BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of Energy Efficiency Rolling Portfolio Business Plan.	Application 17-01-013 (Filed January 17, 2017)
And Related Matters	Application 17-01-014 Application 17-01-015 Application 17-01-016 Application 17-01-017

FINAL COMMENTS OF MARIN CLEAN ENERGY ON
ENERGY EFFICIENCY BUSINESS PLANS

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I. INTRODUCTION

Marin Clean Energy ("MCE") submits the following comments in response to the *Administrative Law Judges' Ruling Clarifying July 25, 2017 Ruling and Denying, in Part, Pacific Gas and Electric Company's Motion to Amend its Application* ("Clarification Ruling") filed August 4, 2017. The Clarification Ruling modified a previous ruling[1] such that opening and reply briefs are replaced with final and reply comments. MCE provides its final comments below and, for the reasons described herein, respectfully requests that the Commission:

1) Approve MCE's business plan with an expanded portfolio of programs;
2) Adopt MCE's downstream liaison proposal to address program overlap and savings attribution;
3) Authorize MCE's statewide downstream pilots and reject the IOUs' proposed statewide pilots;

[1] *Administrative Law Judge's Ruling Denying Motions for Evidentiary Hearings and Testimony, but Providing for Briefs* ("Ruling on Briefs"), filed July 25, 2017.

4) Direct PG&E to provide MCE with prior program participation data to support implementation of MCE's business plan;
5) Authorize a threshold for budget increases based on the inclusion of new communities within MCE's service area;
6) Modify MCE's gas funding process to align it with the electric funding process;
7) Consolidate MCE's December 1 unspent funds advice letter into the annual budget advice letter;
8) Incorporate CCAs into the approach for integration of energy efficiency ("EE") and demand response ("DR"); and
9) Approve the business plans of the San Francisco Bay Area Regional Energy Network ("BayREN"); the Southern California REN ("SoCalREN"); the Tri-County REN ("3C-REN"); and the Local Government Sustainable Energy Coalition ("LGSEC").

II. BACKGROUND

MCE is the only Community Choice Aggregator ("CCA") EE Program Administrator ("PA") authorized by the California Public Utilities Commission ("Commission"). MCE filed its application and business plan on October 27, 2015.[2] The Commission held a prehearing conference on February 1, 2016, but did not issue a scoping memo or take any further action. Subsequently, the Commission issued Decision ("D.") 16-08-019, which directed MCE to file a revised business plan incorporating new guidance concurrently with other PAs on January 15, 2017.[3]

[2] Application ("A.") 15-10-014.
[3] D.16-08-019, Ordering Paragraph 2 at p. 109.

Consistent with D.16-08-019, MCE filed a revised business plan application on January 17, 2017.[4] MCE served its business plan as Attachment C to its testimony filed on the same date.[5] On January 18, 2017, MCE filed a motion to withdraw the 2015 business plan and close A.15-10-014. On April 12, 2017, the Commission issued D.17-04-004 granting MCE's motion to withdraw the application and closing A.15-10-014.

On January 30, 2017, the Commission consolidated MCE's application with the applications of the investor-owned utilities ("IOUs") into a single proceeding: A.17-01-013 et al.[6] The Commission established multiple opportunities to provide supplemental information and comments to develop the record in this proceeding.[7] These final comments are an opportunity for parties to address subjects not already covered and supplement the record with comments on the full breadth of the proceeding issues.[8]

III. MCE'S EXPANDED PORTFOLIO SHOULD BE APPROVED

A. The Status Quo is Not an Option for California's EE Programs as the Commission Calls for Substantial Changes in Program Design

Over a series of recent decisions, the Commission has substantially changed California's framework for energy efficiency program design and administration related to: (1) statewide programs; (2) third party programs; and (3) CCA programs. These changes remove the IOU from

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[4] Application ("A.") 17-01-013 et. al., Application of Marin Clean Energy for Approval of Its Energy Efficiency Business Plan ("MCE Application") (filed January 17, 2017).
[5] Testimony of MCE Regarding Its Application for Approval of Its Energy Efficiency Business Plan ("MCE Testimony"), served on January 17, 2017, Attachment C ("MCE Business Plan").
[6] *Chief Administrative Law Judge's Ruling Consolidating Proceedings; Preliminarily Determining Category, Need for Hearings, and Assignment; and Setting Protest and Response Deadlines*, filed January 30, 2017.
[7] *See e.g. Administrative Law Judges' Ruling Modifying Schedule*, filed June 9, 2017 at p. 7-9 (providing revised schedule of proceeding).
[8] Clarification Ruling at p. 2.

their traditional role and empower other entities to advance new program designs to better serve California.

In D.16-10-028, the Commission required third party implementers to design and deliver all statewide[9] and third party[10] programs. The Commission also limited the traditional role of the IOU by removing the decision making about each statewide program to a single lead PA for the entire state.[11] The third-party programs are a particularly substantial shift from the status quo because the Commission set a minimum target of 60 percent of the utilities' portfolios to be designed by third parties by the end of 2020,[12] only three years from now. These changes alone represent a substantial shift in program design and will largely modify the mix of programs currently being offered by the IOUs.

The Commission has also changed the rules to enable CCA PAs to design and administer programs that overlap with legacy IOU programs. CCA programs were initially restricted to serve gaps in IOU programs and hard to reach markets.[13] Approximately one year later, in the seminal decision that interpreted the CCA statutory right to administer EE programs, the Commission lifted those restrictions on CCA portfolios, now allowing for CCA programs to overlap with the IOUs' programs.[14]

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[9] "One or more statewide implementers, under contract to the lead administrator, should propose the design and deliver the program or subprogram in coordination with the lead program administrator." D.15-10-028 at p. 61-62 (emphasis added).

[10] "…[T]o be designated as a third-party, the program must be primarily designed and presented to the utility by the third party, in addition to delivered under contract to a utility." D.16-08-019 at p. 69-70 (emphasis added).

[11] D.16-08-019 at p.

[12] D.16-08-019 at p. 74.

[13] D.12-11-015 at p. 45-46.

[14] "If CCAs want to undertake regional or statewide programs…we see no prohibition on their doing so in Section 381.1. There are obvious practical implications…including whether and how to deal with overlap between an IOU and CCA offering." D.14-01-033 at p. 36. *See also* D.14-10-046 at p. 120 (clarifying that the same rules apply to gas funding).

B. CCAs have a Right and an Obligation to Serve Customers with EE Programs

The California legislature provided CCAs a right to administer energy efficiency programs in California Public Utilities Code Section 381.1. This right is subject to Commission oversight and approval,[15] but should not be categorically denied due to the preexistence of IOU programs.

CCAs also have an obligation to provide EE programs that supersedes the IOU obligation. EE is at the top of the loading order for generation resources under California state policy.[16] CCAs have a greater degree of responsibility for procurement under the law than IOUs; the governing board of a CCA bears the sole responsibility for generation procurement on behalf of its customers.[17] MCE also has a greater degree of responsibility for procurement based on the fact that over 80% of customers in MCE's service area receive generation services from MCE.[18] In law and in fact, MCE has a greater obligation and need than PG&E to procure EE programs to effectively and efficiently serve its customers. In recognition of this reality, the Commission should approve MCE's business plan, including the expanded portfolio of programs and the downstream liaison proposal.[19]

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[15] D.14-01-033 at p. 11-12.
[16] Cal. Pub. Util. Code § 454.5(b)(9)(C) indicates: "[t]he electrical corporation shall first meet its unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible." See also State of California Energy Action Plan I, 2003 at p. 4 (defining a loading order with energy efficiency as the primary resource); and the Energy Efficiency Policy Manual at p. 1 (noting energy efficiency is a procurement resource and first in the loading order).
[17] Cal. Pub. Util. Code § 366.2(a)(5).
[18] This proportion is generally consistent for CCAs that have completed enrollment in their service areas.
[19] The downstream liaison proposal is discussed in more detail in Sections IV and V below.

C. MCE's Business Plan Represents Bold and Innovative New Program Concepts

MCE's expanded business plan advances bold and innovative program concepts that will help the State achieve targets for increased adoption of energy efficiency and carbon reductions. The programs will also produce useful insights and potentially identify successful strategies for other PAs.

1. A Single Point of Contact to Drive Impact

MCE's initial business plan filed in October 2015 included Single Point of Contact ("SPOC") approach that was maintained in MCE's revised business plan.[20] This model was later incorporated into all of the IOU business plans filed in January of 2017. The SPOC model supports customers as they participate in EE programs, reduces marketplace confusion, and takes advantage of MCE's close ties to the community to drive impact. The SPOC model is not a proposal to replace PG&E and may in fact *help* customers access PG&E programs. MCE's shared attribution proposal, discussed in Section IV below, will allow SPOCs to focus on driving customers to programs that will have the greatest impact, regardless of whether the programs are administered by a REN, CCA, or IOU.

2. Customer Transformation and Declining Incentives

MCE's ten-year vision for EE embraces customer transformation through a positive customer experience and declining incentives for adopted measures. The proposal includes a mechanism that ties incentive levels to adoption rates; as adoption of a measure increases, the incentives for that measure decrease.[21] This type of innovative approach is only possible if the Commission authorizes MCE's downstream liaison proposal, discussed in Sections IV and V

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[20] MCE Business Plan at p. 29-31.
[21] MCE Business Plan at p. 28, 127-130.

below, so that customers and contractors do not simply switch to a similar PG&E program with relatively higher incentives.

MCE's emphasis on transforming EE goes beyond a project-by-project approach to foster a culture where EE is the norm — a program design originally anticipated by the Long Term Energy Efficiency Strategic Plan.[22] MCE's SPOC will create and leverage initial positive experiences to engage customers for subsequent and expanded projects. This approach is intended to transform customers thinking and engagement with EE and create opportunities for MCE to provide the customer deeper savings and other demand-side offerings.

3. Integrated Program Offerings

If authorized, MCE plans to substantially improve on traditional IOU programs by leveraging customer interactions to achieve broader resource conservation goals, maximizing carbon reductions, grid benefits, and stacking value streams through integrated program delivery.[23] MCE's business plan includes diagrams demonstrating this program logic for each of the sectors (*i.e.* Single Family;[24] Multifamily;[25] Industrial;[26] Agricultural;[27] and Commercial[28]). MCE will integrate its Low-Income Families and Tenants ("LIFT") pilot program, funded through the Energy Savings Assistance program, that will provide additional incentives to income-qualified customers and pilot the deployment of heat pumps for the purposes for fuel

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[22] The Long Term Energy Efficiency Strategic Plan, jointly adopted by the CEC and the CPUC, calls for a market in which ratepayer subsidies are no longer necessary. January 2011 Update, Section 1.3 at p. 4-5. Available at http://www.cpuc.ca.gov/NR/rdonlyres/A54B59C2-D571-440D-9477-3363726F573A/0/CAEnergyEfficiencyStrategicPlan_Jan2011.pdf.
[23] *See e.g.* MCE Business Plan at p. 29-30 (discussing integrated offerings).
[24] MCE EE Business Plan, Figure 15 at p. 37.
[25] MCE EE Business Plan, Figure 19 at p. 54.
[26] MCE EE Business Plan, Figure 23 at p. 70.
[27] MCE EE Business Plan, Figure 25 at p. 83.
[28] MCE EE Business Plan, Figure 28 at p. 96.

switching.[29] MCE will support an open market for Property Assessed Clean Energy ("PACE") programs within its service area.[30] MCE will continue to provide water savings through partnerships with local water agencies.[31] MCE was also able to collaborate with the City of Richmond to provide extra EE incentives for projects located within Richmond.[32] These integrated offerings are imperative because traditional IOU administered EE programs are currently missing out on opportunities to integrate multiple types of efficiency offerings or develop a SPOC relationship over time with all customers.

D. MCE Must Expand Its Portfolio of Programs to be Cost Effective

In 2012, the Commission acknowledged that the initial restrictions on CCA portfolios would make it difficult to achieve a cost-effective portfolio and did not impose a cost-effectiveness requirement on CCAs.[33] Therefore in 2014, when the Commission lifted those restrictions on CCAs and allowed overlapping programs with IOUs,[34] it also imposed the same cost effectiveness requirement on CCAs that is required of IOUs.[35] The Commission "encourage[d] CCAs to continue to target hard to reach markets and offer innovative programs, but also employ a mix of programs which will result in a cost-effective energy efficiency portfolio."[36]

MCE cannot maintain its current restricted portfolio, designed to focus on gaps in existing IOU portfolios, and be cost effective. As discussed above in Section II, MCE filed a

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[29] MCE Advice Letter 23-E-A, filed July 20, 2017.
[30] MCE Business Plan at p. 43, 46, 62, 77, 91, 109.
[31] MCE Business Plan at p. 34.
[32] *See e.g.* Richmond City Council Agenda Meeting, February 21, 2017, Item H-1 (proposing partnership between Richmond and MCE to deliver EE to multifamily homes).
[33] D.12-11-015 at p. 45-56.
[34] *Supra* Section III.A at p. 3-4.
[35] *See* D.14-01-033, OP 3 at p. 50 (Applying IOU cost effectiveness standards to CCAs); D.14-10-046 at p. 109-110 (Setting a TRC ratio of 1.25 for IOUs and CCAs).
[36] D.14-10-033 at p. 14-15.

business plan in 2015 with a mix of programs that would have resulted in a cost-effective portfolio. The Commission directed MCE to file a revised business plan in 2017. Thus, MCE's current business plan is the first opportunity since the restrictions were lifted to propose a mix of programs that will result in a cost-effective portfolio. The Commission should approve MCE's business plan as it includes a mix of programs that will achieve a cost-effective and balanced portfolio.

MCE has limited opportunities to achieve cost-effective savings relative to PG&E, the largest utility in the country.[37] MCE's request for savings attribution, a component of the downstream liaison proposal, discussed below in Sections IV and V, addresses the limited opportunities for cost-effective savings within MCE's service area while also preserving activities of other PAs and programs. The Commission should approve MCE's business plan and downstream liaison proposal in order to ensure that MCE can achieve cost effectiveness.

E. MCE is Proposing a Balanced Portfolio

MCE's 2015 business plan was the first proposed portfolio following the lifted restrictions and imposition of cost-effectiveness requirements on CCAs. MCE's current business plan is its second proposal. MCE is following the Commission's encouragement and continuing to target hard to reach markets while employing a mix of programs that will result in a cost-effective portfolio.[38] MCE is not cherry picking programs for cost-effectiveness, but rather is focusing on administering downstream activities. MCE is proposing to expand its portfolio to include comprehensive downstream offerings – including serving industrial, agricultural, and large commercial customers while expanding offerings to single family, multifamily, and small

[37] *See* Electricity Explained. United Stated Energy Information Administration, Available at https://www.eia.gov/energyexplained/index.cfm?page=electricity_home#tab2 (stating PG&E was the largest utility in the country by retail sales revenues ($12.6 billion) in 2015) accessed on September 19, 2017.
[38] D.14-10-033 at p. 14-15.

commercial customers.[39] The Commission should approve this balanced expanded portfolio as described in MCE's business plan.

F. MCE's Budget is Reasonable[40]

Table 1. MCE's Annual Budgets for 2018-2025[41]

Year	Electric Budget	Gas Budget	Total Budget
2018	$1,466,771	$5,678,444	$7,145,215
2019	$3,653,084	$6,645,441	$10,298,525
2020	$3,830,391	$7,776,854	$11,607,245
2021	$3,830,391	$7,776,854	$11,607,245
2022	$3,486,286	$6,767,497	$10,253,783
2023	$3,486,286	$6,767,497	$10,253,783
2024	$3,486,286	$6,767,497	$10,253,783
2025	$3,444,482	$6,686,347	$10,130,829

The proposed budget is based on achieving cost-effective savings and reflects the growth of MCE's programs. For example, MCE will achieve more savings through expanded programs that serve new sectors including industrial, agricultural, and large commercial. MCE will also serve customers in an expanded service area. In 2016, the Commission increased MCE's EE budget to ensure funding for an expanded customer base after MCE included several new communities in its service area.[42] Since then, MCE has continued to grow and now serves additional communities, including in the cities within Napa County (American Canyon, Calistoga, Napa, St. Helena, and Yountville) and the cities of Lafayette and Walnut Creek. These

[39] MCE Application at p. 6.
[40] *See e.g.* Comments of Marin Clean Energy on Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judges ("Supplemental Budget Information"), filed June 12, 2017 (providing additional information to support MCE's budget request).
[41] MCE's business plan proposes ten years of annual budgets. *See* MCE Business Plan, Appendix A: Placemats at p. 133-134. This budget table covered 2018-2025 and was compiled from MCE's response to a PG&E data request that is also included as Attachment A to these comments.
[42] *See i.e.* D.16-05-004 (increasing budget to account for Unincorporated Napa County, the City of San Pablo, the City of Benicia, and the City of El Cerrito, in addition to a majority of cities in Marin County and the City of Richmond joining MCE's service area).

newest member communities represent a 40% increase in MCE customer accounts. The additional communities and additional programmatic offerings support MCE's requested increase in savings goals and budgets relative to MCE's previous programs.

MCE requests a proportion of electric to gas funds[43] that is commensurate with the estimated savings resulting from planned programmatic activities. The Commission ordered PG&E to enter a contract with MCE to transfer gas funds for MCE EE programs that have a gas savings component.[44] The Commission further stated:

> "We do not want to be overly prescriptive here regarding how to split MCE's revenue requirement between gas and electric funds. We direct PG&E to provide a high level of deference to MCE on the terms of this contract."[45]

MCE has experienced shortfalls in gas funding[46] and requests the current proportion in an attempt to better align gas funding with customer need.

MCE's budget is based on a cost-effectiveness analysis that utilized the 2013 avoid costs. MCE anticipates that recent and upcoming changes to cost-effectiveness inputs (*e.g.* 2017 avoided costs, greenhouse gas ("GHG") adder) will require another cost-effectiveness analysis and result in adjustments to budgets and savings targets for all PAs. MCE, like other PAs, will incorporate any necessary adjustment to the budget through a business plan amendment or via annual budget advice letters based on Commission direction. For the purposes of this application, MCE's proposed budget is reasonable.

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[43] *See* Attachment A (data request response provided by MCE to PG&E demonstrating the gas and electric split).
[44] D.14-10-046, Ordering Paragraph 26 at p. 168.
[45] D.14-10-046 at p. 119.
[46] In the three years of administering gas funding, MCE has requested two increases to the gas budget through a fund shift from PG&E. PG&E Advice Letter 3642-G/4720-E, filed October 15, 2015; MCE Advice Letter 26-E, filed September 15, 2017.

G. MCE's Proposed Metrics are Reasonable

On July 14, 2017, MCE filed revised metrics that replaced the metrics provided in MCE's business plan.[47] These include portfolio metrics from the *Administrative Law Judge's Ruling Seeking Comment on Energy Efficiency Business Plan Metrics* ("Metrics Ruling") filed May 10, 2017.[48] They also include sector-level metrics that were provided in MCE's revised metrics filing as Attachment A.[49] MCE is open to considering additional metrics in the future, if needed, however MCE is not proposing any additional metrics at this time due to challenges related to feasibility of additional metrics and time for discussion with stakeholders.

H. Local Government PAs Provide Advantages Over IOU PAs

In addition to the justification for MCE's business plan provided above, there are several fundamental advantages of local government program administration[50] over IOU program administration. The Commission's recent changes to third party programs are based, in part, on a desire for innovation in program design.[51] Local governments are uniquely situated to innovate in program design. Local governments possess connections to their constituents and knowledge of their communities on a deeper and broader level than IOUs, whose purpose is to sell utility service and increase profits. Local governments are also accustomed to accessing external revenue, for example through grants, IOUs typically do not pursue. These funds can leverage ratepayer funds and deepen resource conservation improvements at customer properties. These advantages provide extra insights and program elements that contribute to innovation in program design.

[47] Revised Metrics Submission of Marin Clean Energy, filed July 14, 2017.
[48] Metrics Ruling at p. 6.
[49] Revised Metrics Submission of Marin Clean Energy, Attachment A.
[50] This includes CCAs, RENs, and the Local Government Sustainable Energy Coalition ("LGSEC") serving as a PA for Local Government Partnerships ("LGPs").
[51] D.16-08-019 at p. 70.

As not-for-profit public service entities, local governments are often more aligned with state policy and the Commission's interests in serving ratepayers and do not pursue shareholder returns. Local governments have a strong interest in serving their communities and often prioritize disadvantaged and hard to reach community members. Local governments are also aligned with the recent shift in focus away from strict energy savings and toward an emphasis on reducing GHG emissions and integrating more renewable energy. MCE is an agency built on these standards.[52] Each of these institutional advantages provides CCAs and local government PAs with a unique and valuable perspective for innovation in program design. The Commission should encourage and empower CCAs and local governments to compete in the marketplace of ideas for program design by expanding their PA functions.

IV. MCE IS THE ONLY PA THAT PROPOSED A SOLUTION FOR ADDRESSING PROGRAM OVERLAP WITH A CCA

The Commission has determined that program overlap may present challenges but has declined to address overlap until the factual situation arose in a program, application, or advice letter.[53] MCE's application presents this factual situation as MCE proposes intervention strategies for sectors that overlap with PG&E's proposed intervention strategies and sectors.[54] MCE is in the unique position of being the only PA with cost effectiveness obligations whose service territory is contained completely within that of another PA. MCE is also the only PA that proposed a solution to address overlap between PA portfolios.

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[52] "[MCE's] mission is to address climate change by reducing energy related greenhouse gas emissions through renewable energy supply and energy efficiency at stable and competitive rates for customers while providing local economic and workforce benefits." About Us. Available at https://www.mcecleanenergy.org/about-us/; More broadly, local governments in California engage in climate action planning and have an interest in reducing GHG emissions.
[53] D.14-01-033 at p. 36.
[54] *See e.g.* MCE Business Plan at p. 29-126 (describing MCE's proposed sector strategies); *see also* PG&E's Energy Efficiency Business Plan 2018-2025, Portfolio Overview, Table 1.2 at p. 01-6 (summarizing PG&E's proposed sector strategies).

A. Addressing Overlap by Ignoring It or Relying on Collaboration Alone are Not Feasible Solutions

The Commission posed a question to parties to explore overlap in the *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judges* ("Scoping Memo").[55] PG&E's answer focused on arguing against MCE's proposed budget and downstream liaison approach to dealing with overlap but failed to provide any specific counterproposal to manage overlap.[56]

In its reply to MCE's answer on the same question, PG&E provided its suggestion; "in case of overlapping service areas, the Business Plan of the IOU should govern the delivery of energy efficiency to that area."[57] In other words, PG&E suggests that MCE offerings remain confined to the limited gaps in PG&E's portfolio. This draconian suggestion attempts to abrogate MCE's statutory right to administer EE programs for its customers – and the Commission's decision explicitly inviting program overlap.[58] The Commission should reject this blatant attempt to relegate CCAs to the gaps in IOU programs.

SoCalREN and BayREN suggest that either voluntary collaboration[59] or coordination and collaboration ordered by the Commission[60] are sufficient to address overlap. MCE supports coordination and collaboration and includes those elements in the structure of its downstream

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[55] "37. How should the potential for overlap between CCA, REN, and utility programs be identified, planned for, and managed?" Scoping Memo, Attachment B at p. 4.
[56] Response of PG&E to Comments on Attachment A of the Scoping Memo and Ruling and to Attachment B Questions, filed June 22, 2017, at p. 53-57.
[57] Reply Comments of PG&E on Responses to the Questions in Scoping Memo Attachments A and B, filed on June 29, 2017, at p. 10.
[58] *See supra* Sections III.A, III.B, and III.D.
[59] The County of Los Angeles, on Behalf of SoCalREN Energy Efficiency Business Plan Comments on Supplemental Information – Attachment B, and Other Key Issues, filed June 22, 2017, at p. 31.
[60] Response of the Association of Bay Area Governments, on Behalf of the BayREN to Attachment B of the April 14, 2017 Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judges, filed June 22, 2017, at p. 9.

liaison proposal. However, these elements are not a complete solution to addressing program overlap with CCAs.

As MCE described in its supporting testimony, it has experienced serious issues collaborating with PG&E, including a lack of communication from PG&E prior to major incentive changes to a jointly implemented program.[61] This experience is in contrast to MCE's experiences collaborating with local governments, which has generally been constructive and productive.[62] As noted above, PG&E suggests that IOU business plans should govern the delivery of EE in an area with overlapping programs demonstrating its unwillingness to collaborate and its opposition to overlap.[63] Any solution to overlap must address the conflicts of interest that lead IOUs to perceive CCA programs as a threat to their own program administration or Energy Savings Performance Incentive ("ESPI") award.

B. To Address Overlap the Commission Should Designate MCE as the Downstream Liaison within Its Service Area

MCE's solution to address program overlap is comprehensive and aims to accomplish the following goals: (1) address overlap collaboratively among PAs; (2) encourage innovative program designs; (3) address cost-effectiveness; and (4) reduce customer confusion. MCE's solution is to serve as the downstream liaison within its service area.[64] As discussed further in the MCE Application, the downstream liaison proposal is necessary to ensure equity and cost effectiveness.[65] The three key functional components of this downstream liaison designation are (1) the ability to preclude duplicative PG&E and third party downstream programs from delivery

[61] MCE Testimony at p. 34, lines 5-14.
[62] MCE Testimony at p. 34, lines 5-9; MCE has had similarly cooperative discussions with BayREN.
[63] Reply Comments of PG&E on Responses to the Questions in Scoping Memo Attachments A and B, filed on June 29, 2017, at p. 10.
[64] MCE Application at p. 14-21.
[65] MCE Application at p. 19-21.

in MCE's service area[66] (with an 18 month transition period for third party programs);[67] (2) funding and receiving savings attribution for all ratepayer-funded, Commission-authorized EE activities within MCE's service area;[68] and (3) a requirement for other PAs to coordinate with MCE prior to customer outreach.[69]

1. Precluding Duplicative Programs

MCE's option to preclude duplicative programs should be limited to precluding PG&E and third party downstream programs.[70] This resolves challenges associated with each of the goals listed above. First, it greatly mitigates the conflict of interest issue that results in contention between PG&E and MCE in implementing programs.[71] If MCE has the ability to preclude duplicative PG&E programs, even if MCE does not exercise the ability, PG&E will have a strong incentive to collaborate and coordinate with MCE.

Second, this addresses a challenge that limits innovative program design, discussed in Section III.C above, such as the declining incentive structure when customers and contractors can simply utilize a duplicative program with higher incentives. Inversely, it avoids a potential "race to the top" as PAs could seek to attract customers or contractors to competing programs by offering higher incentives - at ratepayer expense.

Third, MCE is in a unique position among California PAs, as it is both held to a cost-effectiveness requirement and it exists completely within another PA's service area. The ability to preclude duplicative programs allows MCE to limit the number of programs that are

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[66] MCE Testimony at p. 32-34.
[67] Comments of Marin Clean Energy on Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judges ("MCE Attachment B Answers"), filed June 22, 2017 at p. 8-9.
[68] MCE Application at p. 17-19.
[69] MCE Testimony at p. 32, lines 10-19; *Infra*, Table 2 at p. 19.
[70] MCE does not request the option to preclude statewide programs, REN programs, or LGP programs. MCE Testimony at p. 32-34; *Infra*, Table 2 at p. 19.
[71] *See supra* Section IV.A at p. 14-15.

competing for the same savings within MCE's service area. MCE can limit redundant outreach and prevent fragmentation of savings opportunities among programs to improve cost-effectiveness. Finally, this ability also allows MCE to eliminate customer confusion arising from multiple duplicative programs operating in the same geographic area.

This proposal is factually distinguished from PG&E's proposal that the IOU business plan should govern the delivery of EE.[72] If MCE's proposal is approved, PG&E can still operate its full portfolio of programs outside MCE's service area. If PG&E's proposal is approved, MCE's portfolio will remain restricted to the gaps in PG&E's programs. MCE's proposal still allows PG&E to administer comprehensive programs while the inverse is not true for PG&E's proposal.

MCE proposes a process by which duplicative offerings would be identified. The mechanics of this process would involve MCE filing a tier 2 advice letter. The advice letter would include: (1) a description of the relevant MCE offering, (2) a description of the duplicative PG&E or third party offering. Energy division staff could then determine whether the offerings are "substantially similar" by finding each of the following to be true: (1) the offerings serve the same class of customers; (2) the offerings provide similar intervention strategies or measures; and (3) the offerings are available in the same area. To the extent the offerings are substantially similar, those PG&E or third party activities would need to cease. The scope of the activities outlined in an advice letter could include a single downstream measure or the full mix of offerings for a sector. Any activities that are not substantially similar (*e.g.* implementation outside MCE's service area, additional intervention strategies, or additional classes of customers) could continue.

[72] Reply Comments of PG&E on Responses to the Questions in Scoping Memo Attachments A and B, filed on June 29, 2017, at p. 10.

2. Funding and Receiving Savings Attribution for Statewide and Downstream Activities

MCE's proposal regarding funding and receiving savings attribution also addresses numerous challenges. First, it resolves how to attribute savings for statewide programs in one geographic area shared by two PAs:[73] MCE pays for the savings and they are attributed to MCE for the purpose of cost-effectiveness analysis. MCE proposes to extend this approach to all downstream programs. This will provide three significant benefits: (1) it eliminates any incentive MCE may have to preclude programs or refrain from making referrals to programs simply to preserve the limited cost-effective opportunities for MCE's own programs; (2) it ensures that MCE can achieve a cost-effective portfolio with other program administrators operating in the same service area; and (3) it creates a shared interest among MCE and other PAs in the success of all programs, even those not directly administered by MCE.

MCE will use these attributed savings when performing *ex post* cost effectiveness analysis and reporting achievements. However, all of MCE's savings will continue to count toward IOU savings goals as directed by the Commission,[74] until MCE is assigned its own goals. The mechanics of this proposal are intended to substantially mirror the approach to statewide funding and shared attribution,[75] which is still being finalized among the PAs. To facilitate this process, MCE requests that the Commission direct the IOUs and PG&E to collaborate with MCE to determine the appropriate portion of budget that should be covered by MCE for statewide programs.

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[73] Currently, this situation is unique to MCE and PG&E and is not addressed in D.16-08-019 where the Commission outlined the shared attribution for statewide programs. As discussed in MCE's testimony, PG&E refused to discuss an approach to statewide program attribution with MCE. MCE Testimony at p. 35, lines 6-8.
[74] D.14-01-033 at p. 36-37.
[75] D.16-08-019 at p. 55-56.

3. PA Coordination with MCE Prior to Program Outreach

All PAs in MCE's service territory will be required to coordinate with MCE prior to reaching out to its customers.[76] This coordination will enhance MCE's ability to serve customers as the SPOC for downstream EE programs. MCE is not proposing to provide all outreach activities for non-MCE programs. However, in its role as downstream liaison, MCE will strive to eliminate customer confusion about multiple program offerings. This coordination also helps to identify and address program overlap prior to contacting customers.

Table 2: Coordination in MCE's Role as Downstream Liaison and with Savings Attribution[77]

	Required to Coordinate with MCE Prior to Outreach	MCE has Authority to Preclude Duplicative Offerings	100% Savings Attribution for Activities within MCE Service Area	100% Budget Attribution for Activities within MCE Service Area
Upstream & Midstream Statewide Programs	No	No	Yes	Yes
Downstream Statewide Programs	Yes	No	Yes	Yes
Third Party Programs	Yes	Yes	Yes	Yes
Other IOU Downstream Programs	Yes	Yes	Yes	Yes
REN Programs	Yes	No	Yes	Yes
LGP Programs	Yes	No	Yes	Yes

[76] MCE Testimony at p. 32, lines 10-19; *Infra*, Table 2 at p. 19.
[77] This table is also in the MCE Application (Table 1 at p. 21) and summarizes the role of the downstream liaison related to various types of programs and in different contexts. This is discussed in more detail in the MCE Application. MCE Application at p. 14-19.

V. MCE'S DOWNSTREAM LIAISON SOLUTION ALLOWS FOR MCE AND PG&E TO CO-EXIST

MCE seeks a functional co-existence with PG&E. Co-existence can be interpreted in multiple ways: (1) jointly administering programs; (2) working around PG&E programs; or (3) administering similar programs in different geographic areas. A fourth option is competing programs, but that raises numerous issues discussed above in Section IV.B. The first two options present significant challenges, though the downstream liaison role reduces the challenges with jointly administered programs.

As discussed in Section IV above, MCE has experience jointly implementing a program with PG&E and it is not an efficient or an effective partnership. PG&E consistently makes decisions that impact the program without consulting, or in some cases, even informing MCE. This was the case with sweeping incentive changes and the program policy related to classification of hard to reach customers. While these program modifications may serve the best interests of PG&E's portfolio, they significantly impaired MCE's ability to remain cost effective with the jointly implemented program. The objectives of PG&E's broader and larger portfolio may always conflict with MCE's portfolio objectives. This challenge could be alleviated through designating MCE as the downstream liaison because PG&E would then have a natural incentive to meaningfully collaborate on joint programs. Failure to collaborate could result in MCE launching its own program and precluding the duplicative PG&E program from continuing to operate within MCE's service area.

The second option, working around PG&E programs, abrogates MCE's right to administer programs.[78] Additionally, it is impossible to predict what programs MCE would be able to offer, since new statewide and third party programs will disrupt the status quo of PG&E's

[78] *See supra* Sections III.A, III.B, and III.D.

programs.[79] Since third parties will be designing these programs, it is infeasible to identify what activities will result from PG&E's competitive solicitations. This would require MCE to wait for PG&E to execute all of its contracts prior to MCE proposing programs to fill the gaps. PG&E supports this approach and requested that "it should be permitted to hold its solicitation prior to any solicitation by a local PA."[80] PG&E will not complete solicitations until 2020.[81] Further, PG&E's approach does not address MCE's need to be cost effective, which will be infeasible if MCE is merely filling gaps in PG&E's programs. PG&E's proposal to limit and delay MCE's programs in this manner is completely unreasonable and should be rejected.

Finally, PG&E and MCE could co-exist as PAs in different geographic areas. MCE has only a small portion of PG&E's service territory. PG&E can continue to provide its EE programs to the vast majority of its customers that reside outside MCE's service area. This option for co-existence provides minimal disruption to PG&E's portfolio while addressing many of the challenges discussed in Section IV.B above.

Jointly administering programs and working around PG&E programs are problematic approaches to co-existence. The downstream liaison proposal preserves and encourages a supportive co-existence between PAs through overlapping programs operating in different geographic areas and mitigating issues with jointly administered programs.

A. Co-existence Should Focus on Supporting Each Other as PAs

MCE seeks a supportive co-existence with PG&E. This support extends in both directions and should include data sharing; customer referrals; coordinating Marketing,

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[79] *See supra* Section III.A.
[80] PG&E Third Party Solicitation Process Proposal, filed August 4, 2017, Attachment: 2018-2025 Energy Efficiency Rolling Portfolio Solicitation Plan ("PG&E Solicitation Plan"), Appendix 1: Responses to Third Party Solicitation Proposal Guidance at p. 16.
[81] PG&E Solicitation Plan, Appendix 1: Responses to Third Party Solicitation Proposal Guidance, Figure 3 at p. 11.

Education, and Outreach ("ME&O") and customer outreach; and collaborating on solicitations. To facilitate this co-existence, MCE discusses a component of data (*i.e.* program participation data) that should be shared following the approval of business plans in Section VII below. MCE also recommends that PG&E receive compensation in exchange for effective data sharing and customer referrals in the form of additional ESPI incentives[82] and incentives for PG&E account representatives.[83] This type of cooperative relationship will improve the delivery of EE programs.

B. MCE Proposes a Solution that is Responsive to the Disruption Caused by the New Framework for Statewide and Third Party Programs

MCE's downstream liaison proposal is compatible with the Commission's recent changes to statewide and third party programs. MCE is planning to help fund and receive savings attribution for upstream and midstream statewide programs similar to the other PAs under D.16-08-019, though MCE seeks clarification from the Commission that CCA PAs are eligible to do so.[84] MCE does not seek to create local iterations of statewide programs. These upstream and midstream programs have a broader focus than current local PAs and MCE intends to focus administration on downstream activities.

MCE's plan also introduces mechanics to inform third parties about the downstream liaison role and proactively plans for overlap in solicitations.[85] This includes providing (1) a description of each PA in the geographic area subject to the solicitation;[86] and (2) the applicable rules for interacting with each PA.[87] It also includes bidders providing a plan to address overlap

[82] MCE Testimony at p. 33, lines 12-17.
[83] MCE Testimony at p. 33, lines 17-18.
[84] MCE Application at p. 17-19.
[85] *See i.e.* MCE Attachment B Answers at p. 9-10, 13.
[86] MCE Attachment B Answers at p. 9-10.
[87] MCE Attachment B Answers at p. 9.

with other PAs within their bids.[88] Finally each winning bidder would be bound by standard contract terms that require coordination with the other PAs in the same region on marketing, outreach, and implementation.[89] These mechanics will help identify and address overlap before it is enshrined in an implementer's contract.

VI. MCE'S PROPOSED STATEWIDE DOWNSTREAM PILOTS PROVIDE GREATER BENEFITS THAN THE IOUS' PROPOSED PILOTS

The Commission ordered PAs to pilot a statewide approach for four separate downstream programs.[90] In doing so, the Commission recognized the benefit of statewide programs run under a lead administrator to ensure consistency throughout the state.[91] Furthermore, the Commission opined that downstream programs would benefit from having "a consistent set of program rules, documentation requirements, savings measurement requirements, etc.…"[92] and that the downstream pilots should "test the use of common elements even with regional or local variations."[93] In ordering the downstream approaches, the Commission called for a "statewide administration framework even though individual program participation activities would still occur at a local level."[94]

In response, MCE proposed four statewide downstream pilot programs and requests the Commission authorize these pilots and reject the IOU downstream pilot proposals.[95] The IOUs have proposed four discrete downstream programs to be piloted on a statewide basis. However, MCE's proposed programs cut across all other downstream programs, will ensure greater

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88 MCE Attachment B Answers at p. 9.
89 MCE Attachment B Answers at p. 10.
90 *See* D.16-08-019, mimeo at 65, 111 (Ordering Paragraph No. 9).
91 D.16-08-019 at p. 53.
92 D.16-08-019 at p. 59.
93 D.16-08-019, Conclusion of Law 52 at p. 104.
94 D.16-08-019, Ordering Paragraph 9 at p. 111.
95 MCE Application at p. 21-23; MCE Testimony at p. 37-40.

consistency throughout the state, and will reduce overall administrative costs. The Commission should approve these cross-cutting pilot programs designed to positively impact numerous other downstream programs as they are fundamentally different from, and superior to, the more narrowly focused programs the IOUs proposed.

MCE's four pilots are similar to PG&E's proposed platforms[96] in that they focus on elements that are common to many downstream programs as opposed to a single discrete program. First, MCE proposes a Consolidated Workpaper Development Pilot Program. This program would be administered by PG&E and would consolidate the development of all workpapers for all PAs into one program. Second, MCE proposes a Transparent Deemed Savings Development Pilot Program. This program would be administered by Southern California Edison Company ("SCE") and would replace the existing process for developing deemed values to establish a more transparent process. Third, MCE proposes a Consistent Normalized Metered Energy Consumption ("NMEC") Methodology Pilot Program. This program would be administered by San Diego Gas & Electric Company ("SDG&E") and would develop and maintain a consistent approach for NMEC to cost-effectively support the use of existing conditions baselines as called for by Assembly Bill 802 (2015). Fourth, MCE proposes a Statewide Data Support Pilot Program. This program would be administered by Southern California Gas Company ("SoCalGas"), or perhaps an independent administrator that specializes in data management, and would develop a common platform to access data for all PAs to support statewide program administration, enable EM&V activities across multiple PAs, and other benefits. This will reduce the cost of accessing data for entities such as implementers, local

[96] PG&E Solicitation Plan at p. 8.

governments, Commission staff, and perhaps the California Energy Commission in accessing data by consolidating the data into a single platform.

MCE's proposed workpaper program, the deemed measure program, and the NMEC methodology program support the statewide creation of a consistent set of rules, documentation requirements, and savings measurement requirements. Each of these programs, in addition to the Statewide Data Support Program, also provide a statewide framework and allow for individual program participation activities to occur at a local level, with regional or local variations. Thus, these programs are consistent with the Commission's direction regarding statewide downstream pilots.

In addition, MCE's proposed pilot programs have four benefits that are not found in the IOUs' proposals. First, MCE's programs preserve the ability to locally tailor the downstream customer interface because they pilot common approaches and elements that exist within other downstream programs. Second, MCE's programs have the potential to greatly reduce administrative costs associated with each PA undertaking these activities individually. Third, MCE's programs reduce the challenge of coordinating statewide and non-statewide customer-facing offerings that may result in siloed delivery and excess customer touchpoints. Fourth, program delivery for implementers will be more consistent across PA service areas. These are substantial advantages over the IOU programs and clearly justify the Commission authorizing MCE's proposed statewide downstream pilot programs.

VII. THE COMMISSION SHOULD DIRECT PG&E TO PROVIDE MCE PRIOR PROGRAM PARTICIPATION DATA TO SUPPORT IMPLEMENTATION OF MCE'S BUSINESS PLAN

In order to achieve its goals, and build on its prior success, MCE needs access to prior participation data to better understand the potential for energy savings within its service area and to design the most effective portfolio to realize that potential.[97] Prior participation data is critical to support MCE in: (1) improving and tracking metrics for all sectors; (2) evaluating market potential for portfolio design; and (3) pursuing targeted marketing opportunities.

PG&E's proposal to aggregate industrial customer data prior to sending it to MCE is wholly inadequate, even to support MCE tracking a new industrial sector metric.[98] The utility opposes MCE's request for an order directing PG&E to share its prior program participation data with MCE.[99] As a CCA, a PA, and a load serving entity ("LSE"), MCE's request for energy efficiency program participation data is entirely reasonable and necessary for effective program design. Participation data will improve MCE's ability to effectively perform its PA functions across all sectors.[100] PG&E fails to demonstrate that providing participation data would be inappropriate, costly, or burdensome.[101] Ratepayers, including MCE's customers, have funded PG&E's energy efficiency programs and the associated collection of data through rates over many years. Those customers now should be able to benefit from their past investments via the open sharing of such data among PAs to facilitate the efficient use of their funding.

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[97] Application of Marin Clean Energy for Approval of Its Energy Efficiency Business Plan, filed January 17, 2017 at p. 20; Revised Metrics Submission of Marin Clean Energy at p. 4-5; Reply Comments of Marin Clean Energy on Revised Sector-Level Metrics Proposals ("MCE Metrics Reply Comments"), filed July 31, 2017, at p. 3-8.

[98] MCE Metrics Reply Comments at p. 8-9.

[99] PG&E's Comments on Revised Sector-Level Metrics Proposals and Energy Efficiency and Demand Response Integration Options, filed July 24, 2017 at p. 2-5.

[100] Reply Comments of Marin Clean Energy on Revised Sector-Level Metrics Proposals at p. 4-6.

[101] Reply Comments of Marin Clean Energy on Revised Sector-Level Metrics Proposals at p. 6-7.

VIII. THE COMMISSION SHOULD AUTHORIZE A THRESHOLD FOR BUDGET INCREASES BASED ON THE INCLUSION OF NEW COMMUNITIES WITHIN MCE'S SERVICE AREA

CCAs have the potential to include new communities within their service area at any time.[102] MCE's business plan includes a service area map, budget, and market characterization based on its existing communities. The Commission's recent decision created a new budget process under the rolling portfolio framework.[103] The new process uses annual budget advice letters to request the actual authorized budget consistent with an approved business plan, while the business plan is intended to provide a general sense of the budget supported by program strategies.[104] If a budget increase is deemed too large to be consistent with an approved business plan, the plan will need to be updated before the budget increase can be approved. MCE anticipates that including new communities will generally not require a reconsideration of the logic or fundamental approach articulated in its business plan. However, updating the business plan to reflect a newly included community would require considerable administrative work through an application filing and a resulting proceeding.

MCE recommends that the Commission develop a rule to avoid the administrative costs associated with such an application. MCE proposes a threshold of 50% for budget increases based on inclusion of new communities without the need to update the business plan. To request such an increase, MCE will submit a tier 2 advice letter specifying the additional funding, including a description of the activities that will be funded, and providing an updated cost effectiveness assessment. MCE will also maintain an updated implementation plan that provides

[102] In 2015, additional communities joined MCE's service area including unincorporated Napa County and the cities of San Pablo, Benicia, and El Cerrito. As a result of this expansion, MCE served approximately 30% more customers compared to 2014. In 2016, MCE included Walnut Creek, Lafayette, and the cities and towns in Napa County, resulting in approximately 40% more customers than were served in 2015.

[103] D.15-10-028 at p. 54-57.

[104] D.15-10-028 at p. 55-56.

a current service area map with associated market characterization information to reflect any new communities, similar to what is included in the MCE Business Plan for existing communities.[105] The proposed threshold will reduce administrative costs because it will avoid the need for MCE to prepare and for the Commission to review a new business plan application each time a new community is included in MCE's service area. This is particularly effective if the logic and fundamental approach of the business plan does not change. The Commission should address the budget impacts of CCA service area growth by approving this threshold and a tier 2 advice letter process to request budget increases for new community inclusion.

IX. MCE'S GAS FUNDING PROCESS SHOULD BE MODIFIED TO ALIGN WITH MCE'S ELECTRIC FUNDING PROCESS

The Commission should direct PG&E to amend the terms of the gas funding contract with MCE to simplify the gas funding processes by aligning it with the electric funding process. The Commission directed PG&E to enter into a contract with MCE to provide gas funding that is modeled after the contract PG&E has with BayREN.[106] The Commission also directed PG&E to provide a high level of deference to MCE on the terms of this contract.[107] MCE requests that the Commission further direct PG&E to amend the terms of this contract to align it with the process by which MCE receives electric funds. The Commission should direct PG&E to revise the gas funding contract within 60 days of the approval of MCE's business plan.

MCE receives electric funds in quarterly installments from PG&E based on MCE's approved budget.[108] MCE specifies all unspent electric funds each year in an advice letter

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[105] MCE Business Plan at p. 21-27.
[106] D. 14-10-046 at p. 119.
[107] D.14-10-046 at p. 119.
[108] D.14-10-046, Ordering Paragraph 24 at p. 167-168.

filing.[109] This advice letter is used to offset the quarterly installments from PG&E in the following year.[110] This process is simple, functional, and administratively efficient relative to an invoicing process.[111]

The gas funding contract requires MCE to invoice PG&E on a monthly basis for expenditures. These invoices are approved both by PG&E and by Energy Division staff. PG&E subsequently transfers the invoiced gas funds to MCE. This process is functional, but involves unnecessary administrative burdens from the invoicing process and creates complexity that the Commission should eliminate.

The complexity involves accounting and budget presentment, particularly in the unspent funds advice letter. Since MCE receives electric funds from PG&E prior to making expenditures but receives gas funds after making expenditures, only the unspent electric funds are available to offset future budget transfers. This complexity is unnecessary and should be eliminated through amending the gas funding process to align with the electric funding process.

X. MCE'S DECEMBER 1 UNSPENT FUNDS ADVICE LETTER SHOULD BE CONSOLIDATED INTO THE ANNUAL BUDGET ADVICE LETTER

MCE has experienced fluctuations in overall customer participation and in demand for gas saving measures from year to year. These fluctuations have a greater impact on small PAs due to the relative impact of a single measure or project on the overall portfolio. MCE intends to propose broader changes to the use of unspent funds in the EE rulemaking that will improve operational flexibility and MCE's capacity to meet this fluctuating need. However, in advance of

[109] D.14-10-046, Ordering Paragraph 25 at p. 168.
[110] D.14-10-046, Ordering Paragraph 24 at p. 167-168.
[111] However, MCE proposes a modification to improve the unspent funds process below in Section X.

those proposals, MCE requests one administrative change to reduce unnecessary complexity related to the unspent funds reporting.

MCE currently specifies all unspent electric funds each year in an advice letter filed on December 1.[112] This filing includes an estimate of unspent funds from the current year, before the year is over, to offset budget transfers from PG&E for the following year.[113] In practice, the advice letter also includes a true up from previous estimates. The use of estimated unspent funds creates a complex process with varying numbers in different advice letters for "unspent" funds from the same year.

This complexity creates confusion when completing the annual budget advice letter tables. For example, MCE's unspent funds advice letter will have an estimate of unspent funds from within the year it is filed. The 2016 and 2017 annual budget advice letter appendices included a field to input unspent funds from two years prior. Since the numbers reference unspent funds from two years in the past, MCE has actual figures, not estimates. Thus, the unspent funds in the annual budget advice letter may vary from the unspent funds in the unspent funds advice letter for the same year.

The current rules require MCE to report unspent funds in two advice letters that are filed three months apart. This process should be greatly simplified by requiring only the actual unspent funds that are reported in the annual budget advice letter. This process eliminates a duplicative advice letter filing and provides the unspent funds amount to PG&E months earlier than the current process. This amount is certain, not an estimate, and would be used to offset the budget transfers from PG&E in the following year. This approach still protects ratepayers because any unspent funds from MCE programs will still be used to offset budget transfers from

[112] D.14-10-046, Ordering Paragraph 25 at p. 168.
[113] D.14-10-046 at p. 126.

PG&E to MCE. Consolidating the unspent funds reporting into the annual budget advice letter will simplify the filings and reduce complexity associated with reporting and tracking unspent CCA funds.

XI. DEMAND RESPONSE AND ENERGY EFFICIENCY INTEGRATION SHOULD REFLECT THE EXISTENCE OF NON-IOU PROGRAMS

MCE provided comments in response to the *Administrative Law Judge's Ruling Requesting Comments on Energy Efficiency and Demand Response Integration Options* ("EE-DR Integration Ruling") filed June 30, 2017. MCE proposes that EE-DR integration reflects the Commission's competitive neutrality cost causation principle for Demand Response ("DR") programs in the EE and DR integration.[114] MCE requests that CCA customers be included in EE-DR integration.[115] The Commission should authorize MCE to request funds to integrate DR with EE program delivery in the annual budget advice letter.[116] Finally, MCE requests the Commission take note that EE-DR integration is a core component of MCE's Single Point of Contact ("SPOC") model and will include MCE DR programs that are separate from any Commission funding.[117]

XII. THE COMMISSION SHOULD APPROVE THE 3C-REN, BAYREN, SOCALREN, AND LGSEC BUSINESS PLANS

As discussed above in Section III.H, local government PAs provide unique benefits that are not provided by IOU PAs. The Commission should encourage local government PAs. MCE supports the business plans of the 3C-REN, BayREN, SoCalREN, and the LGSEC. The Commission should approve these plans to support local government program administration.

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[114] Comments of MCE on Administrative Law Judge's Ruling Requesting Comments on EE and DR Integration Options ("MCE EE-DR Comments"), filed July 24, 2017, at p. 2-3.
[115] MCE EE-DR Comments at p. 3-4.
[116] MCE EE-DR Comments at p. 4-5.
[117] MCE EE-DR Comments at p. 5.

XIII. CONCLUSION

MCE thanks Commissioner Peterman, Administrative Law Judge Fitch, and Administrative Law Judge Kao for their thoughtful consideration of these comments.

Respectfully submitted,

/s/ Michael Callahan

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September 25, 2017

Attachment A:
Response of Marin Clean Energy
to Pacific Gas and Electric Company
Data Request 1: Question 1

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of Energy Efficiency Rolling Portfolio Business Plan.	Application 17-01-013 (Filed January 17, 2017)
Application of San Diego Gas & Electric Company (U902M) to adopt Energy Efficiency Rolling Portfolio Business Plan Pursuant to Decision 16-08-019.	Application 17-01-014 (Filed January 17, 2017)
Application of Pacific Gas and Electric Company for Approval of 2018-2025 Rolling Portfolio Energy Efficiency Business Plan and Budget (U39M).	Application 17-01-015 (Filed January 17, 2017)
Application of SOUTHERN CALIFORNIA GAS COMPANY (U904G) for adoption of its Energy Efficiency Rolling Portfolio Business Plan and related relief.	Application 17-01-016 (Filed January 17, 2017)
In the Matter of the Application of Marin Clean Energy for Approval of its Energy Efficiency Business Plan.	Application 17-01-017 (Filed January 17, 2017)

RESPONSE OF MARIN CLEAN ENERGY TO PACIFIC GAS & ELECTRIC COMPANY DATA REQUEST 1

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February 16, 2017

Marin Clean Energy
Response to Pacific Gas & Electric Company February 1, 2017 Data Request 1 in A.17-01-013 et al., In the Matter of the Application of Marin Clean Energy for Approval of its Energy Efficiency Business Plan

GENERAL STATEMENT

Nothing in this response to Pacific Gas & Electric Company ("PG&E") Data Requests ("Data Requests" or "Requests") should be construed as prejudicing or waiving Marin Clean Energy's ("MCE") right to produce and provide additional documentary evidence based on information, evidence or analysis hereafter obtained or evaluated. MCE's responses are made subject to inadvertent or undiscovered errors, and are limited by records and information still in existence and or presently recollected and thus far discovered in the course of preparing this response. MCE reserves the right to update and/or supplement the responses provided herein if and when additional evidence, which is responsive to the Requests becomes available and at any time if it appears that inadvertent errors or omissions have been made.

These responses are made without intending to waive or relinquish MCE's rights to take the following actions:

1. Raise all questions regarding relevancy, materiality, privilege, admissibility as evidence for any purpose as to any documents identified or produced in response to these Requests which may arise in any subsequent proceeding, in, or at the trial of this, or any other action;

2. Object on any grounds to the use of said documents in any subsequent proceeding, in, or at the trial of this, or any other action;

3. Object on any grounds to the introduction into evidence of documents identified or produced in response to these Requests; and/or

4. Object on any grounds at any time to other requests for production or other discovery involving said documents, or the subject matter thereof.

MARIN CLEAN ENERGY

RESPONSE TO PG&E DATA REQUEST

DOCKET NO.:	Application 17-01-013 et al.	**REQUEST DATE:**	February 1, 2017
REQUEST NO.:	PG&E-MCE_001	**RESPONSE DATE:**	February 16, 2017
REQUESTER:	Matthew Lewis, PG&E (415) 973-8151 M2LD@pge.com	**RESPONDER:**	Beckie Menten

QUESTION NO. 1

For each year from 2018 to 2025, please identify: (1) the total amount of MCE's budget request; (2) the amount of electric funds requested; and (3) the amount of gas funds requested. Please complete the following chart:

	Total Budget	Electric Funds	Gas Funds
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			

CONFIDENTIAL (yes or no): No.

RESPONSE:

Marin Clean Energy ("MCE") provides the amended table below that includes the total budget, electric funds, and gas funds inclusive of evaluation, measurement, and verification ("EM&V") funds. These figures are general projections of the annual budget requests. MCE will request each year's budget in the corresponding Tier 2 annual budget advice letter as directed in D.15-10-028. MCE also notes that its business plan is a ten year plan that extends beyond 2025 and may not start in 2018, depending on the California Public Utilities Commission approval. MCE's response assumes year 1 of the business plan is 2018.

Table 1. MCE's Budget Request Including Fuel Type

	Total Budget[1]	Total EM&V	Electric Funds[1]	Electric EM&V	Gas Funds[1]	Gas EM&V
2018	$7,145,215	$296,040	$1,466,771	$60,771	$5,678,444	$235,269
2019	$10,298,525	$408,754	$3,653,084	$144,993	$6,645,441	$263,761
2020	$11,607,245	$483,635	$3,830,391	$159,600	$7,776,854	$324,035
2021	$11,607,245	$483,635	$3,830,391	$159,600	$7,776,854	$324,035
2022	$10,253,783	$427,241	$3,486,286	$145,262	$6,767,497	$281,979
2023	$10,253,783	$427,241	$3,486,286	$145,262	$6,767,497	$281,979
2024	$10,253,783	$427,241	$3,486,286	$145,262	$6,767,497	$281,979
2025	$10,130,829	$422,118	$3,444,482	$143,520	$6,686,347	$278,598

[1]Total Budget, Electric Funds, and Gas Funds include evaluation, monitoring, and verification (EM&V) budget.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2018 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation (U39E)	Application 17-06-005 (Filed June 1, 2017)

PROTEST OF MARIN CLEAN ENERGY, PENINSULA CLEAN ENERGY AUTHORITY, THE SILICON VALLEY CLEAN ENERGY AUTHORITY, AND SONOMA CLEAN POWER AUTHORITY TO PG&E'S ENERGY RESOURCE RECOVERY ACCOUNT APPLICATION

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Dated: July 7, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2017 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation (U39E)	Application 17-06-005 (Filed June 1, 2017)

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Pursuant to Rule 2.6 of the Commission's Rules of Practice and Procedure, Marin Clean Energy (MCE), Peninsula Clean Energy Authority (PCE), the Silicon Valley Clean Energy Authority (SVCEA), and the Sonoma Clean Power Authority (SCPA) or "Joint CCA Parties" submit this protest to PG&E's Energy Resource Recovery Account (ERRA) application, filed June 1, 2017. CleanPowerSF, through the City and County of San Francisco, is separately protesting PG&E's application. Collectively, this constitutes the five largest operational Community Choice Aggregators (CCAs) in PG&E's service territory.

The PCIA is as opaque as it is volatile. For example, when SCPA started serving customers in 2014, the Power Charge Indifference Adjustment (PCIA) applicable to its residential (E1) customers was $0.01101 per kWh. As a part of this ERRA proceeding, PG&E proposes to charge those same customers a PCIA of $0.03404 per kWh – an increase of 336% in less than four years, and an increase of 15% over the 2017 PCIA rate. Meanwhile, PG&E's application proposes to reduce its generation rates for its own customers.

The Joint CCA Parties protest PG&E's ERRA application on the following grounds:

- The PCIA is not calculated based on truly unavoidable costs because PG&E has not taken any action to mitigate "stranded" resources.
- The calculation of the PCIA contains several errors.
- The departing load forecast needs to be based on publicly available data.
- The PCIA calculation needs to be transparent and the data should be made available to certain CCA staff for verification.

The Joint CCA Parties will serve data requests on PG&E and reserves the right to raise additional issues that arise from PG&E responses.

I. PG&E's Proposed PCIA Is Not Solely Based on Unavoidable Costs

Under State law, PG&E can only recover from CCA customers PG&E's "net *unavoidable* electricity purchase contract costs attributable to the customer" (emphasis added). All costs that PG&E could have avoided are not recoverable as a part of the PCIA.[1]

1 California Public Utilities Code Section 366.2(f)(2)

The "unavoidability" concept is similar to the well-recognized legal rule that a party seeking to recover damages or losses from another is under a legal duty to take all reasonable steps to mitigate those damages or losses. A damaged party may not simply sit back and do nothing, if doing so will increase the amount of its loss. It is under a legal duty to mitigate – to *avoid* – its losses if at all possible.

This mitigation requirement is particularly applicable to situations in which a party has an economic incentive to sit back and take no action, thereby transferring all risk of market changes to its competitors. As the result, the party can reduce or eliminate competition. To avoid this unfair practice, the law requires such a party to mitigate its damages by promptly recontracting with a third party for the sale of the goods. If the party fails to do so, it cannot recover any damages or losses it could have avoided.[2] The Commission's Standards of Conduct for IOUs incorporate this duty to mitigate. In particular, Standard of Conduct 4 (SOC 4) states (emphasis added):

> Prudent Administration of Contracts. The utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner. The utility bears the burden of proving compliance with the standards set forth in its plan. Prudent contract administration includes administration of all contracts within the terms and conditions of those contracts, including dispatching dispatchable contracts when it is economical to do so. **In administering contracts, the utilities have**

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2 "A party injured by a breach of contract is required to do everything reasonably possible to negate his own loss and thus reduce the damages for which the other party has become liable. The plaintiff cannot recover for harm he could have foreseen and avoided by such reasonable efforts and without undue expense. However, the injured party is not precluded from recovery to the extent that he has made reasonable but unsuccessful efforts to avoid loss." (*Brandon & Tibbs v. George Kevorkian Accountancy Corp.* (1990) 226 Cal.App.3d 442, 460 [277 Cal.Rptr. 40], internal citations omitted.)

the responsibility to dispose of economic long power and to purchase economic short power in a manner that minimizes ratepayer costs.[3]

Once a contract has been deemed compliant with the utilities' procurement plan, the contract is not subject to a reasonableness review. However, **the administration of the contract by the utility remains subject to reasonableness review and disallowance through ERRA proceedings.** (D.02-10-062 at 52, as modified by D.02-12-074, D.03-06-067 and D.03-06-076; D.05-01-054 (regarding scope of review and standard of review for contract administration in ERRA proceedings); D.02-12-074 at OP 24.b.)

PG&E's current ERRA application does not present any evidence that it has mitigated avoidable costs to the best of its ability. When CCA customers departed from PG&E service, PG&E was under a legal duty to take action to mitigate and avoid losses resulting from that departure. Instead, for years, with power prices constantly dropping, PG&E held onto resources for which it admittedly did not need.[4] Given the market prices for both brown and renewable energy have declined over the past four years, it is undeniable that had PG&E divested of its unneeded generation resources at the time of a The Joint CCA customers' various departures, or shortly thereafter, it

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[3] California Public Utilities Commission AB57, AB 380 and SB 1078 Procurement Policy Manual at p. 5-11. Available online at: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=10906

[4] As the Commission itself has noted, the primary driver of PCIA increases in the past 4 years has been the decline in market prices for "brown" and renewable power: "The main cause for the PCIA increase in recent years has been the drop in the market value of the IOU's portfolio due to the steep decline in natural gas prices and the fact that renewable power prices have come down below what the utilities are contracted for." CPUC "Fact Sheet – Power Charge Indifference Adjustment" (January 2017), http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/Fact_Sheets/English/PCIAFactSheet010917.pdf.

would have avoided some portion of the costs it is now seeking to recover from CCA customers under the PCIA in this application.[5]

PG&E's failure to dispose of some of those contracts once they were no longer needed means that some of costs PG&E is trying to recover in this application are not "unavoidable." Though the Commission has approved these procurement contracts, providing authorization for cost recovery does not abrogate PG&E's responsibility to prudently manage its portfolio of resources manner – as the Commission's SOC 4 requires. Under SOC 4, PG&E has the burden to show that it managed its contracts prudently. Moreover, because the question of whether PG&E acted reasonably or unreasonably is to some extent affected by how long PG&E delayed taking any action to mitigate damages (perhaps it couldn't have done so in three months, but after four years?), the answer to the "avoidability" question may well vary over time. Since PG&E can only collect costs under the PCIA if those costs are "unavoidable", the "avoidability" question is pertinent and squarely within the scope of this proceeding.[6]

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[5] In principle it is easy to see why: The amount a buyer would be willing to pay for an energy contract is, at base, the net present value of the buyer's estimate of the value of the future stream of energy to be delivered under the contract. By selling an unneeded contract in 2014, the (imputed) amount PG&E would have received from the buyer as payment for deliveries from that contract during 2018 would likely be greater than the "market value" ascribed to those deliveries under the PCIA methodology, because of the general market decline since 2014. The difference between those two figures is the "avoidable" loss that should be disallowed from recovery under the PCIA.

[6] PG&E's may also say that the "unavoidability" issue should be determined in the Commission's new "exit fee" rulemaking proceeding. But that rulemaking will address more general policy issues regarding the PCIA. In contrast, the issue in this ERRA proceeding is narrow, and specific to the Joint CCA Parties' customers and PG&E's action (or inaction) during a particular time frame with respect to those customers. A failure to address the avoidability issue in this proceeding will effectively preclude the Joint CCA Parties and their customers from ever being able to contest the costs PG&E is asking to impose on the Joint CCA Parties' customers in 2018. Once paid, those fees will be gone; nothing in the new rulemaking will change that, and no other proceeding is available for contesting the fees.

It bears noting that above-market costs impact all customers – whether through the PCIA (for departed customers) or as part of the generation rate (in the case of bundled customers). Thus while PG&E professes concern for its bundled customers' costs in making the unsubstantiated claim that the current PCIA results in a cost-shift to bundled customers, it ignores the fact that the lack of prudent contract management may be a driving factor in increasing those costs.

In short, the "avoidability" question is not the kind of "generic policy issue" that the Commission has excluded from considering in past ERRA proceedings.[7] It is, rather, a foundational question that must be considered here and now, for until a cost is determined to be unavoidable, it is inappropriate to include it in the PCIA calculation.[8]

II. Incorrect Calculation of PCIA

The Commission specified a specific set of steps for calculating the PCIA in Decision 11-12-018 and Resolution E-4475. There are several errors in PG&E's application of the methodology that the Commission should order to be corrected. These include the following:

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[7] *See, e.g., Pacific Gas and Electric Company's Reply to Protests and Responses to Its Application for 2017 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation* at 2: "In recent years, parties have repeatedly tried to expand the scope of the Energy Resource Recovery Account ("ERRA") Forecast proceedings to address generic policy issues, such as issues related to cost allocation methodologies and non-bypassable charges. The Commission has consistently determined that these policy issues are outside the scope of the ERRA Forecast proceedings, which are intended to address rate recovery for annual, forecasted procurement costs."

[8] If the Commission eliminates avoidable costs from the PCIA due to PG&E's failure to mitigate, it would be unfair to transfer those costs to bundled customers. To retain the principle of customer indifference, those costs should be borne by PG&E or its shareholders.

1. PG&E has not used the correct source for the calculation of the Green Tariff Renewables Adder ("GTSR"). The included table of utility tariffs does not match any information on the listed website. In addition, the table includes a number of tariffs that are no longer offered by those utilities. Finally, the premiums are miscalculated as they compare one mix of "green" and "brown" power with a different mix of "green" and "brown" power. The correct method consistent with the green adder calculation for investor-owned utilities is compared to a 100% "brown" power baseline, excluding any green power, with a 100% renewable product.
2. PG&E has included avoidable variable and fuel costs in the portfolio costs eligible for recovery through the PCIA. Those costs are for energy generated or purchased solely for the benefit of bundled customers. All fuel costs are inherently avoidable; if output from a fuel-fired generation facility is not needed to serve bundled load, why is PG&E running the facility? The inclusion of these costs cross-subsidizes energy consumption by bundled customers at the expense of direct access ("DA") and CCA customers.
3. PG&E may not have removed from the PCIA revenue requirement the costs of power purchase agreements that have been renewed. Power purchase agreements that were renewed after a DA or CCA customer has left bundled service should be excluded purposes of calculating charges applicable to those customers.

4. PG&E may not have included renewed renewable PPAs in the "Green Adder" market price benchmark. These resources are incremental in the same manner as new PPAs.

III. Departing Load Forecasts

The Joint CCA Parties will evaluate PG&E's departing load forecasts by expounding discovery requests to ensure proper departing load charges are calculated and implemented. PG&E's testimony indicated the forecast of various departing loads due to the potential of emerging CCAs, and those figures must be further vetted to ensure that the forecast is based on the dates of actual load departure, so that the final PCIA is accurate and fair.

IV. Lack of Transparency

The IOUs, interested stakeholders, and the Commission itself have long recognized the need for stakeholders to have access to relevant PCIA information to inform their analyses and internal planning processes. The California Community Choice Association ("CalCCA") submitted a Petition for Modification of confidentiality provisions, which is currently before the Commission.[9] The Joint CCA Parties note that the inability of CCA staff to review underlying cost data is an unnecessary barrier to informed decision making. While this theme will likely emerge in the PCIA OIR, there

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9 CalCCA Petition for Modification, submitted June 13, 2017. Available online at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M190/K624/190624007.PDF

is an independent need for data access to ensure accuracy in this ERRA process. We encourage the Administrative Law Judge to assist the Joint CCA Parties and PG&E to develop a mechanism to allow CCA staff members access to confidential information for purposes of evaluating the propriety of the requests made by PG&E in this ERRA proceeding.

V. Interest in this Proceeding

CCAs are governed by their respective Board of Directors which are comprised of appointees from the participating cities and the counties. CCAs provide their customers with stable and competitive electric rates, providing a power portfolio with a higher renewable content (and lower greenhouse-gas emissions) than PG&E. The Joint CCA Parties' participation in this proceeding is to ensure fair and transparent competition between different load-serving entities ("LSEs") and that the PCIA is applied in a manner that truly implements ratepayer indifference.

VI. Protest

In light of the foregoing, The Joint CCA Parties protest the calculation and reasonableness of PG&E's proposed revenue requirements for CCA rates and CCA rate components, including the PCIA and the CAM.[10] The Joint CCA Parties expect other

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10 Previously the Commission has found it reasonable to cap departing load charges for DA customers under the Cost Responsibility Surcharge ("CRS") to 2.7¢/kWh in order to preserve the economic viability of DA programs. (See Decision D.02-11-022 at 118 and Ordering Paragraph 19.) Consideration of a cap on the PCIA should be considered within the scope of this proceeding.

issues may arise during the course of this proceeding and reserves the right to amend this protest or seek other relief as appropriate.

VII. Proposed Categorization and Need for Hearings

The Joint CCA Parties agree that this proceeding should be categorized as ratesetting and expects that evidentiary hearings will be required to address the assumptions, calculations and reasonableness of PG&E's CCA, PCIA and CAM revenue requirement proposals. At this time, the Joint CCA Parties have no objections to PG&E's proposed procedural schedule which includes time for hearings, as necessary.

VIII. Notice

Communications and correspondence regarding this proceeding should be directed to the following individuals:

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IX. Conclusion

The Joint CCAs respectfully request that the scope of this proceeding include, but not be limited to, the issues identified in this protest.

Dated: July 7, 2017

Respectfully submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements	))))))	Rulemaking 16-02-007 (Filed February 11, 2016)

REPLY COMMENTS OF MARIN CLEAN ENERGY AND PENINSULA CLEAN ENERGY ON THE ENERGY DIVISION STAFF PROPOSAL

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements	))))))	Rulemaking 16-02-007 (Filed February 11, 2016)

REPLY COMMENTS OF MARIN CLEAN ENERGY AND PENINSULA CLEAN ENERGY ON THE ENERGY DIVISION STAFF PROPOSAL

I. INTRODUCTION

In accordance with the *Administrative Law Judge's Ruling Seeking Comment on Staff Proposal on Process for Integrated Resource Planning*, dated May 16, 2017 ("Ruling"), as modified by ruling on June 13, 2017, Marin Clean Energy ("MCE") and Peninsular Clean Energy ("PCE") respectfully submits the following reply comments on the Energy Division Staff Proposal ("Staff Proposal"). MCE has been an active participant in the California Public Utilities Commission's ("Commission") Integrated Resource Plan ("IRP") proceeding thus far, and has filed many joint comments with other Community Choice Aggregators ("CCAs"). In addition, MCE and PCE are members of the California Community Choice Association ("CalCCA") and fully support CalCCA's opening and reply comments on the Staff Proposal. MCE and PCE offer the following reply comments *in addition to* the reply comments filed by CalCCA.

II. REPLY COMMENTS

A. The Commission Should Adopt A Separate "Mid-Level" Plan For CCAs That Focuses On Commission-Jurisdictional IRP Requirements And Incentivizes Uniform Disclosures Across LSE Categories

Several parties have voiced concerns regarding IRP content and filing requirements. Both Pacific Gas and Electric Company ("PG&E") and Southern California Edison Company ("SCE") ask that the Commission impose identical IRP requirements on all Load Serving Entities ("LSE"), regardless of LSE type or category.[1] In other words, PG&E and SCE argue that CCA programs, Energy Service Providers ("ESP"), and Small and Multi-Jurisdictional Utilities ("SMJU") should be subject to the same IRP requirements as the state's three major Investor Owned Utilities ("IOU"). PG&E claims that by subjecting LSEs to different rules and requirements, the LSEs will not achieve the collective Greenhouse Gas ("GHG") reduction goals.[2] SCE argues that all requirements and rules should be applied equally to LSEs to avoid cost shifting.[3]

i. CCA Programs And IOUs Should Not Be Subject to Identical Requirements

PG&E and SCE's request for identical IRP process and requirements for all types of LSE is clearly inconsistent with the requirements of Senate Bill ("SB") 350. As discussed in detail in CalCCA's opening and reply comments, SB 350 recognizes the different categories of LSE, and establishes very different substantive and procedural IRP requirements for electrical corporations (including IOUs and for-profit SMJUs), CCAs and ESPs. IOUs, in particular, are subject to significantly broader substantive IRP requirements than CCAs.[4] Procedurally, SB 350 mandates an IRP process for IOUs in which the Commission has broad authority to adopt substantive IRP requirements; approve, deny, or modify an IOU's IRP; and authorize or require procurement.

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1 PG&E Comments at 7; SCE Comments at 6.
2 PG&E Comments at 7.
3 SCE Comments at 7.
4 *See, e.g* Pub. Util. Code § 454.51(b) (requiring each electrical corporation to include in its IRP a strategy for procuring best-fit and least-cost resources to satisfy the portfolio identified by the commission pursuant to subdivision (a)); Pub. Util. Code § 454.52(b)(2) (each electrical

In contrast, for CCAs' IRPs, SB 350 vests the authority to approve or deny a CCA's IRP in that program's governing board.[5] SB 350 further specifies that the governing board's decision to approve a plan must be based on the plan's compliance with three specific criteria. Notably, these criteria do not include compliance with the Commission's preferred portfolio, or compliance with Commission-imposed substantive IRP requirements. In addition, CCAs are required to "provide" their IRPs to the Commission "for certification." "Certification" is a process in which the Commission reviews CCAs' IRPs to ensure that they are in compliance with requirements that have been expressly made Commission-jurisdictional by statute, such as resource adequacy and renewables integration.

ii. <u>MCE and PCE Propose A Balanced Approach For Certifying a CCA's IRP</u>

MCE and PCE recognize that the Commission has a legitimate interest in developing an IRP process with broad participation from all categories of LSEs. In addition, MCE and PCE understand that the Commission's important IRP work will be considerably more efficient if parties submit (or, in the case of CCAs, provide for certification) IRPs that follow a common template or templates, use a common methodology or methodologies, provide data that can be compared across plans, and provide data that the Commission needs in order to do its job.

At the same time, SB 350 explicitly recognizes the exclusive right of each CCA program to determine its own procurement mix.[6] MCE and PCE place a high value on preserving CCA

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corporation's IRP is required to follow the provisions of Section 454.5). All further statutory references are to the Public Utilities Code.

5 *See, e.g.,* Pub. Util. Code § 454.52(b)(3).

6 *See, e.g.,* Section 454.52(b)(3) ("The plan of a community choice aggregator shall be submitted to its governing board for approval and provided to the commission for certification, consistent with paragraph (5) of subdivision (a) of Section 366.2, …."). *See also* Section 366.2(a)(5) ("A community choice aggregator shall be solely responsible for all generation procurement activities on behalf of the community choice aggregator's customers, except where other generation procurement arrangements are expressly authorized by statute.") Through the

procurement responsibility and local governance. The fundamental purpose underlying CCA programs is to allow local communities to choose their own energy resources. The concept of local procurement independence is at the heart of the State's policy in favor of promoting and encouraging the development of CCA programs,[7] and is embedded in the name itself: Community *Choice* Aggregation. Centralized procurement planning would, by definition, conflict with local procurement independence. While CCAs are comfortable meeting *and exceeding* State standards, the means by which CCAs achieve these standards is a discretionary act rooted in the local governance process, and should not be disturbed (intentionally or otherwise) absent clear and express legislative directive. MCE and PCE propose a way to address the concerns raised by several parties while still respecting CCA local governance and remaining in compliance with SB 350.

Non-bypassable charges ("NBCs") have been perhaps the most contentious and frequently litigated issue for CCA programs. One solution to the NBC issue is the self-provision option that is currently reflected in SB 350. Both SB 350 and the Staff Proposal represent major steps forward with regard to self-provision. SB 350 authorizes the use of an NBC consistent with the so-called Cost Allocation Methodology ("CAM") to address the renewable integration need identified in the Commission's portfolio, but guarantees CCAs the right to self-provide their share of the need in lieu of paying the CAM for renewable integration needs. Although SB 350 *does not* authorize the imposition of any new NBCs, other than using an NBC consistent

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reference to "certification" rather than "approval," and by expressly limiting the Commission's certification powers by referring to a statute making CCAs "solely responsible" for procurement decisions, the Legislature plainly wanted to retain CCA procurement authority in SB 350.

[7] *See, e.g.,* Decision ("D.")04-12-046 at 3 ("The state Legislature has expressed the state's policy to permit and promote CCAs by enacting AB 117…."). *See also* D.10-05-050 at 13 ("Certainly, Section 336.2(c)(9) evidences a substantial governmental interest in encouraging the development of CCA programs and allowing customer choice to participate in them.").

with the CAM for renewables integration, SB 350 does authorize the Commission to use the IRP process to approve IOU procurement to meet specific NBC-eligible resource mandates, such as resource adequacy, which CAM has traditionally been utilized for.[8] The Staff Proposal recommends that if the Commission determines that a CCA program's IRP meets the Commission's reliability and GHG reduction requirements at the LSE level, then that CCA program would be exempt from NBCs for IOU procurement authorized in the IRP process—presumably resources that are subject to CAM and statutorily authorized to be imposed on a CCA.[9]

The opportunity to avoid application of the CAM by means of self-provision is a powerful incentive for CCA programs to *voluntarily* comply with applicable Commission IRP requirements, including many of the requirements that the Staff Proposal would appear to impose on a compulsory basis, contrary to SB 350.

Accordingly, MCE and PCE propose the following modifications to the Staff Proposal. These modifications are also being proposed to further streamline the review process for CCAs' IRPs.

- The Staff Proposal provides for two types of IRPs – "Standard LSE plans" for LSEs with greater than 700 GWh of load, and "Alternative LSE plans" for LSEs with load under that threshold. MCE and PCE propose that the Commission develop a separate "certification" process for CCA IRPs, and develop a third, CCA-specific plan for CCA programs.

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8 *See* Section 365.1(c)(2).

9 *See* Staff Proposal at 65 ("If the CCAs and ESPs submit plans that meet reliability and GHG reduction requirements at the LSE level, and the CPUC has identified a reasonable approach to allocating responsibility for any deficiencies in the aggregated LSE Plans... then staff recommends that only IOU bundled ratepayers cover the costs of additional IOU procurement identified in the individual IOU plans.") *See also* Staff Proposal at 75.

- The Commission should adopt a two-level certification process, and CCA programs would have the option of providing the Commission with Level-1 or Level-2 IRPs for certification.

Level 1 Certification

- Level-1 "certification" would satisfy Section 454.52(b)(3) by providing a "certification" process that closely mirrors the Commission's process for "certifying" other CCA filings, such as their implementation plans.

- Level-1 certification would consist of a high-level review of CCA programs' Level-1 IRPs for compliance with Commission-jurisdictional requirements, such as resource adequacy and renewable integration. Level-1 certification would not include a review of the plans' compliance with the Commission's preferred portfolio, or the IRP criteria set forth at 454.52(a)(1)(A-H).

- The Staff Proposal does not include a process for allowing CCA self-provision of renewable integration resources. This process is required by Section 454.51(d), and must be developed by the Commission to comport with this statutory requirement. MCE and PCE propose that a CCA program seeking to self-provide their share would include its self-provision request and the showings required by Section 454.51(d)(1-3) in its IRP and the Commission would make its determination on the request as part of its first-level certification process. The Commission's determination on the self-provision of resources should offset only potential procurement authorized by Section 454.51(c). CCAs that do not satisfy their obligation will have their programs subject to an NBC consistent with Section 365.1.

Level 2 Certification

- In order to qualify for Level-2 certification, CCA programs would *voluntarily* prepare IRPs according to a Commission-adopted Level-2 template and associated content requirements.

- In recognition of CCA programs' status as public agencies, and their significantly smaller footprint and fewer compliance resources as compared to the IOUs, Level 2 CCA IRPs would represent a mid-point between the broad requirements of the Standard LSE plans and the significantly simplified Alternative LSE plans.

- In order to qualify for Level-2 certification, a CCA program's IRP would have to provide reasonable demonstration of the program's compliance with material IRP requirements adopted by the Commission.

- CCA programs that receive Level-2 certification from the Commission would be *automatically exemp*t from receiving procurement and associated NBCs authorized in that IRP proceeding (and/or any resource-specific proceeding under the IRP proceeding's "umbrella")

- CCA programs that receive Level-1 certification would still have the option of demonstrating self-provision of resources in order to avoid NBCs, but would not receive automatic exemption. For instance, a CCA program with a Level-2 certification would *automatically* be exempt from procurement and related NBCs for renewables integration without further showing, while a CCA program with Level-1 program would have the additional burden of demonstrating self-provision through the process described at Section 454.51(d).

- As additional NBC eligible procurement mandates are integrated into the IRP process through legislative mandates, these mandates should be incorporated into the Commission's certification review, and CCA programs that have been certified as meeting their share of those requirements should not be subject to NBCs for IOU procurement toward those requirements.

- The 2017-2018 IRP should act as a "proof of concept" that tests and improves the communications and processes between CCAs and the Commission.

This approach would allow the Commission to ensure full compliance with SB 350, recognize CCA local governance, and encourage CCA programs to participate in those aspects of the Staff Proposal's approach that are not mandatory for CCA programs under SB 350.

B. Reply to PG&E Opening Comments

Several points raised PG&E in its opening comments are problematic. MCE and PCE address these issues as follows.

In arguing that the IRP should be viewed as a planning process, not a procurement process, and that LSEs need flexibility in actual resource procurement to adjust to changing market conditions, PG&E mentions its "commitment to procure 55 percent eligible renewable energy resources by 2031," which PG&E made in connection with its application to close the Diablo Canyon Nuclear Plant (A.16-08-006).[10] This "commitment" is voluntary and entirely non-binding, and should not be relied upon by the Commission in any way in the IRP proceeding. PG&E should procure based on needs identified by the Commission through the

IRP process, and PG&E's non-binding commitment should not be used as an input in the Commission's modeling or given any weight in assessing PG&E's IRP.

PG&E argues that demand response programs offered by CCA programs should be required to support state and Commission mandates that currently only apply to IOUs.[11] This recommendation has no basis in statute and should be disregarded. In addition, PG&E's recommendation is in direct conflict with Section 366.2(a)(5), which guarantees a CCA shall be solely responsible for all generation procurement activities on behalf of its customers except where other arrangements are expressly authorized by statute. Other than resources needed for system and local area reliability and an energy storage target, there are no statutes that specifically authorize other CCA generation services, such as demand response programs.

C. Reply to TURN Opening Comments

In its opening comments, The Utility Reform Network ("TURN") criticizes the Staff Proposal's proposal for providing exemption to NBCs for CCA IRPs that meet reliability and GHG reduction requirements at the LSE level. TURN states that this proposal "may look good on paper" but "will be very difficult and controversial to administer, as every LSE can be expected to make a case that its plan meets its own share of reliability and GHG reduction needs and that no other costs of obligations should be allocated to it."[12] TURN, however, fails to explain why allowing LSEs the flexibility to determine how they meet GHG reduction and reliability needs would be detrimental. MCE and PCE do not see any issue with providing LSEs the opportunity to establish that they have met their individual shares of IRP requirements. Indeed, MCE and PCE are proud to have met and exceeded reliability and GHG reduction

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10 PG&E Comments at 9.

11 PG&E Comments at 40.

12 TURN Comments At 20.

requirements. Imposing additional NBCs on an LSE that has fully met its share of required procurement would unfairly and unlawfully shift costs from IOU bundled customers to the unbundled customers of non-IOU LSEs.

D. Reply to SCE Opening Comments

SCE argues that SB 350's requirements relating to disadvantaged communities ("DACs") should apply to all LSEs.[13] The Commission should reject this argument, as it is directly contrary to SB 350. SB 350 directs IOUs and other LSEs to minimize local air pollutants and GHG emissions in their IRPs, based on Section 454.52(a)(1)(H). However, Section 454.52(b)(3) makes clear that each CCA's governing board, not the Commission, has the substantive authority to determine whether the CCA's IRP is in compliance with these requirements. SB 350 does not give the Commission the authority to impose requirements regarding DACs on CCAs, and doing so would unreasonably interfere with the CCAs governing boards' clearly defined role and independent authority under the statute.

That said, CCAs, the Commission, and the IOUs would all likely benefit from increased coordination on the question of DACs. MCE and PCE are committed to doing their part to help ratepayers in DACs by providing incentives for energy efficiency and renewable energy products, with particular efforts in multilingual and hard-to-reach communities. MCE and PCE are willing to engage and coordinate with the Commission on this issue, while continuing to offer their own expertise effective strategies, communication, and programs to their DAC customers.

SCE also argues that the current Power Charge Indifference Adjustment ("PCIA") is "fundamentally broken" and asks the Commission to avoid imposing any new procurement mandates not required by law or tied to reliability until the Commission fixes PCIA.[14] As discussed in detail in CalCCA's reply comments, SCE's characterization of the PCIA is clearly erroneous. MCE and PCE do not, however, agree with SCE's "ask." The Commission should pause all non-essential IOU procurement. Given expected CCA growth, additional IOU procurement is likely to be unnecessary and will result in an increase in stranded IOU assets.

Lastly, SCE asks that the Commission make the RESOLVE model and associated documentation available to parties, and that parties be given adequate time to review and test RESOLVE before workshops and comments on the Proposed System Plan.[15] MCE and PCE agree with SCE's request. Parties should be given access to RESOLVE well in advance of the workshop to allow them to familiarize themselves with the model, and to identify possible improvements or modifications to the model.

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13 *See* SCE Comments at 8-9, 15.

14 *See* SCE Comments at 9.

15 *See* SCE Comments at 10-11.

III. CONCLUSION

MCE and PCE thank the Commission for taking the time to consider these reply comments.

Respectfully submitted,

/s/ C.C. Song

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July 12, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Joint Application to Establish Non-Bypassable Charge ("NBC") for Above-Market Costs Associated with Tree Mortality Power Purchase Agreements ("Tree Mortality") in Compliance with Senate Bill 859 and Resolution E-4805.	Application No. 16-11-005 (Filed November 14, 2016)

MOTION OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION FOR INCLUSION OF CONSOLIDATED COST-RECOVERY ISSUE

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July 14, 2017

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

Joint Application to Establish Non-Bypassable Charge ("NBC") for Above-Market Costs Associated with Tree Mortality Power Purchase Agreements ("Tree Mortality") in Compliance with Senate Bill 859 and Resolution E-4805.	)))))))	Application No. 16-11-005 (Filed November 14, 2016)

MOTION OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION FOR INCLUSION OF CONSOLIDATED COST-RECOVERY ISSUE

In accordance with Rule 11.1 of the Rules of Practice and Procedure of the Public Utilities Commission of the State of California ("Commission") and the opportunity afforded by the Administrative Law Judge ("ALJ") at the prehearing conference on June 23, 2017 ("PHC"),[1] the California Community Choice Association ("CalCCA") submits this motion requesting that parties be allowed to address within the scope of this proceeding the issue of whether costs incurred pursuant to Resolution ("Res.") E-4770 may be recovered in a manner different than costs incurred pursuant to Res. E-4805. Moreover, CalCCA requests that the Commission clarify that the investor-owned utilities ("IOUs") carry the burden of proof in requesting consolidated cost-recovery treatment for costs under Res. E-4770 and Res. E-4805.[2]

I. INTRODUCTION

As indicated in CalCCA's protest, there are meaningful distinctions with respect to cost-recovery for procurement pursuant to Res. E-4770, issued in response to the Governor's Emergency

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1 *See* PHC Transcript at 59:1-3.

2 CalCCA uses the phrase "consolidated cost-recovery" to mean cost-recovery treatment for costs under Res. E-4770 that is the *same as* cost-recovery treatment for costs under Res. E-4805. While the Commission may ultimately determine that consolidated cost-recovery is appropriate, it has yet to do so.

Proclamation, and cost-recovery for procurement pursuant to Res. E-4805, issued in response to Senate Bill ("SB") 859. Without exhaustively addressing substantive points, since this motion is focused on procedural matters, CalCCA summarily states that SB 859 cannot be used by the IOUs to justify cost-recovery treatment for costs incurred under Res. E-4770. SB 859 allows *excess* procurement under Res. E-4770 to count toward the IOUs' respective procurement obligation under SB 859 (Res. E-4805). Other than *excess* procurement under Res. E-4770, SB 859's authorization for cost-recovery on a non-bypassable basis does not apply to costs incurred under Res. E-4770.[3] The IOUs must therefore find another statutory basis to justify their proposal for consolidated cost-recovery treatment.

At the PHC, CalCCA reiterated that the Commission had yet to change its earlier determination on cost-recovery treatment for costs under Res. E-4770, and that the IOUs should bear the burden of proof in arguing for a different approach.[4] The IOUs disagreed, arguing that consolidated cost-recovery treatment had already been determined in Decision ("D.")16-12-006.[5]

The IOUs' position at the PHC differs materially from their position in their joint application. In their joint application, the IOUs *request* that the Commission *adopt in this proceeding* a determination on consolidated cost-recovery treatment, whereas at the PHC the IOUs now assert that a determination by the Commission on consolidated cost-recovery *has already been made*.[6] The IOUs' revised position may derive from a statement by the ALJ in the *Administrative Law Judge's Ruling Setting Prehearing*

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3 *See* Pub. Util. Code § 399.20.3(f). All further statutory references are to the Public Utilities Code.

4 *See* PHC Transcript at 36-37 and 43-44.

5 *See* PHC Transcript at 40-41.

6 *See, e.g.,* Joint-IOU Application at 4-5 ("The Joint IOUs specifically request that the Commission…[a]dopt the same Tree Mortality NBC methodology for all Tree Mortality Procurement, whether entered into pursuant to Resolution E-4770 or Resolution E-4805, and SB 859, for all three Joint IOUs, as set forth in this Joint Application."). *See also* Exhibit No. IOU-01 at 5, note 2 (emphasis

Conference and Requesting Prehearing Conference Statements, dated June 9, 2017 ("PHC Ruling"). In the PHC Ruling, the ALJ stated that "[i]n Decision (D.) 16-12-006, the Commission determined that the cost recovery mechanism should be the same for procurement undertaken pursuant to both Res. E-4770 and Res. E-4805."[7] In any event, noting the different viewpoints with respect to consolidated cost-recovery, the ALJ provided CalCCA the opportunity to file a motion requesting that parties be allowed to argue for different cost-recovery treatment.

Pursuant to the opportunity afforded by the ALJ, CalCCA renews its request that parties be allowed to address within the scope of this proceeding the issue of whether costs incurred pursuant to Res. E-4770 should be recovered in a manner different than costs incurred pursuant to Res. E-4805. Moreover, in light of traditional burden of proof imposed on the IOUs in ratemaking applications, CalCCA seeks clarification that the IOUs bear the burden of proof in this proceeding with respect to their proposal for consolidated cost-recovery treatment. These requests are warranted because:

- The procedural history and posture of this issue demonstrate that the issue of consolidated cost-recovery has yet to be determined.
- D.16-12-006 did not *substantively* determine that consolidated cost-recovery is appropriate. D.16-12-006 addressed *procedural* matters by which this issue could subsequently be determined.
- A record to determine the issue of consolidated cost-recovery has yet to be developed.
- Excluding consolidated cost-recovery from this proceeding would deprive parties of the expectation set in D.16-12-006 with respect development of the record and other procedural safeguards.
- The Commission has repeatedly recognized the natural litigation advantage held by the IOUs, and have consistently placed the burden of proof on the IOUs in ratemaking applications.

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added) ("The approach to cost allocation ordered by Resolution E-4805 *should* apply equally to procurement mandated by Resolution E-4770.").

[7] PHC Ruling at 2.

II. DISCUSSION

A. The Procedural History Demonstrates That Consolidated Cost-Recovery Has Yet To Be Determined.

In response to the State's tree mortality crisis, the Governor, Legislature, and the Commission introduced several mandates to increase procurement from existing biomass facilities using prescribed amounts of dead and dying trees located in high hazard zones ("HHZs") as feedstock. In review of the procedural history it becomes apparent that the Commission anticipated addressing, in a subsequent proceeding, the complex nature of cost-recovery issues for Res. E-4770 and Res. E-4805 and that those issues are ripe for consideration in this proceeding.

1. Resolution E-4770

On March 17, 2016, the Commission adopted Res. E-4770 pursuant to Governor Brown's Emergency Proclamation, and directed the IOUs to procure 50 megawatts ("MW") from biomass facilities using feedstock from HHZs. In Res. E-4770, the Commission declined to apply the IOUs' request to recover costs of procurement from all customers through the Cost Allocation Methodology ("CAM"). The Commission explained that requesting CAM treatment would require a modification of the Renewable Auction Mechanism decision (D.10-12-048), which mandates that an IOU recover costs incurred in meeting its RPS obligation from its bundled customers.[8]

On April 18, 2016, the IOUs filed petitions for modification requesting modification of D.10-12-048 to allow costs under Res. E-4770 to be recovered from all customers through a non-bypassable charge ("NBC") ("E-4770-Related PFMs"). As described below, in D.16-12-006 the Commission denied the E-4770-Related PFMs on *procedural* grounds, and directed that the IOUs renew their

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8 *See* Res. E-4770 at 15.

requested modifications for Res. E-4770 cost-recovery in a separate application where the record for such cost-recovery could be developed.

2. Resolution E-4805

On September 14, 2016, while a decision was pending on the E-4770-Related PFMs, the Legislature responded to the tree mortality crisis by passing SB 859, codified in Section 399.20.3. Importantly, SB 859 expressly authorized the recovery of procurement costs *from all customers* through an NBC.[9] While SB 859 authorized the application of excess procurement from Res. E-4770 to count towards meeting the requirements of Section 399.20.3, it provided no explicit authorization to apply an NBC to procurement undertaken by an IOU pursuant to Res. E-4770.

The Commission adopted Res. E-4805 to authorize procurement under SB 859. In Res. E-4805, the Commission also directed the IOUs to file an application to create a new tree mortality NBC to allocate the capacity costs and benefits of procurement *ordered in Res. E-4805* to unbundled customers.[10] The Commission further directed the IOUs to create separate (*not* consolidated) memorandum accounts for procurement ordered by Res. E-4770 and by Res. E-4805, noting that the Commission was still considering the E-4770-Related PFMs.[11] In comments to Draft Res. E-4805, parties again raised issues with respect to consolidated cost-recovery. The Commission responded in the

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9 *See* Section 399.20.3(f).

10 Res. E-4805 at 17.

11 Res. E-4805 at 12. The IOUs are heeding this directive for separate, not consolidated, cost accounting. For example, Southern California Edison Company ("SCE") states that, although it views the distinction as "artificial," SCE "is making this distinction [between Res. E-4770 contracts and Res. E-4805 contracts] in its memorandum accounts as ordered by the Commission." (SCE Discovery Response 001; 7.a.)

final version of Res. E-4805, and stated that those issues were "complex" and would be better addressed "within a formal proceeding."[12]

The procedural history of Res. E-4770 and Res. E-4805, as well as the directives within those resolutions, demonstrate that the Commission not only intended to address the complex nature of consolidated cost-recovery issues at some point in the future, but that such a review and determination had yet to be made. This procedural posture was affirmed in D.16-12-006.

B. D.16-12-006 Did Not *Substantively* Determine That The Tree Mortality NBC is Applicable to Costs Under Resolution E-4770; D.16-12-006 Is A *Procedural* Decision That Provides Guidance On Next Steps

In D.16-12-006, the Commission denied the E-4770-Related PFMs. In doing so, the Commission did *not* make a determination on consolidated cost-recovery, nor did the Commission disturb or modify its previous determination in Res. E-4770 on cost-recovery. Rather, in D.16-12-006 the Commission provided procedural next steps for development of the record and consideration of this issue.

In D.16-12-006, the Commission agreed with Marin Clean Energy's ("MCE") request that the IOUs' proposed modifications be brought forward "by application, *with full record development*, rather than via PFMs.[13] This is important, since the Commission ultimately decided in D.16-12-006 that it would *not* address the *substance* of the IOUs' proposal, but rather the *process*:

> It is unnecessary to engage with the parties' arguments in any detail at this time. As MCE has proposed, it is more appropriate and will ultimately be more effective for the IOUs to file applications to address the *complex regulatory issues* implicated by their requests for allocation of costs for procurement pursuant to Res. E-4770. Furthermore, since the context for these requests has been changed by SB 859 and Res. E-4805, it is more efficient to *consider* the allocation of the capacity costs and benefits in the development of a Tree Mortality NBC, rather than trying to shoehorn

[12] Res. E-4805 at 16.

[13] D.16-12-006 at 9 (emphasis added).

> that allocation into modification of a decision setting up a particular RPS procurement program.[14]

As such, D.16-12-006 is a decision addressing process, not substance. In fact, the Commission explicitly declined to further address parties' comments on cost-recovery, finding them *complex regulatory issues*. Instead, the Commission found that it would be more efficient to *consider* the allocation of costs under Res. E-4770 as part of *the development* of the tree mortality NBC, instead of modifying D.10-12-048.

In defense of their revised position,[15] the IOUs asserted at the PHC that the Commission, in D.16-12-006, had made a final determination with respect to consolidated cost-recovery. The IOUs cite page 11 of D.16-12-006, wherein the Commission states the following:

> The approach taken by Res. E-4805 is also appropriate in considering cost recovery to allocate the capacity costs and benefits of procurement required by Res. E-4770. As noted in Finding 5 of Res. E-4805, procurement that is in excess of an IOU's required procurement under Res. E-4770 may be applied to the IOU's biomass procurement allocation under Res. E-4805. It therefore is reasonable, and likely to improve the efficiency of both procurement processes, for the IOUs to use the same mechanism to allocate allowable costs and benefits of procurement under both resolutions.[16]

The IOUs fail to recognize the context of this statement. Here, the "approach taken by Res. E-4805" referred to SB 859's requirement that the IOUs establish SB 859 Memorandum Accounts and file applications to create a new tree mortality NBC. As such, in determining that such an approach would be appropriate in *considering* cost recovery for Res. E-4770, the Commission was referring to the *process* of establishing a memorandum account and filing an application, similar to what was required by Res. E-4805. The Commission's statement therefore was not a substantive conclusion that the same

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14 D.16-12-006 at 10 (emphasis added).

15 *See* note 2, above.

16 *See* PHC Transcript at 38-40 (where counsel for SCE and Pacific Gas and Electric Company argue for a conclusion as a matter of law that consolidated cost-recovery has been adopted by the Commission).

cost-recovery mechanism set forth for Res. E-4805 should be applied to costs under Res. E-4770. If it had been a substantive conclusion, it surely would have been supported by a conclusion of law, which it was not. Rather, the Commission's statement was an assessment as to the appropriate *procedural* steps for addressing the issue of consolidated cost-recovery.

C. Exclusion Of The Consolidated Cost-Recovery Issue From This Proceeding Would Run Contrary To The Process Set Forth In D.16-12-006, And Would Deprive Parties An Opportunity To Address This Key Issue.

As described above, with respect to any modification of the cost-recovery method established in Res. E-4770, the Commission stated that "it is more appropriate and will ultimately be more effective for the IOUs to file applications to address the complex regulatory issues implicated by their requests for allocation of costs for procurement pursuant to Res. E-4770."[17] Therefore, the Commission expected that the same process and burdens associated with a normal application would apply to the Res. E-4770 application.[18] Among other things, with respect to the Res. E-4770 application, a record will need to be developed on which the Commission can base its determination on Res. E-4770 cost-recovery, and the IOUs will need to carry their burden of proof with clear and convincing evidence.[19] This has yet to occur. As such, excluding the consolidated cost-recovery issue from this proceeding at this juncture would be premature, and prejudicial to the procedural rights of CalCCA and other parties.

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17 D.16-12-006 at 10.

18 By ruling at the PHC, the "Res. E-4770 application" has now been joined with the Res. E-4805 application "to get the various streams of tree mortality issues flowing all in one place into this proceeding." (*See* PHC Transcript 11-12.)

19 *See, e.g.,* D.00-02-046 at 21 (describing the disadvantages faced by a group of municipalities in contending with the IOUs – "The natural litigation advantage enjoyed by utilities, and the fact that we must rely in significant part on their experts, combine to reinforce the importance of placing the burden of proof in ratemaking applications on the applicant utilities.")

III. CONCLUSION

For the reasons set forth above, the Commission should issue a ruling determining that parties are allowed to address within the scope of this proceeding the issue of whether costs incurred pursuant to Res. E-4770 may be recovered in a manner different than costs incurred pursuant to Res. E-4805. Moreover, the Commission should clarify that the IOUs carry the burden of proof in requesting consolidated cost-recovery treatment.

CalCCA thanks the assigned ALJ and Commissioner for their consideration of these requests.

Dated: July 14, 2017

Respectfully submitted,

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of Energy Efficiency Rolling Portfolio Business Plan.	Application 17-01-013 (Filed January 17, 2017)
Application of San Diego Gas & Electric Company (U902M) to adopt Energy Efficiency Rolling Portfolio Business Plan Pursuant to Decision 16-08-019.	Application 17-01-014 (Filed January 17, 2017)
Application of Pacific Gas and Electric Company for Approval of 2018-2025 Rolling Portfolio Energy Efficiency Business Plan and Budget (U39M).	Application 17-01-015 (Filed January 17, 2017)
Application of SOUTHERN CALIFORNIA GAS COMPANY (U904G) for adoption of its Energy Efficiency Rolling Portfolio Business Plan and related relief.	Application 17-01-016 (Filed January 17, 2017)
In the Matter of the Application of Marin Clean Energy for Approval of its Energy Efficiency Business Plan.	Application 17-01-017 (Filed January 17, 2017)

REVISED METRICS SUBMISSION OF MARIN CLEAN ENERGY

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July 14, 2017

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

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Application of SOUTHERN CALIFORNIA GAS COMPANY (U904G) for adoption of its Energy Efficiency Rolling Portfolio Business Plan and related relief.	Application 17-01-016 (Filed January 17, 2017)
In the Matter of the Application of Marin Clean Energy for Approval of its Energy Efficiency Business Plan.	Application 17-01-017 (Filed January 17, 2017)

REVISED METRICS SUBMISSION OF MARIN CLEAN ENERGY

I. INTRODUCTION

Marin Clean Energy ("MCE") provides this revised metrics submission pursuant to the *Administrative Law Judge's Ruling Seeking Comment on Energy Efficiency Business Plan Metrics* ("Metrics Ruling") filed May 10, 2017. The Metrics Ruling called for revised metrics to be submitted on June 26, 2017. A subsequent ruling, *Administrative Law Judges' Ruling Modifying Schedule* filed June 9, 2017 set a new date for revised metrics submissions from all PAs of July 14, 2017. In response to these two rulings, MCE provides this revised metrics submission.

II. BACKGROUND

MCE filed a business plan on January 17, 2017 that included portfolio-level and sector-level metrics. The Commission subsequently called for Program Administrators ("PAs") to revise their metrics and provided a set of metrics to use as a starting point.[1] The PAs, Commission staff, and stakeholders engaged in subsequent discussions to collaboratively identify appropriate metrics for all PAs to adopt. On July 10, Commission staff provided a guidance document ("Staff Guidance") for the metrics that was used to develop this submission.

III. THE ORIGINAL BUSINESS PLAN METRICS ARE REPLACED BY THIS SUBMISSION

The revised metrics will replace all of the metrics in MCE's original business plan. The Metrics Ruling identified that Commission staff had numerous concerns related to the PAs' original metrics and directs discussion to identify metrics to improve portfolio oversight.[2] MCE will follow the direction of the Commission and use the metrics identified through the discussions directed in the Metrics Ruling for inclusion in its business plan. MCE may utilize some of the original business plan metrics within implementation plans or for internal tracking purposes.

IV. STAFF GUIDANCE PROVIDES CLARITY FOR SOME METRICS AND REQUIRES ADDITIONAL WORK FOR OTHER METRICS

The July 10th Staff Guidance comprehensively addresses the business plan metrics. The guidance lists all of the metrics for PAs to incorporate in their business plans. The guidance generally falls into one of three categories: (1) metrics from the Metrics Ruling with no

[1] Metrics Ruling at p. 4-12.
[2] Metrics Ruling at p. 4-6.

additional staff clarification; (2) metrics from the Metrics Ruling that are modified by a staff clarification; and (3) excluding metrics from the Metrics Ruling.

MCE is adopting those metrics from the Metrics Ruling that were included in the Staff Guidance with no additional staff clarification. Some work remains to identify targets or gather data for a subset of those metrics.

MCE is not adopting those metrics from the Metrics Ruling that were not required in the Staff Guidance. MCE appreciates staff's work to identify reasonable metrics and does not include metrics staff has decided to exclude, with the exception of the portfolio-level metrics. MCE will also include the portfolio-level metrics from the Metrics Ruling,[3] even though they were not reflected in the Staff Guidance.

The last set of metrics, those modified from the Metrics Ruling by clarifications in the Staff Guidance, is somewhat varied:

Clear Staff Guidance: Staff guidance is very clear in some cases, and MCE adopted those metrics and included them in this submission.[4]

Working Staff Guidance: In other instances, staff guidance requires additional work to determine the path forward or identify the specific information to support the metrics. An example of this is how to address Disadvantaged Communities ("DAC") and Hard to Reach ("HTR") customers in the residential sector. It appears staff provides some information related to these two types of customers, but does not explicitly require any metrics.[5] For this type of guidance, MCE will continue to engage in dialogue with

[3] Metrics Ruling at p. 6.
[4] The metrics are provided as Attachment A.
[5] *See* Staff Guidance at p. 1 ("With regard to concerns about penetration of Hard to Reach (HTR) and Disadvantaged Communities (DAC) populations- Commission staff's understanding is that the competing Commission definitions of HTR will be clarified. For DAC, PAs need to identify

Commission staff, the other PAs, and stakeholders to develop a common understanding for finalizing the metrics.

New Staff Metrics: Finally, staff introduces new metrics in some cases. An example of this is the greenhouse gasses savings metric in a number of the sectors.[6] These new metrics may benefit from additional stakeholder input and MCE requires additional time to ascertain the data and information to develop the baselines and targets. Similar to the working staff guidance, MCE will continue to engage the stakeholder process to develop a common understanding and approach for these metrics.

V. THE COMMISSION SHOULD DIRECT PG&E TO PROVIDE PRIOR PROGRAM PARTICIPATION DATA TO SUPPORT IMPLEMENTATION OF MCE'S BUSINESS PLAN

The Commission should issue an order directing PG&E to share its prior program participation data with MCE. One of the metrics for the Industrial Sector is related to new participation.[7] Staff clarified the metric should track participants that have not received an incentive for the past three years.[8] In order to track this, MCE will need prior program participation data from PG&E to identify whether a customer is a new participant.

MCE requested the Commission support PG&E providing MCE with prior participation data in its business plan application.[9] PG&E possesses this data for the entire history of its ratepayer-funded program administration. This data can be used for many useful activities, including: improved targeting of customers, understanding available savings potential, and

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by a specific date whether they can map census tract to zip code. If there is overlap between HTR, DAC and low income, PAs need to propose a way to clarify that overlap.").

[6] Staff Guidance at p. 1, 3-6.

[7] Staff Guidance at p. 6.

[8] Staff Guidance at p. 6.

[9] Application of Marin Clean Energy for Approval of Its Energy Efficiency Business Plan, filed January 17, 2017 at p. 20

tracking new customer participation. The sharing of this data will help improve the administration of these rate-payer funded programs. These benefits are relevant not only for the Industrial Sector, but for all sectors. The Commission should direct PG&E to share prior program participation data with MCE in an ongoing manner for all sectors to better leverage this valuable ratepayer-funded data set.

VI. CONCLUSION

MCE thanks Commissioner Peterman, Administrative Law Judge Fitch, and Administrative Law Judge Kao for their thoughtful consideration of these revised metrics.

Respectfully submitted,

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July 14, 2017

Attachement A:
MCE Revised Metrics Tables and Narrative

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of Energy Efficiency Rolling Portfolio Business Plan.	Application 17-01-013 (Filed January 17, 2017)
And Related Matters	Application 17-01-014 Application 17-01-015 Application 17-01-016 Application 17-01-017

RESPONSE OF MARIN CLEAN ENERGY TO MOTION OF PACIFIC GAS AND ELECTRIC COMPANY (U-39M) FOR LEAVE TO AMEND ITS APPLICATION FOR APPROVAL OF ITS 2018-2025 ROLLING PORTFOLIO ENERGY EFFICIENCY BUSINESS PLAN AND BUDGET

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July 19, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of Energy Efficiency Rolling Portfolio Business Plan.	Application 17-01-013 (Filed January 17, 2017)
And Related Matters	Application 17-01-014 Application 17-01-015 Application 17-01-016 Application 17-01-017

RESPONSE OF MARIN CLEAN ENERGY
TO MOTION OF PACIFIC GAS AND ELECTRIC COMPANY (U-39M)
FOR LEAVE TO AMEND ITS APPLICATION FOR APPROVAL OF ITS 2018-2025
ROLLING PORTFOLIO ENERGY EFFICIENCY BUSINESS PLAN AND BUDGET

Pursuant to Rule 11.1 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), Marin Clean Energy ("MCE") respectfully submits this response ("Response") to the *Motion of Pacific Gas and Electric Company ("PG&E") (U-39M) for Leave to Amend its Application for Approval of its 2018-2025 Rolling Portfolio Energy Efficiency Business Plan and Budget*, filed in the above-captioned dockets on July 3, 2017 ("Motion").

I. Introduction

Six months after the initiation of this docket, PG&E filed its Motion requesting to remove the statewide downstream Indoor Agriculture Program pilot from its Business Plan.[1] In its place, PG&E states, "Southern California Gas Company ("SoCalGas") will propose and serve as its statewide lead a newly designed pilot, the statewide Downstream Foodservice Rebate Program."[2]

[1] Motion at p. 2.
[2] *Id*.

PG&E's Motion should be denied, and SoCalGas should not be allowed to amend its business plan at this late date.

The change the Investor Owned Utilities ("IOUs") are seeking[3] would significantly expand the breadth of the statewide downstream pilot programs. This expansion has three important, substantive and detrimental impacts on the proceeding. First, it disadvantages MCE's planned small commercial programs, depriving it of critical opportunities to achieve its energy efficiency goals within its small service area. Second, it exacerbates the problem of overlap. This docket is unlikely to be the last time the Commission addresses the issue of statewide administration of energy efficiency programs in the context of Community Choice Aggregators ("CCAs") serving as Program Administrators ("PAs"). MCE's Application begins to chart a path forward for how to manage the complex question of program overlap as CCAs expand across the State, but the Motion changes the nature of that critical question in the middle of the docket. Finally, by replacing a smaller pilot with a larger one, the Motion substantially increases the risks of the Commission's exploration into the statewide administration of downstream programs.

Moreover, the Motion is untimely, prejudicial and unsupported. Rule 1.12 prohibits amendments to applications after a Scoping Memo has issued. This Rule protects parties from wasting resources in attempts to hit a constantly moving target. The parties have already expended significant resources to litigate this docket and have not had an opportunity to weigh in on this new statewide program proposal over the past six months. Further, neither PG&E nor SoCalGas raised this proposal at the California Energy Efficiency Coordinating Committee where MCE and other parties would have had time to consider it and work to address any related

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concerns. Instead, the IOUs inappropriately attempt to circumvent the processes established through Decisions D.15-10-028 and D.16-08-019 by springing a change in direction at the eleventh hour. Finally, neither PG&E nor SoCalGas provides any explanation for this change, let alone one that would justify either the resulting prejudice to other parties, or the time and expense necessary for the Commission and parties to essentially start the record over on an expansive new pilot program.

II. PG&E's Motion Substantially Expands the Breadth of the Proposed Statewide Downstream Program Pilot and Would Limit the Effectiveness of MCE's Plan.

When Applicants filed their business plans, the IOUs proposed to make PG&E the lead administrator for an Indoor Agriculture Program, serving a relatively specific and limited market segment. But PG&E's Motion seeks to eliminate this program entirely, without explanation, and replace it with the Downstream Foodservice Rebate Program,[4] which would substantially increase the footprint of IOU's statewide programs. The IOU's proposed expansion to the statewide downstream programs encroaches on the opportunities for MCE's proposed commercial programs – in a sector the IOUs acknowledge is ripe for energy efficiency savings – and would substantially limit MCE's ability to maintain a cost-effective portfolio.

A. The Amendment Exacerbates the Overlap Issues Already at Issue in this Docket.

Through its Application, MCE has requested the Commission address this overlap issue, in part, by designating it as the "Downstream Liaison" within MCE's service area.[5] While this role would allow MCE to prevent some competing programs in its territory, and encourage collaboration, it would not be able to prevent other PAs from administering Commission-

("SCE") filed a Joint Response in support of PG&E's Motion.
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approved *statewide* programs.[6] Thus, even if the Commission approves MCE as Downstream Liaison status, the proposed amendments to Chapter 11 would significantly limit MCE's program opportunities to serve the many restaurants and other food service industries in its territory. The Commission should deny PG&E's Motion because the amendment shifts a substantial portion of MCE's market potential into the hands of SoCalGas without addressing overlap issues that are already making it difficult for MCE to provide comprehensive and balanced programs to its customers.

B. The Proposed Amendment Would Further Frustrate MCE's Ability to Meet State Requirements.

First, in order to meet the Commission's cost-effectiveness standards, MCE is now required to achieve a 1.25 TRC ratio, the same TRC ratio as IOU PAs. In order to achieve this requirement, MCE must be able to launch expanded programs to achieve a comprehensive and balanced portfolio.[7] As such, MCE proposed as part of its timely filed and unamended Application to significantly expand its existing programs in the commercial sector and identified restaurants/foodservice as one segment where targeted programs could be cost effective.[8] PG&E's Motion asks the Commission to accept a significant change to statewide programming that encroaches on MCE's Business Plan by taking the entire downstream restaurant/foodservice segment out of MCE's portfolio and frustrates MCE's ability to achieve a 1.25 TRC.

Second, approving the Amendment would inhibit MCE's ability to meet its statutory procurement obligations for its customers. Section 366.2(a)(5) of the Public Utilities Code

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makes a CCA "solely responsible for all generation procurement activities on behalf of the community choice aggregator's customers, except where other generation procurement arrangements are expressly authorized by statute." California Law defines energy efficiency as a procurement resource and places it at the top of the loading order.[9] Granting the Motion will diminish MCE's ability to follow the loading order and leverage energy efficiency as a means to cost-effectively serve its customers.

C. The Proposed Amendment Increases the Risk of Failure in Statewide Programs.

Piloting a statewide downstream program for foodservice customers dramatically increases the market segment targeted and the risk of failure relative to focusing on the smaller customer segment associated with the indoor agriculture program. The statewide downstream pilot programs are part of a Commission effort to "test out whether the statewide approach can be applied to some downstream program approaches" in addition to the midstream and upstream programs.[10] Pilots carry inherent risks in expending resources that may either fail to achieve the program's goals or fail to provide the data necessary to fix or replicate the result. Exploring a narrower program, such as the indoor agriculture program, can assist the Commission in assessing the concept of utilizing a statewide approach to downstream programs with less risk than through a broader, and more resource-intensive, downstream foodservice rebate program.

III. PG&E's Motion is Procedurally Deficient, Prejudices MCE and Other Parties, and is Unsupported.

In addition to the substantive impacts discussed above, the late-filed motion should be denied as untimely because it (a) violates the Commission's procedural rules; (b) fails to meet

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the requirements of previous key Commission decisions on the subject; (c) is prejudicial to MCE and other parties that will have missed opportunities to comment on the new Downstream Foodservice Rebate Program; (d) comes at a time before the Commission has had the opportunity to weigh in on fundamental policy issues regarding statewide overlap with MCE's Business Plan and (e) is unsupported.

A. PG&E's Motion to Amend Violates the Commission's Rules of Practice and Procedure.

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B. The Proposed Amendment, Supported by the IOUs, Fails to Meet the Requirements of Commission Decision 15-10-028.

The Scoping Memo specifically notes that the proposals for all program proponents will be "evaluated for compliance with the directives in D.15-10-028 and D.16-08-019."[12] D.15-10-028 provided guidance to PAs and instituted a mandatory collaborative process for developing business and implementation plans through a stakeholder-led coordinating committee.[13] That Decision specially stated, "*PAs shall give stakeholders early and meaningful opportunities for input* … ."[14] Because the proposed new statewide program was not discussed at the California

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Energy Efficiency Coordinating Committee, the proposed amendment fails to meet the requirements of D.15-10-028.

C. Granting PG&E's Motion at this Late Date would be Prejudicial to MCE and Other Parties.

The PAs, including PG&E and MCE, filed their applications six months ago. Since that time, parties have repeatedly weighed in on substantive and procedural issues based on the proposals that were before the Commission. For example, on March 3, 2017, multiple entities filed protests and responses regarding various business plans. MCE specifically objected to certain elements of PG&E's plan. Because no party had raised the issue of a statewide downstream foodservice program, neither MCE nor any other party was able to address the issue in their protests.

Subsequently, and pursuant to the Scoping Memo, the IOU and other PAs were required to provide additional detailed information, *inter alia,* about statewide programs, including budget information and issues surrounding overlap with other PA's programs.[15] On June 12, 2017, both PG&E and SoCalGas submitted responses to the Scoping Memo's supplemental information requests, including detailed budget information. Neither IOU provided any information regarding the Downstream Foodservice Rebate Program, thus depriving MCE and other parties' from commenting on it or considering it in submitting requests for hearings or pre-filed testimony.

In its Reply Comments regarding supplemental information, MCE did take exception to PG&E's stated assumptions that Strategic Energy Management ("SEM") should become a statewide program.[16] MCE expressed its position that such programs should be locally

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As stated by the Supreme Court of California, "[The] fundamental requirement of due process is the opportunity to be heard 'at a meaningful time and in a meaningful manner.'"[17] Ensuring due process here would require substantial revisions to the procedural schedule and, effectively, require the Commission and parties to start the record over with regard to a material component of the IOUs' business plans. In a footnote, PG&E admits as much, stating "SoCalGas expects that the Commission will provide additional guidance, upon deciding on this motion, on how the Downstream Foodservice Rebate Program pilot should be submitted for consideration to the Commission."[18] This admission indicates significant delays would be necessary to afford SoCalGas this opportunity and would leave the currently filed Business Plans in limbo. The Commission should not allow this late amendment to delay the implementation of the eight pending business plans.

D. The Proposed Amendment Fundamentally Changes the Statewide Program Landscape Before the Rules Have Been Established.

If allowed, the proposed Amendment would change the basic landscape of the IOU's business plans without any opportunity for MCE or other parties to engage in a meaningful dialogue on the fundamental issues of statewide administration and overlap. For example, the Commission has not yet determined how statewide program savings would be attributed between a CCA and an IOU, but MCE has formally requested that the Commission attribute all savings

[17] *Conway v. State Bar*, 47 Cal. 3d 1107, 1113 (1989) (citing, *Mathews* v. *Eldridge* 424 U.S. 319, 333 (1976), quoting *Armstrong* v. *Manzo* 380 U.S. 545, 552 (1965)).
[18] PG&E Motion at p. 2, n. 2.

achieved in MCE's service area through statewide programs to it.[19] Further, the Commission identified in its Scoping Memo that this docket would include examinations of CCA proposals to utilize natural gas funding and create natural gas energy savings[20] and how to handle real or perceived overlap between CCA, Regional Energy Network and IOU proposals.[21]

The debate on these fundamental policy issues has already begun and will likely continue throughout this docket. However the proposed amendment would serve to significantly expand the footprint of the IOU-led statewide programs before the Commission can fully examine and resolve these fundamental policy issues.

E. The Motion is Unsupported.

The additional administrative time and expense necessary to accommodate the IOUs' last-minute change are exacerbated by the lack of support for the Motion. The Motion simply explains SoCalGas will serve as the statewide lead for a newly designed pilot and will make proposals corresponding to this role.[22] The only justification the IOUs provide for this change is "SoCalGas is the only IOU that has no proposed assignment as Lead Program Administrator for a downstream pilot."[23] The Motion fails to explain why SoCalGas should administer the program instead of PG&E. The Motion fails to explain why the IOUs could not have included the foodservice program in their business plans in January or in the collaborative discussions required to take place before the Applications were due. The Motion fails to explain the deficiencies in the indoor agriculture program, or why the foodservice program would be a superior choice for a statewide downstream program.

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[19] MCE's Application at p. 18.
[20] Scoping Memo at p. 6.
[21] *Id.*
[22] PG&E Motion at p. 2.
[23] *Id.* at 2.

A motion requesting the Commission ostensibly waive Rule 1.12, prejudice other parties to the docket, rework the procedural schedule, and incur the additional time and effort to accommodate the requested relief should at least explain the circumstances leading up to the request. The Motion includes none of this discussion, let alone reasons sufficient to warrant granting the relief requested at the expense of the Commission and other parties.

IV. Conclusion

For the foregoing reasons, MCE respectfully requests the Commission deny PG&E's Motion.

Respectfully submitted,

Michael Callahan

By: */s/Michael Callahan*
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July 19, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of Energy Efficiency Rolling Portfolio Business Plan.	Application 17-01-013 (Filed January 17, 2017)
And Related Matters	Application 17-01-014 Application 17-01-015 Application 17-01-016 Application 17-01-017

MARIN CLEAN ENERGY MOTION FOR LEAVE TO LATE-FILE RESPONSE OF MARIN CLEAN ENERGY TO MOTION OF PACIFIC GAS AND ELECTRIC COMPANY (U-39M) FOR LEAVE TO AMEND ITS APPLICATION FOR APPROVAL OF ITS 2018-2025 ROLLING PORTFOLIO ENERGY EFFICIENCY BUSINESS PLAN AND BUDGET

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ROLLING PORTFOLIO ENERGY EFFICIENCY BUSINESS PLAN AND BUDGET**

Pursuant to Rule 11.1 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), Marin Clean Energy ("MCE") respectfully requests leave to late-file the response of Marin Clean Energy to *Motion of Pacific Gas and Electric Company (U-39M) for Leave to Amend its Application for Approval of its 2018-2025 Rolling Portfolio Energy Efficiency Business Plan and Budget* ("PG&E's Motion") filed July 3, 2017. MCE's response is provided with this motion at Attachment A. The due date for this filing was yesterday, July 18, 2017 and the response was finalized on that day, however the filing was inadvertently neither filed nor served to parties. MCE now respectfully requests an opportunity to include its response in the record for the purpose of ruling on PG&E's Motion. No party should be prejudiced by this late filing as there was no opportunity to reply to MCE's response and the delay in the filing is minor.

MCE is an applicant in this proceeding and is the only Community Choice Aggregator ("CCA") currently administering energy efficiency programs under the jurisdiction of the

Commission. As a CCA an applicant, MCE's unique perspective will contribute to the basis for the eventual ruling on PG&E's Motion. MCE's response contributes to the record by introducing new arguments and further supporting arguments raised in the *National Association of Energy Service Companies Response to Motion of Pacific Gas and Electric Company (U 39-M) for Leave to Amend its Application for Approval of its 2018-2025 Rolling Portfolio Energy Efficiency Business Plan and Budget* filed on July 18, 2017. These arguments relate to impacts on MCE's application, market risks posed by PG&E's motion, and various procedural and factual deficiencies in PG&E's motion. If MCE's response is included in the record, the Commission will benefit from the ability to consider these arguments when drafting a ruling.

MCE thanks Commissioner Peterman, Administrative Law Judge Fitch, and Administrative Law Judge Kao for their thoughtful consideration of this motion.

Respectfully submitted,

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By:__________/s/*Michael Callahan*__________
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<u>Attachment A</u>

Response of Marin Clean Energy to Motion of Pacific Gas and Electric Company (U-39M) for Leave to Amend its Application for Approval of its 2018-2025 Rolling Portfolio Energy Efficiency Business Plan and Budget

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Pursuant to Rule 11.1 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission"), Marin Clean Energy ("MCE") respectfully submits this response ("Response") to the *Motion of Pacific Gas and Electric Company ("PG&E") (U-39M) for Leave to Amend its Application for Approval of its 2018-2025 Rolling Portfolio Energy Efficiency Business Plan and Budget*, filed in the above-captioned dockets on July 3, 2017 ("Motion").

I. Introduction

Six months after the initiation of this docket, PG&E filed its Motion requesting to remove the statewide downstream Indoor Agriculture Program pilot from its Business Plan.[1] In its place, PG&E states, "Southern California Gas Company ("SoCalGas") will propose and serve as its statewide lead a newly designed pilot, the statewide Downstream Foodservice Rebate Program."[2]

[1] Motion at p. 2.
[2] *Id*.

PG&E's Motion should be denied, and SoCalGas should not be allowed to amend its business plan at this late date.

The change the Investor Owned Utilities ("IOUs") are seeking[3] would significantly expand the breadth of the statewide downstream pilot programs. This expansion has three important, substantive and detrimental impacts on the proceeding. First, it disadvantages MCE's planned small commercial programs, depriving it of critical opportunities to achieve its energy efficiency goals within its small service area. Second, it exacerbates the problem of overlap. This docket is unlikely to be the last time the Commission addresses the issue of statewide administration of energy efficiency programs in the context of Community Choice Aggregators ("CCAs") serving as Program Administrators ("PAs"). MCE's Application begins to chart a path forward for how to manage the complex question of program overlap as CCAs expand across the State, but the Motion changes the nature of that critical question in the middle of the docket. Finally, by replacing a smaller pilot with a larger one, the Motion substantially increases the risks of the Commission's exploration into the statewide administration of downstream programs.

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II. PG&E's Motion Substantially Expands the Breadth of the Proposed Statewide Downstream Program Pilot and Would Limit the Effectiveness of MCE's Plan.

When Applicants filed their business plans, the IOUs proposed to make PG&E the lead administrator for an Indoor Agriculture Program, serving a relatively specific and limited market segment. But PG&E's Motion seeks to eliminate this program entirely, without explanation, and replace it with the Downstream Foodservice Rebate Program,[4] which would substantially increase the footprint of IOU's statewide programs. The IOU's proposed expansion to the statewide downstream programs encroaches on the opportunities for MCE's proposed commercial programs – in a sector the IOUs acknowledge is ripe for energy efficiency savings – and would substantially limit MCE's ability to maintain a cost-effective portfolio.

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B. The Proposed Amendment Would Further Frustrate MCE's Ability to Meet State Requirements.

First, in order to meet the Commission's cost-effectiveness standards, MCE is now required to achieve a 1.25 TRC ratio, the same TRC ratio as IOU PAs. In order to achieve this requirement, MCE must be able to launch expanded programs to achieve a comprehensive and balanced portfolio.[7] As such, MCE proposed as part of its timely filed and unamended Application to significantly expand its existing programs in the commercial sector and identified restaurants/foodservice as one segment where targeted programs could be cost effective.[8] PG&E's Motion asks the Commission to accept a significant change to statewide programming that encroaches on MCE's Business Plan by taking the entire downstream restaurant/foodservice segment out of MCE's portfolio and frustrates MCE's ability to achieve a 1.25 TRC.

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As stated by the Supreme Court of California, "[The] fundamental requirement of due process is the opportunity to be heard 'at a meaningful time and in a meaningful manner.'"[17] Ensuring due process here would require substantial revisions to the procedural schedule and, effectively, require the Commission and parties to start the record over with regard to a material component of the IOUs' business plans. In a footnote, PG&E admits as much, stating "SoCalGas expects that the Commission will provide additional guidance, upon deciding on this motion, on how the Downstream Foodservice Rebate Program pilot should be submitted for consideration to the Commission."[18] This admission indicates significant delays would be necessary to afford SoCalGas this opportunity and would leave the currently filed Business Plans in limbo. The Commission should not allow this late amendment to delay the implementation of the eight pending business plans.

D. The Proposed Amendment Fundamentally Changes the Statewide Program Landscape Before the Rules Have Been Established.

If allowed, the proposed Amendment would change the basic landscape of the IOU's business plans without any opportunity for MCE or other parties to engage in a meaningful dialogue on the fundamental issues of statewide administration and overlap. For example, the Commission has not yet determined how statewide program savings would be attributed between a CCA and an IOU, but MCE has formally requested that the Commission attribute all savings

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[17] *Conway v. State Bar*, 47 Cal. 3d 1107, 1113 (1989) (citing, *Mathews* v. *Eldridge* 424 U.S. 319, 333 (1976), quoting *Armstrong* v. *Manzo* 380 U.S. 545, 552 (1965)).
[18] PG&E Motion at p. 2, n. 2.

achieved in MCE's service area through statewide programs to it.[19] Further, the Commission identified in its Scoping Memo that this docket would include examinations of CCA proposals to utilize natural gas funding and create natural gas energy savings[20] and how to handle real or perceived overlap between CCA, Regional Energy Network and IOU proposals.[21]

The debate on these fundamental policy issues has already begun and will likely continue throughout this docket. However the proposed amendment would serve to significantly expand the footprint of the IOU-led statewide programs before the Commission can fully examine and resolve these fundamental policy issues.

E. The Motion is Unsupported.

The additional administrative time and expense necessary to accommodate the IOUs' last-minute change are exacerbated by the lack of support for the Motion. The Motion simply explains SoCalGas will serve as the statewide lead for a newly designed pilot and will make proposals corresponding to this role.[22] The only justification the IOUs provide for this change is "SoCalGas is the only IOU that has no proposed assignment as Lead Program Administrator for a downstream pilot."[23] The Motion fails to explain why SoCalGas should administer the program instead of PG&E. The Motion fails to explain why the IOUs could not have included the foodservice program in their business plans in January or in the collaborative discussions required to take place before the Applications were due. The Motion fails to explain the deficiencies in the indoor agriculture program, or why the foodservice program would be a superior choice for a statewide downstream program.

[19] MCE's Application at p. 18.
[20] Scoping Memo at p. 6.
[21] *Id.*
[22] PG&E Motion at p. 2.
[23] *Id.* at 2.

A motion requesting the Commission ostensibly waive Rule 1.12, prejudice other parties to the docket, rework the procedural schedule, and incur the additional time and effort to accommodate the requested relief should at least explain the circumstances leading up to the request. The Motion includes none of this discussion, let alone reasons sufficient to warrant granting the relief requested at the expense of the Commission and other parties.

IV. Conclusion

For the foregoing reasons, MCE respectfully requests the Commission deny PG&E's Motion.

Respectfully submitted,

Michael Callahan

By: /s/*Michael Callahan*
Michael Callahan

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July 19, 2017

July 20, 2017

CA Public Utilities Commission
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

Advice Letter 23-E-A

Re: Supplement to Identification of Metrics to Track Marin Clean Energy's Low Income Families and Tenants Pilot

Marin Clean Energy ("MCE") filed Advice Letter ("AL") 23-E on April 6, 2017, which identified metrics to track MCE's Low Income Families and Tenants ("LIFT") pilot program. On April 24, 2017, the California Public Utilities Commission ("Commission") staff notified MCE that it suspended AL 23-E. Staff worked with MCE to develop revised metrics and some modifications to the program. MCE now submits this supplemental filing to update the LIFT pilot metrics and provide notice of the modifications to the pilot.

Effective Date: August 3, 2017

Purpose

Commission staff suspended MCE AL 23-E and worked with MCE to revise metrics and identify some modifications to the LIFT pilot. This advice filing supplements MCE's AL 23-E, filed on April 6, 2017, and provides updated metrics and notice of revisions to the pilot.

Background

MCE originally proposed a LIFT pilot budget of $4.6 million.[1] The Commission approved a number of MCE's LIFT pilot elements and a reduced budget of $3.5 million for the two-year pilot.[2] The Commission directed MCE to provide additional metrics to track the LIFT pilot.[3] MCE developed the metrics submitted in MCE AL 23-E in consultation with several stakeholders. Commission staff suspended MCE AL 23-E and provided feedback in discussions with MCE. MCE utilized this feedback to revise its proposed metrics and also identified some modifications to improve the impact of the pilot.

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[1] Testimony of Marin Clean Energy Regarding a Proposed Low-Income Energy Efficiency Pilot Program for the Program Years 2015-2017, April 27, 2015 ("MCE Testimony"), Exhibit C at 5.

[2] D.16-11-022, OP 147 at 492.

[3] D.16-11-022, OP 147 at 492.

Scope of the Pilot

MCE's LIFT proposal requested $4.6 million in funding. MCE received budget approval for $3.5 million and guidance from Commission staff to narrow the scope of the pilot to allow for greater focus on key offerings with the greatest impact. The Single Family Matched Energy Savings Account ("MESA") and Single Family Behavioral Mobile Application were removed from the pilot to focus on areas that are expected to have a deeper impact. MCE notes that the Single Family Behavioral Mobile Application is similar to the mobile access efforts currently underway.[4]

Pilot Duration and Launch

The LIFT pilot is a two-year pilot.[5] MCE will start the two-year pilot within ninety ("90") days of the Commission's approval of the revised metrics to track the pilot's progress.

Incentive Levels

The LIFT Pilot has two main components: (1) the Multifamily component; and (2) the Heat Pump ("HP") Fuel Switching component. The Multifamily component has a $1,200 per-unit incentive cap.[6] The costs of the equipment and installation under the HP Fuel Switching component will be separate from this incentive cap. HPs represent a promising technology that is not widely deployed. HPs have the potential to decarbonize space and water heating end uses while improving comfort for low-income customers. The potential benefits of HP technology justify additional investment to encourage adoption and to generate data about HP performance in a low-income setting. MCE anticipates the data collected from the HP installations will be useful to the Commission in considering fuel substitution policies.

Leveraging MCE's Multifamily Energy Savings Program

The LIFT pilot will leverage incentives from MCE's general Multifamily Energy Savings Program with the LIFT pilot incentives where feasible. Customers receiving LIFT pilot incentives will satisfy Commission-approved ESA program eligibility criteria. Administrative processes will be shared by both programs (*e.g.* one application, one rebate check) though MCE will track expenditures and savings separately. This will reduce administrative costs and provide a less burdensome experience to the program participant. Tracking the costs and savings of each program separately will provide insight to the performance of each program and the efficacy of the leveraging strategy while meeting compliance reporting requirements.

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[4] D.16-11-022 Conclusion of Law 152 at p. 435.

[5] D.16-11-022 at p. 376.

[6] This per unit cap will be evaluated as the average funding provided across all the treated units in a single building. This level of funding is also available to offset the cost of common area measures and to increase the incentive available for central systems that treat tenant units, e.g. domestic hot water systems.

Propane Customers

In addition to providing fuel substitution measures for eligible gas customers, the LIFT pilot will also provide fuel switching options for eligible propane customers. MCE will cap propane fuel switching at 10% of the total number of heat pumps installed through the pilot program. Moving customers from propane to electric space or water heating represents a unique opportunity to reduce customers' energy costs as well as provide valuable data to inform policy decisions relating to the Commission's implementation of Assembly Bill 2672 (2014).

Overall Performance Metrics and Data Collection for the HP Fuel Switching Components

The revised metrics, provided in Attachment A, include both performance metrics for all activities and data collection to advance research on HPs. The performance metrics will be used to measure the performance of the pilot and include targets to assess achievement. MCE reduced the number and complexity of metrics compared to those filed in MCE AL 23-E based on feedback from Commission staff. The data collection component includes a list of the data sets that will be collected to support research on the application of HPs for fuel substitution. MCE's data collection objective is intended to provide useful information to inform broader policy decisions such as whether to expand gas infrastructure in the San Joaquin Valley or potential revisions to the Commission's three-prong test used for fuel substitution.

Revised Pilot Budget Table

MCE provided a budget table in MCE AL 23-E. The changes to the pilot described above require modifications to that table. MCE provides Table 1 below, which incorporates the changes to the pilot and replaces the budget table MCE provided in MCE AL 23-E.

Table 1: Revised Budget, Targets, and Savings[7]

Sector	Requested Budget	Approved Budget	kWh	Revised kWh	Therms	Revised Therms	Units	Revised Units
Multifamily	$3,770,358	$3,500,000	568,105	232,979	27,170	15,368	2,470	1,482

Notice

MCE respectfully requests a waiver of the protest period to enable expedient approval of the metrics and allow the pilot to launch in the near term.

If the protest period is not waived, anyone wishing to protest this advice filing may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days

[7] MCE developed these savings and targets based on its experience administering its general EE portfolio.

after the date of this advice filing. Protests should be mailed to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTariffUnit@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4004 (same address as above).

In addition, protests and all other correspondence regarding this AL should also be sent by letter and transmitted via facsimile or electronically to the attention of:

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San Rafael, CA 94901
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Facsimile: (415) 459-8095
bmenten@mceCleanEnergy.org

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

MCE is serving copies of this advice filing to the relevant parties shown on the A.14-11-007 et al. service list. For changes to this service list, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

Correspondence

For questions, please contact Nathaniel Malcolm at (415) 464-6048 or by electronic mail at nmalcolm@mceCleanEnergy.org.

/s/ Michael Callahan_
Michael Callahan
Regulatory Counsel
Marin Clean Energy

cc: Service List A.14-11-007 et al.

Attachment A
LIFT Pilot Multifamily Barriers and Metrics Table

LIFT Pilot Multifamily Barriers and Metrics Table

Problem Statement	Market Barriers	Desired Effects/2-Year Vision	Intervention Strategies	Metrics	Baseline	Metric Source	Short-Term Target (1 Year)[1]	Mid-Term Target (2 Year)[1]
Programs operating in siloed pots of funding do not deliver comprehensive treatment, missing an opportunity to be cost efficient and to have a higher program participation and satisfaction rate	The design of current low-income programs limits the potential for comprehensive savings while still attaining cost effective program delivery	Programs are blended to provide maximum benefits to the owners and tenants of multifamily properties while enabling improved program resource efficiency	1. Blend the LIFT incentives with MCE's Multifamily Energy Savings Program rebates to provide maximum incentives to the property owners	1. % of units receiving comprehensive upgrades[2] using both MCE's Energy Savings and LIFT program offerings 2. Average savings per unit for LIFT is more than the average savings per unit for PG&E's ESA program 3. % of property owners/ managers that rate the ease of participation as high	1. Program Year 1 2. 3.32 MMBTU[3] saved per unit 3. Program Year 1	1. Program tracking data 2. Program tracking data 3. Post-treatment participant survey data	1. 60% (330/550 units) 2. The average savings per unit for LIFT is more than the average savings per unit for PG&E's ESA program 3. 80% of participants rate that it is easy to participate in the program	1. 60% (560/932 units) 2. The average savings per unit for LIFT is more than the average savings per unit for the PG&E's ESA program 3. 80% of participants rate that it is easy to participate in the program
The apprehension of the consequences around income verification and sharing of personal information creates a barrier to program participation even if the consequences will not actually occur	Fear of consequences related to personal information disclosure	Increased participation from "hidden communities" as residents are assured that it is safe to share information with the program	1. Work with community-based organizations (CBOs) and trusted messengers[4] to educate residents on the value of programs, benefits of energy efficiency, and address other concerns prohibiting them from participation	1. % of units meeting one or more of the following criteria: - residents receive program information in a language other than English (will track languages) - residents are engaged by community based organizations (CBOs) who indicate they had not previously participated in energy efficiency programs due to concerns around sharing personal information - located outside of Cal Enviro Screen 2.0 designated disadvantaged communities - are occupied by extended or multiple families	1. Program Year 1	1. Program tracking data	1. 40% (220/550 units)	1. 40% (373/932 units)
Low-income multifamily renters face higher energy burden and are hard to reach	Landlord approval, rent increase and lack of incentive	Increased participation from income eligible communities	1. Targeting landlords and property owners to reach eligible and hard to reach multifamily renters	1. % of the eligible households[5] that install efficiency measures through the LIFT program	1. Program Year 1	1. Program tracking data	1. 1% of income eligible households in MCE's service territory[6] (550/56,087)	1. 2% of income eligible households in MCE's service territory[6] (932/56,087)

[1] MCE assumes it will serve 550 units in the first year of the program and 932 units in the second year, touching between 12-24 properties in total. Second year targets are not cumulative.
[2] Comprehensive upgrades refer to projects with measures that fall into two or more end-use categories.
[3] The MMBTU was calculated using the costs and savings data presented in the ESA Table 1 "Overall Program Expenses" and ESA Table 2 "Expenses and Energy Savings by Measures Installed" of the Pacific Gas and Electric Company ESA Program and CARE 2016 Annual Report.
[4] Trusted Messengers include local organizations and community leaders that are well-known and trusted in low-income communities. Due to trusted messengers' status in these communities, they will help alleviate customer concerns about program participation and help target messaging to effectively reach hidden communities and drive participation.
[5] An eligible household is one that meets a Commission-approved ESA eligibility criterion, for example a household income at or below 200% of the federal poverty level.
[6] The eligible population figures for Napa and Marin were taken as is from PG&E's Attachment A of "Compliance Filing Regarding Annual Estimates of Care Eligible Customers and Related Information" filed on February 10, 2017 in A.14-11-007 et al. For Contra Costa County, the total eligible population was calculated by multiplying the American Community Survey 5-Year Estimates 2015 occupied housing units in Richmond, Benicia, El Cerrito, San Pablo, Walnut Creek, and Lafayette with the demographic eligibility rate (from Attachment A). Available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M175/K295/175295964.PDF.

LIFT Pilot Heat Pump Barriers and Metrics Table

Problem Statement	Market Barriers	Desired Effects/2-Year Vision	Intervention Strategies	Metrics	Baseline	Metric Source	Short-Term Target (1 Year)[7]	Mid-Term Target (2 Year)
Fuel-switching measures are hard to justify as the environmental, and health and comfort benefits are not considered when compared to existing technology	The high upfront cost of fuel switching owing to current regulatory framework	The full potential of fuel switching measures is valued and quantified	1. Replacing problematic natural gas heating or hot water system equipment to resolve health and safety issues and improve the efficiency of a home's heating system	1. # of heat pumps installed 2. Gather the following data to support advancement of fuel switching policies: - procurement and installation costs of heat pumps including costs of bulk purchase - the impacts of fuel switching on bill savings and net costs to the customers - reduction in greenhouse gas (GHG) emissions, nitrogen oxides (NOx), and sulfur oxides (SOx) - source British thermal units (BTU) savings - impacts on resident's health, comfort, and safety	1. Program Year 1	1. Program tracking data	1. 30 heat pumps	1. 90 heat pumps
Lack of tenant education could lead to misunderstanding and misuse of the heat pump technology	Lack of customer exposure due to the newness of heat pump technology	Tenants are comfortable and satisfied with heat pump technology	1. Providing tenants with post-installation education on potential bill reductions or associated bill increases when there is added cooling and heating load	1. % of residents who report comfort and satisfaction with the heat pump technology	1. Program Year 1	1. Post-treatment participant survey data	1. 80% (tenants of 24/30 heat pumps installed)	2. 80% (tenants of 72/90 heat pumps installed)

[7] MCE assumes it will install 30 heat pumps in the first year of the program and 90 heat pumps in the second year. Second year targets are not cumulative.

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY LSE (Attach additional pages as needed)

Company name/CPUC Utility No. Marin Clean Energy

Utility type:	Contact Person for questions and approval letters: Nathaniel Malcolm
☑ ELC ☐ GAS	Phone #: (415) 464-6048
☐ PLC ☐ HEAT ☐ WATER	E-mail: nmalcolm@mcecleanenergy.org

EXPLANATION OF UTILITY TYPE			(Date Filed/ Received Stamp by CPUC)
ELC = Electric	GAS = Gas		
PLC = Pipeline	HEAT = Heat	WATER = Water	

Advice Letter (AL) #: MCE 23-E-A

Subject of AL: Supplement to Identification of Metrics to Track Marin Clean Energy's Low Income Families and Tenants Pilot

Tier Designation: ☐ 1 ☑ 2 ☐ 3

Keywords (choose from CPUC listing): Compliance

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other ______________________________

If AL filed in compliance with a Commission order, indicate relevant Decision: D.16-11-022, OP 147

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL _____________________________

Summarize differences between the AL and the prior withdrawn or rejected AL[1]: ____________________

Resolution Required? ☐ Yes ☑ No

Requested effective date: August 3, 2017 No. of tariff sheets: 0

Estimated system annual revenue effect: (%): n/a

Estimated system average rate effect (%): n/a

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: n/a

Service affected and changes proposed[1]:

Pending advice letters that revise the same tariff sheets: none

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division	**Utility Info (including e-mail)**
Attention: Tariff Unit	**Marin Clean Energy**
505 Van Ness Ave.	**Nathaniel Malcolm, Policy Counsel**
San Francisco, CA 94102	**1125 Tamalpais Ave. San Rafael, CA 94901**
EDTariffUnit@cpuc.ca.gov	**nmalcolm@mcecleanenergy.org**

[1] Discuss in AL if more space is needed.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of Energy Efficiency Rolling Portfolio Business Plan.	Application 17-01-013 (Filed January 17, 2017)
And Related Matters	Application 17-01-014 Application 17-01-015 Application 17-01-016 Application 17-01-017

COMMENTS OF MARIN CLEAN ENERGY ON
ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING COMMENTS ON
ENERGY EFFICIENCY AND DEMAND RESPONSE INTEGRATION OPTIONS

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July 24, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of Energy Efficiency Rolling Portfolio Business Plan.	Application 17-01-013 (Filed January 17, 2017)
And Related Matters	Application 17-01-014 Application 17-01-015 Application 17-01-016 Application 17-01-017

COMMENTS OF MARIN CLEAN ENERGY ON ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING COMMENTS ON ENERGY EFFICIENCY AND DEMAND RESPONSE INTEGRATION OPTIONS

I. INTRODUCTION

Marin Clean Energy ("MCE") submits the following comments in response to the *Administrative Law Judge's Ruling Requesting Comments on Energy Efficiency and Demand Response Integration Options* ("Ruling") filed June 30, 2017. MCE provides answers to a subset of the questions in the Ruling and calls for the Commission to:

1) Reflect the Commission's competitive neutrality cost causation principle for Demand Response ("DR") Programs in the Energy Efficiency ("EE") and DR integration;
2) Ensure CCA customers are not excluded from EE-DR integration;
3) Authorize MCE to request funds to integrate DR with EE program delivery in the annual budget advice letter; and
4) Take note that EE-DR integration is a core component of MCE's Single Point of Contact ("SPOC") model and will include separate MCE DR programs that are separate from any Commission funding.

II. BACKGROUND

MCE is the only Community Choice Aggregator ("CCA") energy efficiency ("EE") Program Administrator ("PA") authorized by the California Public Utilities Commission ("Commission"). MCE filed an application with a business plan on January 17, 2017.

III. OTHER/GENERAL QUESTIONS

Question 5. What changes should the Commission make to program rules, including participation rules or rules about funding of incentives, if any, to facilitate rational integration of energy efficiency and demand response technologies in residential and non-residential buildings?

A. The EE-DR Integration Should Reflect the Commission's Competitive Neutrality Cost Causation Principle for DR Programs.

The Commission adopted the competitive neutrality cost causation principle ("CNCC Principle") for demand response programs in 2014.[1] This principle addresses funding sources for DR programs and relies on a general cost causation principle that requires costs to be borne only by those that create costs for utilities.[2] For example, costs for DR programs that are only available to bundled customers are borne by bundled customers and costs for DR programs available to all customers are borne by all customers.[3] The Commission extended this general principle to address concerns about competitive neutrality for CCAs and direct access providers that offer "similar" programs to IOUs.[4] Specifically, the Commission provided that:

> "once a direct access and community choice aggregation provider begins to offer a demand response program, the competing utility shall discontinue cost recovery from that providers' customers for that or any similar program, no later than one year following the implementation of that program."[5]

[1] D. 14-12-024 at p. 47-50.
[2] D.14-12-024 at p. 48-50.
[3] *Id.* at p. 48.
[4] *Id.* at p. 48-49.
[5] *Id.* at p. 49-50.

The CNCC Principle is currently being implemented through the DR proceeding (Rulemaking 13-09-011). The Commission recently issued a ruling calling for comments to help implement the CNCC Principle including clarifying the definition of "similar demand response program."[6] Comments on the ruling were due in June[7] and the Commission has yet to issue a decision or ruling is response to parties' comments. The EE-DR integration approach should incorporate the CNCC Principle as implemented in the DR proceeding to ensure a consistent set of rules and policies governing Commission-authorized DR programs.

B. The Commission Should Ensure CCA Customers are not Excluded from EE-DR Integration

MCE currently has limited DR program offerings and intends to expand these offerings and integrate them with MCE's EE program delivery over time. In the meantime, MCE intends to support the staff proposal for EE-DR integration by facilitating delivery of PG&E's DR programs through MCE's EE program infrastructure. To facilitate this approach, the Commission should make it clear that PG&E cannot condition customer participation in EE-DR integration efforts on participation in PG&E's EE programs.

This joint approach to delivering PG&E's DR programs may require arrangements related to cost sharing for measures that have embedded DR controls and for DR program delivery carried out by MCE implementers. The Commission should direct PG&E to work in good faith with MCE to develop a mutually agreed-upon approach to embedding PG&E's DR programs into MCE's EE program implementation.

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[6] *Administrative Law Judge's Ruling Requesting Responses to Questions Regarding the Pathway to New Models of Demand Response, Implementation of the Competitive Neutrality Cost Causation Principle, and Remaining Barriers to the Integration of Demand Response into the CAISO Market* ("CNCCP Comments Ruling") filed May 22, 2017, Attachment A at p. 5.
[7] CNCCP Comments Ruling at p. 7.

As part of the EE-DR integration approach, the Commission should also direct PG&E to include some DR programs that can be utilized by CCA customers. PG&E currently has DR programs that are not available to CCA customers including the Residential SmartRate Program and the Peak Day Pricing Program.[8] However, the Commission should avoid a scenario where PG&E's EE-DR integration efforts are limited to DR offerings available only to bundled customers. While some of PG&E's DR offerings may be limited to bundled customers, the Commission should direct PG&E to include other DR offerings that can be availed by CCA customers as well.

Question 7. If the Commission re-purposes the integrated demand side management funds currently authorized as part of the energy efficiency portfolios, as suggested by staff, are there any activities that are currently funded through this mechanism that should be continued? Explain.

A. MCE Should be Authorized to Request Funds to Integrate DR with EE Program Delivery in the Annual Budget Advice Letter

MCE plans to offer DR programs in conjunction with EE program delivery. As discussed in response to Question 5 and further in response to Question 8 below, MCE will initially work with PG&E to deliver their DR programs in conjunction with MCE's EE program delivery. Over time, MCE plans to launch its own DR programs and deliver them in conjunction with MCE's EE program delivery. MCE's own DR programs will be separate from any Commission-funded DR programs. There will be some cost, additional to the DR program cost, to integrate the DR program with EE program delivery. To the extent Integrated Demand Side Management ("IDSM") funds are authorized in the EE proceeding to support joint EE/DR program delivery, as staff proposes,[9] these funds should also be available to MCE to support the costs of integrating DR programs. MCE

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[8] Community Choice Aggregation Frequently Asked Questions: Service Section, PG&E. Accessed July 20, 2017. Available at https://www.pge.com/en_US/residential/customer-service/other-services/alternative-energy-providers/community-choice-aggregation/faq.

[9] Staff Proposal at p. 14-17.

will not use these IDSM funds to launch DR programs, but only to support the costs of integrating separate DR programs into EE program delivery. These integrated demand side management funds should continue to be approved via the annual budget advice letter.

Question 8. Are there additional activities and associated funding that the Commission should consider for better energy efficiency and demand response integration outside of those proposed by staff in the attached proposal?

A. EE-DR Integration is a Core Component of MCE's Single Point of Contact ("SPOC") Model and will Include Separate MCE DR Programs

As discussed above in response to Question 5, MCE intends to integrate delivery of EE and DR programs. MCE's Business Plan illustrates that DR will be integrated with EE in each market sector.[10] MCE's SPOC model provides information to customers and assists them in accessing demand side and resource opportunities.[11] In its proposed role as downstream liaison,[12] MCE will serve as the primary point of contact for many customers. In this role, MCE will work to ensure customers are aware of applicable DR programs when providing EE opportunities. MCE will first recommend MCE-administered DR programs. Otherwise, MCE will continue to work with PG&E to facilitate enrollment of customers in PG&E DR programs. The Commission should be aware of the separate DR programs that MCE intends to launch and administer, and should not create rules that would impede those programs.

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[10] *See* MCE Energy Efficiency Business Plan ("MCE Business Plan") p. 37, 54, 70, 83, 96. Available at https://www.mcecleanenergy.org/2017-EE-Business-Plan.
[11] MCE Business Plan at p. 5.
[12] *See e.g.* MCE Business Plan at p. 13-14.

IV. CONCLUSION

MCE thanks Commissioner Peterman, Administrative Law Judge Fitch, and Administrative Law Judge Kao for their thoughtful consideration of these comments.

Respectfully submitted,

/s/ Michael Callahan

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July 24, 2017

DOCKETED

Docket Number:	16-OIR-05
Project Title:	Power Source Disclosure - AB 1110 Implementation Rulemaking
TN #:	220436
Document Title:	CalCCA Comments on Assembly Bill 1110 Implementation Draft Proposal for Power Source Disclosure
Description:	N/A
Filer:	System
Organization:	California Community Choice Association
Submitter Role:	Public
Submission Date:	7/28/2017 11:15:02 AM
Docketed Date:	7/28/2017

Comment Received From: Troy Nordquist
Submitted On: 7/28/2017
Docket Number: 16-OIR-05

CalCCA Comments on Assembly Bill 1110 Implementation Draft Proposal for Power Source Disclosure

Additional submitted attachment is included below.

CalCCA
California Community Choice Association

Board Officers
Barbara Hale, CleanPowerSF
President

Geof Syphers, Sonoma Clean Power
Vice President

Dawn Weisz, MCE
Secretary

Tom Habashi, Silicon Valley Clean Energy
Treasurer

Joseph Moon, Apple Valley Choice Energy

Cathy DeFalco, Lancaster Choice Energy

Jan Pepper, Peninsula Clean Energy

Matthew Marshall, Redwood Coast Energy Authority

Affiliate Members
Central Coast Power
City of Corona
City of Hermosa Beach
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City of San Jose
City of Solana Beach
County of Los Angeles
County of Placer
East Bay Community Energy Authority
Monterey Bay Community Power Authority
Pico Rivera Innovative Municipal Energy
Valley Clean Energy
Western Riverside Council of Governments

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July 28, 2017

California Energy Commission
Docket Unit, MS-4
Re: Docket No. 16-OIR-05
1516 Ninth Street
Sacramento, CA 95814-5512

CalCCA Comments on Assembly Bill 1110 Implementation Draft Proposal for Power Source Disclosure

California Community Choice Association ("CalCCA") hereby submits its comments on the Draft Staff Paper Assembly Bill 1110 Implementation Proposal for Power Source Disclosure ("Draft Proposal") filed on June 27, 2017. CalCCA appreciates this opportunity to comment on the Draft Proposal and strongly urges the California Energy Commission ("CEC") staff to modify the Draft Proposal to ensure that the new regulations do not result in inconsistent state regulations, create customer confusion, or undermine California's ambitious clean energy policies.

I. Introduction

CalCCA represents the interests of California's Community Choice Aggregators ("CCAs") in the legislature and at jurisdictional regulatory agencies, including the CEC. CalCCA's current operational members include Apple Valley Choice Energy, CleanPowerSF, Lancaster Choice Energy, MCE, Peninsula Clean Energy, Redwood Coast Energy Authority, Silicon Valley Clean Energy, and Sonoma Clean Power.

CalCCA also has several affiliate members that anticipate becoming operational members soon, including Central Coast Power, City of Corona, City of Hermosa Beach, City of San Jacinto, City of San Jose, City of Solana Beach, County of Los Angeles, County of Placer, East Bay Community Energy Authority, Monterey Bay Community Power Authority, Valley Clean Energy, and Western Riverside Council of Governments.

CalCCA's membership demonstrates the growth of community interests in CCAs across California. Many of CalCCA's members have developed procurement strategies to exceed the State's Renewable Portfolio Standard ("RPS") mandates to reflect local communities' desire to reduce Greenhouse Gas ("GHG") emissions. Many operational CCAs offer electricity products that exceed the current RPS standard. The ability to purchase renewable energy is a powerful tool for communities to take actions to replace fossil fuel resources, and it is important that such actions are accounted for properly so that customers are aware of the nature of electricity that is procured on their behalf.

II. Overall Comments

CalCCA appreciates the hard work of the CEC staff in undertaking the implementation of Assembly Bill ("AB") 1110. In working with the CEC staff, CalCCA hopes that the final Power Source Disclosure ("PSD") regulations will accomplish the following:

- Ensure that California ratepayers understand the GHG emissions impact of their electricity products;
- Ensure that renewable energy resources receive treatment that is consistent with California's RPS statute and regulations and electricity industry GHG emissions inventory best practices;
- Ensure that regulations adopted by the CEC do not create conflicts with other agencies' regulations.

CalCCA is deeply concerned with the Draft Proposal because it is inconsistent with California's clean energy policies and state programs, and the electricity industry standard practices. Unless the proposal is significantly modified, the implementation of AB 1110 will inevitably create customer confusion, disrupt the electricity market, and subject electricity market participants to regulatory uncertainties and litigation risks.

CalCCA urges the CEC staff to adopt the proposed modifications discussed below. CalCCA also welcomes ongoing conversations with the CEC staff to ensure the final PSD template will be compliant with the legislative intent of AB 1110, easily understood by consumers, and consistent with other state law and renewable energy industry practices.

III. Specific Comments on the Draft Proposal

A. REC Reporting for the Power Mix Should Be Modified

CalCCA urges the staff to modify the proposed REC reporting mechanism set forth in the Draft Proposal to require retail suppliers to disclose the purchase of eligible renewable energy resources based on the year the REC is retired instead of when it is generated. This modification is consistent with California's RPS program, which requires a REC to be reported in the year it is retired and provides a three-year compliance period, or 36-month life-cycle for REC retirement.[1]

Under the current Draft Proposal, a REC has to be reported in the same year that the associated power is generated.[2] This approach is flawed because this mechanism does not adhere to the existing reporting practice of the RPS program, where the retirement of a REC may occur after the conclusion of the year in which the electricity is generated.[3] The proposed mechanism would create significant and untenable reporting complications for load-serving entities, especially for transacted portfolio contracts that deliver renewable energy volumes over multi-year periods. As Bear Valley Electric warned in its pre-rulemaking scoping comments, if staff's Draft Proposal approach is taken, RPS reports and RPS Adjustments under the California Air Resources Board's ("ARB") Cap-

[1] Cal. Pub. Util. Code § 399.21(a)(7).

[2] Draft Proposal at 11. CalCCA notes that the Draft Proposal correctly finds that unbundled RECs should be reported in the year they are retired. Draft Proposal at 14. The reasoning behind this element of the Draft Proposal should apply to all RECs.

[3] The Climate Registry Comments on Proposed Pre-Rulemaking Scoping Questions (March 15, 2017) at 3.

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and-Trade program will differ from a retail supplier's PSD report, which will lead to inconsistency across agencies, customer confusion, and a lack of transparency.[4]

Most importantly, this reporting misalignment could lead to lead to double counting of RECs. If a REC has not been properly retired, it could be subsequently sold off and used for other state RPS programs or for other retail product claims in California or elsewhere.[5] In such a circumstance, electricity may be reported as renewable, whereas in actuality the electricity is null power, lacking the renewable and zero-GHG attributes. Such a result would violate the express provisions of the PSD statute, which requires the CEC to:

> "[E]nsure that there is no double-counting of the greenhouse gas emissions or emissions attributes associated with any unit of electricity production reported by a retail supplier for any specific generating facility or unspecified source located within the Western Electricity Coordinating Council when calculating greenhouse gas emissions intensity."[6]

As explained by the Center for Resource Solutions in their pre-rulemaking scoping comments, RECs must be retired in order for renewable energy to be reported as a "specified purchase" under the PSD statute. [7] Under Public Utilities Code section 398.2(d), "Purchases of electricity from specified sources" or "purchases from specified sources" is defined as "electricity transactions that are traceable to specific generation sources by any auditable contract trail or equivalent, such as a tradable commodity system, that provides commercial verification that the electricity source claimed has been sold once and only once to a retail consumer." By contrast, "Electricity from unspecified sources" is defined to mean electricity that is *not* traceable to specific generation sources by such an auditable contract trail (including the REC system).[8] If a REC has not been retired, "it is not traceable and there is no verification that it has been sold only once."[9]

As a result of the double-counting risk and misalignment of reporting and retirement requirements, reporting of RECs based on the year of generation would be highly misleading to consumers and regulators. Along these lines, reporting of RECs based on the date the electricity was generated could also cause load-serving entities to violate federal rules on environmental marketing claims if the REC has not been properly retired in that year.[10] Such a rule would put load-serving entities in an untenable position, subject to litigation and enforcement risk.

For all of these reasons and the reasons discussed by the numerous stakeholders who filed pre-rulemaking scoping comments along these lines,[11]CEC staff should modify the Draft Proposal so that all types of RECs are reported in the year the REC is be retired.

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[4] *See* Comments of Bear Valley Electric Service on the Preliminary Scoping Questions on Updates to the Power Source Disclosure Regulations (March 15, 2017).

[5] CRS Comments on proposed Pre-Rulemaking Scoping Questions to PSD Regulations (March 15, 2017) ("CRS Scoping Comments") at 3.
[6] Cal. Pub. Util. Code § 398.4(k)(2)(E).
[7] CRS Scoping Comments at 3.
[8] Cal. Pub. Util. Code §398.2(e).
[9] CRS Scoping Comments at 3.
[10] *See Federal Trade Commission Guides for the Use of Environmental Marketing Claims*, 16 C.F.R. §260.15.
[11] *See* Pre-Rulemaking Scoping Comments of Alliance for Retail Energy Markets, Bear Valley Electric Service, CalCCA, LibertyUtilities (CalPeco Electric) LLC, San Francisco PUC, SDGE & Sempra, Sempra Services and The Climate Registry.

B. Firmed-and-Shaped Products Are Zero-Emission Resources and Should Be Treated As Such

CalCCA supports the Draft Proposal's recommendation that firmed-and-shaped electricity products should be categorized in the power mix according to the resource type of the transacted RECs.[12] The contracted-for renewable energy should be reported and counted in the Power Content Label ("PCL").

To be consistent with this position, however, because fuel type and direct GHG emissions are attributes that are exclusively contained in a REC, firmed-and-shaped electricity products should be assigned an emissions factor of zero. Assigning any positive emissions to firmed-and-shaped products would be extremely inconsistent with California's RPS program, as well as the accounting practices in GHG Protocol Scope 2 Guidance for the accounting and reporting of GHG emissions,[13] which is widely adopted by the electricity market in the United States as well as other countries. Without modifying the proposal, the implementation of AB 1110 will create great customer confusion, and increase costs for ratepayers due to stranded assets and RPS/AB 1110 compliance costs. Retailers and suppliers may also be exposed to greater litigation risks, which would further increase the cost of electricity. CalCCA urges the staff to revise the proposed treatment of firmed-and-shaped power to avoid these unintended market consequences.

As LADWP aptly stated in its scoping comments:

> The GHG emissions intensity of firmed and shaped electricity products should be based on the emissions profile associated with the generation source of the REC, to reflect the fact that a MWh of renewable electricity was generated and put into the electricity grid. Electricity produced by a renewable generating facility anywhere within the electrical grid decreases the overall GHG emissions intensity of the electricity grid. Once electrons are put into the electricity grid, the electrons mix with electrons from other generating facilities and become impossible to track. The REC is used to track the renewable attributes of electricity produced by renewable generating facilities. There is one and only one REC for each MWh of renewable electricity generated. Therefore, the owner of the REC should be able to claim the GHG emission profile of the renewable generating facility regardless of where the electrons went once they entered the grid.[14]

First, the Draft Proposal's attempt to attribute no environmental value to RECs associated with PCC 2 products conflicts with California law. Firmed-and-shaped products, or PCC 2 products, are bundled with RECs, which convey the renewable, GHG-free and environmental attributes associated with eligible renewable energy production.[15] Firmed-and-shaped electricity products are expressly permitted for RPS compliance purposes under the RPS statute[16] because the California Legislature recognized the renewable attributes of this electricity source. Firmed-and-shaped transactions are also

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[12] Draft Proposal at 13.
[13] World Resources Institute, *GHG Protocol Scope 2 Guidance: An Amendment to the GHG Protocol Corporate Standard, available at* http://www.wri.org/sites/default/files/Scope_2_Guidance_Final.pdf.
[14] LADWP's Comments re AB 1110 Implementation and PSD Pre-Rulemaking Workshop (March 15, 2017).
[15] Cal. Pub. Util. Code § 399.12(h); California Public Utilities Commission Decision 08-08-028 (August 21, 2008), Ordering Paragraph 1 (explaining that RECs contain all avoided GHG emissions).
[16] Cal. Pub. Util. Code § 399.16(b)(2), (c).

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eligible for express credits acknowledging the clean emissions profile of the RECs under the Cap and Trade Program RPS Adjustment rules.[17] As PG&E explained, "[t]he RPS adjustment allows the imported electricity to adjust its emissions profile to correspond to the emissions profile associated with the generation source of the REC."[18] The Draft Proposal should be revised to conform to these other bodies of law.[19]

In choosing to align its proposal with some aspects of the ARB's Cap-and-Trade program while conflicting with the express terms of the RPS statute, staff's reliance on statements made to the press of AB 1110's author is misplaced, as the statutory language of AB 1110 does not require or prioritize conformity of the CEC's PSD regulations with the ARB's regulations. Indeed, the California Supreme Court indicated, "We have frequently stated… that the statements of an individual legislator, including the author of a bill, are generally not considered in construing a statute, as the court's task is to ascertain the intent of the Legislature as a whole in adopting a piece of legislation."[20]

Second, failing to recognize the environmental attributes of firmed-and-shaped electricity would greatly decrease the market value of RECs and PCC 2 Products. By counting a REC for its renewable attribute through the RPS program, but discounting the environmental attribute in the PSD, the CEC's regulations will create friction with federal guidance and industry practices and will disrupt renewables markets in California. This approach would de-value PCC 2 products already contracted for, which would be grossly unfair to retail suppliers and would create stranded costs for ratepayers, as discussed below. As SMUD expressed in scoping comments:

> Utilities enter into firmed and shaped contracts in order to procure zero-emission, renewable power for their customers. Utility customers should enjoy the environmental benefits of the procurement their dollars support for firmed and shaped contracts, just like any other renewable procurement.[21]

Moreover, by de-valuing firmed-and-shaped products, the Draft Proposal could have the effect of discriminating against out-of-state renewable energy resources, which is prohibited under the RPS statute.[22]

Third, significant future costs to ratepayers will be incurred under the Draft Proposal. A retailer would be limited to procuring PCC 1 products to preserve low GHG emission profiles, even though California's RPS program allows retailers the flexibility to procure firmed-and-shaped products as well. By assigning GHG emissions to PCC 2 products and essentially deeming PCC 2 products as non-renewable resources, the implementation of AB 1110 would increase costs to comply with RPS requirements, as well as the cost of building new resources moving forward. The staff's proposal will also undermine the ongoing effort to improve the California Independent System Operator's ("CAISO") Energy Imbalance Market ("EIM"), and lead to stranded assets of regional transmission infrastructure. The EIM has been created to help retailers, as well as ratepayers, realize economic

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[17] 17 CFR § 95852(b)(4).
[18] Pacific Gas and Electric Comments on Feb. 21 Staff Pre-Rulemaking Workshop on Updates to the PSD Regulations (March 15, 2017) at 4.
[19] *See* Draft Proposal at 4; *cf People v. Rodriguez*, 55 Cal. 4th 1125, 1146 n.4 (2012) (discounting the relevance of the statements of an individual legislator in statutory interpretation).

[20] *Quintano v. Mercury Casualty Co.* (1995) 11 Cal.4th 1049, 1062, 48 Cal.Rptr.2d 1, 906 P.2d 1057.
[21] William Westerfield III Comments: SMUD Comments on Staff Workshop - AB 1110 Implementation Rulemaking (March 15, 2017) ("SMUD Pre-Rulemaking Scoping Comments") at 4.
[22] *See* Cal. Pub. Util. Code § 399.11(e)(2).

savings that are made possible through regionally traded electricity. The CEC staff proposal would create a disincentive to utilize PCC 2 resources, which is at odds with efficiencies and savings gained through the EIM. Furthermore, a great deal has been invested in transmission infrastructure to allow for imports and exports to facilitate achieving climate goals. If PCC 2 products are no longer valuable because the environmental attributes in their associated RECs are not counted, these transmission assets would be underutilized, and may lead to stranded costs for ratepayers to bear.

CalCCA urges the staff to treat firmed-and-shaped products in a manner that is consistent with its approach to the power mix disclosures, the state's RPS program, the ARB's RPS Adjustment Rules and the electricity industry's GHG emissions accounting practices. Firmed-and-shaped products should not be assigned any emissions values, as the RECs associated with those powers contain both the renewable energy and environmental attributes.

C. The Generation Resource Type Associated with Unbundled RECs Should Be Reported in the Power Mix

CalCCA supports the staff's Draft Proposal to reflect the percentage of retail sales associated with unbundled RECs on the PCL as a footnote.[23] However, CalCCA does not agree with the staff's proposal to exclude unbundled RECs from the eligible renewables category of the power mix, and urges the staff to adjust the proposal to reflect unbundled RECs in the power mix.

Unbundled RECs, like all other RECs, contain the renewable and environmental attributes,[24] and should be assigned the same validity as other RECs. The PSD regulations should recognize that unbundled RECs provide proof of renewable electricity generation from an eligible renewable resource under the RPS,[25] as well as the associated environmental attributes resulting from the use of renewable generation.

AB 1110 requires the disclosure of the portion of annual sales derived from unbundled RECs, but it does not provide that unbundled RECs be excluded from the PCL.[26] Excluding unbundled RECs from the eligible renewables category in the PCL portrays an inaccurate emissions profile of purchased electricity by a retailer, which would result in inconsistency with the RPS statute as well as customer confusion. A statutory purpose of AB 1110 was to ensure that the PCL disclosures are "accurate, reliable and simple to understand."[27] To fulfill this legislative purpose, Customers should see the renewable attributes of RECs purchased on their behalf in the PCL. Furthermore, as greenhouse gases are regional in nature, the growth of renewable energy in other parts of the Western grid will lead to the reduction of GHG emissions regionally. By discounting unbundled RECs, the CEC essentially discourages the opportunity for the Western region to work together to reduce GHG emissions. For these reasons, the generation source type associated with unbundled RECs should be reported in the power mix to recognize the renewable and environmental attributes of these RECs.

D. Asset Controlling Supplier ("ACS") Products Should Be Associated with Fuel Types within the PCL, Rather Than Being Listed as Unspecified

[23] Draft Proposal at 14; *see also* SMUD Pre-Rulemaking Scoping Comments at 5.
[24] § 399.12(h).
[25] § 399.16(b)(3), (c).
[26] Cal. Pub. Util. Code § 398.4(h)(7).
[27] § 398.1(b).

Staff's Draft Proposal would assign ACS-specific GHG emissions factors to ACS resources as determined under the ARB's Mandatory Reporting Regulation ("MRR"), yet, for the power mix, purchases from ACSs would continue to be categorized as unspecified power.[28] CalCCA asserts that if the ARB is able to assign ACS-specific emissions factors based on data submitted by the suppliers, ACS products should be prorated and associated with specified fuel types under the PCL.

Under the MRR, once an ACS is approved and an emissions factor assigned by ARB, "ACS power procured from an ACS's system is considered specified source power."[29] CalCCA recommends that, rather than continue to report ACS purchases as unspecified power, the Commission should adopt ARB's treatment of ACSs under MMR as specified power. As Staff noted at the July 14, 2017 Pre-Rulemaking Workshop, this would mean that a purchase from an ACS would be broken into subcategories of resources (e.g., hydro and other sources), rather than simply listed as unspecified power.[30] If the ARB can provide the ratio of hydroelectric or other sources of power embedded within the emissions factor, then LSE can calculate the emissions and tie them to specific fuel types based on the ratio. The goal of doing this is to maximize the use of available data to provide consumers with higher accuracy emissions intensity information. This treatment of ACS would promote the stated purpose of AB 1110 to ensure that entities offering electric service "disclose accurate, reliable, and simple to understand information on the sources of energy, and the associated emissions of greenhouse gases, that are used to provide electric service."[31]

E. Transmission Losses Should Not Be Assigned GHG Emissions Factor

The Draft Proposal would assign a "transmission loss correction factor" of 1.02 to electricity imported into a California balancing authority, where the retail supplier has not demonstrated that transmission losses are otherwise accounted for.[32] Under Staff's current proposal, this factor would be used to calculate the power mix and GHG emissions intensity factor of the retail supplier's electricity portfolio.

This proposal would greatly contribute to customer confusion and deviate from data use in existing retail-level reporting programs, which utilize retail sales and not loss-adjusted volumes. CalCCA urges Staff to modify the proposal to eliminate the transmission loss correction factor to remain consistent with existing retail reporting protocols.

While transmission losses are a natural occurrence of electricity delivery, they are not an element of electric service well understood by consumers, nor are they necessary to provide customers an accurate picture of the resource types and GHG emissions characteristics of the electricity they consume. The concept of transmission losses will likely be confusing to customers, thereby frustrating the intent of AB 1110 that the information provided to customers be "simple to understand."[33] CalCCA therefore asserts that the proposed transmission line loss correction factor should not be introduced in the PCL or GHG emissions intensity calculations.

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[28] Draft Proposal at 16.

[29] California Air Resources Board, ARB Specified Source Electrical Imports Greenhouse Gas Reporting, Frequently Asked Questions (May 23, 2014) at 5, *available at* https://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/specified_source_acs_faqs.pdf.

[30] Draft Proposal at 16; Transcript of the 07/14/2017 Workshop Updated to the Power Source Disclosure Regulations at 18:18-25 – 19:1-3.

[31] Cal. Pub. Util. Code § 398.1(b).

[32] Draft Proposal at 14-15.

[33] Cal. Pub. Util. Code § 398.1(b).

IV. Conclusion

CalCCA respectfully requests that the CEC modify its AB 1110 implementation Draft Proposal to reflect these changes:

- CEC staff should modify the Draft Proposal so that all types of RECs are reported in the year the REC is be retired.
- Firmed-and-shaped products should not be assigned any emissions values, as the RECs associated with those powers contain both the renewable energy and environmental attributes.
- The generation source type associated with unbundled RECs should be reported in the power mix to recognize the renewable and environmental attributes of these RECs.
- ACS should be treated as specified power, reported based on fuel type, and the associated emissions should be prorated based on fuel type.
- The proposed transmission line loss correction factor should not be introduced in the PCL or GHG emissions intensity calculations.

CalCCA believes that these requests are reasonable, consistent with existing California law and the statutory purpose of AB 1110, and will clearly educate consumers about their electricity product without disrupting the electricity market.

Docket No.: R.03-10-003

Exhibit No.: ____________________

Date: July 28, 2017

TESTIMONY OF MARK FULMER
ON BEHALF OF CALCCA CONCERNING
COMMUNITY CHOICE AGGREGATION FINANCIAL SECURITY REQUIREMENTS
AS REQUIRED BY CALIFORNIA PUBLIC UTILITIES CODE SECTION 394.25(e)

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I. INTRODUCTION AND SUMMARY

A. Qualifications

Q: Please state your name and business address.

A: Mark Fulmer of MRW & Associates, LLC (MRW). MRW's business address is 1736 Franklin Street, Suite 700, Oakland, California.

Q: Mr. Fulmer, have you previously testified before the California Public Utilities Commission?

A: Yes. A list of my prior testimonies and qualifications are included in ***Appendix C***.

Q: On whose behalf are you testifying?

A: This testimony is being provided on behalf of the California Community Choice Association (CalCCA). CalCCA represents the interests of California's community choice aggregators (CCAs) in the legislature and at the relevant regulatory agencies, including the California Public Utilities Commission (Commission), California Energy Commission and California Air Resources Board. CCAs are administered by local governments with a mission to provide competitive alternatives to investor-owned utility (IOU) electric generation service. CalCCA's voting members are the operating CCA programs in California. The current voting members are: Apple Valley Choice Energy (AVCE), CleanPowerSF (CPSF), Lancaster Choice Energy (LCE), Marin Clean Energy (MCE), Peninsula Clean Energy (PCE), Redwood Coast Energy Authority (RCEA), Silicon Valley Clean Energy (SVCE), and Sonoma Clean Power Authority (SCPA). Local governments interested in community choice may join as affiliate members.

CalCCA fosters cooperative collaboration between new and existing CCAs. New CCAs can mitigate risk and ensure best practices by learning from the experiences of operational CCA programs and organizations. Communities investigating whether to create a CCA are able to better plan and identify opportunities by understanding the business strategies and lessons learned from existing CCA programs in the State.

Q: What is the purpose of your testimony?

A: The purpose of this testimony is to present the positions of CalCCA regarding to the Commission's goal of "developing a permanent methodology and process to implement the requirements of Section 394.25(e) with respect to customers of CCAs that are involuntarily returned to service provided by investor-owned utilities."[1] This testimony outlines and addresses the various factors that should and should not be considered when determining the Financial Security Requirement (FSR) for CCAs in compliance with California Public Utilities Code Section 394.25(e).[2]

Q: How is your testimony organized?

A: The first section provides an introduction and summarizes CalCCA's position on the CCA FSR. The second section provides background on CCAs. The third section provides background regarding the FSR. The fourth section explains how the risk for CCA failure is extremely low because specific events that would need to occur to result in CCA failure are each unlikely and the confluence of all such events even more unlikely. The fifth section explains that even in the unlikely event that a CCA fails, the failure would not occur overnight but instead would occur over a lengthy period of time, allowing for appropriate responses. Based on this context, the final section presents the details of the CalCCA FSR proposal.

[1] R.03-10-003, "Fourth Amended Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge," March 1, 2017 at 2.
[2] All references are to the California Public Utilities Code unless otherwise indicated.

B. Summary of CalCCA's Position

Q: Please summarize CalCCA's recommendations regarding the CCA FSR.

A: CCAs are low-risk entities and the likelihood of CCA failure is very unlikely. In setting the CCA FSR, the Commission should determine that:

1. the reentry fees deemed necessary are the estimated incremental administrative costs to re-integrate the former CCA customers into IOU bundled service;
2. this estimated incremental administrative cost be based on the tariffed rate for the CCA Mass Transfer fee plus the Community Choice Aggregation Service Request (CCASR) fee, discounted for the probability of occurrence;
3. the CCA FSR be re-calculated annually or when the CCA's customer count changes by 15% or more; and
4. the CCAs should have the maximum flexibility in how to meet the CCA FSR, including, but not limited to the CCA's own reserve funds, guarantees from creditworthy entities, surety bonds, insurance products, or a letter of credit.

II. BACKGROUND ON CCA

Q: What is a Community Choice Aggregator?

A: CCAs are local government not-for-profit load-serving entities (LSE). CCAs are permitted to form and operate within the State in accordance with Assembly Bill (AB) 117 (2002, Migden). CCAs provide ratepayers with an alternative to electricity sourced by the incumbent Investor Owned Utility (IOU). To date all CCAs that have formed in California have focused on providing their communities with high renewable and low greenhouse-gas emitting supplies while remaining cost competitive with the incumbent IOU.[3]

Q: What other services do CCAs provide in addition to sourcing electricity for the customers in the communities that they serve?

A: CCAs also provide other services to their communities through programs that focus on, for example, energy efficiency, demand response, energy storage, electric vehicles, net-energy metering, local renewable development, and local economic development. The exact program offerings vary among the different CCAs.

Q: What customers do CCAs serve?

A: CCAs serve all customer classes within their communities and service areas. Customers within a CCA's service area are automatically enrolled and served by the CCA upon the CCA's formation unless a customer affirmatively chooses to opt-out and remain with the incumbent IOU.

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[3] *See* **Appendix A**.

Q: How are CCAs organized?

A: CCAs are structured either through a Joint Powers Authority (JPA), such as MCE, SCPA, PCE, SVCE, and RCEA, or a municipal jurisdiction model, such as CPSF, which operates within the City and County of Francisco's Public Utilities Commission (SFPUC) Power Enterprise,[4] LCE, which operates within the City of Lancaster, and AVCE, which operates within the Town of Apple Valley.

A CCA is governed directly by its board, which is comprised of elected or appointed public officials that represent the specific communities served by the CCA. A CCA's Board has authority over the CCA's business operations.

Q: What is the difference between a CCA and an Energy Service Provider (ESP)?

A: ESPs are private-sector LSEs who serve customers taking Direct Access (DA) service. DA customers agree to service terms through bilateral contacts with ESPs rather than a published rate. The terms of these agreements tend to be shorter, for example 3 to 5 years. In contrast, CCAs, have an indefinite obligation to service their customers. DA customers also affirmatively enter into ESP agreements; while CCAs serve their customers by default unless the customer opts out of CCA service. ESPs are free to refuse service to any customers; whereas CCAs have an obligation to offer service to all residential customers within their jurisdictions.[5] ESPs also operate under a different set of statutes and are presently held to an operational cap of 28.4 million MWh of annual customer load.[6]

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[4] The SFPUC is a municipal utility that provides water, wastewater, and electricity sales and services.
[5] Section 366.2(b).
[6] "Direct Access Implementation Activity Report," accessed June 2017, http://www.cpuc.ca.gov/General.aspx?id=6598

III. BACKGROUND ON THE CCA FINANCIAL SECURITY REQUIREMENT

Q: What is a financial security requirement?

A: The FSR is a type of collateral intended to offset costs associated with the "involuntary return" of CCA customers to the IOU's bundled electricity service. In such an event, any FSR provided by the CCA could be leveraged by the IOU to cover incremental costs caused by this "involuntary return" of customers. Public Utilities Code Section 394.25(e) establishes the FSR for a CCA, stating:

> If a customer of an electric service provider or a community choice aggregator is involuntarily returned to service provided by an electrical corporation, any reentry fee imposed on that customer that the commission deems is necessary to avoid imposing costs on other customers of the electric corporation shall be the obligation of the electric service provider or a community choice aggregator except in the case of a customer returned due to default in payment or other contractual obligations or because the customer's contract has expired. As a condition of its registration, an electric service provider or a community choice aggregator shall post a bond or demonstrate insurance sufficient to cover those reentry fees. In the event that an electric service provider becomes insolvent and is unable to discharge its obligation to pay reentry fees, the fees shall be allocated to the returning customers.

Q: What does "involuntarily returned" to IOU service mean?

A: "Involuntarily returned" means that the CCA has ceased providing power to its customers outside of the process laid out in each IOUs' CCA Rules.[7] Those customers then, through no choice of their own, must take electric service from the incumbent IOU. It does not include customers whom the CCA turns over to the IOU for non-payment of the CCA portion of their bills. It also does not include customers that have affirmatively opted to return to the IOU.

[7] *See, for example*, PG&E Rule 23, §S.

Q: Has the Commission addressed the FSR requirement previously?

A: Yes, when it first began this rulemaking (R.) 03-10-003 in 2003, the Commission considered numerous details necessary to enable the operation of CCA programs; however, the Commission did not set an amount for the FSR nor a methodology for calculating how the FSR that could be applied to CCAs.

In 2005, the San Joaquin Valley Power Authority (SJVPA) was the first entity to attempt to form a CCA. SJVPA would have served customers in both Pacific Gas and Electric Company's (PG&E) and Southern California Edison Company's (SCE) service territories. The Commission's Energy Division staff requested that PG&E and SCE work with SJVPA to develop and calculate an appropriate FSR amount.

The parties' efforts failed. PG&E proposed an amount equal to the incremental costs of procuring for SJVPA's returned customers under "stressed" market conditions for one year.[8] Later, PG&E clarified:

> SJVPA is expected to serve approximately 2100 GWh of customer load annually. Even at a nonstressed market price of $67/MWh [...] the cost for PG&E to procure power to serve the returning CCA customers for a year is more than $140 million.[9]

While SCE did not make a proposal, it generally agreed with PG&E's methodology.[10] In contrast, SJVPA proposed that the "[FSR] requirement should be equivalent to the security deposit requirement that currently applies to an Energy Service Provider's (ESP) registration with the Commission – currently between $25,000 and $100,000."[11]

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[8] Resolution E-4133 at 3.
[9] *Ibid.* at 3-4.
[10] *Ibid.* at 2.
[11] *Ibid.* at 2.

In late 2007, the Commission sided with SJVPA and determined that an FSR in the amount of $100,000 would be sufficient to cover the risks associated with the SVJPA CCA formation. The Commission looked to its treatment of comparable ESPs for guidance:

> We come to this conclusion in light of fact that there are ESPs currently serving load in California that is of a magnitude comparable to that which SJVPA plans to serve. The bond [FSR] requirement for these ESPs ranges from $25,000 to $100,000, depending on how many customer accounts that ESP serves.[12]

In addition to reaching this finding, the Commission pledged to revisit "the methodology for calculating the amount of this bond […] in the near future."[13]

In June 2009, in this same rulemaking, several parties proposed a settlement regarding the FSR and reentry fee requirements for CCAs.[14] These parties were the City of Victorville, PG&E, San Diego Gas and Electric (SDG&E), SJVPA, SCE, and The Utility Reform Network (TURN). That settlement called for a stressed market-based FSR calculation, effectively like that offered by PG&E in 2007.[15] Non-signatory parties, including the Alliance for Retail Energy Markets, Marin Energy Authority (now known as MCE), and City and County of San Francisco, opposed the settlement. Although the assigned Administrative Law Judge (ALJ) issued a proposed decision approving the settlement, the ALJ later withdrew that proposed decision because SJVPA had dissolved

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[12] "Resolution E-4133" at 8.
[13] "Resolution E-4133" at 1.
[14] *See* R.03-10-003, "Joint Motion Of City Of Victorville, Pacific Gas And Electric Company (U 39-E), San Diego Gas & Electric Company (U 902-E), San Joaquin Valley Power Authority, Southern California Edison Company (U 338-E), And The Utility Reform Network For Adoption Of Settlement Agreements," June 24, 2009.
[15] *Ibid.,* Exhibit A.

and withdrew as a party to this rulemaking.[16] In addition, newly-formed CCAs largely opposed the settlement reached by SJVPA.

On January 14, 2011, Assigned Commissioner Peevey and ALJ Yip-Kikugawa requested briefs to address "supplemental information on legal issues pertaining to the bond requirement and methodology for calculating the [CCA] bond requirement."[17] Briefs, reply briefs, and supplemental briefs were filed by the IOUs and other interested parties, including CCAs. No action was taken, thus effectively keeping the $100,000 security requirement set in 2007.

Q: Has the Commission considered this issue in other proceedings?

A: Yes. Around the same time that the Commission sought supplemental briefing on this issue in this rulemaking, the Commission addressed the FSR requirements for ESPs in the Direct Access rulemaking (R.07-05-025). For a third time, the IOUs proposed the stressed-market based FSR for ESP FSR calculations.[18] DA Parties opposed the proposal stating that the assumption of a 95% confidence interval for calculating the bond amount produced an unreasonably high assessment of risk.[19] In addition, DA Parties further argued that volatility data quotes were inaccessible or unavailable, and that reliance on such data would be inappropriate.[20]

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[16] R.03-10-003, "Amended Scoping Memo And Ruling Of The Assigned Commissioner And Administrative Law Judge Amending The Scoping Memo And Reopening The Record," January 14, 2011 at 3.
[17] *Ibid.* at 7.
[18] *See,* D.11-12-018 at 76-82.
[19] *Ibid.*
[20] *Ibid.* at 80.

In D.11-12-018, the Commission again rejected the stressed-market based FSR for ESPs criticizing that "…the proposed bond model offered by PG&E/SCE does not offer a suitable framework for determining the applicable ESP bond amount."[21] The Commission explained that the timeframe of one year for calculating incremental costs was excessive and reiterated that a 95% confidence interval was not to be used in such calculations.[22] Instead, the Commission ordered the ESP bond to be set at estimated administrative costs plus the incremental IOU procurement costs necessary to serve returned small commercial and residential direct access customers.[23]

Q: Given that the Commission has already declined to adopt the stressed-market based FSR three separate times, what do you propose for the FSR?

A: As I will explain more fully in Section VI, I believe that the Commission can only deem necessary at this time an FSR to cover the reentry fees associated with the estimated incremental administrative cost of re-integrating the former CCA customers into the IOU's bundled service. As with any FSR requirement, the proposed amount should be discounted by an assessment of the likelihood of occurrence.

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[21] *Ibid.* at 82.
[22] *Ibid.* at 83.
[23] *Ibid.* at Ordering Paragraphs 14, 22.

IV. A CCA IS UNLIKELY TO FAIL

Q: Please describe the scenario in which you believe CCA customers could be involuntarily returned to IOU service and the CCA FSR would be necessary.

A: CCA customers could be involuntarily returned to IOU bundled service if a CCA program fails due to a confluence of the following unlikely events persisting for a number of years:

First, market prices would need to become exceedingly high and remain high for several years.

Second, the CCA must fail to hedge against this type of market fluctuation. Either the CCA must have committed to highly uneconomic contracts or the market conditions would need to be so unpredictable and so extreme that the CCA's managed portfolio would not sufficiently protect against that specific market pressure.

Third, the CCA's rates would need to become substantially uncompetitive with the incumbent IOU's generation rates for a significant period of time. This would only happen after several years in increased market pressures and assumes that the IOU rates would be less impacted by these hypothetical rising market pressures. This further assumes that CCAs would be unable to mitigate the increased pressures through their rate stabilization funds and be otherwise unable to raise revenues. Moreover, the CCA rates would have to remain uncompetitive despite the fact that increased market pressures would correspond with decreased non-bypassable charges as the Power Charge Indifference Adjustment (PCIA) decreases.

Finally, a significant amount of CCA customers would have to voluntarily choose to leave CCA service, making it difficult for the CCA to cover their fixed costs.

Q: Do you believe that this worst-case scenario is unlikely?

A: Yes. For the reasons I describe below, each of these specific events is highly unlikely and thus the confluence of all of these events is even more unlikely. Accordingly, the overall risk of a CCA failing is quite small and the likelihood that an IOU would ever need to utilize an FSR is extremely unlikely.

A. Market Prices Are Unlikely to Become Exceedingly High and Remain Consistently High for Several Years

Q: Please describe why you believe California's present-day electricity market will not result in exceedingly high market prices occurring consistently over several years.

A: California's present-day electricity market is far more protected against the types of market manipulation that led to the California Energy Crisis of 2000-2001 (Energy Crisis). The current electricity market has numerous legal and regulatory requirements that protect the ratepayers against the sorts of price spikes and market manipulation that occurred during the Energy Crisis. Based on these considerations, the present likelihood for similar crisis conditions is dramatically lower.

Q: What legal and regulatory requirements implemented since the Energy Crisis must CCAs meet?

A: CCAs, like IOUs and other LSEs, comply with numerous state-mandated procurement and reporting requirements. All of these obligations were initiated following the Energy Crisis, and were intended to lower the risk of failure for all of California's LSEs, including CCAs. These obligations not only help to stabilize the operation of the California electricity grid, and cumulatively, they make the energy market today significantly less risky than the time leading to the Energy Crisis. By meeting and exceeding these requirements, CCAs also limit their exposure to market risk. These regulatory requirements are associated with:

(i) the Renewables Portfolio Standard[24]

(ii) System, local, and flexible Resource Adequacy[25]

(iii) Energy Storage[26]

(iv) Renewable Integration[27]

(v) Long-Term Procurement[28]

Furthermore, CCAs are taking steps to coordinate with the State's implementation of the Integrated Resources Plan (IRP), as required by Senate Bill (SB) 350 (De León, 2015).[29] CCAs are also subject to certain statewide reporting obligations such as the Emissions Performance Standards (EPS) requirements.[30]

Q: How does the Renewables Portfolio Standard obligation help to ensure market prices are stable?

A: The California Renewable Portfolio Standard (RPS), as most recently modified by SB 350, requires all LSEs, including CCAs, and Publicly Owned Utilities to procure 50% of their electricity from eligible renewable energy sources by 2050. In addition to this percentage requirement, the RPS also imposes certain limitations on the generation

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[24] *See* "RPS Program Overview," accessed June 28, 2017, http://www.cpuc.ca.gov/RPS_Overview/.
[25] *See* "Resource Adequacy Homepage," accessed June 28, 2017, http://www.cpuc.ca.gov/ra/.
[26] *See* "Energy Storage," accessed June 28, 2017, http://www.cpuc.ca.gov/General.aspx?id=3462.
[27] The CPUC is implementing the Renewable Integration segment of statute introduced by SB 350 (2015) within the Integrated Resources Plan and Long-Term Procurement Plan (IRP-LTPP) proceeding R.16-02-007.
[28] The CPUC is implementing the long-term procurement segment of statute introduced by SB 350 (2015) within the current RPS proceeding R.15-02-020.
[29] *See* "Long Term Procurement Planning," accessed June 28, 2017, http://www.cpuc.ca.gov/irp/.
[30] *See* "SB 1368 Emission Performance Standards," accessed June 28, 2017, http://www.energy.ca.gov/emission_standards/.

sources and the means of delivery for electricity used to satisfy this mandate. In essence, this is a state-mandated portfolio diversification obligation that contributes to market price stability. While prices for renewable and conventional power have come down since the RPS was implemented, there have not been volatile price swings like what occurred during the Energy Crisis or following hurricane Katrina.[31]

Q: How does the RA obligation help to ensure market prices are stable?

A: The Resource Adequacy (RA) mandates for LSEs were first enacted by the State to protect California from capacity constraints caused by transmission line outages and power plant shutdowns. Over time, the RA mandate has become more specific with system, local, and flexible capacity procurement requirements for LSEs, intended to protect electricity grid reliability from different types of strain. Most recently, the flexible RA requirement took effect to respond to increasing periods of fast ramping needs caused by increasing amounts of daytime electricity generation due to adoption of solar and wind.

To date, CCAs have met or exceeded their RA obligations. CCAs and their customers are continuing to support a stable and reliable electricity grid by ensuring adequate generation capacity remains contracted on an annual basis.

Q: How do the Energy Storage, Renewable Integration, and Long-Term Procurement obligations help to ensure market prices are stable?

A: The Energy Storage (ES), Renewable Integration (RI), and Long-Term Procurement mandates are all much more recent than either RPS or RA programs. The

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[31] *See,* Energy Information Administration, Wholesale Electricity and Natural Gas Market Data, accessed July 27, 2017. https://www.eia.gov/electricity/wholesale/#history

implementation of these mandates remains ongoing, but all three of these obligations are also intended to improve the reliability of the electricity grid.

The ES mandate is motivated, at least in part, by the increasing need for flexible capacity resources within the grid to help offset fast ramps that result from increased solar and wind generation. Similarly, the RI mandate is intended to link the costs of integrating intermittent generation sources, such as wind and solar, back to LSEs who are choosing to take generation from these resources over other sources. Both mandates, when fully implemented, will allow CCAs to better balance their own local communities' preferences for renewable electricity supplies while addressing the statewide concern for grid reliability. Again, increased grid reliability results in a stable energy market for all participants.

With regard to the Long-Term Procurement obligation, the more mature CCAs are already focused on supplying their electricity portfolios through long-term contracts.[32] In addition to satisfying their statewide obligations, CCAs strive to satisfy their local communities' preferences too. These local preferences drive CCA procurement and programs that stimulate local economic development, increase access to electricity-related technologies, and facilitate rate affordability and stability, while accelerating the State's progress towards its energy and climate goals.

To strike this balance between state mandates and local preferences, CCAs seek long-term procurement of electricity resources through feed-in-tariffs or open-season requests for offers that prioritize new, local resource development through long-term contracts. Presently, the active CCAs have committed to at least 29 long-term power

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[32] *See,* Appendix B.

purchase agreements for renewable generating resources (solar, wind, and biogas) ranging from 0.3 MW to 125 MW in project size.[33] The CCAs' focus on long-term development of new resources further diversifies the CCAs' portfolios and helps ensure a stable energy market.

Q: Would the high market price conditions that could stress CCAs affect other load serving entities?

A: Of course. In instances when market prices are high, all participants in the market—CCAs, IOUs, and ESPs— face the same burdens. How each would be ultimately affected would depend upon their respective portfolio management strategies, but none would be immune.

B. CCAs are Stable Entities That Hedge Against Market Fluctuations and Plan to Operate for the Long Term

Q: Please discuss the risk of market fluctuations to a CCA.

A: Market fluctuation presents risk from both downward and upward pressures. If the market price goes substantially lower, this could cause a CCA's portfolio to be significantly above market, meaning that it may have difficulty competing with the incumbent IOU's rates. This assumes that the IOU is not similar affected by the upward pressures. If the market price rises dramatically, the CCA could also have difficulty providing a cost-competitive service because any incremental procurement may be priced too high for the CCA's overall portfolio to remain cost-competitive. Market fluctuation is a risk faced by all LSEs, and CCAs follow industry best practices to mitigate this risk by implementing strategies to effectuate a well hedged procurement portfolio.

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[33] *See,* Appendix B.

Q: Please summarize the strategies CCAs use to protect against these risks.

A: CCAs have adopted numerous industry best practices to ensure they operate in a manner that does not expose their communities to adverse risks of market fluctuation.

First, CCAs manage their procurement portfolios and utilize other risk management practices to limit their exposure to market price fluctuations. Second, CCAs adhere to business and financial processes that ensure stability and accountability, including robust accounting and financial controls. These strategies are discussed below and summarized in fact sheets for each CCA (Appendix A).

1. CCAs Successfully Manage Their Portfolios and Utilize Various Risk Management Practices to Limit Risk

Q: How do CCAs' procurement practices protect against risk and failure?

A: CCAs employ a managed portfolio approach that commits to laddered procurement of renewable and greenhouse-gas free electricity supplies that often exceed the State's goals. CCAs also observe the State's preferred resources loading order, as well as long-term and integrated resource procurement to better serve existing load while allowing flexibility to serve new load.

Q: How does a managed portfolio approach help mitigate the risks of market fluctuation?

A: Managed portfolio practice entails sourcing the supply of the portfolio through a diverse mix of resources, including differences in: (i) resource technology types, (ii) contract durations, (iii) project size and location, (iv) production profiles, (v) counterparties, and

(vi) timing of market purchases.[34] The advantages of the portfolio management approach include limiting risks due to: (i) wholesale market fluctuations, (ii) future environmental regulations, (iii) fuel price and supply fluctuations, (iv) peak costs due to extreme weather, (v) system reliability and security, and (vi) market power.[35] CCAs using such portfolio management practices have less exposure to these market risks than other LSEs who do not employ such practices.

For example, MCE's Integrated Resources Plan states:

> MCE uses a portfolio risk management approach in its power purchasing program, seeking low cost supply as well as diversity among technologies, production profiles, project sizes and locations, counterparties, length of contract, and timing of market purchases. These factors are taken into consideration when MCE engages the market.
>
> MCE continually manages its forward load obligations and supply commitments with the objective of balancing cost stability and cost minimization, while leaving some flexibility to take advantage of market opportunities or technological improvements that may arise.[36]

CCAs further manage their portfolios by practicing laddered or segmented procurement.[37] A laddered approach is where the entity enters into contracts over multiple years, instead of all at once. A segmented approach is where the entity enters into contracts with varying durations so they do not all expire at the same time. As discussed, CCAs have begun entering into more long-term commitments. For example,

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[34] *See, for example,* Amy Roschelle and William Steinhurst, "Best Practices in Procurement of Default Electric Service: A Portfolio Management Approach," *The Electricity Journal* 17, no. 8 (October 2004): 63–69, doi:10.1016/j.tej.2004.07.009.
[35] *Ibid.* at 63-64.
[36] "MCE-2017-Integrated-Resource-Plan.pdf," accessed June 30, 2017, https://www.mcecleanenergy.org/wp-content/uploads/2017/07/MCE-2017-Integrated-Resource-Plan-Rev2017.04.07.pdf. at 21.
[37] *Ibid.* at 7.

MCE, SCPA, and LCE have all entered into contracts with durations lasting up to 25 years. These long-term contracts for renewable electricity vary by start dates and generating resource technology types.[38] By managing their procurement in these ways, CCAs mitigate their exposure due to market volatility and increases in non-bypassable charges.

Q: Do CCA-managed portfolios have a preference for renewable or greenhouse gas-free electricity procurement?

A: Yes, all CCAs formed in California to-date have a heightened preference for sourcing their electricity from renewable and greenhouse gas-free sources and long-term procurement.[39]

Q: Does a preference for renewable or greenhouse gas-free electricity procurement help mitigate the risks of market fluctuation?

A: Historically, California electricity prices have fluctuated due to: (i) fluctuations in cost of fuel (*e.g.* natural gas), (ii) reductions in hydroelectric generation output due to drought, (iii) impacts of regulatory changes (*e.g.* creation of the RPS causing a premium cost for renewable generation, or generation plant retirements due to environmental regulations such as the Once Through Cooling (OTC) requirement), and (iv) overloading of transmission and distribution grid infrastructure (*i.e*. transmission constraints). All four of these risks can be mitigated by operating cleaner and more efficient electricity resource portfolios.[40]

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[38] *See,* Appendix B**.**
[39] *See,* Appendix A.
[40] *See,* Woolf et al., "Managing Electric Industry Risk with Clean and Efficient Resources."

While all RPS-compliant LSEs mitigate these risks to a certain degree, to date, nearly all CCAs have exceeded their RPS obligations and have a greater percentage of renewable generation than their incumbent IOU.[41] Because CCA generation portfolios collectively depend far less on natural gas and nuclear generation than the IOUs, CCAs are less exposed to these risks. By incorporating greater amounts of renewable generation into their portfolios, CCAs will also most likely experience lesser fluctuations in portfolio cost due to gas price fluctuations, increasing costs due to tighter environmental regulations, or reduced hydro production due to drought.

Q: Please discuss how CCA risk management practices help mitigate the risks of rate fluctuation.

A: CCAs have varying types of practices to manage risk. Many of the CCAs, like SCPA for example, use modeling to simulate potential portfolio costs under varying circumstances.[42] Similarly, RCE performs monthly simulated "stress tests" on its portfolio to simulate adverse conditions and resulting outcomes.[43] MCE has purchased insurance policies "from investment grade commercial carriers to mitigate risks that include those associated with earthquakes, theft, general liability, errors and omissions, and property damage."[44] The SFPUC also includes CPSF in its broader Enterprise Risk

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[41] *See,* Appendix B.
[42] *See,* Financial Policy C.1 within "Sonoma Clean Power Authority Board Policies." accessed June 28 2017, https://sonomacleanpower.org/wp-content/uploads/2015/01/Revised-Board-Policies-amended-2015.12.03.pdf
[43] *See,* "Redwood Coast Energy Authority Meeting Agenda," accessed July 14, 2017, http://www.redwoodenergy.org/images/PDFs/Board_Meetings/2016/RCEA-December-12-2016-Board-Packet-Web.pdf at 6
[44] *See,* "Financial Statements Years Ended March 31, 2016 & 2015 with Independent Auditors' Report," accessed June 28, 2017, https://www.mcecleanenergy.org/wp-content/uploads/2016/09/MCE-Audited-Financial-Statements-2015-2016.pdf at 19.

Management framework, which tracks and identifies agency risks, determines appropriate mitigating actions, and allows for prudent strategic risk taking.[45] This policy helped inform a decision to implement CPSF in phases.

Q: What conclusions can you draw about how CCAs manage the risk of rate fluctuation?

A: CCAs utilize utility best practices to manage the risk of rate fluctuation by managing their portfolios and utilizing myriad risk management practices. Thus, a CCA should successfully be able to hedge against the risk of rate fluctuations, which in turn should help ensure that a CCA does not fail.

2. CCAs Adhere to Business and Financial Processes That Ensure Stability and Accountability

Q: Please discuss CCA budgeting practices and how they ensure stability and accountability.

A: CCAs typically operate on an annualized, rigorous, and transparent budget cycle. Each CCA staff prepares the CCA's budget and presents it to the CCA's governing board at public meetings that are noticed to the general public in advance. Often the budgeting process coincides with the CCA's rate setting process which is also noticed substantially in advance of the public board meeting where the rate adjustments can be voted on.

To take one example of rigor and transparency of a CCA's budget cycle, CPSF sets its budget biennially as part of the City and County of San Francisco's budgeting

[45] *See,* "Comprehensive Annual Financial Report," accessed June 28, 2017, http://sfwater.org/modules/showdocument.aspx?documentid=9978 at 14.

process which entails review and approval by the SFPUC and the Board of Supervisors in numerous public hearings.[46] This coincides with the City of San Francisco's bi-annual budgeting process. The SFPUC prepares quarterly budget status reports to ensure that costs are within the approved budget and that the SFPUC is within all required reserve and other financial policies. These quarterly status reports are reviewed by the SFPUC Commission in a public and noticed meeting. These reports help to ensure that CPSF meets its Charter obligation to keep revenues at a level that covers expenditures on an on-going basis. CPSF contracts are also subject to the City's requirements for City Controller certification that sufficient revenues will be available to meet CPSF's obligations under each contract.

Q: Please discuss CCA financial controls and how they ensure stability and accountability.

A: Active CCAs have annual financial statements audited by a third party and released publicly.[47] Releasing the financial statements publicly, including independent audits, provides additional layers of transparency and accountability.

For example, as required by its Joint Powers Agreement, SCPA implemented a Community Advisory Committee "to review and comment upon proposals for new programs, policies, or significant operational changes proposed by the Chief Executive Officer for the CCA program."[48] This committee meets bi-monthly to address areas of

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[46] City Charter, § 9.101. The budget submitted to the Board of Supervisors for approval must be balanced for each fiscal year such that the proposed annual expenditures of each fund does not exceed the estimated annual revenues for that fund.
[47] *See, for example*, MCE, SCPA, and CPSF all issue annual financial reports that are independently audited, presented to the CCAs' boards during publicly noticed meetings, and ultimately made available for public review.
[48] Sonoma Clean Power Authority Third Amended and Restated Joint Powers Agreement §4.5.2.2, https://sonomacleanpower.org/wp-content/uploads/2015/01/Third-Amended-JPA-Final-Version-Approved-10-13-16.pdf.

budgeting, management, power generation, power sales and marketing, customer programs, and rate-setting. Notably, SCPA's annual budget and rates must be presented to the Committee for review and comment before they can be presented to the Board of Directors for final approval. The Committee also has a limited independent budget to conduct its own investigations or studies, and can place matters on the Board of Directors' agenda without SCPA staff approval.[49] In practice the Committee has provided another venue for public participation in, and has acted as another set of "eyes" in the review of, all SCPA activities. SCPA's Joint Powers Agreement also requires an annual independent audit of its financial transactions by an external auditor.[50] Finally, SCPA's Board has adopted several administrative policies relating to contracting, power procurement, and budget reserves.

Similarly, the SFPUC, as the operator of CPSF, prepares annual audited financial statements and a Comprehensive Annual Financial Report for all its enterprises including CPSF. All financial reports comply with the Government Accounting Standards Board standards for public agencies. The SFPUC is also required by the San Francisco Charter to hold annual public hearings to review, update, and adopt ten (10) year financial plans and long-term strategic plans.[51]

Q: Please summarize your view of how CCA budgeting and financial controls help mitigate the risk of market fluctuation and increasing non-bypassable charges.

A: These processes allow for stable pricing, so that the CCA is not harmed by unexpected large spikes in power or in non-bypassable charges. The accountability of the CCA

[49] *Ibid.*, Sections 4.7.2.1 and 4.7.2.3.
[50] *Ibid.*, Section 4.9.3.
[51] City and County of San Francisco City Charter, § 8B.123.

management to the CCA Board and the CCA Board members to their city councils and communities is established and maintained by the transparency of management decisions and operations.

Q: Why does being an accountable public agency mitigate the risks of market fluctuation for a CCA?

A: Because CCAs are not-for-profit, public agencies, they are held to mandates for decision-making that do not apply to private entities such as IOUs and ESPs. For example, CCA budgeting, rate-setting, and other key decision-making processes are transparent and made through publicly noticed meetings in accordance with the requirements of California's Brown Act.[52] CCAs must also comply with California's Public Records Act.[53] In addition, the CCAs are governed by elected or appointed public officials who are directly accountable to the constituents they serve.

In sum, CCAs are held to a comparable level of transparency and accountability as other California public agencies such as city councils or regulatory agencies like the Commission. This means CCAs must operate in a transparent and, more importantly, a risk-averse manner. Thus, a stable, accountable and accordingly risk-averse CCA will be highly focused on mitigating the risks associated with market fluctuation.

C. CCA Rates Will Remain Competitive to IOU Generation Rates

Q: Please discuss how CCAs set their rates and remain competitive to the IOUs.

A: CCA rate setting processes generally coincide with each CCA's individual budget cycles, which are typically annual. CCAs try to minimize customer confusion by limiting their

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[52] *See,* California Government Code Section 54950 et seq.
[53] *See,* California Government Code §§ 6250 through 6276.48.

rate adjustments to once a year. CCAs balance their goals of providing customers with cleaner, higher renewable content electricity, and making rates affordable. Most CCAs try to keep their customers' overall bill close to the cost of comparable service under the incumbent IOU's bundled electricity rates.

Some CCAs also have rate setting obligations specified by their policy makers or constituents that further assist with ensuring that CCA rates remain competitive. For CPSF, the SF Charter (a document approved by voters) requires the SFPUC to adopt cost-of service rates, and:

> establish rates, fees, and charges at levels sufficient to improve or maintain financial condition and bond ratings at or above levels equivalent to highly rated utilities of each enterprise under its jurisdiction, meet requirements and covenants under all bond resolutions and indentures ... and provide sufficient resources for the continued financial health (including appropriate reserves), operations, maintenance and repair of each enterprise, consistent with good utility practice[.][54]

CPSF is also obligated to review its rates annually,[55] conduct an independent rate study once every five years,[56] and comply with the SFPUC's rate setting principles of affordability, compliance, sufficiency, and transparency.[57] Presently, the rates for CPSF's Green[58] and SuperGreen[59] products are slightly lower than PG&E's costs for generation service.

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[54] City Charter §8B.125.
[55] Resolution 15-0268.
[56] City Charter §8B.125.
[57] "SFPUC Rates Policy" accessed July 25, 2017, http://www.sfwater.org/modules/showdocument.aspx?documentid=3236 at 1.
[58] *N.b.* "Green" is CPSF's default product and has a targeted renewable content of between 33 and 50% RPS, currently at 40% Product Content Category (PCC) 1,[58] and CPSF's optional premium product "SuperGreen" is 100% renewable electricity. *See* "San Francisco Public Utilities Commission : Green," accessed July 14, 2017, http://sfwater.org/index.aspx?page=960.
[59] *N.b.* "SuperGreen" is CPSF's premium "opt-up" product with 100% renewable electricity. *See* "San Francisco Public Utilities Commission : SuperGreen," accessed July 14, 2017, http://sfwater.org/index.aspx?page=961.

Q: Do CCAs have advisory boards that help ensure rates remain competitive?

A: Yes. SCPA, for example, has implemented a Community Advisory Committee. This committee consists of seven to eleven non-board members who are customers, and who represent both residential and commercial/industrial customers. Under SCPA's Joint Powers Agreement, the annual budget and rates must be first presented to the Committee for review and comment before they can be presented to the Board of Directors. In line with the CCA's goals of serving localities, the Rate Payer Advisory Committee takes into account customer input during the rate setting process.[60]

Similarly, CPSF's rates are subject to review by the San Francisco Rate Fairness Board. The Rate Fairness Board is an advisory group of ratepayers and City financial officers created under the voter-approved Proposition E (2002) to ensure rate stability, fairness and affordability.[61] The Rate Fairness Board holds an annual review of five-year rate forecasts and reports such reviews to the SFPUC for consideration.

Q: What other tools do CCAs have at their disposal to remain competitive with IOUs?

A: CCA reserves and rate stabilization funds are important tools that CCAs can use to remain competitive with the IOUs. A rate stabilization fund is a set-aside of a CCA's overall operational reserves dedicated exclusively for offsetting future revenue requirements so that the CCA's generation rates can be kept stable and competitive with the incumbent IOU's rates. Establishing reserves or rate stabilization funds allows the

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[60] Sonoma Clean Power Authority Third Amended and Restated Joint Powers Agreement §4.5.2.2, https://sonomacleanpower.org/wp-content/uploads/2015/01/Third-Amended-JPA-Final-Version-Approved-10-13-16.pdf.

[61] "Rate Fairness Board," accessed July 18, 2017, http://www.sfwater.org/index.aspx?page=120

CCA to maintain competitive rates during wholesale power price deviations and increases to non-bypassable charges, including the PCIA in particular. Because CCAs typically aim to reserve a portion of their operational costs in such reserves,[62] it would likely take several years of upward market conditions to exhaust any such reserve or rate stabilization fund. Only after the CCA's reserve and/or rate stabilization fund was exhausted and the CCA was otherwise unable to meet its costs, would the CCA's rates no longer be competitive with the incumbent IOU's generation service rates.

Q: Please explain how CCA's operate their reserves/rate stabilization funds.

A: Pursuant to CCA policy objectives, CCAs can set aside excess revenues as cash reserves in rate stabilization funds.[63] CCA operations are different than IOUs in that rather than paying income taxes and returns to shareholders, CCAs can set aside reserve funds as part of their overall risk management strategy and ensure that they remain competitive with the IOUs. While each CCA has a slightly different approach to how they handle their reserves and/or rate-stabilization funds, all CCAs leverage their reserves to mitigate their exposure to risks due to market fluctuation, increases in costs, including increases in non-bypassable charges.

MCE "provide[s] a reserve to manage the risk of adverse economic or regulatory events, and to improve its credit worthiness." [64] SCPA ensures that "[a]ny remaining surplus shall be divided 50/50 between early principal payment of outstanding debt or

[62] *See* Appendix A.
[63] *See* Appendix A.
[64] *See* " Financial Statements Years Ended March 31, 2016 & 2015 with Independent Auditors' Report," accessed July 11, 2017, https://www.mcecleanenergy.org/wp-content/uploads/2016/09/MCE-Audited-Financial-Statements-2015-2016.pdf. at 6.

rate reductions, and contribution to a Project Fund to support local renewable energy projects, energy efficiency and other projects consistent with SCP's mission."[65] PCE operates with a large rate stabilization reserve, $4.4 million in 2017, with plans to allocate between $10-12 million in 2018-2021 for rate stabilization.[66] For Fiscal Year 2017-2018 CPSF reserves are projected to be $4.5 million and at full program roll-out to all customers within San Francisco, the Operating Reserve will be approximately $50 million and the Contingency/Rate Stabilization Reserve will be approximately $45 million.[67]

As the CCAs continue to operate, these reserves will continue to grow and allow them to protect against future risks and remain competitive with the IOUs.

Q: How does the current form of the PCIA actually serve to ensure that a CCA can remain competitive with an IOU even if market prices rise?

A: As market prices rise, PCIA rates should come down because PCIA rates are inversely linked to market rates. The PCIA is a mechanism for recovering the *above market* costs within an IOU's total portfolio that are stranded due to load departing from the IOU's electricity generation services. As market prices rise, the *above market* portion of the IOU's total portfolios will diminish. Even as market prices rise, the decreasing non-bypassable costs borne by CCAs should partially mitigate the market increases.

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[65] *See,* Financial Policy B.2 within "Sonoma Clean Power Authority Board Policies," accessed July 14, 2017, https://sonomacleanpower.org/wp-content/uploads/2015/01/Revised-Board-Policies-amended-2015.12.03.pdf.
[66] *See,* "Peninsula Clean Energy JPA Board Correspondence," accessed July 14, 2017, https://www.peninsulacleanenergy.com/wp-content/uploads/2016/03/PCE-Budget-FY-16-17-All-Items.pdf.
[67] *See*, SFPUC May 9, 2017 Agenda, Item 5a, Appendix A-8.. http://sfwater.org/modules/showdocument.aspx?documentid=10719

D. CCA Customers Are Likely to Remain CCA Customers

Q: How have CCA customers reacted when CCAs rates have increased above the rates of the incumbent IOUs?

A: In the event that CCA rates rise above the rates of the incumbent IOUs, CCA customers may voluntarily return to bundled IOU service. However, while there have been short periods when CCA rates have modestly exceeded the IOU's rates, customer opt-outs have remained low.

Q: How can you predict if CCA customers are likely to remain CCA customers in a stressed environment?

A: As noted, it would be very difficult to predict, but there have been several instances when CCA rates have exceeded that of the incumbent IOU but the CCA has not experienced increased customer attrition. For example, MCE has periodically been more expensive than PG&E service, but has not seen a significant shift in customer participation as a result. The largest recent example of higher rates was in 2016, when there was a significant increase to the PCIA accompanied by a decrease to PG&E generation rates. These factors pushed the typical MCE residential customer's bill to an approximately $4/month premium relative to PG&E bundled service. During the nine-month period that this variance continued, MCE's opt-out rate increased by only 0.09%. Even this increase in opt-outs can be attributed to the stabilization period for MCE's recent enrollments of unincorporated Napa County, Benicia, El Cerrito, and San Pablo. During this same time, MCE's opt-out rate in its existing service territories (Richmond and Marin County) actually ***decreased*** by 0.10%.

One can rationally infer from this that modestly higher CCA rates, such was the case with MCE in 2016, are still "competitive" with the incumbent IOU. Thus, simply not "beating" the IOU rate will not result customer attrition or CCA failure.

Q: Are there other considerations that could impact the analysis?

A: Yes. Examining the overall health and risk management strategies of CCAs would help to determine whether CCAs would be able to remain viable in the face of these risks. The testimony above addresses the many ways that CCAs are well positioned to do so.

One additional way to evaluate whether these strategies are sufficient to withstand these risks would be to look at how other public entities fared during a stressed environment. If the public entity fared well during that stressed environment, it would suggest that a CCA entity would similarly fare well and indicate that CCAs could keep their rates competitive.

Q: How did other public entities in California fare during the 2000-2001 California energy crisis?

A: Overall, they fared well. While some municipal utilities were forced to raise rates, none had to declare bankruptcy or implement long-term rate elements like PG&E's Energy Cost Recovery Amount (ERCA), SCE's Historic Procurement Charge (HPC), or the DWR Bond Charge. For Example, Modesto Irrigation District was forced to implement two tiered increases: 9.5% in January 2001 and another 5% increase in January 2002. Before this increase, MID had not raised rates in six years.[68]

The Sacramento Municipal Utility District (SMUD), on the other hand, decided not to pass its higher energy costs onto its customers. SMUD could do this in part,

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[68] "Regional Roundup" in California Energy Markets No. 596 December 8, 2000 at 14.

because of contracts it signed for half of its natural gas price needs through March 2001. In other words, it had appropriately hedged its primary fuel cost. SMUD also owned space on the interstate natural gas pipeline network which helped it alleviate costs.[69]

Some municipalities even lowered their rates during the Energy Crisis, like Alameda Power and Telecom and Silicon Valley Power.[70] According to Zane Mann, publisher of the California Municipal Bond Advisor "The LA Department of Water and Power (LADWP) was making $200M a year selling [its] power to people who needed it more than they did.".[71]

The municipal utility in Redding fared well too, having invested in capital improvements and new power generation a few years prior to the energy crisis. Though some 40,000 of its customers' bills were boosted 23% to pay for these investments, they, along with its long-term power contracts, resulted in Redding consuming less electricity than it generated. As a consequence, Redding was able to sell roughly $8 million worth of electricity to other customers in Arizona, Nevada, Washington, and California. It was also able to sell at the wholesale rate, between 16-25 cents/kWh to further help pay down its investment-incurred debts. While Redding's customers saw a rate increase, it was less extreme than those endured by customers in San Diego, who witnessed rate spikes

[69] "SMUD Board Approves Budget" in California Energy Markets No. 597 December 15, 2000 at 2

[70] "Municipal Utilities, Customers Shielded From State's Energy Crisis," San Francisco Chronicle, January 5, 2001. Accessed July 12, 2017, http://www.sfgate.com/business/networth/article/Municipal-Utilities-Customers-Shielded-From-2969046.php

[71] "Municipal Utilities, Customers Shielded From State's Energy Crisis," San Francisco Chronicle, January 5, 2001. Accessed July 12, 2017, http://www.sfgate.com/business/networth/article/Municipal-Utilities-Customers-Shielded-From-2969046.php

upwards of 200%.[72] The gap between the IOU rates and those of municipal utilities was further highlighted in January 2001 when the Commission approved rate increases for the IOUs.

All told, "Wall Street seem[ed] to like the munis," with Standard & Poor noting that the municipal utilities "continue[d] to meet the goals of their competitive business strategies, while pressure [was] mounting on the investor owned utilities."[73]

V. <u>IN THE UNLIKELY EVENT THAT A CCA FAILS, IT WILL NOT HAPPEN OVERNIGHT</u>

Q: Why will a CCA not suddenly fail, causing an unexpected involuntary return of CCA customers to a CCA?

A: Importantly, for the involuntary return of CCA customers to an IOU, all the conditions described in Section IV would need to persist for an extended period of time, most likely several years. Absent that unlikely confluence of events, these conditions would not result in a CCA suddenly and dramatically shuttering overnight and dumping its customers on to the IOU. Instead, these conditions would cause a slow decline that could ultimately cause a CCA to fail but provides ample advanced warning to the public, its customers, the Commission, and the incumbent IOU.

Q: Describe the warning signs that would accompany such a slow failure.

A: Since the scenario described in the previous section has not yet taken place, one can only speculate as to what the warning signs might be. One indicator could be ratepayer

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[72] "Publicly Owned Utility Prospers, With Energy To Spare For Others," San Diego Union-Tribune, October 9, 2000. Accessed July 10, 2017 as part of California Energy Market Clips No. 598

[73] *Ibid.*

migration. It is not clear whether this would occur quickly or slowly, as it would depend on individual ratepayer preferences. But in that event, CCA customers returning to IOU bundled service would be subject to the IOU's switching rules, including notice requirements and payment of Transitional Bundled Service (TBS) Rates, if applicable.[74]

There would also be warning signs from several years of public meetings and related public discussion showing the CCA struggling to maintain competitive rates. Agenda items such as requests to borrow from the reserve funds to offset rate requirements would be plainly visible.

Q: In this unlikely hypothetical scenario, are there existing tariffs in place to address CCA failure?

A: Yes. A CCA that determines it is no longer viable may initiate voluntary termination under the existing CCA tariffs. These tariffs require a one year advanced notice.[75] Furthermore, because CCAs are risk averse, public entities with strong ties to the local governments of the communities served by the CCAs, it is in a CCA's interest to facilitate an orderly transition if failure seems likely.

Only customers remaining with the CCA to the very end would ultimately be forced to involuntarily return to the IOU's bundled electricity service. The FSR would only be necessary to cover the incremental costs of these last customers.

[74] PG&E Electric Rule 23, § L
[75] PG&E Rule 23 §S.

VI. GIVEN THE LOW LIKELIHOOD OF FAILURE, THE REENTRY FEES DEEMED NECESSARY FOR THE FSR SHOULD ONLY INCLUDE THE ESTIMATED INCREMENTAL ADMINISTRATIVE COSTS OF REINTEGRATING INVOLUNTARILY RETURNED CCA CUSTOMERS

Q: What costs should the Commission deem necessary to be included in a CCA FSR?

A: Under Section 394.25(e), the Commission should only deem the incremental administrative costs associated involuntarily returning customers to bundled service as being necessary at this time. As noted above, the FSR must cover potential "reentry fees" that the IOU would face if a CCA involuntarily returns its customers to bundled service outside of the proscribed provisions of a voluntary termination of CCA service.[76] In practice, such administrative costs would likely include the incremental cost of IOU staff time and materials to facilitate the communication, outreach, billing, and other services necessary to handle such an involuntary return of customers.

Q: Are there costs that the Commission should not deem necessary to be included in a CCA FSR?

A: Yes, the CCA FSR need not include the hypothetical and highly speculative costs intended to cover the projected incremental procurement costs for the IOU to serve the involuntarily returned CCA customers for the following reasons. *First*, it would not be clear in advance exactly how many customers would remain with the CCA at the time of failure, or what the market conditions would be at the actual time of failure. *Second,* a hypothetical price spike would create risks, but given the institutional actions that would occur before failure (rate changes, reserve fund draw-downs, *etc.*) the price spike could pass without incident. *Third*, the marginal cost to serve the customer (*i.e.*, market prices)

[76] *See* Rule 23, Section S of IOU tariffs.

would have to exceed the retail rates over an extended period for a procurement-related FSR to be appropriate. As such, attempting to include a procurement-rated element in the CCA FSR is both highly speculative and unwarranted.

Q: Are there other considerations that should impact the determination of the CCA FSR?

A: Yes. The Commission should consider the operational impact of carrying an FSR. Given the low risk of sudden CCA failure, the Commission should not burden CCAs with unnecessarily high financial obligations which could be a barrier to entry for new CCAs and an unnecessary burden on existing CCAs' day to day operations.

Q: How should the Commission incorporate this low likelihood of CCA failure into the CCA FSR?

A: Given how uncertain and unlikely it is that the market conditions coinciding with an involuntary termination might manifest, the Commission should not consider the potential magnitude of costs to establish the CCA FSR in isolation. Any consideration of the CCA FSR costs should also be tempered by a consideration of the likelihood of occurrence.

Q: How should the CCA FSR be calculated?

A: Since the only cost that can be deemed necessary at this time is the projected administrative costs of re-integrating CCA customers into IOU bundled service, the CCA FSR should be based upon an estimated cost per customer multiplied by the number of customers. Like many of the tariffed CCA-related fees that the IOUs charge CCAs, the FSR should include a fixed amount plus a per-customer amount that is multiplied by the number of customers.

Q: What do you propose for these fees?

A: The FSR should be set at the tariffed CCA Mass Enrollment Fee plus an estimate of the number of customers being switched over to bundled service multiplied by the tariffed CCASR Fee. The proposed elements are summarized in Table 1, below.

Table 1. Proposed Elements of the CCA FSR

Utility	Mass Enrollment Fee	CCASR Fee
PG&E[77]	$4,475	$0.79/acct.
SCE[78]	$3,041 + $0.13/acct.	$0.98/acct.
SDG&E[79]	$3,600	$1.12/acct.

Q What is the basis for your recommendation fees?

A: The FSR should be based on easily calculated and verified values while reflecting a reasonable estimate of the costs to return the customers to bundled service. The Mass Enrollment fee reflects the cost of the transfer of many accounts from bundled to CCA service. I find it reasonable to assume that the costs an analogous mass switch from CCA to bundled service would be similar. However, due to the unexpected nature of the switch, the simple mass enrollment fee would likely not be sufficient, nor reflect any economies of scale of switching many accounts relative to just a few. Therefore, including a per-customer variable element in the FSR calculation—the CCASR estimated fee—will reflect an amount to cover the variable per-customer costs in setting the CCA FSR.

[77] PG&E Schedule E-CCA, Sections 3 and 5a.
[78] SCE Schedule CCA-SF, Sections C and E.1.
[79] SDG&E Schedule CCA, Sheet 2.

Q: Why is it appropriate to use the *estimated* number of returning customers?

A: As discussed earlier, a failure of a CCA is not likely to occur without warning or without CCA Board actions. A CCA Board may significantly raise rates to cover its costs, which in turn would likely result in some number of customers voluntarily returning to bundled utility service. To reflect this likelihood, in calculating the per-customer element of the FSR, the actual number of customers should be multiplied by a value less than one to reflect this likelihood. Since there is no historical data to use to precisely estimate this factor. I recommend using a value between 0.6 and 0.8; to assume a factor of 1.0 is the same as assuming that no customers would voluntarily leave a struggling CCA prior to failure, which I do not find to be reasonable.

Q: For the ESP FSR, the administrative cost per customer is set at the tariffed rate for voluntarily returned CCA accounts. Why is that not applicable here?

A: As noted in D.11-12-018, the Commission set the administrative-related portion of the ESP FRS equal to the number of returned customers multiplied by the default CCA Voluntary Return Fee. However, as the Commission noted, there was no specific rationale for this value, as nothing was offered in evidence:

> Parties offered no specific dollar estimate of the administrative costs necessary to process involuntarily returned DA customers, and no Commission approved cost figure has previously been adopted. To determine the incremental administrative costs to use for purposes of an ESP security bond, we shall thus adopt use of the re-entry fee approved for a CCA customer, as proposed by SCE.[80]

Furthermore, this voluntary return fee reflects the cost of a one-off transaction. The CCA FRS is intended to address the re-entry fees when customers are transferred *en*

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[80] D.11-12-018 at 70-71.

masse, not a series of one-off transfers. As such, the IOU's CCA mass enrollment fees—a large-scale transfer of customers—better reflect the actual administrative costs that an IOU would face in the event of a mass return of CCA customers.

Q: How often should the CCA FSR be recalculated?

A: It should be calculated upon the CCA's initiation of service, and reviewed annually. If the re-calculated FSR is within 15% of the FSR in place, no change would be made. If the re-calculated FSR differs from the FSR in place by more than 15%, then the re-calculated value would take effect.

Q: Who should calculate the CCA FSR?

A: The CCA should calculate the FSR amount. The FSR calculation should be made via an advice letter to the Commission Energy Division and noticed to the incumbent IOU after submission to the Commission. If the IOU disputes the calculation, it could protest the advice letter. Given that the proposed calculation is straightforward and uses published tariffs and data available to both the CCA and IOU, I cannot see that disputes concerning the FSR would be common. The FSR would then be posted within 45 days of the Energy Division disposition of the advice letter.

Q: Would the FSR need to be adjusted when a new community or phased-in tranche joins a CCA?

A: If a CCA is not adding new communities or offering service to a new tranche of customers from an existing community, the underlying values (cost per customer or number of customers) should not change dramatically from year-to-year. Thus, a simple annual true-up should be sufficient. If the CCA is taking an action, such as beginning service to a new community, which causes its customer count to change by 15% or more, then the FSR should be re-calculated and reposted.

Q: How should a CCA be able to meet the financial security requirement?

A: In general, CCAs should be allowed maximum flexibility as to how they can meet the FSR. A CCA should be able to meet its FSR through such mechanisms as cash on-hand via rate stabilization funds and reserves, a guarantee from a creditworthy entity, a surety bond, or a letter of credit. This is consistent with the ESP FSR; Decision 11-12-018 which states:

> We conclude that an ESP may satisfy the requirements of § 394.25(e) by posting a bond or demonstrating insurance sufficient to pay cover re-entry fees of the ESP, through comparable financial instruments that provide equivalent coverage. Acceptable instruments include surety bonds, letters of credit, cash deposits or third party guarantees with a credit worthy entity.[81]

When the Commission considered how the ESP could meet the FSR it was primarily focused on counterparty risk. That is, the Commission ensured that whatever instrument the ESP used, the counterparty who would have to provide the re-entry fees in the event of an ESP failure needed to be creditworthy.[82] The Commission found that "[t]hird party guarantors should at least have investment grade credit. The essential requirement is that whatever instruments are used, the requisite re-entry fee obligations are covered;"[83] and "An agreement with a creditworthy third party who will guarantee the ESP's financial obligation in the event the ESP cannot do so (a guarantee agreement) would also meet § 394.25(e) requirements."[84]

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[81] D.11-12-018 at 75.
[82] D.11-12-018 at 73-76.
[83] *Ibid.* at 75.
[84] *Ibid.* at 76.

The Commission should apply the following similar considerations to the CCA FSR: as long as the mechanism is liquid or provided by a creditworthy party, it should be sufficient for meeting the CCA FSR.

Q: If a CCA program already has cash set aside in rate stabilization funds and reserve accounts that is at or above the scale of the FSR, then is it necessary for the CCA to provide any additional showing to satisfy their FSR?

A: If a CCA program has a cash balance within its rate stabilization fund that meets or exceeds the scale of the CCA FSR ultimately deemed necessary by the Commission, the CCA should have the choice to leverage that cash balance to satisfy the CCA's FSR requirement. No further showing or financial instrument should be required of the CCA. If the CCA program has a cash balance within its rate stabilization fund that is less than the CCA FSR requirement the Commission deems necessary, then the CCA should still have the choice to leverage some or all of its cash balance to satisfy a portion of the CCA's FSR. If there is a difference between the FSR amount and the portion of the CCA's cash reserves that the CCA wishes to count towards its FSR, then the CCA would submit an Advice Letter to make a showing via another financial instrument to cover this difference so that the CCA's FSR is fully met. In other words, if the CCA elects to leverage its cash reserves to satisfy its FSR, then these cash reserves should count first towards the CCA's FSR. If the cash reserve falls below the FSR amount, then the CCA would need to make up the shortfall using some other means.

Q: Does this conclude your testimony?

A: Yes

Docket No.: R. 03-10-003
Exhibit No.: (MCE-1)
Date: July 28, 2017
Witness: David McNeil

OPENING TESTIMONY OF MARIN CLEAN ENERGY
REGARDING IMPLEMENTATION OF PUBLIC UTILITIES CODE SECTION 394.25(E)

TABLE OF CONTENTS

I. INTRODUCTION

Marin Clean Energy ("MCE") began serving customers in 2010 as the first operating Community Choice Aggregator ("CCA") in California. MCE is currently the default electricity provider in its service area. MCE currently serves 264,000 customers representing 83% of eligible customers. MCE's service area includes the entirety of Marin and Napa Counties and the cities of Benicia, El Cerrito, Lafayette, Richmond, San Pablo, and Walnut Creek.

In this testimony, MCE articulates a method to satisfy the requirements of California Public Utilities Code Section 394.25(e) without requiring a collateral posting. MCE recommends that the California Public Utilities Commission ("Commission") incorporate the use of a Credit Rating Screen that relies on credit ratings published by Moody's Investors Service ("Moody's") or S&P Global Ratings ("Standard and Poor's") in the determination of the collateral posting amounts required of CCAs. Specifically, MCE recommends that CCAs that maintain a long term, issuer or issue credit rating of Baa3 or better from Moody's or BBB- or better from Standard and Poor's (commonly known as an "investment grade credit rating") should be deemed to be adequately self-insured and exempted from any additional requirement to post collateral.

II. BACKGROUND ON CREDIT RATING AGENCIES AND CCAS

Moody's and Standard and Poor's are both major credit rating agencies. Their primary function is to evaluate the creditworthiness of entities in various industries and markets. Their determinations of creditworthiness are indicated with a range of credit ratings and are used in commercial transactions as reliable indicators of the risk of default.

These agencies are experienced with rating participants in electricity markets globally. Appendices C-E to this testimony are three sets of rating methodologies developed by Moody's to evaluate different sectors within electricity markets.[1] These methodologies examine different factors depending on the sector:

> **Regulated Electric and Gas Networks Factors:** (1) Regulatory Environment and Asset Ownership Model; (2) Scale and Complexity of Capital Program; (3) Financial Policy; (4) Leverage and Coverage; and (5) Structural Consideration and Sources of Rating Uplift From Creditor Protection.[2]
>
> **Unregulated Utilities and Unregulated Power Companies Factors:** (1) Scale; (2) Business Profile; (3) Financial Policy; and (4) Leverage and Coverage.[3]
>
> **US Public Power Electric Utilities With Generation Ownership Exposure:** (1) Cost Recovery Framework Within Service Territory; (2) Willingness and Ability to Recover Costs with Sound Financial Metrics; (3) Generation and Power Procurement Risk Exposure; (4) Competitiveness; (5) Financial Strength and Liquidity; (6) Operational Considerations; (7) Debt Structure and Reserves; and (8) Revenue Stability and Diversity.[4]

Appendix F is the rating criteria developed by Standard and Poor's to evaluate regulated utilities[5] and considers numerous factors related to business risks,[6] financial risks,[7] and other rating modifiers.[8]

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[1] See Appendix C: Moody's Rating Methodology: Regulated Electric and Gas Networks; Appendix D: Moody's Ratings Methodology: Unregulated Utilities and Unregulated Power Companies; and Appendix E: Moody's Ratings Methodology: US Public Power Electric Utilities.

[2] Appendix C at p. 2.

[3] Appendix D at p. 2.

[4] Appendix E at p. 2.

[5] This is one of the twelve criteria used to evaluate Pacific Gas & Electric Corporation in a change to their credit rating that took place on May 12, 2017.

[6] Appendix F: Standard and Poor's Rating Methodology: Key Credit Factors For The Regulated Utilities Industry at p. 1-4.

In the California energy markets, Moody's and Standard and Poor's rate major market participants, including Pacific Gas & Electric Company ("PG&E"), San Diego Gas and Electric ("SDG&E"), and Southern California Edison ("SCE"). They also rate the financial instruments of major municipal utilities, such as Sacramento Municipal Utility District ("SMUD") and the Los Angeles Department of Water and Power ("LADWP").

Rating scales and types vary between the rating agencies. A long term issuer credit rating is a forward-looking opinion about an entity's overall creditworthiness.[9] A long term issue credit rating is associated with a specific financial obligation, class of obligations, or financial program.[10] For example, a municipal entity may issue bonds and those bonds may have an issue credit rating that is separate and distinct from the municipal entity's issuer credit rating.

Both Moody's[11] and Standard and Poor's[12] utilize 20 rating levels for long term, issuer or issue ratings. Standard and Poor's characterizes entities with a BBB rating as having "adequate capacity to meet its financial commitments."[13] Baa3 (Moody's) and BBB- (Standard and Poor's) or better long term issuer or issue ratings are generally considered by financial and energy market participants to be "investment grade" ratings correlated with low rates of default. The lowest rating for Moody's (*i.e.* C)[14] and Standard and Poor's (*i.e.* D)[15] indicate the rated entity is in default of their financial obligations. There are 10 long term ratings below "investment grade"

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[7] Appendix F at p. 4-6.
[8] Appendix F at p. 6-7.
[9] Appendix G: Moody's Rating Symbols and Definitions at p. 8; Appendix H: Standard and Poor's Rating Definitions at p. 5-6.
[10] *See e.g.* Appendix H at p. 3-5 (discussing issue credit ratings).
[11] Appendix G at p. 5-7.
[12] Appendix H at p. 6.
[13] Appendix H at p. 6.
[14] Appendix G at p. 6.
[15] Appendix H at p. 6.

and above "in default."[16] Many companies and public agencies operate successfully with ratings below investment grade. A long term issuer or issue credit rating provided by Moody's or Standard and Poor's is an independent and objective assessment of an entity's willingness and ability to meet its financial obligations and is well recognized in financial and energy markets.

Ongoing monitoring by Moody's and Standard and Poor's ensures an up-to-date assessment of the creditworthiness of any rated entity. Entities that may receive a change to their credit rating are typically placed on "credit watch," which alerts the market that a possible rating change may occur. The outcome of a credit watch is uncertain and could result in an increase, a decrease, or no change to the entity's credit rating. Investment grade credit ratings provide commercially reasonable assurance that a rated entity will not suddenly or imminently default and that it will continue operating and serving customers for the foreseeable future.

Credit rating agencies do not currently rate any CCAs in North America. To my knowledge, MCE is the first CCA to begin the process of obtaining a credit rating. While rating agencies do not currently rate CCAs, the Commission should have confidence that Moody's and Standard and Poor's are qualified to assess, rate, and monitor the risk of a CCA, similar to the assessments they make on similarly situated California energy utilities.

III. USE OF RATINGS TO DETERMINE COLLATERAL POSTING REQUIREMENTS IN ENERGY MARKETS

In the energy industry, it is common practice for energy suppliers and buyers to rely on credit ratings from Moody's and Standard and Poor's. For instance, The Edison Electric

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[16] *See* Appendix G at p. 6 (providing a table with ratings and noting the numerical modifiers for various ratings); *see also* Appendix H at p. 6 (providing a table with ratings and noting the plus or minus modifiers for various ratings).

Institute's Master Power Purchase and Sale Agreement ("EEI Master")[17] is used widely in the electricity industry to contract for purchase and sales of electricity. Paragraph 10 to the Collateral Annex[18] to the EEI Master outlines provisions for tying the collateral posting requirement to the credit rating of the counter party.[19] Energy market participants often rely upon these credit ratings to determine the need for collateral posting; an entity with a high rating will generally be required to post less collateral because the risk of default is low; an entity with a low rating may be required to post higher levels of collateral to mitigate higher credit risk.

IV. A CREDIT RATING SCREEN IS APPROPRIATE BEFORE REQUIRING A COLLATERAL POSTING REQUIREMENT

MCE endorses the approach proposed by the California Community Choice Association ("CalCCA") in their opening testimony to this proceeding that the Financial Security Requirement ("FSR") include only administrative costs. Additionally, a Credit Rating Screen should be applied to preclude the need for any collateral posting, including the FSR, for those CCAs with an investment grade long term issuer or issue credit rating. As long as a CCA is able to maintain an investment grade credit rating, there is insufficient need or risk present to justify a requirement to post collateral.

MCE agrees with the demonstration in the CalCCA opening testimony related to the very unlikely risk of a CCA failing and causing an involuntary return of customers to the incumbent IOU, even absent an investment grade credit rating. Imposing a collateral requirement (*e.g.* a letter of credit or surety bond) upon an investment grade rated CCA would needlessly increase CCA costs and drain CCA liquidity. Letters of credit and bonds require ongoing issuances fees

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[17] EEI Master. Available at http://www.eei.org/resourcesandmedia/mastercontract/Documents/contract0004.pdf.

[18] See Appendix I: Paragraph 10 to the Collateral Annex.

[19] Appendix I, Sections I.A and I.B at p. 2.

that can be very significant depending on the size of the collateral requirement. The issuance of letters of credit restrict the use of credit lines that would otherwise support the liquidity and financial health of the CCA. Acquiring letters of credit or surety bonds additionally creates administrative costs associated with sourcing, negotiating and managing contracts. MCE recognizes that many CCAs will meet their bond obligation through posting collateral under this framework. However, there is no need to add costs to and drain the liquidity of financially sound and credit-rated CCAs. To do so would create an unreasonable harm to CCA ratepayers by adding unnecessary costs that will lead to higher electric generation rates.

MCE recommends that the threshold for the Credit Rating Screen would be met when a CCA has an investment grade long term issuer or issue credit rating published by Moody's or Standard and Poor's. Specifically, the Credit Rating Screen threshold should be set at a Moody's rating of Baa3 or Standard and Poor's rating of BBB-. If the CCA has a rating from both rating agencies, the lower rating would apply. If the CCA has a credit rating equal to or better than the Credit Rating Screen threshold, it would not be required to post collateral (in the form of a bond or other instrument). If the CCA's credit rating is below the threshold or the CCA does not have a credit rating, the CalCCA methodology for the FSR collateral posting would apply. If the CCA's credit rating was reduced from investment grade, the CCA would follow the process articulated in CalCCA's opening testimony and file an advice letter with the FSA calculated and prepare to post the collateral.

This approach considers the creditworthiness of individual CCAs and strikes a reasonable balance between requiring a demonstration of sufficient insurance, in this case self-insurance, and limiting unnecessary costs. An investment grade rated CCA does not pose a significant risk of failure that may cause a mass involuntary return of customers. Because the determination of the credit rating would be made by an independent entity responsible for assessing risks in the electricity market, the Commission could reasonably rely on this determination and should adopt a Credit Rating Screen that would avoid an unnecessary collateral posting.

Appendix A

Statement of Qualifications of David McNeil

Q1: Mr. McNeil, please state your name, position, and address.

A1: My name is David McNeil. I am the Manager of Finance at Marin Clean Energy (MCE). My business address is 1125 Tamalpais Avenue, San Rafael, California 94901.

Q2: Please describe your background.

A2: I am a full-time employee with MCE where I fulfill the role of Manager of Finance. As Manager of Finance, I am responsible for banking, cash management, insurance, counter party credit risk management, liquidity risk management, budgets and financial forecasts, audit and financial statement preparation and supporting the board of directors in their oversight of financial risks and opportunities. I am leading MCE's efforts to obtain a credit rating.

I have nearly 20 years of experience in the financial services industry including senior roles in credit underwriting, strategic planning, mergers and acquisitions and project management. Prior to joining MCE, I served as President of EEF Advisors which consulted to governments, electric utilities, and regulators on the design of energy efficiency and renewable energy financing programs, financial models and organizational structures. Prior to EEF, I served a senior credit and political risk underwriter for the global credit insurance company Atradius NV, and as a credit analyst for a non-bank commercial lender, Newcourt Credit Group. I studied history at Queen's University in Kingston and hold the Chartered Financial Analyst designation. My resume is attached as Exhibit B.

Q3: What is the purpose of your testimony?

A3: As the Manager of Finance at MCE, I am responsible for controlling MCE's credit and liquidity risks. The purpose of my testimony is to inform the Commission about the use of credit ratings to manage risks and responsibly reduce the costs and burdens associated with that endeavor.

Q4: Does this conclude your statement of qualifications?

A4: Yes, it does.

Appendix B

Resume of David McNeil

PROFESSIONAL EXPERIENCE

Manager of Finance, Marin Clean Energy 2015-present

- Oversee finance operations of MCE including budgeting, financial reporting, risk management and establish and maintain financial and risk management policies and procedures
- Plan, maintain and grow banking, credit rating and financing relationships, manage collateral requirements and counter party risk
- Provide guidance and support to the Board of Directors on finance related matters; present budgets, financial reporting and finance related policies
- Support the CEO, Human Resources, Energy Procurement, Energy Efficiency and Public Relations teams on contracting and financial management at the enterprise and departmental level

President, EEF Advisors (Montreal) 2012-2015

- EEF provides consulting services to governments, regulators and electric utilities in jurisdictions around North America. Offering strategic planning, market characterization and opportunity analysis, corporate restructuring and business model and program design, EEF worked with governments to encourage private sector investment that achieves public policy objectives
- As President I was responsible for all aspects of the firm's operations including developing and maintaining client relationships, formation of project specific teams, proposal and report writing, research and project management
- Key Public Sector Clients: California Public Utilities Commission, Rhode Island Department of Energy, Manitoba Hydro and the Manitoba Municipal Government department

Manager, Business Development, BCA Research, (Montreal) 2008-2011

- BCA Research is a leading, independent macro-economic investment research firm providing research services to central banks and institutional investors on a global basis.
- As a business development manager my responsibilities were to maintain and grow a portfolio of US based institutional clients and ensure clients understood investment themes and key financial and economic risks and opportunities impacting equity, fixed income, commodity and currency markets on a global basis.

Senior Underwriter, Global Credit & Political Risk, Atradius NV, (UK & New York) 2005-2008

- Atradius NV is a leading global credit insurer. I worked in the "Special Products" group which provided bespoke structuring and underwriting of "single situation" credit risks.

- With a transaction approval authority of 5 million euro, my responsibilities were to originate, price, evaluate, structure and decision customized contracts assuring against credit and political risks on public (eg government) and private borrowers.

Director, Mergers & Acquisitions, Matlock Enterprises (Winnipeg) 2004-2005

- Broker mergers and acquisitions opportunities
- Prepare offering memoranda, identify and development relations with potential buyers / investors, broker negotiations between buyers and sellers of businesses
- Focus: large corporate acquirers of small and medium size enterprises

Manager, Corporate Development, National Leasing Group (Winnipeg) 1997-2004

- National Leasing Group and Newcourt Credit Group (see below) are/were leading North American commercial equipment finance companies. I served a number of operating roles for these companies including credit underwriting, strategic planning, strategic partnerships, M&A and special projects.
- Manage the company's acquisition strategy: prospect, evaluate, price, value, structure and negotiate acquisition opportunities. Organize due diligence teams from among the operating areas of the company and create integration plans for acquires. Lead a variety of business projects including reorganization of the insurance business, software development, new product launches and strategic partnerships

Credit Analyst, Newcourt Credit Group (Toronto) 1995-1997

- Evaluate, manage and adjudicate revolving lines of credit for medium sized corporate borrowers operating in the transportation and construction industries
- Conduct financial statement and industry analysis. Establish and manage appropriate loan and security documentation

GOVERNANCE ROLES

Board Member and Chair of the Audit Committee, Dawson College	2014-2015
Chairman, Pop Montreal International Music Festival	2011-2014
Treasurer and Chair of the Finance and Audit Committee, Santropol Roulant	2012-2015
Treasurer and member of the Finance Committee, CKUT Radio	2012-2015
Treasurer and Member of the Executive Committee, Projet Montreal	2013-2015

EDUCATION

Chartered Financial Analyst	CFA Institute	
Bachelor of Arts, Honours	History, Queen's University, Kingston	1995

PERSONAL

Interests:	Corporate Governance, macro economics, energy markets, politics
Athletics:	Cycling, Telemark Skiing, Tennis
Citizenship:	United Kingdom, USA, Canada
Languages:	English (maternal), French (advanced)

Appendix C:
Moody's Rating Methodology: Regulated Electric and Gas Networks

MOODY'S
INVESTORS SERVICE

RATING METHODOLOGY

Regulated Electric and Gas Networks

Table of Contents:

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This rating methodology replaces "Regulated Electric and Gas Networks" last revised November 25, 2014. We have updated some outdated links and removed certain issuer-specific information.

Summary

This rating methodology explains Moody's approach to assessing credit risk for regulated electric and gas networks globally. It provides general guidance that helps companies, investors, and other interested market participants understand how qualitative and quantitative risk characteristics are likely to affect rating outcomes for companies in the regulated electric and gas networks industry. It does not include an exhaustive treatment of all factors that are reflected in Moody's ratings but should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector.[1]

This report includes a detailed rating grid which is a reference tool that can be used to approximate credit profiles within the regulated electric and gas networks sector in most cases. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to companies in the regulated electric and gas networks industry. However, the grid is a summary that does not include every rating consideration. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions but actual importance may vary. In addition, the grid typically uses historical results while ratings are based on our forward-looking expectations. As a result, the grid-indicated rating is not expected to match the actual rating of each company.

1 This update may not be effective in some jurisdictions until certain requirements are met.

The grid contains five factors that are important in our assessment for ratings in the regulated electric and gas networks sector:

1. Regulatory Environment and Asset Ownership Model
2. Scale and Complexity of Capital Program
3. Financial Policy
4. Leverage and Coverage

The scoring for factors 1-4 results in a preliminary grid-indicated outcome. In addition, we apply the following factor 5, which can result in upward notching for issuers that benefit from structural enhancements, incorporated in their corporate structure, their regulatory license or their financing arrangements.

5. Structural Considerations and Sources of Rating Uplift From Creditor Protection

Some of these factors also encompass a number of sub-factors.

This rating methodology is not intended to be an exhaustive discussion of all factors that our analysts consider in assigning ratings in this sector. We note that our analysis for ratings in this sector covers factors that are common across all industries such as ownership, management, liquidity, corporate legal structure, governance and country related risks, which are not explained in detail in this document, as well as factors that can be meaningful on a company-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a grid format. The grid used for this methodology reflects a decision to favor a relatively simple and transparent presentation rather than a more complex grid that might map grid-indicated ratings more closely to actual ratings.

Highlights of this report include:

» An overview of the rated universe
» A summary of the rating methodology
» A description of factors that drive rating quality
» Comments on the rating methodology assumptions and limitations, including a discussion of rating considerations that are not included in the grid

The Appendices show the full grid (Appendix A), an explanation of how we calculate an adjusted interest coverage ratio (Appendix B), a brief discussion of our approach to networks within a corporate family (Appendix C), and a brief summary of industry issues over the medium term (Appendix D).

About the Rated Universe

The Regulated Electric and Gas Networks methodology is applicable to companies that are primarily engaged in the transmission and/or distribution of electricity and/or natural gas. They provide their services primarily to non-retail customers, and operate as monopolies within their service territory with tariffs regulated at the national/sovereign level. This methodology also applies to oil pipelines that are national monopoly businesses and subject to tariff regulation.

Transmission companies are engaged in the high-voltage/high-pressure transportation of electricity and gas while distribution companies are responsible for low-voltage/low-pressure transportation services. Issuers rated pursuant to this methodology predominantly own infrastructure assets with no significant ownership of upstream or downstream activities, e.g. electricity generation/gas production. While they may physically transmit electricity or gas to end-users on behalf of retail energy suppliers, regulated networks are generally not responsible for providing utility services to the final consumer. Instead, the customers of regulated networks are other energy companies, including retail energy suppliers, who procure electricity and gas on behalf of the end consumer and are themselves responsible for providing utility services, including billing and metering. As natural monopolies, the charges that networks can levy are determined by a regulatory authority at the national/sovereign level, with tariffs typically reviewed periodically.

While the majority of issuers rated pursuant to this methodology are financed on a corporate basis, this methodology also applies to some project-financed entities that are predominantly engaged in the ownership and operation of network infrastructure as many factors - including regulatory environment and the mechanisms for recovery of costs and investment are common across these corporate-financed and project-financed regulated networks.

This methodology excludes the following types of issuers, which are covered by separate rating methodologies: Regulated Electric and Gas Utilities (companies that are engaged in the transmission and/or distribution of electricity and/or natural gas but that also provide regulated utility services to a retail customer base, that in many cases also own regulated electricity generation assets, and that typically have a different type of regulatory framework), Unregulated Utilities and Power Companies, US Public Power Utilities (including US municipal utilities), US Electric Cooperatives, and Natural Gas Pipelines (companies that usually do not hold a monopoly franchise, could be subject to some competition, and whose revenues are determined primarily by commercial contracts, albeit with some regulatory oversight).

About this Rating Methodology

This report explains the rating methodology for electric and gas networks in several sections, which are summarized as follows:

1. Identification and Discussion of the Grid Factors

The grid in this rating methodology focuses on five rating factors. The first four grid factors are comprised of sub-factors that provide further detail. The fifth factor is used to make notching adjustments for structural enhancements where they are incorporated either in the company's regulatory license, its corporate structure or through its financial arrangements.

EXHIBIT 1

Regulated Electric and Gas Networks

Broad Grid Factors	Factor Weighting	Sub-Factors	Sub-Factor Weighting
Regulatory Environment and Asset Ownership Model	40%	Stability and Predictability of Regulatory Regime	15%
		Asset Ownership Model	5%
		Cost and Investment Recovery (Ability and Timeliness)	15%
		Revenue Risk	5%
Scale and Complexity of Capital Program	10%	Scale and Complexity of Capital Program	10%
Financial Policy	10%	Financial Policy	10%
Leverage and Coverage	40%	(FFO + Interest Expense - Non-Cash Accretion - Capital Charges) / (Interest Expense - Non-Cash Accretion) OR (FFO + Interest Expense) / Interest Expense	10%
		Net Debt / RAB OR Net Debt / Fixed Assets	12.5%
		FFO / Net Debt	12.5%
		RCF / Net Debt	5%
Total	**100%**		**100%**

Factor 5 – Structural Considerations and Sources of Rating Uplift From Creditor Protection – is a notching adjustment to the preliminary grid-indicated rating that results from Factors 1-4.

2. Measurement or Estimation of Factors in the Grid

We explain our general approach for scoring each grid factor and show the weights used in the grid. We also provide a rationale for why each of these grid components is meaningful as a credit indicator. The information used in assessing the sub-factors is generally found in or calculated from information in company financial statements, derived from other observations or estimated by Moody's analysts.

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of a company's performance as well as for peer comparisons. In this case we typically utilize historical data (in most cases, an average of the last three years of reported results). All of the quantitative credit metrics incorporate Moody's standard adjustments to income statement, cash flow statement and balance sheet amounts for restructuring, impairment, off-balance sheet accounts, receivable securitization programs, under-funded pension obligations, and recurring operating leases.[2] However, the factors in the grid can be assessed using various time periods. Rating committees typically assess both historical and expected future performance for periods of several years.

3. Mapping Grid Factors to the Rating Categories

After estimating or calculating each sub-factor, the outcomes for each of the sub-factors are mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, B or Caa).

4. Assumptions, Limitations and Rating Considerations Not Included in the Grid

This section discusses limitations in the use of the grid to map against actual ratings, some of the additional factors that are not included in the grid but can be important in determining ratings, and limitations and assumptions that pertain to the overall rating methodology.

5. Determining the Overall Grid-Indicated Rating [3]

To determine the overall grid-indicated rating before notching considerations, we convert each of the sub-factor scores into a numerical value based upon the scale below.

EXHIBIT 2

Sub-factor score to numeric value

Aaa	Aa	A	Baa	Ba	B	Caa
1	3	6	9	12	15	18

The sub-factor weightings are modified by applying a further weighting by rating category as shown in the table below.

EXHIBIT 3

Over-weighting of certain sub-factor scores

Aaa	Aa	A	Baa	Ba	B	Caa
1	1	1	1.15	2	3	5

We weight lower rating scores more heavily than higher scores in the grid because a serious weakness in one area often cannot be completely offset by strength in another. For example, the lack of flexibility normally associated with a high degree of leverage can increase risk more than would be reflected without the additional weighting for a low grade score on this measure.

The actual weighting applied to each sub-factor is the product of that sub-factor's standard weighting and its over-weighting, divided by the sum of these products for all the sub-factors (an adjustment that brings the sum of all the sub-factor weightings back to 100%).

2 See "Financial Statement Adjustments in the Analysis of Non-Financial Corporations". A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

3 In general, the grid-indicated rating is oriented to the Corporate Family Rating (CFR) for speculative-grade issuers and the senior unsecured rating for investment-grade issuers. For issuers that benefit from ratings uplift due to parental support, government ownership or other institutional support, the grid-indicated rating is oriented to the baseline credit assessment. For an explanation of baseline credit assessment, please refer to our rating methodology on government-related issuers. Individual debt instrument ratings also factor in decisions on notching for seniority level and collateral. The documents that provide broad guidance for these notching decisions are our rating methodologies on loss given default for speculative grade non-financial companies and for aligning corporate instrument ratings based on differences in security and priority of claim. The link to these and other cross-sector methodologies can be found in the Related Research section of this report.

The numerical score for each sub-factor is multiplied by the adjusted weight for that sub-factor with the results then summed to produce a composite weighted-factor score. The composite weighted-factor score is then mapped back to an alphanumeric rating based on the ranges in the table below.

EXHIBIT 4
Grid-Indicated rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Aaa	$x < 1.5$
Aa1	$1.5 \leq x < 2.5$
Aa2	$2.5 \leq x < 3.5$
Aa3	$3.5 \leq x < 4.5$
A1	$4.5 \leq x < 5.5$
A2	$5.5 \leq x < 6.5$
A3	$6.5 \leq x < 7.5$
Baa1	$7.5 \leq x < 8.5$
Baa2	$8.5 \leq x < 9.5$
Baa3	$9.5 \leq x < 10.5$
Ba1	$10.5 \leq x < 11.5$
Ba2	$11.5 \leq x < 12.5$
Ba3	$12.5 \leq x < 13.5$
B1	$13.5 \leq x < 14.5$
B2	$14.5 \leq x < 15.5$
B3	$15.5 \leq x < 16.5$
Caa1	$16.5 \leq x < 17.5$
Caa2	$17.5 \leq x < 18.5$
Caa3	$18.5 \leq x < 19.5$

For example, an issuer with a composite weighted factor score of 11.7 would have a Ba2 preliminary grid-indicated rating.

We apply a fifth factor called "Structural Considerations and Sources of Rating Uplift From Creditor Protection" to the preliminary grid-indicated rating score that results from factors 1-4, in order to arrive at a final grid-indicated rating. Factor 5 can result in upward adjustment of the grid-indicated rating due to structural enhancements that are incorporated in the company's regulatory license, its corporate structure, or through its financial arrangements. How we assess the effectiveness of any such enhancements to determine the appropriate uplift is described in the section "Structural Considerations and Sources of Rating Uplift From Creditor Protection".

7. Appendices

The Appendices provide a presentation of the full grid and additional commentary and insights on our view of credit risks in this industry.

Discussion of the Grid Factors

The grid for regulated electric and gas networks focuses on four broad factors:

1. Regulatory Environment and Asset Ownership Model
2. Size and Complexity of Capital Program
3. Financial Policy
4. Leverage and Coverage

There is also a fifth factor: "Structural Considerations and Sources of Rating Uplift From Creditor Protection", which is scored as a notching adjustment to the preliminary grid-indicated rating score that results from the combination of the four factors above.

Factor 1: Regulatory Environment and Asset Ownership Model (40% Weight)

Why It Matters

As monopoly providers of essential transmission and distribution services, electric and gas networks rated pursuant to this methodology are regulated, i.e. their revenues (or tariffs) are subject to price control limits that are typically reset periodically. Price-setting mechanisms are generally structured to limit volatility and tend to be highly predictable. In addition to price-setting, there are a number of ways that regulatory decisions can affect a network's business position, including a regulator's ability to agree on a capital expenditure program or to set efficiency targets to reduce operating costs. Finally, the ability to recover prudently-incurred costs in a timely manner is one of the most important credit considerations for regulated electric and gas networks, as a delay in cost recovery may cause financial stress. Therefore, the predictability and supportiveness of the regulatory framework in which a network operates – as well as the legal and political framework that underpins it - is a key credit consideration and the one that differentiates this sector from most other corporate sectors.

The asset ownership model of one network can be significantly different from other networks serving similar regions (in terms of size or population) elsewhere in the world. Indeed, the nature of the ownership and/or exploitation rights of the network can vary from full ownership and control of all key assets, through some form of concession arrangement, to a short-term lease or license arrangement that is capable of being terminated relatively easily by the regulator or the licensing authority, hence giving only a short period of time to enjoy the revenue earning capacity of the network. This risk may be further elevated in jurisdictions where there is an increased likelihood of expropriation or where the laws detailing property rights are weaker or less established. The ability of a company to sell, if necessary, its network without constraint is also a key consideration and allows substantial operational and capital flexibility. This is most easily achieved where assets are owned outright in jurisdictions with strong property rights. Therefore, the type of asset ownership arrangement will drive the business flexibility of an issuer.

To assess this factor, we examine the following four sub-factors:

» Stability and Predictability of Regulatory Regime

» Asset Ownership Model

» Cost and Investment Recovery (Ability and Timeliness)

» Revenue Risk

How We Assess Stability and Predictability of Regulatory Regime for the Grid

We consider the characteristics of the regulatory environment in which a network operates. These include how developed and transparent the regulatory framework is; the strength of the political and legal underpinnings of the regulatory framework; the regulator's track record for predictability and stability in terms of decision making; its independence from political interference; and our forward looking view on whether these conditions will continue to persist. In addition, this sub-factor also considers the effectiveness of the independent body or legal system that can arbitrate disputes between a regulator and a regulated company in a timely fashion.

A network operating in a stable, reliable and highly predictable regulatory environment will be scored highly; those networks operating in a less developed regulatory framework or one that is characterized by a high degree of political intervention in the regulatory process will receive much lower scores for this factor. Nevertheless, changes to the regulatory framework or to existing utility law do occur, although the way that this is achieved can vary significantly. Where regulatory or legislative changes do occur, networks can still have a high score on this sub-factor if there was sufficient consultation with the affected companies during the process and the changes are supportive of networks' credit quality. In contrast, networks will have a low score on this factor if changes to the regulatory framework have been implemented without consultation, are unclear, or are detrimental to credit quality.

How We Assess Asset Ownership Model for the Grid

In those cases where network assets are not owned outright by the rated entity, we consider the risk that a license or concession may be terminated. We also consider whether the right to exploit the network assets effectively may be short-to-medium term and therefore transitory in nature. It is common practice throughout the world that the ownership of what are, in many cases, assets of national importance is subject to a license, and this would be considered the usual arrangement. It is less common to see private sector companies own assets outright in perpetuity, although this ownership model may be seen in certain countries or in cases where alternative transportation systems exist (e.g. transit pipeline, interconnector, etc).

A company that owns all key network assets outright in perpetuity and has control over them would have a high score under this factor, and a company that held its key assets under a short-term operating lease or license type arrangement would have a low score. Issuers with concession agreements or more permanent licenses would score somewhere in the middle of the grid depending on (i) the nature of events that could cause a loss of concession or license, (ii) the timeframe thereof, and (iii) the entitlement to compensation upon termination.

We also consider the general rule of law and the value and enforcement of asset property rights. In order to score 'A' and above, unless there are mitigating factors such as government ownership, networks are expected to operate in jurisdictions where there is no perceived risk of expropriation and where the laws pertaining to property rights are well established, thereby reducing the risk for creditors. For example, if there is a heightened risk of expropriation of assets in this sector with limited potential for compensation, we would score a company at a lower level even if it currently owns its assets outright.

How We Assess Cost and Investment Recovery for the Grid

This sub-factor focuses on the supportiveness of the regulatory framework, i.e. the extent to which the regulatory formula is supportive of cost recovery, including the mechanism by which one-off costs or over-spends are recovered, if at all. In other words, it focuses on the risk allocation between the network operator and its customers. Prevalent regulatory models for unbundled networks across the world are "ex-ante", "ex-post" or "cost-plus". While in theory ex-ante regulation provides the greatest certainty for the recovery of capital investment, each type of regulatory model may have greater or lesser predictability in cost recovery depending on the details of the framework and the manner in which it is applied by regulators.

We assess whether the regulator seeks to insulate consumers from the volatility and the uncertainty associated with operating and financial costs, whether there is risk-sharing between the network and its consumers, and whether the network easily is able to pass through its incurred costs, including financial costs. A network that has complete flexibility to set tariffs so that it can meet current and future operating and capital costs without impediment likely will have a high score under this sub-factor. A network that benefits from fair and timely cost and investment recovery but is subject to efficiency targets or high regulatory scrutiny would likely score in the middle of the grid. Where there is a significant deferral of allowed revenue, e.g. for a greenfield development where the current number of customers is very low but expected to grow, or where a company has been significantly over-spending on its investments, a low score on this sub-factor likely would apply.

How We Assess Revenue Risk for the Grid

In this sub-factor we consider the ability of a network to generate the revenue allowed to it by the regulator. In general, the revenues achieved by networks can vary from this pre-determined level due to differences in consumed volumes from that forecast when charges were initially set. However, the extent to which networks are affected by volume risk depends on the structure of the regulatory charge, which can include both a fixed and a variable element. The greater the proportion of the end-user charge that is fixed, the lower the potential revenue variability.

As a general rule, we believe that gas and electricity transmission tends to be less volatile than distribution due to its wider geographic outreach (e.g. volumes are arguably more stable and predictable where exposed to a country's entire economy vs. a subset thereof). From a commodity perspective, gas volumes are likely to be more exposed to weather conditions than electricity volumes, given the role of gas as a heating fuel source in many jurisdictions. However, there may be ultimately no direct link between volume volatility and revenue generation as some regulators may de-couple the two, given that volumes are outside of a network company's control. Furthermore, regulators do not typically wish to incentivize networks to distribute more energy, which would run contrary to the principles of energy efficiency. If so, the regulator may choose to eliminate volume risk entirely (by setting a fully fixed charge for transmission and distribution activities) or may allow a true-up mechanism that allows networks to reset their charges in a timely fashion to recover any lost revenue.

Issuers will likely score more highly on this sub-factor if their revenues are entirely de-linked from volumes transported. Networks will likely score in the middle of the grid if they have some exposure to volume risk but benefit from a regulatory formula that allows for the recovery of any lost revenue. In contrast, networks that have high exposure to volumes or where volumes are expected to be particularly volatile would likely have a low score on this sub-factor. We will also take into account a network's reliance on revenues associated with new connections. While the costs incurred in connecting new customers are normally a pass-through under most developed regulatory frameworks, such activity may generate significant cash flows if the network is allowed to make a margin, thereby raising the overall volatility of the business.

Factor 1: Regulatory Environment and Asset Ownership Model (40% Weight)

Sub-factor	Sub-factor weight	Aaa	Aa	A	Baa	Ba	B	Caa
Stability and Predict-ability of Regulatory Regime	15%	Regulation is independent, well established (> 15 years of being predictable and stable) and transparent (well-established regulatory principles clearly define risk allocation between companies and customers and are consistently applied, with public or shared financial models). These conditions are expected to continue.	Regulation is independent, well established (> 10 years of being predictable and stable) and transparent (well-established regulatory principles clearly define risk allocation between companies and customers and are generally consistently applied). These conditions are expected to continue.	Regulation is generally independent and developed (regulatory principles define risk allocation between companies and customers and are based on established precedents in the same jurisdiction). These conditions are expected to continue.	Regulatory framework is relatively new and untested, although regulatory principles are based on established precedents. Jurisdiction has a history of independent and transparent regulation for other utility services. These conditions are expected to continue.	Regulatory framework is defined but not consistently applied; tariff setting is subject to negotiation and political interference; some precedents in the country of predictable regulation for other utility services. These conditions are expected to continue.	Regulatory framework is unclear, untested or undergoing significant change, with a history of political interference. These conditions are expected to continue.	Regulatory framework is not defined, is unpredictable or politically driven with significant adverse consequences for the utility. These conditions are expected to continue.

Factor 1: Regulatory Environment and Asset Ownership Model (40% Weight)

Sub-factor	Sub-factor weight	Aaa	Aa	A	Baa	Ba	B	Caa
Asset Ownership Model	5%	All key T&D assets held outright in perpetuity AND no risk that a change in ownership would negatively affect creditor rights.	All key T&D assets held outright under licence which can be terminated for underperformance, failure to meet certain financial parameters or insolvency OR held under long term concession with clearly defined right to timely recovery of residual asset value at termination/end of concession underpinned by highly rated entity AND no risk that a change in ownership would negatively affect creditor rights.	All key T&D assets held under long-term concession with clearly defined right to recover value of residual assets at termination/end of concession underpinned by highly rated entity but with undefined timeframe OR held under medium/long-term operating leases or management contracts with very substantial portfolio diversification, very established market position and very high renewal rate (>95%) AND no risk that a change in ownership would negatively affect creditor rights.	All key T&D assets held under long-term concession with some entitlement to recover value of residual assets at termination/end of concession but procedures untested/undefined OR held under medium-term operating leases or management contracts with substantial portfolio diversification, established market position and high renewal rate (>90%) AND/OR jurisdiction has reasonably strong property rights although there is some, albeit low risk that a change in ownership would negatively affect creditor rights.	All key T&D assets held under concession with recovery of residual asset value at termination/end of concession subject to negotiation OR held under short-term operating leases or management contracts with good degree of portfolio diversification and renewal rate (>80%) AND/OR jurisdiction may have some laws detailing property rights although these may be untested. A change of ownership would likely result in a loss for creditors.	Key T&D assets held under short-term operating leases or management contracts (limited portfolio diversification) with limited clarity on renewal and/or compensation AND/OR probability of termination/ expropriation is elevated. Compensation likely to be minimal and could be subject to significant delays in payment.	Company is in default of its licence, concession or lease/contract and is likely to lead to termination AND/OR expropriation very likely, no prospect of compensation.

Factor 1: Regulatory Environment and Asset Ownership Model (40% Weight)

Sub-factor	Sub-factor weight	Aaa	Aa	A	Baa	Ba	B	Caa
Cost and Investment Recovery (Ability and Timeliness)	15%	No regulatory or contractual impediment to adjust tariffs (no approval or reviews required).	Tariff formula is expected to allow for timely recovery of operating expenditure including depreciation, electricity losses and balancing costs/shrinkage gas and a fair return on all investment. All capital expenditure is included in asset base as incurred. Unanticipated expenditure quickly reflected in allowed revenue with low, if any, efficiency assessment.	Tariff formula is expected to allow for recovery of operating expenditure including depreciation based on allowances set at frequent price reviews (5-yearly intervals or shorter) and a fair return on all efficient investment. Capital expenditure is included in asset base as incurred. Opex and capex subject to efficiency tests; electricity losses and balancing costs/shrinkage gas subject to efficiency test on volumes only (price is a pass through). Unanticipated expenditure generally quickly reflected in allowed revenue although this may not be until the following regulatory period and may be subject to a degree of regulatory scrutiny or sharing factor with customers. Performance is likely to be in line with regulatory expectations.	Tariff formula is expected to allow for recovery of operating expenditure including depreciation and return on investment but subject to retrospective regulatory approval or infrequent price reviews (> 5-yearly intervals); recovery of electricity losses and balancing costs/shrinkage gas is somewhat exposed to price. Some instances of revenue backloading expected (e.g. depreciation allowance set below asset consumption or operating expenditure is capitalized). Unanticipated expenditure slow to be reflected in allowed revenue or may be subject to a stringent efficiency assessment/low sharing factor. Performance may be below regulatory expectations.	Tariff formula is not expected to take into account all cost components and depreciation is set below asset consumption; recovery of electricity losses and balancing costs/shrinkage gas has large exposure to price. Revenues expected to cover most operating expenditure but investment is not clearly or fairly remunerated. Overspend either not recognized in allowed revenue or there is high uncertainty about its future recognition. Operational underperformance likely to be significantly impacting the returns achieved by the business.	Tariff formula is not expected to take into account all cost components and depreciation is set below asset consumption; recovery of electricity losses and balancing costs/shrinkage gas is fully exposed to price. Revenues expected to cover cash operating expenditure.	Revenues expected to only partially cover cash operating costs.
Revenue Risk	5%	No exposure to volume risk. Collected revenues based on capacity charges.	Very low exposure to volume risk. Collected revenues based on volume charges with stable volumes expected. Revenue cap mechanism with timely recovery in place.	Limited exposure to volume risk. Collected revenues based on volume charges with some volatility in volumes expected. Revenue cap mechanism in place; OR Hybrid price/revenue cap with low volatility in volumes.	Moderate exposure to volume risk. Hybrid price/revenue cap with moderate volatility in volumes; OR Some reliance on connection revenues.	Material exposure to volume risk: price cap with significant volatility in volumes; OR Material reliance on connection revenues.	High exposure to volume risk: price cap with substantial volatility in volumes; OR Very high reliance on connection revenues.	Very high exposure to volume risk: price cap with high concentration of volumes to one particular customer or sector; OR Revenues mainly driven by connections.

Factor 2: Scale and Complexity of Capital Program (10% Weight)

Why It Matters

Factor 2 considers a network's investment plan and the associated execution risk. Given the global trend of population growth, renewable generation deployment and decarbonization requirements, the emergence of new energy technologies (such as smart grids and electric cars), many networks have large and ongoing capital investment programs.

Many companies also have substantial needs for replacement of grids that are ageing, or for improvement of their reliability. For most networks, a sizeable capital expenditure program is thus a constant feature of their business model. While networks are generally experienced in large construction programs, they nonetheless introduce execution risk to the enterprise. The program may take longer than envisaged or could cost more. Furthermore, such cost overruns may not be recoverable from future revenues or may be subject to an efficiency review by the regulator. In addition to the direct financial impact, a large or complex capital program may prove a distraction for the management of a network, which could lead to an under-performance in other areas of the business.

How We Assess Scale and Complexity of Capital Program for the Grid

Moody's makes an assessment of a regulated network's capital expenditure program by considering (i) its size and scope, (ii) the complexity of this capex program, i.e. the type of assets to be built and associated technical issues as well as the relative concentration of challenging projects within the issuer's total capex program, (iii) management's ability to deliver the plan without material cost over-runs, and (iv) whether the program will introduce financing challenges.

To some extent, the size of a network's capital expenditure plans can be correlated to the complexity of the program, particularly for material capacity increases or technically challenging projects. Thus, we consider the size of the total annual capex plan as percentage of its Regulatory Asset Base or its total fixed assets. However, this percentage may not directly correlate to risk in all scenarios. For example, replacement programs that are large in scope may nevertheless present only limited execution risk, for example the laying of polyethylene gas pipe. Here the technology is simple and well-established. A large capital expenditure program could also reflect a significant number of individual projects where overall execution risk is reduced through diversification.

As a result, a network undertaking a relatively small investment program but one which is specific and/or complex will likely have a score lower than a network involved in a number of small and simple projects. For this sub-factor we consider total capital expenditure, including those outside of the core regulated activity. Although such activities would generally not directly prejudice the network operations, material investments outside of the core regulated business may impair debt service or cause a significant drain on management's time and resources.

Issuers with large, modern asset bases requiring a limited amount of simple maintenance (with capital expenditure representing a low percentage of fixed assets) will likely have very high scores for this sub-factor. In contrast, networks that need to modernize their systems and must engage in complex, concentrated programs that are challenging to finance (and where annual capex represents a high percentage of fixed assets) will likely have very low scores for this factor.

Factor 2: Scale and Complexity of Capital Program (10% Weight)

Sub-factor	Sub-factor weight	Aaa	Aa	A	Baa	Ba	B	Caa
Scale and Complexity of Capital Program	10%	Capex program is extremely limited in scale, reflecting a modern, highly developed asset base that requires only simple maintenance expenditure (e.g. total annual capex is < 4% of total fixed assets or regulated asset base).	Capex program is limited in scale, reflecting a well developed asset base that requires only maintenance expenditure (e.g. total annual capex is 4-6% of total fixed assets or regulated asset base).	Capex program is modest in size, reflecting a well developed asset base. Expenditure primarily relates to maintenance although some projects may be larger (e.g. total annual capex is 6-8% of total fixed assets or regulated asset base) or more complicated.	Capex program is manageable in size (e.g. total annual capex is 8-12% of total fixed assets or regulated asset base) or is generally straightforward (expenditure consists of a combination of replacement plus a number of development projects albeit with limited execution risk).	Capex program is large in size (e.g. total annual capex is 12-20% of total fixed assets or regulated asset base) or is challenging in scope (small number of large and complex development projects account for the majority of capital expenditure and carry a degree of execution risk). Obligation to invest poses a financing challenge.	Capex program is very large in size (e.g. total annual capex is 20-30% of total fixed assets or regulated asset base) or highly complex in scope (one large or complex project accounts for majority of expenditure and carries a high execution risk). Capex obligation likely to pose a significant financing challenge.	Capex program is extremely large in size (e.g. total annual capex is ≥ 30% total fixed assets or regulated asset base) or is highly technically complex (one or more large projects account for the majority of expenditure and together carry a very high execution risk). Capex obligation likely to undermine the ongoing financial stability of the company.

Factor 3: Financial Policy (10% Weight)

Why It Matters

Management and board tolerance for financial risk is an important rating factor as it directly affects debt levels, credit quality and risk in the capital structure (e.g., refinancing risk, counterparty risk or exposure to interest rates or foreign exchange movements).

The generally stable and predictable cash flows of a regulated network create significant capacity to incur debt financing and potentially to invest in related businesses. While debt financing may be considered essential to the efficient capital structure of a network, a desire to enhance shareholder returns may lead to the pursuit of higher leverage, which increases credit risk. The way in which a network owner uses its debt capacity, therefore, is a key rating consideration.

In this factor we assess the likelihood that financial policy decisions, in their totality, could add uncertainty to future cash flow levels and divert resources away from creditors. In this regard, management's track record and their public commitment to maintaining the issuer's credit quality are key considerations.

How We Assess Financial Policy for the Grid

In this factor, we consider the company's approach to financing its activities, in particular the balance it strikes in apportioning risk between shareholders and creditors. We assess both the company's historical track record and its stated objectives with respect to leverage and financing decisions, as well as the investment return requirements of its owners. The behavior of owners can be a key differentiating credit consideration – where owners' objectives are short-term, opaque or where there is a lack of track record, the regulated network will likely be scored lower than if its shareholders have more long-term return requirements and may be willing to forego near-term distributions to maintain flexibility.

Issuers are likely to have a high score on this factor if they have an extended track record of low levels of leverage plus a public commitment to maintaining high levels of credit quality. A network that employs an average level of leverage for the industry (e.g. to a level implied within the regulator's allowed rate return) and that has a solid record of commitment to maintaining its targeted financial metrics is likely to be scored in the middle of the range. However, scores of "Baa" and above generally would apply only where there are no (or only very limited) concerns regarding owners' behavior – e.g. listed companies, government majority owned companies or those owned by industrial shareholders. Issuers with consistently higher levels of leverage or those with a less transparent financial policy would likely score "Ba" or lower on this factor.

This factor is scored separately from a notching factor for specific structural enhancements that provide additional creditor protection (Factor 5). However, where they exist, such enhancements will be considered to the extent they define or clarify the issuer's overall financial policy.

Factor 3: Financial Policy (10% Weight)

Sub-factor	Sub-factor weight	Aaa	Aa	A	Baa	Ba	B	Caa
Financial Policy	10%	Long track record and expected maintenance of extremely conservative financial policy; very stable metrics; low debt levels for the industry; AND Public commitment to the highest credit quality over the long-term.	Long track record and expected maintenance of a conservative financial policy; stable metrics; lower than average debt levels for the industry; AND Public commitment to a very high credit quality over the long-term.	Extended track record and expected maintenance of a conservative financial policy; moderate debt leverage and a balance between shareholders and creditors; Not likely to increase shareholder distributions and/or make acquisitions which could lead to a weaker credit profile; Solid commitment to high credit quality.	Track record and expected maintenance of a conservative financial policy; an average level of debt for the industry and a balance between shareholders and creditors; Some risk that shareholder distributions and/or acquisitions could lead to a weaker credit profile; Solid commitment to targeted metrics.	Track record or expectation of maintenance of a financial policy that is likely to favor shareholders over creditors; higher than average, but not excessive, level of leverage; Owners are likely to focus on extracting distributions and acquisitions but not at the expense of financial stability.	Track record of aggressive financial policies or expected to have a financial policy that favors shareholders through high levels of leverage with only a modest cushion for creditors; OR High financial risk resulting from shareholder distributions or acquisitions.	Expected to have a financial policy unfavorable to creditors with a track record of or expected policy of maintaining excessively high debt leverage; OR Elevated risk of debt restructuring.

Factor 4: Leverage and Coverage (40% Weight)

Why It Matters

The first three rating factors aim to capture the credit strengths and weaknesses afforded by the network's fundamental business and its financial policies. However, a company's ultimate credit profile must also incorporate its financial metrics, because a network that is substantially weaker than its peers in terms of cash flow generated or debt relative to the value of its asset base will generally have a higher probability of default.

When examining leverage and coverage, there is no single measure that can predict the likelihood of default. We utilize metrics that measure both the absolute capacity of the issuer to service its debt and the size of its debt burden relative to those of its peers. Leverage ratios aim to capture different measures of how easily an issuer can repay its debt; coverage ratios focus more on the ability to service the debt prior to repayment but also need to take into account the peculiarities of different regulatory frameworks.

To score this factor in the grid, we examine four financial metrics:

» Adjusted Interest Coverage Ratio ("Adjusted ICR") or FFO Interest Coverage

» Net Debt / Regulatory Asset Base ("RAB") or Net Debt / Fixed Assets

» FFO / Net Debt

» RCF / Net Debt

How We Assess Interest Coverage for the Grid

Interest coverage is used as an indicator of a regulated network's ability to cover the cost of its debt. Depending on the regulation type and the level of publicly available information, we will calculate the interest coverage ratio (ICR) in one of two ways.

The adjusted ICR is our preferred metric for networks where allowed revenues/tariffs are determined using a 'building block approach' and where the components of allowed revenues/tariffs are routinely published and can be verified by an independent source, which in most cases is the regulatory authority itself. Components of the revenue building block analysis include: the total amount of operating and capital expenditure, the portion of the RAB/asset base that provides for a return of capital (known as regulatory depreciation) and any other adjustments that can change the timing of cost recovery. This information is necessary as the adjusted ICR seeks to normalize for different regulatory approaches to the capitalization and depreciation of networks' expenditure, which affects the timing of their cash flow. The adjusted ICR therefore adjusts funds from operations (FFO) by an amount of money (Capital Charges) that the regulator provides as current revenues at the expense or benefit of future revenues. Capital Charges include elements such as regulatory depreciation, the timing of cost recovery (the so called 'speed of money') or a profiling of the company's revenues over a regulatory period resulting in a potential volatility that we seek to adjust. Further information can be found in Appendix B.

The formula for the Adjusted ICR is as follows:

$$\frac{\text{FFO} + \text{Interest Expense} - \text{Non-Cash Accretion} - \text{Capital Charges}}{\text{Interest Expense} - \text{Non-Cash Accretion}}$$

For regulated networks that utilize unconventional debt funding, such as zero-coupon, capital accretion, index-linked bonds or swap arrangements, we seek to make the appropriate adjustments to the ratio calculations to improve consistency and comparability to the peer portfolio.

In jurisdictions where regulatory revenues/tariffs are not determined with a 'building block approach' or where the regulatory information needed to calculate Capital Charges may not be consistently available, publicly or otherwise, the ICR is calculated as (FFO + Interest Expense) / Interest Expense.

How We Assess Net Debt / RAB or Net Debt / Fixed Assets for the Grid

Typically, the Net Debt / RAB ratio is preferred for regulated networks, especially where the RAB serves as a proxy for the long-term average enterprise value of a regulated business. The RAB is analogous to the Rate Base in the US albeit with some differences. In this methodology we use the term RAB throughout.

Under some regulatory regimes, however, RAB may not accurately represent the invested capital on which the network will earn a return over time (e.g. because of ex-post rate-setting), or it may not be publicly available. In these circumstances we typically utilize Net Debt / Fixed Assets. For example, a network may be allowed to earn a return on construction-work-in-progress, but it will not be part of RAB until the asset is completed. Alternatively, a regulator may designate certain assets (for example receivables, deferred charges or regulatory assets) to be outside of RAB but permit the network to earn a regulated return on them.

For this ratio and those that follow, net debt is calculated as total debt less unrestricted cash.

How We Assess FFO / Net Debt for the Grid

This ratio is one of Moody's most commonly used dynamic leverage measures to measure cash flow in comparison to its indebtedness. This ratio may be more useful in comparing the ability of a company (or a peer group of networks operating under similar regulatory financial models) to generate sufficient cash flow to cover future debt repayments than in comparing networks operating under very different regulatory financial models (see Appendix B). More specifically, a higher level of FFO / net debt may not be a sign of financial strength when it is driven by a higher level of regulatory depreciation. Nevertheless, in comparing two companies that maintain a similar net debt / RAB ratio over a period of time, a higher level of FFO / net debt is usually indicative of greater financial strength.

The numerator in this ratio is FFO, and the denominator is net debt.

How We Assess RCF / Net Debt for the Grid

This ratio is an indicator for financial leverage as well as an indicator of the strength of a network's cash flow after dividend payments are made. Dividend obligations of networks are often substantial, quasi-permanent outflows that can affect the ability of a network to cover its debt obligations, and this ratio can also provide insight into its financial policies. The higher the level of retained cash flow relative to a network's debt, the more cash it has to support its capital expenditure program. The numerator of this ratio is FFO minus dividends, and the denominator is net debt.

Factor 4: Leverage and Coverage (40% Weight)

Sub-factor	Sub-factor weight	Aaa	Aa	A	Baa	Ba	B	Caa
Adjusted Interest Coverage Ratio:[4] (FFO + Interest Expense - Non-Cash Accretion[5] - Capital Charges) / (Interest Expense - Non-Cash Accretion)	10%	≥ 5.5x	3.5 - 5.5x	2 - 3.5x	1.4 - 2x	1.1 - 1.4x	0.9 - 1.1x	< 0.9x
OR		OR	OR	OR	OR	OR	OR	OR
FFO Interest Coverage: (FFO + Interest Expense) / Interest Expense		≥ 7.5x	5.5 - 7.5x	4 - 5.5x	2.8 - 4x	1.8 - 2.8x	1.1 - 1.8x	< 1.1x
Net Debt / RAB OR Net Debt / Fixed Assets[6]	12.5%	< 30%	30 - 45%	45 - 60%	60 - 75%	75 - 90%	90 - 100%	≥ 100%
FFO / Net Debt[7]	12.5%	≥ 35%	26 - 35%	18 - 26%	11 - 18%	5 - 11%	0 - 5%	< 0%
RCF / Net Debt[6]	5%	≥ 30%	21 - 30%	14 - 21%	7 - 14%	1 - 7%	(4) - 1%	< (4)%

4 The adjusted ICR is our preferred metric for networks where allowed revenues/tariffs are determined using a 'building block approach' and where the components of allowed revenues/tariffs are routinely published and can be verified by an independent source, which in most cases is the regulatory authority itself. Required components of the revenue building block include: the total amount of allowed operating and capital expenditure, the portion of the RAB/asset base that provides for a return of capital (known as regulatory depreciation) and any other adjustments that can change the timing of cost recovery. For regulated networks that utilize unconventional debt funding, such as zero-coupon, capital accretion, index-linked bonds or swap arrangements, we seek to make the appropriate adjustments to the ratio calculations to improve consistency and comparability to the peer portfolio. Please see Appendix B for a discussion of Capital Charges and some illustrative example of this ratio.

For other regulated networks, the FFO Interest Coverage Ratio is used.

5 For clarity, Non-Cash Accretion is deducted in the numerator only to the extent it has been added to FFO, and it is deducted from the denominator only to the extent that it has been included in Interest Expense.

6 Net Debt / Regulatory Asset Base (RAB) is the preferred ratio where RAB is publicly available and when it represents the invested capital on which the network earns a return. Net Debt / Fixed assets is used in all other cases. Net Debt is total debt minus unrestricted cash. When Net Debt is negative, the score for this sub-factor is Aaa.

7 For FFO / Net Debt and RCF / Net Debt, when Net Debt is negative and the numerator is a positive number (thus, a negative ratio), the score is Aaa. When Net Debt is negative and the numerator is a negative number (thus, a positive ratio), the score is B.

Factor 5: Structural Considerations and Sources of Rating Uplift From Creditor Protection

Why It Matters

Electric and gas networks may be financed using a range of different techniques. The simplest form is arguably a lowly leveraged, unsecured debt structure with few, if any, restrictive covenants. In contrast, some networks are very highly leveraged but operate within the confines of a tightly covenanted financial structure that significantly restricts their flexibility in a manner that is generally beneficial to debt holders. Indeed, in the recent past, many electric and gas networks have increased their leverage following changes in their ownership with large, vertically integrated utilities reducing their ownership in favor of specialist investment funds. These funds can also vary significantly in their complexity, ranging from traditional private equity owners with a relatively short-term return requirement to an open-ended and long-duration infrastructure fund backed by pension funds.

In response to the emergence of new owners, higher leverage and a somewhat shorter track record of financial policy, debt investors have increasingly sought additional credit protection mechanisms more akin to those in project financing.

We believe that structural enhancements may provide valuable protection to financial creditors in the regulated electric and gas network sector, and this can result in rating uplift. Such enhancements may be incorporated into the terms and conditions of financing agreements pertaining to essentially all of a network's securities holders, or they may be a feature within the networks' regulatory license, and include requirements such as maintaining a certain credit rating and demonstrating sufficient operating and financial resources (as is the case in the United Kingdom).

How We Assess It for the Grid

Our determination of the degree of ratings uplift that debt structural features and/or regulatory ring-fence provisions provide a regulated network is based primarily on an assessment of the following:

A. Factors that reduce the likelihood that an issuer will default on its debt, and

B. Factors that give creditors either the right, or ability to influence the taking of corrective action - to stop or reverse credit deterioration.

In order for structural features to provide ratings uplift they typically must benefit all debt creditors, although individual creditors may be subject to different payment priorities.

A. Factors that reduce the likelihood that an issuer will default on its debt

These comprise:

1. **Restriction on business activities.** Prohibiting an issuer from engaging in new activities or making acquisitions is seen as credit positive because it eliminates the business risk associated with corporate activity and ensures that all critical functionality is subject to the debt structural features.
2. **Restriction on raising additional debt.** Restricting additional indebtedness reduces the risk that additional obligations can cause a payment default.
3. **Distribution lock-up tests.** Prohibiting distributions to shareholders in a distressed scenario preserves cash within the business, thus reducing the risk of default.

4. **Limits on debt structure.** Requiring the issuer to remove or mitigate certain financial risks, such as interest rate, currency or refinancing risk. The latter can range from restrictions on debt maturity concentration to the implementation of a fully amortizing debt structure, which in itself can achieve a full notch of ratings uplift. Covenants can also restrict the issuer's use of derivative products, thus reducing the likelihood of additional and/or sizeable claims on the business.

5. **Reserves to cover large future or unforeseen costs.** Dedicated timing reserves for large-cost items, e.g., one-off capital expenditure.

B. Factors that give creditors either the right, or ability, to influence the taking of corrective action – to stop or reverse credit deterioration

An important element of leveraged infrastructure debt structures has been the ability of debt creditors to force owners to reduce debt ahead of the point where equity value is lost and debt is impaired, and to take action to repay debt through the enforcement of security if this is not achieved. The debt event of default tests and the consequences of these are key elements of this protection. To provide effective protection to creditors, these features need to work within the context of the business being financed, in most cases to allow the operating businesses to continue as a going concern and to allow debt service to be paid though available liquidity facilities while action is being taken.

The elements of debt structural features that provide control rights are assessed in the following areas:

1. **Effectiveness of control rights.** The degree to which the exercise of control rights may be impeded (e.g., local jurisdiction laws or certain regulatory restrictions). We assess the proposed terms and conditions in conjunction with legal guidance to ascertain whether the proposed control rights are likely to operate as intended.

2. **Length of the control period.** The length of time debt creditors have to exercise control rights before the issuer loses the right to generate cash flow from the assets (e.g., before an insolvency process or before a concession/regulatory license is terminated).

3. **Dedicated liquidity support.** Dedicated liquidity support facilities to cover ongoing debt service while control rights are exercised. To be considered valuable, such dedicated liquidity would need to be available for use in circumstances where control rights are exercised.

In almost all cases, to be effective and/or to assure the structure has integrity, debt structural features need to include the following elements:

1. The entity subject to the financing and the restrictions would be separated from the wider ownership group and any wider business group. The separation is achieved through legal means related to the creation of the issuer and/or restrictions in the financial structure.

2. All debt creditors must be subject to common terms that ensure that individual creditors or creditors cannot take unilateral action to destabilize the financing.

3. Creditor step-in rights should be specifically permitted under the concession, regulatory license or legal framework, as well as the finance documents. Note that we give value to security arrangements only as one element, albeit usually a critical element, of a wider package of features designed to improve creditors' ability to detect early potential problems and rectify them if possible (in the first instance by retaining cash surpluses within the company). Further, if remedial action is not possible or fails, the security arrangements are used to maximize recovery prospects.

Structural features that provide a meaningful level of creditor protection would provide a notching uplift to the composite score generated from the grid factors, a final step to arrive at the grid-indicated rating.

When assessing rating uplift we consider the package as a whole (i.e. elements of both A. and B. above) in order to gauge the overall effectiveness. For example, independent validation of compliance with financial ratio covenants may be an important consideration in assessing the ongoing effectiveness of such covenants.

Security is sometimes not allowed or is not enforceable on certain assets, the title of which may be retained by the state or other granting authority, or where the company is restricted from giving security over its assets by a pre-existing statute.

Structural enhancements that we view as very comprehensive and effective can deliver an uplift of up to three notches within the grid. However, across the rated universe, the current typical uplift is in the range of zero to two notches. Due to the broad spectrum of possible financing structures (which can contain a variety of elements in an array of potential combinations), these enhancements are scored in increments of half-a-notch. While debt structural features could in theory be stronger than those we have encountered, more restrictive terms and conditions would constrain management abilities to pursue strategies and policies and may not be suited to certain types of businesses, so they have typically fallen within a moderately narrow range.

Ratings fully incorporate our view of the actual structural or contractual features in a particular transaction. In rare cases contractual features may provide greater uplift to the issuer's credit quality that what is reflected in the scorecard.

Rating Methodology Assumptions, Limitations, and Rating Considerations That Are Not Covered in the Grid

The grid in this rating methodology represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that might enable the grid to map more closely to actual ratings. Accordingly, the five rating factors in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in this regulated networks sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used in the grid is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we cannot disclose. In other cases, we estimate future results based upon past performance, industry trends, competitor actions or other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

Assumptions that may cause our forward-looking expectations to be incorrect include unanticipated changes in any of the following factors: the macroeconomic environment and general financial market conditions, industry competition, disruptive technology, regulatory and legal actions.

Key rating assumptions that apply in this sector include our view that sovereign credit risk is strongly correlated with that of other domestic issuers, that legal priority of claim affects average recovery on different classes of debt, sufficiently to generally warrant differences in ratings for different debt classes of the same issuer, and the assumption that lack of access to liquidity is a strong driver of credit risk.

In choosing metrics for this rating methodology grid, we did not explicitly include certain important factors that are common to all companies in any industry such as the quality and experience of management, assessments of corporate governance and the quality of financial reporting and information disclosure. Therefore ranking these factors by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that have a meaningful effect in differentiating credit quality only in some cases, but not all. Such factors include financial controls, exposure to uncertain licensing regimes and possible government interference in some countries. Regulatory, litigation, liquidity, technology and reputational risk as well as changes to consumer and business spending patterns, competitor strategies and macroeconomic trends also affect ratings. While these are important considerations, it is not possible to precisely express these in the rating methodology grid without making the grid excessively complex and significantly less transparent. Ratings may also reflect circumstances in which the weighting of a particular factor will be substantially different from the weighting suggested by the grid.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the grid. For example, liquidity is a consideration frequently critical to ratings and which may not, in other circumstances, have a substantial impact in discriminating between two issuers with a similar credit profile. As an example of the limitations, ratings can be heavily affected by extremely weak liquidity that magnifies default risk. However, two identical companies might be rated the same if their only differentiating feature is that one has a good liquidity position while the other has an extremely good liquidity position.

Other Rating Considerations

Ratings consider a number of additional considerations. These include but are not limited to: the impact of non-core businesses, our assessment of the quality of management, corporate governance, financial controls, liquidity management and event risk.

Impact of Non-Core Businesses

This methodology grid is applied to the assessment of issuers, who primary activity is the ownership and operation of regulated electric and gas networks. Where the company has or will seek to diversify its operations towards other business types, we will determine the impact of such entities on credit quality. In particular, the ownership of material businesses with higher credit risk than electric and gas networks would likely result in an actual rating that is lower than the grid-indicated rating.

Liquidity and Access to Capital Markets

Liquidity analysis is a key element in the financial analysis of electric and gas networks, and it encompasses a company's ability to generate cash from internal sources as well as the availability of external sources of financing to supplement these internal sources. Liquidity and access to financing are of particular importance in this sector. Network assets can often have a very long useful life - 30, 40 or even 60 years is not uncommon, as well as high price tags. Furthermore, the sector has historically experienced prolonged periods of negative free cash flow, such that a portion of capital expenditure must be debt financed. Dividends also represent a quasi-permanent outlay, as networks only rarely will cut their dividend. Liquidity is also important to meet maturing obligations, which often occur in large chunks, and to meet collateral calls under any hedging agreements.

Our assessment of liquidity for regulated networks involves an analysis of total sources and uses of cash over the next 12 months or more. Using our financial projections and our analysis of its available sources of liquidity (including an assessment of the quality and reliability of alternate liquidity such as committed credit facilities), we evaluate how its projected sources of cash (cash from operations, cash on hand and existing committed multi-year credit facilities) compare to its projected uses (including all or most capital expenditures, dividends, maturities of short and long-term debt, our projection of potential liquidity calls on financial hedges, and important issuer-specific items such as special tax payments). We assume no access to capital markets or additional liquidity sources, no renewal of existing credit facilities, and no cut to dividends. We examine a company's liquidity profile under this scenario, its ability to make adjustments to improve its liquidity position, and any dependence on liquidity sources with lower quality and reliability.

Management Quality

The quality of management is an important factor supporting a company's credit strength. Assessing the execution of business plans over time can be helpful in assessing management's business strategies, policies, and philosophies and evaluates management performance relative to performance of competitors and our projections. A record of consistency provides Moody's with insight into management's likely future performance in stressed situations and can be an indicator of management's tendency to depart significantly from its stated plans and guidelines.

Size

The size and scale of a regulated networks has generally not been a major determinant of its credit strength in the same way that it has been for most other industrial sectors. However, size can still be a very important factor in our assessment of certain risks that impact ratings, including event risk, construction risk and access to external funding. While the grid attempts to incorporate some of the execution risk around large or complex projects into Factor 2, for some issuers these considerations may be sufficiently important that the rating reflects a greater weight for these risks.

Interaction of Ratings with Government Policies and Sovereign Ratings

Compared to most industrial sectors, regulated networks are more likely to be impacted by government actions. Credit impacts can occur directly through regulation, and indirectly through energy, environmental and tax policies. While Factor 1 of the grid attempts to capture many of these risks, for some issuers a greater weighting may be appropriate in assessing the rating.

Corporate Governance

Among the areas of focus in corporate governance are audit committee financial expertise, the incentives created by executive compensation packages, related party transactions, interactions with outside auditors, and ownership structure.

Financial Controls

We rely on the accuracy of audited financial statements to assign and monitor ratings in this sector. The quality of financial statements may be influenced by internal controls, including centralized operations and the proper tone at the top and consistency in accounting policies and procedures. Auditors comments in financial reports and unusual financial statement restatements or delays in regulatory filings may indicate weaknesses in internal controls.

Event Risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in an issuer's fundamental creditworthiness. Typical special events include mergers and acquisitions, asset sales, spin-offs, capital restructuring programs, litigation and shareholder distributions.

Structural Subordination

A utility company can finance itself in many different ways but it may involve a regulated network operating company (OpCo) and a holding company (HoldCo) structure with debt located at different levels. Given that creditors of the HoldCo usually have a secondary claim on the group's cash flows and assets after OpCo creditors, this leads to structural subordination. Our ratings of HoldCo debt are usually notched downwards from our assessment of group credit quality (which ignores priority of claim) but takes into account a number of other factors including, *inter alia*, the following:

» Regulatory or other barriers to cash movement from OpCos to HoldCos

» Specific ring-fencing provisions or financial covenants at the OpCo level

» HoldCo exposure to subsidiaries with high business risk or volatile cash flows

» Strained liquidity at the HoldCo level

Appendix A: Regulated Electric and Gas Networks Methodology Factor Grid

	Sub-factor weight	Aaa	Aa	A	Baa	Ba	B	Caa
Factor 1: Regulatory Environment and Asset Ownership Model (40%)								
Stability and Predictability of Regulatory Regime	15%	Regulation is independent, well established (> 15 years of being predictable and stable) and transparent (well-established regulatory principles clearly define risk allocation between companies and customers and are consistently applied, with public or shared financial models). These conditions are expected to continue.	Regulation is independent, well established (> 10 years of being predictable and stable) and transparent (well-established regulatory principles clearly define risk allocation between companies and customers and are generally consistently applied). These conditions are expected to continue.	Regulation is generally independent and developed (regulatory principles define risk allocation between companies and customers and are based on established precedents in the same jurisdiction). These conditions are expected to continue.	Regulatory framework is relatively new and untested, although regulatory principles are based on established precedents. Jurisdiction has a history of independent and transparent regulation for other utility services. These conditions are expected to continue.	Regulatory framework is defined but not consistently applied; tariff setting is subject to negotiation and political interference; some precedents in the country of predictable regulation for other utility services. These conditions are expected to continue.	Regulatory framework is unclear, untested or undergoing significant change, with a history of political interference. These conditions are expected to continue.	Regulatory framework is not defined, is unpredictable or politically driven with significant adverse consequences for the utility. These conditions are expected to continue.
Asset Ownership Model	5%	All key T&D assets held outright in perpetuity AND no risk that a change in ownership would negatively affect creditor rights.	All key T&D assets held outright under licence which can be terminated for underperformance, failure to meet certain financial parameters or insolvency OR held under long term concession with clearly defined right to timely recovery of residual asset value at termination/end of concession underpinned by highly rated entity AND no risk that a change in ownership would negatively affect creditor rights.	All key T&D assets held under long-term concession with clearly defined right to recover value of residual assets at termination/end of concession underpinned by highly rated entity but with undefined timeframe OR held under medium/long-term operating leases or management contracts with very substantial portfolio diversification, very established market position and very high renewal rate (>95%) AND no risk that a change in ownership would negatively affect creditor rights.	All key T&D assets held under long-term concession with some entitlement to recover value of residual assets at termination/end of concession but procedures untested/undefined OR held under medium-term operating leases or management contracts with substantial portfolio diversification, established market position and high renewal rate (>90%) AND/OR jurisdiction has reasonably strong property rights although there is some, albeit low risk that a change in ownership would negatively affect creditor rights.	All key T&D assets held under concession with recovery of residual asset value at termination/end of concession subject to negotiation OR held under short-term operating leases or management contracts with good degree of portfolio diversification and renewal rate (>80%) AND/OR jurisdiction may have some laws detailing property rights although these may be untested. A change of ownership would likely result in a loss for creditors.	Key T&D assets held under short-term operating leases or management contracts (limited portfolio diversification) with limited clarity on renewal and/or compensation AND/OR probability of termination/ expropriation is elevated. Compensation likely to be minimal and could be subject to significant delays in payment.	Company is in default of its licence, concession or lease/contract and is likely to lead to termination AND/OR expropriation very likely, no prospect of compensation.

	Sub-factor weight	Aaa	Aa	A	Baa	Ba	B	Caa
Cost and Investment Recovery (Ability and Timeliness)	15%	No regulatory or contractual impediment to adjust tariffs (no approval or reviews required).	Tariff formula is expected to allow for timely recovery of operating expenditure including depreciation, electricity losses and balancing costs/shrinkage gas and a fair return on all investment. All capital expenditure is included in asset base as incurred. Unanticipated expenditure quickly reflected in allowed revenue with low, if any, efficiency assessment.	Tariff formula is expected to allow for recovery of operating expenditure including depreciation based on allowances set at frequent price reviews (5-yearly intervals or shorter) and a fair return on all efficient investment. Capital expenditure is included in asset base as incurred. Opex and capex subject to efficiency tests; electricity losses and balancing costs/shrinkage gas subject to efficiency test on volumes only (price is a pass through). Unanticipated expenditure generally quickly reflected in allowed revenue although this may not be until the following regulatory period and may be subject to a degree of regulatory scrutiny or sharing factor with customers. Performance is likely to be in line with regulatory expectations.	Tariff formula is expected to allow for recovery of operating expenditure including depreciation and return on investment but subject to retrospective regulatory approval or infrequent price reviews (> 5-yearly intervals); recovery of electricity losses and balancing costs/shrinkage gas is somewhat exposed to price. Some instances of revenue backloading expected (e.g. depreciation allowance set below asset consumption or operating expenditure is capitalized). Unanticipated expenditure slow to be reflected in allowed revenue or may be subject to a stringent efficiency assessment/ low sharing factor. Performance may be below regulatory expectations.	Tariff formula is not expected to take into account all cost components and depreciation is set below asset consumption; recovery of electricity losses and balancing costs/shrinkage gas has large exposure to price. Revenues expected to cover most operating expenditure but investment is not clearly or fairly remunerated. Overspend either not recognized in allowed revenue or there is high uncertainty about its future recognition. Operational underperformance likely to be significantly impacting the returns achieved by the business.	Tariff formula is not expected to take into account all cost components and depreciation is set below asset consumption; recovery of electricity losses and balancing costs/shrinkage gas is fully exposed to price. Revenues expected to cover cash operating expenditure.	Revenues expected to only partially cover cash operating costs.
Revenue Risk	5%	No exposure to volume risk. Collected revenues based on capacity charges.	Very low exposure to volume risk. Collected revenues based on volume charges with stable volumes expected. Revenue cap mechanism with timely recovery in place.	Limited exposure to volume risk. Collected revenues based on volume charges with some volatility in volumes expected. Revenue cap mechanism in place; OR Hybrid price/revenue cap with low volatility in volumes.	Moderate exposure to volume risk. Hybrid price/revenue cap with moderate volatility in volumes; OR Some reliance on connection revenues.	Material exposure to volume risk: price cap with significant volatility in volumes; OR Material reliance on connection revenues.	High exposure to volume risk: price cap with substantial volatility in volumes; OR Very high reliance on connection revenues.	Very high exposure to volume risk: price cap with high concentration of volumes to one particular customer or sector; OR Revenues mainly driven by connections.

	Sub-factor weight	Aaa	Aa	A	Baa	Ba	B	Caa
Factor 2: Scale and Complexity of Capital Program (10%)								
Scale and Complexity of Capital Program	10%	Capex program is extremely limited in scale, reflecting a modern, highly developed asset base that requires only simple maintenance expenditure (e.g. total annual capex is < 4% of total fixed assets or regulated asset base).	Capex program is limited in scale, reflecting a well developed asset base that requires only maintenance expenditure (e.g. total annual capex is 4-6% of total fixed assets or regulated asset base).	Capex program is modest in size, reflecting a well developed asset base. Expenditure primarily relates to maintenance although some projects may be larger (e.g. total annual capex is 6-8% of total fixed assets or regulated asset base) or more complicated.	Capex program is manageable in size (e.g. total annual capex is 8-12% of total fixed assets or regulated asset base) or is generally straightforward (expenditure consists of a combination of replacement plus a number of development projects albeit with limited execution risk).	Capex program is large in size (e.g. total annual capex is 12- 20% of total fixed assets or regulated asset base) or is challenging in scope (small number of large and complex development projects account for the majority of capital expenditure and carry a degree of execution risk). Obligation to invest poses a financing challenge.	Capex program is very large in size (e.g. total annual capex is 20-30% of total fixed assets or regulated asset base) or highly complex in scope (one large or complex project accounts for majority of expenditure and carries a high execution risk). Capex obligation likely to pose a significant financing challenge.	Capex program is extremely large in size (e.g. total annual capex is ≥ 30% total fixed assets or regulated asset base) or is highly technically complex (one or more large projects account for the majority of expenditure and together carry a very high execution risk). Capex obligation likely to undermine the ongoing financial stability of the company.
Factor 3: Financial Policy (10%)								
Financial Policy	10%	Long track record and expected maintenance of extremely conservative financial policy; very stable metrics; low debt levels for the industry; AND Public commitment to the highest credit quality over the long-term.	Long track record and expected maintenance of a conservative financial policy; stable metrics; lower than average debt levels for the industry; AND Public commitment to a very high credit quality over the long-term.	Extended track record and expected maintenance of a conservative financial policy; moderate debt leverage and a balance between shareholders and creditors; Not likely to increase shareholder distributions and/or make acquisitions which could lead to a weaker credit profile; Solid commitment to high credit quality.	Track record and expected maintenance of a conservative financial policy; an average level of debt for the industry and a balance between shareholders and creditors; Some risk that shareholder distributions and/or acquisitions could lead to a weaker credit profile; Solid commitment to targeted metrics.	Track record or expectation of maintenance of a financial policy that is likely to favour shareholders over creditors; higher than average, but not excessive, level of leverage; Owners are likely to focus on extracting distributions and acquisitions but not at the expense of financial stability.	Track record of aggressive financial policies or expected to have a financial policy that favours shareholders through high levels of leverage with only a modest cushion for creditors; OR High financial risk resulting from shareholder distributions or acquisitions.	Expected to have a financial policy unfavourable to creditors with a track record of or expected policy of maintaining excessively high debt leverage; OR Elevated risk of debt restructuring.

	Sub-factor weight	Aaa	Aa	A	Baa	Ba	B	Caa
Factor 4: Leverage and Coverage (40%)								
Adjusted Interest Coverage Ratio: [8] (FFO + Interest Expense - Non-Cash Accretion[9] - Capital Charges) / (Interest Expense - Non-Cash Accretion)	10%	≥ 5.5x	3.5 - 5.5x	2 - 3.5x	1.4 - 2x	1.1 - 1.4x	0.9 - 1.1x	< 0.9x
OR		OR	OR	OR	OR	OR	OR	OR
FFO Interest Coverage: (FFO + Interest Expense) / Interest Expense		≥ 7.5x	5.5 - 7.5x	4 - 5.5x	2.8 - 4x	1.8 - 2.8x	1.1 - 1.8x	< 1.1x
Net Debt / RAB OR Net Debt / Fixed Assets[10]	12.5%	< 30%	30 - 45%	45 - 60%	60 - 75%	75 - 90%	90% - 100%	≥ 100%
FFO / Net Debt[11]	12.5%	≥ 35%	26 - 35%	18 - 26%	11 - 18%	5 - 11%	0 - 5%	< 0%
RCF / Net Debt[10]	5%	≥ 30%	21 - 30%	14 - 21%	7 - 14%	1 - 7%	(4) - 1%	< (4)%
Factor 5: Structural Considerations and Sources of Rating Uplift From Creditor Protection								
Number of Notches Provided by Debt Structural Features (0-3 notches)								

8 The adjusted ICR is our preferred metric for networks where allowed revenues/tariffs are determined using a 'building block approach' and where the components of allowed revenues/tariffs are routinely published and can be verified by an independent source, which in most cases is the regulatory authority itself. Required components of the revenue building block include: the total amount of allowed operating and capital expenditure, the portion of the RAB/asset base that provides for a return of capital (known as regulatory depreciation) and any other adjustments that can change the timing of cost recovery. It is calculated as: (FFO + Interest Expense – Non-Cash Accretion – Capital Charges) / (Interest Expense – Non-Cash Accretion). For regulated networks that utilize unconventional debt funding, such as zero-coupon, capital accretion, index-linked bonds or swap arrangements, we seek to make the appropriate adjustments to the ratio calculations to improve consistency and comparability to the peer portfolio. Please see Appendix B for a discussion of Capital Charges and some illustrative example of this ratio.

For other regulated networks, the ratio is calculated as (FFO + Interest Expense) / Interest Expense.

9 For clarity, Non-Cash Accretion is deducted in the numerator only to the extent it has been added to FFO, and it is deducted from the denominator only to the extent that it has been included in Interest Expense.

10 Net Debt / Regulatory Asset Base (RAB) is the preferred ratio where RAB is publicly available and when it represents the invested capital on which the network earns a return. Net Debt / Fixed assets is used in all other cases. Net Debt is total debt minus unrestricted cash. When Net Debt is negative, the score for this sub-factor is Aaa.

11 For FFO / Net Debt and RCF / Net Debt, when Net Debt is negative and the numerator is a positive number (thus, a negative ratio), the score is Aaa. When Net Debt is negative and the numerator is a negative number (thus, a positive ratio), the score is B.

Appendix B: Calculating the Adjusted Interest Coverage Ratio for the Regulated Electric and Gas Networks Grid

As discussed in the section explaining Factor 4: Leverage and Coverage, a regulator has significant ability to alter the timing of a networks' cost recovery by changing specific parts of the regulatory formula, for example through:

1. **Regulatory asset lives/regulatory depreciation:** a regulator can change the rate at which capital is returned to a network by changing the rate of depreciation of the RAB. Reducing asset lives to increase the rate of depreciation increases a networks' regulatory revenue and thus its FFO in the short-term but decreases the RAB in relative terms in the long term (thus reducing future cash returns).
2. **Speed of money:** under ex-ante regulatory frameworks, a regulator can change the rate at which allowed total expenditure (operating + capital) is capitalized into the RAB. In the UK, the regulatory allowances for operating expenditure are known as 'fast money' whereas the allowances for capital expenditure are known as 'slow money'. If the regulator's rate of capitalization into the RAB is lower than is implied in a company's financial accounts, 'fast money' will be higher than statutory operating expenditure, which increases a networks' regulatory revenue and thus FFO.
3. **Revenue profiling:** a regulator may choose to smooth the impact of revenue changes on the end customer by profiling the trajectory of tariffs over a control period. Volatility in revenue potentially results from a regulated network's investment program which could be lumpy. This may lead to a trajectory of costs that rises and falls within a short-term frame. This may be undesirable from a regulator's perspective which may choose to manage this by profiling allowed revenue such that all costs are recovered but the impact on the consumer is reduced.

The adjusted ICR attempts to normalize for these 'regulatory levers' by adjusting FFO by an amount of money ("Capital Charges") that can be influenced by regulatory decision making in the allowed revenue calculation. The Capital Charges typically consist of some or all of the following:

» Regulatory depreciation (for many regulated networks, this is the only Capital Charge)

» The excess of 'fast money' over operating expenditure

» The excess of 'profiled revenue' over 'un-profiled revenue'

In eliminating the effects of regulatory timing differences, the adjusted ICR instead tries to capture the credit effects of true cost outperformance and provide better comparability between networks that may be allowed greater current cash returns (either because revenue is being pushed forward or because the RAB is effectively being depleted faster) with those that are likely to have more stable returns over the longer term.

To illustrate these points, we consider four hypothetical regulated networks – company A, B, C and D, which have the same RAB. For all four companies, the regulator calculates allowed revenue using a 'building block' approach, i.e. money to cover operating expenditure (i.e. fast money), an allowed return to cover debt and equity costs plus regulatory depreciation, i.e. the portion of the RAB that has been allowed by the regulator to reward historic investment. Please see the table on the following page, which contains the specific numbers and ratios for each example.

Company A has a revenue of 200, of which 40 reflects regulatory depreciation, while company B has revenue of 240 and regulatory depreciation of 80. This reflects the regulator adopting a policy of 'accelerated depreciation' for company B, effectively bringing forward cash flow into the near-term to the detriment of the longer-term. This change results in an increase of revenue and FFO of 40 for company B, which significantly boosts its FFO-based financial ratios. In this example, FFO / net debt increases to 18%

from 12% and FFO interest coverage increases to 4.7x from 3.3x. In contrast, however, the adjusted ICR remains stable at 2.0x as the higher amount of regulatory depreciation is deducted from FFO for the purpose of the interest coverage ratio calculation. Our point in time example does not illustrate the effect of accelerated depreciation on net debt / RAB, which for Company B would be expected to increase over time unless debt were commensurately reduced or capex were commensurately higher.

Company C has a revenue of 220, which is 20 higher than for company A. The difference reflects the regulator allowing the company a higher amount of 'fast money' than their statutory amount of operating expenditure. In contrast, the amount of 'slow money' capitalized into the RAB (not illustrated) will be 20 lower than the statutory level of capital expenditure, lead to either less growth or a depletion of the RAB. Moody's considers this regulatory lever to be equivalent to the way revenue is influenced by changes to regulatory depreciation. Moody's therefore treats the 20 delta to be a further capital charge which is then deducted from FFO for the purpose of calculating the adjusted ICR. While FFO-based financial ratios are improved by increasing the speed of money, the adjusted ICR remains the same at 2.0x.

Company D has a revenue of 210, which is 10 higher than for company A. The difference reflects the regulator profiling the allowed revenue over the period of a price control in a different way than is implied by the company's expected evolution of costs (which may be volatile) but is preferred by the regulator because of the experience from the end consumer's perspective. If the profiling is calculated correctly, the Net Present Value of allowed revenue should be the same irrespective of the profiling method employed. In this example Moody's would treat the 10 amount of revenue benefit as a capital charge and would be deducted from FFO for the purpose of calculating the adjusted ICR. In contrast, in other periods within the price control, the profiling adjustment will be a negative amount but Moody's would adjust for it in a similar way (that negative amount would increase FFO net of Capital Charges).

		Company A (Conventional approach)	Company B (Accelerated regulatory depreciation)	Company C (Fast speed of money)	Company D (Revenue profile adjusted)
Regulatory Asset Base (RAB)	[a]	1000	1000	1000	1000
Regulatory depreciation as a % of RAB	[b]	4%	8%	4%	4%
Net debt	[c]	600	600	600	600
Total debt	[d]	600	600	600	600
Allowed rate of return	[e]	6%	6%	6%	6%
Actual cost of debt	[f]	5%	5%	5%	5%
Actual interest expense	[g] = [d] x [f]	30	30	30	30
Regulatory capitalization rate (slow money as a % of total expenditure)	[h]	75%	75%	70%	75%
Statutory capitalization rate (capital expenditure as a % of total expenditure)	[i]	75%	75%	75%	75%
Total expenditure	[j]	400	400	400	400
Statutory operating expenditure	[k] = [1 – [i]] x [j]	100	100	100	100
Speed of money adjustment	[l] = [[i] – [h]] * [j]	0	0	20	0
Revenue Building Block					
Fast money	[m] = [k] + [l]	100	100	120	100
Regulatory depreciation	[n] = [a] x [b]	40	80	40	40
Allowed return	[o] = [a] x [e]	60	60	60	60
Revenue profiling adjustment	[p]	0	0	0	10
Revenue allowance	[q] = [m] + [n] + [o] + [p]	200	240	220	210
FFO	[r] = [[q] – [k] – [g]]	70	110	90	80
Capital charges					
-regulatory depreciation	[n]	40	80	40	40

		Company A	Company B	Company C	Company D
		(Conventional approach)	(Accelerated regulatory depreciation)	(Fast speed of money)	(Revenue profile adjusted)
-excess fast money over opex	[s] = [m] – [k]	0	0	20	0
-profiled revenue over unprofiled revenue	[p]	0	0	0	10
Total capital charges	[t] = [n] + [s] + [p]	40	80	60	50
FFO net of Capital Charges	[y] = [r] – [t]	30	30	30	30
Ratios					
- Net Debt / RAB	[u] = [c] / [a]	60%	60%	60%	60%
- FFO / Net debt	[v] = [r] / [c]	12%	18%	15%	13%
- (FFO + Interest Expense) / Interest Expense	[w] = [[r] + [g]] / [g]	3.3x	4.7x	4.0x	3.7x
- Adjusted Interest Coverage Ratio	**[x] = [[y] + [g]] / [g]**	**2.0x**	**2.0x**	**2.0x**	**2.0x**

Appendix C: Considerations for Ratings Within a Corporate Family

Our approach to the ratings of network entities within a corporate family includes an assessment of the degree to which the credit quality of each legal entity is interlinked with the rest of the family or the degree to which the family members are insulated from each other. We assess the total landscape in determining whether probability of default is similar for each family entity, differentiated but tightly banded around an overall family credit quality, or differentiated with a wider banding. There can be a broad range in the combinations of credit insulating elements that are present in each family and also in their effectiveness. Major considerations include:

Regulatory framework

» Requirement that a network maintain a minimum financial profile (e.g., to comply with its regulatory license)

» Requirement that a network maintain a particular capital structure in order to earn its allowed revenues/tariffs (versus a network whose tariffs are set based on an assumed capital structure)

» Prohibition on pooling cash with a parent or certain affiliates or making loan advances to those entities (versus an ability of the parent company to pool the cash of all family entities)

» Pre-approval by the regulator for debt issuance and liquidity arrangements (versus the ability of a network's management to freely make financing decisions)

» Ability and willingness of the regulator to limit/prohibit the network from making dividend distributions to its parent

Financing structure

» Strength or weakness of financial covenants and other structural features

» The relative amounts of debt at each network and at holding companies (networks may have leverage at intermediate holding companies and at the parent company)

» For a holding company, the extent to which it is dependent on the distributions of a particular network in order to meet its own obligations

» Ability of each entity to meet its own liquidity needs (e.g., its dependence on external sources of support)

Corporate structure

» A network subsidiary may have independent board members whose votes are necessary for major corporate actions, including voluntary bankruptcy (versus a corporate family where the board members of each subsidiary are all parent company board members or managers)

» Network subsidiaries may have minority (and/or blocking) shareholders that must be consulted for major corporate actions

In many circumstances, the rating of a regulated network subsidiary is constrained by the overall credit quality of the group to which it belongs, because the regulatory treatment of its activities provides little credit insulation between entities and there is little restriction in the movement of cash between entities in the corporate or financing documents. The absence of such barriers tends to align the credit quality of a network with its family and parent. In these circumstances our rating analysis places a much heavier weight on an assessment of the consolidated group's credit quality, and the ratings of the family members are likely to be the same or very closely aligned. In these circumstances, a certain amount of credit deterioration at a weaker subsidiary within a utility family would more than likely be counterbalanced by stronger subsidiary(ies) and an expectation that the parent would find a way to direct support to the weak entity.

However, if the deterioration at a network subsidiary was severe (e.g., due to material regulatory challenges) and parent support was not assured, ratings within the group could be more differentiated, since the distressed regulated network could be rated well below the parent. There are aspects of the UK regulatory framework that have led to a partial de-linkage of ratings for group members. Typically, UK networks must: (1) maintain an investment grade credit rating; (2) not participate in sizeable unregulated business activities; (3) maintain at least 12 months of operating and financial resources; and (4) not pledge any of the network assets as collateral. Nevertheless, our approach to these groups typically starts with an assessment of consolidated credit quality and incorporates our view of the parent's activities, because until one of these triggers is breached, networks are mostly unimpeded from making distributions or maintaining a capital structure that is different than the one regulators assume when revenues/tariffs are set. However, were a trigger point to occur, e.g. if the credit quality of the wider parent fell below a certain level, the ratings of regulated networks with sufficiently protective arrangements may vary much more from the consolidated credit profile. Even in a situation of distress at the parent, regulated networks that are subject to these provisions may likely maintain a relatively high credit rating and could thus pierce the consolidated credit quality of the group by a substantial number of notches. In addition, notching within the family may be wider in the presence of debt structural features – these have been more widely used in the UK than other markets.

Even when meaningful regulatory barriers exist such that ratings of individual networks vary more widely from the consolidated credit profile, the credit quality of the parent still has an impact in most circumstances. Therefore, while credit analysis of the individual regulated network may have greater weight in our ratings, parent credit quality also plays a role. Nevertheless, in some jurisdictions there may be significant barriers to cash movement. For instance, in the United States, some state regulators engage in pervasive oversight of the financing arrangements of utility companies. Examples of state level oversight can include: (1) pre-approval by the regulator to increase indebtedness; (2) explicit leverage restrictions on the regulated entity and potentially on its immediate parent; (3) an expectation that the utility will maintain the capital structure utilized for rate-setting; (4) limitations on the exposure of a regulated network to its affiliates, for example via a regulated moneypool arrangement; and (5) higher regulatory pressure that restricts dividends. Nevertheless, the benefit to creditors of these arrangements can vary significantly between different states and leads to a range in the barriers to cash movement between regulated companies and related entities. US networks rated pursuant to this methodology are regulated primarily by the Federal Energy Regulatory Commission (FERC), which has tended to exercise less pervasive oversight than most state regulators with respect to financing arrangements. A change in approach by regulators may change our approach to assessing the ratings of networks in any family that we consider to be affected.

Appendix D: A Summary of Industry Issues over the Intermediate Term

Political and regulatory issues

The credit quality of a regulated electric and gas network is particularly sensitive to its regulatory and political environment. Issuers that are highly rated tend to be domiciled in jurisdictions where there is a sizeable track record of consistent and predictable decision making by the regulator and an absence of political interference. A fundamental change in the overall regulatory environment for rated networks would have a significant impact on ratings of the affected issuers.

High investment requirements

Regulated networks face ongoing high capital expenditure programs to maintain, upgrade and grow their asset base. Across many jurisdictions, the age of network infrastructure is relatively old and often results in high inefficiencies in the system through losses and equipment failure. Networks are often therefore obliged to invest significant amounts to replace and upgrade these ageing assets in order to improve the reliability of electricity and gas supplies. In addition, networks are often required to expand their asset base in response to macroeconomic drivers such as population growth and increases in wealth and consumption. Networks often need to invest ahead of expected higher loads and changing demand patterns. Significant additional capital expenditure also reflects the changing structure of the electricity and gas industry, particularly in Europe but also in the United States. In these regions, the old model of large power stations producing power away from demand centers is changing with distributed generation sources (e.g., solar photovoltaic and onshore wind) increasingly dominant in power supplies. The abundance of such non-conventional generation sources requires networks to invest in new connections but also to facilitate the two-way flow of electricity across the grid.

In a supportive regulatory environment, which allows for cost recovery and a reasonably contemporaneous return on investments, high levels of capital expenditure need not be a major credit concern. Should upward pressure on utility rates to consumers caused by major new grid investments diminish the regulatory support for regulated networks, there could be a negative impact on their ratings. In addition, a significant capital program that is either: (1) high relative to the size of the existing asset base; and/or (2) complex and involves new forms of technology (and thus greater likelihood of substantial cost over-runs) - could introduce meaningful execution risk that could negatively affect a networks' credit profile and its rating. In addition, an out-sized capital program will also likely present a financing challenge for a network, potentially negatively impacting its liquidity profile.

Economic and financial market conditions

Compared with other corporate issuers, networks tend to be more insulated from macroeconomic and financial market conditions as their revenues are determined by a regulatory authority and are set for a fixed period of time. Networks also tend to be relatively immune from a reduction in demand partly reflecting the generally lower elasticity of electricity and gas consumption but also the presence of 'revenue caps', also called 'de-coupling'. Revenue caps allow networks to adjust their tariffs as required in order to recover their full revenue entitlement even as demand profiles change – revenues are de-coupled from volumes.

In general, regulated networks tend to be more highly leveraged than similarly rated corporate issuers on account of their typically lower business risk profile. Since the 2008-09 global financial crisis, regulated networks have therefore benefitted from a significant decline in market interest rates reflecting in part the monetary policies of global central banks. However, a secondary consequence of a reduction in interest rates is that the allowed financial return (as determined by regulators) has also fallen. In general, networks were positively affected as their overall cost of debt has declined at a quicker rate than regulatory returns. However, some networks may be exposed, particularly if their average debt tenor is substantially longer than the time period considered by regulators when making this assessment. In such a scenario, regulatory returns will fall at a quicker rather than a company's cost of debt, leading to a weakening of key credit metrics. A further uncertainty is the response of regulators to rising interest rates, if and when this occurs, as both debt and equity investors will require a higher overall rate of return, but regulators may be unwilling to increase regulated tariffs by the same amount.

Moody's Related Research

The credit ratings assigned in this sector are primarily determined by this credit rating methodology. Certain broad methodological considerations (described in one or more credit rating methodologies) may also be relevant to the determination of credit ratings of issuers and instruments in this sector. Potentially related sector and cross-sector credit rating methodologies can be found here.

For data summarizing the historical robustness and predictive power of credit ratings assigned using this credit rating methodology, see link.

Definitions of Moody's most common ratio terms can be found in "Moody's Basic Definitions for Credit Statistics, User's Guide", accessible via this link.

Please refer to Moody's Rating Symbols & Definitions, which is available here, for further information.

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Appendix D:
Moody's Ratings Methodology: Unregulated Utilities and Unregulated Power Companies

MOODY'S
INVESTORS SERVICE

RATING METHODOLOGY

Unregulated Utilities and Unregulated Power Companies

Rate this Research

This rating methodology replaces "Unregulated Utilities and Unregulated Power Companies" last revised on October 31, 2014. We have updated some outdated links and removed certain issue-specific information.

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Summary

This rating methodology explains our approach to assessing credit risk for unregulated utilities and unregulated power companies globally. This document provides general guidance that helps companies, investors, and other interested market participants understand how qualitative and quantitative risk characteristics are likely to affect rating outcomes for companies in these sectors. This document does not include an exhaustive treatment of all factors that are reflected in our ratings but should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector. [1]

This report includes a detailed rating grid which is a reference tool that can be used to approximate credit profiles within the unregulated utilities and unregulated power sector in most cases. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to companies in these industries. However, the grid does not include every rating consideration. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions but actual importance may vary substantially. In addition, the grid in this document uses historical results while ratings are based on our forward-looking expectations. As a result, the grid-indicated rating is not expected to match the actual rating of each company.

[1] This update may not be effective in some jurisdictions until certain requirements are met.

The grid contains four factors that are important in our assessments for ratings in the unregulated utilities and unregulated power companies sector:

1. Scale
2. Business Profile
3. Financial Policy
4. Leverage and Coverage

Some of these factors also encompass a number of sub-factors.

This rating methodology is not intended to be an exhaustive discussion of all factors that our analysts consider in assigning ratings in this sector. We note that our analysis for ratings in these sectors covers factors that are common across all industries such as ownership, management, liquidity, corporate legal structure, governance and country related risks which are not explained in detail in this document, as well as other factors that can be meaningful on a company-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a grid format. The grid used for this methodology reflects a decision to favor a relatively simple and transparent presentation rather than a more complex grid that might map grid-indicated ratings more closely to actual ratings.

Highlights of this report include:

» An overview of the rated universe

» A summary of the rating methodology

» A description of factors that drive rating quality

» Comments on the rating methodology assumptions and limitations, including a discussion of rating considerations that are not included in the grid

The Appendices show the full grid (Appendix A), and some key issues for the sector over the intermediate term (Appendix B).

This methodology describes the analytical framework used in determining credit ratings. In some instances our analysis is also guided by additional publications which describe our approach for analytical considerations that are not specific to any single sector. Examples of such considerations include but are not limited to: the assignment of short-term ratings, the relative ranking of different classes of debt and hybrid securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities.[2]

[2] A link to sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

About the Rated Universe

This methodology is applicable to unregulated utilities and unregulated power companies. The principal business of unregulated utilities is the production and/or procurement and supply to end-users of electricity, gas and other energy-related utility[3] services/products (including district heating and ancillary services) in unregulated or lightly regulated markets. The principal business of unregulated power companies is the production and/or procurement and sale of electricity and, to a lesser extent, natural gas, in unregulated markets. For both subsectors, the selling price of the commodity is determined by market forces or is a negotiated contractual price agreed between the buyer and seller, as opposed to a price determined (or heavily influenced) by a regulator.

An additional distinction between unregulated utilities and unregulated power companies lies in activities outside their principal business of selling electricity or gas on an unregulated or lightly regulated basis. Specifically, unregulated utilities own and operate other material assets along the electricity and gas value chains that may have lower business risk profiles relative to their core activity and may also diversify their consolidated cash flow. These may include some combination of (i) electricity and gas network/utility activities (distribution and transmission), which continue to be regulated as monopoly businesses; (ii) other quasi-regulated activities, such as district heating; (iii) upstream oil and gas assets; and (iv) midstream assets including gas storage or LNG terminals.

Other characteristics common to unregulated utilities and unregulated power companies follow:

» They earn the majority of earnings and cash flow from unregulated rather than regulated activities and are differentiated in this respect from both Regulated Electric and Gas Utilities and Regulated Electric and Gas Networks, [4] while their profit motive differentiates them from U.S. Public Power Electric Utilities with Generation Exposure (there are separate rating methodologies for each of these sectors).

» They typically have no credit enhancing structure, such as debt service reserve requirements or trustee administered waterfall of accounts, nor are there inherent curbs on their ability to grow which differentiates them from Power Generation Projects covered under a separate methodology.[5]

» They operate in countries or sub-sovereign jurisdictions that have undergone or are undergoing a process of liberalization and deregulation of the upstream generation and wholesale markets and the downstream supply market.

» They operate in markets where both wholesale and retail prices are, or will be, primarily set by market mechanisms, although in some countries there may be a provision for 'tariffs/providers of last resort' to ease consumers' transition to full de-regulation.

» While the prices they charge are not regulated, many of the companies' activities typically are subject to other types of regulation. Oversight to prevent market manipulation through collusion or withholding power from the markets is typically achieved through a combination of the relevant legal framework, such as anti-trust and anti-conspiracy laws, or an energy market framework and consumer protection regulations.

[3] In some countries, the word utility is synonymous with the entity that supplies electricity and gas to end-use customers, even though the market has been liberalized and the price of these products/services is unregulated. In other countries, the word utility connotes an entity that provides products and services on a price-regulated basis, and entities that provide energy products/services to end-use customers on an unregulated basis are typically called retail energy suppliers.

[4] A link to these and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

[5] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

About This Rating Methodology

This report explains the rating methodology for unregulated utilities and unregulated power companies in six sections, which are summarized as follows:

1. Identification and Discussion of the Grid Factors

The business models of unregulated utilities and unregulated power companies have many similarities, and these are reflected in the close alignment of the grid factors for the two types of companies. At the same time, certain specific industry characteristics and nuances are reflected in modest differences in definitions and weightings for certain sub-factors. For example, the impact on unregulated utilities' business risk profile from ownership of assets apart from power generation and supply is captured by an additional sub-factor, 'Business mix impact on cash flow predictability', not applicable to unregulated power companies. Moreover, a greater weight is given to the 'Hedging and integration impact on cash-flow predictability' and 'Market framework and positioning' sub-factors for unregulated power companies because hedging and competitive positioning play a relatively more important role in their more narrowly-based business model than they do for unregulated utilities, whose greater breadth of business generally also contributes to more cash flow predictability.

The grids in this rating methodology focus on four broad rating factors. The four factors are comprised of sub-factors that provide further detail.

EXHIBIT 1

Unregulated Utilities and Unregulated Power Companies

Broad Rating Factor	Rating Sub-Factor	Unregulated Utility Sub-Factor Weighting	Unregulated Power Company Sub-Factor Weighting
1. Scale	Scale	10%	10%
2. Business Profile	Market diversification	10%	5%
	Hedging and integration impact on cash flow predictability	5%	10%
	Market framework and positioning	10%	15%
	Capital requirements and operational performance	5%	5%
	Business mix impact on cash flow predictability	10%	-
3. Financial Policy	Financial policy	10%	15%
4. Leverage and Coverage	(CFO Pre-W/C + Interest) / Interest Expense	10%	10%
	(CFO Pre-W/C) / Debt	15%	20%
	RCF / Debt	15%	10%
Total		**100%**	**100%**

2. Measurement or Estimation of Factors in the Grid

We explain our general approach for scoring each grid factor and show the weights used in the grids. We also provide a rationale for why each of these grid components is meaningful as a credit indicator. The information used in assessing the sub-factors is generally found in or calculated from information in company financial statements, derived from other observations or estimated by our analysts.

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends in a company's performance as well as for peer comparisons. In this case, we utilize historical data (in most cases, the most recent three years of reported results). All of the quantitative credit metrics incorporate Moody's standard adjustments to the income statement, cash flow statement and balance sheet amounts for restructuring, impairment, off-balance sheet accounts, receivable securitization programs, under-funded pension obligations, and recurring operating leases.[6] However, the factors in the grid can be assessed using various time periods. Rating committees often find it analytically useful to examine both historical and expected future performance for periods of several years or more.

3. Mapping Grid Factors to the Rating Categories

After estimating or calculating each sub-factor, the outcomes for each of the sub-factors are mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, B, Caa, or Ca).

4. Assumptions, Limitations and Rating Considerations Not Included in the Grid

This section discusses limitations in the use of the grid to map against actual ratings, some of the additional factors that are not included in the grid but can be important in determining ratings, and limitations and assumptions that pertain to the overall rating methodology.

5. Determining the Overall Grid-Indicated Rating[7]

To determine the overall grid-indicated rating, we convert each of the sub-factor scores into a numeric value based upon the scale below.

Aaa	Aa	A	Baa	Ba	B	Caa	Ca
1	3	6	9	12	15	18	20

6 For a description of Moody's standard adjustments, please see Moody's Approach to Global Standard Adjustments in the Analysis of Financial Statements for Non-Financial Corporations. A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

7 In general, the grid-indicated rating is oriented to the Corporate Family Rating (CFR) for speculative-grade issuers and the senior unsecured rating for investment-grade issuers. For issuers that benefit from ratings uplift due to parental support, government ownership or other institutional support, the grid-indicated rating is oriented to the baseline credit assessment. For an explanation of baseline credit assessment, please refer to our rating methodology on government-related issuers. Individual debt instrument ratings also factor in decisions on notching for seniority level and collateral. The documents that provide broad guidance for these notching decisions are our rating methodologies on loss given default for speculative grade non-financial companies and for aligning corporate instrument ratings based on differences in security and priority of claim. The link to these and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

The numerical score for each sub-factor is multiplied by the weight for that sub-factor with the results then summed to produce a composite weighted-factor score. The composite weighted factor score is then mapped back to an alphanumeric rating based on the ranges in the table below.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Aaa	x < 1.5
Aa1	1.5 ≤ x < 2.5
Aa2	2.5 ≤ x < 3.5
Aa3	3.5 ≤ x < 4.5
A1	4.5 ≤ x < 5.5
A2	5.5 ≤ x < 6.5
A3	6.5 ≤ x < 7.5
Baa1	7.5 ≤ x < 8.5
Baa2	8.5 ≤ x < 9.5
Baa3	9.5 ≤ x < 10.5
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5
Caa1	16.5 ≤ x < 17.5
Caa2	17.5 ≤ x < 18.5
Caa3	18.5 ≤ x < 19.5
Ca	x ≥ 19.5

For example, an issuer with a composite weighted factor score of 11.7 would have a Ba2 grid-indicated rating.

6. Appendices

The Appendices exhibit the full grid and provide additional commentary and insights on our view of credit risks in this industry.

Discussion of the Grid Factors

The grid for unregulated utilities and unregulated power companies focuses on four broad factors:

» Scale

» Business Profile

» Financial Policy

» Leverage and Coverage

Factor 1: Scale

Why it Matters

Scale is important because it typically provides flexibility for a company to mitigate the risks associated with liberalized power and gas markets, including competition in generation and supply and the management of commodity price volatility.

Larger companies benefit from greater diversification, financial resources and liquidity relative to smaller firms, which can provide increased resiliency to external shocks, weather variability and economic downturns. Larger firms may also have increased bargaining strength with customers and suppliers, a competitive advantage.

How We Assess it For the Grid

Scale is assessed using total assets measured in USD. We also consider the size of the overall market in which the company operates. Certain companies – while smaller in scale – have focused on maintaining or building entrenched national or regional positions where they can capitalize on certain strengths such as a high market share in supply.

Sub-Factor/ (Weighting)	Aaa	Aa	A	Baa	Ba	B	Caa
Scale (USD Billion) (10%)	Total assets ≥ $100	Total assets $50-100	Total assets $25-50 OR Total assets > $10 and entrenched position in substantial national/regional market	Total assets $10-25 OR Total assets $5-10 and entrenched position in substantial national/regional market	Total assets $5-10 OR Total assets $2.5-5 and entrenched position in substantial national/regional market	Total assets $2.5-5 OR Total assets $1-2.5 and entrenched position in local market	Total assets < $2.5

Factor 2: Business Profile

Why it Matters

The Business Profile factor considers an entity's ability to generate recurring cash flows to support capital intensive assets and sustain its business model and financial viability. Given the inherent volatility of energy commodity prices, an evaluation of a company's business risk profile is central to our assessment of the sustainability of an issuer's cash flows and its ability to meet its obligations over time. This includes consideration of market diversification, asset quality, competitive positioning, hedging, integration of generation and supply outlets, and business mix.

How We Assess it For the Grid

In considering the business profile of unregulated utilities and unregulated power companies, we focus on several sub-factors, including the diversification of operations, cash flow predictability, market structure and competitive position and the capital requirements of the business. For unregulated utilities, we also take into account the contribution from and risk profile of businesses beyond their core activity of the generation/procurement and supply of utility services.

Market Diversification

This grid sub-factor considers the number of uncorrelated regions, countries, or continents in which a company operates as well as the materiality of its operations. Generally speaking, the greater the degree of geographic diversification, the higher the scoring for this sub-factor assuming the geographic diversification is across stable economic regions. Issuers that operate in one concentrated geographic region are likely to be scored quite low in this sub-factor, especially if the region's market is undeveloped.

For unregulated power companies, scoring is based on the geographic diversification in the core operations. For unregulated utilities, in addition to the core operations, scoring may take into consideration the diversification of businesses outside an issuer's principal activities.

Sub-Factor/ (Weighting)	Aaa	Aa	A	Baa	Ba	B	Caa
Market Diversification[8]	Expected to maintain material operations in 5 or more separate well developed geographic or market regions	Expected to maintain material operations in 3 or more separate well developed geographic or market regions with no one market accounting for 50% or more of EBITDA	Expected to maintain material operations in 3 or more separate well developed geographic or market regions but > 50% of EBITDA comes from a single market	Expected to maintain material operations in more than one geographic or market regions with no one market accounting for >75% of EBITDA	Expected to operate predominantly in a single well developed geographic region	Expected to operate in multiple geographic regions but power markets are undeveloped or emerging	Expected to operate in a single undeveloped or emerging power market

Hedging and Integration Impact on Cash Flow Predictability

We evaluate the relative predictability of a company's year-over-year cash flow by considering the effectiveness of its hedging strategy with respect to conventional generation, the contribution from other contractual or market arrangements (such as PPAs or capacity payments) and the extent to which a high quality customer supply base can help dampen overall cash flow volatility. A company's ability to achieve a high degree of earnings visibility with respect to its conventional power output over an extended period of time is a function of the tenor and form of contracts or hedging arrangements in place as well as the

8 Sub-factor weighting for Unregulated Utilities is 10% and for Unregulated Power Companies 5%

company's policy regarding how hedged its cash flows will remain in future years. The contractual arrangements for most power and utility companies tend to range from one to five years, although some can be significantly longer, with the amount of currently contracted or hedged output tending to decline on a total percentage basis in each future year. We also assess an issuer's hedging policy and practices. Some issuers' level of hedging is very consistent over time, others are more opportunistic leading to greater fluctuations, and some choose to ride the markets with relatively open positions. In addition, we consider the extent to which other contractual or market arrangements can enhance the predictability of earnings. These could include power purchase agreements (PPAs) with dependable counterparties, capacity payments under a stable market framework or output from renewable energy sources (RES) operating under an established and stable incentive framework.

We recognize that aside from customized bilateral contractual arrangements, it is generally difficult and expensive to hedge effectively beyond five years and that market liquidity is often limited to three years. We also recognize that the potential and motivation to hedge varies from market to market depending on local conditions. Issuers whose contracts or hedges provide sound visibility on a majority of expected future cash flows over the next three year period are often scored Baa or higher. Issuers that choose not to hedge or hedge over very short tenors tend to score lower in this sub-factor as their cash flows tend to be volatile.

The scoring of this sub-factor also takes into account how a sizeable downstream customer base (most typically retail customers) can help dampen overall cash flow volatility. For a given sub-factor score, companies with a substantial, high quality customer base can have a shorter tenor for contracts or hedges than companies with a less meaningful or resilient customer base. A high quality customer base would typically be characterized by sizeable market share, wide diversification by customer type and low churn, with usage patterns that are generally predictable and either stable or growing.

In addition: (1) where an unregulated utility has a large gas supply business, we take into account its procurement strategy, including consideration of the benefits/costs of any upstream gas position or portfolio of long term supply contracts; and (2) where a utility's principal business is its downstream customer base, with little or no generation capacity of its own, in scoring this sub-factor we consider the extent to which power price arrangements and hedges mitigate price and volume risk, acknowledging that the degree of hedging depends on the terms of the agreement.

Sub-Factor	Aaa	Aa	A	Baa	Ba	B	Caa
Hedging and Integration Impact on Cash Flow Predictability[9]	Forward hedges or other contractual/ market arrangements provide a high degree of visibility on substantially all expected cash flow for the next 10 years OR Large, high quality captive downstream customer base in non-competitive market eliminates exposure to commodity risk over the long-term	Forward hedges or other contractual/ market arrangements provide good visibility on 75% or more of expected cash flow for the next 7 years OR good visibility on > 50% expected cash flow for the next 5 years, if underpinned by sizeable high quality customer base	Forward hedges or other contractual/ market arrangements provide good visibility on 50% or more of expected cash flow for the next 5 years OR good visibility on > 50% expected cash flow for the next 3 years, if underpinned by sizeable high quality customer base	Forward hedges or other contractual/ market arrangements provide good visibility on 50% or more of expected cash flow for the next 3 years OR good visibility on > 30% expected cash flow for the next 2 years, if underpinned by sizeable high quality customer base	Forward hedges or other contractual/ market arrangements provide good visibility on 30% or more of expected cash flow for at least the next 2 years OR good visibility on > 30% expected cash flow for at least the next year, if underpinned by sizeable high quality customer base	Minimal reliable cash flow visibility OR Limited ability to hedge OR Portfolio of contracts/hedges very short term OR Substantial short generation position versus customer base	No reliable cash flow visibility OR Hedging strategy is ineffective OR Most assets in underdeveloped markets characterised by little transparency, poor liquidity and limited potential to hedge

9 Sub-factor weighting for Unregulated Utilities is 5% and for Unregulated Power Companies 10%

Market Framework and Positioning - Unregulated Utilities

This rating sub-factor assesses the predictability and supportiveness of an unregulated utility's principal generation market, and its own positioning within that market. Our evaluation of the generation market will take account of how developed and settled the energy market framework is, the width of the reserve margin, and the market's susceptibility to political interference and intervention. Evidence of the credit supportiveness of a wholesale market framework may, for example, be adduced by the development of capacity markets whereby power producers are compensated for putting secured power plant capacity at the market's disposal in addition to receiving income from the sale of electricity. Our scoring also considers these elements for any substantial position an unregulated utility might have established beyond its principal market.

We assess how closely aligned a generator's fleet is expected to be to its principal market by comparing its power output by fuel/technology with the output of the market overall. Those generators whose fuel mix matches the merit order will typically benefit from higher load factors and a lower risk of mismatch between their cost drivers and the drivers of market prices. By contrast, a power generator whose generation fuel mix is significantly unbalanced in relation to the merit order will be at risk of under capacity utilization and/or more exposed to market price movements. Our assessment is prospective, and takes account of how we expect the fleet and market will evolve, including the effect of changes in environmental policies, energy efficiency legislation and other government policies. Perfect alignment is consistent with a score of Aaa. A generator is defined as being very well aligned with the market average where there is no material variance by fuel technology or plant efficiency – and is scored at A or Aa, and it would earn the higher score only when the market framework is both settled and supportive and when the portfolio is diversified. Most generators, however, have a material exposure by comparison with the market to at least one section of the merit order, and these are typically scored Baa (when that exposure is sufficiently limited and they remain well aligned with the market overall) or lower. We also take into account a generator's concentration in a single generation technology, defined as more than 50% of output.

Sub-Factor/ (Weighting)	Aaa	Aa	A	Baa	Ba	B	Caa
Market Framework & Positioning (10%)	Company operates in generation markets with clear, transparent and settled market frameworks, AND Generation mix is perfectly aligned with market and is expected to mirror future changes, and diversified portfolio (no fuel/ technology > 50% output)	Company operates in generation markets with settled and supportive market frameworks, AND Generation mix is expected to remain very well aligned with market average and diversified portfolio (no fuel/ technology > 50% output)	Company operates in generation markets with frameworks that are supportive but may be evolving, AND Generation mix is expected to remain very well aligned with market average and some fuel/ technology concentration (single technology > 50% output) may be present	Company operates within generation markets whose frameworks may be undergoing some change, Generation mix is expected to remain well aligned with market average and diversified portfolio (no fuel/ technology > 50% output)	Company operates within generation markets whose frameworks are undergoing change, Generation mix is expected to remain well aligned with market average and some fuel/technology concentration (single technology > 50% output) OR Generation mix is not well aligned with market average, and is expected to remain so for the foreseeable future and diversified portfolio (no fuel/ technology > 50% output)	Company operates the majority of its fleet in a relatively new and untested markets with high risk of adverse political interference, OR Generation mix is expected to remain mis-aligned with market average for the foreseeable future and Fuel/ technology concentration (single technology > 50% output)	Company operates within undeveloped market frameworks, which are unfavourable to generators, OR Generation mix is expected to remain mis-aligned with market average for the foreseeable future and single generation technology

Market Framework and Positioning - Unregulated Power Companies

This rating sub-factor considers the transparency and effectiveness of the wholesale power market(s) in which a company operates as well as the competitive profile and positioning of company-specific assets within the region. Aspects to consider in determining the effectiveness of a market framework include liquidity, pricing transparency, prevailing reserve margins and market demand, prospects for new generation, the length of time that the framework has been in place, the degree to which it has been tested (including in the courts) and expectations for material modifications.

Factors to consider in determining competitiveness include fleet diversification, capacity factors, cost structure, heat rates and fuel mix.

In order to score Baa or better, a company must operate predominantly in well-designed competitive market(s) and the competitive profile of its assets must be at least above average. Competitive assets that reside in a relatively new and untested wholesale power market are likely to score no better than B. Meaningful fuel concentration is also likely to impact scoring negatively.

Sub-Factor/ (Weighting)	Aaa	Aa	A	Baa	Ba	B	Caa
Market Framework & Positioning (15%)	Assets operate as a monopoly with unquestioned statutory government protection of competitive position AND Absence of fuel concentration risk	All assets operate in well designed, stable markets and company enjoys a dominant market position that provides it with a degree of pricing power AND Location, quality and cost competitiveness of assets are among the top decile and provide commanding market position with limited threat AND Absence of meaningful fuel concentration risk (e.g. no more than 50% of generation from single fuel type)	All assets operate in liquid, well designed competitive markets with supportive frameworks AND Location, quality and cost competitiveness of assets are within the top quartile and provide a clear competitive advantage or provide for contractual pass-through of costs AND Absence of meaningful fuel concentration risk (e.g. no more than 50% of generation from single fuel type)	Majority of assets operate in a liquid, well-designed competitive markets but whose frameworks may be undergoing some change AND Location, quality and cost competitiveness of assets are above average and provide some advantage or a solid market position AND Absence of meaningful fuel concentration risk (e.g. no more than 50% of generation from single fuel type)	Some assets operate in competitive markets that exhibit design weaknesses or are undergoing more substantial change OR Asset quality, cost profile and market position is average. Assets may have some exposure to environmental issues OR Presence of fuel concentration risk (e.g. more than 50% of generation from single fuel type)	Majority of assets operate in competitive markets that are oversupplied, poorly designed or new and untested or have a high risk of adverse political interference OR Asset quality, cost profile and market position are below average and assets may have significant exposure to environmental issues OR Presence of meaningful fuel concentration risk (e.g. 90% or more of generation from single fuel type)	Assets operate in markets that are persistently oversupplied, undeveloped or exhibit characteristics that are unfavorable to generators OR Assets are of questionable quality or at significant risk of shut-down due to economic and/or environmental considerations

Capital Requirements and Operational Performance

This sub-factor considers the general operational and financial risks associated with an extensive capital expenditure program and/or very complex investment projects. Companies facing a very large investment program compared to their existing asset base and/or projects of high technical complexity generally would score at the lower end of the spectrum. By contrast, companies with a relatively low capital investment requirement compared to their existing asset base would be considered less risky and typically achieve a higher score for this sub-factor.

To avoid beneficial treatment of companies which postpone maintenance investments and therefore achieve a low ratio of capital expenditures to net PP&E, we also consider the general age of a utility's asset base and its replacement requirements. Consequently, groups with significant replacement requirements might score lower on this sub-factor than the size of their planned capital expenditures might appear to warrant. For each scoring category there is an approximate guidepost of expenditures in comparison to net property, plant and equipment that would typically be found in that category, but the scoring takes all of the above-described aspects of future capital spending requirements into consideration.

While this sub-factor is primarily an assessment designed to capture the risk associated with large capital expenditure programs, the scoring also considers the impact of operational performance of the fleet on the issuer's prospective business risk.

Sub-Factor / (Weighting)	Aaa	Aa	A	Baa	Ba	B	Caa
Capital Requirements and Operational Performance (5%)	Extremely modest levels of capex needed for maintenance, environmental related expenditures or expansion of asset base, reflecting a modern, highly developed asset base (e.g. total annual future capex typically 3% or less of net PP&E).	Minimal levels of capex needed for maintenance, environmental related expenditures or expansion of asset base, reflecting a modern, well developed asset base (e.g. total annual future capex typically 5% or less of net PP&E).	Modest levels of capex needed for maintenance, environmental related expenditures or expansion of asset base, reflecting a modern, well developed asset base (e.g. total annual future capex typically 8% or less of net PP&E). Expenditures generally straightforward consisting of replacement plus a number of development projects with limited execution risk.	Manageable levels of capex needed for maintenance, environmental related expenditures or expansion of asset base (e.g. total annual future capex is typically 12% or less of net PP&E). Operational performance of the fleet is typically average relative to competitors.	Large capex program needed for maintenance, environmental related expenditures or expansion of asset base (e.g. total annual future capex is typically 15% or less of net PP&E) OR Capex program is challenging in scope and complexity and carries a degree of execution risk OR Operational performance is somewhat below average relative to competitors.	Significant capex program needed for maintenance, environmental related expenditures or expansion of asset base (e.g. total annual future capex is typically 20% or less of net PP&E) OR Capex program is challenging in scope and complexity and carries a high degree of execution risk OR Operational performance is decidedly below average relative to competitors.	Significant capex program needed for maintenance, environmental related expenditures or expansion of asset base (e.g. total annual future capex is typically 20% or more of net PP&E) OR Capex program is challenging in scope and complexity and carries a very high degree of execution risk OR Severe operational challenges.

Business Mix Impact on Cash Flow Predictability - Unregulated Utilities Only

Many of the unregulated utilities in Moody's rated universe have developed from a base which included ownership of the local monopoly transmission and distribution systems. Our methodology therefore factors in that unregulated utilities with an integrated model may derive a meaningful portion of their cash flows from regulated and quasi regulated activities. These businesses can exhibit a materially lower business risk profile compared with the predominant unregulated activities and thus enhance the resilience of a utility's earnings and cash flows in the face of economic and commodity cycle downturns. Conversely, a significant contribution to earnings and cash flows from high risk operations, due to the nature of the activities (e.g. speculative energy trading) or their location (e.g. developing and unstable markets) is a credit negative.

This methodology sub-factor is designed to adjust for the influence that contributions from lower- or higher-risk businesses may have on the overall stability of a utility's earnings and cash flows. The percentages are approximate guideposts, and our scoring also reflects the relative stability or volatility of these non-core businesses. The strongest score is attributed to utilities with very high EBITDA contribution from low-risk businesses (in most cases, regulated monopolies) and generated in developed countries/markets/regulatory frameworks, typically over 35% on a sustainable basis[10]. The lowest possible score is attributed to an operator with over 35% of EBITDA originating from high risk businesses, countries and/or markets. Where an operator generates some contribution from both regulated activities in

[10] Generally, the upper end of contribution from businesses outside the core unregulated utility business is about 49% for issuers rated under this methodology.

developed countries and higher risk operations, the factor assigned will reflect a "blend" of those different businesses.

Sub-Factor/ (Weighting)	Aaa	Aa	A	Baa	Ba	B	Caa
Business Mix Impact on Cash Flow Predictability (10%)	Very high, fully accessible contribution from low-risk businesses (typically, higher than 35% of EBITDA)	High, fully accessible contribution from low-risk businesses (typically 20-35% of EBITDA)	Sizeable, fully accessible contribution from low-risk businesses (typically 10-20% of EBITDA)	Contribution from low/higher-risk businesses limited as to scale or accessibility	Sizeable contribution from higher risk businesses / markets (typically 10-20% of EBITDA)	High contribution from higher risk businesses / markets (typically 20-35% of EBITDA)	Very high contribution from high risk businesses/ markets (typically, higher than 35% of EBITDA)

Factor 3: Financial Policy

Why It Matters

Management and board tolerance for financial risk is an important rating factor as it directly affects debt levels, credit quality and risk in the capital structure (e.g. refinancing risk, counterparty risk or exposure to interest rates or foreign exchange movements).

Our assessment of financial policies includes the perceived tolerance of a company's governing board and management for financial risk and the future direction for the company's capital structure. Considerations include a company's public commitments in this area, its track record for adhering to commitments, and our views on the ability for the company to achieve its targets.

Financial risk tolerance serves as a guidepost to investment and capital allocation. An expectation that management will be committed to sustaining an improved credit profile is often necessary to support an upgrade. For example, we may not upgrade a company that has built flexibility within its rating category if we believe the company will use that flexibility to fund a strategic acquisition, cash distribution to shareholders, spin-off or other type of leveraging transaction. Conversely, a company's credit rating may be better able to withstand a moderate leveraging event if management places a high priority on returning its credit metrics to pre-transaction levels and has consistently demonstrated the commitment to do so through prior actions.

Unregulated utilities and power companies have historically used acquisitions to consolidate market positions and advance cost synergies. The impact of an acquisition on a rating will invariably depend on the company's existing capital structure and the degree to which it is changed by the acquisition. A number of power companies have been implementing more aggressive shareholder return initiatives, including higher share repurchase activity, as top line growth has become more challenging.

How We Assess Financial Policy For The Grid

Moody's assesses the issuer's desired capital structure or targeted credit profile, history of prior actions and adherence to its commitments. Attention is paid to the issuer's operating performance over time and management's use of cash flow through different phases of economic and commodity cycles. Also of interest is the way in which management responds to key events, such as changes in the credit markets and liquidity environment, legal actions, competitive challenges, and regulatory pressures.

Management's appetite for M&A activity is assessed, with a focus on the type of transactions (i.e. core competency or new business) and funding decisions. Frequency and materiality of acquisitions and previous financing choices are evaluated. A history of debt-financed or credit-transforming acquisitions will generally result in a lower score for this factor.

We also consider a company and its owners' past record of balancing shareholder returns and debt holders' interests. A track record of favoring shareholder returns at the expense of debt holders is likely to be viewed negatively in scoring this factor.

Sub-Factor	Aaa	Aa	A	Baa	Ba	B	Caa
Financial Policy[11]	Long track record and expected maintenance of extremely conservative financial policy; very stable metrics; low debt levels for the industry; AND Public commitment to the highest credit quality over the long-term	Long track record and expected maintenance of a conservative financial policy; stable metrics; lower than average debt levels for the industry; AND Public commitment to a very high credit quality over the long-term	Extended track record and expected maintenance of a conservative financial policy; moderate debt leverage and a balance between shareholders and creditors; Not likely to increase shareholder distributions and/or make acquisitions which could lead to a weaker credit profile Solid commitment to high credit quality	Track record and expected maintenance of a conservative financial policy; an average level of debt for the industry and a balance between shareholders and creditors; Some risk that shareholder distributions and/or acquisitions could lead to a weaker credit profile; Solid commitment to targeted metrics	Track record or expectation of maintenance of a financial policy that is likely to favor shareholders over creditors; higher than average but not excessive, level of leverage; Owners are likely to focus on extracting distributions and/or acquisitions but not at the expense of financial stability	Track record of aggressive financial policies or expected to have a financial policy that favours shareholders through high levels of leverage with only a modest cushion for creditors; OR High financial risk resulting from shareholder distributions or acquisitions	Expected to have a financial policy unfavorable to creditors with a track record of or expected policy of maintaining excessively high debt leverage; OR Elevated risk of debt restructuring

Factor 4: Leverage and Coverage

Why it Matters

Leverage and coverage measures are indicators for a company's financial flexibility and long term viability. Financial flexibility is critical to unregulated utilities and unregulated power companies given the cyclical and capital intensive nature of the business and potential for volatility in cash flows. In assessing the sustainability of internally generated cash flow, we believe that analyzing cash from operations before changes in working capital (CFO pre-W/C) provides one of the best measures for issuers in this sector. While both CFO pre-W/C and funds from operations (FFO) exclude working capital changes, CFO pre-W/C is different in that it captures certain changes in assets and liabilities, which could include regulatory assets and liabilities as well as cash collateral posting requirements. Working capital changes are generally viewed as less important in the financial analysis of unregulated utilities and power companies, as these items are typically related to seasonal variations in receivables and fuel inventory.

The Leverage and Coverage factor is comprised of three financial metrics:

[11] Sub-factor weighting for Unregulated Utilities is 10% and for Unregulated Power Companies 15%

Interest Coverage

CFO pre-W/C Interest Coverage is used as an indicator for a company's ability to pay interest from internally generated cash flow. A stronger ratio indicates greater capacity to absorb a decline in earnings and cash flow without impairing the company's ability to meet interest payments on a timely basis.

Leverage

CFO pre-W/C to Debt is an important measurement of comparative leverage among companies in this sector and is an indicator of the cash generating ability of an unregulated utility or power company relative to its debt.

Retained Cash Flow to Debt is an indicator for financial leverage and of the strength of an issuer's cash flow after dividend payments. The higher the level of retained cash flow relative to an issuer's debt, the more cash the issuer has to finance its working capital, capital expenditure program, acquisitions and/or any debt reduction.

Debt - Net vs. Gross

Leverage metrics for unregulated utilities are calculated on a "net debt" basis (defined as total debt minus unrestricted cash) while those for unregulated power companies are calculated on a gross or total debt basis. The different treatment is driven by characteristics for each business sector. For example, unregulated utilities typically have greater diversification and a lower overall business risk profile that allows their cash flow to be more stable. Moreover, when these companies keep large cash balances, it tends to reflect a conservative financial policy, such as the pre-funding of debt maturities.

By contrast, unregulated power companies tend to have a more volatile business profile and when they have substantial cash balances, it tends to be for operating requirements, potential liquidity calls associated with hedges or because they do not have sufficient committed, syndicated credit facilities. Furthermore, as a group, these companies face more pressure to provide shareholder rewards in the form of share repurchases as well as pressure to engage in mergers and acquisition activities to better compete in their more highly competitive market environment.

How We Assess It For The Grid

» CFO pre-W/C Interest Coverage:

The numerator is CFO pre-W/C plus interest expense and the denominator is interest expense.

» CFO pre-W/C to Debt:

The numerator is CFO pre-W/C, and the denominator is net debt for unregulated utilities and total debt for unregulated power companies.

» Retained Cash Flow to Debt:

The numerator is FFO minus dividends and the denominator is net debt for unregulated utilities and total debt for unregulated power companies.

3-year Average/(Weighting)	Aaa	Aa	A	Baa	Ba	B	Caa
(CFO Pre-W/C + Interest) / Interest [12]	≥18x	13x - 18x	8x - 13x	4.2x - 8x	2.8x - 4.2x	1x - 2.8x	<1x
(CFO Pre-W/C) / Debt [13][14]	≥90%	60% - 90%	35% - 60%	20% - 35%	12% - 20%	5% - 12%	<5%
RCF / Debt [15]	≥60%	45% - 60%	25% - 45%	15% - 25%	8% - 15%	3% - 8%	<3%

Assumptions, Limitations, and Rating Considerations That Are Not Covered in the Grid

The grid in this rating methodology represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that might enable the grid to map more closely to actual ratings. Accordingly, the four rating factors in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in the unregulated utilities and unregulated power companies sectors. In addition, our ratings incorporate expectations for future performance, while the financial information that typically is used in the grid in this document is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we can't disclose. In other cases, we estimate future results based upon past performance, industry trends, competitor actions or other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

Assumptions that may cause our forward-looking expectations to be incorrect include unanticipated changes in any of the following factors: the macroeconomic environment and general financial market conditions, industry competition, disruptive technology, regulatory and legal actions.

Key rating assumptions that apply in this sector include our view that sovereign credit risk is strongly correlated with that of other domestic issuers, that legal priority of claim affects average recovery on different classes of debt sufficiently to generally warrant differences in ratings for different debt classes of the same issuer, and the assumption that access to liquidity is a strong driver of credit risk.

In choosing metrics for this rating methodology grid, we did not explicitly include certain important factors that are common to all companies in any industry such as the quality and experience of management, assessments of corporate governance and the quality of financial reporting and information disclosure. Ranking these factors by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that have a meaningful effect in differentiating credit quality only in some cases, but not all. Such factors include financial controls, exposure to uncertain licensing regimes and possible government interference in some countries. Regulatory, litigation, liquidity, technology and reputational risk as well as changes to consumer and business spending patterns, competitor strategies and macroeconomic trends also affect ratings. While these are important considerations, it is not possible to precisely express these in the rating methodology grid without making the grid excessively complex and significantly less transparent. Ratings may also reflect circumstances in which the weighting of a particular factor will be substantially different from the weighting suggested by the grid.

12 Sub-factor weighting for Unregulated Utilities and Unregulated Power Companies is 10%

13 Sub-factor weighting for Unregulated Utilities is 15% and for Unregulated Power Companies 20%

14 Leverage metrics for unregulated utilities are calculated on a "net debt" basis (defined as total debt minus unrestricted cash) while those for unregulated power companies are calculated on a total debt basis.

15 Sub-factor weighting for Unregulated Utilities is 15% and for Unregulated Power Companies 10%

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the grid. For example, liquidity is a consideration frequently critical to ratings and which may not, in other circumstances, have a substantial impact in discriminating between two issuers with a similar credit profile. As an example of the limitations, ratings can be heavily affected by extremely weak liquidity that magnifies default risk. However, two identical investment grade companies might be rated the same if their only differentiating feature is that one has a good liquidity position while the other has an extremely good liquidity position.

Other Rating Considerations

Ratings consider a number of additional considerations. These include but are not limited to: our assessment of the quality of management, corporate governance, financial controls, liquidity management, event risk and seasonality.

Management Strategy

The quality of management is an important factor supporting a company's credit strength. Assessing the execution of business plans over time can be helpful in assessing management's business strategies, policies, and philosophies including an evaluation of management's performance relative to the performance of competitors and our projections. A record of consistency provides us with insight into management's likely future performance in stressed situations and can be an indicator of management's tendency to depart significantly from its stated plans and guidelines.

Corporate Governance

Among the areas of focus in corporate governance are audit committee financial expertise, the incentives created by executive compensation packages, related party transactions, interactions with outside auditors, and ownership structure.

Financial Controls

We rely on the accuracy of audited financial statements to assign and monitor ratings in this sector. The quality of financial statements may be influenced by internal controls, including centralized operations and the proper tone at the top and consistency in accounting policies and procedures. Auditors' comments in financial reports and unusual financial statement restatements or delays in regulatory filings may indicate weaknesses in internal controls.

Liquidity Management

Liquidity is an important rating consideration for all unregulated utilities and unregulated power companies. Liquidity can be particularly important for non-investment grade unregulated utilities and unregulated power companies where issuers typically have less operating and financial flexibility. We form an opinion on likely near-term liquidity requirements from the perspective of both sources and uses of cash, including all contingent calls on cash flow.

Event Risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in an issuer's fundamental creditworthiness. Typical special events include mergers and acquisitions, asset sales, spin-offs, capital restructuring programs, litigation and shareholder distributions.

Appendix A

Unregulated Utilities Methodology Factor Grid								
Factor 1: Scale - 10%								
	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
Scale (USD billions)	Total assets ≥ $100	Total assets $50-100	Total assets $25-50 OR Total assets > $10 and entrenched position in substantial national/regional market	Total assets $10-25 OR Total assets $5-10 and entrenched position in substantial national/regional market	Total assets $5 -10 OR Total assets $2.5-5 and entrenched position in substantial national/regional market	Total assets $2.5-5 OR Total assets $1-2.5 and entrenched position in local market	Total assets < $2.5	10%

Unregulated Utilities Methodology Grid

Factor 2: Business Profile - 40%

	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
Market Diversification	Expected to maintain material operations in 5 or more separate well developed geographic or market regions	Expected to maintain material operations in 3 or more separate well developed geographic or market regions with no one market accounting for 50% or more of EBITDA	Expected to maintain material operations in 3 or more separate well developed geographic or market regions but > 50% of EBITDA comes from a single market	Expected to maintain material operations in more than one geographic or market regions with no one market accounting for >75% of EBITDA	Expected to operate predominantly in a single well developed geographic region	Expected to operate in multiple geographic regions but power markets are undeveloped or emerging	Expected to operate in a single undeveloped or emerging power market	10%
Hedging and Integration Impact on Cash Flow Predictability	Forward hedges or other contractual/ market arrangements provide a high degree of visibility on substantially all expected cash flow for the next 10 years OR Large, high quality captive downstream customer base in non-competitive market eliminates exposure to commodity risk over the long-term	Forward hedges or other contractual/ market arrangements provide good visibility on 75% or more of expected cash flow for the next 7 years OR good visibility on > 50% expected cash flow for the next 5 years, if underpinned by sizeable high quality customer base	Forward hedges or other contractual/ market arrangements provide good visibility on 50% or more of expected cash flow for the next 5 years OR good visibility on > 50% expected cash flow for the next 3 years, if underpinned by sizeable high quality customer base	Forward hedges or other contractual/ market arrangements provide good visibility on 50% or more of expected cash flow for the next 3 years OR good visibility on > 30% expected cash flow for the next 2 years, if underpinned by sizeable high quality customer base	Forward hedges or other contractual/ market arrangements provide good visibility on 30% or more of expected cash flow for at least the next 2 years OR good visibility on > 30% expected cash flow for at least the next year, if underpinned by sizeable high quality customer base	Minimal reliable cash flow visibility OR Limited ability to hedge OR Portfolio of contracts/hedges very short term OR Substantial short generation position versus customer base	No reliable cash flow visibility OR Hedging strategy is ineffective OR Most assets in underdeveloped markets characterized by little transparency, poor liquidity and limited potential to hedge	5%

Unregulated Utilities Methodology Grid

Factor 2: Business Profile - 40%

	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
Market Framework & Positioning	Company operates in generation markets with clear, transparent and settled market frameworks,	Company operates in generation markets with settled and supportive market frameworks,	Company operates in generation markets with frameworks that are supportive but may be evolving,	Company operates within generation markets whose frameworks may be undergoing some change,	Company operates within generation markets whose frameworks are undergoing change,	Company operates the majority of its fleet in a relatively new and untested markets with high risk of adverse political interference,	Company operates within undeveloped market frameworks, which are unfavourable to generators,	10%
	AND	AND	AND			OR	OR	
	Generation mix is perfectly aligned with market and is expected to mirror future changes, and diversified portfolio (no fuel/ technology > 50% output)	Generation mix is expected to remain very well aligned with market average and diversified portfolio (no fuel/ technology > 50% output)	Generation mix is expected to remain very well aligned with market average and some fuel/ technology concentration (single technology > 50% output) may be present	Generation mix is expected to remain well aligned with market average and diversified portfolio (no fuel/ technology > 50% output)	Generation mix is expected to remain well aligned with market average and some fuel/technology concentration (single technology > 50% output)	Generation mix is expected to remain mis-aligned with market average for the foreseeable future	Generation mix is expected to remain mis-aligned with market average for the foreseeable future	
					OR	and	and	
					Generation mix is not well aligned with market average, and is expected to remain so for the foreseeable future and diversified portfolio (no fuel/ technology > 50% output)	Fuel/ technology concentration (single technology > 50% output)	Single generation technology	

Unregulated Utilities Methodology Grid

Factor 2: Business Profile - 40%

	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
Capital Requirements and Operational Performance	Extremely modest levels of capex needed for maintenance, environmental related expenditures or expansion of asset base, reflecting a modern, highly developed asset base (e.g. total annual future capex typically 3% or less of net PP&E).	Minimal levels of capex needed for maintenance, environmental related expenditures or expansion of asset base, reflecting a modern, well developed asset base (e.g. total annual future capex typically 5% or less of net PP&E).	Modest levels of capex needed for maintenance, environmental related expenditures or expansion of asset base, reflecting a modern, well developed asset base (e.g. total annual future capex typically 8% or less of net PP&E). Expenditures generally straightforward consisting of replacement plus a number of development projects with limited execution risk.	Manageable levels of capex needed for maintenance, environmental related expenditures or expansion of asset base (e.g. total annual future capex is typically 12% or less of net PP&E). Operational performance of the fleet is typically average relative to competitors.	Large capex program needed for maintenance, environmental related expenditures or expansion of asset base (e.g. total annual future capex is typically 15% or less of net PP&E) OR Capex program is challenging in scope and complexity and carries a degree of execution risk OR Operational performance is somewhat below average relative to competitors.	Significant capex program needed for maintenance, environmental related expenditures or expansion of asset base (e.g. total annual future capex is typically 20% or less of net PP&E) OR Capex program is challenging in scope and complexity and carries a high degree of execution risk OR Operational performance is decidedly below average relative to competitors.	Significant capex program needed for maintenance, environmental related expenditures or expansion of asset base (e.g. total annual future capex is typically 20% or more of net PP&E) OR Capex program is challenging in scope and complexity and carries a very high degree of execution risk OR Severe operational challenges.	5%

Unregulated Utilities Methodology Grid

Factor 2: Business Profile - 40%

	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
Business Mix Impact on Cash Flow Predictability	Very high, fully accessible contribution from low-risk businesses (typically, higher than 35% of EBITDA)	High, fully accessible contribution from low-risk businesses (typically 20-35% of EBITDA)	Sizeable, fully accessible contribution from low-risk businesses (typically 10-20% of EBITDA)	Contribution from low/higher-risk businesses limited as to scale or accessibility	Sizeable contribution from higher risk businesses / markets (typically 10-20% of EBITDA)	High contribution from higher risk businesses / markets (typically 20-35% of EBITDA)	Very high contribution from high risk businesses/ markets (typically, higher than 35% of EBITDA)	10%

Factor 3: Financial Policy - 10%

	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
Financial Policy	Long track record and expected maintenance of extremely conservative financial policy; very stable metrics; low debt levels for the industry; AND Public commitment to the highest credit quality over the long-term	Long track record and expected maintenance of a conservative financial policy; stable metrics; lower than average debt levels for the industry; AND Public commitment to a very high credit quality over the long-term	Extended track record and expected maintenance of a conservative financial policy; moderate debt leverage and a balance between shareholders and creditors; Not likely to increase shareholder distributions and/or make acquisitions which could lead to a weaker credit profile Solid commitment to high credit quality	Track record and expected maintenance of a conservative financial policy; an average level of debt for the industry and a balance between shareholders and creditors; Some risk that shareholder distributions and/or acquisitions could lead to a weaker credit profile; Solid commitment to targeted metrics	Track record or expectation of maintenance of a financial policy that is likely to favor shareholders over creditors; higher than average but not excessive, level of leverage; Owners are likely to focus on extracting distributions and/or acquisitions but not at the expense of financial stability	Track record of aggressive financial policies or expected to have a financial policy that favours shareholders through high levels of leverage with only a modest cushion for creditors; OR High financial risk resulting from shareholder distributions or acquisitions	Expected to have a financial policy unfavorable to creditors with a track record of or expected policy of maintaining excessively high debt leverage; OR Elevated risk of debt restructuring	10%

Unregulated Utilities Methodology Grid

Factor 4: Leverage and Coverage - 40%

3-year Average	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
(CFO Pre-W/C + Interest) / Interest	≥18x	13x - 18x	8x - 13x	4.2x - 8x	2.8x - 4.2x	1x - 2.8x	<1x	10%
(CFO Pre-W/C) / Net Debt	≥90%	60% - 90%	35% - 60%	20% - 35%	12% - 20%	5% - 12%	<5%	15%
RCF / Net Debt	≥60%	45% - 60%	25% - 45%	15% - 25%	8% - 15%	3% - 8%	<3%	15%

Note: Leverage metrics for unregulated utilities are calculated on a "net debt" basis (defined as total debt minus unrestricted cash) while those for unregulated power companies are calculated on a total debt basis. The different treatment is driven by characteristics for each business sector.

Unregulated Power Companies Methodology Factor Grid

Factor 1: Scale - 10%

	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
Scale (USD Billion)	Total assets ≥ $100	Total assets $50-100	Total assets $25-50 OR Total assets > $10 and entrenched position in substantial national/regional market	Total assets $10-25 OR Total assets $5-10 and entrenched position in substantial national/regional market	Total assets $5 -10 OR Total assets $2.5-5 and entrenched position in substantial national/regional market	Total assets $2.5-5 OR Total assets $1-2.5 and entrenched position in local market	Total assets < $2.5	10%

Unregulated Power Companies Methodology Grid

Factor 2: Business Profile - 35%

	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
Market Diversification	Expected to maintain material operations in 5 or more separate well developed geographic or market regions	Expected to maintain material operations in 3 or more separate well developed geographic or market regions with no one market accounting for 50% or more of EBITDA	Expected to maintain material operations in 3 or more separate well developed geographic or market regions but > 50% of EBITDA comes from a single market	Expected to maintain material operations in more than one geographic or market regions with no one market accounting for >75% of EBITDA	Expected to operate predominantly in a single well developed geographic region	Expected to operate in multiple geographic regions but power markets are undeveloped or emerging	Expected to operate in a single undeveloped or emerging power market	5%
Hedging and Integration Impact on Cash Flow Predictability	Forward hedges or other contractual/ market arrangements provide a high degree of visibility on substantially all expected cash flow for the next 10 years OR Large, high quality captive downstream customer base in non-competitive market eliminates exposure to commodity risk over the long-term	Forward hedges or other contractual/ market arrangements provide good visibility on 75% or more of expected cash flow for the next 7 years OR good visibility on > 50% expected cash flow for the next 5 years, if underpinned by sizeable high quality customer base	Forward hedges or other contractual/ market arrangements provide good visibility on 50% or more of expected cash flow for the next 5 years OR good visibility on > 50% expected cash flow for the next 3 years, if underpinned by sizeable high quality customer base	Forward hedges or other contractual/ market arrangements provide good visibility on 50% or more of expected cash flow for the next 3 years OR good visibility on > 30% expected cash flow for the next 2 years, if underpinned by sizeable high quality customer base	Forward hedges or other contractual/ market arrangements provide good visibility on 30% or more of expected cash flow for at least the next 2 years OR good visibility on > 30% expected cash flow for at least the next year, if underpinned by sizeable high quality customer base	Minimal reliable cash flow visibility OR Limited ability to hedge OR Portfolio of contracts/hedges very short term OR Substantial short generation position versus customer base	No reliable cash flow visibility OR Hedging strategy is ineffective OR Most assets in underdeveloped markets characterized by little transparency, poor liquidity and limited potential to hedge	10%

Unregulated Power Companies Methodology Grid

Factor 2: Business Profile - 35%

	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
Market Framework & Positioning	Assets operate as a monopoly with unquestioned statutory government protection of competitive position AND Absence of fuel concentration risk	All assets operate in well designed, stable markets and company enjoys a dominant market position that provides it with a degree of pricing power AND Location, quality and cost competitiveness of assets are among the top decile and provide commanding market position with limited threat AND Absence of meaningful fuel concentration risk (e.g. no more than 50% of generation from single fuel type)	All assets operate in liquid, well designed competitive markets with supportive frameworks AND Location, quality and cost competitiveness of assets are within the top quartile and provide a clear competitive advantage or provide for contractual pass-through of costs AND Absence of meaningful fuel concentration risk (e.g. no more than 50% of generation from single fuel type)	Majority of assets operate in a liquid, well-designed competitive markets but whose frameworks may be undergoing some change AND Location, quality and cost competitiveness of assets are above average and provide some advantage or a solid market position AND Absence of meaningful fuel concentration risk (e.g. no more than 50% of generation from single fuel type)	Some assets operate in competitive market that exhibit design weaknesses or are undergoing more substantial change OR Asset quality, cost profile and market position is average. Assets may have some exposure to environmental issues OR Presence of fuel concentration risk (e.g. more than 50% of generation from single fuel type)	Majority of assets operate in competitive markets that are oversupplied, poorly designed or new and untested or have a high risk of adverse political interference OR Asset quality, cost profile and market position are below average and assets may have significant exposure to environmental issues OR Presence of meaningful fuel concentration risk (e.g. 90% or more of generation from single fuel type)	Assets operate in markets that are persistently oversupplied, undeveloped or exhibit characteristics that are unfavorable to generators OR Assets are of questionable quality or at significant risk of shut-down due to economic and/or environmental considerations	15%

Unregulated Power Companies Methodology Grid

Factor 2: Business Profile - 35%

	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
Capital Requirements and Operational Performance	Extremely modest levels of capex needed for maintenance, environmental related expenditures or expansion of asset base, reflecting a modern, highly developed asset base (e.g. total annual future capex typically 3% or less of net PP&E).	Minimal levels of capex needed for maintenance, environmental related expenditures or expansion of asset base, reflecting a modern, well developed asset base (e.g. total annual future capex typically 5% or less of net PPE).	Modest levels of capex needed for maintenance, environmental related expenditures or expansion of asset base, reflecting a modern, well developed asset base (e.g. total annual future capex typically 8% or less of net PPE). Expenditures generally straightforward consisting of replacement plus a number of development projects with limited execution risk.	Manageable levels of capex needed for maintenance, environmental related expenditures or expansion of asset base (e.g. total annual future capex is typically 12% or less of net PPE). Operational performance of the fleet is typically average relative to competitors.	Large capex program needed for maintenance, environmental related expenditures or expansion of asset base (e.g. total annual future capex is typically 15% or less of net PPE) OR Capex program is challenging in scope and complexity and carries a degree of execution risk OR Operational performance is somewhat below average relative to competitors.	Significant capex program needed for maintenance, environmental related expenditures or expansion of asset base (e.g. total annual future capex is typically 20% or less of net PPE) OR Capex program is challenging in scope and complexity and carries a high degree of execution risk OR Operational performance is decidedly below average relative to competitors.	Significant capex program needed for maintenance, environmental related expenditures or expansion of asset base (e.g. total annual future capex is typically 20% or more of net PPE) OR Capex program is challenging in scope and complexity and carries a very high degree of execution risk OR Severe operational challenges.	5%

Unregulated Power Companies Methodology Grid

Factor 3: Financial Policy - 15%

	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
Financial Policy	Long track record and expected maintenance of extremely conservative financial policy; very stable metrics; low debt levels for the industry; AND Public commitment to the highest credit quality over the long-term	Long track record and expected maintenance of a conservative financial policy; stable metrics; lower than average debt levels for the industry; AND Public commitment to a very high credit quality over the long-term	Extended track record and expected maintenance of a conservative financial policy; moderate debt leverage and a balance between shareholders and creditors; Not likely to increase shareholder distributions and/or make acquisitions which could lead to a weaker credit profile Solid commitment to high credit quality	Track record and expected maintenance of a conservative financial policy; an average level of debt for the industry and a balance between shareholders and creditors; Some risk that shareholder distributions and/or acquisitions could lead to a weaker credit profile; Solid commitment to targeted metrics	Track record or expectation of maintenance of a financial policy that is likely to favor shareholders over creditors; higher than average but not excessive, level of leverage; Owners are likely to focus on extracting distributions and/or acquisitions but not at the expense of financial stability	Track record of aggressive financial policies or expected to have a financial policy that favours shareholders through high levels of leverage with only a modest cushion for creditors; OR High financial risk resulting from shareholder distributions or acquisitions	Expected to have a financial policy unfavorable to creditors with a track record of or expected policy of maintaining excessively high debt leverage; OR Elevated risk of debt restructuring	15%

Unregulated Power Companies Methodology Grid

Factor 4: Leverage and Coverage - 40%

3-year Average	Aaa	Aa	A	Baa	Ba	B	Caa	Sub-Factor Weighting
(CFO Pre-W/C + Interest) / Interest	≥18x	13x - 18x	8x - 13x	4.2x - 8x	2.8x - 4.2x	1x - 2.8x	<1x	10%
(CFO Pre-W/C) / Debt	≥90%	60% - 90%	35% - 60%	20% - 35%	12% - 20%	5% - 12%	<5%	20%
RCF / Debt	≥60%	45% - 60%	25% - 45%	15% - 25%	8% - 15%	3% - 8%	<3%	10%

Note: Leverage metrics for unregulated utilities are calculated on a "net debt" basis (defined as total debt minus unrestricted cash) while those for unregulated power companies are calculated on a total debt basis. The different treatment is driven by characteristics for each business sector.

Appendix B: Some Key Issues for Unregulated Utilities and Unregulated Power Companies Over the Intermediate Term

Shale Gas and Fuel Price Volatility

The development of shale gas and shale gas resources in the United States, due largely to improved drilling techniques, has been a material negative for unregulated utilities and unregulated power companies, especially in North America. Specifically, the significant increase in supply has directly exerted downward pricing pressure on natural gas and, indirectly, power prices - placing particular downward pressure on gross margins derived from coal, nuclear and hydro-based generation.

Given the high correlation between natural gas and power prices, the demand/supply balance of natural gas in the lower 48 states will continue to impact both unregulated utilities and unregulated power companies. Trends that may influence the demand/supply balance over the intermediate term include weather patterns (while temporary, they can have a large impact on forward prices and ability to hedge), the state of the US economy, the export of liquefied natural gas to overseas markets and climate change legislation.

Presence and Absence of Capacity Markets

Power markets that value and compensate for capacity are a positive for credit quality of unregulated utilities and unregulated power companies. Specifically, in creating long-term price signals, capacity markets provide for a transparent cash flow stream that provides a degree of predictability to merchant generators' otherwise volatile revenue streams. There is a diversity among various geographies with some markets, especially in the US, providing value for capacity while others do not. Even within the US, some capacity markets provide longer term price signals than others. The cash flow predictability associated with capacity revenue is sometimes one of the drivers for differences in ratings between companies that solely operate in a region that highly values capacity (e.g. PSEG Locational Deliverability Area in PJM) and companies operating in regions that place little or no value on capacity (e.g. Midwest Independent System Operator). As such, the implementation of capacity markets in regions without one, or the development of a more sophisticated market in a market which currently has a rudimentary structure, could have positive rating implications.

Conventional power generation will continue to be displaced in Europe

Cash flow generated by European unregulated utilities' conventional fleets has decreased sharply because power output is under pressure from two structural trends: (1) electricity consumption will continue to decline or stagnate as energy efficiency efforts offset or partly offset any upside to power demand from recovering GDP; and (2) renewable energy will continue to increase its share of total power generated at the expense of conventional generation. Wide reserve margins – especially in Germany, Spain and Italy – have caused conventional generation load factors to decline sharply, especially for combined cycle gas turbines.

In addition to lower output, profitability and cash-flow generation will continue to be under pressure because of lower commodity prices. Lower prices for coal and carbon dioxide emission credits, combined with high reserve margins, have depressed power prices in coal-led markets. A future recovery in power prices would require a combination of stronger demand, firmer carbon dioxide credit prices and narrowing reserve margins.

Conflict between EU Energy Policy and National Interests harms European Unregulated Utilities

European Union (EU) energy policies have driven both the expansion of the renewable energy sector and the closure of older coal plants across much of Europe. The response of EU member states to the fallout from these policies (e.g. renewable energy intermittency, falling revenues for conventional power generators and rising consumer bills) has given rise to some conflict between EU objectives and the national interests of individual states. We do not see a resolution of these conflicts in the short-term, which creates uncertainty and thus risk for utilities.

» To ensure the security of their energy supplies against the backdrop of falling energy prices, narrowing spreads and renewable energy shortfalls, some EU member states have introduced capacity payment mechanisms as a way of partially compensating existing thermal operators with quasi-regulated revenues. However, these payment mechanisms arguably run contrary to the EU's aim to increase interconnection and the coupling of regional electricity markets to provide energy supply security.

» Reconciling the two priorities of consumer affordability and energy sustainability has become a challenge for EU member states. This is particularly true given that the widespread increase in renewable power generation (and its associated infrastructure) continues to increase the end-cost for consumers at a time of continued macroeconomic strain. The increasingly 'fixed-cost' nature of final energy tariffs is also serving to undermine the EU's efforts to promote efficiency, as a reduction in consumers' consumption may not significantly reduce costs.

Moody's Related Research

The credit ratings assigned in this sector are primarily determined by this credit rating methodology. Certain broad methodological considerations (described in one or more credit rating methodologies) may also be relevant to the determination of credit ratings of issuers and instruments in this sector. Potentially related sector and cross-sector credit rating methodologies can be found here.

For data summarizing the historical robustness and predictive power of credit ratings assigned using this credit rating methodology, see link.

Definitions of Moody's most common ratio terms can be found in "Moody's Basic Definitions for Credit Statistics, User's Guide", accessible via this link.

Please refer to Moody's Rating Symbols & Definitions, which is available here, for further information.

Report Number: 1066389

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Appendix E:
Moody's Rating Methodology: US Public Power Electric Utilities

MOODY'S
INVESTORS SERVICE

RATING METHODOLOGY

US Public Power Electric Utilities With Generation Ownership Exposure

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Summary

This rating methodology replaces "US Public Power Electric Utilities With Generation Ownership Exposure" published on December 29, 2015. It slightly revises the description of how two ratios are calculated in order to clarify that they remain consistent with the predecessor methodology for this sector. More specifically, it clarifies that the fixed obligation charge coverage ratio applies only to a public power utility that purchases some portion of its power under a take-or-pay contract with a Joint Action Agency (JAA) that has issued debt related to fulfilling that contract. In contrast, the adjusted debt service coverage ratio applies to a utility that does not have any such take-or-pay contracts, which typically occurs when that utility has direct ownership exposure and/or has entered into an all requirements take-and-pay contract. In addition, we clarify that the same adjustment to operating expenses described in the fixed obligation charge coverage ratio (under which a portion of operating expenses is re-classified as debt service) is also made in the adjusted days liquidity on hand ratio.

The text of this methodology is otherwise unchanged. For instance, ratings and sample scoring information contained herein (including Appendices B and C in their entirety) is as of December 29, 2015, and the What Has Changed section relates to the differences between the 2015 publication and the 2011 publication.

This rating methodology explains Moody's approach to assessing credit risk for US Public Power Electric Utilities with Generation Ownership Exposure. This document provides general guidance that helps issuers, investors, and other interested market participants understand how qualitative and quantitative risk characteristics are likely to affect rating outcomes for US public power electric utilities whose credit profile is largely influenced by power generation ownership. This document does not include an exhaustive treatment of all factors that are reflected in Moody's ratings but should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector.

This rating methodology replaces the US Public Power Electric Utilities with Generation Ownership Exposure Methodology published in November 2011. While reflecting many of the same core principles as the 2011 methodology, this updated document provides a more transparent presentation of the rating considerations that are usually most important for issuers in this sector and incorporates refinements in our analysis that better reflect credit fundamentals of the industry. No rating changes will result from the publication of this rating methodology.

This report includes a detailed rating grid and illustrative examples that compare the mapping of various issuers against the factors in the grid. The grid is a reference tool that can be used to approximate credit profiles within the US public power electric utilities with generation ownership exposure sector in most cases. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to issuers in the US public power electric utility sector whose credit profile is largely influenced by power generation ownership. However, the grid is a summary that does not include every rating consideration. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions but actual importance may vary substantially. In addition, the illustrative mapping examples in this document use historical results while ratings are based on our forward-looking expectations. As a result, the grid-indicated rating is not expected to match the actual rating of each issuer.

The grid contains five factors that are important in our assessment for ratings in the US public power electric utilities with generation ownership exposure sector:

1. Cost Recovery Framework Within Service Territory

2. Willingness and Ability to Recover Costs with Sound Financial Metrics

3. Generation and Power Procurement Risk Exposure

4. Competitiveness

5. Financial Strength and Liquidity

The scoring for factors 1-5 is aggregated to produce a preliminary grid-indicated rating that is adjusted upwards or downwards based on our view of scoring for factors 6, 7 and 8. Scoring for factors 6-8 can result in upward or downward notching for issuers that exhibit better or worse than typical positions in these areas.

6. Operational Considerations

7. Debt Structure and Reserves

8. Revenue Stability and Diversity

The combination of factors 1-8 results in the grid-indicated rating.

Since an issuer's scoring on a particular grid factor or sub-factor often will not match its overall rating, in Appendix C we include a discussion of some of the grid "outliers" – issuers whose grid-indicated rating for a specific factor or sub-factor differs significantly from the actual rating – in order to provide additional insights.

This rating methodology is not intended to be an exhaustive discussion of all factors that our analysts consider in assigning ratings in this sector. We note that our analysis for ratings in this sector covers factors that are common across all industries such as ownership, management, liquidity, legal structure, governance and country related risks, which are not explained in detail in this document, as well as factors that can be meaningful on an issuer-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a grid format. The grid used for this methodology reflects a decision to favor a relatively simple and transparent presentation rather than a more complex grid that would map grid-indicated ratings more closely to actual ratings.

Highlights of this report include:

» An overview of the rated universe

» A summary of the rating methodology

» A description of factors that drive rating quality

» Comments on the rating methodology assumptions and limitations, including a discussion of rating considerations that are not included in the grid

The Appendices show the full grid (Appendix A), a list of the 138 entities currently covered by this rating methodology (Appendix B), tables that illustrate the application of the grid to a representative sample of the covered issuers, with explanatory comments on some of the more significant differences between the grid-implied rating for each factor or sub-factor and our actual rating (Appendix C), and a brief summary of industry issues over the medium term (Appendix D).

Due to the prevalence in this sector of financing secured by a senior net revenue pledge (senior revenue bonds), the grid in this methodology is calibrated for this rating class, and the rating utilized for comparison to the grid-indicated rating is the issuer's senior revenue bond rating. Ratings for individual debt instruments also factor in assessments reflected in notching for seniority level and collateral. The document that provides broad guidance for such notching decisions is the methodology for aligning corporate instrument ratings based on differences in security and priority of claim, which can be found here**.** All issuers in this sector are owned by government entities in the US, and the grid is calibrated to incorporate the benefits of government ownership. As a result, uplift under Moody's Rating Methodology entitled "Government-Related Issuers" does not apply to this sector.

This methodology describes the analytical framework used in determining credit ratings. In some instances our analysis is also guided by additional publications which describe our approach for analytical considerations that are not specific to any single sector. Examples of such considerations include but are not limited to: the assignment of short-term ratings, the relative ranking of different classes of debt and hybrid securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities. Documents that describe our approach to such cross-sector methodological considerations can be found here.

What Has Changed?

While incorporating the core principles of the 2011 publication, this methodology introduces certain relatively minor changes that better reflect our current thinking.

More specifically, we have extended the lower end of each grid factor to include the B scoring category in order to better capture our views of more challenging political and/or regulatory environments and weaker business models. We have refined the title and scoring descriptions for Factor 3 (Generation and Power Procurement Risk Exposure) to clarify that there is potential risk exposure in both the generation and procurement strategies that a public power electric utility employs to meet its service obligation. We have also refined our definition for Factor 4 (Competitiveness) to better reflect that our view of a public utility's competitiveness is not confined to the historical percentage comparison above or below the state average system price of power as reported by EIA. Instead, our view of competitiveness is forward looking, and a comparison of rates for a key customer class or rates vis-á-vis neighboring utilities may in some cases be more important than a comparison to the state average. In Financial Strength and Liquidity, we have slightly revised the percentage ranges for the Debt Ratio to reflect the leverage we consider to be reasonably consistent with a particular rating category, which takes into consideration the monopolistic but capital intensive nature of this sector and the rate autonomy that public power utilities generally enjoy. Finally, to further improve transparency, we have introduced a new notching factor, "Stability and Diversity of Revenue", and eliminated the less specific "Other" notching factor. We considered all of the previously existing notching assigned under the "Other" category and determined that it could be incorporated into the previously existing "Operational Considerations" and "Debt Structure and Reserves" factors or under "Stability and Diversity of Revenue."

About the Rated Universe

This methodology is applicable to US public power utilities that own significant generation assets or that obtain at least 20% of their capacity/energy from directly owned power generation assets and/or from participation in municipal joint action agencies (JAAs). The issuers rated under this methodology include autonomous US federal, state and local power authorities (e.g. the Bonneville Power Administration, WA (Aa1/Stable, the Salt River Agricultural Improvement and Power District (Salt River Project; Aa1/stable)), departments of a municipality (e.g., the Los Angeles Department of Water and Power (Aa3/positive) or the San Antonio CPS (Aa1/stable)). The bonds issued by all of these entities are serviced solely from their utility and related operations; they do not represent general obligations of the governments that own or control them. Some of the utilities rated under this methodology are integrated, combining generation with high voltage transmission and lower-voltage distribution systems to sell power directly to end-users. Some issuers rated hereunder do not have distribution systems – they sell the power they generate and/or procure on a wholesale basis to other utilities.

Further characteristics that typify US public power utilities with generation exposure include:

» Near monopoly position in providing an essential service

» Unregulated and independent local rate-setting authority[1]

» Cost structure that is generally lower than investor-owned utilities due to the ability to issue lower cost tax-exempt debt and, for some, the availability under federal statute of federal low cost preference power

[1] Certain exceptions may apply; for example public power utilities in Wisconsin, Indiana, and the US Virgin Islands are subject to regulation

- Although not typically subject to income taxes or property taxes, most make payments in lieu of taxes (PILOTs); some also may make payments referred to as General Fund Transfers (GFTs)
- Lack of profit motive or need to generate a return on equity

US public power utilities with generation exposure under the 20% threshold on a sustained basis and those that have only transmission and distribution operations are rated under the US Municipal Utility Revenue Debt methodology. Municipal joint action agencies are entities formed by a group of US municipal utilities (participants) to provide reliable and competitively priced energy or energy related services – typically power, though they may also provide natural gas, electric transmission, or telecommunications services for energy assets. The participating municipal utility systems share an obligation established through a long-term contractual arrangement to cover the JAA's operating, capital, and debt service costs. JAAs are rated under the US Municipal Joint Action Agencies methodology.

Approximately 138 US public power electric utilities with generation exposure are currently rated under this methodology, representing approximately $130 billion of debt outstanding. Of this group, approximately half, with approximately $127 billion of debt outstanding, are issuers that have direct ownership of generation, while the other half, with approximately $3 billion of debt outstanding, are issuers that do not own material generation directly but are participants in one or more JAAs. Most of the electric revenue bond debt outstanding for the US public power sector has been issued by public power electric utility generators, like the Los Angeles Department of Water and Power (Aa3/positive) or San Antonio CPS (Aa1/stable), that own their transmission, distribution and power generation facilities, and correspondingly have ongoing capital programs.

Public power electric utilities that either own significant generation assets or obtain at least 20% of their electricity from directly owned power generation assets and/or from JAA participation generally have more fundamental credit risks than other essential purpose enterprises such as public power electric utilities that do not own generation assets. These fundamental risks include exposure to commodity markets, environmental regulation and larger capital requirements to maintain, refurbish or replace generation assets.

The ratings and outlooks for the 138 entities currently covered by this rating methodology are reflected in Appendix B (e.g.; 71 public power electric utilities that own generation directly and 67 public power electric utilities that do not own material generation but are participants in JAAs and receive more than 20% of their power supply through one or more JAA agreements).

The ratings distribution and history of US public power utilities with generation exposure generally reflects the essentiality of their service, monopoly positions, and, in most cases, autonomous rate-setting ability. However, US public power electric utilities that own generation have a higher degree of business complexity and credit risk than other essential municipal services such as electric and gas distribution, water, sewer, and storm water systems. Specifically, generation-owning electric utilities have greater operating and capital deployment risks, because they have a more complex asset conversion cycle and are subject to ongoing changes in regulations and commodity price that can affect the relative cost-efficiency of their generating fleets. While there remain many similarities with other essential purpose revenue bonds such as governance, bondholder security provisions and rate-setting flexibility, the challenging operating environment for a generation-owning electric utility is more pronounced. While there are some nuanced differences between direct ownership and JAA participation, in broad terms, a public power electric utility shares in the risks associated with JAA generation, and the grid factors are mostly the same for these two sub-groups.

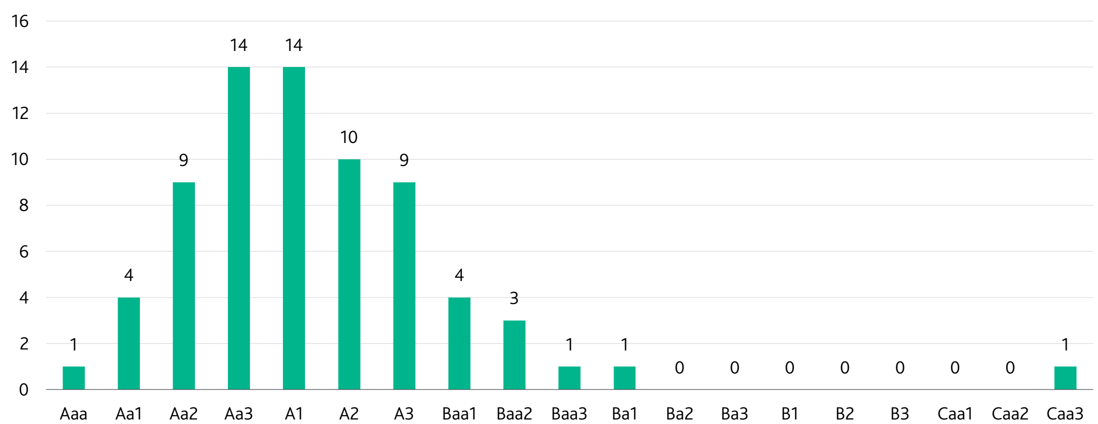
JAA participation typically takes one of two forms - a take-or-pay contract or an all requirements take-and-pay contract. Under a typical take-or-pay contract for a particular power plant, the utility is required to pay its share (usually a fixed percentage) of the JAA's total life-cycle costs of owning and operating that plant, even if the plant is not operable and regardless of whether the utility takes the power the plant generates. Termination provisions under take-or-pay contracts are essentially non-existent. Under a typical all requirements take-and-pay contract, the utility agrees to purchase all of its power needs (or a portion thereof) from the JAA and is responsible for a percentage of the JAA's total costs while the contract is in effect. The utility typically has the right to terminate the all requirements take-and-pay contract after a multi-year notice period, and the utility's obligation with respect to the JAA's costs is based on the utility's percentage share of the total power taken by all participants, which can vary over time according to usage patterns or the entry/exit of JAA participants.

Broad industry changes continue to introduce uncertainty to the public power sector, such as deregulation initiatives that have introduced a degree of competition, ongoing environmental policy changes, and supply and demand factors. Electric generation is capital intensive, and US public power electric utilities with generation exposure must make decisions that result in long-term obligations amidst a changing operating environment.

There have been no bond defaults and no bankruptcies in the past 50 years among US public power utilities with generation exposure, reflecting the sector's fundamental strengths. However, the current rating of one issuer, Puerto Rico Electric Power Authority (Caa3/negative) reflects the expectation of a near-term default. There was a major default in a related public power sector. In 1983, the Washington Public Power Supply System (WPPSS), a JAA, defaulted on approximately $2.25 billion of revenue bonds.

The rating distribution in this sector currently ranges from Aaa to Caa3. The rating distribution of those with directly owned generation is summarized in Exhibit 1, while the distribution for those owning generation through a JAA is summarized in Exhibit 2. In broad terms, the issuers that own material generation have higher ratings on average than those with generation exposure solely via JAAs. This reflects greater fundamental credit strengths in the former sub-group. While issuers that have generation exposure via JAAs have lower ratings on average, this does not typically stem from their JAA participation, which in many cases is an effective generation procurement and diversification strategy for these utilities relative to direct plant ownership.

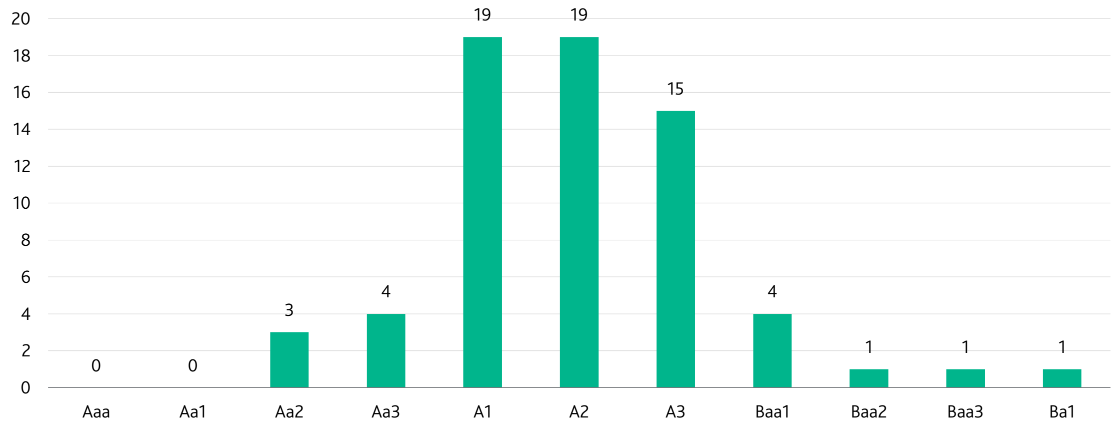
EXHIBIT 1
Owned Generation Rating Distribution



Source: Moody's Investors Service

EXHIBIT 2

Owned Generation Through JAA Rating Distribution



Source: Moody's Investors Service

About this Rating Methodology

This report explains the rating methodology for US public power electric utilities with generation ownership exposure in several sections, which are summarized as follows:

1. Identification and Discussion of the Grid Factors

The grid in this rating methodology focuses on eight rating factors. One of these factors is comprised of sub-factors that provide further detail. Factors 6-8 are used to make notching adjustments for operational considerations, debt structure and reserves, and revenue stability and diversity.

EXHIBIT 3

US Public Power Electric Utilities with Generation Ownership Exposure Methodology Factor Grid

Grid Factors	Factor Weighting	Sub-Factors	Sub-Factor Weighting
Cost Recovery Framework Within Service Territory	25%		25%
Willingness and Ability to Recover Costs with Sound Financial Metrics	25%		25%
Generation and Power Procurement Risk Exposure	10%		10%
Competitiveness	10%		10%
Financial Strength and Liquidity	30%	Adjusted days liquidity on hand (3-year avg) (days)	10%
		Debt ratio (3-year avg) (%)	10%
		Adjusted Debt Service Coverage OR Fixed Obligation Charge Coverage (3-years avg) (x)	10%
Total	**100%**	**Total**	**100%**
Operational Considerations	(notching adjustment)		
Debt Structure and Reserves	(notching adjustment)		
Revenue Stability and Diversity	(notching adjustment)		

2. Measurement or Estimation of Factors in the Grid

We explain our general approach for scoring each grid factor or sub-factor and show the weights used in the grid. We also provide a rationale for why each of these grid components is meaningful as a credit indicator. The information used in assessing the factors and sub-factors is generally found in or calculated from information in utility financial statements, derived from other observations or estimated by Moody's analysts.

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of an issuer's performance as well as for peer comparisons. We utilize historical data (in most cases, an average of the last three years of reported results) in this document to illustrate the application of the rating grid. However, the factors and sub-factors in the grid can be assessed using various time periods. For example, rating committees may find it analytically useful to examine both historic and expected future performance for periods of one year, several years or more.

The quantitative credit metrics in the grid incorporate any Moody's adjustments to the income statement, cash flow statement and balance sheet amounts.

3. Mapping Grid Factors to the Rating Categories

After estimating or calculating each factor or sub-factor, the outcomes for each of the factors and sub-factors are mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, or B).

4. Mapping Issuers to the Grid and Discussion of Grid Outliers

In Appendix C, we provide a table showing how a representative sampling of 30 utilities in this sector map to grid-indicated ratings for each rating sub-factor and factor. We highlight utilities whose grid-indicated performance on a specific factor or sub-factor is two or more broad rating categories higher or lower than its actual rating and discuss some general reasons for such positive and negative outliers for a particular factor or sub-factor.

5. Assumptions, Limitations and Rating Considerations Not Included in the Grid

This section discusses limitations in the use of the grid to map against actual ratings, some of the additional factors that are not included in the grid but can be important in determining ratings, and limitations and assumptions that pertain to the overall rating methodology.

6. Determining the Overall Grid-Indicated Rating

To determine the preliminary grid-indicated rating before notching considerations, we convert each of the factor and sub-factor scores into a numerical value based upon the scale below.

Sub-factor score to numeric value

Aaa	Aa	A	Baa	Ba	B
1	3	6	9	12	15

The numerical score for each grid factor or sub-factor is multiplied by the weight for that factor with the results then summed to produce a composite weighted-factor score. The composite weighted factor score is then mapped back to an alphanumeric rating based on the ranges in the table below.

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Aaa	x < 1.5
Aa1	1.5 ≤ x < 2.5
Aa2	2.5 ≤ x < 3.5
Aa3	3.5 ≤ x < 4.5
A1	4.5 ≤ x < 5.5
A2	5.5 ≤ x < 6.5
A3	6.5 ≤ x < 7.5
Baa1	7.5 ≤ x < 8.5
Baa2	8.5 ≤ x < 9.5
Baa3	9.5 ≤ x < 10.5
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5
Caa1	16.5 ≤ x < 17.5
Caa2	17.5 ≤ x < 18.5
Caa3	18.5 ≤ x < 19.5
Ca	x ≥ 19.5

For example, an issuer with a composite weighted factor score of 11.7 would have a Ba2 preliminary grid-indicated rating

Finally, we consider whether the preliminary grid-indicated rating score that results from factors 1-5 should be notched upward or downward based on operational considerations, debt structure and reserves, and revenue stability and diversity, in order to arrive at a final grid-indicated rating.

We used a similar approach to derive the grid-indicated ratings shown in the illustrative examples in Appendix C.

7. Appendices

The Appendices provide illustrative examples of grid-indicated ratings based on historical financial information and also provide additional commentary and insights on our view of credit risks in this industry.

Factor 1: Cost Recovery Framework Within Service Territory (25% Weight)

Why It Matters

The ability to recover prudently-incurred costs in a timely manner is one of the most important credit considerations for US public power electric utilities with generation ownership exposure, as a delay in cost recovery may cause financial stress. Therefore, the monopoly status, rate autonomy and where applicable, predictability and supportiveness of the regulatory framework in which a public power utility operates – as well as the legal and political framework that underpins it - are key credit considerations that differentiate this sector from most corporate sectors. In addition, the strength and diversity of the service territory is important because it can indirectly influence a public power electric utility's cost recovery framework. Larger, more diverse service areas with greater economic wealth are better able than smaller, less diverse areas to support rate increases that may be required as a result of changes in fuel and operating costs, required capital expenditures, or other causes.

In general, the US public power electric utilities with generation ownership exposure rated under this methodology are effectively monopoly providers of essential electric services, which limits competitive threats. With few exceptions, they are not subject to rate regulation, i.e. their revenues are not subject to price controls under the jurisdiction of any state public utility service commission as part of the process to reset them periodically. Price-setting mechanisms are generally structured by management, governing boards and or city councils at their sole discretion to limit volatility wherever possible and therefore tend to be highly predictable. The benefits of monopoly status and rate autonomy are further bolstered for most public utilities by minimum bond security covenants that require current revenues to match current expenses, including payment of debt service. There are some instances where regulation of rates by state public utility service commissions does apply. In these instances, the regulators may also have an effect on capital spending decisions and efficiency targets to reduce operating costs, which can affect the public utility's business position.

How We Assess the Cost Recovery Framework Within Service Territory for the Grid

Collectively three components, [1] the strength of monopoly control over a service area, [2] unregulated rate raising ability, and [3] the strength of a public power utility's customer base and service area economy are core characteristics in assessing this factor. In the US, public power electric utilities have maintained a near monopoly role in their service area, limiting competitive threats to their customer base. This monopoly control, in combination with an unregulated rate setting process, provides a greater certainty of the utility's ability to access its revenue requirement from the region served. Among utilities with strong monopolies and autonomous rate-setting (currently the large majority of issuers), assessment of the customer base and service area economic strength provides differentiation for this factor.

When evaluating the credit characteristics of the utility's service area, we consider population, employment trends, wealth indicators, and local economic diversity and growth projections. For example, we often utilize Moody's Economy.com for an assessment of current and projected economic strength of a particular service area. Weak economic characteristics and limited economic diversity would contribute to a lower score for Factor 1.

We also evaluate the wealth indicators of the population that a utility serves to gauge the ability of customers to pay their electric bills, both currently and in the future, if rates rise. Affluent residential customers generally have a higher tolerance for higher overall rates, since the electric bill is a small part of their disposable income.

We look at the relative mix of residential, commercial and industrial customers when assessing the stability of the customer base. Factor scoring for US public power electric utilities that serve a primarily residential customer base (e.g., more than 50% residential sales) would generally be favorably influenced because of benefits from the more stable load and revenue trends that typify the customer class. Alternatively, a customer base dominated by industrial load, particularly if concentrated in one or just a few industrial customers, would exert negative influence on scoring because public utilities with such a characteristic are more susceptible to economic cycles and demand changes that could affect revenue stability.

US public power electric utilities with generation ownership exposure that are subject to rate regulation typically receive lower scores for Factor 1, because rate regulation can sometimes limit or delay cost recovery. Public power electric utilities predominantly have amortizing debt and a debt service coverage requirement, so regulatory lag or cost disallowance that creates uncertainty could increase default risk. For utilities with regulated rate-setting, the regulatory framework can vary by state and may provide greater or lesser predictability in the certainty and timing of cost recovery depending on its details and the manner in which it is applied by regulators. Some states like Wisconsin and Indiana regulate public power electric utilities, but the regulation tends to be credit supportive, and regulators are required to consider bond covenants in their rulemaking. As reflected in the grid, regardless of other considerations in this factor, including service area economic strength and customer concentration, if a public power electric utility falls under typical state regulation (as normally applied to investor owned utilities) our assessment of Factor 1 would typically not exceed a Baa score.

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Cost Recovery Framework Within Service Territory	25%	Monopoly with unregulated rate setting and very strong customer base and service area economy	Monopoly with unregulated rate setting and strong customer base and service area credit economy	Monopoly with unregulated rate setting; average customer base and service area economy	Regulation of rates by state; weak customer base / service area economy	Regulation of rates by state with some inconsistency; or very weak customer base or service area economy	Regulation of rates by state is unpredictable; or extremely weak customer base or service area economy

Factor 2: Willingness and Ability to Recover Costs with Sound Financial Metrics (25% Weight)

Why It Matters

Willingness to use the independent and local rate-setting authority guided by sound bond covenants and governance is an extremely important consideration and a heavily weighted rating factor. Unregulated public power utilities may have the ability to raise rates but there can be meaningful differences in their willingness to do so, for a variety of public policy reasons that may have the effect of placing rate-payer concerns ahead of sound financial policy. Regulated public power utilities must have both the willingness to seek rate increases and the ability to obtain the necessary regulatory approvals. In either case, implementing rate increases in a timely fashion in order to maintain sound financial credit strength has been a fundamental credit strength for most issuers in the sector. Credit risk increases in the absence of the stability and certainty that maintenance of a financial buffer provides in mitigating the impact of modest credit stress events. Political risk or (when applicable) lack of regulatory support can result in an unwillingness or inability to establish sufficient rates to maintain sound financial metrics. Without sound rate-setting that is predictable and timely, debt service coverage ratios or liquidity are likely to be compromised. This factor may be a leading indicator of the direction of future financial performance for a US public power electric utility with generation ownership exposure.

Another important aspect is the degree of support, or lack thereof, from a related governmental entity, since most public power electric utilities are owned by local governments. This matters because a city may use its broader governance authority and or financial resources to prevent financial deterioration of the utility, which serves to protect revenue bond holders. Conversely, the government owner can take distributions from the utility, typically in the form of General Fund Transfer (GFTs), that limit the latter's financial flexibility, and the government can pressure the utility to hold down rates or increase capital expenditures in a manner that is detrimental to the maintenance of sound financial metrics.

The ability to automatically adjust rates for changes in fuel or power purchase costs has become a more notable credit factor in the past decade given wide fluctuations in natural gas prices, ongoing hydrology risk, and the volatility of the wholesale power market. Some utilities source a portion of their energy needs in the wholesale market, while others have used profits from wholesale sales to reduce the revenue requirement from retail users.

Rate-setting is a dynamic process that will continue to be tested in the next several years as power supply costs rise due to increased environmental regulation, demand growth remains slow due to the slow economic recovery, and utilities shift to cleaner but sometimes more expensive sources of supply (i.e., to comply with renewable portfolio standards). A forward view of a utility's ability and willingness to set rates to recover all costs has high importance.

How We Assess Willingness and Ability to Recover Costs with Sound Financial Metrics for the Grid

In assessing this factor, we evaluate the governing board's rate-setting process for its transparency, timeliness and supportiveness in setting the rates and charges necessary to ensure that costs, including debt service, are fully recovered. This may include considerations regarding the utility's ability to generate targeted revenue based on underlying volume assumptions. Rate mechanisms that mitigate the impact of revenue volatility are viewed positively.

Another key part of our assessment for this factor is length of time it takes to implement new rates and collect the additional revenues. A demonstrated record of ability and willingness to change rates on a timely or pro-active basis as required to recover operating and capital costs, to provide a cushion for debt service coverage, and to maintain sound liquidity are credit positives and would likely lead to scores at the mid-to-higher end of the rating scale for this factor, when that record is expected to continue. In those cases where utilities waiver and delay on actions to adjust rates as necessary to provide timely assurance of cost recovery, we would likely score them lower for this factor than we would for those who are more proactive in adjusting their rates.

Utilities that have an automatic fuel and purchased power cost adjustment mechanism are able to recover these costs on a more timely basis. Such adjustment mechanisms would typically contribute to a higher score for this factor because the mechanisms serve to narrow the potential drain on liquidity and the resulting impact on credit quality and are of particular importance should there be a fuel price spike or a forced outage of a generating unit. A material lag before the utility can recover these costs would likely contribute to a lower score.

When assessing this factor we also consider the relationship of the local government with the electric utility. This will not always be a material consideration, as some utilities have no fiscal relationship with a local government, or the utility may have been established as a separate and independent authority. We consider who governs the utility, who sets its rates, and who issues the revenue bonds for the utility, as well as the degree to which the general government is responsible for supporting the utility in times of financial stress.

Higher scores for this factor would be likely under circumstances where the interests of the utility and the government are aligned, and where a highly-rated local government has a strong record of supporting their public power electric utility in times of fiscal stress. Political risks and/or regulatory barriers that impede a utility's willingness to enact rates and charges on a timely basis that are sufficient to maintain the associated financial metrics for a utility's rating category would likely result in a lower score for this factor.

Finally, we focus on GFT policies when assessing this factor because the policies are an example of the relationship between a utility and their local government. The GFT is the transfer of surplus utility revenues from the utility to the city's General Fund. Policy-driven GFTs in very limited or conservative amounts typically contribute to higher scores for this factor, while ad hoc, larger amounts of GFTs not governed by policy typically contribute to a lower score. Established, prudent GFT policies that are accepted by both the utility and the local government add credit strength because they increase the predictability of the amount to be transferred. Alternatively, a policy established after a contentious debate for a transfer amount that represents a substantial portion of the utility's own revenues could have a negative impact, (i.e. if it produces uncompetitive electric rates or leaves limited internal funds available for utility operations, maintenance, and repairs) and contribute to a lower score for this factor.

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Willingness and Ability to Recover Costs with Sound Financial Metrics	25%	Excellent rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments less than 10 days; No political intervention in past or extremely high support from related government; Very limited General Fund transfers governed by policy	Strong rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments 10 to 30 days; Limited political intervention in past or high support from related government; Conservative and well-defined General Fund transfers governed by policy	Adequate rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments 31 to 60 days; Some political intervention in past or average support from related government; Moderate General Fund transfers	Below average rate-setting record; Rates, fuel, & purchased power cost adjustments 61 to 99 days; Persistent political intervention or below average support from related government; Large General Fund transfer not governed by policy	Some history or expectation of insufficient rate-setting; Rates, fuel, & purchased power cost adjustments 100 to 120 days; Highly political climate or very limited support from related government; Sizeable General Fund transfer not governed by policy	Lengthy record of, or expectation for a prolonged period of insufficient rate-setting ; Rates, fuel, & purchased power cost adjustments 120 days or more; Highly contentious political climate or clear lack of support from related government; Very sizeable General Fund transfer not governed by policy

Factor 3: Generation and Power Procurement Risk Exposure (10% Weight)

Why It Matters

Generation and power procurement risks, power supply costs and system reliability have an important influence on a utility's ability to meet its service obligations, the competiveness of current and future rates, and financial metrics over time. Efficiently meeting its current electricity demand and planning effectively for future demand has direct bearing on a utility's leverage, customer satisfaction, rate levels, service reliability, and often on the political support for the utility. Political and regulatory support rooted in customer satisfaction can translate into a greater willingness and ability to establish the rate levels needed to keep the utility in sound financial condition.

Successful resource planning, most often accomplished through fuel source diversity and the maintenance of a sufficient but not excessive reserve margin, is fundamental to the utility's future health given the objective to provide low-cost, safe and reliable power supply to its customers. The continuing challenge of managing environmental regulations related to clean air and renewable standards underscores the importance of this factor. These standards can vary by state, have been increasing over time and are often litigated, which typically delays implementation, but may cloud the visibility into the standards that will eventually be enforced.

How We Assess Generation and Power Procurement Risk Exposure for the Grid

When assessing generation and power procurement risks, we consider the mix and diversity of a utility's power supply, as well as the cost and reliability. Maintaining a diverse fuel and resource mix increases the utility's flexibility to manage peak demand while limiting the utility's exposure to volatile commodity and energy market prices, disruptions in the delivery of a single fuel source, or increased costs associated with a particular asset, for instance the cost of environmental compliance for a coal plant. Our review of the utility's generation performance record may include indicators such as availability (% of time a generation unit is operational); capacity factor (% of capacity the generation fleet runs); and heat rates (efficiency of a generator to convert fuel into electrical energy). Additional considerations may include the primary terms and conditions of any purchase power agreements in the context of the utility's overall power supply mix, the positioning of the assets on the regional dispatch curve and the associated impact on the all-in cost of power supply, and the main drivers of the overall retail price charged to the end-use customer. Above-market power supply costs could lead to higher retail charges to end-use customers, which would likely contribute to a lower score for this factor.

We consider the utility's main generation sources, whether owned or purchased under contract, since each type (e.g. natural gas, coal, nuclear, hydro) has risks which must be properly managed. Such risks include fuel price (for instance, natural gas prices can demonstrate high seasonal volatility), transportation issues (e.g., availability of rail and barging delivery for coal, availability of peak period pipeline capacity for natural gas), safety regulations (e.g., Nuclear Regulatory Commission (NRC) regulations for nuclear generation facilities), hydrology risks for hydroelectric generating units, and environmental compliance issues for coal-fired generating units.

In evaluating the generation strategy, we consider the utility's flexibility with regard to fuel-switching. Alternate transportation modes/routes and fuel storage may also be meaningful considerations. By maintaining sufficient power resource reserve margin, a utility is better positioned to manage an unexpected forced outage of a large generating facility. Risk exposures that are not adequately mitigated would contribute to a lower score on this factor.

Public power electric utilities with limited diversification or that are heavily reliant on a single type of generation and fuel source typically score lower on this factor. In some cases, such as high reliance on hydro, the risk may be mitigated somewhat by the cost competitiveness of the fuel source, provided there is ready access to alternative sources of generation. Utilities with a high reliance on coal-fired generation are likely to score lower on this factor due to their vulnerability to future EPA regulations, including under the Clean Power Plan.

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Generation and Power Procurement Risk Exposure[2]	10%	Very limited exposure to negative repercussions from generation, procurement and commodity price risks; High degree of diversification of generation and/or fuel sources; Single generation asset typically provides less than 20% of power; or up to 20% of energy from coal-fired generation with carbon mitigation strategy	Limited exposure to negative repercussions from generation, procurement and commodity price risks; Some diversification of generation and/or fuel sources; Single generation asset typically provides less than 40% of power; or up to 40% of energy from coal-fired generation with carbon mitigation strategy	Moderate exposure to negative repercussion from generation, procurement and commodity price risks; Some reliance in one type of generation and/or fuel source, but diversified with purchased power sources; Single generation asset may provide up to 55% of power; or up to 55% of energy from coal-fired generation with carbon mitigation strategy	Moderate to high exposure to negative repercussion from generation, procurement and commodity price risks; Reliance on a single type of generation or fuel source, with somewhat limited diversification via purchased power; Single generation asset typically provides up to 75% of power; or up to 70% of energy from coal-fired generation with carbon mitigation strategy	High exposure to negative repercussion from generation, procurement and commodity price risks; Very high concentration in a single type of generation or very high reliance on a single fuel source, with limited diversification via purchased power; Single generation asset typically provides up to 75% of energy from coal-fired generation with carbon mitigation strategy, or up to 50% of energy from coal with no mitigation strategy	Very high exposure to negative repercussion from generation, procurement and commodity price risks; very high concentration in a single type of generation, almost entirely reliant on a single fuel source, with very limited diversification via purchased power; Single generation asset typically provides over 85% of power; or over 85% of energy from coal-fired generation with carbon mitigation strategy, or over 50% of energy from coal-fired generation with no mitigation strategy

Factor 4: Competitiveness (10% Weight)

Why It Matters

Despite the closed retail market for almost all public power electric utilities, an important advantage of the sector is the price competitiveness for retail and/or wholesale customers, especially relative to investor-owned utilities. We would expect increased political and regulatory risks if the utility has uncompetitive rates, leading to a potentially more challenging rate setting environment despite the rate autonomy that is prevalent in the sector. High retail rates cause pressure on the governing board (and regulators when applicable) to delay rate increases or perhaps even lower rates, which could affect the utility's ability to recover costs and weaken debt service coverage. In addition, high rates may discourage economic development and contribute to a stagnant or declining revenue base, which could impact debt service coverage in the long-run. Public power electric utilities with large, energy-intensive customers that contribute significantly to their net income could face pressure if high industrial or commercial retail rates motivate those large customers to relocate. The shuttering/relocation of large users can weigh negatively on the local economy and also place additional upward pressure on electric rates for the utility's remaining customers.

How We Assess Competitiveness for the Grid

In assessing this factor, we consider a utility's average system retail rate in the context of its regional peers. In many cases, the state average rate is very relevant, but a competiveness comparison to neighboring utilities may be more important for some issuers. For instance, in some states a single utility may dominate, rendering in-state comparisons less meaningful. For public utilities near major metropolitan areas, the

[2] In scoring this factor, generation includes generation from owned assets and via participation in JAAs, unit power agreements and similar arrangements.

important comparison may be to neighboring utilities, especially if there are transmission constraints to in-state utilities that may have a different cost base.

A comparison of retail rates is generally considered in terms of the system average revenue per kilowatt hour (cents/kwh). The average system rate is a useful benchmark that can allow comparisons among regional markets, but it does not distinguish between different customer classes and rate designs. For instance, for some utilities with heavy industrial loads, competitiveness of the industrial rate may be more important than the system average rate, especially if industry is a major driver of employment. For utilities in a contentious political/regulatory environment, residential rates may be most important. For utilities with meaningful wholesale generation, we typically also compare wholesale rates against regional benchmarks to assess the competitive position of that portion of the utility's business, which can be a meaningful consideration, because in most cases the wholesale business is less stable than regulated retail supply.

Our view in this factor is forward-looking, and when relevant we consider future capital spending plans and other cost pressures, such as those for environmental compliance, to assess the likelihood they will create a need for rate increases that pressure the utility's competitive standing.

Generally, those utilities with a stronger competitive starting point compared to the relevant benchmark and that are not facing material cost pressures have more flexibility to withstand competitive challenges and score toward the higher end of the grid for this factor. Competitively challenged utilities, whether on a current basis or prospectively would typically score in the mid-to-lower portion of the grid for this factor.

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Competitiveness	10%	Extremely competitive current and expected rates[3] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates more than 25% below state average); and virtually no material prospective cost pressures that could lead to higher rates	Very competitive current and expected rates[3] in the state and/or compared to neighboring utilities on a consistent basis (e.g. average system rates in a range of 7.5% to 25% below state average); very low likelihood of material prospective cost pressures that could lead to higher rates	Competitive current and expected rates[3] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 7.5% below state average to 7.5% above state average); modest likelihood of material prospective cost pressures that could lead to higher rates	Somewhat competitive current and expected rates[3] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 7.5% to 25% above state average); high likelihood of material prospective cost pressures that could lead to higher rates	Uncompetitive current or expected rates[3] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 25% to 35% above state average); or high likelihood of imminent, material cost pressures that could lead to higher rates	Extremely uncompetitive current or expected rates[3] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates more than 35% above state average); or currently in a period of persistent cost pressures that are causing material rate increases

3 Retail rates are typically calculated as average revenue per kilowatt hour sold; however, this factor may also be assessed based on competitive positioning of rates in a dominant customer class (residential, commercial, industrial or wholesale).

Factor 5: Financial Strength and Liquidity (30% Weight)

Why it Matters

A utility's ultimate credit profile must incorporate its financial metrics, as any public power utility that is substantially weaker than its peers in terms of liquidity, cash flow generated in relation to debt service, or debt relative to the value of its asset base will generally have a higher probability of default. Public power electric utilities, especially those that own generation, are typically capital intensive with an ongoing need to invest in their assets and have a higher leverage profile than their investor-owned counterparts, which typically necessitates consistent access to debt capital markets to assure adequate sources of funding. A utility's financial strength is key to its maintaining this market access and, in general, its long-term viability. Public power electric utilities with weaker metrics may find that their access to markets decreases rapidly when markets shift or their debt load is viewed as unsustainable.

When examining financial strength, there is no single measure that can predict the likelihood of default. We utilize metrics that are indicators for liquidity resources in relation to operating and maintenance expenses, the capacity of the issuer to service its debt and the size of its debt burden relative to its assets. Comparison to peers is typically useful.

How We Assess Financial Strength and Liquidity for the Grid

Adjusted Days Liquidity on Hand Ratio (10% weight)

The formula for Adjusted Days Liquidity on Hand Ratio (days) is as follows:

(Available unrestricted cash and investments + Eligible unused bank lines and capacity under commercial paper programs) x 365 days / (Utility's annual operating and maintenance expenses exclusive of depreciation and amortization expenses and the debt portion of annual payments made to JAAs under take-or-pay contracts)

For the numerator, certain designated reserves (but excluding debt service funds and reserve requirement) that are available when needed by the utility are included in unrestricted cash and investments. The unused portion of eligible bank lines (described below) are included. Capacity under commercial paper programs is included without duplication to unused eligible bank lines. Some utilities have commercial paper programs that are backed by letters of credit, and the unused portion is included when the LC issuing bank is rated P-1.

To be included in this ratio, eligible bank lines must meet all of the following criteria:

» Committed facilities

» Remaining tenor of committed drawdown availability is at least one year

» Absence of impediments to drawdown, including:

- No material adverse change (MAC) representation requirement for borrowings
- No material adverse litigation (MAL) representation requirement for borrowings
- No covenants set at a level reasonably expected to restrict borrowings

» If bilateral, provided by a bank rated P-1

» If syndicated, provided by a group of banks predominantly rated P-1

Bank lines that do not meet the eligibility requirements are not included in calculating the ratio. However, depending on their strength, they may be assessed qualitatively as a credit positive if they constitute incremental liquidity as part of prudent financial policies. While bank lines over a year are included in the ratio, bank line maturities are considered in the broader context of a utility's future cash flow requirements, including capital expenditures, and loan/bond amortizations. Longer dated tenors are more favorable from a credit perspective.

Debt Ratio (10% weight):

(Gross debt – Debt service funds – Interest payable and debt service reserve funds) / (Gross fixed plant assets –Accumulated depreciation on plant + Net working capital)

Net working capital is defined as cash and investments plus receivables expected to be collected minus current liabilities unrelated to debt.

Adjusted Debt Service or Fixed Obligation Charge Coverage Ratio (10% weight)

In order to improve comparability between utilities that have chosen different generation procurement and financing strategies, there are some differences between their coverage ratios. For a public power electric utility that does not have any generation exposure via take-or-pay contracts with JAAs, we use the Adjusted Debt Service Coverage Ratio. For a utility that purchases some portion of its power under a take-or-pay contract with a JAA that has issued debt related to fulfilling that contract, we use the Fixed Obligation Charge Coverage Ratio.

Adjusted Debt Service Coverage Ratio:

(Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFTs) / Aggregate annual debt service

In the numerator, recurring revenue and recurring expenses exclude special, one-time items. Annual cash operating expenses exclude depreciation and amortization expenses. GFTs are general fund transfers.

Most public power utilities transfer a portion of their surplus revenues to a municipal government at an agreed upon level. While the transfers typically come after debt service in the legal flow of funds, in practical terms the transfer is a requirement that in many cases is made on a monthly basis. Therefore, our Adjusted Debt Service Coverage Ratio treats the transfer as akin to an operating expense, which differentiates it from the traditional bond ordinance debt service coverage ratio. We utilize the adjusted debt service coverage ratio in the grid because it provides a better overall indicator of a utility's operating results that provides greater comparability among public power electric utilities. In some cases, the bond ordinance coverage ratio may also be important to our analysis.

Fixed Obligation Charge Coverage Ratio:

(Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFT + Debt service portion of annual payments made to JAAs under take-or-pay contracts) / (Aggregate annual debt service + Debt service portion of annual payments made to JAAs under take-or-pay contracts)

In the numerator, recurring revenue and recurring expenses exclude special, one-time items. Annual cash operating expenses exclude depreciation and amortization expenses. GFTs are general fund transfers.

Many public power enterprises finance the development or purchase of generation assets through JAAs under take-or-pay contracts to increase power reliability, diversify the power resource mix, and lower power costs. We view a take-or-pay contractual obligation as fixed and the debt service portion of annual payments made to the JAA as a debt service obligation of the utility.

Financial Strength and Liquidity	Weight	Aaa	Aa	A	Baa	Ba	B
Adjusted days liquidity on hand[4] (3-year avg) (days)	10%	≥ 250	150 - 250	90 - 150	30 - 90	15 - 30	< 15
Debt ratio (3-year avg)[5] (%)	10%	< 35%	35% - 60%	60% - 75%	75% - 90%	90% - 100%	≥ 100%
Adjusted Debt Service Coverage[6] OR Fixed Obligation Charge Coverage[7] (3-years avg) (x)	10%	≥ 2.5x	2x - 2.5x	1.5x - 2x	1.1x - 1.5x	1x - 1.1x	< 1x

Factors 6, 7, and 8

These factors result in upward or downward adjustments to the preliminary grid indicated rating resulting from factors 1-5. In aggregate, these factors can result in a total of 3 notches up or down from the preliminary grid-indicated rating to arrive at the grid-indicated rating. In the unusual circumstance that the importance of these factors in assessing the issuer's credit profile is greater than can be incorporated within the range of this notching band, they may nonetheless be incorporated in the actual rating – please see Other Rating Considerations.

Factor 6: Operational Considerations

Operational considerations include construction risks and whether the utility is a vital service provider. In aggregate, operational considerations can result in adjustments ranging from 2 notches down to one notch up.

We assess each utility's construction risks and may apply up to 2 negative notches to the preliminary grid-indicated rating in accordance with the construction program's complexity, technical difficulty, scale relative to the size of the utility, and risk-allocation between the utility and its contractors for cost over-runs and delays, including liquidated damages. We may consider feasibility studies and other reports provided by third-party consulting engineers to inform our assessment of the risks associated with a particular project. Risk mitigation may include fixed-price contracts with liquidated damages, performance and payment

4 Defined as: (Available unrestricted cash and investments + Eligible unused bank lines and capacity under commercial paper programs) x 365 days / (Utility's annual operating and maintenance expenses exclusive of depreciation and amortization expenses and the debt service portion of annual payments made to JAAs under take-or-pay contracts). For the numerator, certain designated reserves (but excluding debt service funds and reserve requirement) that are available when needed by the utility are included in unrestricted cash and investments. The unused portion of eligible bank lines are included. Capacity under commercial paper programs is included without duplication to unused eligible bank lines. To be included in this ratio, eligible bank lines must meet all of the following criteria:

- » Committed facilities
- » Remaining tenor of committed drawdown availability is at least one year
- » Absence of impediments to drawdown, including:
  - No material adverse change (MAC) representation requirement for borrowings
  - No material adverse litigation (MAL) representation requirement for borrowings
  - No covenants set at a level reasonably expected to restrict borrowings
- » If bilateral, provided by a bank rated P-1
- » If syndicated, provided by a group of banks predominantly rated P-1

5 Defined as: (Gross debt – Debt service funds – Interest payable and debt service reserve funds) / (Gross fixed plant assets –Accumulated depreciation on plant + Net working capital). Net working capital is defined as cash and investments plus receivables expected to be collected minus current liabilities unrelated to debt.

6 Defined as: (Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFTs) / Aggregate annual debt service. In the numerator, recurring revenue and recurring expenses exclude special, one-time items. Annual cash operating expenses exclude depreciation and amortization expenses. GFTs are general fund transfers.

7 Defined as: (Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFT + Debt service portion of annual payments made to JAAs under take-or-pay contracts) / (Aggregate annual debt service + Debt service portion of annual payments made to JAAs under take-or-pay contracts).

bonds, and program management oversight. Technological risk is heightened for first-in-kind engineering risks.

We assess whether the utility provides vital services to a very large economic region and may apply up to one positive notch, for instances where the utility serves as a vital transmission provider and generation resource for a variety of utilities in a very large economic region.

Factor 7: Debt Structure and Reserves

In this factor, we consider the utility's debt service reserves, special borrowing arrangements and debt structure. In aggregate, these considerations can result in adjustments ranging from 2 notches down to 2 notches up.

Public power utilities have different approaches to debt service reserve funds. We consider fully funded maximum annual debt service reserve funds to be an important part of revenue bondholder security, particularly during periods of uncertainty in the credit markets. The lack of a debt service reserve fund could result in a downward adjustment of up to one notch. Some utilities have fully cash funded reserves equal to a full year's debt service requirements, others have no debt service reserve fund, and the rest have something in between. For a utility that has less than a full year debt service reserve fund, we also consider the other elements of its liquidity position in determining the level of downward adjustment, which is typically one half or one notch. However, in cases where the utility maintains at least 100 days of liquidity on hand on a sustained basis (see Factor 6: Financial Strength and Liquidity), the downward adjustment may be reduced or eliminated.

Some utilities benefit from preferential borrowing or guarantee arrangements with strong governmental entities. These may provide alternate sources of liquidity, assured borrowing access even when markets are in turmoil, or patient capital that is willing to provide flexibility in the debt terms, e.g. payment-in-kind in lieu of cash interest or deferrable principal payments. When such arrangements are particularly important and are provided by very highly rated government lenders, we may apply uplift of up to two notches.

Most public power utilities primarily use fixed-rate amortizing debt. The use of other types of debt or financing instruments may add meaningful incremental risk that can result in a downward rating adjustment of up to 2 notches. In most cases, the principal risk is an unexpected drain on liquidity resulting, for instance, from short or long-term debt maturities, suddenly higher interest expense, unexpected collateral calls, a decrease in available bank and commercial paper backstop facilities, or market disruptions.

In assessing debt structure, we typically evaluate the existing and projected debt structure, including reliance on short-term debt, bond-covenanted legal protections, the amortization profile (especially bullet, balloon or other large maturities), use of variable rate debt, exposure to interest rate swap agreements, any use of unusual derivatives, and collateral posting requirements. We generally evaluate exposure to unhedged variable rate instruments in relation to the utility's liquidity and its debt management record, including the absolute level of variable rate debt. We may also consider debt management and interest rate swap policies, board oversight of interest rate swaps, and a utility's disclosure of the risks and exposures associated with its debt. Some potential concerns with swaps and other derivatives, depending on their terms, are requirements the utility may face to post mark-to-market collateral and termination rights of the swap counter-party upon occurrence of certain events, such as a downgrade of the utility below a certain rating level. Another important aspect of debt structure is the utility's bond security provisions. Weakness versus the industry norm, for instance a lack of a covenant requiring the utility to set rates sufficient to support a DSCR of at least one times, may lead to a downward adjustment in this factor.

Factor 8: Revenue Stability and Diversity

Revenue stability and diversity considerations include exposure to wholesale power markets and other higher risk businesses, customer concentration and diversity from combined utility operations. In aggregate, revenue stability and diversity considerations can result in adjustments ranging from 2 notches down to one notch up.

In general, public power electric utilities have a very low business risk profile, typically based on their status as monopoly providers of essential services and their ability to set retail rates at a level that allows recovery of all costs, including debt service. Utilities that have meaningful exposure to wholesale power markets or other higher risk businesses (including telephone service) face incremental credit risks, which may include price and revenue volatility, competition, greater liquidity needs and potential asset stranding. Typically, wholesale public power electric utilities sell electricity under long-term power supply contracts with established, financially sound counterparties that ensure cost recovery, and these contracts can insulate them from wholesale markets, provided the counterparty has high credit quality and the contracts can be renewed at maturity. However, some utilities that have excess supply may choose to sell into wholesale energy markets, often utilizing the potentially larger near-term margins earned to limit retail rate increases on native-load retail customers. The latter strategy introduces very meaningful revenue and cash flow volatility, and there is no certainty that wholesale power margins will be achieved, because the price of power and the relative economics of various fuel types can fluctuate widely over time. Wholesale market exposure may be mitigated if the utility has strong liquidity permitting it to withstand a period of lower wholesale energy margins and a timely and transparent rate-setting process that will allow it to recover costs in retail rates when wholesale margins are lower. Material exposure to re-contracting risk, to wholesale purchasers with weak credit quality, to wholesale power markets when mitigants are insufficient, or to other higher risk businesses may result in a downward adjustment of up to 2 notches in this factor.

Large customer concentration can create credit pressure, especially at smaller utilities, because a single large customer (or group of customers in a particular sector) may leave the system without compensating the utility for any outstanding debt used to construct the generation facilities needed to serve that load and may leave the utility with excess power that can only be sold into the wholesale market. Meaningful customer concentration can typically lead to a downward adjustment of one half to one notch in this factor, depending on the level of fixed system costs that would have to be shared with the remaining customer base and the resultant significance of potential rate increases. However, the downward adjustment in this factor may be up to 2 notches in circumstances where a customer is particularly large and engaged in a competitive, cyclical industry or a very weak sector. Customer concentration with a stable university, government, or health care institution may not lead to a downward adjustment unless that customer has a notable weakness.

The presence of other material essential utility services such as water, sewer/wastewater and natural gas in the utility's business mix, i.e. a combined utility enterprise system, may reduce risk by providing revenue diversity that offsets weather-related and seasonal volume fluctuations, or by increasing the enterprise's importance to the municipal owner. When these other utility businesses are well-managed, and depending on the level of diversity and stability they provide, they may result in an upward adjustment of one-half to one notch.

Rating Methodology Assumptions and Limitations, and Rating Considerations That Are Not Covered in the Grid

The grid in this rating methodology represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that would enable the grid to map more closely to actual ratings. Accordingly, the eight rating factors in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of entities in this sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used to illustrate the mapping in the grid in this document is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we cannot disclose. In other cases, we estimate future results based upon past performance, industry trends, competitor actions or other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

Assumptions that may cause our forward-looking expectations to be incorrect include unanticipated changes in any of the following factors: the macroeconomic environment and general financial market conditions, industry competition, disruptive technology, regulatory and legal actions.

Key rating assumptions that apply in this sector include our view that legal priority of claim affects average recovery on different classes of debt, sufficiently to generally warrant differences in ratings for different debt classes of the same issuer, and the assumption that access to liquidity is a strong driver of credit risk.

In choosing metrics for this rating methodology grid, we did not explicitly include certain important factors that are common to all entities in any industry such as the quality and experience of management, assessments of governance and the quality of financial reporting and information disclosure. Therefore ranking these factors by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that have a meaningful effect in differentiating credit quality only in some cases, but not all. Such factors include financial controls, exposure to uncertain licensing regimes and possible government or other political interference in some jurisdictions. Regulatory, litigation, liquidity, technology and reputational risk as well as changes to consumer and business spending patterns, competitor strategies and macroeconomic trends also affect ratings. While these are important considerations, it is not possible to precisely express these in the rating methodology grid without making the grid excessively complex and significantly less transparent. Ratings may also reflect circumstances in which the weighting of a particular factor will be substantially different from the weighting suggested by the grid.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the grid. For example, liquidity is a consideration frequently critical to ratings and which may not, in other circumstances, have a substantial impact in discriminating between two issuers with a similar credit profile. As an example of the limitations, ratings can be heavily affected by extremely weak liquidity that magnifies default risk. However, two identical companies might be rated the same if their only differentiating feature is that one has a good liquidity position while the other has an extremely good liquidity position, unless these are low rated companies for which liquidity can be a substantial differentiator for relative default risk.

Other Rating Considerations

Ratings encompass a number of additional considerations. These include but are not limited to: the impact of non-core businesses, our assessment of the quality of management, governance, financial controls, liquidity management, event risk, size, and interaction of ratings with government policies and sovereign ratings.

Impact of Non-Core Businesses

This methodology grid is applied to the assessment of issuers whose primary activity is operating a US public power electric utility with generation ownership exposure. Where the utility has or will seek to diversify its operations towards other business types, we consider the impact of such diversification on credit quality. In particular, the ownership of material businesses with a higher credit risk than a US public power electric utility with generation ownership exposure would likely result in an actual rating that is lower than the grid-indicated rating.

Management Strategy

The quality of management is an important factor supporting any issuer's credit strength. Assessing the execution of business plans over time can be helpful in assessing management's business strategies, policies, and philosophies and in evaluating management performance relative to performance of competitors and our projections. A record of consistency provides us with insight into management's likely future performance in stressed situations and can be an indicator of management's tendency to depart significantly from its stated plans and guidelines.

Governance

Among the areas of focus in governance are audit committee financial expertise, the incentives created by executive compensation packages, related party transactions, interactions with outside auditors, ownership structure and working relationship between the board, government stakeholders (e.g., city councils) and management teams.

Financial Controls

We rely on the accuracy of audited financial statements to assign and monitor ratings in this sector. The quality of financial statements may be influenced by internal controls, including centralized operations and the proper tone at the top and consistency in accounting policies and procedures. Auditors' comments in financial reports and unusual financial statement restatements or delays in regulatory or other required filings may indicate weaknesses in internal controls.

Liquidity Management

Liquidity is an important rating consideration for all US public power electric utilities with generation ownership exposure. We form an opinion on likely near-term liquidity requirements from the perspective of both sources and uses of cash. While liquidity is specifically considered in certain grid factors, when it is very weak, the impact it has on ratings may be much greater than the standard weights for these factors would otherwise imply.

Event Risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in an issuer's fundamental creditworthiness. Typical special events could include, asset sales, mandated changes in business activities, capital restructuring programs, litigation and material changes that increase payments in lieu of taxes or other similar distributions by the utility to the municipality.

Size

The size and scale of a US public power electric utility with generation ownership exposure has generally not been a major determinant of its credit strength in the same way that it has been for most other industrial sectors. However, size can still be a very important factor in our assessment of certain risks that impact ratings, including natural and man-made disasters, event risk, construction risk and access to external funding. While construction risk is specifically considered in certain grid factors, when it is very high relative to the size of the utility, the impact it has on ratings may be much greater than the standard weights for these factors would otherwise imply.

Interaction of Ratings with Government Policies and Sovereign and Sub-Sovereign Ratings

Compared to most industrial sectors, US public power electric utilities with generation ownership exposure are more likely to be impacted by government and related political actions. Credit implications can occur directly through regulation, and indirectly through energy, environmental and tax policies.

Conclusion: Summary of the Grid-Indicated Rating Outcomes

The illustrative mapping of 30 representative issuers results in the following comparison of grid-indicated outcomes to ratings (see Appendix C for details):

» 16 issuers map to their actual revenue bond rating

» 13 issuers have a grid-indicated rating that is one alpha-numeric notch from their actual revenue bond ratings

» 1 issuer has a grid-indicated rating that is two alpha-numeric notches from its actual revenue bond rating

Appendix A: US Public Power Electric Utilities with Generation Ownership Exposure Methodology Factor Grid

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Cost Recovery Framework Within Service Territory	25%	Monopoly with unregulated rate setting and very strong customer base and service area economy	Monopoly with unregulated rate setting and strong customer base and service area credit economy	Monopoly with unregulated rate setting; average customer base and service area economy	Regulation of rates by state; weak customer base / service area economy	Regulation of rates by state with some inconsistency; or very weak customer base or service area economy	Regulation of rates by state is unpredictable; or extremely weak customer base or service area economy

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Willingness and Ability to Recover Costs with Sound Financial Metrics	25%	Excellent rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments less than 10 days; No political intervention in past or extremely high support from related government; Very limited General Fund transfers governed by policy	Strong rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments 10 to 30 days; Limited political intervention in past or high support from related government; Conservative and well-defined General Fund transfers governed by policy	Adequate rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments 31 to 60 days; Some political intervention in past or average support from related government; Moderate General Fund transfers	Below average rate-setting record; Rates, fuel, & purchased power cost adjustments 61 to 99 days; Persistent political intervention or below average support from related government; Large General Fund transfer not governed by policy	Some history or expectation of insufficient rate-setting; Rates, fuel, & purchased power cost adjustments 100 to 120 days; Highly political climate or very limited support from related government; Sizeable General Fund transfer not governed by policy	Lengthy record of, or expectation for a prolonged period of insufficient rate-setting ; Rates, fuel, & purchased power cost adjustments 120 days or more; Highly contentious political climate or clear lack of support from related government; Very sizeable General Fund transfer not governed by policy

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Generation and Power Procurement Risk Exposure[8]	10%	Very limited exposure to negative repercussions from generation, procurement and commodity price risks; High degree of diversification of generation and/or fuel sources; Single generation asset typically provides less than 20% of power; or up to 20% of energy from coal-fired generation with carbon mitigation strategy	Limited exposure to negative repercussions from generation, procurement and commodity price risks; Some diversification of generation and/or fuel sources; Single generation asset typically provides less than 40% of power; or up to 40% of energy from coal-fired generation with carbon mitigation strategy	Moderate exposure to negative repercussion from generation, procurement and commodity price risks; Some reliance in one type of generation and/or fuel source, but diversified with purchased power sources; Single generation asset may provide up to 55% of power; or up to 55% of energy from coal-fired generation with carbon mitigation strategy	Moderate to high exposure to negative repercussion from generation, procurement and commodity price risks; Reliance on a single type of generation or fuel source, with somewhat limited diversification via purchased power; Single generation asset typically provides up to 75% of power; or up to 70% of energy from coal-fired generation with carbon mitigation strategy	High exposure to negative repercussion from generation, procurement and commodity price risks; Very high concentration in a single type of generation or very high reliance on a single fuel source, with limited diversification via purchased power; Single generation asset typically provides up to 75% of energy from coal-fired generation with carbon mitigation strategy, or up to 50% of energy from coal with no mitigation strategy	Very high exposure to negative repercussion from generation, procurement and commodity price risks; very high concentration in a single type of generation, almost entirely reliant on a single fuel source, with very limited diversification via purchased power; Single generation asset typically provides over 85% of power; or over 85% of energy from coal-fired generation with carbon mitigation strategy, or over 50% of energy from coal-fired generation with no mitigation strategy

8 In scoring this factor, generation includes generation from owned assets and via participation in Joint Action Agencies, unit power arrangements and similar arrangements.

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Competitiveness	10%	Extremely competitive current and expected rates[9] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates more than 25% below state average); and virtually no material prospective cost pressures that could lead to higher rates	Very competitive current and expected rates[9] in the state and/or compared to neighboring utilities on a consistent basis (e.g. average system rates in a range of 7.5% to 25% below state average); very low likelihood of material prospective cost pressures that could lead to higher rates	Competitive current and expected rates[9] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 7.5% below state average to 7.5% above state average); modest likelihood of material prospective cost pressures that could lead to higher rates	Somewhat competitive current and expected rates[9] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 7.5% to 25% above state average); high likelihood of material prospective cost pressures that could lead to higher rates	Uncompetitive current or expected rates[9] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 25% to 35% above state average); or high likelihood of imminent, material cost pressures that could lead to higher rates	Extremely uncompetitive current or expected rates[9] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates more than 35% above state average); or currently in a period of persistent cost pressures that are causing material rate increases

Financial Strength and Liquidity	Weight	Aaa	Aa	A	Baa	Ba	B
Adjusted days liquidity on hand[10] (3-year avg) (days)	10%	≥ 250	150 - 250	90 - 150	30 - 90	15 - 30	< 15
Debt ratio (3-year avg)[11] (%)	10%	< 35%	35% - 60%	60% - 75%	75% - 90%	90% - 100%	≥ 100%
Adjusted Debt Service Coverage[12] OR Fixed Obligation Charge Coverage[13] (3-years avg) (x)	10%	≥ 2.5x	2x - 2.5x	1.5x - 2x	1.1x - 1.5x	1x - 1.1x	< 1x

9 Retail rates are typically calculated as average revenue per kilowatt hour sold; however, this factor may also be assessed based on competitive positioning of rates in a dominant customer class (residential, commercial, industrial or wholesale).

10 Defined as: (Available unrestricted cash and investments + Eligible unused bank lines and capacity under commercial paper programs) x 365 days / (Utility's annual operating and maintenance expenses exclusive of depreciation and amortization expenses and the debt service portion of annual payments made to JAAs under take-or-pay contracts). For the numerator, certain designated reserves (but excluding debt service funds and reserve requirement) that are available when needed by the utility are included in unrestricted cash and investments. The unused portion of eligible bank lines are included. Capacity under commercial paper programs is included without duplication to unused eligible bank lines. To be included in this ratio, eligible bank lines must meet all of the following criteria:

- » Committed facilities
- » Remaining tenor of committed drawdown availability is at least one year
- » Absence of impediments to drawdown, including:
  - No material adverse change (MAC) representation requirement for borrowings
  - No material adverse litigation (MAL) representation requirement for borrowings
  - No covenants set at a level reasonably expected to restrict borrowings
- » If bilateral, provided by a bank rated P-1
- » If syndicated, provided by a group of banks predominantly rated P-1

11 Defined as: (Gross debt – Debt service funds – Interest payable and debt service reserve funds) / (Gross fixed plant assets –Accumulated depreciation on plant + Net working capital). Net working capital is defined as cash and investments plus receivables expected to be collected minus current liabilities unrelated to debt.

12 Defined as: (Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFTs) / Aggregate annual debt service. In the numerator, recurring revenue and recurring expenses exclude special, one-time items. Annual cash operating expenses exclude depreciation and amortization expenses. GFTs are general fund transfers.

13 Defined as: (Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFT + Debt service portion of annual payments made to JAAs under take-or-pay contracts) / (Aggregate annual debt service + Debt service portion of annual payments made to JAAs under take-or-pay contracts).

Factors 1-5 Preliminary Grid Indicated Rating

Factors 6, 7, and 8 These factors result in upward or downward adjustments to the preliminary grid indicated rating resulting from factors 1-5. In aggregate, these factors can result in a total of 3 notches up or down from the preliminary grid-indicated rating to arrive at the grid-indicated rating.
Factor 6: Operational Considerations Operational considerations include construction risks and whether the utility is a vital service provider. In aggregate, operational considerations can result adjustments ranging from 2 notches down to one notch up. Construction Risks: up to 2 negative notches Vital Services to a Very Large Economic Region: up to one positive notch
Factor 7: Debt Structure and Reserves In this factor, we consider the utility's debt service reserves, special borrowing arrangements and debt structure. In aggregate, these considerations can result in adjustments ranging from 2 notches down to 2 notches up. Debt Service Reserves: up to one negative notch Preferential Borrowing/Guarantee Arrangements: up to 2 positive notches Debt Structure: up to 2 negative notches
Factor 8: Revenue Stability and Diversity Revenue stability and diversity considerations include exposure to wholesale power markets and other higher risk businesses, customer concentration and diversity from combined utility operations. In aggregate, revenues stability and diversity considerations can result adjustments ranging from 2 notches down to one notch up. Exposure to Wholesale Power Markets and Other Higher Risk Businesses: up to 2 negative notches Customer Concentration: up to 2 negative notches Revenue Diversity: up to one positive notch

Grid Indicated Rating

Appendix B: US Public Power Utilities with Generation Exposure - Directly Owned Generation

Electric Enterprise	Rating	Outlook
Anaheim (City of) CA Electric Enterprise	Aa3	STA
Arizona Power Authority, AZ	Aa2	STA
Austin (City of) TX Electric Enterprise	A1	STA
Batavia (City of) IL Electric Enterprise	A1	NEG
Bonneville Power Administration, WA	Aa1[14]	STA
Brownsville Public Utility Board, TX	A2	STA
Bryan (City of) TX Electric Enterprise	A2	STA
Burbank (City of) CA Combined Utility Enterprise	A1	STA
Burlington (City of) VT Electric Enterprise	Baa1	STA
California Dept. of Wtr. Res. (Power Sys.)	Aa2	STA
Chelan County Public Utility District 1, WA	Aa3	STA
Clark County Public Utility District 1, WA	A1	STA
Clatskanie People's Utility District, OR	A3	NEG
Cleveland (City of) OH Electric Enterprise, OH	A3	STA
Colorado Springs (City of) CO Combined Utility Enterprise	Aa2	STA
Colton (City of) CA Electric Enterprise	A2	STA
Confederated Tribes Warm Springs Reservation, OR	A3	STA
Douglas County Public Utility District 1, WA	Aa3	STA
Gainesville (City of) FL Combined Utility Enterprise	Aa2	STA
Glendale (City of) CA Electric Enterprise	Aa3	STA
Grand Island (City of) NE Electric Enterprise	A1	STA
Grand River Dam Authority, OK	A1	STA
Grant County Public Utility District 2, WA	Aa3	STA
Green Island Power Authority, NY	Ba1	STA
Guam Power Authority, GU	Baa2	STA
Hamilton (City Of) OH Electric Enterprise, OH	A3	STA
Hastings (City of) NE Electric Enterprise	A2	STA
Henderson Municipal Power & Light, KY	Baa2	STA
Holland (City of) MI Electric Enterprise	Aa3	STA
Holyoke Gas and Electric Department, MA	A1	STA
Imperial Irrigation District, CA Electric Enterprise	A1	STA
JEA, FL	Aa2	STA
Key West Utility Board, FL	A1	STA
Lafayette (City of) LA Combined Utilities Enterprise	A1	STA
Lakeland (City of) FL Electric Enterprise	Aa3	STA
Lakeview Light and Power, WA	Baa2	STA
Lansing Board of Water & Light, MI	Aa3	STA

[14] Issuer Rating

Electric Enterprise	Rating	Outlook
LCRA Transmission Services Corporation, TX	A1	STA
Lodi (City of) CA	A2	STA
Long Island Power Authority, NY	Baa1	STA
Los Alamos (County of) NM Combined Utility Enterprise	A2	STA
Los Angeles Department of Water & Power, CA Electric Enterprise	Aa3	POS
Lower Colorado River Authority, TX	A2	STA
Manitowoc (City of) WI Electric Enterprise	A1	STA
Memphis (City of) TN Electric Enterprise	Aa2	STA
Modesto Irrigation District, CA	A2	STA
Nebraska Public Power District, NE	A1	STA
New York State Power Authority, NY	Aa1	STA
Omaha Public Power District, NE	Aa2	STA
Orlando Utilities Commission, FL	Aa2	STA
Owensboro (City of) KY Electric Enterprise	A3	STA
Paducah (City of) KY Electric Enterprise	Baa1	STA
Pend Oreille County Public Utility District 1, WA	A3	NEG
Princeton Electric Plant Board, KY	Baa1	STA
Puerto Rico Electric Power Authority, PR	Caa3	NEG
Rochelle (City of) IL Electric Enterprise	A3	STA
Rochester (City of) MN Electric Enterprise	Aa3	STA
Roseville (City of) CA Electric Enterprise	A2	POS
Sacramento Municipal Utility District, CA	Aa3	STA
Salt River Project Agricultural Improvement and Power District, AZ	Aa1	STA
San Antonio (City of) TX Combined Utility Enterprise	Aa1	STA
Seattle (City of) WA Electric Enterprise	Aa2	STA
Snohomish County Public Utility District 1, WA Electric Enterprise	Aa3	STA
South Carolina Public Service Authority, SC	A1	STA
Springfield (City of) IL Electric Enterprise	A3	NEG
Tacoma (City of) WA Electric Enterprise	Aa3	STA
Tallahassee (City of) FL Electric Enterprise	Aa3	STA(m)
Tennessee Valley Authority	Aaa	STA
Turlock Irrigation District, CA	A2	STA
Unified Gov't of Wyandotte Ct/Kansas City, KS Combined Utility Enterprise	A3	STA
Virgin Islands Water & Power Authority, VI	Baa3	STA

US Public Power Utilities with Generation Exposure - Generation through JAA Participation:

Electric Enterprise	Rating	Outlook
Alexandria (City of) MN Electric Enterprise	A1	NOO
Algona (City of) IA Electric Enterprise	Baa1	STA
Atlantic (City of) IA Electric Enterprise	A1	NOO
Azusa (City of) CA Electric Enterprise	A2	STA
Benson (City of) MN Electric Enterprise	Baa2	NOO
Bryan Rural Electric System, TX	A2	NOO
Cedar Falls (City of) IA Electric Enterprise	Aa2	NOO
Coldwater (City of) MI Electric Enterprise	A3	NEG
Cowlitz County Public Utility District 1, WA	A1	NOO
Dalton (City of) GA Combined Utility Enterprise	A2	NOO
Denton (City of) TX Combined Utility Enterprise	A1	NOO
Detroit Lakes (City of) MN Electric Enterprise	A3	NOO
Easley (City of) SC Combined Utility Enterprise	A2	NOO
Elk River Municipal Utilities, MN	Aa3	NOO
Eugene Water & Electric Board, OR Electric Enterprise	Aa3	STA
Fayetteville Public Works Commission, NC	Aa2	STA
Gaffney (City of) SC Combined Utility Enterprise	A3	NOO
Greenville (City of) TX Electric Enterprise	A2	STA
Greenville Utilities Commission, NC	Aa2	STA
Greer Commission of Public Works, SC	A1	NOO
Griffin (City of) GA Combined Utility Enterprise	A3	STA
Harlan Municipal Utilities, IA	A3	NOO
Heber Light & Power Company, UT	A2	STA
Hutchinson (City of) MN Combined Utility Enterprise	A1	NOO
Indianola (City of) IA Electric Enterprise	A2	NOO
Jackson (City of) MN Electric Enterprise	A3	NOO
Jacksonville Beach (City of) FL Combined Utility Enterprise	A1	NOO
Kaukauna (City of) WI Electric Enterprise	A3	NOO
Kissimmee Utility Authority, FL	A1	NOO
Klickitat County Public Utility Dist. 1, WA	A2	NOO
Leesburg (City of) FL Electric Enterprise	A2	NOO
Marshall (City of) MN Combined Utility Enterprise	A3	NOO
Miller (City of) SD Electric Enterprise	Baa1	Neg
Monroe (City of) NC Combined Utility Enterprise	A2	NOO
Moorhead (City of) MN Combined Utility Enterprise	Aa3	NOO
Mount Horeb (Village of) WI Electric Enterprise	A1	NOO
Murray City (City of) UT Electric Enterprise	A2	NOO
New London (City of) WI Combined Util. Ent.	A3	NOO
New Richmond (City of) WI Electric Enterprise	A2	NOO

Electric Enterprise	Rating	Outlook
Newberry (City of) SC Combined Utility Ent	A3	NOO
Newnan Water, Sewerage & Light Commission, GA	A1	NOO
North Branch (City of) MN Electric Enterprise, MN	Baa3	STA
North St. Paul (City of) MN Electric Ent	A2	Neg
Ocala (City of) FL Combined Utility Enterprise	A1	NOO
Oconomowoc (City of) WI Electric Utility Enterprise	A2	NOO
Opelika (City of) AL Electric Enterprise	A1	NOO
Orange City Electric Enterprise, IA	A3	NOO
Pella (City of) IA Electric Enterprise, IA	A2	NOO
Peru (City of) IL Electric Enterprise	A1	NOO
Plymouth (City of) WI Combined Utility Ent.	A2	NOO
Princeton (City of) MN Combined Utility Enterprise	A3	NOO
Redwood Falls (City of) MN Electric Enterprise	A3	STA
Rock Hill (City of) SC Combined Utility Enterprise	A3	STA
Santa Clara (City of) UT Electric Enterprise	Ba1	NOO
Shakopee Public Utilities Commission, MN	A1	NOO
Shelby (City of) NC Combined Utility Enterprise	A1	NOO
Spencer (City of) IA Electric Enterprise	A1	NOO
St. George (City of) UT Electric Enterprise	Baa1	STA
St. James (City of) MN Electric Enterprise	A2	NOO
Stoughton (City of) WI	A2	NOO
Sun Prairie (City of) WI Combined Utility Enterprise	A1	NOO
Sylacauga Utilities Board, AL	Aa3	NOO
Vernon (City of) CA Electric Enterprise	Baa1	STA
Vero Beach (City of) FL Electric Enterprise	A1	NOO
Waunakee (Village of) WI Combined Utility Enterprise	A1	NOO
Waupun (City of) WI Combined Utility Enterprise	A3	NOO
Waverly Municipal Electric Utility, IA	A2	POS

Appendix C: US Public Power Electric Utilities with Generation Ownership Exposure Grid Outcomes and Outlier Discussion

In the table below, positive or negative "outliers" for a given factor or sub-factor are defined as issuers whose grid factor or sub-factor score is at least two broad rating categories higher or lower than a utility's rating (e.g. an A-rated issuer whose rating on a specific sub-factor is in the Ba-scoring category is flagged as a negative outlier for that factor or sub-factor).

Green is used to denote a positive outlier, whose grid-indicated performance for a sub-factor is two or more broad rating categories higher than Moody's rating.

Red is used to denote a negative outlier, whose grid-indicated performance for a sub-factor is two or more broad rating categories lower than Moody's rating.

Issuer	Moody's Rating	Outlook	Grid Rating	Factor 1. Cost Recovery Framework Within Service Territory	Factor 2. Willingness and Ability to Recover Costs with Sound Financial Metrics	Factor 3. Generation and Power Procurement Risk Exposure	Factor 4. Competitive -ness	Factor 5. Financial Strength and Liquidity: Adjusted days liquidity on hand (3 Year Avg)	Factor 5. Financial Strength and Liquidity: Debt ratio (3 Year Avg)	Factor 5. Financial Strength and Liquidity: Adjusted Debt Service Coverage OR Fixed Obligation Charge Coverage (3 Years Avg)	Preliminary Grid Rating	Factor 6. Operat-ional Consider-ations	Factor 7. Debt Structure and Reserves	Factor 8. Revenue Stability and Diversity
Arizona Power Authority	Aa2	Stable	Aa3	Aaa	Aaa	Aa	Aaa	215	110.0%	1.05	Aa3	0	0	0
Austin (City of) TX Electric Enterprise	A1	Stable	A1	Aaa	A	A	Baa	151	45.0%	1.46	A1	0	-0.5	0
Batavia (City of) IL Electric Enterprise	A1	Negative	A1	Aa	A	Baa	Aa	137	28.0%	2.41	Aa3	0	0	-0.5
Bonneville Power Administration, OR	Aa1	Stable	Aa2	Aa	A	Aa	Aa	129	96.0%	1.13	A2	1	1.5	0
Bryan (City of) TX Electric Enterprise	A2	Stable	A2	Aa	A	Baa	A	110	59.0%	1.23	A2	0	0	0
Chelan County Public Util. Dist 1, WA	Aa3	Stable	A2	A	A	A	Aaa	564	65.0%	1.86	A2	-0.5	0	0
Clark County Public Utility District 1, WA	A1	Stable	A2	Aa	A	A	A	88	63.0%	1.66	A2	0	0	0
Cleveland (City of) Public Power	A3	Stable	A3	Baa	A	A	A	145	63.0%	1.3	A3	0	-0.5	0
Colorado Springs (City of) CO Comb. Util Ent.	Aa2	Stable	Aa3	Aa	Aa	A	A	226	59.4%	1.98	Aa3	0.5	-0.5	0
Grand River Dam Authority	A1	Stable	A1	Aa	A	A	Aa	163	60.7%	1.13	A1	0	0	0
Hastings (City of) Electric System, NE	A2	Stable	A2	A	Aa	Baa	Aa	481	29.6%	1.40	A1	0	0	-1
Henderson Municipal Power & Light, KY	Baa2	Stable	Baa1	A	Baa	Ba	Aa	118	15.0%	1.95	A3	0	0	-1
Holland (City of) MI Electric Enterprise	Aa3	Stable	Aa3	A	Aa	Aa	Aa	590	80.0%	2.09	Aa3	0	0.5	-0.5
JEA, FL	Aa2	Stable	Aa3	Aa	Aa	Aa	A	270	77.0%	2.31	Aa3	0	-0.5	0
Lakeland (City of) FL Electric Enterprise	Aa3	Stable	Aa3	A	Aa	Aa	Aa	214	56.9%	1.56	Aa3	0	0	0
LCRA Transmission Services Corporation	A1	Stable	A1	A	Aa	Aaa	A	350	81.2%	1.49	A1	0	0	0
Long Island Power Authority	Baa1	Stable	Baa1	Aa	Baa	A	A	80	129.0%	1.09	A3	0	-0.5	0
Los Alamos (County of) NM Comb. Util. Ent	A2	Stable	A2	A	A	A	A	210	14.2%	1.71	A1	0	0	-1
Los Angeles Dept. of Wtr.& Pwr., CA Elec. Ent.	Aa3	Positive	Aa3	Aa	Aa	Aa	Aa	202	70.7%	1.61	Aa3	0	-0.5	0
Nebraska Public Power District	A1	Stable	A1	A	Aa	Aa	A	231	72.0%	1.25	A1	0	-0.5	0
New York State Power Authority	Aa1	Stable	Aa2	Aaa	Aa	Aa	Aaa	241	49.0%	2.42	Aa1	0	-0.5	0
Orlando Utilities Commission, FL	Aa2	Stable	Aa3	Aa	Aa	Aa	A	281	56.1%	1.77	Aa2	0	-0.5	0
Paducah (City of) KY Electric Enterprise	Baa1	Stable	Baa2	A	Baa	Baa	Ba	50	85.0%	1.18	Baa2	0	0	0

Issuer	Moody's Rating	Outlook	Grid Rating	Factor 1. Cost Recovery Framework Within Service Territory	Factor 2. Willingness and Ability to Recover Costs with Sound Financial Metrics	Factor 3. Generation and Power Procurement Risk Exposure	Factor 4. Competitive -ness	Factor 5. Financial Strength and Liquidity: Adjusted days liquidity on hand (3 Year Avg)	Factor 5. Financial Strength and Liquidity: Debt ratio (3 Year Avg)	Factor 5. Financial Strength and Liquidity: Adjusted Debt Service Coverage OR Fixed Obligation Charge Coverage (3 Years Avg)	Preliminary Grid Rating	Factor 6. Operat-ional Consider-ations	Factor 7. Debt Structure and Reserves	Factor 8. Revenue Stability and Diversity
Pend Oreille County P.U.D. 1, WA	A3	Negative	A3	Baa	A	A	Aaa	272	51.0%	1.37	A2	0	0	-1
Sacramento Municipal Utility District, CA	Aa3	Stable	Aa3	Aa	Aa	Aa	Aaa	186	72.0%	2.09	Aa2	0	-0.5	0
Salt River Proj. Agric. Imp. & Pwr. Dist. AZ	Aa1	Stable	Aa2	Aaa	Aa	Aa	Aa	236	51.8%	2.30	Aa2	0	-0.5	0
San Antonio (City of) TX Combined Util. Ent.	Aa1	Stable	Aa2	Aaa	Aa	Aa	Aa	259	62.9%	1.64	Aa2	0	0	0
South Carolina Public Service Authority	A1	Stable	A2	Aa	Aa	A	A	262	90.1%	1.41	A1	-1	0	0
Turlock Irrigation District, CA	A2	Stable	A2	A	Aa	A	A	229	82.0%	1.33	A2	0	0	0
Virgin Islands Water & Power Authority	Baa3	Stable	Ba1	Ba	Ba	Ba	A	31	86.0%	0.95	Ba1	0	0	0

Outlier Discussion

As depicted above, the only grid indicated rating that is 2 notches away from the actual rating is Chelan PUD's whose Aa3 rating compares to a grid-indicated rating of A2. Chelan PUD's expected improvement in financial profile over time, combined with a high liquidity position and strong risk management, are factors that support the Aa3 actual assigned rating. The following comments provide insights on some of the outliers for factor and sub-factor grid scores.

Cost Recovery Framework Within Service Territory

Austin (City of) TX Electric Enterprise (Austin Energy) and Long Island Power Authority (LIPA) are both positive outliers in this factor. In the case of Austin Energy, this high score is offset by its generation and power procurement risk exposure, in particular relating to its aggressive strategy to take on renewable generation supply resources, while LIPA's strong score in this factor is offset by weaker financial metrics scores.

Willingness and Ability to Recover Costs with Sound Financial Metrics

There are no outliers for this factor.

Generation and Power Procurement Risk Exposure

The lone positive outlier is LCRA Transmission Services Corp., whose Aaa score for this factor reflects its status as a transmission affiliate of Lower Colorado River Authority, with a low business risk profile, offset by scores that are closer to its rating in cost recovery and competitiveness.

Competitiveness

Two positive outliers have strong competitive positions. For Pend Oreille County P.U.D. 1, WA, this is offset by a weaker cost recovery framework and customer concentration. For Henderson Municipal Power & Light this is offset by weaker generation and power procurement risk exposure resulting from a high dependence on coal fired generation as well as revenue stability risks relating to customer concentration and large wholesale power sales to a non-investment grade electric generation and transmission cooperative.

Liquidity-Adjusted Days Liquidity on Hand Ratio

There are 4 positive outliers. LCRA Transmission Corp.'s very strong adjusted days liquidity on hand ratio is offset by its weaker debt ratio and adjusted debt service coverage ratio. For Pend Oreille County P.U.D. 1, WA, this is offset by a weaker cost recovery framework and customer concentration. For Hastings (City of) NE Electric Enterprise, this is offset by weakness in its generation and power procurement risk exposure score and customer concentration. For South Carolina Public Power Authority this is offset by its weaker debt ratio and construction risks related to its nuclear new-build.

Debt Ratio

There are 5 negative outliers and 4 positive outliers. Collectively, the five negative outliers have been through or, in some instances, are still in the midst of large capital programs relying extensively on debt financing to fund the investment costs. Notably, South Carolina Public Service Authority is involved in a large new nuclear plant construction project which contributes to its high debt ratio. In all five cases, significantly stronger cost recover frameworks, willingness and ability to recover costs, generation and power procurement risk exposure and competitiveness offset weakness in this sub-factor.

Batavia (City of) IL Electric System's strong debt ratio, which in part is due to the off-balance sheet treatment of its participation in the Prairie State Project, is offset by weakness in two factors that reflect that exposure - generation and power procurement risk exposure and operational considerations -

construction risk. Hastings (City of) NE Electric Enterprise's off-balance sheet debt is through participation in the Whelan Energy Center (WEC) II project. Hastings is entitled to a 35 MW allocation from the project, of which 25 MWs is currently sub-allocated to the Municipal Energy Agency of Nebraska and Heartland Consumers Power District. Its strong debt ratio is also offset by weakness in generation and power procurement risk exposure and construction risk. For Los Alamos (County of) NM Combined Utility Enterprise, the strong debt ratio is offset by its concentration risk owing to its significant dependence on the Los Alamos National Laboratory. For Henderson Municipal Power & Light, KY (HMPL), its strong score for this sub-factor is offset by weaker scores for generation and power procurement risk exposure, and wholesale power sales to a non-investment grade rated electric generation and transmission cooperative.

Adjusted Debt Service Coverage or Fixed Obligation Charge Coverage

There are 2 negative outliers. Bonneville Power Association's weak Adjusted DSCR is offset by the strength of its cost recovery framework, generation and power procurement risk exposure, and competitiveness, its role as a vital transmission corridor for a very large economic region, and the beneficial US Treasury borrowing line. Arizona Power Authority's weak Adjusted DSCR offsets strong cost recovery framework, willingness and ability to recover costs, and competiveness.

Appendix D: A Summary of Industry Issues over the Intermediate Term

Environmental Compliance Challenges Under Clean Power Plan

On August 3, 2015, the US Environmental Protection Agency (EPA) issued its final regulatory rules on carbon emissions, known as the Clean Power Plan (CPP). The final rule places a limit on carbon emissions from power plants in the US. The rule is undergoing legal challenges but is likely to have a transformative impact on the industry, since it will result in substantially more demand for renewable generation and less demand for coal generation. Natural gas generation will continue to grow but perhaps at an incrementally slower pace. Keeping existing nuclear power plants running may be another method that states will employ to limit their total carbon emission tonnage.

The CPP requires new coal plants to meet a 1,400 lbs/MWh emission requirement, whereas most coal plants emit carbon at a rate of 2,000 lbs/MWh. In theory, new coal plants can adopt ultra super critical technology, capture carbon or mix in some natural gas to bring down the emission level. However, bringing down emissions to 1,400 lbs/MWh will likely be cost-prohibitive in most cases relative to other generation technologies.

Under the new rule, utilities that own coal-fired plants, such as Springfield, Illinois (A3/stable), JEA, Florida (Aa2/stable), will have limited options to reduce carbon output at their coal fired units. They may have to buy carbon credits, run the plants less or retire them early.

Considering that utilities still have several years to become compliant, we do not believe there are broad near-term impacts for these public power utilities. However, power resource planning is a multiyear activity given the capital and operating costs required to ensure system reliability. Some utilities will be better positioned than others, depending on the strategic decisions they make ahead of the final EPA carbon compliance requirement. For example, many utilities have been waiting on the final carbon rule before deciding how to invest in order to make their coal units mercury emissions-compliant. Some will make power supply decisions now, well in advance of the proposed EPA carbon rule compliance deadline, and these strategies may or may not be successful.

Over 300 cities in the Midwest, including Cleveland Public Power (A3/stable), Omaha Public Power District (Aa2/stable) and Hamilton, Ohio (A3/stable), invested upward of $9 billion in revenue bonds to finance new supercritical coal-fired generation units that came online after 2010. Under the EPA's final compliance rule, it is possible that even though these new coal-fired units meet current environmental standards (nitrogen oxides, sulfur oxides and mercury emissions controls), their economic dispatch could be curtailed if states require the facilities to reduce carbon output at the units as part of the state's broader plan. These are the most efficient units, and gains in efficiency are impractical as is co-firing with natural gas.

In general, the strong ability of this sector to recover costs is a meaningful mitigant to the risk that many coal plants may need to be replaced over time with other types of generation. However, the need to recover closed plants will place upward pressure on rates and may curtail the cost competitiveness that has generally characterized the sector.

For further details on Moody's views relating to Environmental Compliance please see related research here.

Potential Implications Of Distributed Generation

Many electricity customers are seeking to get off the electrical grid and self-generate with renewable energy, which means that cost allocation to ensure electricity reliability for all customers has become an increasingly challenging issue for utilities. Concerns about distributed generation centers on the potential loss of customer revenue and the need for the utility to shift its largely fixed costs to remaining customers. To address the cost-shifting problem, we see an increasing focus on changes to rate design by utilities. More specifically, utilities are implementing changes to raise the fixed or demand component of bills for distributed generation customers so that they continue to pay their share of the costs of maintaining the power grid and availability of at-ready generation resources. Most utilities have been proactive in monitoring the cost shift issue. We have seen clear evidence that policymakers are paying attention and addressing this issue. For example, AB 327 was passed in California, which authorizes the regulator to modify rate design. Although cost shifts due to distributed generation have not had a material financial impact on the utilities to this point, the potential exists that more material impact could develop as distributed generation technology advances. In an extreme scenario, the cost shifts could threaten public power utilities' financial performance and undermine the business model, but we do not currently think this is at all likely.

Moody's Related Research

The credit ratings assigned in this sector are primarily determined by this credit rating methodology. Certain broad methodological considerations (described in one or more secondary or cross-sector credit rating methodologies) may also be relevant to the determination of credit ratings of issuers and instruments in this sector. Potentially related secondary and cross-sector credit rating methodologies can be found here.

For data summarizing the historical robustness and predictive power of credit ratings assigned using this credit rating methodology, see link.

Please refer to Moody's Rating Symbols & Definitions, which is available here, for further information.

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

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Appendix F:
Standard and Poor’s Rating Methodology: Key Credit Factors For The Regulated Utilities Industry

S&P Global Ratings (/en_US/web/guest/home)

Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry

19-Nov-2013 17:53 EST

View Analyst Contact Information

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(**Editor's Note:** We originally published this criteria article on Nov. 19, 2013. We're republishing it following our criteria review completed on June 6, 2017. As a result of our review, we've updated contact information and criteria references and clarified paragraphs 4 and 84.)

1. This article presents S&P Global Ratings methodology and assumptions for Regulated Utilities. This article relates to "Corporate Methodology (/en_US/web/guest/article/-/view/sourceId/8314109)," Nov. 19, 2013 and "Principles Of Credit Ratings (/en_US/web/guest/article/-/view/sourceId/6485398)," Feb. 16, 2011.

2. [This paragraph has been deleted.]

SCOPE OF THE CRITERIA

3. These criteria apply to entities where regulated utilities represent a material part of their business, other than U.S. public power, water, sewer, gas, and electric cooperative utilities that are owned by federal, state, or local governmental bodies or by ratepayers. A regulated utility is defined as a corporation that offers an essential or near-essential infrastructure product, commodity, or service with little or no practical substitute (mainly electricity, water, and gas), a business model that is shielded from competition (naturally, by law, shadow regulation, or by government policies and oversight), and is subject to comprehensive regulation by a regulatory body or implicit oversight of its rates (sometimes referred to as tariffs), service quality, and terms of service. The regulators base the rates that they set on some form of cost recovery, including an economic return on assets, rather than relying on a market price. The regulated operations can range from individual parts of the utility value chain (water, gas, and electricity networks or "grids," electricity generation, retail operations, etc.) to the entire integrated chain, from procurement to sales to the end customer. In some jurisdictions, our view of government support can also affect the final rating outcome, as per our government-related entity criteria (see "General Criteria: Rating Government-Related Entities: Methodology and Assumptions (/en_US/web/guest/article/-/view/sourceId/9032821)," March 25, 2015).

SUMMARY OF THE CRITERIA

4. This article presents S&P Global Ratings criteria for analyzing regulated utilities, applying its corporate criteria. The criteria for evaluating the competitive position of regulated utilities amend and partially supersede the "Competitive Position" section of the corporate criteria when evaluating these entities. The criteria for determining the cash flow leverage assessment partially supersede the "Cash Flow/Leverage" section of the corporate criteria for the purpose of evaluating regulated utilities, specifically, the conditions to apply low, medial, and standard volatility tables. The section on liquidity for regulated utilities partially amends existing criteria. All other sections of the corporate criteria apply to the analysis of regulated utilities.

5. [This paragraph has been deleted.]

6. [This paragraph has been deleted.]

METHODOLOGY

Part I--Business Risk Analysis

Industry risk

7. Within the framework of Standard & Poor's general criteria for assessing industry risk, we view regulated utilities as a "very low risk" industry (category '1'). We derive this assessment from our view of the segment's low risk ('2') cyclicality and very low risk ('1') competitive risk and growth assessment.

8. In our view, demand for regulated utility services typically exhibits low cyclicality, being a function of such key drivers as employment growth, household formation, and general economic trends. Pricing is non-cyclical, since it is usually based in some form on the cost of providing service.

Cyclicality

9. We assess cyclicality for regulated utilities as low risk ('2'). Utilities typically offer products and services that are essential and not easily replaceable. Based on our analysis of global Compustat data, utilities had an average peak-to-trough (PTT) decline in revenues of about 6% during recessionary periods since 1952. Over the same period, utilities had an average PTT decline in EBITDA margin of about 5% during recessionary periods, with PTT EBITDA margin declines less severe in more recent periods. The PTT drop in profitability that occurred in the most recent recession (2007-2009) was less than the long-term average.

10. With an average drop in revenues of 6% and an average profitability decline of 5%, utilities' cyclicality assessment calibrates to low risk ('2'). We generally consider that the higher the level of profitability cyclicality in an industry, the higher the credit risk of entities operating in that industry. However, the overall effect of cyclicality on an industry's risk profile may be mitigated or exacerbated by an industry's competitive and growth environment.

Competitive risk and growth

11. We view regulated utilities as warranting a very low risk ('1') competitive risk and growth assessment. For competitive risk and growth, we assess four sub-factors as low, medium, or high risk. These sub-factors are:

Effectiveness of industry barriers to entry;
Level and trend of industry profit margins;
Risk of secular change and substitution by products, services, and technologies; and
Risk in growth trends.

Effectiveness of barriers to entry--low risk

12. Barriers to entry are high. Utilities are normally shielded from direct competition. Utility services are commonly naturally monopolistic (they are not efficiently delivered through competitive channels and often require access to public thoroughfares for distribution), and so regulated utilities are granted an exclusive franchise, license, or concession to serve a specified territory in exchange for accepting an obligation to serve all customers in that area and the regulation of its rates and operations.

Level and trend of industry profit margins--low risk

13. Demand is sometimes and in some places subject to a moderate degree of seasonality, and weather conditions can significantly affect sales levels at times over the short term. However, those factors even out over time, and there is little pressure on margins if a utility can pass higher costs along to customers via higher rates.

Risk of secular change and substitution of products, services, and technologies--low risk

14. Utility products and services are not overly subject to substitution. Where substitution is possible, as in the case of natural gas, consumer behavior is usually stable and there is not a lot of switching to other fuels. Where switching does occur, cost allocation and rate design practices in the regulatory process can often mitigate this risk so that utility profitability is relatively indifferent to the substitutions.

Risk in industry growth trends--low risk

15. As noted above, regulated utilities are not highly cyclical. However, the industry is often well established and, in our view, long-range demographic trends support steady demand for essential utility services over the long term. As a result, we would expect revenue growth to generally match GDP when economic growth is positive.

B. Country risk

16. In assessing "country risk" for a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology (/en_US/web/guest/article/-/view/sourceId/8314109)").

C. Competitive position

17. In the corporate criteria, competitive position is assessed as ('1') excellent, ('2') strong, ('3') satisfactory, ('4') fair, ('5') weak, or ('6') vulnerable.

18. The analysis of competitive position includes a review of:

Competitive advantage,
Scale, scope, and diversity,
Operating efficiency, and
Profitability.

19. In the corporate criteria we assess the strength of each of the first three components. Each component is assessed as either: (1) strong, (2) strong/adequate, (3) adequate, (4) adequate/weak, or (5) weak. After assessing these components, we determine the preliminary competitive position assessment by ascribing a specific weight to each component. The applicable weightings will depend on the company's Competitive Position Group Profile. The group profile for regulated utilities is "National Industries & Utilities," with a weighting of the three components as follows: competitive advantage (60%), scale, scope, and diversity (20%), and operating efficiency (20%). Profitability is assessed by combining two sub-components: level of profitability and the volatility of profitability.

20. "Competitive advantage" cannot be measured with the same sub-factors as competitive firms because utilities are not primarily subject to influence of market forces. Therefore, these criteria supersede the "competitive advantage" section of the corporate criteria. We analyze instead a utility's "regulatory advantage" (section 1 below).

Assessing regulatory advantage

21. The regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance.

22. We base our assessment of the regulatory framework's relative credit supportiveness on our view of how regulatory stability, efficiency of tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to recover its costs and earn a timely return. Our view of these four pillars is the foundation of a utility's regulatory support. We then assess the utility's business strategy, in particular its regulatory strategy and its ability to manage the tariff-setting process, to arrive at a final regulatory advantage assessment.

23. When assessing regulatory advantage, we first consider four pillars and sub-factors that we believe are key for a utility to recover all its costs, on time and in full, and earn a return on its capital employed:

24. Regulatory stability:

Transparency of the key components of the rate setting and how these are assessed
Predictability that lowers uncertainty for the utility and its stakeholders
Consistency in the regulatory framework over time

25. Tariff-setting procedures and design:

Recoverability of all operating and capital costs in full
Balance of the interests and concerns of all stakeholders affected
Incentives that are achievable and contained

26. Financial stability:

Timeliness of cost recovery to avoid cash flow volatility
Flexibility to allow for recovery of unexpected costs if they arise
Attractiveness of the framework to attract long-term capital
Capital support during construction to alleviate funding and cash flow pressure during periods of heavy investments

27. Regulatory independence and insulation:

Market framework and energy policies that support long-term financeability of the utilities and that is clearly enshrined in law and separates the regulator's powers
Risks of political intervention is absent so that the regulator can efficiently protect the utility's credit profile even during a stressful event

28. We have summarized the key characteristics of the assessments for regulatory advantage in table 1.

Table 1

Preliminary Regulatory Advantage Assessment

Qualifier	What it means	Guidance
Strong	The utility has a major regulatory advantage due to one or a combination of factors that support cost recovery and a return on capital combined with lower than average volatility of earnings and cash flows. There are strong prospects that the utility can sustain this advantage over the long term. This should enable the utility to withstand economic downturns and political risks better than other utilities.	The utility operates in a regulatory climate that is transparent, predictable, and consistent from a credit perspective. The utility can fully and timely recover all its fixed and variable operating costs, investments and capital costs (depreciation and a reasonable return on the asset base). The tariff set may include a pass-through mechanism for major expenses such as commodity costs, or a higher return on new assets, effectively shielding the utility from volume and input cost risks. Any incentives in the regulatory scheme are contained and symmetrical. The tariff set includes mechanisms allowing for a tariff adjustment for the timely recovery of volatile or unexpected operating and capital costs. There is a track record of earning a stable, compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record. There is support of cash flows during construction of large projects, and pre-approval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs. The utility operates under a regulatory system that is sufficiently insulated from political intervention to efficiently protect the utility’s credit risk profile even during stressful events.

Adequate	The utility has some regulatory advantages and protection, but not to the extent that it leads to a superior business model or durable benefit. The utility has some but not all drivers of well-managed regulatory risk. Certain regulatory factors support the business's long-term stability and viability but could result in periods of below-average levels of profitability and greater profit volatility. However, overall these regulatory drivers are partially offset by the utility's disadvantages or lack of sustainability of other factors.	It operates in a regulatory environment that is less transparent, less predictable, and less consistent from a credit perspective. The utility is exposed to delays or is not, with sufficient certainty, able to recover all of its fixed and variable operating costs, investments. and capital costs (depreciation and a reasonable return on the asset base) within a reasonable time. Incentive ratemaking practices are asymmetrical and material, and could detract from credit quality. The utility is exposed to the risk that it doesn't recover unexpected or volatile costs in a full or less than timely manner due to lack of flexible reopeners or annual revenue adjustments. There is an uneven track record of earning a compensatory rate of return in cash through various economic and political cycles and a projected ability to maintain that record. There is little or no support of cash flows during construction, and investment decisions on large projects (and therefore the risk of subsequent disallowances of capital costs) rest mostly with the utility. The utility operates under a regulatory system that is not sufficiently insulated from political intervention and is sometimes subject to overt political influence.
Weak	The utility suffers from a complete breakdown of regulatory protection that places the utility at a significant disadvantage. The utility's regulatory risk is such that the long-term cost recovery and investment return is highly uncertain and materially delayed, leading to volatile or weak cash flows. There is the potential for material stranded assets with no prospect of recovery.	The utility operates in an opaque regulatory climate that lacks transparency, predictability, and consistency. The utility cannot fully and/or timely recover its fixed and variable operating costs, investments, and capital costs (depreciation and a reasonable return on the asset base). There is a track record of earning minimal or negative rates of return in cash through various economic and political cycles and a projected inability to improve that record sustainably. The utility must make significant capital commitments with no solid legal basis for the full recovery of capital costs. Ratemaking practices actively harm credit quality. The utility is regularly subject to overt political influence.

29. After determining the preliminary regulatory advantage assessment, we then assess the utility's business strategy. Most importantly, this factor addresses the effectiveness of a utility's management of the regulatory risk in the jurisdiction(s) where it operates. In certain jurisdictions, a utility's regulatory strategy and its ability to manage the tariff-setting process effectively so that revenues change with costs can be a compelling regulatory risk factor. A utility's approach and strategies surrounding regulatory matters can create a durable "competitive advantage" that differentiates it from peers, especially if the risk of political intervention is high. The assessment of a utility's business strategy is informed by historical performance and its forward-looking business objectives. We evaluate these objectives in the context of industry dynamics and the regulatory climate in which the utility operates, as evaluated through the factors cited in paragraphs 24-27.

30. We modify the preliminary regulatory advantage assessment to reflect this influence positively or negatively. Where business strategy has limited effect relative to peers, we view the implications as neutral and make no adjustment. A positive assessment improves the preliminary regulatory advantage assessment by one category and indicates that management's business strategy is expected to bolster its regulatory advantage through favorable commission rulings beyond what is typical for a utility in that jurisdiction. Conversely, where management's strategy or businesses decisions result in adverse regulatory outcomes relative to peers, such as failure to achieve typical cost recovery or allowed returns, we adjust the preliminary regulatory advantage assessment one category worse. In extreme cases of poor strategic execution, the preliminary regulatory advantage assessment is adjusted by two categories worse (when possible; see table 2) to reflect management decisions that are likely to result in a significantly adverse regulatory outcome relative to peers.

Table 2

Determining The Final Regulatory Advantage Assessment

	--Strategy modifier--			
Preliminary regulatory advantage score	**Positive**	**Neutral**	**Negative**	**Very negative**
Strong	Strong	Strong	Strong/Adequate	Adequate
Strong/Adequate	Strong	Strong/Adequate	Adequate	Adequate/Weak
Adequate	Strong/Adequate	Adequate	Adequate/Weak	Weak
Adequate/Weak	Adequate	Adequate/Weak	Weak	Weak
Weak	Adequate/Weak	Weak	Weak	Weak

Scale, scope, and diversity

31. We consider the key factors for this component of competitive position to be primarily operational scale and diversity of the geographic, economic, and regulatory foot prints. We focus on a utility's markets, service territories, and diversity and the extent that these attributes can contribute to cash flow stability while dampening the effect of economic and market threats.

32. A utility that warrants a Strong or Strong/Adequate assessment has scale, scope, and diversity that support the stability of its revenues and profits by limiting its vulnerability to most combinations of adverse factors, events, or trends. The utility's significant advantages enable it to withstand economic, regional, competitive, and technological threats better than its peers. It typically is characterized by a combination of the following factors:

A large and diverse customer base with no meaningful customer concentration risk, where residential and small to medium commercial customers typically provide most operating income.
The utility's range of service territories and regulatory jurisdictions is better than others in the sector.
Exposure to multiple regulatory authorities where we assess preliminary regulatory advantage to be at least Adequate. In the case of exposure to a single regulatory regime, the regulatory advantage assessment is either Strong or Strong/Adequate.
No meaningful exposure to a single or few assets or suppliers that could hurt operations or could not easily be replaced.

33. A utility that warrants a Weak or Weak/Adequate assessment lacks scale, scope, and diversity such that it compromises the stability and sustainability of its revenues and profits. The utility's vulnerability to, or reliance on, various elements of this sub-factor is such that it is less likely than its peers to withstand economic, competitive, or technological threats. It typically is characterized by a combination of the following factors:

A small customer base, especially if burdened by customer and/or industry concentration combined with little economic diversity and average to below-average economic prospects;
Exposure to a single service territory and a regulatory authority with a preliminary regulatory advantage assessment of Adequate or Adequate/Weak; or
Dependence on a single supplier or asset that cannot easily be replaced and which hurts the utility's operations.

34. We generally believe a larger service territory with a diverse customer base and average to above-average economic growth prospects provides a utility with cushion and flexibility in the recovery of operating costs and ongoing investment (including replacement and growth capital spending), as well as lessening the effect of external shocks (i.e., extreme local weather) since the incremental effect on each customer declines as the scale increases.

35. We consider residential and small commercial customers as having more stable usage patterns and being less exposed to periodic economic weakness, even after accounting for some weather-driven usage variability. Significant industrial exposure along with a local economy that largely depends on one or few cyclical industries potentially contributes to the cyclicality of a utility's load and financial performance, magnifying the effect of an economic downturn.

36. A utility's cash flow generation and stability can benefit from operating in multiple geographic regions that exhibit average to better than average levels of wealth, employment, and growth that underpin the local economy and support long-term growth. Where operations are in a single geographic region, the risk can be ameliorated if the region is sufficiently large, demonstrates economic diversity, and has at least average demographic characteristics.

37. The detriment of operating in a single large geographic area is subject to the strength of regulatory assessment. Where a utility operates in a single large geographic area and has a strong regulatory assessment, the benefit of diversity can be incremental.

Operating efficiency

38. We consider the key factors for this component of competitive position to be:

Compliance with the terms of its operating license, including safety, reliability, and environmental standards;
Cost management; and

Capital spending: scale, scope, and management.
39. Relative to peers, we analyze how successful a utility management achieves the above factors within the levels allowed by the regulator in a manner that promotes cash flow stability. We consider how management of these factors reduces the prospect of penalties for noncompliance, operating costs being greater than allowed, and capital projects running over budget and time, which could hurt full cost recovery.

40. The relative importance of the above three factors, particularly cost and capital spending management, is determined by the type of regulation under which the utility operates. Utilities operating under robust "cost plus" regimes tend to be more insulated given the high degree of confidence costs will invariably be passed through to customers. Utilities operating under incentive-based regimes are likely to be more sensitive to achieving regulatory standards. This is particularly so in the regulatory regimes that involve active consultation between regulator and utility and market testing as opposed to just handing down an outcome on a more arbitrary basis.

41. In some jurisdictions, the absolute performance standards are less relevant than how the utility performs against the regulator's performance benchmarks. It is this performance that will drive any penalties or incentive payments and can be a determinant of the utilities' credibility on operating and asset-management plans with its regulator.

42. Therefore, we consider that utilities that perform these functions well are more likely to consistently achieve determinations that maximize the likelihood of cost recovery and full inclusion of capital spending in their asset bases. Where regulatory resets are more at the discretion of the utility, effective cost management, including of labor, may allow for more control over the timing and magnitude of rate filings to maximize the chances of a constructive outcome such as full operational and capital cost recovery while protecting against reputational risks.

43. A regulated utility that warrants a Strong or Strong/Adequate assessment for operating efficiency relative to peers generates revenues and profits through minimizing costs, increasing efficiencies, and asset utilization. It typically is characterized by a combination of the following:

High safety record;
Service reliability is strong, with a track record of meeting operating performance requirements of stakeholders, including those of regulators. Moreover, the utility's asset profile (including age and technology) is such that we have confidence that it could sustain favorable performance against targets;
Where applicable, the utility is well-placed to meet current and potential future environmental standards;
Management maintains very good cost control. Utilities with the highest assessment for operating efficiency have shown an ability to manage both their fixed and variable costs in line with regulatory expectations (including labor and working capital management being in line with regulator's allowed collection cycles); or
There is a history of a high level of project management execution in capital spending programs, including large one-time projects, almost invariably within regulatory allowances for timing and budget.
44. A regulated utility that warrants an Adequate assessment for operating efficiency relative to peers has a combination of cost position and efficiency factors that support profit sustainability combined with average volatility. Its cost structure is similar to its peers. It typically is characterized by a combination of the following factors:

High safety performance;
Service reliability is satisfactory with a track record of mostly meeting operating performance requirements of stakeholders, including those of regulators. We have confidence that a favorable performance against targets can be mostly sustained;
Where applicable, the utility may be challenged to comply with current and future environmental standards that could increase in the medium term;
Management maintains adequate cost control. Utilities that we assess as having adequate operating efficiency mostly manage their fixed and variable costs in line with regulatory expectations (including labor and working capital management being mostly in line with regulator's allowed collection cycles); or
There is a history of adequate project management skills in capital spending programs within regulatory allowances for timing and budget.
45. A regulated utility that warrants a weak or weak/adequate assessment for operating efficiency relative to peers has a combination of cost position and efficiency factors that fail to support profit sustainability combined with below-average volatility. Its cost structure is worse than its peers. It typically is characterized by a combination of the following:

Poor safety performance;
Service reliability has been sporadic or non-existent with a track record of not meeting operating performance requirements of stakeholders, including those of regulators. We do not believe the utility can consistently meet performance targets without additional capital spending;
Where applicable, the utility is challenged to comply with current environmental standards and is highly vulnerable to more onerous standards;
Management typically exceeds operating costs authorized by regulators;
Inconsistent project management skills as evidenced by cost overruns and delays including for maintenance capital spending; or
The capital spending program is large and complex and falls into the weak or weak/adequate assessment, even if operating efficiency is generally otherwise considered adequate.

Profitability

46. A utility with above-average profitability would, relative to its peers, generally earn a rate of return at or above what regulators authorize and have minimal exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations. Conversely, a utility with below-average profitability would generally earn rates of return well below the authorized return relative to its peers or have significant exposure to earnings volatility from affiliated unregulated business activities or market-sensitive regulated operations.

47. The profitability assessment consists of "level of profitability" and "volatility of profitability."

Level of profitability

48. Key measures of general profitability for regulated utilities commonly include ratios, which we compare both with those of peers and those of companies in other industries to reflect different countries' regulatory frameworks and business environments:

EBITDA margin,
Return on capital (ROC), and
Return on equity (ROE).
49. In many cases, EBITDA as a percentage of sales (i.e., EBITDA margin) is a key indicator of profitability. This is because the book value of capital does not always reflect true earning potential, for example when governments privatize or restructure incumbent state-owned utilities. Regulatory capital values can vary with those of reported capital because regulatory capital values are not inflation-indexed and could be subject to different assumptions concerning depreciation. In general, a country's inflation rate or required rate of return on equity investment is closely linked to a utility company's profitability. We do not adjust our analysis for these factors, because we can make our assessment through a peer comparison.

50. For regulated utilities subject to full cost-of-service regulation and return-on-investment requirements, we normally measure profitability using ROE, the ratio of net income available for common stockholders to average common equity. When setting rates, the regulator ultimately bases its decision on an authorized ROE. However, different factors such as variances in costs and usage may influence the return a utility is actually able to earn, and consequently our analysis of profitability for cost-of-service-based utilities centers on the utility's ability to consistently earn the authorized ROE.

51. We will use return on capital when pass-through costs distort profit margins--for instance congestion revenues or collection of third-party revenues. This is also the case when the utility uses accelerated depreciation of assets, which in our view might not be sustainable in the long run.

Volatility of profitability

52. We may observe a clear difference between the volatility of actual profitability and the volatility of underlying regulatory profitability. In these cases, we could use the regulatory accounts as a proxy to judge the stability of earnings.

53. We use actual returns to calculate the standard error of regression for regulated utility issuers (only if there are at least seven years of historical annual data to ensure meaningful results). If we believe recurring mergers and acquisitions or currency fluctuations affect the results, we may make adjustments.

Part II--Financial Risk Analysis

D. Accounting

54. Our analysis of a company's financial statements begins with a review of the accounting to determine whether the statements accurately measure a company's performance and position relative to its peers and the larger universe of corporate entities. To allow for globally consistent and comparable financial analyses, our rating analysis may include quantitative adjustments to a company's reported results. These adjustments also align a company's reported figures with our view of underlying economic conditions and give us a more accurate portrayal of a company's ongoing business. We discuss adjustments that pertain broadly to all corporate sectors, including this sector, in "Corporate Methodology: Ratios And Adjustments (/en_US/web/guest/article/-/view/sourceId/8330212)." Accounting characteristics and analytical adjustments unique to this sector are discussed below.

Accounting characteristics

55. Some important accounting practices for utilities include:

For integrated electric utilities that meet native load obligations in part with third-party power contracts, we use our purchased power methodology to adjust measures for the debt-like obligation such contracts represent (see (http://) below).
Due to distortions in leverage measures from the substantial seasonal working-capital requirements of natural gas distribution utilities, we adjust inventory and debt balances by netting the value of inventory against outstanding short-term borrowings. This adjustment provides an accurate view of the company's balance sheet by reducing seasonal debt balances when we see a very high certainty of near-term cost recovery (see below).
We deconsolidate securitized debt (and associated revenues and expenses) that has been accorded specialized recovery provisions (see below).
For water utilities that report under U.K. GAAP, we adjust ratios for infrastructure renewals accounting, which permits water companies to capitalize the maintenance spending on their infrastructure assets (see below). The adjustments aim to make those water companies that report under U.K. GAAP more comparable to those that report under accounting regimes that do not permit infrastructure renewals accounting.
56. In the U.S. and selectively in other regions, utilities employ "regulatory accounting," which permits a rate-regulated company to defer some revenues and expenses to match the timing of the recognition of those items in rates as determined by regulators. A utility subject to regulatory accounting will therefore have assets and liabilities on its books that an unregulated corporation, or even regulated utilities in many other global regions, cannot record. We do not adjust GAAP earnings or balance-sheet figures to remove the effects of regulatory accounting. However, as more countries adopt International Financial Reporting Standards (IFRS), the use of regulatory accounting will become more scarce. IFRS does not currently provide for any recognition of the effects of rate regulation for financial reporting purposes, but it is considering the use of regulatory accounting. We do not anticipate altering our fundamental financial analysis of utilities because of the use or non-use of regulatory accounting. We will continue to analyze the effects of regulatory actions on a utility's financial health.

Purchased power adjustment

57. We view long-term purchased power agreements (PPA) as creating fixed, debt-like financial obligations that represent substitutes for debt-financed capital investments in generation capacity. By adjusting financial measures to incorporate PPA fixed obligations, we achieve greater comparability of utilities that finance and build generation capacity and those that purchase capacity to satisfy new load. PPAs do benefit utilities by shifting various risks to the electricity generators, such as construction risk and most of the operating risk. The principal risk borne by a utility that relies on PPAs is recovering the costs of the financial obligation in rates.

58. We calculate the present value (PV) of the future stream of capacity payments under the contracts as reported in the financial statement footnotes or as supplied directly by the company. The discount rate used is the same as the one used in the operating lease adjustment, i.e., 7%. For U.S. companies, notes to the financial statements enumerate capacity payments for the coming five years, and a thereafter period. Company forecasts show the detail underlying the thereafter amount, or we divide the amount reported as thereafter by the average of the capacity payments in the preceding five years to get an approximation of annual payments after year five.

59. We also consider new contracts that will start during the forecast period. The company provides us the information regarding these contracts. If these contracts represent extensions of existing PPAs, they are immediately included in the PV calculation. However, a contract sometimes is executed in anticipation of incremental future needs, so the energy will not flow until some later period and there are no interim payments. In these instances, we incorporate that contract in our projections, starting in the year that energy deliveries begin under the contract. The projected PPA debt is included in projected ratios as a current rating factor, even though it is not included in the current-year ratio calculations.

60. The PV is adjusted to reflect regulatory or legislative cost-recovery mechanisms when present. Where there is no explicit regulatory or legislative recovery of PPA costs, as in most European countries, the PV may be adjusted for other mitigating factors that reduce the risk of the PPAs to the utility, such as a limited economic importance of the PPAs to the utility's overall portfolio. The adjustment reduces the debt-equivalent amount by multiplying the PV by a specific risk factor.

61. Risk factors based on regulatory or legislative cost recovery typically range between 0% and 50%, but can be as high as 100%. A 100% risk factor would signify that substantially all risk related to contractual obligations rests on the company, with no regulatory or legislative support. A 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers, as when the utility merely acts as a conduit for the delivery of a third party's electricity. These utilities are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties that act as intermediaries between retail customers and electricity suppliers. We employ a 50% risk factor in cases where regulators use base rates for the recovery of the fixed PPA costs. If a regulator has established a separate adjustment mechanism for recovery of all prudent PPA costs, a risk factor of 25% is employed. In certain jurisdictions, true-up mechanisms are more favorable and frequent than the review of base rates, but still do not amount to pure fuel adjustment clauses. Such mechanisms may be triggered by financial thresholds or passage of prescribed periods of time. In these instances, a risk factor between 25% and 50% is employed. Specialized, legislatively created cost-recovery mechanisms may lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors. We also exclude short-term PPAs where they serve merely as gap fillers, pending either the construction of new capacity or the execution of long-term PPAs.

62. Where there is no explicit regulatory or legislative recovery of PPA costs, the risk factor is generally 100%. We may use a lower risk factor if mitigating factors reduce the risk of the PPAs on the utility. Mitigating factors include a long position in owned generation capacity relative to the utility's customer supply needs that limits the importance of the PPAs to the utility or the ability to resell power in a highly liquid market at minimal loss. A utility with surplus owned generation capacity would be assigned a risk factor of less than 100%, generally 50% or lower, because we would assess its reliance on PPAs as limited. For fixed capacity payments under PPAs related to renewable power, we use a risk factor of less than 100% if the utility benefits from government subsidies. The risk factor reflects the degree of regulatory recovery through the government subsidy.

63. Given the long-term mandate of electric utilities to meet their customers' demand for electricity, and also to enable comparison of companies with different contract lengths, we may use an evergreening methodology. Evergreen treatment extends the duration of short- and intermediate-term contracts to a common length of about 12 years. To quantify the cost of the extended capacity, we use empirical data regarding the cost of developing new peaking capacity, incorporating regional differences. The cost of new capacity is translated into a dollars-per-kilowatt-year figure using a proxy weighted-average cost of capital and a proxy capital recovery period.

64. Some PPAs are treated as operating leases for accounting purposes--based on the tenor of the PPA or the residual value of the asset on the PPA's expiration. We accord PPA treatment to those obligations, in lieu of lease treatment; rather, the PV of the stream of capacity payments associated with these PPAs is reduced to reflect the applicable risk factor.

65. Long-term transmission contracts can also substitute for new generation, and, accordingly, may fall under our PPA methodology. We sometimes view these types of transmission arrangements as extensions of the power plants to which they are connected or the markets that they serve. Accordingly, we impute debt for the fixed costs associated with such transmission contracts.

66. Adjustment procedures:

Data requirements:
Future capacity payments obtained from the financial statement footnotes or from management.
Discount rate: 7%.
Analytically determined risk factor.
Calculations:
Balance sheet debt is increased by the PV of the stream of capacity payments multiplied by the risk factor.
Equity is not adjusted because the recharacterization of the PPA implies the creation of an asset, which offsets the debt.
Property, plant, and equipment and total assets are increased for the implied creation of an asset equivalent to the debt.
An implied interest expense for the imputed debt is determined by multiplying the discount rate by the amount of imputed debt (or average PPA imputed debt, if there is fluctuation of the level), and is added to interest expense.
We impute a depreciation component to PPAs. The depreciation component is determined by multiplying the relevant year's capacity payment by the risk factor and then subtracting the implied PPA-related interest for that year. Accordingly, the impact of PPAs on cash flow measures is tempered.
The cost amount attributed to depreciation is reclassified as capital spending, thereby increasing operating cash flow and funds from operations (FFO).
Some PPA contracts refer only to a single, all-in energy price. We identify an implied capacity price within such an all-in energy price, to determine an implied capacity payment associated with the PPA. This implied capacity payment is expressed in dollars per kilowatt-year, multiplied by the number of kilowatts under contract. (In cases that exhibit markedly different capacity factors, such as wind power, the relation of capacity payment to the all-in charge is adjusted accordingly.)
Operating income before depreciation and amortization (D&A) and EBITDA are increased for the imputed interest expense and imputed depreciation component, the total of which equals the entire amount paid for PPA (subject to the risk factor).
Operating income after D&A and EBIT are increased for interest expense.

Natural gas inventory adjustment

67. In jurisdictions where a pass-through mechanism is used to recover purchased natural gas costs of gas distribution utilities within one year, we adjust for seasonal changes in short-debt tied to building inventories of natural gas in non-peak periods for later use to meet peak loads in peak months. Such short-term debt is not considered to be part of the utility's permanent capital. Any history of non-trivial disallowances of purchased gas costs would preclude the use of this adjustment. The accounting of natural gas inventories and associated short-term debt used to finance the purchases must be segregated from other trading activities.

68. Adjustment procedures:

Data requirements:
Short-term debt amount associated with seasonal purchases of natural gas devoted to meeting peak-load needs of captive utility customers (obtained from the company).
Calculations:
Adjustment to debt--we subtract the identified short-term debt from total debt.

Securitized debt adjustment

69. For regulated utilities, we deconsolidate debt (and associated revenues and expenses) that the utility issues as part of a securitization of costs that have been segregated for specialized recovery by the government entity constitutionally authorized to mandate such recovery if the securitization structure contains a number of protective features:

An irrevocable, non-bypassable charge and an absolute transfer and first-priority security interest in transition property;
Periodic adjustments ("true-up") of the charge to remediate over- or under-collections compared with the debt service obligation. The true-up ensures collections match debt service over time and do not diverge significantly in the short run; and,
Reserve accounts to cover any temporary short-term shortfall in collections.
70. Full cost recovery is in most instances mandated by statute. Examples of securitized costs include "stranded costs" (above-market utility costs that are deemed unrecoverable when a transition from regulation to competition occurs) and unusually large restoration costs following a major weather event such as a hurricane. If the defined features are present, the securitization effectively makes all consumers responsible for principal and interest payments, and the utility is simply a pass-through entity for servicing the debt. We therefore remove the debt and related revenues and expenses from our measures. (See "Securitizing Stranded Costs (/en_US/web/guest/article/-/view/sourceId/1341705)," Jan. 18, 2001, for background information.)

71. Adjustment procedures:

Data requirements:
Amount of securitized debt on the utility's balance sheet at period end;
Interest expense related to securitized debt for the period; and
Principal payments on securitized debt during the period.
Calculations:
Adjustment to debt: We subtract the securitized debt from total debt.
Adjustment to revenues: We reduce revenue allocated to securitized debt principal and interest. The adjustment is the sum of interest and principal payments made during the year.
Adjustment to operating income after depreciation and amortization (D&A) and EBIT: We reduce D&A related to the securitized debt, which is assumed to equal the principal payments during the period. As a result, the reduction to operating income after D&A is only for the interest portion.
Adjustment to interest expense: We remove the interest expense of the securitized debt from total interest expense.
Operating cash flows:
We reduce operating cash flows for revenues and increase for the assumed interest amount related to the securitized debt. This results in a net decrease to operating cash flows equal to the principal repayment amount.

Infrastructure renewals expenditure

72. In England and Wales, water utilities can report under either IFRS or U.K. GAAP. Those that report under U.K. GAAP are allowed to adopt infrastructure renewals accounting, which enables the companies to capitalize the maintenance spending on their underground assets, called infrastructure renewals expenditure (IRE). Under IFRS, infrastructure renewals accounting is not permitted and maintenance expenditure is charged to earnings in the year incurred. This difference typically results in lower adjusted operating cash flows for those companies that report maintenance expenditure as an operating cash flow under IFRS, than for those that report it as capital expenditure under U.K. GAAP. We therefore make financial adjustments to amounts reported by water issuers that apply U.K. GAAP, with the aim of making ratios more comparable with those issuers that report under IFRS and U.S. GAAP. For example, we deduct IRE from EBITDA and FFO.

73. IRE does not always consist entirely of maintenance expenditure that would be expensed under IFRS. A portion of IRE can relate to costs that would be eligible for capitalization as they meet the recognition criteria for a new fixed asset set out in International Accounting Standard 16 that addresses property, plant, and equipment. In such cases, we may refine our adjustment to U.K. GAAP companies so that we only deduct from FFO the portion of IRE that would not be capitalized under IFRS. However, the information to make such a refinement would need to be of high quality, reliable, and ideally independently verified by a third party, such as the company's auditor. In the absence of this, we assume that the entire amount of IRE would have been expensed under IFRS and we accordingly deduct the full expenditure from FFO.

74. Adjustment procedures:

Data requirements:
U.K. GAAP accounts typically provide little information on the portion of capital spending that relates to renewals accounting, or the related depreciation, which is referred to as the infrastructure renewals charge. The information we use for our adjustments is, however, found in the regulatory cost accounts submitted annually by the water companies to the Water Services Regulation Authority, which regulates all water companies in England and Wales.
Calculations:
EBITDA: Reduced by the value of IRE that was capitalized in the period.
EBIT: Adjusted for the difference between the adjustment to EBITDA and the reduction in the depreciation expense, depending on the degree to which the actual cash spending in the current year matches the planned spending over the five-year regulatory review period.
Cash flow from operations and FFO: Reduced by the value of IRE that was capitalized in the period.
Capital spending: Reduced by the value of infrastructure renewals spending that we reclassify to cash flow from operations.
Free operating cash flow: No impact, as the reduction in operating cash flows is exactly offset by the reduction in capital spending.

E. Cash flow/leverage analysis

75. In assessing the cash flow adequacy of a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology (/en_US/web/guest/article/-/view/sourceId/8314109)"). We assess cash flow/leverage on a six-point scale ranging from ('1') minimal to ('6') highly leveraged. These scores are determined by aggregating the assessments of a range of credit ratios, predominantly cash flow-based, which complement each other by focusing attention on the different levels of a company's cash flow waterfall in relation to its obligations.

76. The corporate methodology provides benchmark ranges for various cash flow ratios we associate with different cash flow leverage assessments for standard volatility, medial volatility, and low volatility industries. The tables of benchmark ratios differ for a given ratio and cash flow leverage assessment along two dimensions: the starting point for the ratio range and the width of the ratio range.

77. If an industry's volatility levels are low, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment are less stringent, although the width of the ratio range is narrower. Conversely, if an industry has standard levels of volatility, the threshold levels for the applicable ratios to achieve a given cash flow leverage assessment may be elevated, but with a wider range of values.

78. We apply the "low-volatility" table to regulated utilities that qualify under the corporate criteria and with all of the following characteristics:

A vast majority of operating cash flows come from regulated operations that are predominantly at the low end of the utility risk spectrum (e.g., a "network," or distribution/transmission business unexposed to commodity risk and with very low operating risk);
A "strong" regulatory advantage assessment;
An established track record of normally stable credit measures that is expected to continue;
A demonstrated long-term track record of low funding costs (credit spread) for long-term debt that is expected to continue; and
Non-utility activities that are in a separate part of the group (as defined in our group rating methodology) that we consider to have "nonstrategic" group status and are not deemed high risk and/or volatile.
79. We apply the "medial volatility" table to companies that do not qualify under paragraph 78 with:

A majority of operating cash flows from regulated activities with an "adequate" or better regulatory advantage assessment; or
About one-third or more of consolidated operating cash flow comes from regulated utility activities with a "strong" regulatory advantage and where the average of its remaining activities have a competitive position assessment of '3' or better.
80. We apply the "standard-volatility" table to companies that do not qualify under paragraph 79 and with either:

About one-third or less of its operating cash flow comes from regulated utility activities, regardless of its regulatory advantage assessment; or
A regulatory advantage assessment of "adequate/weak" or "weak."

Part III--Rating Modifiers

F. Diversification/portfolio effect

81. In assessing the diversification/portfolio effect on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology (/en_US/web/guest/article/-/view/sourceId/8314109)").

G. Capital structure

82. In assessing the quality of the capital structure of a regulated utility, we use the same methodology as with other corporate issuers (see "Corporate Methodology (/en_US/web/guest/article/-/view/sourceId/8314109)").

H. Liquidity

83. In assessing a utility's liquidity/short-term factors, our analysis is consistent with the methodology that applies to corporate issuers (See "Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers (/en_US/web/guest/article/-/view/sourceId/6881137)," Dec. 16, 2014) except for the standards for "adequate" liquidity set out in paragraph 84 below.

84. The relative certainty of financial performance by utilities operating under relatively predictable regulatory monopoly frameworks make these utilities attractive to investors even in times of economic stress and market turbulence compared to conventional industrials. Also, recognizing the cash flow stability of regulated utilities we allow more discretion when calculating covenant headroom. For this reason, when determining if utilities with business risk profiles of at least "satisfactory" meet our definition of "adequate" liquidity, we use slightly lower thresholds:

A ratio of sources to uses higher than 1.1x, compared with the standard 1.2x;
Positive sources over uses even if forecast EBITDA declines by 10% (compared with a 15% decline for corporate issuers); and
No covenant breach even if forecast EBITDA declines by 10% (compared with a 15% decline for corporate issuers).

I. Financial policy

85. In assessing financial policy on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology (/en_US/web/guest/article/-/view/sourceId/8314109)").

J. Management and governance

86. In assessing management and governance on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology (/en_US/web/guest/article/-/view/sourceId/8314109)").

K. Comparable ratings analysis

87. In assessing the comparable ratings analysis on a regulated utility, our analysis uses the same methodology as with other corporate issuers (see "Corporate Methodology (/en_US/web/guest/article/-/view/sourceId/8314109)").

APPENDIX--Frequently Asked Questions

Does Standard & Poor's expect that the business strategy modifier to the preliminary regulatory advantage will be used extensively?

88. Globally, we expect management's influence will be neutral in most jurisdictions. Where the regulatory assessment is "strong," it is less likely that a negative business strategy modifier would be used due to the nature of the regulatory regime that led to the "strong" assessment in the first place. Utilities in "adequate/weak" and "weak" regulatory regimes are challenged to outperform due to the uncertainty of such regulatory regimes. For a positive use of the business strategy modifier, there would need to be a track record of the utility consistently outperforming the parameters laid down under a regulatory regime, and we would need to believe this could be sustained. The business strategy modifier is most likely to be used when the preliminary regulatory advantage assessment is "strong/adequate" because the starting point in the assessment is reasonably supportive, and a utility has shown it manages regulatory risk better or worse than its peers in that regulatory environment and we expect that advantage or disadvantage will persist. An example would be a utility that can consistently earn or exceed its authorized return in a jurisdiction where most other utilities struggle to do so. If a utility is treated differently by a regulator due to perceptions of poor customer service or reliability and the "operating efficiency" component of the competitive position assessment does not fully capture the effect on the business risk profile, a negative business strategy modifier could be used to accurately incorporate it into our analysis. We expect very few utilities will be assigned a "very negative" business strategy modifier.

Does a relatively strong or poor relationship between the utility and its regulator compared with its peers in the same jurisdiction necessarily result in a positive or negative adjustment to the preliminary regulatory advantage assessment?

89. No. The business strategy modifier is used to differentiate a company's regulatory advantage within a jurisdiction where we believe management's business strategy has and will positively or negatively affect regulatory outcomes beyond what is typical for other utilities in that jurisdiction. For instance, in a regulatory jurisdiction where allowed returns are negotiated rather than set by formula, a utility that is consistently authorized higher returns (and is able to earn that return) could warrant a positive adjustment. A management team that cannot negotiate an approved capital spending program to improve its operating performance could be assessed negatively if its performance lags behind peers in the same regulatory jurisdiction.

What is your definition of regulatory jurisdiction?

90. A regulatory jurisdiction is defined as the area over which the regulator has oversight and could include single or multiple subsectors (water, gas, and power). A geographic region may have several regulatory jurisdictions. For example, the Office of Gas and Electricity Markets and the Water Services Regulation Authority in the U.K. are considered separate regulatory jurisdictions. In Ontario, Canada, the Ontario Energy Board represents a single jurisdiction with regulatory oversight for power and gas. Also, in Australia, the Australian Energy Regulator would be considered a single jurisdiction given that it is responsible for both electricity and gas transmission and distribution networks in the entire country, with the exception of Western Australia.

Are there examples of different preliminary regulatory advantage assessments in the same country or jurisdiction?

91. Yes. In Israel we rate a regulated integrated power utility and a regulated gas transmission system operator (TSO). The power utility's relationship with its regulator is extremely poor in our view, which led to significant cash flow volatility in a stress scenario (when terrorists blew up the gas pipeline that was then Israel's main source of natural gas, the utility was unable to negotiate compensation for expensive alternatives in its regulated tariffs). We view the gas TSO's relationship with its regulator as very supportive and stable. Because we already reflected this in very different preliminary regulatory advantage assessments, we did not modify the preliminary assessments because the two regulatory environments in Israel differ and were not the result of the companies' respective business strategies.

How is regulatory advantage assessed for utilities that are a natural monopoly but are not regulated by a regulator or a specific regulatory framework, and do you use the regulatory modifier if they achieve favorable treatment from the government as an owner?

92. The four regulatory pillars remain the same. On regulatory stability we look at the stability of the setup, with more emphasis on the historical track record and our expectations regarding future changes. In tariff-setting procedures and design we look at the utility's ability to fully recover operating costs, investments requirements, and debt-service obligations. In financial stability we look at the degree of flexibility in tariffs to counter volume risk or commodity risk. The flexibility can also relate to the level of indirect competition the utility faces. For example, while Nordic district heating companies operate under a natural monopoly, their tariff flexibility is partly restricted by customers' option to change to a different heating source if tariffs are significantly increased. Regulatory independence and insulation is mainly based on the perceived risk of political intervention to change the setup that could affect the utility's credit profile. Although political intervention tends to be mostly negative, in certain cases political ties due to state ownership might positively influence tariff determination. We believe that the four pillars effectively capture the benefits from the close relationship between the utility and the state as an owner; therefore, we do not foresee the use of the regulatory modifier.

In table 1, when describing a "strong" regulatory advantage assessment, you mention that there is support of cash flows during construction of large projects, and preapproval of capital investment programs and large projects lowers the risk of subsequent disallowances of capital costs. Would this preclude a "strong" regulatory advantage assessment in jurisdictions where those practices are absent?

93. No. The table is guidance as to what we would typically expect from a regulatory framework that we would assess as "strong." We would expect some frameworks with no capital support during construction to receive a "strong" regulatory advantage assessment if in aggregate the other factors we analyze support that conclusion.

REVISION HISTORY

These criteria became effective on Nov. 19, 2013. This criteria article superseded:

"Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry (/en_US/web/guest/article/-/view/sourceId/4998326)," published Nov. 26, 2008;
"Assessing U.S. Utility Regulatory Environments (/en_US/web/guest/article/-/view/sourceId/5089726)," Nov. 7, 2007; and
"Revised Methodology For Adjusting Amounts Reported By U.K. GAAP Water Companies For Infrastructure Renewals Accounting (/en_US/web/guest/article/-/view/sourceId/5793802)," published Jan. 27, 2010.
We republished this article following the periodic criteria review completed on June 17, 2016. As a result of our review, we updated contact information and criteria references and deleted outdated sections that appeared in paragraphs 2, 5, and 6, which were related to the initial publication of our criteria and no longer relevant.

RELATED CRITERIA AND RESEARCH

Related Criteria

General Criteria: Rating Government-Related Entities: Methodology And Assumptions (/en_US/web/guest/article/-/view/sourceId/9032821), March 25, 2015
Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers (/en_US/web/guest/article/-/view/sourceId/8956570), Dec. 16, 2014
Corporate Methodology (/en_US/web/guest/article/-/view/sourceId/8314109), Nov. 19, 2013

Group Rating Methodology (/en_US/web/guest/article/-/view/sourceId/8336067), Nov. 19, 2013
Methodology: Industry Risk (/en_US/web/guest/article/-/view/sourceId/8304862), Nov. 19, 2013
Corporate Methodology: Ratios And Adjustments (/en_US/web/guest/article/-/view/sourceId/8330212), Nov. 19, 2013
Ratings Above The Sovereign--Corporate And Government Ratings: Methodology And Assumptions (/en_US/web/guest/article/-/view/sourceId/8343660), Nov. 19, 2013
Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property (/en_US/web/guest/article/-/view/sourceId/7785024), Feb. 14, 2013
Methodology: Management And Governance Credit Factors For Corporate Entities and Insurers (/en_US/web/guest/article/-/view/sourceId/7629699), Nov. 13, 2012
General Criteria: Principles Of Credit Ratings (/en_US/web/guest/article/-/view/sourceId/6485398), Feb. 16, 2011
Securitizing Stranded Costs (/en_US/web/guest/article/-/view/sourceId/1341705), Jan. 18, 2001

These criteria represent the specific application of fundamental principles that define credit risk and ratings opinions. Their use is determined by issuer- or issue-specific attributes as well as Standard & Poor's Ratings Services' assessment of the credit and, if applicable, structural risks for a given issuer or issue rating. Methodology and assumptions may change from time to time as a result of market and economic conditions, issuer- or issue-specific factors, or new empirical evidence that would affect our credit judgment.

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

Application of Southern California Edison Company (U338E) for Approval of Energy Efficiency Rolling Portfolio Business Plan.	Application 17-01-013 (Filed January 17, 2017)
And Related Matters	Application 17-01-014 Application 17-01-015 Application 17-01-016 Application 17-01-017

**REPLY COMMENTS OF MARIN CLEAN ENERGY
ON REVISED SECTOR-LEVEL METRICS PROPOSALS**

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July 31, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of Energy Efficiency Rolling Portfolio Business Plan.	Application 17-01-013 (Filed January 17, 2017)
And Related Matters	Application 17-01-014 Application 17-01-015 Application 17-01-016 Application 17-01-017

REPLY COMMENTS OF MARIN CLEAN ENERGY
ON REVISED SECTOR-LEVEL METRICS PROPOSALS

Pursuant to the Administrative Law Judge's ("ALJ") Ruling Seeking Comment on Energy Efficiency Business Plan Metrics ("Ruling"), issued on May 10, 2017, Marin Clean Energy ("MCE") respectfully submits its Reply Comments to the initial comments filed by Pacific Gas and Electric Company ("PG&E") on July 24, 2017.

I. Introduction

PG&E's proposed approach for treatment of participation data is wholly inadequate. The utility opposes MCE's request for an "order directing PG&E to share its prior program participation data with MCE." [1] Instead, it makes the unreasonable assertion that any prior participation data disclosed to MCE be limited to aggregated industrial sector participation data and be only for the narrow purpose of complying with the ALJ and Staff's directives to track new customer participation in industrial energy

[1] *Revised Metrics Submission of Marin Clean Energy* ("MCE's Revised Metrics") at p. 4.

efficiency programs.[2] Such an approach makes little sense and underutilizes valuable data gathered at the expense of ratepayers:

- Sharing customer participation data with MCE is entirely appropriate given its status as a community choice aggregator ("CCA"), a load serving entity ("LSE") and a program administrator ("PA"). PG&E fails to demonstrate that providing such data would be legally inappropriate, costly or burdensome. Indeed, such information will improve MCE's ability to effectively perform its PA functions across all sectors.

- MCE's request is consistent with its stated goals in this Docket of fostering further collaboration and partnerships among all PAs.[3] Closer collaboration will increase program efficiency, resulting in additional energy savings that benefit all Californians.

- PG&E's offer to provide aggregated industrial participation data is insufficient to track new industrial customer participation, as directed by the Commission.

The better path forward for both ratepayers and achieving the Commission's goals is to direct PG&E to share its prior program participation data with MCE.

II. MCE's Request is Appropriate.

As a CCA, a PA, and LSE, MCE's request for energy efficiency program participation data is entirely reasonable. Such data will improve implementation of *all* of MCE's proposed programs, not just those in the industrial sector. Ratepayers, including MCE's customers, funded PG&E's energy efficiency programs and the associated collection of data. Those customers now should be able to benefit from their past investments via the open sharing of such data among PAs to facilitate the efficient use of funding.

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[2] ALJ Ruling Seeking Comment on Energy Efficiency Business Plan Metrics ("Metrics Ruling") at p. 9; "Commission Staff Additional Clarifications," issued July 10, 2017 ("July 10 Staff Metrics").
[3] *See*, MCE's Application at p. 16.

A. Participation Data will Improve MCE's Ability to Effectively Perform its PA Functions Across All Sectors.

The Commission authorized MCE to provide energy efficiency programing in August of 2012. Since that time, MCE's energy efficiency programs have ramped up significantly with a 269% increase in kWh savings and a 133% increase in therms savings in MCE's 2016 annual report compared to MCE's 2013 annual report.[4] The MCE Energy Efficiency Business Plan ("Business Plan") articulates MCE's ten–year vision to dramatically ramp up its role in providing energy efficiency programs.[5]

In order to achieve its ambitious goals, and build on its prior success, MCE needs access to prior participation data to better understand the potential for energy savings within its service area and to design the most effective portfolio to realize those opportunities. Prior participation data is critical to support MCE in: (1) improving and tracking metrics for all sectors; (2) evaluating market potential for portfolio design; and (3) pursuing targeted marketing opportunities. Indeed, the Local Government Sustainable Energy Coalition ("LGSEC"), supports MCE's request, stating "this data is necessary for other metrics as well as for identifying and calculating available savings potential, targeting new customers and tracking new customer participation. These benefits are relevant to all sectors."[6]

Prior program participation data is critical for the development of metrics that are required by the Commission. As discussed below, MCE cannot track and report on the

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[4] Gross savings as reported to the CPUC in MCE's annual reports. Available at http://eestats.cpuc.ca.gov/.

[5] MCE Energy Efficiency Business Plan at p. 4. Available at https://www.mcecleanenergy.org/2017-EE-Business-Plan.

[6] Comments of the LGSEC to the July 14, 2017 Revised Metrics Filings ("LGSEC Comments"), filed July 24, 2017, at p. 6.

new customer industrial sector metric as required by the Commission.[7] However, the data is also critical for improving and tracking metrics across all sectors. The data will support targets that are realistic and achievable for metrics in all sectors, including metrics at the implementation plan level. For example, the saturation of lighting or other measures is invaluable context for determining targets for reducing energy intensity. The prior program participation data provides necessary information and invaluable context for metrics across all sectors in MCE's Business Plan.

The Goals and Potential study, used to identify savings potential and goals for the investor-owned utilities ("IOUs"), is not granular enough for CCAs. The analysis is conducted for each IOU service area and does not provide meaningful insights for CCAs that operate in a subset of that service area. The Commission has acknowledged the data limitation as a reason not to assign goals to non-IOU PAs.[8] MCE will utilize the prior program participation information to conduct a more accurate analysis of potential to aid with portfolio design. This is an important step toward providing MCE with data to develop its own potential analysis and provides a more level playing field between IOU PAs and non-IOU PAs.

MCE will also use the prior participation information to achieve new capabilities and efficiencies in outreach through targeted marketing. As an example of targeted marketing, MCE may use prior participation data to revisit a customer that has completed a project in the past and provide them with more comprehensive measures. MCE may also use the data to avoid marketing to a saturated customer segment. The IOUs have the

[7] *See infra* Section IV.
[8] D.15-10-028 at p. 8.

data to engage in these activities and should provide that data to MCE to support more effective program administration.

B. PG&E Fails to Demonstrate that Providing Participation Data Would be Inappropriate, Costly, or Burdensome.

PG&E asserts, without citation to any legal authority, that an individual customer's prior participation in an energy efficiency program is confidential information and that PG&E would need to obtain individual customer consent prior to providing it to MCE.[9] However, PG&E fails to establish that such information is in fact confidential under any state law, rule or Commission Decision.

PG&E's own privacy policy also does not support withholding prior participation data from MCE. First, the policy clearly informs customers that their personal information may be disclosed to comply with a valid Commission request or a request by another governmental agency.[10] A Commission order to provide MCE, an LSE and PA, with this data falls squarely within this allowance. Second, PG&E's policy explains that it can release customer information to enable third parties to provide utility-related services on behalf of PG&E subject to confidentiality and security requirements.[11] While MCE is not providing utility-related services *on behalf of* PG&E, the privacy policy clearly contemplates that third parties need access to data to provide services that may have been traditionally provided by the utility. PG&E provides no clear reason why the Commission could not order it to share prior participation data with MCE.

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[9] PG&E Comments on Revised Sector-Level Metrics Proposals and Energy Efficiency and Demand Response Integration Options ("PG&E Comments"), filed July 24, 2017, at p. 4.
[10] PG&E Privacy Policy at p. 4, available at https://www.pge.com/en_US/about-pge/company-information/privacy-policy/privacy-policy/privacy-policy.page.
[11] *Id.*

However, even if PG&E could prove that prior customer participation data were confidential, it does not explain why MCE should be denied access to such data. California law requires that all electrical corporations fully cooperate with local governments that implement CCA programs.[12] The Commission is provided authority to "determine the terms and conditions under which the electrical corporation provides service to community choice aggregators and retail customers."[13] PG&E fails to explain why prior participation information regarding eligible participants for MCE's efficiency programs should be withheld in light of clear legislative intent to facilitate data sharing with CCAs, particularly a CCA that is also a Commission-designated PA such as MCE. The Commission should assert its authority and order PG&E to provide this information to MCE.

PG&E further alleges without support that MCE's request would require additional expenditures of customer resources.[14] The company fails to explain why providing data in its possession would create an incremental costs or an unreasonable burden on the company. Even if PG&E could demonstrate an incremental cost to ratepayers, the costs would likely be outweighed by the benefits, including compliance with Commission direction, more cost-effective programming, and increased energy savings through a better understanding of potential and ability to target customers.

III. The Commission Should Encourage Closer Collaboration Among PAs.

As noted in MCE's Application for Approval of its Energy Efficiency Business Plan ("Application"), MCE supports increased collaboration among PAs to accommodate

[12] Cal. Pub. Util. Code. 366.2(c)(9).
[13] *Id.*
[14] PG&E Comments at p. 4.

the evolving energy efficiency landscape as statewide and third-party programs take on new forms.[15] MCE has further proposed that the Commission add a component in the Energy Savings Performance Incentive that rewards such collaboration.[16]

Increased collaboration across PAs is a step in the right direction for advancing California's energy savings and carbon reduction goals. Access to PG&E's prior participation data will allow MCE to streamline its programs, increase cost effectiveness and unlock funding for more rebates to promote customer adoption of additional energy efficiency measures.

IV. PGE's Offer of Aggregated Data is Unreasonable.

The narrow set of data PG&E offers with regard to the new industrial metric is inadequate to achieve the Commission's goals. PG&E states that if the Commission approves MCE's request to expand its portfolio into the industrial sector, PG&E could assist MCE with this metric "by providing the total number of new participants that have not received a financial incentive from industrial energy efficiency programs within the most recent three years, as well as the total number of participants receiving a financial incentive from industrial energy efficiency programs in the current reporting year."[17]

PG&E's offer for assistance does not comport with MCE's Revised Metrics proposal. MCE has proposed that in order to track new customer participation in industrial energy efficiency programs, it will need to discern whether an individual industrial customer has been served within the last three years.[18] Aggregated data, as

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[15] Application of MCE for Approval of Its Energy Efficiency Business Plan ("MCE Application"), filed January 17, 2017, at p. 14.
[16] *Id*. at p. 16.
[17] PG&E Comments at p. 4.
[18] Revised Metrics Submission of MCE, filed July 14, 2017, Attachment A at A-18.

described by PG&E would not be sufficient to enable MCE to report on this customer-specific industrial metric.

Finally, it is not appropriate for PG&E to control the information MCE must rely on in tracking its own industrial participation metrics. PG&E's proposed path of compiling metrics on behalf of MCE[19] is an inadequate solution. The result would be that PG&E continues to possess an advantage in targeting new industrial customers because they have the data to determine whether a customer participated prior to engaging the customer in a program. PG&E's proposal only provides the information about the customer after MCE has executed a project. This proposal eliminates MCE's ability to develop unique program approaches geared toward reaching new industrial customers. The Commission should provide for competitive neutrality in program administration and direct PG&E to provide the data MCE needs to track its own metrics and target new industrial customers. MCE needs the disaggregated prior program participation data held by PG&E to properly administer its own portfolio to achieve critical goals for the Commission.

[19] "PG&E could assist MCE with this metric by providing the total number of new participants that have not received a financial incentive from industrial energy efficiency programs within the most recent three years, as well as the total number of participants receiving a financial incentive from industrial energy efficiency programs in the current reporting year." PG&E Comments at p. 4.

V. Conclusion

For the foregoing reasons, MCE respectfully requests the Commission grant its request for an order directing PG&E to share its prior program participation data with MCE.

Respectfully submitted,

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July 31, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Review, Revise, And Consider Alternatives to the Power Charge Indifference Adjustment	Rulemaking 17-06-026

COMMENTS OF THE
CALIFORNIA COMMUNITY CHOICE ASSOCIATION

In accordance with Rule 6.2 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), and Commission's July 10, 2017, *Order Instituting Rulemaking to Review, Revise and Consider Alternatives to the Power Charge Indifference Adjustment* (the OIR), the California Community Choice Association (CalCCA) respectfully submits these comments.[1]

I. Introduction.

CalCCA commends the Commission for opening this rulemaking to undertake a much needed review of the Power Charge Indifference Adjustment (PCIA). The issues the OIR raises are pressing. On June 1, 2017, Pacific Gas and Electric Company (PG&E) made its 2018 Energy Resource Recovery Account (ERRA) filing, which indicates that $2.26 billion, or 42% of the utility's 2018 vintage generation portfolio, is above market.[2] All California customers, including bundled customers and customers taking service from Community Choice Aggregators (CCAs) and Energy Service Providers (ESPs) would benefit from a framework that better assures that the

[1] The OIR made operating CCAs respondents in this proceeding and directed them to file responses to the OIR. *See* OIR Ordering Paragraphs (OP) 6 and 7. These comments serve as the comments required pursuant to OP 7 for Apple Valley Choice Energy, CleanPowerSF, Marin Clean Energy, Peninsula Clean Energy Authority, Redwood Coast Energy Authority, Silicon Valley Clean Energy Authority and Sonoma Clean Power Authority and each of these CCAs has independent party status and reserves the right to make individual filings in this proceeding. (MCE is listed as a Certified CCA in Appendix B to the OIR; however MCE was omitted from the list of named respondents in OP 6. MCE too should be a respondent and have independent party status.) Lancaster, Pico Rivera and San Jacinto are filing separate comments in this proceeding.
[2] *See* A.17-06-005, PG&E Testimony, page 9-15, Table 9-4.

Investor Owned Utilities (IOUs) prudently manage their costs to avoid such a dramatic discrepancy between market prices and utility purchases.

The OIR ordered respondents to comment on the OIR itself, the proposed Guiding Principles and the preliminary scoping memo.[3] CalCCA generally supports the OIR, which identifies most of the key issues, but offers some refinements to the list of principles and the issues in the case. These refinements highlight the rights of CCAs and their customers under state law to determine their own generation portfolios provided that the resulting procurement meets the requirements of state law. These comments also (1) identify the need for the Commission to ensure going forward that IOUs prudently manage their portfolio as the electric industry continues to evolve and (2) stress the need for adequate transparency. Finally, CalCCA offers procedural suggestions to facilitate timely, efficient and effective examination of the issues.

II. CalCCA and Its Members

Noting that the PCIA touches a wide range of customers, a wide variety of interests, and a large number of load-serving entities,[4] the OIR made all California CCAs respondents. CalCCA is a nonprofit organization formed in June 2016 to represent the interests of California's CCA programs in regulatory and legislative matters. Local communities are investigating and establishing CCA programs to customize and accelerate efforts to address climate change, renewable energy development, and other important environmental and social issues.

The operational CCA programs in California – Apple Valley Choice Energy, CleanPowerSF, Lancaster Choice Energy, Marin Clean Energy, Peninsula Clean Energy Authority, Redwood Coast Energy Authority, Silicon Valley Clean Energy Authority, and the

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3 *See* OIR at 16; OPs 6 and7.

4 *See* OIR at 2.

Sonoma Clean Power Authority – comprise CalCCA's current voting members. In addition, CalCCA's affiliate members include Central Coast Power (counties of San Luis Obispo, Santa Barbara and Ventura), East Bay Community Energy Authority (Alameda County), Monterey Bay Community Power Authority, Pico Rivera Innovative Municipal Energy, Valley Clean Energy (city of Davis and Yolo County), the cities of Corona, Hermosa Beach, San Jose, Solana Beach, and San Jacinto, the counties of Los Angeles and Placer, and Western Riverside Council of Governments.

CalCCA's interests in this proceeding stem from both their operations and their role as advocates for customers, including bundled customers, within the boundaries of their service territories. The residents and businesses within these territories require reliable, clean electric service at reasonable prices and a fair determination of the costs customers must bear to ensure bundled customer indifference.

III. Principles

The guiding principles included in the OIR's draft scoping memo fairly recognize tenets important to bundled ratepayers, but leave out a handful of corresponding provisions critical to CCAs and their customers. CalCCA suggests below both a revision to Principle 5, and the addition of five other principles, to better reflect the rights of CCAs and their customers and the importance of prudent portfolio management by the IOUs.

A. Guiding Principle 5 Should Be Modified to Recognize California Policies to Promote Development of CCAs.

Guiding Principle 5 in the OIR should be modified as follows:

5. Any methodology to ensure bundled customer indifference should be consistent with state policies to promote CCAs and should not create unreasonable obstacles for customers of non-IOU energy providers.

The Legislature and the Commission have recognized the state's interest in promoting the development of CCAs and other competitive options for customers. The Commission should strive to do more than simply avoid the creation of "unreasonable obstacles" for CCA customers.

In Decision 04-12-046 the Commission recognized the Legislature's express policy to "permit and *promote* CCAs by enacting AB 117…"[5] The Legislature made this intent to promote CCA even more explicit when it passed Senate Bill (SB) 790 in 2011. The legislative declaration section of SB 790 states that California has "a substantial governmental interest in ensuring that conduct by electrical corporations does not threaten the consideration, development, and implementation of community choice aggregation programs."[6]

CCAs are unlike IOUs or ESPs in that they have been created by elected officials to advance specific public policy objectives. Simply striving to avoid "unreasonable obstacles" does not go far enough to support local government or statewide policy directives. The Commission should examine any new non-bypassable charge (NBC) methodologies consistent with these policies to promote, protect, and support the formation of CCAs.

B. Additional Principles Necessary to Better Reflect the Rights of CCAs and Their Customers and IOUs' Obligations to Prudently Manage Their Portfolios.

1. The Principles Should Recognize and Respect CCAs' Responsibility to Develop Their Own Generation Portfolios.

The following two guiding principles should be added to the list:

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5 D. 04-12-046 at 1 (emphasis added).

6 SB 790; 2(g); Pub. Util. Code § 707(a)(4)(a). *See also* D.12-12-036 at 6 (citing SB 790, § 2(h), and Pub. Util. Code § 707(a)(4)(A)) ("In SB 790, the legislature directed the Commission to develop rules and procedures that 'facilitate the development of community choice aggregation programs, … foster fair competition, and … protect against cross-subsidization paid by ratepayers.'".). All further statutory references are to the Public Utilities Code, unless otherwise noted.

7. Any methodology to ensure bundled customer indifference should allow CCAs to be solely responsible for all generation procurement activities on behalf of their customers, except as expressly required by law.
8. Any methodology to ensure bundled customer indifference should allow a CCA to elect to pay for its share of stranded costs in a manner that complements the CCA's particular procurement needs and goals.

Proposed principle 7 reflects Section 366.2(a)(5). State law recognizes CCAs as the primary entity responsible to procure generation on behalf of their customers,[7] and the OIR should include this provision as a guiding principle. The Legislature made CCA local governments responsible for a CCA's generation portfolio. CCA local governments strive to have the portfolio reflects their customers' needs and values, including, for example, environmental profile, job creation, cost, and reliance on local resources. Proposals that mandate the transfer of electric supplies, renewable energy credits (RECs) and resource adequacy (RA) purchases from an IOU to a CCA could improperly infringe on a CCA's obligation to develop its own portfolio.

Proposed principle 8 provides that CCAs should be allowed to choose an approach for ensuring bundled customer indifference that best comports with their particular business. CalCCA recognizes that the IOUs have entered into long-term contracts to meet the needs of customers who are departing in significant numbers as CCAs form. This situation provides an opportunity for the IOUs to sell or otherwise transfer some of their excess resources to CCAs to the extent CCAs have a need for additional resources. However, to comply with Section 366.2(a)(5), any such transfers should be voluntary.

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[7] Section 366.2(a)(5).

Each CCA is at a different stage of development and has different objectives. Provided that bundled customer indifference is achieved, and that all customers pay their fair share, CCAs can and should be allowed to choose between alternatives, including for example, paying for and obtaining specific IOU resources, paying only for above market costs that are transparent, fairly and accurately calculated, and diligently mitigated, and/or achieving greater certainty through lump-sum, upfront payments.[8]

Moreover, any stranded cost recovery methodology should avoid adversely impacting CCAs that enter into long-term contracts. For example, the mandatory transfer of RA and REC attributes to CCAs would penalize those CCAs that have already largely contracted for the resources they need, forcing them to find buyers for excess resources that the IOU rather than the CCA opted to buy. Similarly, an NBC that fluctuates with and is correlated to short-term market prices could penalize CCAs that enter into long-term contracts that otherwise would have provided a hedge against this fluctuation.

2. The NBC Methodology Should Not Reward Imprudent IOU Procurement and Portfolio Management.

The following guiding principle should be added to the list:

9. Any methodology to ensure bundled customer indifference should only include legitimately unavoidable costs and account for the IOUs' responsibility to prudently manage their generation portfolio and take all reasonable steps to minimize stranded costs.

The OIR includes as an issue "[o]ptimization of IOU portfolio management (*e.g.*, contract extensions and contract renegotiation) to minimize stranded costs."[9] That issue is

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[8] *See, e.g.,* D.-09-08-015 and D.10-11-011 (describing and approving lump-sum buyout arrangements for publicly owned utilities).

[9] OIR at 9.

important, but Section 365.2 provides that departing load should not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load. Moreover, the IOUs can only recover from CCA customers the utility's "net *unavoidable* electricity purchase contract cost attributable to the customer."[10] These statutory provisions necessitate a guiding principle of excluding avoidable costs from NBCs and ensuring prudent IOU procurement and diligent portfolio management to mitigate costs.

Further, the Commission has stated regarding the Cost Responsibility Surcharge (CRS) and Assembly Bill (AB) 117 that the objective of CRS is: "to protect the utilities and their bundled utility customers from paying for the liabilities incurred on behalf of CCA customers. Our complementary objective is to minimize the CRS (and all utilities liabilities that are not required) and promote good resource planning by the utilities."[11] The Commission maintained a ten-year limitation on cost recovery for non-Renewables Portfolio Standard (RPS) resources explaining:

> With respect to non-RPS resources that will be available for more than 10 years but which are limited to 10-year NBC recovery, the utilities can, over time, adjust their load forecasts and resource portfolios to mitigate the effects of DA, CCA, and any large municipalizations on bundled service customer indifference. By the end of a 10-year period, we assume the IOUs would be able to make substantial progress in eliminating such effects for customers who cease taking bundled service during that period.[12]

A cost should not be considered stranded or "unavoidable" if the IOU fails to make reasonable adjustments to its resource portfolio. The fact that 42% of PG&E's 2018 vintage generation portfolio is above market suggests the objective of assuring prudent portfolio management is not being achieved. Rather, the existing methodology rewards the IOUs for any failure to take all available steps to minimize stranded costs by allowing recovery of 100% of

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[10] *See* Section 366.2(f)(2).
[11] D.04-12-046 at 29.
[12] D. 08-09-012 at 54-55.

their above market costs with insufficient consideration of whether those costs were incurred prudently. Unless the objective of minimizing stranded costs becomes a higher priority, and IOUs are held accountable for their obligation to prudently manage their portfolio, the Commission can expect to see stranded costs continue to comprise a disproportionate share of customer bills.

3. The NBC Methodology Should Reflect the Benefits Departing Customers Impart to Remaining Bundled Customers.

The following guiding principle should be added to the list:

10. Any methodology to ensure bundled customer indifference should include the value of the benefits that departing customers impart to remaining bundled service customers.

California law seeks a balanced approach to stranded cost recovery that protects both bundled and departing customers. For example, Section 366.2(g) provides that unavoidable energy costs paid by CCA customers "shall be reduced by the value of any benefits that remain with bundled service customers, unless the customers of the community choice aggregator are allocated a fair and equitable share of those benefits." The Commission has stated, "bundled customers should be no worse off, *nor should they be any better off* as a result of customers choosing alternative energy suppliers."[13] The Commission has a responsibility to promote fair competition between CCAs and IOUs,[14] and should prevent cross-subsidization of IOU costs.[15]

Following these statutory provisions and precedent requires an accounting of the benefits departed load provides. For example, the departure of CCA customers increases the IOUs' RPS percentage, decreases their need to procure additional resources, and allows the utilities to

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13 D.08-09-12 at 10 (emphasis added).
14 Section 365.2.
15 D.04-12-046 at 3.

dispatch more economically efficient generators. Thus, a principle should be added to the scoping memo that reflects a balanced approach by recognizing the benefits departing customers provide to remaining bundled customers.

4. The NBC Methodology Should Accurately Reflect All Short, Medium, And Long-Term Value Streams.

The following guiding principle should be added to the list:

11. Any methodology to ensure bundled customer indifference should accurately reflect and seek to preserve all short, medium, and long-term value of the resources procured by the utilities.

The present NBC framework values energy on a single year-ahead basis that may not adequately reflect long-term hedge value. The IOUs' recent Portfolio Allocation Methodology (PAM) proposal would have exacerbated this problem by valuing energy at an even shorter-term spot market price. Similarly, the IOUs' PAM proposal would have reduced the value of long-term renewables contracts to California users. This would mean that valuable Portfolio Content Category (PCC) 1 resources in the hands of the utilities could have been converted to PCC 3 resources in the hands of CCAs. But even if this problem had been solved, the IOUs' proposal could have eroded the value of renewable contracts because although the IOUs have certainty about the nature and amount of resources within their portfolios, the amounts and types of resources allocated to the CCAs could have fluctuated from year-to-year or been comprised of less valuable "chunks." Finally, to the extent that IOUs decline to sell excess resources directly to CCAs but sell them instead to energy traders, such traders may then in turn sell the resources to CCAs with some margin. The traders' margin becomes value that is lost to California consumers.

Any NBC mechanism should seek to preserve the full value of any excess utility resources so that, to the extent possible, California customers obtain the maximum benefit of existing resources rather than losing or transferring some or all of the value to traders or other jurisdictions. Moreover, the valuation mechanism should recognize the full value of utility resources and make utilities accountable for any forfeiture of this value that could have been preserved for bundled customers and CCA customers by prudent management.

IV. Additional Issues.

The OIR sets forth a fairly comprehensive list of issues. CalCCA identifies only a few additional issues.

1. The OIR should address IOU owned generation. Departing customers pay the above market costs of IOU owned generation. As in the case of contracts, the rulemaking should explore alternatives to maximize the value of these resources to California consumers and identify approaches to minimize stranded costs. In addition, not all IOU costs relating to IOU owned generation incurred *after* the departure of a CCA's load can be considered to be costs incurred *on behalf of* that load.[16] The OIR should consider developing rules addressing this issue, which possibly differentiate between types of IOU costs (capital, replacement, repair, operations).

2. The rulemaking should address the factors used to allocate stranded costs and designate the appropriate mechanism for stranded cost recovery between bundled and unbundled customers as well as the rate design policies used to allocate these costs both by function (i.e. transmission, distribution, generation) or by customer class (*e.g.* residential, commercial).

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[16] The problem becomes more apparent as the time between a load departure and an IOU expense becomes longer: Why should load that departed 20 years ago be required to continue to pay for repair costs at an IOU-owned facility?

Currently, such allocation and designation occurs on a program-by-program basis without a clear standard, *e.g.*, whether the costs of a particular IOU procurement program are eligible for recovery pursuant to the PCIA, or some other mechanism such as the Cost Allocation Mechanism. This proceeding should determine a clear, definitive standard that must be met in order for the IOUs to recover costs via the PCIA, or its replacement. The evaluation of stranded costs should also address equity and reasonableness of allocations to rate classes (*e.g*. residential versus large commercial) as well as to rate components (*e.g.* generation versus transmission and distribution).

3. The rulemaking should establish a list of, and determine a methodology to value, the benefits that departing customers provide to bundled service customers.

4. The rulemaking should address treatment of the IOUs' negative indifference balance amounts and the effects on the Competition Transition Charge (CTC) that may result from any revision to, or replacement of, the PCIA. The issue of negative indifference amounts was raised most recently in A.16-06-003, PG&E's 2016 ERRA application. PG&E proposed to eliminate its negative indifference amount balance for pre-2009 departing load vintages. In D.16-12-038, however, the Commission deferred this issue to a second phase of the proceeding.[17] On May 22, 2017, the Commission issued a ruling consolidating each of the IOUs' ERRA proceedings within A.16-04-018 *et al*,[18] which is to address PG&E's proposal to eliminate the negative indifference balance.[19]

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17 D.16-12-038, at 22, OP 4.

18 *Administrative Law Judge's Ruling Consolidating Proceedings and Establishing Phase II*, A.16-04-018, May 22, 2017, at 3.

19 *Assigned Commissioner's Ruling Amending Scope of by Creating A Second Phase*, A.16-04-018, November 1, 2016, at 3.

Notwithstanding the Commission's intent to address negative indifference amounts in the consolidated ERRA proceeding, this Rulemaking is the appropriate forum to analyze this issue as part of a holistic reform of the PCIA. Not having a negative indifference amount to off-set the CTC could result in inappropriate IOU collections from CCA customers that would benefit bundled customers at the expense of CCA customers. Such a result would violate the rule of bundled customer indifference. Moreover, this issue is not IOU-specific, and it should be addressed as part of the holistic statewide reform of the PCIA to ensure a consistent and equitable policy.

5. This OIR should address the continuing inability of CCA legal and regulatory staff to review confidential IOU information necessary to determine the proper amount of the PCIA or a successor exit fee. In their application for Commission approval of the "Portfolio Allocation Methodology," the IOUs recognized "the need for all LSEs to be fully informed in the development of their portfolios," and that "this will require visibility into the costs and attributes inherent in [the IOUs'] portfolio."[20] The IOUs proposed to have a separate phase in the PAM proceeding to address confidentiality issues.[21] CCAs have filed an application with the Commission to allow specified CCA legal and regulatory employees access to confidential IOU information for purposes of evaluating the PCIA, under an appropriate non-disclosure agreement that would keep such information from CCA employees who work on energy market transactions.[22]

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[20] Joint Utilities' Direct Testimony in Support of Application for Approval of the Portfolio Allocation Methodology for all Customers at 44.

[21] "The Joint Utilities recognize the need for a formal process to provide portfolio and contract data to LSEs as a part of PAM, and anticipate that a detailed process will need to be put in place that balances necessary transparency and planning certainty for LSEs; rules to protect customers and market integrity; and contractual counter-party confidentiality obligations." Id. at 45.

[22] *See* CalCCA Petition for Modification of Decision 11-07-028, filed on June 13, 2017 in docket R. 05-06-040.

In order to fully and effectively participate in this OIR, CCAs need to have access to such confidential data about the IOUs' portfolios. We encourage the Commission to either take up the existing CCA application promptly, or develop a separate mechanism early in the OIR process to allow CCA legal and regulatory personnel access to the data necessary to fully evaluate the issues raised by the OIR.

6. This OIR should also address providing transparent information about above market costs to bundled and CCA customers. In particular, the OIR should explore how above market costs should be reflected in the bills of bundled and CCA customers. Customers paying IOU costs are entitled to accurate and clear information on the nature of these costs.

V. Procedural Matters

A. Use of Workshops and Hearings

CalCCA favors use of a combination of workshops and evidentiary hearings to address the issues in this case. Each workshop could be accompanied by a report by the Energy Division and an opportunity for comment by the parties. After an initial phase of mutual education through workshops, the Commission should schedule evidentiary hearings as necessary. CalCCA believes that at least two workshops would be beneficial: one to discuss the details of the existing PCIA and one to give parties the opportunity to present and discuss alternatives. CalCCA is not proposing a particular schedule, but notes that there are currently underway a number of important proceedings that require participation by the CCAs and the IOUs. These include the Integrated Resource Planning proceeding, the CCA proceeding exploring bonds, PG&E's 2018 ERRA application, and the energy efficiency business plan proceeding. The Commission should review and coordinate the schedules in those cases with this proceeding to ensure that all parties, including those having limited resources, are able to participate effectively.

B. Categorization and the Need for Reporting Ex Parte Contacts

While CalCCA agrees with the Commission's preliminary categorization of this proceeding as quasi-legislative,[23] any discussions with decision-makers within the docket should be subject to the disclosure requirements that apply to ratesetting proceedings pursuant to the Commission's rules. The OIR notes "*[e]x parte* communications are allowed without restriction or reporting requirement in a quasi-legislative proceeding," and preliminarily determines "no *ex parte* restrictions or reporting requirements apply in this proceeding."[24]

However, the structure of the PCIA and the related bundled customer indifference requirements will critically affect the continuing viability of CCAs and other retail choice providers. The gravity of these issues to the State, CCAs, ESPs and ratepayers warrants a substantial degree of transparency with regard to communications between Commission decision-makers and entities interested in the outcome of this docket.

Moreover, as noted above and in the OIR, it is likely hearings may be needed within the proceeding. Transparency is paramount within hearings, where ALJs and other decision-makers will make critical determinations of fact, law and procedural and substantive motions.

Under SB 215 (2016), the Commission may, via order or ruling, increase restrictions related to *ex parte* communications beyond those that would otherwise apply in a quasi-legislative proceeding.[25] Given the need for transparency in this docket, CalCCA respectfully

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23 OIR at 11.

24 *Id.*

25 Section 1701.4(c)(1); Draft Rule 8.2(d) (implementing Cal. Pub. Util. Code § 1701.4(c)) (as proposed in Draft Resolution ALJ-344 (Mar. 4, 2017), Appendix A, at pp. 23-24) ("Notwithstanding subsections (a) and (c) of this rule, the assigned Commissioner may issue a ruling to restrict or prohibit ex parte communications in a quasi-

requests the Commission issue an order or ruling determining that communications with decision-makers in this proceeding are subject to the disclosure requirements that apply to ratesetting proceedings pursuant to the Commission's *ex parte* rules.

VI. Conclusion

CalCCA appreciates the Commission's determination to open this rulemaking and looks forward to participating actively in the proceeding.

Dated: July 31, 2017

Respectfully submitted on behalf of CalCCA by,

DENNIS J. HERRERA
City Attorney
THERESA L. MUELLER
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JEANNE M. SOLÉ
Deputy City Attorney

By: /s/
JEANNE M. SOLÉ

Attorneys for
CITY AND COUNTY OF SAN FRANCISCO

legislative or ratesetting proceeding or to require reporting of ex parte communications in a quasi-legislative proceeding.").

Braun Blaising Smith Wynne, P.C.
Attorneys at Law

July 31, 2017

Via Regular Mail and E-Mail

Mr. Ed Randolph
Director, Energy Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, California 94102

Re: CCA Parties' Comments on Draft Resolution E-4846
Pacific Gas and Electric Company Advice Letters 4979-E, 4979-E-A, 4979-E-B, 4979-E-C, Proposed Residential Default Time-of-Use Pilot

Dear Mr. Randolph:

Pursuant to Rule 14.5 of the Rules of Practice and Procedure of the Public Utilities Commission of the State of California ("Commission"), Marin Clean Energy ("MCE") and Sonoma Clean Power Authority ("SCPA") (collectively, "CCA Parties") hereby submit these comments on Draft Resolution E-4846 ("Draft Resolution"). The Draft Resolution was issued in response to Pacific Gas and Electric Company's ("PG&E") Advice Letters ("AL") 4979-E, 4979-E-A, 4979-E-B, and 4979-E-C, relating to PG&E's proposed default time-of-use ("TOU") pilot for residential customers ("Default TOU Pilot").

The CCA Parties request that the Draft Resolution be slightly revised to address two matters. First, the Draft Resolution should be modified to include express language requiring that PG&E's Default TOU Pilot costs be set for a determination as to the proper allocation of costs between the generation and distribution functions. Second, the Draft Resolution should explicitly require PG&E to propose and take steps towards implementing a robust bill comparison tool for Community Choice Aggregation ("CCA") customers as a part of the upcoming rate design window ("RDW") application, which will be filed by January 1, 2018. The CCA Parties additionally request that the Commission clarify PG&E's proposed budget to develop the aforementioned tool.

BACKGROUND

MCE operates the first CCA program to provide electricity service in California. MCE currently provides generation services to approximately 250,000 customer accounts in Marin County, Napa County, and the cities of Richmond, San Pablo, El Cerrito, Benicia, Lafayette, and Walnut Creek.

SCPA is a California joint powers authority operating a CCA program in Sonoma County. SCPA is the second operational CCA program in California and currently serves about

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198,000 customer accounts encompassing a population of approximately 450,000, which includes all of Sonoma County, except for the City of Healdsburg, which has its own municipal utility. SCPA's Board of Directors recently approved the expansion of service to Mendocino County, which began in the second quarter of 2017.

MCE and SCPA provide their customers with stable and competitive electric rates and provide a power portfolio with a higher renewable content (and lower greenhouse gas emissions) than the incumbent investor-owned utility ("IOU"), PG&E.

Under CCA programs, generation services are furnished by the CCA provider, and rates for this service are set by local governing boards. This construct, by which not all residential rates are set by the Commission, creates the potential for significant customer confusion in conjunction with the rollout of default TOU rates. PG&E and the CCA Parties share the same goal of helping their customers seamlessly transition to full default TOU rates as early as 2019; this is why the CCA Parties elected to participate in the Default TOU Pilot.

As detailed below, the CCA Parties have been engaged with PG&E and the Commission on residential rate matters both in the context of the ALs, as well as in the rulemaking context. On December 16, 2016, through AL 4979-E, PG&E filed a proposal for its 2018 Default TOU Pilot. On January 24, 2017, MCE submitted a timely protest to the Default TOU Pilot. On February 7, 2017, PG&E replied to that protest. On February 24, 2017, PG&E served AL 4979-E-B. On March 16, 2017, the CCA Parties responded to AL 4979-E-B, and requested PG&E to provide more details about its proposed long term solution for a rate comparison tool for CCA customers in its future filing for the full rollout of default TOU rates. In its reply, PG&E stated that it will collaborate with MCE and SCPA to develop a long term solution for a rate comparison tool for CCA customers prior to submitting its plans for the full rollout of default TOU rates.

The CCA Parties remain concerned that PG&E will not develop a robust rate comparison tool in a timely manner because of the lack of progress to date. Therefore, the CCA Parties request that the Draft Resolution be revised to direct PG&E to develop this tool prior to filing PG&E's upcoming RDW application. The CCA Parties are committed to continuing to work with PG&E, the Commission, and other stakeholders to ensure that CCA customers are fully and fairly informed regarding coming changes in residential rate structures.

COMMENTS

1. **The Draft Resolution Should Be Modified to Include Express Language Requiring that PG&E's Default TOU Pilot Costs Be Set for Proper Cost Allocation Determination.**

   a. PG&E's General Rate Case is not an appropriate forum to address cost allocation for the Default TOU Pilot or the Default TOU rollout.

Confusion exists regarding when and in what venue parties will be given an opportunity to examine whether the full panoply of TOU-related implementation costs (not just bill protection costs) will be allocated between generation and distribution rates and to what degree.

On April 25, 2017, the CCA Parties submitted comments in response to the *Administrative Law Judges' Ruling Seeking Comment on Statewide Marketing, Education, and Outreach on Residential Rate Reform* in the Residential Rate Rulemaking ("R.") 12-06-013. In these comments, the CCA Parties argued, *inter alia*, that it is unfair and unreasonable to allocate the entirety of TOU marketing education and outreach ("ME&O") costs to the distribution function. In its reply to these comments, PG&E stated:

> [S]uch costs have been repeatedly allocated to distribution customers in the IOUs' various General Rate Case [("GRC")] proceedings. The CCAs are free to re-litigate these cost allocation principles in the IOUs' respective GRCs, but the issues of cost allocation are not within the scope of this proceeding.[1]

This statement wholly contradicts PG&E's representation in its most-recent GRC, where PG&E stated that parties would have an opportunity to address the allocation of residential rate costs between the generation and distribution functions in the upcoming RDW that PG&E will file by January 1, 2018.[2] Seeking clarification, MCE propounded a data request, asking PG&E to provide additional information to support the unfounded statement in the PG&E reply that "costs have been repeatedly allocated to distribution customers in the IOUs various GRC proceedings."[3] In response to MCE's data request, PG&E stated:

> See, e.g., PG&E 2017 General Rate Case, D.17-05-013, Appendix A: Table 3-A and Table 3-B lines 9 and 11, allocating Customer Account and Customer Services costs to electric and gas distribution customers. PG&E's proposal for allocating its 2017 GRC

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[1] *Reply Comments of Pacific Gas and Electric Company (U 39 E) On Statewide Marketing, Education, And Outreach On Residential Rate Reform*, at 4, dated May 5, 2017.

[2] *See Opening Comments on the Alternate Proposed Decision ("APD") of Commissioner Picker in A.15-09-001*, dated April 24, 2017, at 5 ("PG&E's recommended approach would allow residential rate reform costs to be reviewed via an upcoming stand-alone filing that will, "among other things…afford the parties an opportunity to address the allocation of RRRMA costs between generation and distribution rates.").

[3] *Reply Comments of Pacific Gas and Electric Company (U 39 E) On Statewide Marketing, Education, And Outreach On Residential Rate Reform*, at 4, dated May 5, 2017.

cost was approved by the Commission in D.17-05-013.[4]

This response is not persuasive, since the amounts alluded to are broad categories which do not specifically address the issue of residential rate cost allocation. This vague response highlights the ambiguity surrounding residential rate cost allocation. Residential rate cost allocation was not decided in the GRC and is in fact still ripe for review. PG&E is unable to pinpoint any specific discussion or testimony as to where it claims this issue was decided.

b. Costs for the Default TOU Pilot and Default TOU rollout are not solely assignable to the distribution function.

The CCA Parties appreciate the fact that the Draft Resolution states "All the price variation in PG&E's proposed E-TOU-C3 rate occurs in the generation portion of the rate, and thus we agree with MCE and PG&E that PG&E should record bill protection payments as shortfalls in generation revenue. This shortfall will be recovered across all of PG&E's residential generation customers."[5] The issue of proper cost allocation between generation and distribution rates, however, is not limited to simply generation and distribution revenue shortfalls related to bill protection. Rather, a broader issue is involved.

As it is now, PG&E appears to be charging the entirety of Default TOU Pilot costs to distribution rates when many, if not most, of the costs appear to be attributable to generation rates. It also appears that PG&E wishes to charge the entirety of ME&O costs to distribution rates. This would not be a problem but for the fact that generation services are competitive; CCA providers compete with the IOUs in the provision of generation services, and therefore anti-competitive cross-subsidization occurs when costs attributable to the generation function are improperly assigned to the distribution function. This also impacts customers by requiring them to pay twice for the same services—once in their CCA generation rate and once in their IOU transmission and distribution rate. Senate Bill ("SB") 790 (2011) includes various provisions that speak about the IOUs' potential to cross-subsidize competitive generation services and that seek to redress this potential.[6]

The CCA Parties are concerned that the issue of proper cost allocation between the generation and distribution functions associated with the rollout of default TOU rates is not being given proper attention. Consequently there may continue to be the potential to cross-subsidize the IOUs' competitive generation services. As such, the CCA Parties request that the Draft

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4 *See* PG&E Response to MCE Data Request Q.1, dated June 13, 2017.

5 Draft Resolution at 21.

6 *See, e.g.,* SB 790; § 2(c) ("Electrical corporations have inherent market power derived from, among other things, name recognition among…joint control over regulated operations and competitive generation services…and the potential to cross-subsidize competitive generation services."). *See also* SB 790; § 2(h) ("It is therefore necessary to establish a code of conduct, associated rules, and enforcement procedures, applicable to electrical corporations in order to facilitate the consideration, development, and implementation of community choice aggregation programs, to foster fair competition, and to protect against cross-subsidization by ratepayers.").

Resolution be modified to include express language requiring that PG&E's Default TOU Pilot costs not only be determined to be reasonable in a future proceeding, but also be determined to be properly allocated between the generation and distribution functions. In this regard, the CCA Parties further requests that the Draft Resolution be modified to confirm the expectation that PG&E's standalone application for the full default TOU rollout will be used as the proceeding in which parties may address PG&E's proposed cost allocation methodology for ME&O, the Default TOU Pilot, and related costs associated with the default TOU rollout.

While the issue of cost allocation may be outside the scope of PG&E's ALs, the CCA Parties nevertheless request that the Commission consider this important issue. The CCA Parties request that the Commission provide clarity and instruction as to where and how the issue of cost allocation between generation and distribution rates will be decided. The Commission can and should use the Draft Resolution to describe how the generation and distribution cost allocation split will be reviewed and determined.

c. PG&E's RDW Application Should Address Cost Allocation.

It is worth noting that Southern California Edison Company ("<u>SCE</u>") has expressly committed to addressing residential rate cost allocation in the context of SCE's default TOU application (A.17-04-015).[7] To facilitate consistent treatment of IOUs statewide, PG&E should also be expected to commit to addressing residential rate cost allocation in its upcoming RDW application. Given the recognition that CCA providers are expected to serve a majority of the load in California in the foreseeable future, it is imperative that the issue of proper cost allocation be given appropriate attention now. The CCA Parties have a strong interest in ensuring that California's policy goal of facilitating CCA growth and viability is fully realized.[8] In order to achieve this goal, it is important for the Commission and parties to explore whether attributing all residential rate costs to the distribution function violates the statutory prohibition on cost shifting or otherwise disadvantages CCA programs and their customers. PG&E's RDW is the proper forum to address this issue as it relates to the Default TOU Pilot and Default TOU rollout.

2. The Draft Resolution Should Require PG&E to Implement a Robust Bill Comparison Tool for CCA Customers.

Pursuant to Assembly Bill 117 (2002), PG&E is the default billing service provider. Specifically, PG&E is required by Public Utilities Code section 366.2(c)(9) to "provide all metering billing, collection and customer services to retail customers that participate in [CCA]

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7 See *SCE Reply to Protests to Its Application for Approval of Its Proposal to Implement Residential Default Time-Of-Use Rates*, dated May 26, 2017 ("SCE agrees with Lancaster that in accordance with Resolution E-4847, [citation omitted] cost allocation issues specific to this Application are within scope in this proceeding.")

8 *See* D.04-12-046 at 3 (emphasis added) ("The state Legislature has expressed the state's policy to permit <u>and promote</u> CCAs by enacting AB 117…."). *See also* D.10-05-050 at 13 (emphasis added) "Certainly, Section 336.2(c)(9) [the provision in AB 117 that requires cooperation from the utilities] evidences a substantial governmental interest in <u>encouraging the development</u> of CCA programs and allowing customer choice to participate in them.").

programs." Yet, as revealed in the Draft Resolution, "PG&E does not currently have the capability to provide CCA customers with rate comparisons."[9] The Draft Resolution rightly acknowledges "that this is an important piece of information for customers to have in order to make an informed choice regarding whether or not TOU is the right rate choice for them."[10] Despite the importance of this issue, the Draft Resolution declines to provide any direction "regarding the appropriate method or cost recovery for creating a long term rate comparison tool solution for CCA customers."[11] The CCA Parties respectfully request that the Draft Resolution be revised in order to affirmatively address this key issue.

For lack of a more comprehensive solution, the CCA Parties agreed to PG&E's proposal to set up an auxiliary website to leverage existing PG&E rate modeling functionality to support CCA customers during the Default TOU Pilot. However, this makeshift approach is not sustainable. PG&E expects to have six active CCA programs by the end of 2017 alone.[12] The CCA Parties reiterate their prior request, and ask the Commission to direct PG&E to develop a robust bill comparison tool capable of supporting all CCA programs in PG&E's service territory prior to the rollout of full default TOU rates. Failing to do so would effectively exclude a large – and growing – portion of PG&E's distribution customers from being able to participate in the full TOU Default in 2019, ultimately hampering its potential effectiveness.

Given the lack of progress to date, the CCA Parties doubt PG&E's ability to implement a robust bill comparison tool prior to full default in 2019 unless aggressive work on the tool begins now. However, it appears that PG&E is not motivated to engage in the degree of work that is required. For example, PG&E previously argued that it would be too complicated for it to conduct a TOU rate comparison for CCA programs during the pilot phase because doing so would require it to create an individually tailored model that uses each CCA's "current, unique generation rate, TOU period, and other billing characteristics."[13] PG&E filed the initial AL in December of 2016 for implementation in March of 2018; the RDW will be filed by January 1, 2018 for implementation by March of 2019. Since 15 months was not long enough for PG&E to fashion a robust bill comparison tool for the Default TOU Pilot, which will include a very limited number of CCA customers, the CCA Parties are concerned PG&E will not be able to develop a tool to support *all* CCA customers in the same amount of time, particularly if PG&E remains unmotivated. Clear direction from the Commission is needed in order for PG&E to develop a robust bill comparison tool prior to filing the RDW application.

To incentivize and expedite PG&E's development of a bill comparison tool, this issue should also be set for resolution in the upcoming RDW application. Waiting until the General Rate Case in 2020, as intimated by PG&E, is not an acceptable option. To ensure timely and appropriate review, the CCA Parties request that the Commission revise the Draft Resolution to

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9 Draft Resolution at 17.
10 *Id.*
11 *Id.* at 18.
12 *See* AL 4979-E-B at 15.
13 *Id.* at 4.

explicitly require that funding for the bill comparison tool also be decided in the upcoming RDW application.

Finally, the CCA Parties request that the Draft Resolution be modified to clarify the two varying cost estimates related to CCA rate modeling. The budget associated with the Default TOU Pilot estimates $800,000 for "CCA Rate Modeling,"[14] yet the Draft Resolution states that "PG&E proposes to build a rate comparison tool for MCE and SCP customers for the default pilot at an estimated cost of $250,000."[15] Given the $550,000 discrepancy, the CCA Parties request the Commission clarify the expected budget needed to develop a rate comparison tool for purposes of the pilot. In turn, this clarification can be used to better assess the costs associated with providing this, or a similar, tool to additional CCAs when default TOU rates are fully implemented.

CONCLUSION

The CCA Parties are concerned by the ambiguity and apparent lack of direction with respect to which proceeding will be used to determine residential rate cost allocation issues, and when such determinations will be addressed. Moreover, the CCA Parties urge the Commission to direct PG&E to develop an acceptable bill comparison tool for CCA customers. The CCA Parties thank the Commission in advance for consideration of these comments.

Respectfully,

/s/ Laura Taylor

Copy (via e-mail): CPUC Energy Division Tariff Unit (EDTariffUnit@cpuc.ca.gov)
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Service List – R.12-06-013

[14] *See* Draft Resolution at 35.
[15] *Id.* at 17.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U902E) for Approval of its 2017 Electric Procurement Revenue Requirement Forecasts and GHG-Related Forecasts.	Application 16-04-018 (Filed April 15, 2016)
Application of Southern California Edison Company (U338E) For Approval of its Forecast 2017 ERRA Proceeding Revenue Requirement	Application 16-05-001 (Filed May 2, 2016)
Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Rquirements and Rates Associated with its 2017 Energy Resource Recovery Account (ERRA) AND Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation (U39E)	Application 16-06-003 (Filed June 1, 2016)

JOINT CASE MANAGEMENT STATEMENT OF ALLIANCE FOR RETAIL ENERGY MARKETS, DIRECT ACCESS CUSTOMER COALITION; CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION; MARIN CLEAN ENERGY; PACIFIC GAS AND ELECTRIC COMPANY (U 39-E); PUBLIC AGENCY COALITION; SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E); AND SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E)

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Dated: August 10, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U902E) for Approval of its 2017 Electric Procurement Revenue Requirement Forecasts and GHG-Related Forecasts.	Application 16-04-018 (Filed April 15, 2016)
Application of Southern California Edison Company (U338E) For Approval of Its Forecast 2017 ERRA Proceeding Revenue Requirement	Application 16-05-001 (Filed May 2, 2016)
Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Rquirements and Rates Associated with its 2017 Energy Resource Recovery Account (ERRA) AND Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation (U39E)	Application 16-06-003 (Filed June 1, 2016)

JOINT CASE MANAGEMENT STATEMENT OF ALLIANCE FOR RETAIL ENERGY MARKETS, DIRECT ACCESS CUSTOMER COALITION; CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION; MARIN CLEAN ENERGY; PACIFIC GAS AND ELECTRIC COMPANY (U 39-E); PUBLIC AGENCY COALITION; SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E); AND SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E)

Pursuant to Administrative Law Judge (ALJ) Tsen's August 4, 2017 email ruling in the above-captioned matter (Ruling), Pacific Gas and Electric Company (PG&E) respectfully submits this Joint Case Management Statement on behalf of itself, Alliance for Retail Energy Markets and Direct Access Customer Coalition (AReM/DACC), California Large Energy Consumers Association (CLECA), Marin Clean Energy (MCE), Public Agency Coalition (PAC), San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE).1/

1/ Counsel for AReM/DACC, CLECA, MCE, PAC, SDG&E and SCE have authorized counsel for PG&E to execute and file this Joint Case Management Statement on their behalf pursuant to Commission

Given the timeframe and the number of parties involved, this statement was prepared via email correspondence among the parties. Specifically, on Monday, August 7, PG&E circulated to the parties in this consolidated proceeding, a draft Joint Case Management Statement that stated the positions of PG&E, SDG&E and SCE. PG&E requested that parties provide text to include in the Joint Case Management Statement by Wednesday, August 9. PG&E is submitting this Joint Case Management Statement on behalf of all the parties that provided responses.

This Joint Case Management Statement is organized by the topics identified in the Ruling. A separate response is provided by the parties supporting that response.

1. Identification of the Principal Factual and Legal Issues and the Evidentiary Bases for Claims and Defenses

<u>Joint Utilities' Position</u>: There are no factual issues in dispute. The legal issue in dispute concerns the Power Charge Indifference Adjustment (PCIA) for pre-2009 vintage Direct Access customers in the Joint Utilities' (PG&E, SCE and SDG&E) respective 2017 ERRA (Energy Resource Recovery Account) Forecast Applications and going forward. More specifically, PG&E has discontinued the negative indifference amount associated with pre-2009 Direct Access customers, while SCE and SDG&E proposed a pre-2009 vintage PCIA for Direct Access customers. SCE and SDG&E are now limiting their proposal for the pre-2009 PCIA vintage to only include San Onofre Generating Station (SONGS)-related costs. In establishing this second phase, the Commission determined that pre-2009 Direct Access customers and their associated indifference amounts should be treated consistently, while taking into consideration the unique circumstances of each investor-owned utilities' territory. Thus, the overarching legal issue in this phase is whether any modifications to the proposed treatment of the PCIA for pre-2009 vintage Direct Access customers are warranted for any of the Joint Utilities.

While the parties have briefed this legal issue in the context of their own respective 2017 ERRA Forecast Applications, it has not been briefed in the context of this consolidated Phase 2.

Rule of Practice and Procedure 1.8(d).

PAC's Position: There currently exists an insufficient evidentiary record for the California Public Utilities Commission (Commission) to base a decision on the PCIA and negative indifference amount proposals. Each of the Joint Utilities should either individually or jointly submit testimony in this proceeding that specifically describes the proposals and provides sufficient factual support to carry the Joint Utilities' burden of proof. For example, in past ERRA proceedings, SDG&E and SCE have opposed the proposal to eliminate the PCIA for pre-2009 vintage Direct Access customers. Now, it appears that SDG&E and SCE have changed their respective positions, but there is nothing in the record of this consolidated proceeding to describe the revised positions. Moreover, PAC understands that SCE's proposal to eliminate the PCIA differs fairly significantly from PG&E's proposal. It is only after the submittal of testimony and sufficient discovery that parties will have an understanding of the proposals and sufficient factual support to initiate this consolidated proceeding. Following submittal of the Joint Utilities' testimony, parties should be given an opportunity to engage in discovery and submit intervenor testimony. Among other things, the following factual issues should be described in the Joint Utilities' testimony and set for review in this proceeding:

1. What is the current balance of PG&E's negative indifference amount balance, and what is PG&E's current proposal for the disposition of this balance, including whether or not PG&E intends to credit pre-2009 vintage Direct Access customers for any or all of the balance in light of the obligation of these customers to now pay for the Competition Transition Charge (CTC), which had previously been offset by the carry-forward of negative PCIA amounts.

2. How can bundled customer indifference be achieved if negative PCIA amounts are not identified and applied against the CTC or other charges?

3. How long do the Joint Utilities plan to apply the CTC to pre-2009 vintage Direct Access customers?

MCE's Position: Notwithstanding MCE's position as stated in Section 7, below, MCE agrees that the issue in the instant proceeding is primarily an issue of law as to whether the Joint IOUs' retirement of their negative indifference amounts for pre-2009 Direct Access customers violates longstanding Commission policy regarding the purpose of the negative indifference amounts and bundled customer indifference. MCE, however, agrees with PAC that an insufficient evidentiary record exists for the Commission to base a decision on the PCIA and negative indifference amount proposals. Each of the Joint Utilities should either individually or jointly submit testimony in this proceeding that specifically describes the proposals and provides sufficient factual support to carry the Joint Utilities' burden of proof. This could be most efficiently and comprehensively accomplished in the PCIA Order Instituting Rulemaking (OIR), R.17-06-026.

AReM/DACC and CLECA Position: AReM/DACC and CLECA agree that formal proposals should be submitted by each utility but believe that related discovery and an opportunity for comments and reply comments could eliminate the necessity for intervenor testimony and hearings.

2. Use of Settlement Techniques or Other Alternatives to Litigation

Joint Utilities' Position: While the Joint Utilities are always open to settlement discussions, given that the legal issue stated above has already been briefed to a large extent, it appears the most expeditious approach would be to proceed to a decision by the Commission.

PAC's Position: PAC provides the following two points. First, as stated above, PAC believes that this consolidated proceeding should follow the traditional plan by which the Joint Utilities' submit their proposals through prepared testimony, parties engage in discovery, intervenors submit prepared testimony, and rebuttal testimony is submitted. Following rebuttal testimony, PAC believes that settlement discussions would be fruitful, for a limited period of time. Second, regarding alternatives to litigation, PAC notes that it formally requested in its opening comments on the PCIA Order Instituting Rulemaking (R.17-06-026), a proceeding that is currently categorized as quasi-legislative, that the issues in this consolidated proceeding (elimination of the PCIA and disposition of negative indifference amount balance) should be consolidated with other issues in R.17-06-026 and addressed in a comprehensive fashion.

MCE's Position: Notwithstanding MCE's position as stated in Section 7, below, MCE supports the idea of settlement discussions once the record is more developed. MCE, however, reiterates that any discussion of the negative indifference amount is most appropriate for the PCIA OIR.

AReM/DACC's Position: AReM/DACC believes settlement could be possible once concrete proposals are presented for review and comment.

CLECA's Position: CLECA agrees with AReM/DACC, with the clarification that the comments on the concrete proposals should precede settlement discussions.

3. Need for Disclosure or Discovery of Documents or Other Information

PG&E's Position: Because there are no factual disputes, no further disclosures or discovery is warranted.

SCE and SDG&E Position: SCE and SDG&E are presently responding to discovery requests propounded by AReM/DACC.

PAC's Position: PAC believes that this consolidated proceeding should follow the traditional plan for applications, and that parties should be given an opportunity to engage in discovery after the Joint Utilities have sufficiently described their proposals.

MCE's Position: Notwithstanding MCE's position as stated in Section 7, below, and although MCE agrees the issue in the instant proceeding is primarily a legal question, given the time that has transpired since hearings and briefing on this issue took place in the 2017 ERRA proceedings, and given the change in position of SDG&E and SCE, there may be a need for further disclosure or discovery of documents or other information. To establish the basis for determining the need for further discovery, each of the Joint Utilities should either individually or jointly submit testimony in this proceeding that specifically describes the proposals and provides sufficient factual support to carry the Joint Utilities' burden of proof.

AReM/DACC's Position: As noted AReM/DACC has propounded discovery to SCE and SDG&E and does not wish to foreclose future opportunities to follow up on that discovery.

CLECA's Position: CLECA does not support foreclosing discovery.

4. Plan for Conducting Discovery

PG&E's Position: Because there are no factual disputes, no further discovery is warranted.

SCE and SDG&E Position: While discovery is proceeding, SCE and SDG&E do not believe a formal discovery plan is warranted.

PAC, AReM/DACC, and CLECA Position: The customary discovery rules should apply.

MCE's Position: Notwithstanding MCE's position as stated in Section 7, below, the customary discovery procedures and rules should apply.

5. Identification of Motions Requiring Early Resolution

Joint Utilities' Position: The Joint Utilities are not aware of any motions requiring early resolution.

PAC's Position: As noted above, PAC made a request in R.17-06-026 that the issues in this proceeding be consolidated with and addressed in R.17-06-026.

MCE's Position: Consistent with MCE's position as stated in Section 7, below, MCE, as a member of the California Community Choice Association ("CalCCA"), requested that the issue of negative indifference amounts be addressed in R.17-06-026, wherein the Commission will comprehensively address the PCIA.

AReM/DACC and CLECA Position: AReM/DACC and CLECA are not aware of any motions requiring early resolution.

6. Recommended Dates for Completion of Discovery, Service of Prepared Testimony, Additional Prehearing Conferences, and Hearings

Joint Utilities' Position: Because the outstanding issue is purely legal, no additional discovery, testimony, or hearings are necessary. It may be beneficial, however, to allow parties to brief the discrete issue of whether a consistent approach to the pre-2009 vintage PCIA and associated negative indifference amounts among the three Investor-Owned Utilities is warranted. The Joint Utilities propose that opening supplemental briefs be filed four weeks after the issuance of a Scoping Memo for this phase of the proceeding, with reply briefs filed two weeks after the opening supplemental briefs.

PAC's Position: PAC believes that the traditional procedural schedule should be followed in this consolidated proceeding.

MCE's Position: Notwithstanding MCE's position as stated in Section 7, below, MCE does not propose specific dates for completion of Discovery, service of Prepared Testimony, additional Prehearing Conferences, and Hearings. However, MCE would like to note that there are currently a number of important proceedings underway at the Commission that require participation by the IOUs, MCE, and other Community Choice Aggregators ("CCA"). These proceedings include the PCIA OIR (R.17-06-026), the CCA Bond proceeding (R.03-10-003), the Integrated Resource Planning proceeding (R.16-02-007), the IOUs' 2018 ERRA proceedings, and the anticipated market structure OIR referenced in the Commission Staff White Paper issued in May 2017. To the extent possible, the Commission should coordinate the instant proceeding's schedule with the aforementioned proceedings to ensure all necessary parties, including those with limited resources, are able to participate substantively and effectively. As such, MCE reiterates its position that the issue of negative indifference should be addressed solely in the PCIA OIR.

AReM/DACC and CLECA Position: AReM/DACC and CLECA reiterate that formal proposals should be submitted by each utility but believe that related discovery and an opportunity for comments and reply comments could eliminate the necessity for intervenor testimony and hearings.

7. Other Topics as the Interest of Justice and Efficient Case Management Require

Joint Utilities, PAC, AReM/DACC and CLECA Position: None at this time.

MCE's Position: The issue of whether it is appropriate and legal for the Joint IOUs to retire their negative indifference amounts and the PCIA for pre-2009 Direct Access customers is squarely within the scope of the newly opened OIR addressing the PCIA (R.17-06-026). This issue is most appropriately addressed in that venue.

The dedicated PCIA proceeding did not exist when the Commission issued ("D.") 16-12-038, wherein it deferred the negative indifference issue to a second, consolidated phase of the

IOUs' 2017 ERRA proceedings. The PCIA OIR also did not exist when the Commission issued its ruling consolidating each of the IOUs' ERRA proceedings within the instant proceeding. Now that a dedicated PCIA proceeding exists, all policy related PCIA issues should be addressed together. MCE, as a member of CalCCA, proposed that this issue necessarily be addressed in the PCIA OIR.

Retirement of the IOUs' negative indifference amounts implicates a host of PCIA policy issues, not least of all the issue of bundled customer indifference. The sole purpose of the dedicated PCIA OIR is to holistically evaluate the PCIA in one proceeding with all affected parties present. The issue of negative indifference is a PCIA policy issue that should not be decided in isolation from the myriad of other policy issues involving the PCIA. To do so risks inconsistent treatment of a material PCIA issue and potentially duplicative efforts across proceedings. As such, to promote efficient and comprehensive resolution, this issue should be analyzed and litigated in the PCIA OIR.

Respectfully submitted,

By: *<u>/s/ Matthew A. Fogelson</u>*
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MARIN CLEAN ENERGY;
PUBLIC AGENCY COALITION;
SAN DIEGO GAS & ELECTRIC COMPANY; and
SOUTHERN CALIFORNIA EDISON COMPANY

Dated: August 10, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of Energy Efficiency Rolling Portfolio Business Plan.	Application 17-01-013 (Filed January 17, 2017)
And Related Matters	Application 17-01-014 Application 17-01-015 Application 17-01-016 Application 17-01-017

JOINT COMMENTS OF MARIN CLEAN ENERGY AND THE SAN FRANCISCO BAY AREA REGIONAL ENERGY NETWORK ON THIRD PARTY SOLICITATION PROPOSALS

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August 18, 2017

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) for Approval of Energy Efficiency Rolling Portfolio Business Plan.	Application 17-01-013 (Filed January 17, 2017)
And Related Matters	Application 17-01-014 Application 17-01-015 Application 17-01-016 Application 17-01-017

JOINT COMMENTS OF MARIN CLEAN ENERGY AND THE SAN FRANCISCO BAY AREA REGIONAL ENERGY NETWORK ON THIRD PARTY SOLICITATION PROPOSALS

I. INTRODUCTION

Marin Clean Energy ("MCE") and the Association of Bay Area Governments, on behalf of the San Francisco Bay Area Regional Energy Network ("BayREN") (collectively "Joint Parties") submit the following comments pursuant to the *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judges* ("Scoping Ruling") filed April 14, 2017. The *Administrative Law Judges' Ruling Modifying Schedule* ("Schedule Ruling") filed June 9, 2017 modified the date for these comments on solicitation proposals to August 18,2 017.

The Joint Parties respond to Pacific Gas and Electric Company's ("PG&E's") Third Party Solicitation Process Proposal. This proposal should be improved to: (1) adequately address program overlap; and (2) maximize the value of responses to the proposed Request for Abstract.

II. BACKGROUND

MCE is the only Community Choice Aggregator ("CCA") energy efficiency ("EE") program administrator ("PA") authorized by the California Public Utilities Commission ("Commission"). MCE filed an application with a business plan on January 17, 2017. BayREN is a Regional Energy Network ("REN") PA delivering EE programs throughout the greater San Francisco Bay Area. BayREN filed a motion with a business plan on January 23, 2017.

III. PG&E'S SOLICITATION PLAN SHOULD BE MODIFIED TO ADDRESS PROGRAM OVERLAP

PG&E's proposal to address overlapping programs in solicitations is to allow the investor owned utility ("IOU") "to hold its solicitation prior to any solicitation by the local PA."[1] PG&E claims this resolves a risk that a bidder may be forced to offer services on behalf of more than one PA or that a program would be denied economies of scale.[2]

In reality, this proposal simply avoids coordination among PAs and seeks to establish IOU contracts for programs that may be duplicated by other PAs operating in the same service area. The proposal will also seriously and unreasonably delay the solicitations of local PAs (*i.e.* RENs and CCAs). According to PG&E's Solicitation Timeline, this would prevent the Joint Parties from issuing their own solicitations until at least 2019.[3] Local PAs are approved in part to leverage the expertise of local governments in addressing the needs of their constituents as well as their expertise in energy and other program implementation. PG&E's proposal is not an appropriate solution and only serves to undermine the effectiveness of local PAs.

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[1] PG&E Third Party Solicitation Process Proposal, Attachment: 2018-2025 Energy Efficiency Rolling Portfolio Solicitation Plan ("PG&E Solicitation Plan"), Appendix 1: Responses to Third Party Solicitation Proposal Guidance at p. 16.
[2] *Id.*
[3] *Id.*, Figure 3 at p. 11.

A. PG&E Should Coordinate with Local PAs During the Formation of the Scope of the Solicitation and in Bid Selection

PG&E should be directed to coordinate with local PAs throughout the solicitation process.[4] Early coordination between PG&E and local PAs will help identify areas of overlap and aid in defining a solicitation scope to avoid overlap. This will also help define appropriate coordination on Marketing, Education, and Outreach ("ME&O") to avoid customer confusion. These details could be embodied in a memorandum of understanding and incorporated into the general solicitation terms and vendor outreach and training as discussed in Section III.C below. Local PAs should also have the option to participate in bid selection for programs implemented within each local PA's service area to ensure customers are served with well-designed and high-quality programs. This level of coordination will mitigate issues related to overlapping programs.

B. PG&E's Solicitation Plan Should Include an 18-Month Plan for Programs that are Transitioned from One Program Administrator to Another

PG&E provides plans to transition a program from IOU implementation to third party implementation or from one third party implementer to another.[5] PG&E's plan should be supplemented to include a process to transition a program from PG&E or third party implementation to MCE implementation, which may occur under MCE's role as downstream liaison.[6] MCE recommends maintaining implementer contracts through the end of the contract or for 18 months, whichever occurs first.[7] During this time, the program will be transitioned under a new contract with the existing or a new implementer.

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[4] *See e.g.* Comments of Marin Clean Energy on Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judges, filed June 22, 2017, ("MCE June 22 Comments") at p. 13 (referring to coordination with MCE).
[5] PG&E Solicitation Plan at p. 21.
[6] Comments of Marin Clean Energy on Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judges, filed June 22, 2017, ("MCE June 22 Comments") at p. 5-9.
[7] *Id.* at p. 8-9.

C. Regulatory Requirements Related to Overlapping Programs Should be Embedded within PG&E's General Solicitation Terms and Vendor Outreach and Training

PG&E's solicitation proposal includes communicating regulatory requirements to bidders through: (1) standard form general terms and conditions[8] and; (2) vendor outreach and training.[9] This is a valuable opportunity to communicate with bidders about the rules related to program overlap, particularly MCE's role as downstream liaison. MCE provided comments calling for including: (1) a description of each PA operating within the area of the program being put out to bid; and (2) a summary of the rules governing implementer's engagement with that PA within solicitation materials.[10] Bidders should also be informed about the requirement to provide plans that address overlap with other PAs within their bids.[11] These plans should address: (1) potential for duplication of programs; (2) coordination of marketing and outreach; and (3) coordination of implementation.[12] These should be incorporated into the standard form general terms and vendor outreach and training to help identify and plan for program overlap.

IV. THE RESPONSES TO THE REQUEST FOR ABSTRACT SHOULD BE AVAILABLE TO ALL PAS

PG&E proposes to start the solicitation process by issuing a broad Request for Abstract ("RFA") followed by a more defined sector level Request for Proposal.[13] Participants in the RFA will provide "a short abstract summarizing their proposed program, approach, qualifications and

[8] PG&E Solicitation Plan at p. 9.
[9] *Id.* at p. 20-21.
[10] MCE June 22 Comments at p. 9-10.
[11] *Id.* at p. 10.
[12] *Id.*
[13] PG&E Solicitation Plan at p. 6.

experience, and indicative pricing."[14] All PAs should have access to the RFA responses for third party programs.

These responses will include valuable information for all PAs, not only the PA that issued the RFA. This information will help identify opportunities and potential partners for each PA. The participants will also benefit from this information being shared. It will reduce the need for each PA to issue an RFA and for third parties to participate in multiple RFAs. The PAs will use this information for internal planning and to help guide future solicitations but will not share this information publicly to avoid disclosing program approaches and pricing to the broader market.

V. CONCLUSION

MCE thanks Commissioner Peterman, Administrative Law Judge Fitch, and Administrative Law Judge Kao for their thoughtful consideration of these comments.

Respectfully submitted,

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August 18, 2017

[14] *Id.*

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August 21, 2017

Via Mail and E-Mail (efr@cpuc.ca.gov)

Mr. Ed Randolph
Director, Energy Division
California Public Utilities Commission
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Subject: **Protest of Marin Clean Energy, City of Lancaster, Sonoma Clean Power, and Silicon Valley Clean Energy to Advice Letters 5119-E (PG&E), 3640-E (SCE), and 3103-E (SDG&E) (Update to Community Choice Aggregate and Energy Service Provider Load Data and Utility Investment and Procurement Information.**

Dear Mr. Randolph:

Marin Clean Energy ("MCE"), the City of Lancaster ("Lancaster"), Sonoma Clean Power ("SCP"), and Silicon Valley Clean Energy ("SCVE") (jointly, the "CCA Parties") hereby protest the joint advice letter ("Advice Letter") identified as Advice Letter 5119-E for Pacific Gas and Electric ("PG&E"), Advice Letter 3640-E for Southern California Edison ("SCE"), and 3103-E for San Diego Gas and Electric ("SDG&E"). As set forth below, the Advice Letter fails to comply with Ordering Paragraphs 5 and 6 of Decision ("D.") 17-09-039 in violation of Section 7.4.2(2) of General Order ("GO") 96-B, and the data in the Advice Letter contains material errors and omissions in violation of Section 7.4.2(3) of GO 96-B. In light of these significant flaws, the CCA Parties respectfully request that the California Public Utilities Commission ("Commission") reject the Advice Letter and direct the Investor Owned Utilities ("IOUs") to re-file the Advice Letter with current and accurate information, including the calculation and application of the automatic limiter.

BACKGROUND

The Advice Letter is a mandatory compliance filing required by Ordering Paragraphs 5 and 6 of D.17-04-039.[1] D.17-04-039 adopts an automatic limiter that reduces each CCA program's 1% Energy Storage ("ES") obligation to ensure that the CCA program's total ES obligation (its 1% direct ES procurement obligation plus the CCA customers' share of any IOU ES procurement recovered through non-bypassable charges) does not exceed the total ES

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1 D.17-04-039 at 67-68.

obligation of the CCA program's distribution IOU.[2] In order to provide the information necessary to calculate and apply the automatic limiter, Ordering Paragraph 5 requires that the Investor Owned Utilities ("IOU") submit an annual advice letter that updates Tables 3 through 6 of D.17-04-039[3] with *the most current data available*.[4] In addition, Ordering Paragraph 6 requires the IOUs calculate the automatic limiter, and that if the limiter is reached, the IOU compliance filing *must automatically reflect the reduced Community Choice Aggregator ES procurement obligation*.[5]

The Commission should reject the Advice Letter on two grounds. First, the Advice Letter fails to provide the most current and accurate data available for Tables 5 and 6, in direct violation of Ordering Paragraph 5. Second, the Advice Letter fails to calculate the automatic limiter for *any* CCA program, and fails to apply the automatic limiter for CCA Programs in SCE territory, in direct violation of Ordering Paragraph 6. Taken together, these flaws present overwhelming grounds for rejecting the Advice Letter, as these flaws make the Advice Letter effectively useless for its intended purpose: providing CCA Programs with sufficient information to understand, and plan for, their ES procurement obligations in light of the automatic limiter.

PROTEST

1. The Advice Letter Fails To Update Tables 5 And 6 With The Most Current Data

Pursuant to Section 7.4.2(2) of GO 96-B, the CCA Parties protest the Advice Letter on the grounds that "the relief requested would violate... [a] Commission order." The Advice Letter fails to comply with Ordering Paragraph 5 of D.17-04-039. Ordering Paragraph 5 states:

> Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must coordinate to make a consolidated compliance filing annually as a Tier 1 Advice Letter through 2020 to update Tables 3-6 *based on the most current* Community Choice Aggregator and Energy Service Provider load data and utility investment and procurement information with the first compliance filing due no later than August 1, 2017.[6]

In violation of this clear order, the IOUs have not updated Tables 5 and 6 of the Advice Letter with the most current and accurate data.

i. <u>Table 5 Excludes Data For Newly Operational CCA Programs</u>

2 Id. at 68 (Ordering Paragraph 6).
3 Id. at 24-26 (Tables 3-6).
4 Id. at 67 (Ordering Paragraph 5).
5 Id. at 68 (Ordering Paragraph 6).
6 Id. at 67 (Ordering Paragraph 5) *Emphasis Added*.

In Table 5, titled "Community Choice Aggregators Storage Procurement Cost Obligations" the Advice Letter fails to provide *current* CCA load data.[7] In D.17-04-039, Table 5 only included CCA load data for four CCA programs – Lancaster, MCE, Clean Power San Francisco ("<u>CleanPower SF</u>"), and SCP – on the grounds that, as of January 2017, these were the only four CCA programs for which load data was available.[8] However, the Decision explicitly required that "when additional CCAs report load that load should be reflected in the updates to these tables."[9]

The Advice Letter *does not* update Table 5 with reported load data for newly operational CCA programs for which load data is now available. Although Table 5 of the Advice Letter is marked "Data as of June 2017," the CCA load values included in the Advice Letter are *exactly* the same as the CCA load values used in Table 5 of the Decision, which used data from January 2017. In addition, footnote 17 of the Advice Letter states that the CCA load values set forth in Advice Letter Table 5 only include data from *three* CCA programs – Lancaster, MCE, and SCP.[10] This means that load data for the other CCA programs – Apple Valley Clean Energy ("AVCE"), CleanPower SF, SVCE, and Peninsula Clean Energy ("<u>PCE</u>"), Pico Rivera, and Redwood Coast Energy Authority ("RCEA") – was not included in calculating the CCA load entry to Advice Letter Table 5.

The Advice Letter's failure to include load data for these programs is problematic, as current load data for these programs had been reported to the Commission, and was available to the IOUs, prior to the Advice Letter's August 1 filing. On July 21, 2017, SVCE, AVCE, PCE, and Pico Rivera provided the most current load data and load projections to the Commission in their publicly filed 2017 Renewables Portfolio Standard ("RPS") procurement plans.[11] CleanPower SF, PCE, SVCE, and RCEA provided updated load data to PG&E in February 2017 as part of PG&E's ERRA process, and this load is reflected in PG&E's 2018 ERRA filing.[12] Several of these CCA Programs also provided updated load data to the Commission in their April 2017 Resource Adequacy Updates.

Given the fact that load data for these programs has been filed with the Commission and is available to the IOUs, the Advice Letter's failure to include this load data in Table 5 constitutes both a violation of Ordering Paragraph 5, a violation of the Commission's express instruction in Footnote 36 of the Decision.

ii. <u>Table 5 Flails To Provided Updated Load Values For Programs That Were Included In Table 5 Of The Decision</u>

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7 Advice Letter at 4 (Table 5).
8 D.17-04-039 at 25 (FN 36).
9 Id.
10 Advice Letter at 4 (FN 17).
11 *See* respective procurement plans filed in R.15-02-020.
12 *See* PG&E Prepared Testimony, 2018 ERRA Application (A.17-06-0XX), at 2-15 (Table 2-3).

In direct violation of Ordering Paragraph 5, the Advice Letter fails to provide updated load values for the four CCA programs that were accounted for in Table 5 of the Decision - Lancaster, MCE, CleanPower SF, and SCP.

In Table 5 of the Advice Letter, the IOUs use the exact same CCA load values that were used in the Table 5 of the Decision. This is despite the fact that all four of the programs that were accounted for in Table 5 of the Decision have filed more recent load data with the Commission and made this data available to the IOUs. All four programs provided the Commission with current load data in their July 2017 RPS procurement plans, which are available to the IOUs.[13] In addition, in February 2017, the three programs located in PG&E territory (MCE, SCP, and Clean Power SF) provided load data to PG&E as part of PG&E's ERRA process, and this load is reflected in PG&E's 2018 ERRA filing.[14]

A simple comparison of the CCA load reported in PG&E's ERRA filing and the CCA load figures used in Advice Letter Table 5 demonstrates that the figures used in the Advice Letter are grossly inaccurate. Table 5 of the Advice Letter states that the "Applicable CCA Load" for PG&E territory is 3,486 GWh.[15] However, PG&E's 2018 ERRA filing forecasts a 2018 load of 13,774 GWh for existing CCA Programs, nearly four times as high as the CCA load reported in the Advice Letter.[16] PG&E projects that MCE, SCP, and Clean Power SF alone will account for a combined 5,862 GWh in 2018.[17]

Thus, PG&E's CCA load value in Table 5 is grossly inaccurate and is contradicted by PG&E's own ERRA filing. This inaccuracy constitutes a violation of Ordering Paragraph 5, as well as a "material error" under Section 7.4.2(3) of GO 96-B. SCE's Table 5 CCA load value is likely similarly inaccurate and should be updated using current data.

iii. <u>The Advice Letter Fails To Update Table 6</u>

The Advice Letter fails to update Table 6 with the most current data as required by Ordering Paragraph 5. Advice Letter Table 6 includes exactly the same values as Table 6 from the Decision, and both are marked "Data as of January 2016."[18] In other words, the IOUs have not updated Table 6 with any new data. Pursuant to Ordering Paragraph 5, the IOUs should be required to either update Table 6 with the most current information available, and, at a minimum,

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13 *See* respective procurement plans filed in R.15-02-020

14 PG&E Prepared Testimony, 2018 ERRA Application (A.17-06-0XX), at 2-15 (Table 2-3).

15 Advice Letter at 4 (Table 5).

16 PG&E Prepared Testimony, 2018 ERRA Application (A.17-06-0XX), at 2-15 (Table 2-3). PG&E identifies MCE, SCP, Clean Power San Francisco, Peninsula Clean Energy Authority, Silicon Valley Clean Energy Authority, and Redwood Coast Energy Authority as "Existing CCA Programs."

17 Id. PG&E Projects that MCE will have a 2018 load of 2,743 GWh, SCP will have a 2018 load of 2,574 GWh, and CleanPower SF will have 2018 load of 545 GWh.

18 Advice Letter at 4 (Table 6).

recalculate Table 6 using current CCA load data that includes all CCA programs that have reported load to the Commission.

2. The Advice Letter Fails To Calculate And Apply The Automatic Limiter

Ordering Paragraph 6 of D.17-04-039 requires that "if the [Automatic Limiter] is reached, the consolidated utility compliance filing shall automatically reflect the reduced Community Choice Aggregator / Energy Service Provider energy storage procurement obligation."[19] The Advice Letter fails to calculate the automatic limiter for any CCA program.

In addition, the Advice Letter fails to apply the automatic limiter to CCA programs in SCE service territory. Even based on the data included in Table 6 of the Advice Letter, which, for reasons discussed above, likely significantly underrepresents CCA load, the automatic limiter should have been triggered for CCA programs in SCE territory. SCE's current ES obligation is 580 MW, equal to roughly 2.6% of its total load.[20] The current total ES obligation for CCA programs in SCE's territory is 3 MW, or 2.8% of total CCA load.[21] Thus, the proportional ES obligation for CCA programs exceeds SCE's proportional ES obligation by 0.2%. Under Ordering Paragraph 6, this should have triggered the automatic limiter, which should have been "automatically reflect[ed]" in the IOU compliance filing. In light of this significant violation of Ordering Paragraph 6, the Advice Letter should be rejected and the IOUs should be instructed to re-file the Advice Letter and include the calculation and application of the automatic limiter.

CONCLUSION

For the reasons set forth above, MCE, Lancaster, SCP, and SVCE respectfully request that Commission reject the Advice Letter and instruct the IOUs to re-file the Advice Letter modified to fully comply with Ordering Paragraphs 5 and 6.

Dated: August 21, 2017

Respectfully submitted,

_______/S/_______

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19 D.17-04-039 at 68 (Ordering Paragraph 6).
20 Advice Letter at 4 (Table 6).
21 Id.

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September 1, 2017

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Advice Letter 25-E

Re: MCE 2018 Annual Energy Efficiency Program and Portfolio Budget Request

In compliance with California Public Utilities Commission ("Commission") Decision ("D.") 15-10-028, Ordering Paragraph ("OP") 4, issued October 28, 2015,[1] and *Administrative Law Judge's Ruling Modifying Schedule* ("ALJ Ruling"), filed June 9, 2017,[2] Marin Clean Energy ("MCE") submits this advice letter filing to request its 2018 annual energy efficiency portfolio budget. D.15-10-028 called for the annual budget advice letter to be filed on the first business day in September.[3] The ALJ Ruling confirmed this date to be September 1, 2017.[4]

Effective Date: October 1, 2017

Tier Designation: Tier 2

Pursuant to General Order 96-B, Energy Industry Rule 5.2 and D.15-10-028, this advice letter is submitted with a Tier 2 designation.

Purpose

The purpose of this advice filing is to comply with D.15-10-028, OP 4 and request MCE's 2018 energy efficiency budget.

Background

The Commission is transitioning to a rolling portfolio framework for energy efficiency programs. To this end, Program Administrators ("PA") filed business plans in January 2017, which the Commission expects will be approved in 2018. To facilitate the transition to the rolling portfolio framework, the Commission is continuing its ten-year funding authorization that began in 2014.[5]

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[1] D.15-10-028, OP 4 at p. 123-24.
[2] *Administrative Law Judge's Ruling Modifying Schedule* ("ALJ Ruling") ("A.") 17-01-013, *et al.*, filed June 9, 2017, Ruling Paragraph ("RP") 1 at p. 9.
[3] D.15-10-028, OP 4 at pp. 123-24.
[4] ALJ Ruling at pp. 6, 9.
[5] D.14-10-046, OP 21 at p. 167.

Subsequent to issuing the ten-year funding authorization in D.14-10-046, the Commission adopted related processes and rules to implement a rolling portfolio.[6] The process includes filing this annual budget advice letter to provide a range of information including: (1) the next annual budget; (2) the portfolio cost effectiveness; (3) portfolio changes; (4) fund shifting; (5) carryover or encumbered funds; and (6) the California Energy Data and Reporting System's Filing Module ("CEDARS FM") filing confirmation, which includes a cost effectiveness showing (included as Attachment A to this advice letter).[7]

In July 2017, Energy Division staff provided additional guidance on the annual budget advice letter.[8] This guidance acknowledged a number of uncertainties and changes regarding the rolling portfolio framework and cost effectiveness calculations.[9] Nonetheless, to be consistent with D.15-10-028, Energy Division staff directed PAs to file a Tier 2 advice letter using the portfolio budgets approved in D.15-10-028 and cost effectiveness inputs.[10] PAs are required to file a true-up budget advice letter in 2018.[11] Further guidance is expected from the Commission in its final decision approving business plans.[12]

Energy Division also provided an updated appendix template for purposes of this filing.[13] MCE has uploaded this completed appendix to the CEDARS FM. The appendix will be updated once the Commission approves cost effectiveness adders, business plans, and goals for 2018.[14]

<u>Discussion</u>

MCE requests a programmatic budget for 2018 in the amount of $1,586,347, which is supported by the appendix MCE filed on the CEDARS FM. MCE requests an additional $18,177 for Evaluation Measurement and Verification ("EM&V") funds.[15] MCE also provides a context for the portfolio cost effectiveness for 2018.

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[6] *See* D.15-10-028; D.16-08-019.
[7] D.15-10-028 at pp. 58-63, 91, OP 4 at p. 123; *see also Clarifications on Annual Budget Filings for Program Year 2017* (August 19, 2016).
[8] *2018 Energy Efficiency Portfolio Filing and Reporting Budget* (July 24, 2017).
[9] *Id*. "Energy Division recognizes that many changes are afoot this year that affect portfolio savings goals and cost effectiveness–and indeed the entire portfolio mix of sectors and programs–and that the requirement for a cost effective portfolio showing may not be achievable in 2018 using these parameters and given the current uncertainties."
[10] *Id*.
[11] ALJ Ruling at p. 6.
[12] *Id*.
[13] *2018 Energy Efficiency Portfolio Filing and Reporting Budget* (July 24, 2017).
[14] *Id*.
[15] D.15-10-028 at p. 87.

2018 Energy Efficiency Budget

MCE received an annual budget authorization in D.14-10-046 totaling $1,220,267.[16] In 2016, the Commission increased MCE's annual budget to $1,586,347 to account for new communities that joined MCE's service area.[17] To comply with D.16-05-004, MCE filed advice letter 16-E,[18] which incorporated the budget increase into MCE's overall portfolio budget.[19]

MCE presents its funding allocations by program and its overall 2018 Energy Efficiency Program Budget in Table 1.

Table 1: Authorized MCE 2018 Energy Efficiency Program Budget

MCE Programs	Budget
Single Family	$196,089
Multifamily	$676,437
Small Commercial	$686,790
Financing	$27,031
Program Subtotal	$1,586,347[20]
EM&V	$18,177[21]
Total	**$1,604,524**

As indicated above, MCE's requests $18,177 in EM&V funds based on MCE's approved budget for 2018. Table 2, below, presents MCE's EM&V budget as a percentage of the total EM&V PA funds distribution.

Table 2: Prospective EM&V Funds

2018 Programs Budget	4% EM&V Funding Level	Total Prospective EM&V Funds (27.5% EM&V PA Distribution)
$1,586,347	$66,098	$18,177

[16] D.14-10-046 at p. 125.
[17] D.16-05-004.
[18] D.16-05-004, OP 5 at pp. 13-14.
[19] MCE Advice Letter 16-E at p. 3.
[20] The Commission authorized this budget in D.16-05-004, OP 2 at p. 13.
[21] This amount includes only the PA distribution based on 27.5% of the total EM&V budget as indicated in the discussion in the EM&V Funds section below. MCE included 100% of the EM&V budget in the appendix uploaded to the CEDARS FM.

Portfolio Cost Effectiveness

MCE's portfolio cost effectiveness results for 2018 are:

> Total Resource Cost Test Ratio ("TRC"): .57
> Program Administrator Cost Test Ratio ("PAC"): .63

In 2013, MCE administered the first energy efficiency programs under the authority granted in Cal. Pub. Util. Code § 381.1(a)-(d). These programs were initially restricted by the Commission to serve gaps in investor-owned utility ("IOU") programs and hard-to-reach markets.[22] At that time, the Commission recognized that these restrictions may cause MCE's proposals to fail the TRC test and therefore did not initially impose a minimum cost effectiveness requirement.[23] In 2014, however, the Commission lifted the restrictions[24] and imposed the same cost effectiveness standards on Community Choice Aggregators ("CCA") as IOUs.[25] Yet, at that time MCE was not invited to file an application to update its portfolio because the 2014 programs were extended to 2015, 2016, 2017, and now 2018 while the Commission transitions to the rolling portfolio framework.[26] Although lifting the restrictions will ultimately improve MCE's ability to meet the minimum 1.25 TRC ratio, MCE's current portfolio continues to focus on hard-to-reach markets and gaps in IOU programs.

In January 2017, MCE filed a business plan requesting authority to implement a broader and cost effective portfolio that conforms to the rolling portfolio framework and Commission guidance.[27] The Commission anticipates approval of the business plan in 2018.[28]

In the interim, MCE continues to make efforts to improve the cost effectiveness of its current portfolio. Pursuant to Energy Division guidance, once the new avoided cost calculator and Greenhouse gas ("GHG") adder are released and business plans approved, MCE will adjust its programs to further improve its portfolio's cost effectiveness.

Portfolio Changes

MCE began implementation of a Seasonal Savings pilot that was approved and began in the first quarter of 2017.[29] The savings figures associated with this pilot have been included in the cost effectiveness analysis for the 2018 portfolio.

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[22] D.12-11-015 at pp. 45-46.
[23] *Id*. p. 46.
[24] D.14-01-033 at p. 14; *see also* D.14-10-046 at p. 120 (Commission clarifying the restrictions do not apply to gas programs).
[25] D.14-01-033 at p. 36.
[26] D.14-10-046 at pp. 30-32.
[27] A.17-01-017.
[28] ALJ Ruling at pp. 8-9.
[29] MCE Advice Letter 17-E and 17-E-A.

On July 17, 2017 the Commission approved advice letter 24-E, wherein MCE proposed to discontinue its On-Bill Repayment ("OBR") Program. The OBR Program was designed to provide low-cost financing to improve the energy efficiency of multifamily and commercial buildings. MCE decided to cancel the OBR program due primarily to low customer demand for the program. At the same time, MCE had greater than expected participation in, and customer demand for, MCE's Multifamily and Commercial programs. The previously committed Loan Loss Reserve ("LLR") funds associated with the OBR program are now included within MCE's Multifamily and Commercial 2017 budgets.[30]

Aside from the aforementioned changes, MCE is continuing its 2017 portfolio of programs in 2018, notwithstanding the proposed programmatic changes in MCE's business plan.

Fund Shifting

In budget year 2017, MCE performed one fund shift via advice letter 24-E, which the Commission approved on July 17, 2017.

MCE's 2017 fund shift and the resulting budget allocations are reflected in Table 3, below. The fund shift moved previously committed LLR funds into the Multifamily and Commercial program budgets. Because the committed LLR funds were repurposed for use in the 2017 budget, the LLR funds do not affect MCE's budget request for 2018.

MCE presents its 2017 fund shifting activity in Table 3, below.

Table 3: 2017 Fund Shifting

MCE Programs	Approved 2017 Budget	Shift Out	Shift In	Final 2017 Budget
Single Family	$233,050	-	-	$233,050
Multifamily	$667,555		$ 273,750	$ 941,305
Small Commercial	$658,711		$ 273,750	$932,461
Financing	$27,031	-	-	$27,031
LLR Fund[31]	$547,500	$547,500		$0.00
Total	**$2,133,847**			**$2,133,847**

[30] MCE Advice Letter 24-E, Table 1 at p. 3.

[31] MCE's OBR program was approved in D.12-11-015 as one of three financing pilots. MCE allocated $547,500 to a LLR fund for its Multifamily and Commercial OBR program. These funds were a one-time transfer that carried over year to year as committed funds.

Committed and Carryover Funds

Pursuant to OP 25 of D.14-10-046, MCE reports annually on unspent funds available for carryover in an advice letter filed on December 1.[32] The annual unspent funds advice letter also reports MCE's funds that are committed for use in the next budget year. The appendix to this advice letter provides a true up of MCE's 2016 unspent funds. The amount reflected in Table 7 of the appendix, however, does not include the funds that were unspent in 2016 and used to offset MCE's 2017 budget transfer from PG&E ($3,714).

Table 4, below, illustrates MCE's budgeting practice. The table presents MCE's actual 2016 unspent funds, its projected unspent funds as reported in advice letter 21-E, its 2016 committed electric funds, and how the aforementioned amounts affect the 2016 unspent funds available to offset the 2018 budget transfer.[33]

Table 4: Projection of MCE's Unspent Funds for 2018

Actual 2016 Unspent Funds (Electric Only)	Projected 2016 Unspent Funds Reported in AL 21-E (used to offset 2017 funds)	2016 Committed Funds (Electric Only)	2016 Unspent Funds Available to Offset 2018 funds	Projected 2017 Unspent Funds Available to Offset 2018 Funds
$416,165	($3,714)	($189,268)	$223,182	*To be provided in an Advice Letter on December 1, 2017

Notice

Anyone wishing to protest this advice filing may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days after the date of this advice filing. Protests should be mailed to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, California 94102
E-mail: EDTariffUnit@cpuc.ca.gov

---

[32] D.14-10-046, OP 25 at p. 168.

[33] MCE's actual 2016 unspent funds equal $416,165. This amount is reduced by $3,714, which was the projected, and now trued-up, 2016 unspent funds amount that MCE reported in advice letter 21-E to offset MCE's 2017 funds transfer. MCE's actual 2016 unspent funds are further reduced by $189,268, which is the amount of 2016 funds MCE committed to fund electricity savings in 2017. *See also* Table 7 of MCE's appendix to this advice letter.

Copies should also be mailed to the attention of the Director, Energy Division, Room 4004 (same address above).

In addition, protests and all other correspondence regarding this advice letter should also be sent by letter and transmitted via facsimile or electronically to the attention of:

Nathaniel Malcolm
Policy Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Phone: (415) 464-6048
Facsimile: (415) 459-8095
E-mail: nmalcolm@mceCleanEnergy.org

and

Beckie Menten
Energy Efficiency Director
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Phone: (415) 464-6034
Facsimile: (415) 459-8095
E-mail: bmenten@mceCleanEnergy.org

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

MCE is serving copies of this advice filing to the relevant parties shown on the R.13-11-005 and A.17-01-013 *et al.* service lists. For changes to this service list, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

Correspondence

For questions, please contact Nathaniel Malcolm at (415) 464-6048 or by electronic mail at nmalcolm@mceCleanEnergy.org.

/s/ Nathaniel Malcolm

Nathaniel Malcolm
Policy Counsel
MARIN CLEAN ENERGY

cc: Service Lists: R.13-11-005; A.17-01-013, *et al*.

Attachment A:
CEDARS FM Filing Confirmation

CEDARS FILING SUBMISSION RECEIPT

The MCE portfolio filing has been submitted and is now under review. A summary of the filing is provided below.

PA: Marin Clean Energy (MCE)

Filing Year: 2018

Submitted: 10:42:39 on 31 Aug 2017

By: Alice Stover

Advice Letter Number: 25-E

* Portfolio Filing Summary *

- TRC: 0.5657
- PAC: 0.6262
- TRC (no admin): 1.4763
- PAC (no admin): 1.9736
- RIM: 0.6262
- Budget: $1,586,346.96

* Programs Included in the Filing *

- MCE01: Multi-Family
- MCE02: Small Commercial
- MCE03: Single Family
- MCE04: Financing Pilots

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY LSE (Attach additional pages as needed)

Marin Clean Energy

Utility type:	Nathaniel Malcolm
☑ ELC ☐ GAS	Phone #: 415-464-6048
☐ PLC ☐ HEAT ☐ WATER	E-mail: nmalcolm@mceCleanEnergy.org

EXPLANATION OF UTILITY TYPE	(Date Filed/ Received Stamp by CPUC)
ELC = Electric GAS = Gas	
PLC = Pipeline HEAT = Heat WATER = Water	

Advice Letter (AL): 25-E

Subject of AL: MCE 2018 Annual Energy Efficiency Program and Portfolio Budget Request

Tier Designation: ☐ 1 ☑ 2 ☐ 3

Keywords (choose from CPUC listing):

AL filing type: ☐ Monthly ☐ Quarterly ☑ Annual ☐ One-Time ☐ Other ______________________________

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution: D.15-10-028

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL ______________________________

Summarize differences between the AL and the prior withdrawn or rejected AL[1]: ____________________

Resolution Required? ☐ Yes ☑ No

Requested effective date: October 1, 2017 No. of tariff sheets:

Estimated system annual revenue effect: (%):

Estimated system average rate effect (%):

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected:

Service affected and changes proposed[1]:

Pending advice letters that revise the same tariff sheets:

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division	**Utility Info (including e-mail)**
Attention: Tariff Unit	**Marin Clean Energy**
505 Van Ness Ave.,	**Nathaniel Malcolm, Policy Counsel**
San Francisco, CA 94102	**(415) 464-6048**
EDTariffUnit@cpuc.ca.gov	**nmalcolm@mceCleanEnergy.org**

[1] Discuss in AL if more space is needed.

September 15, 2017

CA Public Utilities Commission
Energy Division
Attention: Energy Efficiency Branch
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

Advice Letter 26-E

Re: Request for Approval to Shift Funds

In compliance with the California Public Utilities Commission's ("Commission") Decision ("D.") 09-09-047, Ordering Paragraph ("OP") 43, filed September 24, 2009, and the Energy Efficiency Policy Manual,[1] Marin Clean Energy ("MCE") submits this filing to request approval to amend MCE's gas savings agreement with Pacific Gas and Electric Company ("PG&E") and shift gas savings funds into MCE's 2017 Multifamily Program budget. This shift of gas savings funds from PG&E to MCE will accommodate project commitments and anticipated gas savings spending for the remainder of 2017.

PG&E supports this fund shift and the attached amendment to the gas savings agreement.

Effective Date: October 15, 2017

Tier Designation: Tier 2

Pursuant to General Order 96-B, Energy Industry Rule 5.2 this advice letter is submitted with a Tier 2 designation.

Purpose

The purpose of this advice letter filing is to seek approval to shift gas savings funds from PG&E to MCE. This fund shift requires an amendment to MCE's gas savings agreement with PG&E. The shift will increase the gas budget for MCE's Multifamily Program to accommodate gas savings project commitments and anticipated spending for the remainder of 2017.

Background

MCE currently administers a Multifamily Program with growing participation since its launch in 2013. Historically, enrollment in this program has exceeded capacity, and the Commission

[1] Version 5, July 2013, Section II.7 at p. 13, available at
http://www.cpuc.ca.gov/NR/rdonlyres/7E3A4773-6D35-4D21-A7A2-9895C1E04A01/0/EEPolicyManualV5forPDF.pdf.

previously authorized MCE to shift funds to this program to accommodate demand for both MCE's electric and gas savings components.[2]

In D.12-11-015, the Commission approved MCE's energy efficiency programs for 2013-2014. D.14-10-046 granted a continuation of funding for these programs. D.14-10-046 directed PG&E to contract with MCE to provide funding for MCE's natural gas efficiency measures.[3] D.14-10-046 also ordered an original gas funding amount of $219,000. Subsequently, the Commission increased MCE's gas funding to $284,700.[4] MCE and PG&E executed a third amendment to their gas savings agreement to reflect this budget increase.

In 2015, the Commission authorized PG&E to increase the amount of gas funds transferred from PG&E to MCE. PG&E Advice Letter 3642-G/4720-E requested an amendment to the gas savings agreement with MCE to provide an additional $200,000 above MCE's approved gas savings budget. The increase ensured MCE had sufficient funding to serve its multifamily projects in 2015. Pursuant to the Commission's authorization, MCE and PG&E revised their gas savings agreement to reflect the funding increase.

This advice letter requests a similar gas funding budget increase to ensure MCE has sufficient funding to serve its multifamily projects in 2017.

<u>Multifamily Program Activity</u>

MCE's Multifamily Program has grown significantly since its launch in 2013. MCE's Multifamily Program provides targeted outreach and training to multifamily property owners, contractors, and tenants. The program focuses on providing incentives for electricity and gas efficiency retrofits in multifamily buildings.

At present, the gas savings component of MCE's 2017 Multifamily Program is fully subscribed for 2017. To enable MCE to continue its programmatic gas savings offerings, MCE requires an additional $200,000 to continue to serve the project pipeline and support program growth and its associated savings through 2017. MCE's anticipated additional need for incentive payments in 2017 is $200,000.

<u>Fund Shifting for MCE's 2017 Gas Savings Budget</u>

MCE requests authority to amend its gas savings agreement with PG&E and shift an additional $200,000 in gas funds into MCE's Multifamily gas savings budget. MCE will continue to invoice PG&E for its 2017 gas savings expenditures through December 31, 2017. MCE will use or commit the 2017 gas savings budget increase for customer incentive payments for gas savings

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2 MCE Advice Letter ("AL") 15-E; MCE AL 20-E; MCE AL 24-E; PG&E AL 3642-G/4720-E.
3 D.14-06-046 at 119.
4 D.16-05-004, OP 2 at 13.

measures in 2017. Any amount of the $200,000 not used or committed by December 31, 2017 will not be dispersed to MCE.

The proposed fund shift is presented in Table 1.

Table 1: Proposed Fund Shift

2017 Multifamily Program Budget[5]	Gas Funds Shifted to MCE from PG&E	New 2017 Multifamily Program Budget	2017 Gas Funds Before Shift	2017 Gas Funds After Shift
$941,305	$200,000	$1,141,305	$284,700	$484,700

A copy of the fourth amendment to the gas savings agreement between PG&E and MCE is provided in Attachment 1 of this advice letter.

Notice

Anyone wishing to protest this advice filing may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days after the date of this advice filing. Protests should be mailed to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, California 94102
E-mail: EDTariffUnit@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4004 (same address above).

In addition, protests and all other correspondence regarding this advice letter should also be sent by letter and transmitted via facsimile or electronically to the attention of:

[5] Pursuant to MCE Advice Letter 24-E, this is MCE's Multifamily energy efficiency program budget as of June 3, 2017.

Nathaniel Malcolm
Policy Counsel
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Phone: (415) 464-6048
Facsimile: (415) 459-8095
E-mail: nmalcolm@mceCleanEnergy.org

and

Beckie Menten
Energy Efficiency Director
MARIN CLEAN ENERGY
1125 Tamalpais Avenue
San Rafael, CA 94901
Phone: (415) 464-6034
Facsimile: (415) 459-8095
E-mail: bmenten@mceCleanEnergy.org

There are no restrictions on who may file a protest, but the protest shall set forth specifically the grounds upon which it is based and shall be submitted expeditiously.

MCE is serving copies of this advice filing to the relevant parties shown on the service lists for R.13-11-005 and A.17-01-013 *et al*. For changes to this service list, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

Correspondence

For questions, please contact Nathaniel Malcolm at (415) 464-6048 or by electronic mail at nmalcolm@mceCleanEnergy.org.

/s/ Nathaniel Malcolm

Nathaniel Malcolm
Policy Counsel
MARIN CLEAN ENERGY

cc: Service Lists: R.13-11-005; A.17-01-013 *et al.*

Attachment 1:
Fourth Amendment to the Agreement Between Pacific Gas and Electric Company and Marin Clean Energy for Gas Energy Efficiency Measures

FOURTH AMENDMENT TO THE AGREEMENT BETWEEN PACIFIC GAS AND ELECTRIC COMPANY AND MARIN CLEAN ENERGY FOR GAS ENERGY EFFICIENCY MEASURES

This Fourth Amendment to the Agreement between Pacific Gas and Electric Company ("PG&E") and the Marin Clean Energy ("MCE") For Gas Energy Efficiency Measures dated February 5, 2015 ("Agreement") is made on September______, 2017 (the "Effective Date"). All terms defined in the Agreement shall have the same meaning in this Fourth Amendment unless otherwise defined.

WHEREAS:

A. The CPUC ordered PG&E to enter into a contract with MCE for $219,000 per year until 2025 or until modified or superseded by further Commission direction, to use funds from gas public purpose program charges to pay in whole or in part for MCE energy efficiency programs that have a gas savings component in D.14-10-046, Ordering Paragraph 26 (Decision).

B. The CPUC increased MCE's gas budget to $284,700 per year for the duration of the ten-year rolling portfolio cycle in D.16-05-004, Ordering Paragraph 2.

C. MCE and PG&E entered into the Third Amendment to the Agreement between PG&E and MCE for Gas Efficiency Measures increasing the annual gas payments that can be made under the agreement to $284,700 from 2016 through 2024.

D. MCE has informed PG&E that its 2017 gas budget is insufficient to pay customer incentives for additional energy efficiency projects with gas savings components that may enroll in MCE's multi-family program in 2017.

The Parties agree to amend the Agreement as follows:

1. MAXIMUM CONTRACT AMOUNT

PG&E and MCE with the written approval and instruction by the CPUC Energy Division in accordance with MCE's advice letter 26-E, agree to increase the maximum contract amount up to an additional $200,000.00 for gas saving projects installed or committed by December 31, 2017. Any amount of the budget increase in this Fourth Amendment not used for customer incentive payments for gas savings measures for projects installed or committed by December 31, 2017, shall not be disbursed to MCE or otherwise available to MCE or its customers for energy efficiency projects after December 31, 2017, unless committed by December 31, 2017. With the additional $200,000 the maximum contract amount for 2017 is $484,700.

IN WITNESS WHEREOF, this First Amendment has been duly signed by the duly authorized representatives of the Parties hereto as of the Effective Date.

Pacific Gas and Electric Company	Marin Clean Energy
By:	By:
Printed: ______________________________	Printed: ___________________________
Title:_________________________________	Title:_____________________________
Date: ________________________________	Date: _____________________________

CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY LSE (Attach additional pages as needed)

Marin Clean Energy

Utility type:	Nathaniel Malcolm, Marin Clean Energy
☑ ELC ☐ GAS	Phone #: 415-464-6048
☐ PLC ☐ HEAT ☐ WATER	E-mail: nmalcolm@mcecleanenergy.org

EXPLANATION OF UTILITY TYPE	(Date Filed/ Received Stamp by CPUC)
ELC = Electric GAS = Gas PLC = Pipeline HEAT = Heat WATER = Water	

Advice Letter (AL): 26-E

Subject of AL: Request for Approval to Shift Funds

Tier Designation: ☐ 1 ☑ 2 ☐ 3

Keywords (choose from CPUC listing):

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☑ One-Time ☐ Other ______________________________

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution: N/A

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL ______________________________

Summarize differences between the AL and the prior withdrawn or rejected AL[1]: ____________________

Resolution Required? ☐ Yes ☑ No

Requested effective date: October 15, 2017 No. of tariff sheets:

Estimated system annual revenue effect: (%):

Estimated system average rate effect (%):

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected:

Service affected and changes proposed[1]:

Pending advice letters that revise the same tariff sheets:

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division	**Utility Info (including e-mail)**
Attention: Tariff Unit	**Marin Clean Energy**
505 Van Ness Ave.,	**Nathaniel Malcolm, Policy Counsel**
San Francisco, CA 94102	**(415) 464-6048**
EDTariffUnit@cpuc.ca.gov	**nmalcolm@mceCleanEnergy.org**

[1] Discuss in AL if more space is needed.

September 28, 2017

CA Public Utilities Commission
Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, CA 94102-3298

Reply to Protest of MCE Advice Letter 25-E

Re: The Protests of the Office of Ratepayer Advocates, GreenFan, Inc., and Verified, Inc. to *MCE 2018 Annual Energy Efficiency Program and Portfolio Budget Request*

Dear Energy Division Tariff Unit:

Pursuant to General Order ("G.O.") 96-B, Rule 7.4.3, Marin Clean Energy ("MCE") hereby replies to *The Office of Ratepayer Advocates' Protest to Pacific Gas and Electric Company Advice 3881-G/5137-E, Southern California Edison Company Advice 3654-E, Southern California Gas Company Advice 5183-G, San Diego Gas and Electric Company Advice 3111-E/2607-G, and Marin Clean Energy Advice 25-E (September 1, 2017 – Energy Efficiency Annual Budget Advice Letters)* ("ORA Protest") filed on September 21, 2017.

Pursuant to G.O. 96-B, Rule 7.4.4, MCE also hereby replies to the *GreenFan, Inc. and Verified, Inc. Protest to Pacific Gas and Electric Company Advice 3881-G/5137-E, Southern California Edison Company Advice 3654-E, Southern California Gas Company Advice 5183-G, San Diego Gas and Electric Company Advice 3111-E/2607-G, and Marin Clean Energy Advice 25-E (September 1, 2017 – Energy Efficiency Annual Budget Advice Letters)* ("Joint Protest") filed on September 22, 2017.

I. Background

Pursuant to Decision ("D.") 15-10-028, Ordering Paragraph ("OP") 4 and *Administrative Law Judge's Ruling Modifying Schedule*, filed June 9, 2017,[1] MCE filed its 2018 Annual Energy Efficiency Program and Portfolio Budget Request on September 1, 2017.

Energy Division ("ED") issued guidance on July 24, 2017 that addressed the 2018 budget filing. This guidance acknowledged a number of uncertainties regarding the rolling portfolio framework and cost effectiveness calculations for the filing and noted that "the requirement for a cost effective showing may not be achievable using these parameters and given the current uncertainties."[2]

[1] *Administrative Law Judge's Ruling Modifying Schedule*, Ruling Paragraph 1 at 9, Application 17-01-013, *et al.*, filed June 9, 2017.

[2] *2018 Energy Efficiency Portfolio Filing and Reporting Budget* ("2018 ED Guidance"), July 24, 2017.

ED directed Program Administrators ("PAs") to use the 2017 Avoided Costs established pursuant to the Commission's updated cost effectiveness framework,[3] which dramatically reduced the cost effectiveness of programs. Moreover, given the number of factors expected in the next 6-9 months that will impact cost effectiveness, such as the Greenhouse Gas Adder and the approval of PAs' Business Plans, the Program Coordination Group ("PCG")[4] discussed deferring major changes to PAs' portfolios to achieve cost effectiveness until those factors had been resolved by the Commission. To ultimately account for these unresolved factors, ED directed PAs to file a true-up budget advice letter in 2018.[5]

II. MCE's Reply

MCE appreciates the cost effectiveness issues raised by the ORA Protest and the Joint Protest. MCE is consistently working to improve its energy efficiency portfolio to ensure effective and responsible use of ratepayer funds to achieve increased energy savings.

MCE will file a supplemental, true-up advice letter in 2018. That advice letter will comply with Commission decisions and guidance and accommodate the anticipated changes to the rolling portfolio framework and cost effectiveness tools that will occur later this year and into 2018.[6] MCE expects that its 2018 filing will address the cost effectiveness concerns raised in the aforementioned protests.

Thank you for your attention to this matter. Please do not hesitate to contact the undersigned with any questions or concerns.

Respectfully submitted,

/s/ Nathaniel Malcolm

Nathaniel Malcolm
Policy Counsel

cc: Service Lists: R.13-11-005; A.17-01-013, *et al*.

---

[3] D.16-06-007, OP 2 at 26; Resolution E-4801, September 29, 2016.

[4] The PCG is a group that facilitates coordination between ED and PAs on reporting related topics.

[5] 2018 ED Guidance.

[6] *See id*.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2018 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation	Application 17-06-005 (Filed June 1, 2017)

OPENING BRIEF OF MARIN CLEAN ENERGY, PENINSULA CLEAN ENERGY, SILICON VALLEY CLEAN ENERGY, AND SONOMA CLEAN POWER AUTHORITY IN PG&E'S ENERGY RESOURCE RECOVERY ACCOUNT APPLICATION

Steven S. Shupe
General Counsel
Neal Reardon
Regulatory Affairs Manager
Sonoma Clean Power Authority
50 Santa Rosa Avenue, 5th Floor Santa
Rosa, CA 95404
Tel: (707) 890-8485
Email: sshupe@sonomacleanpower.org

Dated: October 2, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2018 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation	Application 17-06-005 (Filed June 1, 2017)

OPENING BRIEF OF MARIN CLEAN ENERGY, PENINSULA CLEAN ENERGY, SILICON VALLEY CLEAN ENERGY, AND SONOMA CLEAN POWER AUTHORITY IN TO PG&E'S ENERGY RESOURCE RECOVERY ACCOUNT APPLICATION

I. *Introduction*

Marin Clean Energy, Peninsula Clean Energy, Silicon Valley Clean Energy, and the Sonoma Clean Power Authority, collectively the "Joint CCA Parties," submit this Opening Brief in opposition to PG&E's Energy Resource Recovery Account (ERRA) application, filed June 1, 2017.

The application is subject to two undisputed statutory requirements under Public Utilities Code § 451: (1) any rate proposed by PG&E must be "just and reasonable"; and (2) PG&E may not "change any rate or so alter any classification, contract, practice, or rule as to result in any new rate, except upon a showing before the commission and a finding by the commission that the new rate is justified." Given these requirements, PG&E's application for an increase in the Power Charge Indifference Adjustment ("PCIA") should be rejected. PG&E has not submitted evidence sufficient to carry its burden to show that the proposed PCIA is "fair and reasonable" or "justified."

We focus on three defects in PG&E's Application: (1) the general lack of evidentiary support for the requested PCIA; (2) the improper inclusion of fuel costs that solely benefit bundled customers; and (3) the erroneous reliance on stale, unauthenticated data (derived from a now non-existent website) to calculate the "Green Adder" portion of the Market Price Benchmark ("MPB").

II. <u>Insufficient Evidence Showing Justification for Requested PCIA</u>

The magnitude of PG&E's request ($583,453,557 or over one-half billion dollars) demands cautious and careful consideration under the applicable standards of proof. While the Commission has recently tended to treat the utility's burden of proof in a ratesetting proceeding under the preponderance of the evidence standard,[1]

[1] *See, e.g.,* D.13-11-005 at 8 (SCE's ERRA Compliance and Reasonableness Review, adopting the preponderance standard); D.14-07-006 at 6 (SDG&E's ERRA Costs and Related Matters, adopting the preponderance standard); D.15-07-044 at 29 (observing that the Commission has discretion to apply either the preponderance of evidence or clear and convincing standard in a ratesetting, but noting that the preponderance of evidence is the "default standard to be used unless a more stringent burden is specified by statute or the Courts."); *but see* D.00-02-046 (suggesting that the clear and convincing standard is appropriate across differing types of ratesetting proceedings).

the Commission retains significant discretion in applying its chosen standard to the circumstances at hand. PG&E, as the applicant, has the burden of affirmatively establishing the reasonableness of all aspects of its application.[2] The Commission has previously described the preponderance of evidence standard in "terms of probability of truth, e.g., 'such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth'."[3]

Given the magnitude of this figure and public policy issues at stake, it is reasonable for the Commission to apply this standard vigorously to require PG&E to prove up – to "justify", using the statutory term – both that overall revenue figure and the individual rate-class PCIA rates it is requesting for 2018 in clear, accurate, specific, and transparent way. A review of the written testimony and workpapers supporting the PCIA request, when combined with the testimony of PG&E's witness Donna Barry at the hearing, and the written and oral testimon of all witnesses, shows PG&E has failed to meet its burden, by a preponderance of the evidence, to demonstrate that its request will result in just and reasonable rates according to § 451.

The PCIA differs from most rates (such as PG&E's bundled generation rate), in that the "revenue requirement" used to calculate PCIA rates is not an actual "real" number. Rather, the revenue requirement is itself a "derived" or calculated figure

[2] D.12-12-030 at 40.
[3] *Id.* (citing D.08-12-058).

based on forecasts rather than actual costs. As noted in Ms. Barry's testimony at the hearing, she does not develop the PCIA revenue requirement reflected in Table 9-1 of her written testimony; rather, that figure is calculated by the PG&E rates department,[4] as are the individual PCIA rates for various customer classes and vintages. Although Ms. Barry testified that the "rates department" created a "rate model" and generated workpapers explaining how individual rate-class and vintage PCIA rates were calculated,[5] the path from the "above-market cost" figures in Line 15 of her Table 9-4 to the final PCIA rates for different rate classes in each vintage is completely opaque.

Ms. Barry's testimony during hearings describes a disjointed process to derive the PCIA, where different personnel within PG&E work separately from each other in disconnected silos. Ms. Barry, for example, calculates the PCIA revenue requirement by vintage, but the amount of the forecasted 2018 PCIA revenue requirement and the allocation of it among the various customer classes, *i.e.*, the creation of the actual PCIA rate for each vintage, is done by the rates department.[6] Neither has the context the other is working from, and neither can explain the details of what the other does.[7] The result, whether intentional on PG&E's behalf or not, is a half-billion dollar charge the derivation of which no one person at PG&E is able to walk through and explain to

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4 Transcript of Evidentiary Hearing, 41:7-11, 47:5-10.

5 Transcript, 44:27 – 46:3.
6 Transcript, 40:24 – 47:10.
7 Transcript, 45:16 – 46:23.

the Commission and parties through testimony on the record. PG&E's failure to present its evidence with either clarity or convincing force, ultimately, causes it to fail its burden and frustrates the Commission's duty to make a finding supported by substantial evidence.

PG&E's disjointed process to derive the PCIA also suffers from a "chicken or egg" problem: i.e., Which comes first, the revenue requirement or the PCIA rates? This "which came first" problem is apparent when Ms. Barry's written testimony (PG&E Opening Testimony at 9-5) is compared to Mr. Bremault's testimony in Chapter 14 (PG&E Opening Testimony at 14-4). Ms. Barry says (emphasis added):

> PG&E calculates the vintaged PCIA revenue requirement for non-exempt departing customers by utilizing the vintaged PCIA rates which are developed based on system-level power charge indifference revenue requirements shown on Table 9-4, line 12. *Specifically, the vintaged PCIA rates are multiplied by the non-exempt [Departing Load] to generate a forecast for the PCIA revenue requirements.* The PCIA revenue requirements are positive and reflect a cost of $583.5 million to non-exempt departing customers that depart bundled service between 2009 and 2018. This positive PCIA revenue requirement will be a credit to bundled customers in ERRA.

Mr. Bremault says (emphasis added):

> The rate design approved for the non-DWR cost portion of the indifference calculation was a top 100-hour rate design, which was originally approved in D.02-11-022 and is the same rate design approved for ongoing CTC. The PCIA rate for each vintage year is developed by utilizing the same proportional top 100 allocation factors used to develop ongoing CTC rates (shown in Table 14-2). *For each vintage year, the ratio of the PCIA revenue requirement (Chapter 9, Tables 9-3 and 9-5) to the ongoing CTC revenue requirement is multiplied by the ongoing CTC rates to*

determine the PCIA rates. In all cases, the final PCIA rates include franchise fees for the California Department of Water Resources bond charge.

The problem is clear – Ms. Barry says that PCIA rates are multiplied by expected departed load sales to generate the PCIA revenue requirement; Mr. Bremault says the PCIA revenue requirement is used to develop PCIA rates. Both cannot be right—this is circular reasoning. While perhaps this discrepancy arises due to differences between the two PG&E witnesses as to the meaning of "revenue requirement,"[8] the passages demonstrate the opacity and confusion surrounding PG&E's calculation of the PCIA.[9]

This opacity is not only problematic, it overcomes PG&E's ability to carry its burden on the issue and makes its request deficient a a matter of law. It is impossible to derive vintage-by-vintage PCIA calculations for 2018 without making an estimate of vintage-by-vintage departed load sales in 2018. PG&E, thus, does not provide the necessary evidence when it provides only sales by individual CCAs and for direct

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[8] In fact, neither table referred to by Mr. Bremault contains a "PCIA revenue requirement." Table 9-3 is the CTC revenue requirement calculation, and Table 9-5 is the Market Price Benchmark calculation. And assuming Mr. Bremault meant to refer to Table 9-4, neither Line 12 nor Line 15 represents a "revenue requirement" – rather, they represent the above-market cost of PG&E's generation portfolio for the particular vintages. *See* PG&E Opening Testimony at 9-4, line 15 (using the term "indifference amount").

[9] Although Ms. Barry said she would provide a reference to where in the workpapers the rate department's calculations of the PCIA rates occur, Joint CCA Parties have not received such a reference.

access customers as a whole, with no direct distinction by vintage within those categories (McCann Testimony, 13: Footnote 25.)[10] This is yet another critical piece of evidence that does not appear in PG&E's original testimony and workpapers.

As the foregoing makes clear, PG&E has not provided sufficient evidentiary support to justify its proposed 2018 Rates through the testimony and workpapers it has submitted to the Commission, as required by § 451. PG&E's proposed PCIA rates for 2018 should not be approved unless and until it provides such a justification through clear, understandable analysis – i.e evidence, specifically linking the "above-market" costs for each vintage as shown on Table 9-4 in PG&E's Testimony to the specific PCIA rates proposed to be assessed against departed customers in each vintage.

III. Fuel and other Variable Costs of Dispatchable Generation Facilities Should be Excluded from the PCIA

PG&E includes in the PCIA the cost of fuel and other variable costs incurred by PG&E to generate power used solely to serve its bundled customers or used to generate excess revenues from sales into the CAISO.[11] These fuel and variable costs should not be included in the PCIA because: (1) when incurred to meet PG&E

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[10] *See* Testimony of Richard J. Mccann, Ph.D. On Behalf of Sonoma Clean Power Authority (Revised), August 28, 2017, Exhibit SCP-01, p. 13, footnote 25.

[11] *See* Testimony of Richard McCann, 3:5-9; PG&E Opening Testimony at 3-7:12-14; Transcript, 23:6-12. PG&E does not dispute that such costs are included in the PCIA rates requested by PG&E in its application.

bundled customer demand, such costs are "load based" and subject to exclusion under the rationale of Commission Decision 11-12-018; and (2) when incurred for the purposes of maximizing revenues from sales to the CAISO, such costs are "avoidable" and thus not subject to recovery from departed CCA customers under Public Utilities Code §366.2(f)(2).

It is legal error to include these costs in the PCIA since "avoidable" costs are expressly excluded from the PCIA by law. Specifically, § 366.2(f)(2) limits the inclusion of costs in the PCIA to those that are "net unavoidable electricity purchase contract costs attributable to the [departing] customer, as determined by the commission." Decision 11-12-018 sets a standard for excluding a cost from the PCIA if it "varies directly with the load served."[12] In that case, the Commission addressed "CAISO load-based costs" that had been included in the PCIA despite the fact that "the IOUs avoid load-related CAISO charges when load departs."[13] The Commission concluded that such costs should be excluded from the PCIA because the methodology at the time "inappropriately [treated] CAISO costs as if they are

[12] D.11-12-018, p. 32.

[13] *Id.* at 30, 32 (adopting App. A to Exh. 100 as "constituting the pertinent charges to be excluded from the total portfolio and [Market Price Benchmark] calculation."). "These costs include various charges for grid management services, ancillary services, congestion, unaccounted for energy, neutrality and other load-based fees." R.07-05-025, Exh. 100, 32:17-19 (summarizing the contents of App. A).

unavoidable, above-market utility generation-related costs."[14]

The Commission allows for "fuel costs" to be included in the PCIA, and the Joint CCA Parties are not advocating in this docket that the current PCIA methodology be changed. However, the Commission has never specified *which* fuel costs be included in the current methodology, and those that are avoidable and vary directly with the load being served by an IOU must be excluded as contrary to §366.2(f)(2).

The testimony of PG&E's witness Donna Barry at the evidentiary hearing provides perhaps the best rationale for why such fuel and variable costs should not be included in the 2018 PCIA calculation:

> Q [By Mr. Shupe] And the costs of your spot market purchases that you were talking about where you are just buying power from the ISO and you are not generating at the same time, are those costs put into line 3 of table 9.4?
>
> A No. Spot market purchases are not.
>
> Q And why is that?
>
> A *The idea is that the spot market is used to serve bundled load, spot market purchases. It's not stranded cost associated with long term contracts. It's -- it is power purchased to serve bundled load.*
>
> Q And you used the term, stranded costs?
>
> A I did.

[14] *Id.* at 31, 109 (Conclusion of Law 14).

> Q Yes. Can you tell me what you understand by the term stranded costs?
>
> A It was a term that was used originally in the 04-12-048 decision that established the concept for these nonbypassable charges. *But basically, I think it's looking at gener- -- long-term resources that would have potentially above market cost, meaning they were required to purchase the generation and the amount of revenues we might receive from the market are less than the cost of the resource*. And so the costs above market I think people have referred to as stranded costs.

(Transcript, 19:8 – 20:8, emphasis added). There is no principled difference between fuel and variable costs incurred by PG&E to serve its bundled load (which PG&E has included in the PCIA calculation) and the spot-market CAISO costs incurred by PG&E to serve its bunded load (which are excluded from the PCIA calculation). Neither involves a "stranded cost associated with a long-term contract." Neither involves generation that PG&E was "required to purchase" (or create) before Joint CCA Parties' customers departed. Like the load-based CAISO costs disallowed in D.11-12-018, these load-based costs should also be excluded from the PCIA.

PG&E's arguments against exclusion of these costs either miss the point or, as discussed below, actually support exclusion.

First, PG&E points to Commission decisions that have expressly said that fuel costs can be included in the PCIA. (PG&E Rebuttal Testimony at 1-7.) But the Joint CCA Parties are not contending that *all* fuel costs should be excluded. For example, fuel costs for PG&E's Diablo Canyon nuclear facility, which supplies "baseload" capacity that cannot be ramped up or down in response to changes in load levels or corresponding wholesale prices, are properly included in the PCIA. None of the Commission decisions cited by PG&E say that *all* PG&E fuel and variable generation costs are automatically eligible for inclusion in the PCIA.[15]

PG&E next argues that it does not use its generation assets to serve its own bundled customer load. (PG&E Rebuttal Testimony at 1-9 to 1-10.) This surprising assertion is contradicted by other PG&E testimony (PG&E Opening Testimony at 2-1:23-28, emphasis added):

> This section describes the development of sales and peak demand forecasts for PG&E's service area. PG&E develops its resource mix, as well as a reserve margin, to serve this load. *The electric sales forecast for PG&E's bundled electric customers is a key input to the procurement cost modeling described in subsequent chapters and used in the calculation of the rates discussed in detail in Chapter 14.*

Although Joint CCA Parties have not evaluated the "PPP" model used by PG&E to forecast generation from its portfolio for 2018 because PG&E says it is confidential, and refused to provide it, there is little doubt that serving bundled customer load is the driving factor in the operation of the (mostly) fossil-fuel fired generation resources at issue. To the extent that these facilities incur fuel and variable costs solely to meet this bundled load, those costs should be excluded from the PCIA. As noted above, PG&E

[15] Nor could that be the rule. If, for example, PG&E were to incur engage in an uneconomic dispatch of a fossil fuel facility, even PG&E would concede that the fuel costs related to that uneconomic dispatch should be excluded from PCIA costs. As discussed below, the measure of "economic" differs greatly between bundled and unbundled customers.

bears the burden of clearly demonstrating that the costs it seeks to recover are proper, and it has failed to do this.

Finally, PG&E submitted rebuttal testimony making the claim that departed customers who pay the PCIA are better off when PG&E incurs (and charges departed customers for) fuel and variable costs. In her written rebuttal testimony, Ms. Barry stated:

> Since dispatchable resources are selected to dispatch when their marginal operating costs are less than the market price of power in that hour, by definition, those resources only incur incremental operating costs when they are "in the money," regardless of the demands of bundled customers in the period where the resources are dispatched. In short, the CAISO does not dispatch resources to meet the load of a specific LSE.
>
> Under the total portfolio indifference calculation, the resulting market revenues help to offset the fixed costs of the generating resource. Thus, "in the money" sales of energy into the CAISO market help generate revenues to reduce the PCIA and lower the generation-related costs that would otherwise be allocated to SCP and other LSEs under the PCIA.

(PG&E Rebuttal Testimony at 1-10:16-26.)

However, Ms. Barry's testimony at the evidentiary hearing contradicted these statements. Although Ms. Barry first testified that revenues received by PG&E from the CAISO for power delivered to the grid were netted out from the "Total Portfolio Cost" figures on Line 3 of Table 9-4 (Transcript at 15:7-21), she later stated that was not the case:

Q [By Mr. Shupe] I'm sorry. I want to ask you again about this question of crediting CAISO revenues and whether or not that actually feeds into the figure that's on line 3 of table 9.4. And the reason I'm a little bit confused is as I understand it, the way the PCIA gets calculated is you take that total portfolio cost and then you apply what's called the Market Price Benchmark to it to calculate what you call the above market costs, right?

A That's correct.

Q And --

A I will clarify, though, that the benchmark credit is not on line 3. It is on line 5.

…

Q The total portfolio cost is on line 3. And what you call the market value, which as I understand it is what you get when you multiply the Market Price Benchmark times the amount of generation that's shown on line 1?

A That's correct.

Q Okay. And then you subtract those two and you get above market – essentially above-market costs which are shown on line 6, correct?

A Correct.

Q The Market Price Benchmark itself has a component that's called the brown power component.

A Sure.

Q Right? And that is supposed to represent, as I understand it, the – what you would get basically from just selling non-renewable power on to the CAISO grid next year 2018, correct?

A Yes. It's a proxy for --

Q It's a proxy for that. So my question is, if you are already netting out your revenues from CAISO in line 3, why isn't that a double -- why I'm confused is that seems to me that like it's a double counting.

A That's why I want to try and clarify. *Line 3 does not net the ISO revenues.* That netting of ISO revenues happens in our spot market purchase line. So again, *the netting of the ISO generation revenues received from the market is netted against the costs we receive from ISO to serve our load*. The net of those two equals the spot market purchase line item. *Spot market purchases are not part of this calculation*.

Transcript at 24:1 – 26:4 (emphasis added). Thus, when PG&E incurs fuel and variable costs to run dispatchable facilities, those fuel and variable costs are added into the PCIA, but the revenues received by PG&E are only netted against the costs of power taken from CAISO grid to serve its *bundled* customers. This testimony again demonstrates that such costs are, in fact, load-related costs that should be excluded from the PCIA.[16]

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[16] Note that this testimony also casts doubt on Ms. Barry's testimony that there was no way in which the method by which PG&E dispatches its generation into CAISO that could benefit bundled customers at the expense of departed load customers (Transcript at 22:15-21). PG&E will operate a dispatchable facility (and thus incur fuel and variable operating costs) whenever the CAISO market price is greater than those costs. (Testimony at 3-7:12-14; Rebuttal Testimony at 1-10:10-15.) But while bundled customers receive a benefit from that generation equal to the CAISO market price, Ms. Barry testified at the evidentiary hearing that the benefit to unbundled departed customers is limited to the "brown power" portion of Market Price Benchmark.

PG&E also contends that if fuel and variable costs are excluded from the PCIA calculation, then all generation estimated for 2018 from PG&E dispatchable resources must also be excluded from the PCIA calculation, which in turn would result in a higher PCIA calculation. (Rebuttal Testimony at 1-11:3 – 1-12:10 and Table 1-1.) PG&E's argument is incorrect for two reasons.

First, Ms. Barry testified at the evidentiary hearing that after excluding the specific generation facilities, she did not ask for the "PPP" dispatch model to be rerun to see what PG&E's 2018 generation portfolio would look like without these facilities. (Transcript at 38:12-26.) Without running the PPP model again, there is no way to know what PG&E's 2018 generation mix would be, and thus no basis for any estimate of an "alternative" PCIA. Ms. Barry's written Rebuttal Testimony on this point completely lacks foundation and must not be given any weight.

More importantly, however, PG&E misunderstands the fundamental basis for the Joint CCA Parties' argument for excluding fuel and variable costs only. The Joint

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(Transcript at 29:18 – 31:4.) While in fact departed load customers receive a benefit or "credit" for generation equal to the entire Market Price Benchmark (Testimony at 9-4:8-14), this still creates a system in which PG&E can operate its dispatchable resources to the benefit of bundled customers and the detriment of departed customers. For example, assuming fuel and variable costs equaled $60 per MWh, PG&E would run its facility if the market price were $65 per MWh. Its bundled customers would receive a $5 per MWh benefit, while departed customers would incur an additional cost of approximately $5 (the fuel/variable costs minus the Market Price Benchmark), which would be recovered in the PCIA. This problem disappears if fuel and variable costs are excluded altogether from the PCIA, which, as noted, is appropriate given that they are "load based" and not "stranded" costs.

CCA Parties are not saying that PG&E may not, or should not, run these dispatchable facilities at all. Indeed, for the reasons noted in PG&E's Testimony, Rebuttal Testimony, and testimony at the hearing, running the facilities may well benefit *bundled* customers by reducing their overall costs. Rather, the basis for excluding fuel and variable costs is that they are load-based (they relate solely to *bundled* customers) and they are not "stranded" (they are not costs that PG&E incurred on behalf of departed customers, or must continue to incur after the customers' departure).

PG&E's argument ignores the fact that even if the fuel and variable costs are excluded from the PCIA, departed load customers will continue to pay as a part of the PCIA ongoing fixed costs relating to dispatchable facilities. The Joint CCA Parties are not contending in this proceeding that the capital and fixed costs for these resources should not be included in the PCIA under the current interpretation of the rules. Because departed customers are still paying a part of the overall cost of such facilities, generation from those facilities should be included in the overall PG&E "Portfolio Generation" figures shown on Table 9-4 of PG&E's Testimony.[17]

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[17] In addition, no Commission decision relating to the PCIA or any of its successors says that PG&E may exclude from Lines 1 and 2 of Table 9-4 generation as to which departed customers do not pay their share of 100% of the costs. Indeed, the basis in Commission decisions upon which PG&E excludes *any generation* from the PCIA calculation for different vintages is unclear. The "vintaging" process was designed to keep departed customers from paying for generation resource *costs* that were not incurred on their behalf. PG&E's exclusion of the amount of generation from those resources (shown as diminishing generation values on Lines 1 and 2 of Table 9-4 as

Commission Decision 11-12-018, discussed above, makes clear that some costs relating to a specific facility may be included in the PCIA, while other costs are excluded. That decision disallowed CAISO load-based costs from being included in the total portfolio cost figure from which the PCIA was calculated (i.e., from Line 3 on Table 9-4). But nothing in that decision suggested that this disallowance of costs should result in the exclusion of any generation (i.e., a reduction in Line 1 of Table 9-4). This is consistent with Joint CCA Parties' position, as well as the manner in which the load-based, non-stranded fuel and variable costs were excluded from the PCIA calculation in the Testimony of Richard McCann.

PG&E did not dispute the specific dollar amount of fuel and variable costs that Dr. McCann identified as being load-based and avoidable. As noted in Dr. McCann's testimony, the total amount of these costs is $238.4 million dollars. (McCann Testimony at 10:18-19.) This amount should be excluded from the "Total Portfolio Cost" figures for each vintage (Line 3 of Table 9-4), which results in a decrease in the "PCIA RRQ" shown on Line 15 of Table 9-4 in the range of 11% to 13%.

IV. The "Green Adder" Component of the Market Price Benchmark Relies on a Fictitious Website Link and Should Be Corrected

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vintages go back in time) is inconsistent with the Commission's direction that the PCIA be calculated based on the market value of PG&E's *entire* portfolio. By reducing the amount of generation on Lines 1 and 2 for earlier vintages, PG&E's calculation results in a lower-than-actual "market value" for those vintages, and thus a higher-than-justified PCIA.

The Commission should give no weight to PG&E's proffered evidence on the "DOE Adder" portion of the "Green Adder", as such evidence has not properly been presented in this case. Dr. McCann's testimony shows that the publicly available source for the Department of Energy database purportedly used by PG&E to calculate the "DOE Adder" portion of the "Green Adder" does not actually exist.[18]

While it may be appropriate for the Commission to take judicial notice of data or statistics housed on a website—particularly where the source of the website is reasonably reliable and trustworthy[19]—it is wholly inappropriate for the Commission to take judicial notice of data on a website that no longer exists. Moreover, it is important to note here that the Commission originally recognized the limitations of relying on the DOE source of data in D. 11-12-018 and directed that it only be used

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[18] The problem with the DOE data can be most easily be seen by simply clicking on the web address cited by the advice letter as the source for the data. Contrary to the representation made in the advice letter, that address: (http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml?page=1) does not lead to a database of "State-Specific Utility Green Pricing Programs." Rather, that address redirects to an entirely different page, which nowhere contains any links to or information about the alleged database. A visit to a publicly available web-archive website (https://web.archive.org/) reveals that the last screen shot of this page recorded was January 25, 2017, shortly after the last Presidential inauguration and around the time widespread changes were made to executive agency websites by the new administration.

[19] *See, e.g., Matthews v. Nat'l Football League Mgmt. Council* (9th Cir. 2012) 688 F.3d 1107 (taking judicial notice of a professional football player's statistics on the National Football League's website, noting that Fed. R. Evid. 201(b)(2) "allow[s] a court to take judicial notice of a fact "not subject to reasonable dispute because it… can be accurately and readily determined from sources whose accuracy cannot be reasonably questioned.").

until better sources become available.[20] Thus, when the DOE website is no longer available, it is no longer possible for PG&E to comply with the directive to provide the most recent 12-month data from that website. It would have been prudent for PG&E to alert the Commission to that deficiency (the unavailability of recent DOE data) in its application filing. Instead, the attachment included in Appendix A to PG&E Advice Letter 4927-E—included by reference in the application—indicates that the data relied upon in this application was "last updated January 2015." PG&E's failure to alert the Commission to the unavailability of this data, and to mitigate the loss of the required data source by providing supplemental, relevant data in its filing, does not justify Commission reliance on stale data that can no longer be verified as consistent with the original DOE source.[21]

Further, Dr. McCann's testimony calls into question whether the data used by PG&E even originated with the Department of Energy in the first instance. (McCann Testimony, 11:13-20.) Dr. McCann's testimony demonstrates that the information in the database used by PG&E is in many cases out of date and inaccurate. (McCann Testimony, 12:1 – 13:12.) Given the inability to confirm the origin of the data used by

[20] D.11-12-018 at 23.

[21] The Joint CCA Parties acknowledge that secondary evidence may be appropriate in some circumstances, but oppose reliance on PG&E's account of the contents of the DOE data when the original source is no longer available in the manner contemplated by D.11-12-018 (i.e., a transparent, publicly-available data source) and cannot be independently vetted or examined.

PG&E, plus the inaccuracies in the data shown by Dr. McCann, the Joint CCA Parties contend that the "DOE Adder" must be given no weight in this context and the more accurate and verifiable "URG Green" figure be used as the "Green Adder" for purposes of setting the Market Price Benchmark.

Ignoring or giving no weight to the DOE data is justified under the circumstances present here and is well within the range of discretion the Commission reserved for itself in D. 11-12-018 when considering the prospective validity and value of DOE data sources for this purpose.[22] As the Commission observed in D.11-12-018:

> We recognize that questions and concerns have been raised regarding the usefulness of the DOE data sources as representative of the California market. We conclude, however, these concerns go to the weight that should be accorded to the DOE data sources.[23]

In light of the fact that the Commission's identified source of data no longer exists, and that the data presented is nearly three years old, the Commission should give no weight to the data proffered as DOE data in this case.

In its Rebuttal Testimony, however, PG&E claims that the Commission has already approved the accuracy of the DOE database through its approval of Advice Letter No. 4927-E (PG&E Rebuttal Testimony at 1-12:18-21, providing a link to the advice letter at https://www.pge.com/tariffs/tm2/pdf/ELEC_4927-E.pdf). However, a

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[22] D.11-12-018 at 23.
[23] *Id.*

plain reading of AL 4927-E shows this is incorrect. AL 4927-E by its terms says that it is intended to provide "data necessary to calculate the market price benchmark (MPB) *for 2017*."[24] It is simply inaccurate to claim or imply that the Commission has approved the DOE data for use in the 2018 ERRA forecast. As stated above, the Commission is incapable of taking judicial notice of data from a website that no longer exists, and reliance on stale data is inconsistent with the directive in D. 11-12-018 and Resolution E-4475 that data used be from the most recent 12-month period.[25]

The Commission should not calculate the Market Price Benchmark based upon a database that simply does not exist – particularly when the last available version of that database is full of errors, as Dr. McCann's testimony lays out in detail.[26] Given the lack of data, the "Green Adder" should be calculated based solely on actual in-state IOU renewable energy contracts, as shown in the "IOU RPS Premium" line (Line 18) of Table 9-5 of PG&E's Testimony. This would result in a change to the "Market Price Benchmark" for each vintage as shown in Revised Table 9-4 in Attachment D of Dr. McCann's Testimony.

V. <u>Conclusion</u>

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[24] PG&E AL 4927-E at 1 (emphasis added).

[25] Resolution E-4475 at 4 (citing the directive of D.11-12-018 that each utility file an advice letter providing the most recent 12 month figures derived from the DOE survey of Western US renewable energy premiums.)

[26] Testimony of Richard J. McCann, Ph.D. On Behalf of Sonoma Clean Power Authority (Revised), August 28, 2017, Exhibit SCP-01, pp. 11-13.

PG&E has failed to meet its burden of showing that the PCIA rates requested for 2018 are "just and reasonable." PG&E has failed to meet its burden of showing that its requested 2018 rates are "justified." The evidence presented to the Commission through written and oral testimony is insufficient to allow the Commission to determine whether or not the requested rates were properly calculated. In addition, fuel and variable costs relating to PG&E's dispatchable generation facilities should be excluded from the "Total Portfolio Cost" upon which the PCIA is based, and the Market Price Benchmark should be revised as discussed in Section IV above. The Commission should require PG&E should meet and confer with Joint CCA Parties and develop recalculations of each PCIA rate accounting for such changes.

Dated: October 2, 2017

Respectfully submitted,

/s/

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements.	)))))	Rulemaking 13-09-011 (Filed September 19, 2013)

COMMENTS OF MARIN CLEAN ENERGY ON PROPOSED DECISION AND ALTERNATE PROPOSED DECISION

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October 5, 2017

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RECOMMENDED CHANGES TO

PROPOSED DECISION AND ALTERNATE PROPOSED DECISION

1. Revise the definition of "similar" such that: (1) "approximate number of customers" for a CCA means a CCA ***markets*** to the approximate number of CCA customers to which the utility was offering DR services under its utility program; and (2) the definition reflects Commission jurisdiction with respect to prohibited resources.

2. Correct the references to "bill credits" to conform to Decision 14-12-024.

3. Adopt a Tier Two advice letter process to implement the competitive neutrality cost causation principle.

TABLE OF AUTHORITIES

CPUC DECISIONS, DOCKETS, RULES

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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COMMENTS OF MARIN CLEAN ENERGY
ON PROPOSED DECISION AND
ALTERNATE PROPOSED DECISION

Pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedure, Marin Clean Energy ("MCE") respectfully submits these comments on the Proposed Decision ("PD") issued by Administrative Law Judges Kelly A. Hymes and Nilgun Atamturk and the Alternate Proposed Decision ("APD") issued by Assigned Commissioner Martha Guzman Aceves on September 15, 2017. MCE's comments focus on the rules proposed in the PD and APD for implementing the demand response ("DR") competitive neutrality cost causation principle adopted in Decision ("D.") 14-12-024.[1] According to the "Digest of Differences" issued with the PD and APD, the proposed implementation rules are identical between the PD and the APD. For ease of review, MCE's comments and citations below refer to the PD, but apply equally to the APD.

I. THE PD'S DEFINITION OF "SIMILAR" IS A SIGNIFICANT IMPROVEMENT OVER THE UTILITIES' PROPOSAL, BUT REQUIRES ADDITIONAL CHANGES.

MCE strongly supports the PD's determination that the multi-step process proposed by the Investor-Owned Utilities ("IOUs") for implementing the competitive neutrality cost

[1] D.14-12-024, Ordering Paragraph ("OP") 8b.

causation principle ("Joint Utility Proposal") [2] was "inefficient and unnecessary."[3] The IOUs proposed a complex series of "principles" and "attributes" that the DR program offered by a Community Choice Aggregator ("CCA") or Electric Service Provider ("ESP") would have to meet to be deemed "similar."[4] Instead, the PD sets forth a simpler and more understandable definition of "similar."[5] MCE appreciates and supports the PD's approach, but has identified two aspects of the definition that require modification.

A. The Commission should clarify and revise its requirement that Competing Providers offer DR services to the approximate number of customers as the Utility Provider.

The PD's definition requires that the Competing Provider's DR program be offered to the "same type and approximate number of customers."[6] Whereas there was consensus among the parties that the CCA/ESP DR program should be offered to the "same type" of customers, no party proposed the additional requirement that the program be offered to "the approximate number of customers." This is not a reasonable requirement for a CCA that serves a portion of an IOU's customers. For example, a utility has millions of residential customers. A CCA would only have a fraction of the IOU's residential customers and thus could never meet the "approximate number" requirement. In fact, including such a requirement would erect a new barrier, thereby preventing CCAs (and ESPs) from developing their own competing DR programs, which would undermine both the spirit and intent of the competitive neutrality cost causation principle.

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[2] *Joint Utilities' Proposal on Competitive Neutrality Cost Causation Principle in Response to Administrative Law Judge Hymes' December 2, Ruling*, R.13-09-011, February 17, 2017.

[3] PD at p. 16 and Finding of Fact ("FOF") 1.

[4] Joint Utility Proposal, *loc. cit.* at pp. 8-17.

[5] PD at p. 7 and OP 2.

[6] *Id.*

However, given related discussion in the PD, the intent of the "approximate number" requirement appears to be to ensure that the Competing Provider ***markets*** to the approximate number of its customers to which the utility was offering DR services under its competing program.[7] This is a reasonable requirement, but not properly reflected in the proposed definition of "similar." Also, the reference to "unbundled" customers in the PD[8] and in Conclusion of Law 2 is inaccurate. "Unbundled customers" include both CCA and Direct Access ("DA") customers. The utility generally offers DR services to all the unbundled customers in a particular customer class, but a CCA would only market its competing DR program to its own CCA customers. Thus, the PD and Conclusion of Law 2 require modifications to correct this error.

Accordingly, MCE proposes the following modifications to the PD's definition of "similar" as it appears in the body of the PD and the related discussion. These modifications would require that a similar CCA DR program be marketed to the approximate number of customers of the Competing Provider to which the utility offers DR services for its competing program. In the Appendix, MCE provides the conforming modifications to Conclusion of Law 2 and Ordering Paragraph 2:

<u>PD, p. 7:</u>

- is offered to the same type <u>**of customer**</u> **(e.g., residential customer)** and <u>**marketed to the**</u> approximate number of customers <u>**served by the Competing Provider to which the utility offers DR services for its competing program**</u>~~, e.g., residential customer~~;

<u>PD, p. 20</u>

- This Decision finds that a similar program requires that the customer type and approximate number marketed to are "alike in substance or essentials." Therefore, in order to be deemed similar, the type of customer and

[7] *See* discussion of "approximate number" in PD, p. 20.

[8] PD at p. 20.

> approximate number of customers marketed to in the Competing Provider's program should be similar to the utility program's customer type and approximate number of ~~unbundled~~ customers **served by the Competing Provider** to which the utility **offers DR services**.

B. The Commission's prohibited resource policy does not apply to CCAs.

The Commission does not have the statutory authority to apply its prohibited resource policy to CCAs. The prohibited resource policy is not a requirement of a state law, but rather a previous Commission decision specifically applicable to the IOUs. The PD directs that the Competing Provider's DR program "must demonstrate that the program can validate adherence to the Commission's prohibited resource policy, as required by D.16-09-056."[9] This statement contains both a legal and factual error. D.16-09-056 is solely applicable to the IOUs' DR programs and third-party DR Providers providing DR services to the IOUs.[10] Extension of the prohibited resources policy to non-utility electricity providers was neither considered nor addressed in that proceeding.

However, operational CCAs have thus far embraced the mission to deploy more renewable energy resources to reduce GHG emissions. MCE anticipates that CCAs will administer DR programs that ensure procurement of GHG-free resources, especially because renewable-based portfolios stand to benefit more from DR for load shaping. To address the factual and legal errors, MCE proposes the following modifications to the definition of "similar" and Step One A with conforming changes to Conclusion of Law 6 and Ordering Paragraph 2 provided in the Appendix:

PD, p. 7

- can validate that customers are not receiving load shedding incentives for the use of ~~prohibited~~ resources **prohibited by the Competing Provider** during demand response events;

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[9] PD at p. 23.

[10] *See* OP 4 and 5, D.16-09-056.

PD, Step One A, p. 17

4) description of how the Competing Provider will validate to the Commission that its customers will not receive an incentive for the use of ~~**prohibited**~~ resources **prohibited by the Competing Provider** during a demand response event;

In addition, the PD's legally and factually incorrect discussion of the applicability of the Commission's prohibited resources policy and D.16-09-056 should be deleted.[11]

II. THE DISCUSSION OF BILL CREDITS MUST BE CORRECTED TO CONFORM TO D.14-12-024.

The bill credit is the primary mechanism for implementing the competitive neutrality cost causation principle, in compliance with Ordering Paragraph 8b(i) in D.14-12-024. Thus, it is critical to ensure that the discussion and application of the bill credit is both clear and correct. MCE has identified several areas of the PD that require modification to conform to D.14-12-024.

A. The Commission should not refer to bill credits as compensation.

The PD refers to the bill credits as "compensation" or reimbursements in several spots.[12] This is both a factual and a legal error. D.14-12-024 specified that the utility was required to "end cost recovery" from the CCA's customers for its "similar program."[13] The utilities proposed implementing this requirement through bill credits.[14] Removing costs from a customer's bill does not provide "compensation" or "reimbursement" to the customers – it removes costs that are no longer to be recovered from the customers.

The reason for requiring removal of the utility DR program costs from the customers of CCAs and ESPs was to eliminate the existing barrier, in which the utility recovers the costs of

[11] PD at p. 23.

[12] PD at pp. 8, 10 and OP 3, 4.

[13] D.14-12-024, OP 8b(i).

[14] Joint Utility Proposal, *loc. cit.* at p. 20.

most of its DR programs from all customers through distribution rates. Such cost recovery is a barrier to CCAs and ESPs developing their own DR programs. D.14-12-024 describes this existing barrier (as outlined by MCE) and directs removal of utility costs from CCA/ESP customer bills as the remedy:

> Marin Clean Energy explains that it cannot justify creating such programs at ratepayer expense when CCA customers are already being charged for the utility-offered programs … [W]e acknowledge the barrier to creating such a program. Hence, we adopt the competitive neutrality requirement that once a direct access and community choice aggregation provider begins to offer a demand response program***, the competing utility shall discontinue cost recovery from that providers' customers*** for that or any similar program, no later than one year following the implementation of that program.[15]

Thus, the PD errs in its reference to bill credits as "compensation." Therefore, MCE respectfully requests that the PD be modified as shown to correct these errors; the proposed changes mirror Ordering Paragraph 8b(i) in D.14-12-024:

> PD, p. 8
>
> In order to **~~compensate the~~** **end cost recovery from the Competing Provider's** customers **~~who are no longer eligible~~** for the Utility's similar demand response programs **~~because they are served by a Competing Provider~~**, the utility shall employ the use of a credit on the Competing Provider's customers' bill.
>
> PD, p. 10
>
> Finally, the Proposal recommends the use of a credit on the Competing Provider's customers' bill to **~~compensate for no longer being eligible to participate in the~~** **end cost recovery of the Competing Utility's** similar demand response program.

MCE provides the conforming changes to Ordering Paragraphs 3 and 4 in the Appendix.

B. Bill credits should be applied to all customers of the Competing Provider.

Step Four of the process, as described in the PD and Attachment 1, gives the impression

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[15] D.14-12-024 at pp. 49-50. Emphasis added.

that the bill credits are applied to a subset of the Competing Provider's customers by specifying that "affected customers" receive the bill credit.[16] "Affected customers" are not defined. As cited above, the purpose of the bill credit is to eliminate an existing barrier to development of competing DR programs by CCAs and ESPs. D.14-12-024 specifies that the Competing Utility "shall … end cost recovery from that provider's customers for any similar program."[17] Thus, *all customers* of the Competing Provider receive the bill credit and to provide the bill credit to a subset of such customers, as the PD suggests, would violate the requirements of D.14-12-024. Therefore, MCE respectfully requests that the PD be modified to correct this error, as follows, with conforming changes made to Attachment 1:[18]

> Step Four: Within one billing cycle following the end of cost recovery and marketing of the similar demand response program by the Competing Utility, ~~**affected**~~ customers shall receive a bill credit for the similar program(s).

III. A TIER TWO ADVICE LETTER IS THE APPROPRIATE REGULATORY MECHANISM.

MCE appreciates the PD's decision to implement the competitive neutrality cost causation principle through an advice letter process, as recommended by most parties. However, the PD elects a Tier Three process, as opposed to the Tier Two process recommended by MCE and other parties. MCE continues to believe that the proposed Tier Three process is unnecessary and will likely significantly delay implementation of any competing DR program offered by CCAs or ESPs.

In support of the Tier Three process, the PD cites comments by other parties that the

[16] PD at p. 26; Attachment 1 at p. 2.
[17] D.14-12-024, OP 8(b)(i).
[18] PD at p. 26 and Attachment 1 at p. 2.

Commission's evaluation of the Competing Providers requires "meaningful review"[19] and the opportunity for "interested persons … to be heard by submitting written input."[20] The Tier Two process also fulfills both of these requirements. However, there are substantive and important differences between Tier Two and Tier Three. Tier Three advice letters require a Commission resolution and the schedule to complete the process pursuant to General Order 96-B extends through 330 days from the date the advice letter is filed. These requirements add yet another disincentive for CCAs and ESPs attempting to develop competing DR programs.

The PD states it "strives for simplicity,"[21] yet selects the most cumbersome advice letter process to enact its program. When the IOUs opposed Tier Two advice letters, they were assuming their multi-step process, with workshops and hearings, would be adopted. It was not. The PD opted for a simpler definition of "similar," which provides more than adequate guidance to Staff to determine in the Tier Two advice letter process as a "ministerial act"[22] whether or not the Competing Provider's program meets the definition. Moreover, Energy Division always has the option to require a Commission resolution under the Tier Two advice letter process, depending on the protests received.[23] The Tier Two process provides due process to those interested, yet flexibility to Energy Division to act on the Competing Provider's advice letter efficiently and quickly. MCE reiterates its request to establish rules that *encourage* Competing Provider's to develop their own DR programs by adopting the Tier Two advice letter process as the most reasonable for this purpose.

In the attached Appendix, MCE respectfully recommends modifications to the Findings

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[19] PD at p. 16.
[20] PD at pp. 16-17.
[21] PD at p. 19.
[22] General Order 96-B, General Rule 7.6.1.
[23] *Id,* General Rule 7.3.4.

of Fact and Conclusion of Law to enact this change and notes that additional conforming changes will be required to the text of the PD and Attachment 1, but are too numerous to cite here.

V. CONCLUSION.

MCE appreciates the PD's adoption of a simpler and more reasonable approach for implementing the competitive neutrality cost allocation principle than the complex and cumbersome process recommended by the utilities. However, for the reasons discussed above, MCE respectfully requests that the PD be modified as set forth herein to correct the legal and factual errors identified, clarify requirements, and adopt the simpler Tier Two advice letter process to encourage more participation by Competing Providers and shorten delays in implementation.

Dated: October 5, 2017

Respectfully submitted,

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APPENDIX

PROPOSED MODIFICATIONS TO FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDERING PARAGRAPHS

Proposed Modifications to Findings of Fact

5. The Commission will have the final determination of the Competing Provider's Advice Letter through a Tier ~~**Three**~~ **Two** process.

6. Using a Tier ~~**Three**~~ **Two** Advice Letter process balances expediency, transparency, and the appropriate level of regulatory oversight.

7. Defining the customer type and providing the approximate number of customers to whom the demand response program is marketed in the Tier ~~**Three**~~ **Two** Advice Letter will allow the Commission to ensure that a large group of customers are not omitted from demand response opportunities.

Proposed Modifications to Conclusions of Law

1. The Commission should adopt a Tier ~~**Three**~~ **Two** Advice Letter Process to determine whether a Competing Provider's demand response program is similar to a Competing Utility's demand response program.

2. The Commission should require that the type of customer and approximate number of customers marketed to in the Competing Provider's program should be similar to the Competing Utility program's customer type and approximate number of ~~**unbundled**~~ customers **served by the Competing Provider** to which the Competing Utility markets.

6. The Commission should require a similar program to ~~**demonstrate**~~ **validate** that it will not use a ~~**prohibited**~~ resource **it prohibits** to enable load shed during demand response events.

Proposed Modifications to Ordering Paragraphs

2. A Community Choice Aggregator or Direct Access Provider's (Competing Provider) demand response program is considered similar to a program provided by an investor-owned utility in the overlapping service area (Competing Utility's program) if the Competing Provider's program meets all of the following requirements:

   - is offered to the same type **of customer (e.g., residential customer)** and **marketed to the** approximate number of customers **served by the Competing Provider to which the utility markets for its competing program**~~**, e.g., residential customer**~~;

- is classified as and can be demonstrated to be the same resource, either a load modifying or supply resource, as defined by the Commission;
- can validate that customers are not receiving load shedding incentives for the use of ~~**prohibited**~~ resources **prohibited by the Competing Provider** during demand response events; and
- allows the participation of third-party demand response providers or aggregators, if the Competing Utility's program also allows such third-party participation.

3. Within 30 days of the date a Community Choice Aggregator or Direct Access Provider's demand response program is deemed similar by the Commission, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall serve, to parties in Rulemaking 13-09-011, a proposed method for determining the bill credit to ~~**reimburse**~~ **end cost recovery from** unbundled customers no longer eligible to participate in the similar demand response program.

4. Within 30 days after serving a proposed method for determining the bill credit to ~~**reimburse**~~ **end cost recovery from** unbundled customers, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall facilitate a workshop to ~~**to**~~ discuss the proposed method and develop a consensus proposal. All parties and other interested persons are advised to participate because the final method will be used by the utilities for all future credits for similar demand response programs.