



May 24, 2021

Edward Randolph, Director Energy Division
California Public Utilities Commission
505 Van Ness Avenue, Room 4004
San Francisco, CA 94102

RE: Draft Resolution E-5150. Adopts updates to the Avoided Cost Calculator for use in demand-side distributed energy resource cost-effectiveness analyses

Dear Mr. Randolph,

Pursuant to Rule 14.6 of the Rules of Practice and Procedure of the California Public Utilities Commission (“Commission”) and the Comment Letter accompanying Draft Resolution E-5150 (“Draft Resolution”), the Solar Energy Industries Association (“SEIA”) and Vote Solar, (“Solar Parties”) respectfully comment on the proposed updates to the Avoided Cost Calculator (“ACC”).

I. INTRODUCTION AND RECOMMENDED CHANGES

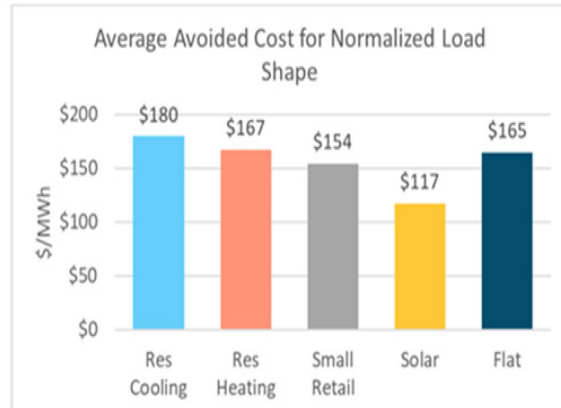
In Decision 19-05-019, the Commission established a bifurcated approach to making changes to the ACC, with “major” changes to be addressed in even years through a formal evidentiary process, while “minor” changes are to be made in odd years through the Commission’s resolution process. Minor changes were clearly defined as “data and input updates as indicated in D.16-06-007” [and] “can also include changes to the modeling method that most parties can reasonably agree are minor in scope and impact.”¹ Consistent with this bifurcated approach, the Draft Resolution says that it is solely proposing “minor” changes to the ACC. As demonstrated below, several of the recommended changes are anything but minor, and involve significant changes to the modeling methods, including the use of a new integrated resource plan (“IRP”) scenario that has not been vetted by parties, nor more importantly approved by the Commission in the IRP proceeding (R. 20-05-003). The Draft Resolution also uses new scarcity pricing and benchmarking methodologies which are not minor in scope and impact and to which most parties have not agreed. The Commission must reject such major changes to the ACC as beyond the established scope and process for a minor update.

In addition, the Solar Parties highlight that there have been significant procedural deficiencies in the process which led to the issuance of the Draft Resolution. The transparency that the Commission envisioned when it established the bifurcated review process has simply not occurred. The result is a Draft Resolution that contains changes to the ACC that would result in a substantial and unwarranted decrease in the value of distributed energy resources (“DERs”) in

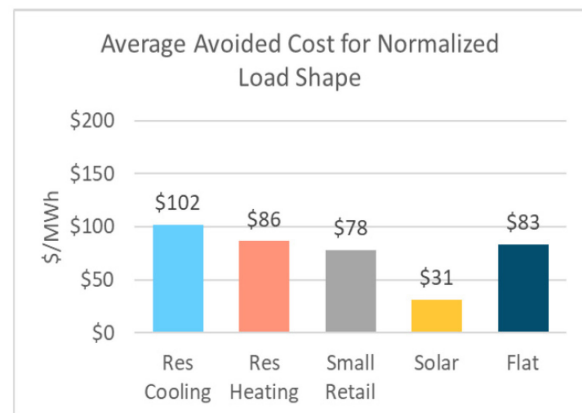
¹ D.19-05-019, at pp. 49-50.

California, including the value of distributed solar and energy efficiency measures. Reproduced below is Figure 4 from the Documentation file for the draft 2021 ACC, showing the single-year change in the value of selected DERs in 2030. The value of solar PV drops by 74%, from 11.7 cents per kWh to 3.1 cents per kWh. Using the detailed hourly outputs in the draft 2021 ACC, we have calculated that similar declines would occur in the value of solar over longer time horizons; for example, the 25-year levelized value of solar from 2021-2045 would drop by 60% to 66%. The value of energy efficiency measures also would drop substantially, on the order of a 50% reduction. There is nothing that has occurred in the California energy market over the last year that justifies such a major drop in the value of distributed resources. In the past, the Solar Parties have supported the Commission’s effort to integrate the valuation of demand- and supply-side resources by using key values from the IRP in the ACC. However, this effort will not succeed if the result is that the values of DERs fluctuate wildly from year-to-year based on modeling and methodology changes over which the Commission fails to exercise adequate oversight. To prevent this, the IRP values used in the ACC must reflect the most recent Commission-approved resource plan that has been thoroughly vetted in the IRP proceeding, not unvetted values from whatever is the latest model run by Commission staff or its consultants. Changes in resource scenarios and modeling methods should occur only in conjunction with fully-litigated “major” updates to the ACC.

2020



2021



Accordingly, and for reasons detailed herein, the Solar Parties recommend that the Commission reject the three “major” changes discussed in Section II below. Specifically, the Commission should continue to use in the 2021 ACC the same components that were derived from the approved RSP in the IRP proceeding, including the greenhouse gas (“GHG”) shadow prices used in the ACC’s GHG Adder and the marginal heat rates based on the SERVVM production cost modeling of the adopted RSP portfolio, using the scarcity pricing and benchmarking methods approved in D. 20-04-010 and Resolution E-5077.

The Solar Parties do not oppose the truly minor changes to the inputs used directly in the ACC that the Resolution proposes, including a new natural gas price forecast and the correction of certain errors and bugs in the 2020 ACC. We also propose in Section III a number of additional minor updates to data and inputs used directly in the ACC and not included in the Resolution.

II. MAJOR CHANGES TO THE ACC

The changes to the ACC in 2021 were supposed to be confined to minor changes in data and inputs, and not to include major changes in methodology. There are three major changes in the draft 2021 ACC that do not comply with this standard, for the reasons discussed below. The Solar Parties believe that the first two changes discussed below account for approximately 90% of the reduction in the value of DERs proposed in the Resolution.

A. Use of A New, Unapproved IRP Scenario

The 2020 ACC approved in D. 20-04-010 was based on the No New DER scenario of the IRP modeling for the IRP Reference System Plan (RSP) that the Commission formally approved in D. 20-03-028. In doing so the Commission emphasized the importance of aligning the ACC with a Commission approved RSP from the IRP proceeding:

“The Commission previously expressed its intention to align the cost-effectiveness work in this proceeding with the efforts to develop a Common Resource Valuation Method in the Integrated Resource Planning proceeding [citing D.19-05-019 at 57]. Hence, aligning the Avoided Cost Calculator with the Integrated Resource Planning proceeding should be the obvious next step. The Reference System Portfolio provides the Commission with a capacity expansion plan that is the least-cost path to meeting future capacity needs, reliability needs, greenhouse gas targets, and renewable requirements. We note that use of the Reference System Portfolio, as adopted by the Commission, should allay concerns expressed by parties that the previously released draft Reference System Portfolio should not be the basis for the 2020 Avoided Cost Calculator update.”²

In specifically addressing the fact that the IRP scenario to be used in the ACC must be the Commission-approved RSP, the Commission was addressing concerns expressed by the major investor-owned electric utilities (“IOUs”). Specifically, the IOUs commented:

The 2020 ACC major update should use the final version of the IRP RSP that will be adopted by the Commission in the IRP proceeding and not the proposed version. The proposed RSP, issued on November 6, 2019, has not yet been subject to party comments and analysis, includes a number of disputed issues (e.g., the addition of 2,000 MW of “perfect capacity” in 2026, the limits on imports imposed in both the RESOLVE and Strategic Energy Risk Valuation Model

² Decision 20-04-010, at p. 32 (emphasis added).

(SERVM) models, and the treatment of once-through cooling units), and has not yet been approved by the Commission. Thus, the proposed RSP should not be the version used for the 2020 ACC major update.³

The situation should not be any different now. The IRP scenario which Staff proposes to use as an allegedly “minor” change to the ACC is a new IRP scenario from a new run of RESOLVE, apparently performed on April 2, 2021.⁴ The release of the draft Resolution is the first time that parties have had any exposure to this new IRP scenario. IRP scenarios which are to be used to value resources simply cannot be the product of a Staff run of the RESOLVE model which is presented without supporting documentation as a *fait accompli* in a draft resolution with a 20-day comment period. IRP scenarios used to value resources must receive the same extensive, multi-month public process used in the IRP docket R. 16-02-007 to develop and approve the RSP and in R. 14-10-007 as the foundation for the approval of the 2020 ACC.⁵ Fundamentally, a key goal of last year’s major update of the ACC was to align it more closely with the results of the IRP proceeding, to move toward the Commission’s goal of a common resource valuation for both demand- and supply-side resources, as stated above in the quote from D. 20-04-010. But this goal will not be achieved unless both types of resources are evaluated using values from the same fully-vetted, Commission-approved RSP or Preferred System Portfolio (“PSP”).

On its face, the Staff’s new IRP scenario is very different than the adopted RSP, and results in significantly lower avoided GHG values than those used in the 2020 ACC. The following **Table 1** compares the 2045 resource portfolios in the No New DER cases from (1) the draft 2021 ACC and (2) the adopted RSP used in the 2020 ACC. The new IRP scenario used in the 2021 ACC includes more than 19 GW of out-of-state wind and 10 GW of offshore wind that was not in the RSP portfolio, as well as major reductions in solar (72 GW less – a 62% reduction) and storage (33 GW less – a 57% reduction) by 2045. The documentation of the draft 2021 ACC posted on May 3 by the Commission’s consultant Energy and Environmental Economics (“E3”) did not include any details on the input assumptions for this run, except for one reference to lower solar and storage costs.⁶ Even though the ACC Documentation is more than 100 pages, the only explanation of the new IRP portfolio is the following statement on page 11: “Over the last year, the IRP proceeding performed analysis with updated inputs and assumptions, including updated resource cost and build inputs and results from the Final 2019 CEC IEPR issued after the 2019 RSP was finalized.” To the Solar Parties’ knowledge, however,

³ See *Joint Opening Comments on Staff Proposal for Major Updates to the Avoided Cost Calculator and Joint Opening Brief of Southern California Edison Company, Pacific Gas and Electric Company and San Diego Gas & Electric Company*, R. 14-10-003 (December 17, 2019), p.3.

⁴ We infer this from the title of the RESOLVE output file posted by staff – “RESOLVE_Results_Viewer_2021-04-02_New46MMTNoDER_NoGas_Clean_Dashboard.”

⁵ See D. 20-03-028, at pp. 6-19, discussing the extensive comments on input assumptions and modeling with both RESOLVE and SERVM that took place during the development of the RSP.

⁶ See the posted “2021 ACC Documentation v1a” file, at p. 2 (hereafter “ACC Documentation”).

few of these “updated resource cost and build inputs” have been vetted among stakeholders in the IRP proceeding.⁷ Nor does the ACC Documentation include any discussion of the reasonableness of the input assumptions or the assumed build-out. Whether changes to IRP input assumptions justify these substantial long-term resource changes has yet to be examined publicly in the IRP proceeding, nor have these changes been approved by the Commission as part of a new RSP or PSP.

Table 1

2045 Selected Resources, in GW		
No New DER cases	2021 ACC	2020 RSP
Geothermal & Biomass	2.3	3.5
Wind	36.7	8.3
instate	4.3	5.2
OOS New Tx	22.2	3.0
offshore	10.2	-
Solar	44.5	116.5
Total Renewables	83.5	128.3
Storage	28.0	61.2
Battery	25.4	59.2
Pumped Storage	2.6	2.0
Total Additions	111.5	189.5
In State Renewables	61.3	125.2
OOS Renewables	22.2	3.0
Total Renewables	83.5	128.2
Gas Retirement	(5.4)	(3.7)

A significant portion of the reduction in DER value is due to a lower 2030 GHG Adder. The GHG Adder is the key metric from the IRP used in the ACC. It measures the cost of the utility-scale renewable generation needed to meet California’s 2030 GHG goal (currently 46 MMT). The single-year 2030 GHG Adder actually sets the avoided costs of meeting the state’s GHG goals in all 30 years modeled in the ACC, because the 2030 value is discounted back to the first year and escalated to years after 2030 using the IOUs’ weighted average cost of capital as the discount or escalation rate.⁸ The 2021 ACC Documentation provides only a one-sentence explanation of the lower GHG Adder, on page 2, stating that the lower GHG Adder is “due

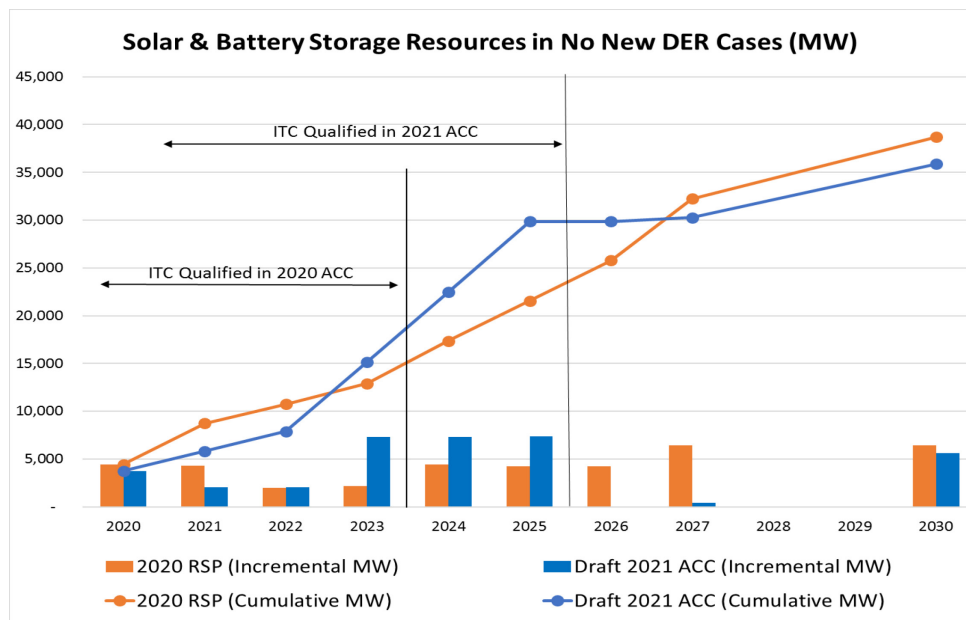
⁷ There have been modified versions of the 2020 RSP released for comment by the parties in the IRP proceeding (R. 20-05-003) in conjunction with transmitting resource portfolios to the CAISO for the 2021-2022 Transmission Planning Process (TPP), but the changes made in these scenarios were limited to use of the 2019 CEC IEPR demand forecast, updates to certain load shapes, and a new gas forecast. The Commission reviewed and approved these changes in D. 21-02-008. For example, consistent with the 2020 RSP, none of the TPP portfolios include any offshore wind, and they have just limited amounts of out-of-state wind on new transmission.

⁸ See D. 20-04-010, at pp. 42-43, and Resolution E-5077, at pp. 8-9, discussing the structure of the GHG Adder.

primarily to lower costs for utility scale solar and energy storage.” In the reviewing the output file for the 2021 ACC’s RESOLVE run, the Solar Parties discovered that almost all of the incremental 30,000 MW of the new solar and storage resources required to be on-line by 2030 to meet the 46 MMT GHG constraint are assumed to be installed in 2024 and 2025 – and thus presumably to qualify for the 26% or 22% federal solar investment tax credit (ITC).⁹ This is a major and unreasonable modeling change in the build-out of the solar and storage resources expected to be installed by 2030, compared to the 2020 RSP which limited the solar build-out to no more than 2.0 GW per year during the years when the ITC was above 10%. This limitation was put in place because RESOLVE tends to install most of the solar in the years when solar qualifies for a high ITC, resulting in infeasible installation scenarios.

Figure 1 below compares the solar and storage build-outs in the 2020 and draft 2021 ACCs, showing that the draft 2021 ACC assumes that almost 85% of the solar and storage needed in 2030 – a full 30 GW – is installed in the next four years, by 2025, compared to 33% in the 2020 ACC.¹⁰ This 30 GW includes 18 GW of solar and 12 GW of storage. This change in the timing of solar and storage additions accounts for much of the reduction in the 2030 GHG Adder in the draft 2021 ACC.

Figure 1



⁹ Although the solar ITC drops from 22% in 2023 to 10% in 2024, projects completed by the end of 2025 can receive the higher ITC if they comply with the “commence construction” requirements by the end of 2023.

¹⁰ The figure includes both solar and storage, although the storage only receives the ITC if paired with solar. Without the input assumptions for the new IRP scenario, we are unsure the extent to which solar and storage area assumed to be paired in the draft 2021 ACC.

The Solar Parties want to see a continued expansion of utility-scale solar in the state, but it is not realistic to assume that 18 GW of new utility-scale solar – 150% more than the state’s entire existing utility-scale solar fleet – and 12 GW of new storage – perhaps ten times the existing battery storage capacity – could be built in California in the next four years.

We are also concerned that the new IRP scenario may include unrealistically low assumptions for future storage capital costs. These forecasts for future declines in storage costs may not reflect the current constraints on raw materials, supply-chain issues, competition for batteries from the growth of electric vehicles, and the worldwide shortage of microchips.¹¹ This issue is also a subject of current litigation before the Commission. The issue of the level and trajectory of storage costs is an active issue in the current PG&E GRC Phase 2 case, A. 19-11-019.¹² including whether the Lazard report used in the IRP is a reasonable source for storage costs¹³ and the extent to which storage costs will decline over the next decade.¹⁴

Finally, the Solar Parties would note that it was not until the close of business on May 19, three business days prior to the date that these comments were due, that the Energy Division, in response to a request from SEIA, posted the other relevant files for the RESOLVE run upon which the 2021 ACC is based, including the file with the input assumptions. There is, however, no written documentation for these input assumptions. Based on the limited period of time that the Solar Parties have had to review this material, we believe that the new RESOLVE run raises numerous issues that must be vetted publicly in the IRP proceeding, including:

- Is it reasonable to include offshore wind as a new candidate resource? Are the costs and transmission needs for this new resource represented accurately in the new run?

¹¹ The significant growth in the worldwide battery storage market is being driven in part by higher demand for EVs. As a result, there is surging demand in the market for the raw materials used in lithium-ion batteries. See <https://www.axios.com/battery-shortage-risk-electric-car-era-fa699bfb-9d57-4bdc-b907-993903cc7620.html>; also <https://www.forbes.com/sites/arielcohen/2020/03/25/manufacturers-are-struggling-to-supply-electric-vehicles-with-batteries/?sh=6e878f271ff3>. High and increasing demand in the market is leading to longer lead times for components and hampering the solar industry’s ability to sustain the growth of systems paired with storage.

¹² In R. 19-11-019, several parties including PG&E and SEIA are proposing to use battery storage costs as the basis for marginal generation capacity costs.

¹³ PG&E is using the same storage costs from the Lazard 5.0 report that appear to be used in the new RESOLVE run. However, other parties including SEIA are challenging PG&E’s assumptions; for example, SEIA supports the use of an NREL meta-review of storage cost projections from many sources that shows 2020 storage capital costs that are significantly higher than the single Lazard report. See A. 19-11-019, Opening Brief of SEIA filed May 20, 2021, at pp. 5-7.

¹⁴ For example, the California Large Energy Consumers Association (“CLECA”) is challenging PG&E’s assumptions for how quickly storage costs will decline. See A. 19-11-019, Opening Brief of CLECA, filed May 20, 2021, at pp. 22-25.

- Should the run exclude hybrid solar-plus-storage as a candidate resource, even though such projects dominate the current interconnection queue on the CAISO system, and almost all utility-scale solar now proposed in California is paired with storage?
- Is it reasonable to remove the 3 GW cap on out-of-state wind on new transmission? Are the costs and transmission needs for this new resource represented accurately as the amount of this resource serving California grows?
- The approved 2020 RSP included a limit of 2 GW per year on the pace of the build-out of new solar resources in California. The new run includes this limit only until 2023, even though it appears to assume that solar projects installed through 2024 or 2025 will qualify for the solar investment tax credit (ITC). There are no limits on the amount of solar that can be installed in 2024 and 2025 in the new run. What justifies no limits on solar deployment in these years?
- What is a reasonable projection of future storage costs? As discussed above, this issue is under active litigation in another docket, A. 19-11-009.

The Solar Parties respectfully suggest that the myriad of important resource planning issues concerning a new IRP scenario cannot be resolved in the 20-day comment period on a draft resolution on what is supposedly a “minor” update to the ACC. It is particularly inappropriate given that staff has did not make the input assumptions available until May 19, with little source documentation available, thus denying parties a reasonable opportunity to understand and question the assumptions behind the new modeling. These are important resource planning issues that will be debated and decided in future proceedings in the IRP and other dockets. When a major update of the ACC is litigated in 2022, how to update and incorporate the GHG Adder and other values from the most recent Commission-approved RSP or PSP should be an important issue. But the Commission should not try to update the IRP modeling or the IRP-based values used in the ACC in this off-year, minor update.

Finally, the Commission needs to appreciate the “Catch 22” situation that it would confront if it were to approve the No New DER scenario modeled in the draft 2021 ACC. The result would be a dramatic reduction in the value of DERs. If the values of energy efficiency and distributed solar are so low that these DERs are no longer economic and customers will not invest in them, then the No New DER case becomes the operative resource plan for California. But if the No New DER scenario that causes the loss of DERs is the one modeled in the Draft Resolution, that scenario is not feasible for the state to pursue. No reasonable planner expects California to install 30 GW of new solar and storage resources in the next four years.

B. Use of New Benchmarking and Scarcity Methods

The 2021 ACC uses revised avoided energy costs from a new SERVIM production cost model run based on the new No New DER IRP scenario. These avoided energy costs are much lower than in the 2020 ACC, particularly in the midday hours and in the later years. The

Appendix to the ACC documentation includes the following heat maps comparing 2030 energy market prices in the draft 2021 ACC to the adopted 2020 ACC.

2021 ACC: 2030 NP-15 Day Ahead Market Prices from SERV

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	Avg
Jan	62	53	44	44	44	53	69	65	47	41	37	35	34	35	35	51	90	151	67	66	65	91	80	62	59
Feb	61	56	46	45	50	49	71	50	41	26	28	19	18	25	22	26	58	140	74	80	76	94	67	55	53
Mar	53	35	40	39	42	50	67	47	17	8	7	6	3	4	11	11	40	91	101	105	96	77	46	45	43
Apr	28	34	31	18	51	45	39	15	1	0	0	0	11	0	1	13	12	44	99	116	101	57	26	29	32
May	39	28	24	27	23	37	47	6	1	1	0	1	3	3	2	8	23	52	60	122	102	87	53	33	33
Jun	42	29	34	29	35	38	56	19	15	9	5	6	7	10	15	24	54	67	103	129	100	74	52	37	41
Jul	39	30	35	17	33	27	39	15	3	4	2	3	4	14	16	34	77	115	105	170	89	80	51	35	43
Aug	43	39	47	40	44	44	40	30	22	20	18	21	29	37	48	78	52	82	192	186	63	49	50	43	55
Sep	45	43	55	47	55	57	45	29	19	20	11	13	16	22	33	37	57	108	176	94	52	56	50	42	49
Oct	51	47	43	42	44	63	62	35	28	23	17	16	17	20	33	56	71	125	92	78	79	55	48	53	50
Nov	63	44	52	53	43	46	63	44	26	21	15	14	15	20	22	43	87	81	78	86	122	77	45	51	51
Dec	44	44	43	43	44	59	80	71	53	40	38	34	32	31	33	50	115	77	75	67	85	61	53	47	55
Avg	47	40	41	37	42	47	56	36	23	18	15	14	16	19	23	36	61	94	102	109	86	71	52	44	47

2020 ACC: 2030 NP-15 Day Ahead Market Prices from SERV

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Avg.
Jan	66	68	63	63	65	68	78	93	89	87	82	77	74	68	64	66	83	102	105	103	100	92	87	73	80
Feb	66	68	67	65	66	70	79	84	64	57	55	54	53	53	52	56	67	89	95	93	88	82	74	72	69
Mar	59	52	60	60	63	66	67	51	40	39	37	38	36	37	31	35	61	70	82	83	83	75	67	67	57
Apr	44	45	46	46	47	56	51	20	10	10	12	13	10	6	3	5	26	67	71	70	66	61	54	52	37
May	50	50	50	51	56	55	41	20	23	24	26	27	26	21	14	20	47	70	76	82	75	68	61	58	45
Jun	53	50	51	51	56	51	41	39	41	44	45	46	48	45	43	51	71	75	85	88	81	72	63	60	56
Jul	48	49	48	48	49	48	41	40	42	46	46	43	40	35	35	52	62	98	96	93	89	87	63	58	56
Aug	64	61	62	63	65	67	57	49	51	51	52	53	57	58	65	79	88	108	104	103	98	96	86	81	72
Sep	65	65	65	66	74	63	46	46	46	46	46	47	48	51	55	66	74	94	93	92	90	87	81	76	67
Oct	62	63	62	62	63	69	68	53	51	49	49	51	51	52	56	67	86	91	91	90	87	81	73	67	66
Nov	61	62	61	60	60	62	65	61	52	51	51	50	50	51	51	58	72	88	88	87	87	83	76	68	65
Dec	68	66	65	64	65	66	70	74	75	73	69	66	65	64	63	68	76	96	97	96	94	92	88	74	75
Avg.	59	58	58	58	60	63	60	52	49	48	47	47	47	45	44	52	68	88	90	90	87	81	73	67	62

The issue here is that the draft 2021 ACC has used several new methodologies to calculate avoided energy costs. The consultant Astrape has made changes to the SERV production cost model apparently Energy Division staff has changed its approach to benchmarking SERV results to CAISO market prices.¹⁵ E3 uses a new scarcity pricing method to adjust the SERV model outputs.¹⁶ Table 2 in the documentation summarizes the changes in the draft 2021 ACC compared to the 2020 ACC, and refers to these changes as “Updated SERV Model” and “Updated Scarcity Pricing Methodology.” These are not simply changes to “data and inputs”; they clearly are changes to modeling methods that are significant in both scope and impact. They are changes that parties have not reviewed and to which parties have not agreed. These changes raise significant issues that should be resolved only in conjunction with fully litigated major changes to the ACC.

¹⁵ See ACC Documentation, at p. 13: “Since the 2020 ACC update, Astrapé has updated algorithms used in SERV and the CPUC staff and Astrapé performed benchmarking of SERV model results to actual CAISO prices.”

¹⁶ See ACC Documentation, at p. 21, discussing the changes made to the scarcity pricing methodology.

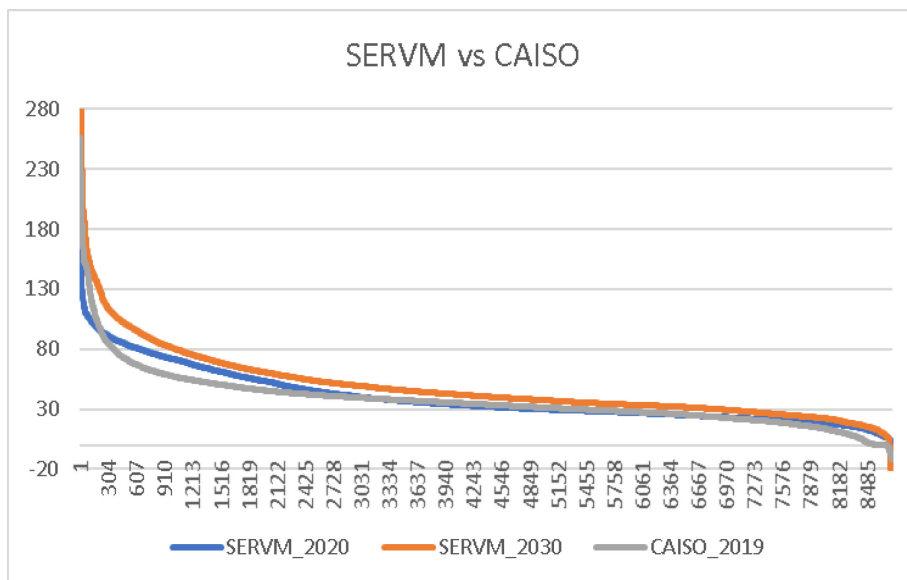
With respect to the changes to benchmark SERVVM results to historical CAISO market prices, on May 19 Energy Division provided additional information that was not included in the May 3 documentation of the draft Resolution.¹⁷ This document, which is provided as **Attachment A** to these comments, states:

In response to party comments both at the December 2020 workshop and in subsequent informal emailed comments, the CPUC’s IRP modeling team analyzed the price formation in our model to determine if errors were made, better methods could be established, and to better simulate energy prices that were more consistent with the way the CAISO arrives at hourly energy prices in the energy market.

Changes as fundamental as how prices are formulated in SERVVM, or whether “better methods could be established,” are changes in modeling methods, not simply updates to data or inputs. The staff document on the SERVVM changes also references the introduction into the SERVVM modeling of apparently-new “overgen prices” that apply when renewable generation is being curtailed, as well as an “overgen penalty.” There is no explanation or justification for this modeling change.¹⁸

The “Additional SERVVM information” posted May 19 includes a figure with price duration curves that purports to compare 2020 and 2030 SERVVM prices to 2019 CAISO prices, as an example of the staff’s benchmarking effort. Here is that figure:

Figure 1 Price Duration - CAISO 2019 vs. SERVVM 2020 and SERVVM 2030

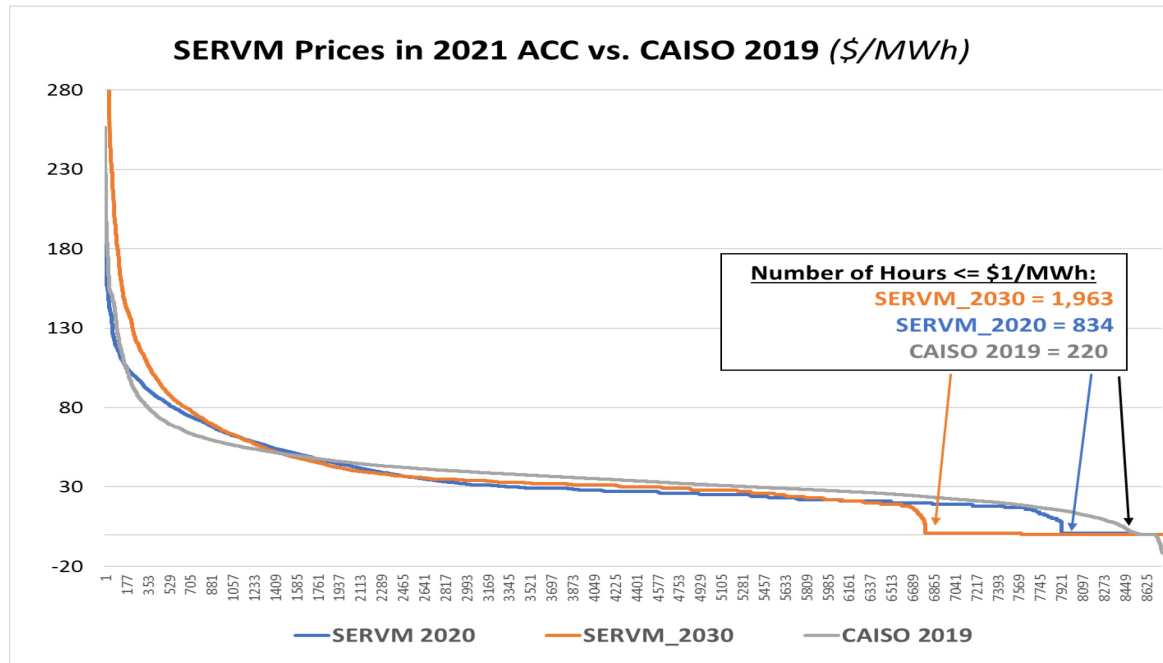


¹⁷ This is the file titled “Additional SERVVM information” posted May 19, at p. 1.

¹⁸ *Ibid.*

The problem with this figure is that the 2020 and 2030 SERVM prices shown are not the SERVM prices used in the draft 2021 ACC. **Figure 3** below shows the 2020 and 2030 SERVM prices actually used in the 2021 ACC.¹⁹

Figure 3



The obvious difference between the staff's figure and Figure 3 is that the SERVM prices used in the 2021 ACC have zero or near-zero prices in a significant fraction of hours (834 hours with prices of \$0 or \$1/MWh in the 2020 SERVM results, and 1,963 such hours in the 2030 SERVM prices), while 2019 CAISO market prices had 220 such hours. We asked staff a follow-up question about the discrepancy between these two figures in an email on May 19. Staff responded that the difference between the 2020 and 2030 SERVM prices in these two figures is that the SERVM prices in the staff's figure include GHG cap & trade ("C&T") costs, while the SERVM prices used in the 2021 ACC do not.²⁰ But this cannot be true at the low end of the

¹⁹ The 2020 and 2030 SERVM prices in Figure 3 are from Columns F (2020) and P (2030) of the tab "SERVM Price Inputs" of "2021 ACC SERVM Prices v1a" posted on May 3.

²⁰ See email from Joy Morgenstern dated May 20, 2021, included as **Attachment B**. As noted in Section III.C below, this clarification that the SERVM prices used in the 2021 ACC do not include cap & trade costs means that there is an error in the calculation of the market heat rates used in the 2021 ACC. The market heat rates are calculated by subtracting a variable O&M adder, then dividing by the gas price plus a cap & trade adder. Since the cap & trade costs have already been removed from the SERVM prices, including the cap & trade cost again in the denominator of the market heat rate calculation

curve – it would mean, for example, that in 2030 SERVM models 1,963 hours in which generators bid only C&T costs because the price is \$1 per MWh or zero or when C&T costs are removed. But this makes no sense – why would a fossil generator bid their C&T costs but not their fuel costs? Further, C&T costs cannot account for the difference in the SERVM prices between the staff’s figure and our Figure 3 at the low end of the price duration curve, because C&T costs in 2020 and 2030 are about \$6 and \$8 per MWh, which is much less than the \$15 to \$30 per MWh differences shown in most of these hours.²¹ By email on May 21 we asked staff to explain these zero-price hours, but have received no response to that inquiry. Thus, in 2030 the draft 2021 ACC includes 22% of the hours of the year with zero or near-zero prices, in a No New DER case in which loads are much higher due to the removal of DERs.²² Staff has not explained how this result makes sense or why it is realistic.

The changes to SERVM to benchmark them to 2019 CAISO prices were made apparently because “several parties expressed concerns with the price levels and distributions from the Avoided Cost Calculator (ACC) update in 2020, which appeared to overly value energy in the middle of the day.”²³ Fundamentally, the Solar Parties do not agree that the results of a No New DER scenario with higher midday and overall loads necessarily should result in the same energy price profile as historical CAISO market prices, particularly in years such as 2030 when loads are substantially higher due to the removal of large amounts of DERs. Importantly, this issue was litigated in conjunction with the major changes that produced the 2020 ACC. Here is the relevant discussion from pages 12-13 of Resolution E-5077 that adopted the final 2020 ACC:

The No New DER scenario is not meant to be a realistic planning scenario. It is a “what if” scenario – for example, what if the IOUs’ service territories didn’t have energy efficiency, new rooftop solar, or the ability to call demand response? The results of the No New DER scenario tell us that, without DERs, utilities would have to purchase more supply-side resources, import more electricity, and use natural gas plants more often. This means that, as compared with the Reference System Plan, the average heat rate would be higher, since gas generation would be higher. As SEIA/VS point out in their reply comments (p. 2), “The removal of EE raises loads in all hours, and these added loads increase steadily over the 2020-2030 decade. In addition, the removal of BTM PV increases midday loads.

incorrectly removes them twice. The market heat rates should be calculated as the SERVM prices less variable O&M, divided by only the gas price. This error is discussed further in Section III.C.

²¹ The difference in the low ends of the two price duration curves is more likely due to the new “overgen prices” that staff has introduced into the SERVM modeling. If so, these are not C&T costs and should not be removed from the SERVM prices used in the ACC.

²² In contrast, the 2020 ACC model showed only 72 hours with prices less than or equal to \$1 per MWh (NP15/SP15 average) in 2020, and 227 such hours in 2030.

²³ See ““Additional SERVM information,” at p. 1.

Thus, it makes sense that the No New DER results from SERVVM show higher market heat rates...as less efficient units are dispatched to serve the higher loads in this scenario.” In addition, mid-day prices would be higher, because there would be less energy efficiency, less solar, and no ability to call demand response. The No New DER scenario results, in and of themselves, point to the value that DERs provide to the electric grid. However, they do not reflect a likely future electric grid, nor were they intended to.²⁴

If the Commission is going to reverse this determination made in conjunction with the major changes to the 2020 ACC, the Commission should do so in a litigated proceeding in which parties can examine these issues in detail. Consistent with our position on the 2020 ACC, the Solar Parties have not agreed and would not agree that the changes to the SERVVM modeling methods or the benchmarking of 2030 SERVVM prices to 2019 CAISO market prices are “minor in scope and impact,”²⁵ nor do we agree substantively.

The Solar Parties also have concerns with and do not agree with E3’s “updated scarcity pricing methodology.” First, E3 has set a price cap of \$250 per MWh on SERVVM prices, on the grounds that “SERVVM prices could jump beyond \$500/MWh in some most extreme hours, which lacks precedent in modern day CAISO market as shown in Figure 8 below.” Figure 8 shows CAISO prices in only one year, 2019. As the Commission is well aware, in August 2020 California and the West experienced high demand conditions that produced an extended period of prices above \$250 per MWh, including 28 such hours in the NP-15 zone and 41 hours in SP-15. Given this experience, and the clear possibility that such extremes may be “the new normal” with climate change, the \$250 per MWh price cap is not reasonable.

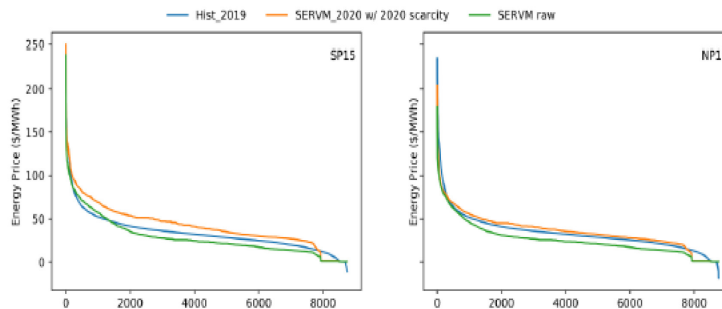
E3 also has used a new methodology for scaling the SERVVM price results to account for scarcity impacts in the CAISO market. Again, as with the staff’s SERVVM benchmarking, there are significant methodological issues here. Figure 10 of the ACC documentation shows the 2020 scarcity adjustment to 2020 SERVVM prices compared to actual 2019 CAISO prices; Figure 11 shows the results of the new scarcity method, which only impacts prices in the top 5% of hours.

²⁴ We reiterate our observation about the “Catch 22” that confronts the Commission if it were to adopt a major reduction in the value of DERs, such that few DERs will be economic in the future. That would leave California with no choice but to pursue what it admits here is “not meant to be a realistic planning scenario.”

²⁵ At the December 9 workshop, Staff emphasized the fact that any methodological change would require them to solicit feedback from stakeholders regarding the reasonableness of such change. *See Integrated Distributed Energy Resources Workshop*, at 2:12:29. These comments on the draft Resolution are the first opportunity that parties have had to comment on the specific methodological changes to the SERVVM modeling based on a description of the specific changes and an opportunity to evaluate the impacts of those changes.

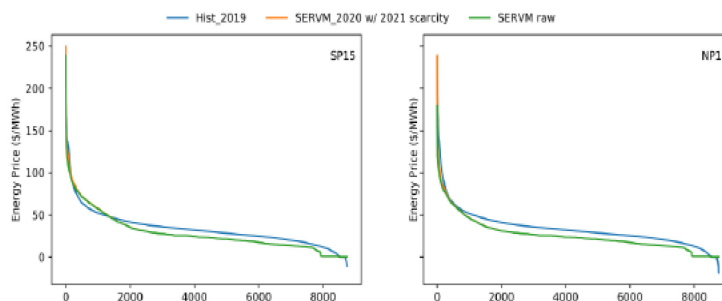
Figure 10 shows that the 2020 scarcity method accurately tracked 2019 prices in NP-15 across most hours; the 2020 method overestimated SP-15 prices.

Figure 10. Impact of previous year's scarcity adjustment on raw SERVM prices relative to historical data



But Figure 11 shows that the new method, which only adjusts the highest prices, systematically underestimates both NP-15 and SP-15 prices, and the SERVM prices produce more hours with very low or zero prices than were actually experienced in 2019. For NP-15, the new approach is clearly less accurate than the 2020 method in the bulk of the hours when prices are moderate.

Figure 11. Impact of current year's scarcity adjustment on raw SERVM prices relative to historical data



Thus, it is far from clear from these figures that the new scarcity method improves on the 2020 approach, in terms of accurately representing 2019 prices. What is obvious is that the new method produces significantly lower prices in almost all hours.

The staff's changes to the SERVM benchmarking and E3's new scarcity pricing methodology clearly are changes to modeling methods, not just matters of changes in "data and input updates." Further, as shown in the heat maps above, the results of this methodological change are far greater than what was suggested at the workshop where E3 described any potential changes as "tweaks,"²⁶ or than was suggested in the staff's March 11, 2021 list of "minor changes" where this issue is described as "[i]nvestigate errors to make minor improvements in scarcity pricing adjustment." These new methods do far more than just correct

²⁶ See Integrated Distributed Energy Resources Workshop, at 25:58.

“errors” or make “minor improvements.”²⁷ Nor has the staff provided the files used to make the new scarcity adjustment, so that formulas can be reviewed; all that staff posted is a file with the results of the new method.²⁸ Nor have parties had a reasonable opportunity to fully understand the benchmarking changes to the SERVM results or whether they are reasonable. As discussed above, the actual SERVM prices in the draft 2021 ACC do not match the prices in the figure that staff distributed on May 19, and the difference cannot be cap & trade costs, as staff alleges. Finally, as discussed further below in the “process” Section IV, the methodological change to the scarcity pricing method was presented at the December 9, 2020 workshop as a “possible future improvement” that was distinct from the minor update in the 2021 ACC. The Solar Parties reasonably concluded that any substantive change to the scarcity pricing method would be a major change to the ACC.

C. PG&E’s Secondary Distribution Marginal Capacity Costs

The 2021 ACC would set PG&E’s secondary distribution system (voltage level < 4kV) marginal capacity costs input to zero, “because secondary capacity costs are not time-differentiated costs and therefore not applicable to ACC.” We disagree conceptually with this methodological change, as a marginal cost does not have to vary by time to produce a change in costs if there is a change in demand. The lack of time dependence simply means that the marginal cost is the same in all hours; it does not mean that the change is zero in all hours. Although this is an issue whose impact on the ACC is small, it is a conceptual issue, not a change in data or inputs.

III. ADDITIONAL MINOR CHANGES AND CORRECTIONS

This section proposes a number of additional minor updates to data and inputs used directly in the ACC. These are changes that are not included in the draft 2021 ACC.

A. Consistent Split in Gas Transportation and Commodity Rates between Northern and Southern California

The 2021 ACC Gas Model v1a assumes an intrastate gas transportation cost that is an average of PG&E Backbone only (BB), PG&E Local Transmission (LT), and SoCalGas transportation costs. The following **Table 2** shows the gas transportation costs that the 2021 ACC Gas Model v1a assumes were effective in 2019.²⁹

²⁷ The forecast 2030 solar-weighted average avoided energy prices are 58% lower in the proposed 2021 ACC than in the 2020 ACC. The baseload average avoided energy prices in 2030 are 32% lower.

²⁸ Available at <https://www.cpuc.ca.gov/general.aspx?id=5267>. See the “2021 ACC SERVM Prices” (v1a) link to ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/CostEffectiveness/2021%20ACC%20SERVM%20Prices%20v1a.xlsb. The derivation of energy price values on the “Scarcity Pricing Adjustment” tab is not provided.

²⁹ See cells G22-G28 of the “Commodity” tab of the 2021 ACC Gas Model v1a.

Table 2: 2021 ACC Gas Transportation Costs Assumptions (\$ per MMBtu)

PG&E BB	PG&E LT	SoCalGas	Average
\$0.171	\$1.006	\$0.468	\$0.548

Using an average of three gas transportation costs means that the 2021 ACC burnertip gas price forecast is based on a gas transportation cost that is two-thirds northern California and one-third southern California. At the same time, the 2021 Gas ACC assumes gas commodity costs that are 50% PG&E / 50% SoCalGas.³⁰ There is a clear inconsistency in these weightings.

The Solar Parties recommend the 50% PG&E / 50% SoCalGas weighting as the more reasonable. Based on data from the *2020 California Gas Report* (“CGR”), recorded Electric Generation (EG) gas throughput over the most recent five years for which data is available (2015 to 2019) supports the 50% PG&E / 50% SoCalGas split.

Table 3: 2020 CGR Recorded EG Throughput (Mcf per day)³¹

Year	Northern California	Southern California
2015	1,025	995
2016	783	899
2017	698	876
2018	855	715
2019	865	665
Average	845	830
Allocation	50%	50%

For the PG&E gas transportation rate, the PG&E rate for EG plants on the local transmission system (G-EG LT) is far higher than the gas transportation rate for EG plants on the backbone system (G-EG BB). Thus, the local transmission plants are the marginal suppliers on the PG&E system due to their higher transportation costs. Accordingly, the G-EG LT rate shown in Table 2 above should be used as the avoided transportation rate on the PG&E system. The 50/50 average of the PG&E G-EG LT rate and the SoCalGas EG rate is \$0.737 per MMBtu.

B. Updated Gas Transportation Rates

The draft 2021 ACC includes a number of natural gas transportation rates that need to be updated. These impact the avoided electric costs because they impact the forecast of gas prices for electric generators (EGs). Some of these updates need to be made in the portions of the

³⁰ See column T of the “IEPR Gas Prices Nominal tab of the 2021 Gas ACC Model v1a. As shown on the “Commodity” tab, cells P4 to W15, this IEPR gas price commodity forecast is used for years 2028 to 20235 of the 2021 ACC forecast gas price.

³¹ See Tables 24, 32, and 42 of the 2020 CGR, at https://www.pge.com/pipeline_resources/pdf/library/regulatory/downloads/cgr20.pdf.

California Energy Commission (CEC) IEPR gas forecast used in the ACC, because the CEC forecast uses historical rates that are out of date, and which have been replaced by updated rates approved by this Commission.³² The necessary updates are as follows.

1. The PG&E transportation costs assumed for 2019 include the **Redwood Path to On-system Modified Fixed Variable usage rate**. The 2021 ACC Gas Model v1a uses of the \$0.1717 per MMBtu Redwood path to on-system MFV usage rate of that was in effect in 2020.³³ This rate is from Decision 19-09-025 in the 2018 PG&E Gas Transmission and Storage (GT&S) rate case, which adopted backbone transmission rates for the four-year period from 2019 to 2022, as shown below.

Table 4: PG&E Redwood to On-System Usage Rate (\$ per MMBtu)³⁴

Year	Adopted Rate	Percent Change
2019	0.1335	
2020	0.1717	29%
2021	0.1925	12%
2022	0.2022	5%

The 2021 ACC Gas Model v1a assumes that the 2020 rate increases in subsequent years at 2% per year. However, as shown above, the Commission has already adopted PG&E Redwood to On-System usage rates for 2021 and 2022 that have larger increases than 2% per year. The Commission-adopted rates for 2021 and 2022 should be used in lieu of the inaccurate 2% escalation assumption.

2. The other element of the assumed PG&E gas transportation cost, aside from the Redwood path MFV usage rate, is the **PG&E G-EG rate**. The 2021 ACC gas price forecast makes use of the following PG&E G-EG rates, which were calculated by the CEC for its IEPR gas forecast.
 - a. As noted above, we do not recommend using the G-EG BB rate. PG&E gas transportation costs should be based on the G-EG LT rate. However, if the Commission decides to use the G-EG BB rate, it needs to be updated.
 - b. For customers requiring backbone-only (BB) service, the CEC assumed a March 2020 effective rate of -\$0.0004 per MMBtu, which is equal to a \$0.5157 per MMBtu

³² In the past, the Energy Division has stated that the CPUC staff defers to the CEC's IEPR gas forecast for certain uses, including in the IRP proceeding. However, it makes no sense, is factually incorrect, and thus is unreasonable for the Commission to defer to those elements of the IEPR gas forecast that use CPUC-established rates that the Commission itself has updated.

³³ See

https://www.pge.com/pipeline/products/rates/redwood_on.page?year=2020&startDate=01/01/2020&ratepath=Redwood%20Path%20On%20System.

³⁴ See Appendix H, Table 13, of D. 19-09-025.

- volumetric transportation rate less a \$0.5161 per MMBtu cap and trade (C&T) exemption credit.³⁵ The current (effective 3/1/2021) G-EG BB rate, net of C&T, is \$0.1495 per MMBtu (= \$0.8861 per MMBtu volumetric rate less \$0.7366 per MMBtu C&T credit).³⁶
- c. The documentation states that the slightly negative rate “is due to annual balancing account adjustments with an unusually large credit.”³⁷ It is not reasonable for a long-term forecast to assume negative rates. Such large balancing account adjustments cannot persist year after year. The fact that the G-EG BB rate is now about \$0.15 per MMBtu demonstrates the error of forecasting a 2021 EG BB rate equal to -\$0.00042 per MMBtu (= -\$0.0004 x 1.022³), as if the slightly negative rate would slowly become even more negative over the years. PG&E backbone system distribution rates will not be negative for each of the next 25 years.
 - d. For local transmission (LT) system customers, the CEC assumed a rate of \$1.0058 per MMBtu, which is also from rates effective March 1, 2020. It is equal to a \$1.5219 per MMBtu volumetric LT rate less the \$0.5161 per MMBtu C&T credit. Today’s G-EG LT rate is \$1.2448 per MMBtu (= \$1.9814 per MMBtu - \$0.7366 per MMBtu), or 24% higher than the March 2020 rate assumed in the 2021 ACC.³⁸
 - e. PG&E’s LT rates were adopted in the 2019 GT&S PG&E rate case decision, as shown in the following **Table 5**. The average annual percent change in the rate from 2020 to 2022 is about 5%. Again, these CPUC-approved rates should be used in lieu of the assume transportation escalation rate of 2.2% per year.

Table 5: PG&E Local Transmission Rate (\$ per MMBtu)³⁹

Year	Adopted Rate	Percent Change
2019	0.9226	
2020	1.0029	9%
2021	1.0654	6%
2022	1.1092	4%

3. The **SoCalGas gas transportation cost** assumed in the 2021 ACC Gas Model v1a is the sum of Backbone Transmission Service (BTS) and Transmission Level Service (TLS) rates, as shown in the table below.⁴⁰

³⁵ See Attachment 4 of Advice E-4223, at

https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_4223-G.pdf.

³⁶ At https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_SCHS_G-EG.pdf.

³⁷ ACC Documentation, at page 18.

³⁸ See https://www.pge.com/tariffs/assets/pdf/tariffbook/GAS_SCHS_G-EG.pdf.

³⁹ See Appendix H, Table 20, of D. 19-09-025.

⁴⁰ See cells B7 and B8 of the “Other References” tab of the 2021 ACC Gas Model v1a.

Table 6: SoCalGas Rates in draft 2021 ACC (\$ per MMBtu)

Rate Component	2021 Gas ACC
SoCalGas BTS4 Interruptible	0.3598
SoCalGas GT-TLS	0.1084
Total	0.4682

The SoCalGas TLS rate calculated by the CEC is an average of rates from various periods as far back as 2013, as shown in the following table:

Table 7: CEC Calculation of a Weighted Average⁴¹ SoCalGas TLS Rate (\$ per MMBtu)

Rate Effective	TLS Rate	CEC Weighting
January 2013	\$0.2113	4.1667%
June 2013	\$0.2404	20% + 5.833%
May 2020	\$1.0011	70%
Weighted Average	\$0.7717	100%
Less C&T and ARB Fee (May 2020)	\$0.6633 (= 0.6477 C&T + \$0.0156 ARB Fee)	
Net Total Rate	\$0.1084	

The draft 2021 ACC Gas Model forecast should rely 100% on the currently-effective SoCalGas TLS rate, rather than the CEC's weighted average calculation that includes rates that were in effect in 2013-2014 and 2020. Also, only the C&T exemption credit, not the CARB fee, should be subtracted from that rate. Today's TLS volumetric rate less the C&T exemption credit is \$0.3523 per MMBtu (i.e., \$0.8052 per MMBtu - \$0.4529 per MMBtu = \$0.3523 per MMBtu).⁴² Today's SoCalGas BTS4 Interruptible rate is \$0.4014.⁴³ Thus, the total SoCalGas transportation rate including the BTS rate component should be \$0.7537 per MMBtu (i.e. \$0.7537 = \$0.3523 + \$0.4014 per MMBtu). We note this results in an updated rate that is 61% higher than the \$0.4682 per MMBtu rate that is used in the draft 2021 ACC Gas Model.

4. The 2021 ACC's includes an input assumption that the long-term **escalation in gas transportation rates** will be at the general inflation rate of 2.2% per year.⁴⁴ This is a Commission-chosen assumption that is not taken from the CEC IEPR gas forecast, which

⁴¹ The CEC gives 10% weight to the average 2013 rate (5/12 x January to May and 7/12 x June to December), 20% weight to the 2014 rate that went into effect June 1, 2013, and 70% weight to the 2020 rate. See cell J3 of the "SoCalGas" tab of the "June_2020_Model_CEC-2014-008_ADA.xlsm" spreadsheet from the link that is referenced in footnote 9 of the ACC documentation:

<https://www.energy.ca.gov/programs-and-topics/topics/energy-assessment/natural-gas-burner-tip-prices-california-and-western>.

⁴² See <http://www2.socalgas.com/regulatory/tariffs/tm2/pdf/GT-TLS.pdf>.

⁴³ See <https://www2.socalgas.com/regulatory/tariffs/tm2/pdf/G-BTS.pdf>.

⁴⁴ See cell G28 of the "Commodity" tab of the 2021 ACC Gas Model v1a.

includes no such assumption.⁴⁵ In Resolution E-5077 adopting the 2020 ACC, the Commission stated that “[w]e agree that this issue deserves more scrutiny,” but suggested that the scrutiny should take place in the CEC’s IEPR proceeding. SEIA and Vote Solar have raised this issue in the CEC’s IEPR proceeding, with no response from the CEC.⁴⁶ With all due respect, it is this Commission that establishes and regulates gas transportation rates in California and, as a result, the Commission is best positioned to adopt this assumption. In addition, the Commission’s consultant, E3, has done substantive and significant technical studies on exactly this issue, and can advise the Commission.⁴⁷ The Commission should choose an escalation rate from E3’s recent studies of how gas transportation costs for EG customers will escalate in a carbon-constrained world in which gas throughput will decline over time.⁴⁸ There are significant facts that support an escalation rate higher than 2.2% per year:

- **Commission-adopted rates.** Tables 4 and 5 above show that the Commission has recently adopted transportation rates for PG&E that are increasing at well above 2.2% per year. The average annual percent change in the adopted Redwood MFV usage rate from 2020 to 2022 is about 8.5%. The adopted PG&E LT rate is escalating at 5% per year.
- **Historical data** also shows that gas transportation costs have been escalating at far above inflation in recent years. PG&E G-EG gas transportation rates have escalated at a rate of 16% per year from 2009 to 2022.⁴⁹
- **The studies performed by the Commission’s consultant E3** for the CEC and Gridworks indicate that these increases in gas transportation rates in California will continue as gas throughput declines in a carbon-constrained world.

This evidence supports the incorporation of a higher escalation rate assumption in the ACC Gas model. We recommend a long-term nominal escalation in natural gas

⁴⁵ The CEC IEPR gas forecast does not include any long-term escalation in gas transportation rates. See the “IEPR Gas Prices Nominal” tab of the 2021 ACC Gas Model v1a.

⁴⁶ See SEIA’s IEPR comments on this issue, provided as **Attachment C** to these comments.

⁴⁷ See E3, “Draft Results: Future of Natural Gas Distribution in California,” presented at the CEC Staff Workshop for CEC PIER-16-011 on June 6, 2019. Hereafter, “E3 Gas Study.” Available at https://ww2.energy.ca.gov/research/notices/2019-06-06_workshop/2019-06-06_Future_of_Gas_Distribution.pdf. Also see E3’s work as technical support for the Gridworks study released in 2019, *California’s Gas System in Transition: Equitable, Affordable, Decarbonized and Smaller*, available at <https://gridworks.org/initiatives/cagas-system-transition/>.

⁴⁸ Even less realistic is the CEC IEPR gas forecast, which assumes no rate escalation at all. See the “IEPR Gas Prices Nominal” tab of the 2021 ACC Gas Model v1a.

⁴⁹ See Figure 1 in the SEIA – Vote Solar comments to the CEC on IEPR gas issues.

transportation rates of 6% per year through 2050, consistent with E3's work in the Gridworks study.⁵⁰

C. Calculation of Market Heat Rates

Energy Division staff has clarified that the SERVVM prices used in the 2021 ACC do not include cap & trade costs. See **Attachment B**. This means that there is an error in the calculation of the market heat rates used in the 2021 ACC. The market heat rates are calculated by taking the raw SERVVM prices, subtracting a variable O&M adder, then dividing by the gas price plus a cap & trade adder.⁵¹ Since the cap & trade costs have already been removed from the SERVVM prices, including the cap & trade cost again in the denominator of the market heat rate calculation incorrectly removes them twice, and results in heat rates that are too low. This error should be corrected by calculating the market heat rates as the raw SERVVM prices less variable O&M, divided by only the gas price.

D. GHG Adder

The 2021 ACC Electric Model v1a escalates the 2020 GHG abatement cost from 2020 dollars to nominal dollars.⁵² However, RESOLVE model outputs are in 2016 dollars.⁵³ Thus, it appears that the \$88 per tCO₂ GHG abatement price in 2030 should be escalated to nominal dollars from 2016 dollars rather than from 2020 dollars. Four more years of escalation should be added to this value.

E. Methane Leakage

The methane leakage setting in the 2021 ACC has been toggled from the 20-year Global Warming Potential ("GWP") of methane to the 100-year GWP.⁵⁴ The 2020 ACC Electric Model v1c used the 20-year setting as the default setting. We believe a 20-year setting also is most appropriate to DERs that have a useful life of 25 years or less.

F. Correct Southern California Market Heat Rates

Northern California market heat rates in the 2021 ACC Electric Model v1a match the

⁵⁰ See Figure 9 on page 14 of the Gridworks Study referenced above, for a long-term projection of the EG transportation rate for PG&E.

⁵¹ See the "SERVVM Price Inputs" tab of the "2021 ACC SERVVM Prices v1a" spreadsheet, starting at cell AE6. The denominator in the heat rate formula includes 'IRP and Fuel Cost Inputs'!G\$15," which is cell with the IRP Carbon Price Input.

⁵² See the "Emissions tab" at cell I19. The formula in that cell refers to a "base year" value that is set to "2020" in cell N3.

⁵³ See cell B3 of the "Portfolio Analytics" tab in the "RESOLVE_Results_Viewer_2021-04-02_New46MMTNoDER_NoGas_Clean_Dashboard."

⁵⁴ See cell C8 of the Methane Leakage tab of the 2021 ACC Electric Model v1a.

Northern California market heat rates in the 2021 ACC SERVVM Prices v1a worksheet. For Southern California, however, they do not. It appears that the Southern California market heat rates need to be copied over correctly to the electric model.⁵⁵

IV. PROCESS ISSUES

In Decision 19-05-019, the Commission described in detail the process that was to be used to make minor changes to the ACC:

The Commission strives for transparency in all processes. A workshop to allow for parties to comment prior to the resolution should provide the requested transparency and allow for agreed-upon minor changes to the modeling methods. A workshop also provides parties a reasonable opportunity to give feedback prior to the resolution being drafted. Accordingly, the Commission should retain the resolution process adopted in D.16-06-007, and, beginning with the 2019 process, hold a public workshop prior to the drafting and issuance of the draft resolution. To further improve transparency, *a list of proposed changes will be sent to the appropriate service lists prior to the workshop, parties will be given an opportunity to provide informal comments on the proposed changes following the workshop, and the draft resolution will incorporate language regarding the discussion at the workshop.*⁵⁶

A workshop was held on December 9, 2020. The workshop was not dedicated to potential minor changes to the ACC, but rather was entitled Integrated Distributed Energy Resources Workshop and covered several topics. No proposed changes to the ACC were distributed prior to the workshop. The workshop presentation made by Commission staff dedicated a sole slide for approximately 15 minutes at the end of the workshop to proposed minor updates to the ACC. Specifically, the Proposed Minor Updates for 2021 ACC were presented as:

1. Minor bug fixes
2. Update Gas Prices
3. Update CARB Refrigerant data and GWP recommendations
4. Possible update of IRP resource costs, RESOLVE No New DER scenario and SERVVM energy and AS prices
5. Possible update of GNA and DDOR inputs for distribution avoided cost, if needed

⁵⁵ Compare the “Emissions” tab of the Electric Model to the SERVVM Price Inputs tab of the 2021 SERVVM Price worksheet.

⁵⁶ D. 19-05-019, pp. 53-54 (emphasis added)

These possible changes were presented only in concept and were describe as “simple updates,” – “nothing too controversial.”⁵⁷ Moreover, there were no details provided on exactly what the changes would be or their impact on the 2021 ACC compared to the 2020 ACC.

Following the workshop, contrary to the process contemplated by D. 19-05-019, Staff did not establish a process for the submittal of informal comments on the proposed minor changes to the ACC presented at the workshop, but merely informed the parties that if they had any questions or concerns they should email Staff.⁵⁸ Then, three months later, on March 11, 2021, Staff presented parties with “a list of minor updates which will be made to the 2021 Avoided Cost Calculator.”⁵⁹ While parties were told that if they had “any questions or comments about the list” to contact staff, there was no solicitation of comments, with established due dates. Moreover, the list given to parties on March 11 still provided little or nothing in way of specifics and no indication of the impacts of the proposed changes on the ACC⁶⁰ and no workshop was held subsequent to the distribution of this list, as required by D. 19-05-019. By circumventing the Commission-ordered process of providing parties with the specific intended changes before the workshop, Staff cut off any “reasonable opportunity” for parties to provide feedback. This lack of opportunity is evidenced in the resolution itself. While Commission stated in D. 19-05-019 that “the draft resolution will incorporate language regarding the discussion at the workshop,” the draft resolution contains no such language because there was no basis to have a substantive discussion of the proposed changes at the workshop, because no details were presented.⁶¹

Moreover, certain of the language used in the Staff’s presentation at the December 9 workshop and again in the list of changes sent to parties on March 11 indicated that some of the contemplated changes were not to be made in a 2021 update to the ACC but would be made at a future time. For example, the first section of the December 9 workshop was entitled “Overview of 2020 Avoided Cost Calculator and discussion of issues, possible future improvements, and questions” (“Overview Section”). This section was distinct from the last section which, as noted above was entitled “Proposed Minor Updates for 2021 ACC.” Given this delineation, the Solar Parties reasonably interpreted the first section as discussing possible future “major” changes that might be pursued for the 2022 ACC. This interpretation was buttressed by the fact that the items

⁵⁷ See *Integrated Distributed Energy Resources Workshop*, starting at 2:06:51.

⁵⁸ *Id.*, at 2:18:30.

⁵⁹ See March 11, 2021 E-mail from J. Morgenstern to R.14-10-003 Service List.

⁶⁰ Indeed, it is unclear as to whether Staff realized the implications of their proposed updates as the RESOLVE model which produced those results was not done until April 2.

⁶¹ The Draft Resolution states that subsequent to the distribution to the March 11 list, “Several stakeholders provided important information about minor errors in the data, modeling, and format of the ACC,” but such information was not shared with all parties, further eroding the transparency of the process.

discussed as part of the Overview Section were described at the workshop as issues that E3 ran into when performing the 2020 Major ACC update and for which additional research was needed; that any changes from such research were not “written in stone” but could have a “substantial impact” on the results of the ACC.⁶² Despite the delineation made at the workshop between “possible future improvement” and “proposed minor updates to the ACC,” the draft 2021 ACC has included a number of the “possible future improvements,” such as the new benchmarking and the “Updated Scarcity Pricing Methodology,” discussed above.

Finally, the Solar Parties would highlight that the March 11 list of changes distributed to parties provided that the ACC will “Incorporate any enhancements to IRP and SERVM *made in IRP proceeding*” (emphasis added). This language clearly states that the ACC will incorporate changes to IRP and SERVM which have been made – and therefore approved by the Commission – in the IRP proceeding. Neither the December workshop nor the March 11 list included any details on the “enhancements to IRP and SERVM.” The Solar Parties did not provide any comments, because we had no specifics on which to comment and because we expected that any IRP or SERVM changes first would appear and be vetted publicly “in IRP proceeding.”⁶³

Federal and state due process clauses impose limitations on federal, state, and local agencies. An agency, such as the Commission, must provide parties with adequate notice and opportunity for a fair hearing, *i.e.*, an opportunity to be heard “at a meaningful time and in a meaningful manner.”⁶⁴ Such a time would have been *prior* to the release of the Draft Resolution. That simply did not occur. First, Commission Staff did not adhere to the process established by the Commission for minor updates to the ACC. The workshop was held before the staff had developed a specific list of the updates that it proposed to make, thus precluding meaningful participation at the workshop. Second, it was only on release of the draft Resolution that parties had a meaningful idea of the specific proposed updates or their impact on the ACC. Indeed, the new RESOLVE run on which the draft Resolution is based was not performed until April 2, 2021. Third, the limited data that the staff released on May 3, as well as the limited 20-day comment period for a Commission resolution, was inadequate to evaluate fully either the new IRP scenario or the SERVM modeling changes. In sum, the parties have not been provided a meaningful opportunity to analyze and comment upon the IRP scenario which is at the heart of

⁶² See *Integrated Distributed Energy Resources Workshop*, starting at 4:18.

⁶³ At the December 9 workshop E3 stated that it would be using outputs for the IRP process from the end of 2019. See *Integrated Distributed Energy Resources Workshop*, starting at 2:08:59. Contrary to this, the draft 2021 ACC is using a new run of RESOLVE completed on April 2, 2021.

⁶⁴ [*Today's Fresh Start, Inc. v. Los Angeles County Office of Education* \(2013\) 57 Cal.4th 197, 212](#), quoting [*Armstrong v. Manzo* \(1965\) 380 U.S. 545, 552](#).



the draft 2021 ACC or to address the impact of all methodological changes prior to their inclusion in the Draft 2021 ACC.

V. RECOMMENDATIONS

For the reasons set forth in these comments, the Commission must reject the major methodological changes proposed in the draft 2021 ACC, for the substantive and process reasons discussed in Sections II and IV above. These major changes include:

- the use of a new IRP scenario and new GHG shadow prices from RESOLVE,
- the use of new SERVM modeling, with changes to the methods used to model price formation and to benchmark prices to historical CAISO market prices, and
- the new scarcity pricing methodology.

For the 2021 ACC, the Commission should retain from the approved 2020 ACC, first, the GHG shadow prices from RESOLVE and, second, the market heat rates based on the SERVM modeling of the No New DER scenario for the approved RSP, as adopted in D. 20-04-010 and Resolution E-5077.

The Commission should make the minor input changes and error corrections that are presented in Section III. Most of these changes impact the natural gas forecast. Other than these changes, the Solar Parties do not oppose the remainder of the updated natural gas forecast used in the draft 2021 ACC. We also do not oppose the “Minor Bug Fixes” described on page 6 of the Draft Resolution.

We appreciate the Commission’s consideration of these comments.

Sincerely,

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Service List 14-10-003