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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CAL

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues	Rulemaking 12-11-005 (Filed November 8, 2012)

COMMENTS FROM ETAGEN INC. REGARDING THE PROPOSED DECISION REVISING THE GREENHOUSE GAS EMISSION FACTOR TO DETERMINE ELIGIBILITY TO PARTICIPATE IN THE SELF-GENERATION INCENTIVE PROGRAM PURSUANT TO PUBLIC UTILITIES CODE SECTION 379.6(b)(2) AS AMENDED BY SENATE BILL 861

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I. INTRODUCTION

EtaGen Inc. ("EtaGen") appreciates the opportunity to files these Comments Regarding the Proposed Decision Revising the Greenhouse Gas Emission Factor to Determine Eligibility in the Self-Generation Incentive Program Pursuant to Public Utilities Code Section 379.6(b)(2) as Amended by Senate Bill 861 ("PD").

II. REPLY COMMENTS

Response to Section 3.1.1. Generation Technology

In determining the weighting that should be applied to short-term ("Operating Margin" or "OM") and long-term ("Build Margin" or "BM") effects when updating the GHG emissions factor ("EF"), the PD references the World Resources Institute's report, *Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects* ("the Report").[1] While EtaGen does not agree with several aspects of the Report, we recognize that the Commission has leveraged its methodology to determine the GHG EF proposed in the PD. As such, this section of our comments is meant to address some inconsistencies in the implementation of the methodology in determining the new GHG EF.

The PD proposes adopting "a methodology that assigns equal weight to the short-term and long-term effects over a ten-year time span" in order to "account for both types of avoided generation effects while balancing the need for an acceptable level of administrative complexity." The Report provides a framework for determining BM/OM weighting factors, "*w*", and summarizes this framework in the Report's Figure 5.1, which is re-presented below. As shown in Figure 5.1, the first question to ask when determining a weighting factor is whether or not there is "already too much capacity." For cases when this is true, the Report recommends using a weighting factor that accounts for only the OM being displaced (i.e., $w = 0$). The Report supports this recommendation by saying, "If the grid has more than enough capacity to meet foreseeable power demands (i.e., there is "overcapacity") then there may be no demand. The project activity may not actually displace any new capacity, and will only affect the OM. In these

[1] http://www.wri.org/sites/default/files/pdf/ghgprotocol-electricity.pdf

cases, assigning a value of zero to *w* is appropriate. The extent and expected duration of grid overcapacity should be documented."[2]

According to the PD, "the most recent Commission LTPP decision authorizing procurement of new capacity, the Commission found that new capacity would not be needed in either the SCE or SDG&E territories before 2022." Additionally, CAISO states in their *2015 Summer Load & Resource Assessment* report that, "Planning reserve margins under the normal peak demand scenario are projected to be 39.1 percent for the CAISO system, 35.3 percent for SP26, and 44.4 percent for NP26 (Table 1). Operating reserve margins, which represent planning reserve margins adjusted for generation outages and hydro derates, under the normal summer conditions are expected to be 25.3 percent for the CAISO system, 25.0 percent for SP26, and 26.4 percent for NP26 (Table 2 and Figure 1). Both the planning reserve margin and the normal operating reserve margin are projected to be greater than the California Public Utility Commission's 15 percent resource adequacy requirement for planning reserve margin."[3] This information, individually or together, suggests that the answer to the first question is "yes", there is already too much capacity. As such, a weighting factor that accounts for only the OM being displaced ($w = 0$) seems appropriate.

However, as the PD notes, the Report later states that "any capacity provided by the [onsite generation] project activity could still avoid the need for new capacity in the future, once demand grows and market conditions change."[4] Although the Report does not provide support for this claim, it does provide guidance for handling such scenarios, which is summarized in their Box 8.3 and re-presented below. As can be seen in Box 8.3, the Report recommends using two time periods with two separate weighting factors: first, a weighting factor that accounts for only the OM being displaced ($w = 0$) for the first time period when there is overcapacity, and second, a weighting factor that "for the second time period using the guidance in Chapter 5, assuming there is no longer excess capacity on the grid." According to this guidance, it is appropriate to use a weighting factor for only displacing the OM (w = 0) for the years before 2022, and then use different weighting factor for the years after 2022 <u>assuming</u> that there will no longer be overcapacity in this time period.

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[2] Page 31 of the WRI report.
[3] Page 4. https://www.caiso.com/Documents/2015SummerAssessment.pdf
[4] Page 31 of the WRI report.

Referring back to the report's Chapter 5 for guidance in determining the weighting factor for the second time period, the second question in Figure 5.1 asks, "is there chronic under-capacity?" Given that the Commission requires, as part of the resource adequacy requirement, that the CAISO maintain a 15% planning reserve margin, the answer to this question should clearly be "no." This takes us to the third question in Figure 5.1, "is the project *not* considered a source of new capacity?" There are significant complexities in answering this question. If one assumes behind the meter generation that receives standby service or pays for standby capacity is not considered new capacity because the IOUs still needs to procure capacity for standby service, then the answer to this question is "yes" (i.e., an SGIP project is not new capacity) and the weighting factor should only be for OM displacement ($w = 0$). In terms of determining the new GHG EF, this would make the GHG standard less stringent for SGIP projects. Although EtaGen believes SGIP projects are not always considered new capacity in this context, since the answers to this question may be "yes" or "no" depending on project specific information, EtaGen will consider the conservative assumption (with respect to lowering the GHG EF) and assume the answer to this question is "no". With this assumption, the following question asks, "does the project provide firm power?" The Report provides clarification on their meaning and use of the term "firm power" by stating, "for the purposes of these guidelines, a firm power plant is one that can be consistently relied on to deliver power to the grid when the power is needed" and "the distinction between firm and non-firm power sources is meant to distinguish between those that are consistently available to deliver power, and those that are only intermittently available."[5] Given the wide-range of SGIP technologies (e.g., fuel cells, CHP, batteries) and applications (e.g., baseload, load tracking, and peaking) and the fact an SGIP project's operation and non-operation is entirely up to the discretion of the project's owner, SGIP projects should not be considered as firm power for the purpose of answering this final question.

Following a "no" answer to the last question in Figure 5.1, the Report then recommends using a weighting factor based on "capacity value" and capacity factor. The Report defines the capacity value of a power plant as "the amount of power it can be reliably called upon to provide, and thus its ability to meet capacity demand." For the same reasons noted in the previous paragraph for why SGIP projects should not be considered firm power, it would be difficult, if not impossible, to determine a capacity value for all SGIP projects planned to be built

[5] Page 87 of the WRI report.

in the future, especially at a program level. The Report provides guidance for such circumstances--specifically, for scenarios "where determining a precise capacity value and/or expected capacity factor is not practical." As summarized in Table 5.1 of the report, an equal weighting factor ($w = 0.5$) is recommended in two scenarios: one, when the project activity provides on-peak, baseload, or intermittent generation and non-firm power, and two, when the project activity provides exclusively off-peak generation and firm power.[6] A weighting factor for only displacing OM ($w = 0$) is recommended when the project activity provides exclusively off-peak generation and non-firm power, and a weighting factor for only displacing BM ($w = 1$) is recommended when the project activity provides on-peak, baseload, or intermittent generation and firm power. Since SGIP projects do not provide firm power and do not exclusively provide off-peak generation, neither weighting factors of only displacing BM ($w = 1$) nor only displacing OM ($w = 0$) are appropriate. Therefore, according to the Reports guidelines, applying an equal weighting factor for displacing BM and OM seems most appropriate for the years after 2022.

Using the weighting factors and time periods described in this section of our comments, EtaGen respectfully urges the Commission to revise their methodology to be more consistent with the WRI's guidelines and recommends using the following equation for determining the new GHG EF:

(1) GHG EF =

$$(Y_{OCE} - Y_{INS})/Y_{PL} * [(1 - w_1) * (ER_{OLF} * (1 - WFP) + ER_{OP} * WFP) +$$
$$w_1 * (1 - RPS\% * (1 - LLF)) * (ER_{BLF} * (1 - WFP) + ER_{BP} * WFP)]/(1 - LLF) +$$
$$(1 - (Y_{OCE} - Y_{INS})/Y_{PL}) * [(1 - w_2) * (ER_{OLF} * (1 - WFP) + ER_{OP} * WFP) +$$
$$w_2 * (1 - RPS\% * (1 - LLF)) * (ER_{BLF} * (1 - WFP) + ER_{BP} * WFP)]/(1 - LLF)$$

Where:

Y_{OCE} = year overcapacity period ends = 2022

Y_{INS} = installation year = dependent on project timing

Y_{PL} = project life = 10 years

w_1 = BM/OM displacement weighting factor = 0

w_2 = BM/OM displacement weighting factor = 0.5

ER_{OLF} = operating margin emission rate of load-following plants = 382 $kgCO_2/MWh$ (from

[6] Table 5.1 of the Report, page 33.

the PD)

WFP = weighting factor for peaker plants = 30% (see our Response to Section 3.2.3)

ER_{OP} = operating margin emission rate of peaking plants = 544 $kgCO_2/MWh$ (from the PD)

RPS% = RPS portfolio requirement = 33% (from the PD)

ER_{BLF} = build margin emission rate of load-following plants = 368 $kgCO_2/MWh$ (from the PD)

ER_{BP} = build margin emission rate of peaking plants = 524 $kgCO_2/MWh$ (from the PD)

LLF = line loss factor = 8.4% (from the PD)

The above equation would require that the Commission update the emissions factor for each year the program is managed. Since annual updates could be administratively burdensome, this can be avoided by assuming that the first projects under the new program rules are installed in 2016 and the last projects are installed in 2020, which we believe to be a reasonable assumption given that current legislation directs the Commission to collect funds through 2019 and administer the program through 2020.[7] With these assumptions, the average installation year of SGIP projects (Y_{INSAVG}) is 2018, which can be used in place of the installation year (Y_{INS}). This yields a fixed overcapacity time period weighting factor (OCTPWF) equal to 0.4, where OCTPWF = $(Y_{OCE} - Y_{INSAVG})/Y_{PL}$.[8] The above equation then simplifies to:

(2) GHG EF =

$$\begin{aligned}
&OCTPWF * [(1 - w_1) * (ER_{OLF} * (1 - WFP) + ER_{OP} * WFP) + \\
&\qquad w_1 * (1\text{-}RPS\% * (1 - LLF)) * (ER_{BLF} * (1 - WFP) + ER_{BP} * WFP)]/(1 - LLF) + \\
&(1 - OCTPWF) * [(1 - w_2) * (ER_{OLF} * (1 - WFP) + ER_{OP} * WFP) + \\
&\qquad w_2 * (1\text{-}RPS\% * (1 - LLF)) * (ER_{BLF} * (1 - WFP) + ER_{BP} * WFP)]/(1 - LLF)
\end{aligned}$$

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[7] SGIP currently has a window of 2 years for installation after money is allocated to a project. If the last award is given by 12/31/2019 (the program has been fully subscribed each year much earlier than at the end of a year), then the last a project would need to be installed by 12/31/2021. Given that not all projects will utilize the full 2 year window and the program is typically oversubscribed within a few months of a new program year, we believe that it's a fair assumption to say that the last projects are installed in 2020.

[8] The value of 0.4 for OCTPWF can also be derived by looking at each installation year, calculating the fraction of project life that only the OM is displaced, and then averaging the fractions. Using this equation $(Y_{OCE} - Y_{INSAVG})/Y_{PL}$, installations in 2016 displace only the OM 60% of their project life ((2022-2016)/10=0.6), those in 2017 for 50%, 2018 for 40%, 2019 for 30%, and 2020 for 20%. The average of these percentages equals 40%, yielding an OCTPWF of 0.4.

Where:

OCTPWF = overcapacity time period weighting factor = average fraction of project years that SGIP projects operate during the time period of overcapacity = $(Y_{OCE} - Y_{INSAVG})/Y_{PL}$ = (2022 - 2018)/10 = 0.4

Inserting the values for OCTPWF, w_1, and w_2, the above equation simplifies to:

(3) GHG EF =

$0.4^* (ER_{OLF} * (1 - WFP) + ER_{OP} * WFP)/(1 - LLF) +$

$0.6^* [0.5 * (ER_{OLF} * (1 - WFP) + ER_{OP} * WFP) +$

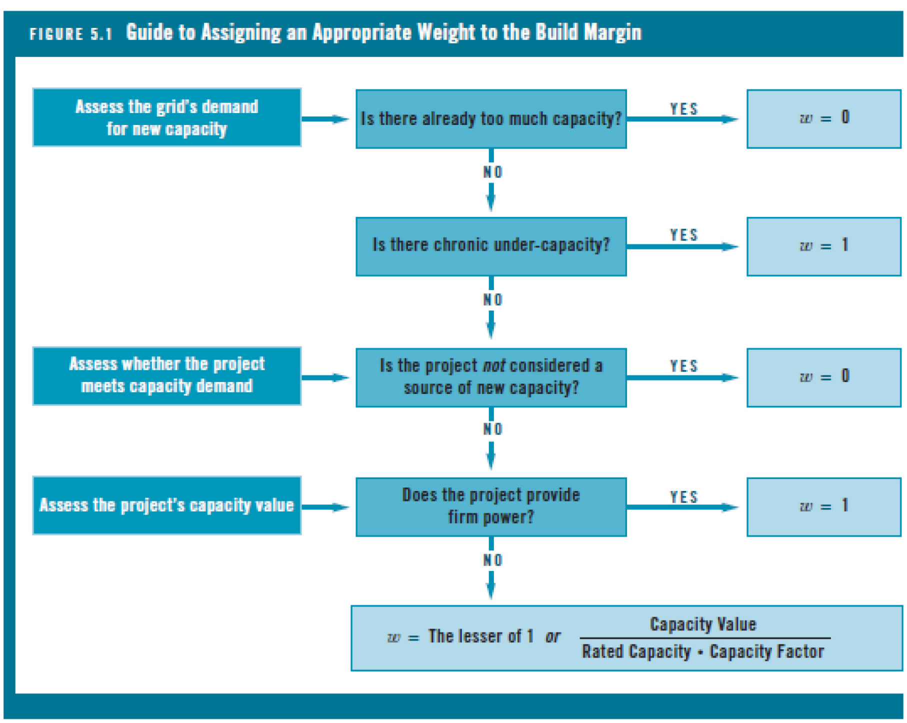
$0.5 * (1\text{-}RPS\% * (1 - LLF)) * (ER_{BLF} * (1 - WFP) + ER_{BP} * WFP)]/(1 - LLF)$

which can be further simplified to:

(4) GHG EF =

$\mathbf{(0.7 * (ER_{OLF} * (1 - WFP) + ER_{OP} * WFP) +}$

$\mathbf{0.3 * (1\text{-}RPS\% * (1 - LLF)) * (ER_{BLF} * (1 - WFP) + ER_{BP} * WFP))/(1 - LLF)}$



BOX 8.3 Lack of Capacity Demand and its Effect on the Baseline Scenario

A grid with excess power capacity – i.e., more than sufficient capacity to meet peak load requirements over a multi-year period – presents a unique type of "market structure" barrier (see Table 8.1). Periods of true overcapacity will be rare, but they can constitute a real barrier to new power generation projects – including, in most cases, the project activity itself (if it involves electricity generation). Under these circumstances, new power plant additions are likely to be uneconomical and therefore unlikely to occur until electricity demand grows. A project activity implemented under these conditions may not immediately displace generation at the BM (see Section 5.1). However, any capacity provided by the project activity could still avoid the need for new capacity in the future, once demand grows and market conditions change. This means that the baseline scenario may involve 100% OM displacement for a number of years, followed by BM displacement (or a combination of BM and OM displacement) once new capacity is needed. The baseline scenario should be characterized as follows:

- Assume the project activity will displace only the OM ($w = 0$) for the first time period, and justify this baseline scenario for the time period accordingly (following the guidance in this chapter).
- Determine a separate weight, w, for the second time period using the guidance in Chapter 5, assuming there is no longer excess capacity on the grid.

The length of the first time period should be estimated transparently using publicly available data. The length of this time period will depend upon the magnitude of excess capacity, and assumptions about load growth and capacity requirements. All data and assumptions used for this estimate should be reported and explained. For further guidance, consult Section 8.2.3, Box 8.6, and Box 8.8 of the *Project Protocol*.

Response to Section 3.2.3. Weighting Load-Following and Peaker Plants in the Final Emission Rate

In order to determine the number of hours an SGIP project displaces peaker heat rates, the PD elects to use a number that represents the average capacity factor of individual peaking plants:

> "...new combustion turbines are estimated to have operated at an approximately 8% capacity factor during the 2010 to 2013 time period. We find this estimate to be more representative of the amount of time that peakers are likely to provide the marginal resource..."

EtaGen strongly disagrees with this sentiment. The *capacity factor* of a *single* combustion turbine is simply not indicative of the total *number of hours* that *any* combustion turbine in CAISO is running and therefore the marginal resource that is being displaced by SGIP projects. For example, one combustion turbine with a capacity factor of 8% could be on 16% of the hours of the year if it is always run at 50% load. Additionally, two peaking facilities always running at 100% load with 8% capacity factors could have staggered run times, and both plants could be running at separate times for a total of 16% of the hours in a the year. As such, EtaGen's initial suggestion to use the highest single capacity factor (KRCD Malaga Peaking Plant in 2013 at 20.6%) was intended to be *conservative* when being used to represent the percentage of the hours that <u>any</u> peaker in the fleet is operating (i.e., any hour that peaker heat rates are on the margin in CAISO).

To further investigate the number of hours peakers were on in CAISO, we have downloaded historical CAISO energy prices to determine which hours peaker heat rates cleared in the day-ahead market. Assuming the avoided peaking heat rate of 10,268 Btu/kWh (HHV) from the Proposed Decision, a non-fuel marginal cost of electricity of $4.60/MWh, and an average $4.71/MMBtu wholesale gas price for 2014 based on EIA data, our analysis of the data shows that **peaker heat rates cleared the day ahead market in CAISO 29.8% of the hours in 2014**.[9,10,11][12] The result is similar (30.2%) when monthly EIA gas prices are used in lieu of the annual average.

This data shows that the average capacity factor of a single peaker plant is in no way indicative of the number of hours per year any peaking plant is chosen to be dispatched in CAISO.

Moreover, the paradigm presented in the PD where peaker heat rates are being offset for only 8% of the year greatly diminishes the value of storage and further errodes its case for

[9] CPUC SGIP Proposed Decision Page 17 - 10,268 Btu/kWh for peaker heat rates

[10] E3 DER Avoided Cost Model (July 24, 2012) , "Inputs" Tab Cell C17, escalated to 2014 dollars is $4.60/MWh - https://ethree.com/documents/DERAvoidedCostModel_v3_9_2011_v4d.xlsm

[11] EIA California Citygate historical prices - average is $4.71/MMBtu for 2014 - http://www.eia.gov/dnav/ng/hist/n3050ca3m.htm

[12] EtaGen Peaker Dispatch Analysis for 2014 - https://docs.google.com/spreadsheets/d/1RmXMT2oRJdEXSNAcecUDmm0UFuRisZ3tWyGqBBqT54A/pubhtml

inclusion in the SGIP program. If this is truly the paradigm the Commission accepts, storage projects should only be allowed to shift demand for two hours per day on average (8% of 24 hours = 2 hours). If storage projects shift demand during periods other than 8% of the year when the PD claims peakers are running, they would be offsetting non-peaker electricity and therefore increasing CA GHG emissions.

For simplicity, we recommend that the Commission uses 30% as the peaker plant weighting factor, and updating when necessary with a simple look back at the latest 12 months of CAISO data.

Response to Section 3.2.2. Build Margin Effect - Emission Rates

EtaGen appreciates the consideration that only dry-cooled combined cycles will be permitted in the future in California. We only wish to clarify on the record that our statement of a decrease in 5-10% efficiency between wet-cooled and dry-cooled combined cycles is for the design case (high ambient temperatures) when steam turbine backpressure cannot be brought to wet-cooled levels economically by air cooled condensers. We find this statement generally supported in a 2006 Public Interest Final Project Report for the California Energy Commission Dated April, where dry-cooling design-case efficiency losses range from 3.25% to 9.15%.[13] We agree with the PD that performance of new dry-cooled combined cycles should continue to be tracked in CA.

Response to Section 6. Energy Storage

EtaGen disagrees with CESA and the PD that PLEXOS production cost modeling would be "...a promising method for determining the GHG emissions eligibility threshold for SGIP energy storage as well as generation technologies." Utilization of PLEXOS is unfortunately not a transparent process and relies heavily on assumptions that greatly affect results. As such, it will be nearly impossible to utilize PLEXOS in a transparent way that correctly incorporates stakeholder scrutiny and input.

Moreover, EtaGen request that no credence be given to the referenced PD statement from CESA that "the assumption that CTs are marginal during peak hours and CCGTs are marginal

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[13] Cost and Value of Water Use at Combined-Cycle Power Plants, - Section 6.4 (pp 21) http://www.energy.ca.gov/2006publications/CEC-500-2006-034/CEC-500-2006-034.PDF

during off-peak hours is no longer valid" and that "renewables will increasingly operate as the marginal resource."

Renewable resources are being curtailed (extremely rarely) because of local congestion and load flow, and not because renewables are the marginal resource in CAISO. This is easily determined by reviewing the hourly energy price in CAISO. Because the fuel for renewable power plants is free, the marginal cost of generation for a renewable resource is zero (negative for wind since a wind project can monetize the production tax credit even when energy prices are negative). As such, hours when energy pricing is negative represents when renewable resources are the marginal resource. A look back from July 1, 2015 through January 1, 2013 shows that there were zero hours when the energy price for CAISO negative.[14] This means that renewables were never the marginal resource in CAISO over the last 2.5 years (the lowest hourly price over the period was $10.22/MWh, much higher than zero).

To capture the impact that local congestion and losses have on pricing at individual buses throughout CAISO, EtaGen also investigated Locational Marginal Prices (LMPs) for over two thousand CAISO nodes. LMPs represent the hourly energy price at individual buses throughout CAISO. Negative LMPs at these nodes would mean that renewables were curtailed because of localized congestion and losses, but not because there were too many renewable resources system-wide. The analysis showed that less than 0.5% of all the nodes analyzed (11 out of 2006 nodes) had greater than 0.5% of hours where prices were negative between January 1, 2014 and May 1, 2015. The node with the highest percentage of hours with negative pricing, KONOCTI6_6_N001 near the Geysers, saw negative pricing only 1.45% of the hours over the period.[15]

III. CONCLUSION

Although EtaGen disagrees with several aspects of WRI's report and believes that zero weight should be given to displacing the build margin, we recognize that the Commission has

[14] EtaGen Summary of CAISO data (January 2015 - July 2015) from oasis.caiso.com https://docs.google.com/spreadsheets/d/10yNg2g148glcpBGAQ8YQONsuLhwJ8i5vtHkkWqklBpc/pubhtml

[15] EtaGen Analysis of CAISO Nodes January 1, 2014 - May 1, 2015 https://docs.google.com/spreadsheets/d/1E-VMOvUxoGUcdqDBF2q156OV1CoE-1-bJivAgNZXVS0/pubhtml

decided to utilize the Report's guidelines for determining the new GHG EF. EtaGen respectfully requests that the Commission, however, revise their methodology to be more consistent with the Report's guidelines, especially with respect to addressing time periods of overcapacity. Furthermore, EtaGen requests that the Commission uses a more realistic weighting factor for peaker plants that is based on CAISO hourly data rather than annual average capacity factor data. EtaGen respectfully urges the Commission to adopt the recommendations outlined in our Comments and calculate the new GHG EF using Equation 4 presented above with the following factors:

GHG EF =

$$\mathbf{(0.7 * (ER_{OLF} * (1 - WFP) + ER_{OP} * WFP) +}$$
$$\boldsymbol{0.3} \mathbf{\ * (1\text{-}RPS\% * (1 - LLF)) * (ER_{BLF} * (1 - WFP) + ER_{BP} * WFP))/(1 - LLF)}$$

Where:

ER_{OLF} = operating margin emission rate of load-following plants = 382 $kgCO_2/MWh$ (from the PD)

WFP = weighting factor for peaker plants = 30% (see our Response to Section 3.2.3)

ER_{OP} = operating margin emission rate of peaking plants = 544 $kgCO_2/MWh$ (from the PD)

RPS% = RPS portfolio requirement = 33% (from the PD)

ER_{BLF} = build margin emission rate of load-following plants = 368 $kgCO_2/MWh$ (from the PD)

ER_{BP} = build margin emission rate of peaking plants = 524 $kgCO_2/MWh$ (from the PD)

LLF = line loss factor = 8.4% (from the PD)

Utilizing these values, the equation (which is consistent with the WRI guidelines in the Report referenced by the PD) yields **424 $kgCO_2/MWh$** as the new SGIP GHG factor. We suggest this number be updated as changes occur in both the RPS percentage and the percentage of hours of the year peaking resources are dispatched.

EtaGen appreciates the opportunity to provide comments and respectfully requests that the Commission adopt our recommendations.

Respectfully submitted,

_________/s/__________

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