issues with the source data. There are no intermediate workpapers with other aggregate information that were provided to Energy Division or E3.

1. What is the source for the 5-year forecast of DERs used in Line 12 of Table 25 of the Unspecified Distribution Deferral analysis? Are these DERs only solar PV projects? Is this DER data consistent with the DER data removed from the No New DER case?

The 5-year DER forecasts were provided by each IOU as part of their GNA. Table 2, showing precisely which DER energy and capacity resources are removed in the No New DER case, is on page 5 of the ACC documentation.

1. D. 20-04-010 states, at pp. 61-62:

*In addition, because the current Avoided Cost Calculator uses utility general rate case data, we adopt the general rate case data hierarchy proposed in Section 5.5.1 of the Staff Proposal. Staff will use data from the following sources, in descending order of preference:*

*1. Values adopted for revenue allocation from most recently completed proceeding.*

*2. Values adopted for rate design purposes from most recently completed proceeding.*

*3. Values agreed to by majority of parties for revenue allocation in settlement agreement from most recently completed proceeding.*

*4. Values agreed to by majority of parties for rate design purposes in settlement agreement from most recently completed proceeding.*

*5. Utility-proposed values for revenue allocation from most recently complete proceeding*. (emphasis added)

Given that the Commission was clear that all of these sources must be from the “most recently complete proceeding,” why does the draft 2020 ACC use transmission and distribution marginal cost data from ongoing GRC Phase 2 cases such as the 2019 SDG&E GRC Phase 2 (see Slide 17) and the 2020 PG&E GRC Phase 2 (for avoided transmission costs)? Are these mistakes?

We believe that the draft ACC is consistent with D.20-04-010, although we realize that we made several errors, for which we apologize. First, the information on Slide 17 was incorrect; the SDG&E distribution marginal cost data is actually from 2016, not 2019.

Second, the quoted data hierarchy section was inadvertently included in the “avoided transmission” section of D.20-04-010, whereas it should have been in the “avoided distribution” section. However, the Decision adopts the data hierarchy “as proposed in Section 5.5.1 of the Staff Proposal." Section 5.5.1 is the avoided distribution section of the Staff Proposal, and accordingly, the data hierarchy is meant to apply to distribution-level data. It would not be sensible or possible to apply the data hierarchy to transmission-level data at this time, because that data is not submitted by SCE nor SDG&E in their GRCs.

D.20-04-010 directs us to “to continue to use the marginal cost method used by PG&E in its derivation of transmission marginal costs to determine unspecified avoided transmission value in the Avoided Cost Calculator; the same method shall then be applied to SCE and SDG&E.” The Decision further states that “We recognize that refinements to the avoided transmission method will be needed. Accordingly, we direct staff to develop those refinements.”

To carry out this directive, we requested transmission data from all three utilities. We believe that PG&E data used for avoided transmission cost is the same data that PG&E has submitted in their 2020 GRC Phase 2, although we have not verified this. However, for the sake of consistency among the utilities, we believe it is a more reasonable interpretation of the Decision to use data supplied by the utilities to determine transmission costs, rather than rely on a data hierarchy for only one utility, especially given that it was intended for distribution avoided costs.

**Section 12 – Avoided Methane Leakage**

1. With whom at CARB did Energy Division consult in developing its proposed Methane Leakage Adder?

Energy Division cannot provide a list of CARB staff here. However, if parties have *specific* questions for CARB, we are happy to request and, if CARB agrees, facilitate a discussion of those questions with CARB staff.

1. From where did Energy Division obtain the figure of 25 for the Global Warming Potential (GWP) of methane? Is this based on the most recent science for methane’s impacts on climate change?

This is the 100-year value from the IPCC’s Fourth Assessment Report (AR4), which is used in the most recent [ARB GHG inventory](https://ww2.arb.ca.gov/ghg-inventory-data). There are newer estimates available, such as the GWP of 28 in AR5, but we have chosen the AR4 value in order to ensure consistency with the ARB inventory.

1. Please provide the source data and calculations for the 0.7% in-state methane leakage rate that is “implied from the CARB inventory” (Documentation, at p. 69). For example, please provide the volume of leaks from the inventory (the numerator) and the total in-state gas use (the denominator), as well as the source for each.
2. Please provide the calculation details on how the 6.4% leakage adder in Slide 10 of the High GWP presentation is decomposed into the adder of 5.57% for distribution/transmission/storage and instate production and 3.78% for residential behind the meter.

**The following response is to both questions 12 and 13.**

All numbers used to calculate methane leakage come from the Economic Sector categorization of the ARB GHG inventory, which is available directly [here](https://ww3.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_by_sector_all_00-17.xlsx) or under the “Full Inventory” heading on [this page](https://ww2.arb.ca.gov/ghg-inventory-data).

The relevant numbers that were taken from this file are below. All numbers are for the year 2017.

* In-state fugitive methane emissions, not including Residential BTM: 6.00 MMT (sum of rows 954, 956, 958, 974, and 976)
* Residential BTM fugitive emissions: 0.893 MMT (row 978)
* Total in-state natural gas combustion emissions: 107.75 MMT (obtained by filtering Column G to “Fuel combustion” and Column H to “Natural gas”)
* Residential natural gas combustion emissions: 23.62 MMT (sum of rows 904, 905, and 906)

Given these numbers, the relevant calculations to obtain the leakage adders discussed are:

* 6.4% leakage adder (initial estimate corresponding to the 0.7% in the Staff Proposal) = 6.89 MMT (total in-state fugitive emissions) / 107.75 MMT (total in-state natural gas combustion emissions)
* 5.57% upstream leakage adder = 6.00 MMT (in-state fugitive emissions excluding Residential BTM) / 107.75 MMT (total in-state natural gas combustion emissions)
* 3.78% residential behind-the-meter leakage adder = 0.893 MMT (Residential behind-the-meter fugitive emissions) / 23.62 MMT (Residential natural gas combustion emissions)

The 0.7% leakage rate discussed in the Staff Proposal (and referenced by this question) can be calculated from the 6.4% leakage adder discussed above, by applying the 9.1 conversion factor between leakage rates and adders discussed in the ACC documentation. 6.4% / 9.1 = 0.7%.

1. We understand that the adder of 5.57% is based only on leakage from instate gas production. What was the volume of in-state production assumed for this leakage rate, and what year(s) of data are used? The documentation, at p. 71, states that this adder only covers the leakage associated with the 5% to 10% of the natural gas used in California that is also produced in the state. Do you have a more exact percentage than the range of 5% to 10%? The data provided in response to Q13 may also help to answer this question.

We do not have a more exact percentage other than the range of 5% to 10%, because the percentage of California’s natural gas that is imported varies from month to month. However, all methane leakage estimates used in the ACC are derived directly from the ARB inventory, as detailed in the answer to questions 12 and 13 above. The percentage of natural gas consumption that is produced in-state is not necessary to derive the leakage adders.

1. Please confirm that, in the 2020 electric ACC model, the adder of 5.57% applies to any and all marginal GHG emissions in an hour, thus assuming that all GHG emissions are from burning natural gas in a power plant.  What if electric imports to California are from coal-fired generation elsewhere in the West?

Yes, it applies to all marginal GHG emissions, because the ACC assumes that marginal fossil generation is always from natural gas.

**Sections 5 and 7 – Avoided Energy and GHG Emissions**

1. What is the source of the heat rates shown on the “Emissions” tab of the 2020 ACC Electric Model, starting at cell B27? Why are these heat rates not the same as in the SERVM worksheet (e,g, see starting at cell AC6 of the “SERVM Price Inputs” tab)?

This has been corrected in version 1b.

**Questions submitted by California Large Energy Consumers Association**

Questions on 2020 ACC documentation

1. On Page 6, the documentation states that the SERVM model uses a historical weather month based upon different years for each month as represented in Table 3.

a. Does this mean that there are no stochastic weather scenarios to generate different load scenarios across the 2020-2030?

The avoided cost calculator only assumes one representative weather year. There are no alternate or stochastic load scenarios.

b. If the annual peak of the CTZ weather year is in September, will the annual peak remain the same for results from 2020-2030?

Given a consistent weather year across 2020-2030, weather-driven system peak will largely remain consistent from 2020-2030. Load growth forecasts between 2020-2030 will alter the shape of system load to a small extent due to changes in load from end uses with different load shapes. Renewable generation will also grow over the time period of 2020-2030, which will change the annual net peak. Based on the results shown in the ACC, these effects are not enough to move the system peak out of September, given the framework of the ACC.

c. If the answer to the previous question is “no,” please explain which month will contain the annual peak during each year from 2020-2030 and why that month would contain the peak.

1. On page 11, the documentation describes the method used to extrapolate the 2030 energy prices to later years by using an implied market heat rate.

a. Since the marginal prices beyond 2030 may not be driven by thermal units, is any type of adjustment performed to account for the fact that the marginal price of energy is likely to decline as more renewables are on the margin?

No. Beyond 2030, there are no adjustments made to account for more renewables likely being on the margin.

b. If the answer to the previous question is “yes,” please describe the adjustment in detail.

c. The calculation uses the variable O&M cost from a CT. Since the marginal prices in 2030, and beyond, may not be driven by thermal units, what is the justification to subtract the variable O&M from the energy price?

Based on price duration curves of the 2030 marginal prices output from SERVM, there is gas on the margin approximately 98% of annual hours. Hours with renewables on the margin, as defined by having zero or negative marginal pricing, do no subtract variable O&M from the price.

d. Did E3 consider using alternative methods to carry forward prices beyond 2030?

Yes.

e. If the answer to the previous question is “yes”, please describe what alternatives were examined and why were they not used.

The additional approaches E3 considered to carry prices forward beyond 2030, were:

A) Run a SERVM production cost model case for 2045, as an “out” year, and interpolate between 2030 and 2045.

B) Run additional production cost model cases between 2030 and 2045 for additional granularity of prices in the intermediate years between 2030 and 2045.

In both cases, the modeling team found insufficient data from IEPR load forecasts to model years beyond 2030. Load forecasts from 2020-2030 are based on hourly and annual load forecasts from IEPR. There was not a readily available approach to develop hourly load forecasts for 2030-2045 that would have been consistent with load forecasts from 2020-2030. This could be considered in future cycles.

f. The analysis assumes that increasing quantities of storage are used to shift solar energy production to later in the day.

i. What impact will this increasing level of storage have on the ratio of on-peak to off-peak prices?

Increasing the level of storage will decrease the ratio of on-peak to off-peak prices. In other words, it will generally decrease prices in on-peak hours, and increase prices in off-peak hours. A good indicator of this is the comparison of the raw price outputs of the Reference System Plan and the No-DER case; the No DER case has approximately 3 GW of additional energy storage relative to the RSP.

ii. Was any impact on energy price differentials taken into account for energy rent calculations post 2030 in the storage energy revenue model?

No.

iii. If the answer to the previous question is “yes,” please provide a detailed description of how the changes in energy price differentials affected the energy rents post 2030.

1. On page 11, the documentation mentions that a price floor of zero and a cap of $150/MWh were set for energy prices.

a. Since observed CAISO prices in 2018 were clearly outside these caps, please provide more explanation on the purpose of employing these caps and why the chosen cap values are appropriate.

Please note that the price cap mentioned on p. 11 of the ACC documentation is $250/MWh, not $150/MWh. The $250 cap was is chosen to encompass historical prices and eliminate any overly-high simulated prices beyond those which the market dynamics allows. The observed historical prices in 2019 all fall below this cap. In each year, the prices are only capped for 1 to 6 hours (averaging 2 hours per year).

b. Were other cap values such as -$15/MWh or $1000/MWh considered?

No, no other caps were considered.

c. If the answer to the previous question is “yes,” then please explain why were these caps were not used.

d. How does price caps impact the calculation of energy rents?

There are approximately 10 hours in any given year that SERVM projects energy prices higher than the cap of $250/MWh. Increasing the cap would generally not have a large impact on energy prices over the course of the year. Decreasing the cap will have an increasingly large impact as the cap is decreased.

1. On page 12, scarcity adjustments were used to capture that “[p]roduction simulation models are often unable to represent extreme hourly market prices, due to a lack of probabilistic real-world variables, such as contingency events, forecast errors and market irrationality”.

a. Please explain how the scarcity adjustment was calculated, providing the formula used and the inputs to that formula.

Please refer to Section 5.1.1 in the ACC documentation on implied marginal heat rate calculation, including formula and inputs, and Section 5.1.3 for more detail on the scarcity adjustment.

b. Why was 2019 used as the historical benchmark year?

2019 was selected as the historical benchmark year because it is the most recent historical year, and will therefore have the most consistency with renewable generation capacity and system loads.

c. Is 2019 considered a 1 in 2 weather year?

No

1. Please explain the X (horizontal) axis on the graphs in Figure 6. How should “IMHR [20:1e+05]” or “IMHR [18:20]” be interpreted in the figure?

IMHR refers to implied market heat rate, as defined in section 5.1.1 of the ACC Documentation. As explained in Section 5.1.3 of the ACC Documentation (p. 12, just above Figure 6), the two numbers in the square bracket refers to the range of unadjusted SERVM IMHR that are plotted in this chart. For example, [18: 20] means that all hours with an unadjusted SERVM IMHR between 18 to 20 MMBTU/MWh are plotted in this section.

1. Does the real-time price forecast in later years assume that the growth of solar [or wind] plus battery storage could smooth real-time forecast errors?

No, it does not.

1. On page 16, in Figures 9 & 10, the highest prices appear to be in August for both NP15 and SP15. On page 32, in Figure 21, the highest level of Expected Unserved Energy (EUE) is in September. Please explain why times of greatest shortage do not result in the highest prices?

Figures 9 and 10 show the month-hour average of prices, so it is not an accurate measure of the peak day. The prices from the peak day in September are likely counter-weighted by slightly lower prices in the remainder of the month.

1. On Page 17, the use of a compounded average growth rate of ancillary service (AS) prices from 2020-2030 is used to extrapolate AS prices beyond 2030.

a. What is the annual average compounded growth rate for 2020-2030?

The compound growth rate of annual average prices from 2020-2030 is approximately 7.8% for both spinning reserve and regulation market prices.

b. Will increased storage capacity installation post 2030 impact the AS pricing market?

Increased storage will likely decrease prices in AS markets, but only once markets are fully saturated with energy storage. For example, the regulation market in California is approximately 700 MW; if energy storage capacity participating in the regulation market exceeds 700 MW, prices will likely decrease. Based on No DER resource build, this level of penetration is project is likely to occur in the 2020s, after which the AS pricing markets will not fundamentally change.

c. If the answer to the previous question is “yes,” did E3 consider an adjustment to take into account the impact of the growth of storage on future prices?

1. On page 31, the energy revenues are calculated using an optimal dispatch model. This is an unrealistic assumption since perfect foresight is also unrealistic. During the web-meeting on May 7, an adjustment of 15% was discussed to reflect optimal dispatch cannot occur. Please confirm this value and explain its basis.

The 15% discount was discussed as a rough estimate. It is based on E3’s experience working with project developers and comparing perfect foresight models to actual dispatch results. E3 does not have workpapers or publicly available analysis to support this figure.

1. In order to provide capacity during the CAISO’s Availability Assessment Hours (AAH):

a. Was the battery state of charge restricted to be at 100% to provide its rated capacity for unexcepted events during the AAH?

Energy storage is modelled to provide resource adequacy and maintain full charge in anticipation of possible calls for system capacity.

b. Was the battery’s ability to offer ancillary services limited during the AHH?

Yes, the battery is able to discharge energy but not provide ancillary services during these hours.

c. If the answer to the previous question is “no,” can the battery provide its rated capacity if the state of charge is less than 100% due to the provision of ancillary services?

1. Please explain how a minimal price differential between a charge and discharge cycle is taken into account in calculating net revenues.

a. Did E3 include a minimum price spread, or profit margin, after taking into account parasitic losses and roundtrip efficiency for the battery to engage in a charge and discharge cycle?

No minimum profit margin is included. We do not find that including a minimum profit margin significantly impacts revenues for energy storage in the day-ahead energy or AS markets.

b. Did E3 take into account the cost associated with battery degradation that would occur if the battery is cycled in determining a minimal price differential necessary to provide the battery owner an incentive to cycle the battery?

Round Trip efficiency is included in the revenue optimization. Parasitic losses are included, but do not affect dispatch decisions. Cycling is limited to one cycle per day. Augmentation costs are assumed to maintain battery health without degradation. Battery cost and performance assumptions are taken from inputs developed in the IRP proceeding. See CPUC IRP – Inputs and Assumptions – 2020-02-27.pdf available at <https://www.cpuc.ca.gov/General.aspx?id=6442459770>.

1. What limitations occurring in battery operations (i.e. depth of discharge, charging and discharging rates, and frequency) are included in the energy revenue model so that its operation conforms to extended warranty restrictions.

Battery dispatch is limited to one cycle per day, with no limits on depth of discharge. Battery cost and performance assumptions are taken from inputs developed in the IRP proceeding. See CPUC IRP – Inputs and Assumptions – 2020-02-27.pdf available at <https://www.cpuc.ca.gov/General.aspx?id=6442459770>.

1. Which energy price case was used to calculate storage’s energy rents, No New DER or Reference System?

No New DER case.

1. The CAISO’s study on the performance of storage resources shows that today, the resources are not moving significant amount of energy across different hours of the day. At the May 7 webmeeting, E3 stated that while that is not happening today, it expects this to happen in the future.

a. When does E3 expect significant energy shift to occur?

b. What factors will drive the change in storage’s behavior?

c. If these include greater price differentials increasing the amount of arbitrage, please provide support for such an assumption.

d. How does the fact that battery operators do not have perfect foresight affect these factors?

e. Can the ACC model be adjusted to calibrate current observed storage performance and then transition to future expected performance?

f. If the answer to the previous question is “yes,” then why did E3 not implement this adjustment?

E3 has experience developing market price forecasts and revenue modeling for project developers, and shared opinions based on this work during the webinars. However, E3’s opinions of future market developments and prices are not included in the ACC, which relies on SERVM production simulation modeling of IRP resource portfolios. The PD direction is to use SERVM production simulation of the No New DER portfolio as the basis for Energy and AS prices. We do see a way to introduce a transition of changing energy storage dispatch and market price formation given that direction.

1. The CAISO’s Energy Storage and Distributed Energy Resources Phase 4 initiative indicates that the CAISO’s real-time energy market advisory schedules may cause resources to be uneconomically dispatched.2 Has E3 incorporated possible economic losses into the determination of market rents in the energy revenue model?

E3 has not included any uneconomic dispatch in our revenue calculations.

1. On page 32, the RCAP model was used to calculate Expected Unserved Energy (EUE) using 63 years of historical load and generation data.

a. Please confirm that the results in Figure 21 are prior to the mapping of EUE to the CTZ22 weather year for 2020.

Figure 21 values are presented prior to mapping to the CTZ weather year.

b. Please provide an explanation of why 63 weather years results in 96.5 % of EUE occurring in September 2020.

The RECAP model shows that September has approximately equal gross loads but lower levels of renewable and hydro generation when compared to summer months of July and August. This leads to the majority of loss of load events to be concentrated in September.

1. On page 32, Figure 21 shows the EUE is over 6 hours for September.

a. Will a 4-hour battery be sufficient to avoid the expected outage event in September?

EUE shows the probability of unserved energy in a given hour, but does not predict individual outages of a specific duration. The ELCC adjustment calculated in RESOLVE does account for the limitations of a 4 hour battery to meet peak loads given the other resources in the portfolio.

b. What resource will be used in hours 5 and 6 if a 4-hour battery is relied upon to meet the peak in a 6-hour event?

The EUE heatmaps only provide a sum of total outage hours across the 63 year period. They do not provide an indication of the duration of each outage. The Expected Load Carrying Capacity of a 4 hour battery is already accounted for in the calculation of generation capacity value, with the battery ELCC data taken from IRP.

The ELCC takes into account that a 4 hour battery could only meet part of a longer outage. Presumably many batteries would be available during a 6-hour event, allowing batteries to be dispatched in succession.

1. Given that the highest prices are in August per Figures 9 & 10, then why is there only 0.9% EUE in August 2020?

Energy prices are generated by running production simulation through SERVM, while EUE values are generated using the RECAP model. SERVM relies more on estimates under average conditions, while RECAP relies on outage conditions and forecasts based on non-normal peak conditions.

1. Please provide a Figure 21 for 2025 and 2030

This will be added to the figure in version 1b of the ACC documentation.

1. On page 32, the documentation mentions the RECAP results are mapped into 8760 hours using the CTZ22 weather year for 2020: “A load-weighted daily maximum statewide temperature is calculated and all hours in days where this value exceeds 90 degrees F receive the corresponding month/hour/day-type EUE value from RECAP.”

a. Does this mapping move EUE between different months and different hours?

EUE is provided in two tables of 12 months by 24 hours (576 values), one for weekdays and one for weekends. The EUE for each month hour is allocated across all the days in that month. For example, the EUE for HE 13 in September, is allocated across all HE 13 for each of 30 days.

b. It is generally accepted that the net load (which subtracts wind and solar) is a period when possible shortage can occur. What analysis has E3 performed that indicates that using temperature in excess of 90 degrees is a reasonable proxy for EUE hours during net load hours that occur in the evening?

The RECAP analysis demonstrates a correlation between high statewide average temperatures and unserved energy potential. The threshold is set at 90 degrees to produce a representative number of PCAF hours that aligns with previous renditions of the ACC.

c. Please provide any model used for this analysis along with the underlying data

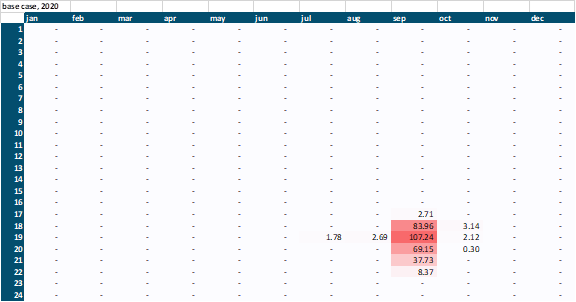
The model used to generate the PCAFs can be uploaded as an additional attachment. We are working on making that data file available.

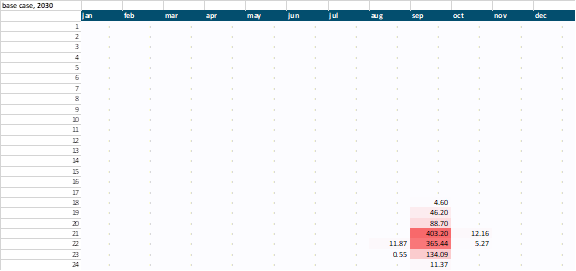
1. Please provide a figure showing the remapped capacity allocation factors (figure 22) using the format (months and hours) style from Figure 21.

This has been updated in v1b of the documentation.

A snapshot of these hourly EUE values in 2020 and 2030 are shown below

Figure 21. Hourly Expected Unserved Energy from RECAP





1. On page 34, the documentation states, “The DTIM has a long history of use for marginal cost estimation in California, and we continue its application for PG&E’s avoided transmission capacity costs.”

a. Has the commission adopted this methodology in the utilities’ General Rate Case (GRC) Phase 2 proceeding which approve marginal costs?

The DTIM was first proposed by PG&E in 1999 and has been used in all PG&E GRC filings since then. (A.16-06-013 (PG&E-9), Chapter 1, footnote 3).

b. If the answer to the previous question is “yes,” please provide the decision number and page reference for this adoption.

Marginal costs are often adopted as part of settlement agreements, so it is unclear if the methodology per se was adopted in any GRC proceedings.

c. Does either Southern California Edison or San Diego Gas & Electric utilize the DTIM methodology in its GRC Phase 2?

SCE and SDG&E utilize regression-based methods rather than the DTIM for their distribution marginal capacity costs. Neither utility provides transmission marginal capacity costs in their GRC filings. We have not researched the methods the utilities use to derive their Transformer, Service Drop, and Meter unit costs used for their Rental Method calculations of marginal customers costs.

Questions Regarding 2020 ACC Net Cone v1a.xlsx

1. The Battery Costs tab provides the costs of capacity battery and energy battery.

a. Please explain in detail the procedure for determining whether a cost is considered a “capacity” cost or an “energy” cost.

b. Why is it important to attempt this classification, which introduces the complexity of adding together capacity and energy capital costs together, before subtracting any energy rents?

Battery system costs are commonly expressed for power ($/kW) and energy ($/kWh of battery capacity installed) components separately.

Battery storage costs are attributed to either the capacity or duration category using AC and DC storage component cost data and comparisons of storage costs at differing durations. The types of costs included in each category are summarized below:

* Capacity (kW): Inverter, switches and breakers, other balance of system and Engineering, procurement and construction (EPC) costs.
* Duration (kWh): Battery cell modules, racking frame/cabinet, battery management system.

These cost assumptions are taken directly from inputs developed in the IRP proceeding. See CPUC IRP – Inputs and Assumptions – 2020-02-27.pdf available at <https://www.cpuc.ca.gov/General.aspx?id=6442459770>.

The IRP relies on storage cost assumptions from Lazard’s Levelized Cost of Storage 4.0 (2018) available at: https://www.lazard.com/media/450774/lazards-levelized-cost-of-storage-version-40-vfinal.pdf and supplemented by NREL’s Solar and Storage Report: Available at: <https://www.nrel.gov/docs/fy19osti/71714.pdf> .

1. IRP Inputs tab: The capital costs on lines 26 & 27 on the IRP Inputs tab do not appear to come from the values on the Battery Costs tab. Please explain the calculations or source of the data for the battery capital costs on lines 26 & 27.

The battery storage resource costs on the IRP tab are inputs from the IPR. These inputs are repeated in the first table in the Generation Capacity tab.

1. Referring to the Battery Costs tab at line 17, given that battery can degrade over time and by cycling:

a. Please explain why the degradation is 0% per year.

b. Is the cost of degradation accounted for by the Annual Augmentation Costs on line 36?

c. Please provide a derivation of the 5% augmentation costs used for some of the battery alternatives.

Periodic replacement and augmentation costs are assumed to maintain battery health over its useful life. Battery cost and performance assumptions are taken from inputs developed in the IRP proceeding. See CPUC IRP – Inputs and Assumptions – 2020-02-27.pdf available at <https://www.cpuc.ca.gov/General.aspx?id=6442459770>.

1. Referring to the Battery Costs tab, line 20, please provide the support for 15% cost reduction from 2016 to 2020.

Battery cost and performance assumptions are taken from inputs developed in the IRP proceeding. See CPUC IRP – Inputs and Assumptions – 2020-02-27.pdf available at <https://www.cpuc.ca.gov/General.aspx?id=6442459770> .

1. Referring to the Battery Costs tab, line 23, given the assumption is a standalone battery, why is there no interconnection costs included in the capital costs?

The IRP uses zero interconnection costs. This would be consistent with an assumption that storage is predominately co-sited with solar (which does have an interconnection cost of $200/kW). We are taking inputs directly from the IRP proceeding and we recommend the issue of which interconnection costs should be included for a battery storage resource be taken up in that proceeding.

1. Referring to the Battery Costs tab, line 25:

a. Please provide the support for decrease in fixed O&M from year to year.

b. What is the percentage of labor and capital costs assumption for the fixed O&M?

c. Is the labor cost expected to decrease over time?

d. If the answer to the previous question is “yes,” please explain if the cost of labor and material was escalated separately.

Capital costs and Fixed O&M both have a progress multiplier to reflect declining battery technology costs. Battery cost and performance assumptions are taken from inputs developed in the IRP proceeding. See CPUC IRP – Inputs and Assumptions – 2020-02-27.pdf available at <https://www.cpuc.ca.gov/General.aspx?id=6442459770>.

1. Referring to the Battery Costs tab, line 28:

a. Why is variable O&M zero?

b. How is the value of degradation of the batteries taken into account when a cycling event occurs?

No degradation is calculated based on the number of cycles. Periodic replacement and augmentation costs are included and assumed to maintain battery performance. Battery cost and performance assumptions are taken from inputs developed in the IRP proceeding. See CPUC IRP – Inputs and Assumptions – 2020-02-27.pdf available at <https://www.cpuc.ca.gov/General.aspx?id=6442459770>.

1. Referring to the Battery Costs tab, line 34:

a. Please provide support for 1.5% annual cost to extend warranty.

b. Does this cost change with depth of discharge and frequency assumptions?

Please refer to the IRP inputs and assumptions referred to above.

1. Referring to the Battery Costs tab, line 36:

a. Why is there no Augmentation Costs for the capacity battery given that in the modeling is it assumed to have frequent cycling?

b. Is the Annual Augmentation Cost considered an investment to maintain the capital asset?

c. Is the Annual Augmentation Cost included as an ongoing capital investment in the financing costs or is it treated as an expense?

d. If the Annual Augmentation Cost is considered an expense, please explain why a replacement cost would be considered an expense.

Augmentation costs are shown for energy (kWh installed) but not for capacity (kW). The augmentation costs of 4.2% for the energy components of the battery includes periodic replacement and augmentation, so periodic replacement is not included separately.

Financial assumptions are shown in the Pro Forma tab of the 2020 ACC Net Cone Excel file. The pro forma assumes IPP financing and all annual expenses are treated the same. There is no capitalization of costs included in rate base as there is with utility financing.

Periodic Replacement and Augmentation costs are included and assumed to maintain battery performance. Battery cost and performance assumptions are taken from inputs developed in the IRP proceeding. Please refer to the IRP inputs and assumptions referred to above.

1. Referring to the Battery Costs tab, line 37: Why is there no property tax included in the capital cost? Please refer to the IRP inputs and assumptions referred to above.
2. Referring to the Battery Costs, line 38: Why is there no periodic replacement given that batteries will degrade over time even if they are not used over the 20-year assumed life?

Augmentation costs are shown for energy (kWh installed) but not for capacity (kW). The augmentation costs of 4.2% for the energy components of the battery includes periodic replacement and augmentation, so periodic replacement is not included separately.

Please refer to the IRP inputs and assumptions referred to above.