Clean Energy Alliance
JOINT POWERS AUTHORITY

AGENDA

Board of Directors Meeting Agenda
October 15, 2020, 2 p.m.
City of Del Mar | Virtual Meeting

Per State of California Executive Order N-29-20, and in interest of public health and safety, we are temporarily taking actions to prevent and mitigate the effects of the COVID-19 pandemic by holding Clean Energy Alliance Joint Powers Authority meetings electronically or by teleconferencing. All public meetings will comply with public noticing requirements in the Brown Act and will be made accessible electronically to all members of the public seeking to observe and address the Clean Energy Alliance Joint Powers Authority Board of Directors.

Members of the public can watch the meeting live on the City of Del Mar's website at: http://delmar.12milesout.com/Video/Live.

You can participate in the meeting by e-mailing your comments to the Secretary at secretary@thecleanenergyalliance.org 1 hour prior to commencement of the meeting. If you desire to have your comment read into the record at the meeting, please indicate so in the first line of your e-mail and limit your e-mail to 500 words or less. These procedures shall remain in place during the period in which state or local health officials have imposed or recommended social distancing measures.

CALL TO ORDER

ROLL CALL

FLAG SALUTE

BOARD COMMENTS & ANNOUNCEMENTS

PRESENTATIONS

PUBLIC COMMENT

APPROVAL OF MINUTES:
Minutes of the Regular Meeting held September 17, 2020.

__Consent Calendar__

Item 1: **Clean Energy Alliance Treasurer's Report**

__RECOMMENDATION__
Receive and File Clean Energy Alliance Interim Treasurer's Report.

Item 2: **Clean Energy Alliance Interim Chief Executive Officer Operational, Administrative and Regulatory Affairs Update**

__RECOMMENDATION__
1) Receive and file Community Choice Aggregation Update Report from Interim CEO.
2) Receive and file Community Choice Aggregation Regulatory Affairs Report from Special Counsel.

Item 3: **Resolution Adopting Clean Energy Alliance Records Retention Schedule**

__RECOMMENDATION__
Approve Resolution Adopting Clean Energy Alliance Records Retention Schedule.

__New Business__

Item 4: **Clean Energy Alliance Draft Energy Risk Management Policy**

__RECOMMENDATION__
Receive presentation and provide input into the Clean Energy Alliance Energy Risk Management Policy.

Item 5: **Clean Energy Alliance Branding Update and Logo Options**

__RECOMMENDATION__
Receive Clean Energy Alliance branding update and select preferred logo option.

Item 6: **Clean Energy Alliance Approval of Community Advisory Committee Nominees, Work Plan and Meeting Schedule**

__RECOMMENDATION__
1) Approve Clean Energy Alliance Community Advisory Committee Nominees for City of Carlsbad.
2) Approve Clean Energy Alliance Community Advisory Committee Nominees for City of Del Mar.

3) Approve Clean Energy Alliance Community Advisory Committee Nominees for City of Solana Beach
4) Approve Clean Energy Alliance Alternate Board Member to serve on Community Advisory Committee.
5) Approve Clean Energy Alliance Community Advisory Committee Meeting Schedule and Work Plan

Item 7: **Clean Energy Alliance Bid Evaluation Criteria Policy**

RECOMMENDATION
Approve Clean Energy Alliance Bid Evaluation Criteria Policy.

Item 8: **Clean Energy Alliance Implementation Phasing Update**

RECOMMENDATION
Authorize Interim Chief Executive Officer to execute letter agreement with San Diego Gas & Electric (SDG&E) memorializing the amended Clean Energy Alliance Implementation Schedule to accommodate the delay in SDG&E's billing system replacement project, subject to General Counsel approval.

BOARD MEMBER REQUESTS FOR FUTURE AGENDA ITEMS

ADJOURN

NEXT MEETING: November 19, 2020, 2 p.m., hosted by City of Solana Beach (Virtual Meeting)

Reasonable Accommodations
Persons with a disability may request an agenda packet in appropriate alternative formats as require by the Americans with Disabilities Act of 1990. Reasonable accommodations and auxiliary aids will be provided to effectively allow participation in the meeting. Please contact the Carlsbad City Clerk's Office at 760-434-2808 (voice), 711 (free relay service for TTY users), 760-720-9461 (fax) or clerk@carlsbadca.gov by noon on the Monday before the Board meeting to make arrangements.

Written Comments
To submit written comments to the Board, please contact the Carlsbad City Clerk's office at secretary@thecleanenergyalliance.org. *Written materials related to the agenda that are received by 5:00 p.m. on the day before the meeting will be distributed to the Board in advance of the meeting and posted on the Authority webpage. To review these materials during the meeting, please contact the Board Secretary.*

Clean Energy Alliance - Board of Directors
Meeting Minutes
August 20, 2020, 2:00 p.m.
City of Solana Beach | City Hall
635 S. Highway 101 | Solana Beach, CA 92075
Teleconference Locations per State of California Executive Order N-29-20.

CALL TO ORDER: 2:00 p.m.

ROLL CALL: Haviland, Becker, Schumacher

FLAG SALUTE:
Board Member Becker led the Pledge of Allegiance.

BOARD COMMENTS & ANNOUNCEMENTS: None

APPROVAL OF MINUTES: None

Consent Calendar

Item 1: **Clean Energy Alliance Treasurer's Report**

RECOMMENDATION
Receive and File Clean Energy Alliance Treasurer's Report.

Motion by Board Member Schumacher, seconded by Vice Chair Becker to approve the Consent Calendar.
Motion carried unanimously 3/0

New Business

Item 2: **Clean Energy Alliance Interim Chief Executive Officer Report & Regulatory Affairs Update**

RECOMMENDATION
1) Receive and file Clean Energy Alliance Interim Chief Executive Officer Report.
2) Receive and file Clean Energy Alliance Regulatory Affairs Update Report.

Barbara Boswell, Interim CEO (Chief Executive Officer), reviewed the report and presented a PowerPoint (on file) regarding the administrative and operational update including seeking clarification of *non-complex* by SDG&E, the results of 11 RFPs for the Communication Outreach and Stakeholder Engagement Strategy, and the recommendation of Tripepi Smith.

Rider Smith, Tripepi Smith, introduced himself and other staff who would be working with CEA.

Karen Villasenor, Tripepi Smith, mentioned other agencies they had worked with on CCA's.

Ty Tosdal, CEA regulatory Special Counsel, continued the PowerPoint (on file) reviewing regulatory developments including filing a joint protest regarding SDG&E's proposal to increase the PCIA (Public California Utilities Commission) rate increase based on SDG&E's application, methodology, amortization period, and the total amount that SDG&E is seeking to collect. He spoke about SDG&E's Energy Resource Recovery Account (ERRA) annual proceeding when the PCIA is set, the confidentiality agreement required to participate in procurement, and involving an outside firm to participate in this proceeding.

Item 3: Clean Energy Alliance Integrated Resource Plan

RECOMMENDATION

Approve Clean Energy Alliance Integrated Resource Plan.

Barbara Boswell, Interim CEO (Chief Executive Officer), presented a PowerPoint (on file).

Kirby Dusel and Brian Goldstein, Pacific Energy Advisors, continued the PowerPoint (on file) reviewing the bi-annual process administered by the California Public Utilities Commission, the two portfolio constructs to be assembled to meet the planning requirements of this process, and the planning capacity resources of renewable technologies as well as existing resources. He said that new information provided last evening regarding incremental capacity procurement and the State's expected shortfall of 3,300 megawatts of capacity, due to cooling plants coming off-line in Southern California, and that SDG&E would be providing a list of resource information to use in the IRP (Integrated Resource Planning) to relfect the resouces that SDG&E had been procuring for customers in order to meet the 3,300 minutes megawatt mandates of incremental capacity.

Boardmembers and Consultants dicussed the timeline for the IRP to be brought back, new wind resources within the State, and outreach to direct access customers.

Motion by Board Member Schumacher, seconded by Vice Chair Becker to approve a Resolution that approved the Clean Energy Alliance Intergrated Resource Plan. **Motion carried unanimously 3/0**

Item 4: Clean Energy Alliance Credit Solution Update

Barbara Boswell, Interim CEO (Chief Executive Officer), presented a PowerPoint (on file).

RECOMMENDATION

1) Authorize Interim Chief Executive Officer to execute a Promissory Note with Calpine Energy Solutions for $400,000, to provide funding for the CEA FY 20/21 budget through February 2021; and

Motion by Chair Haviland, seconded by Vice Chair Becker to approve execution of a Promissory Note with Calpine Energy Solution and authorize funding for the CEA FY 20/21 through February 2021. **Motion carried unanimously 3/0**

2) Direct the Interim Chief Executive Officer to continue to work towards a credit solution for the remaining CEA start-up funding needs and to return with options at the November 19, 2020 CEA Regular Board Meeting.

Board Members discussed potential financing reconsideration by the City of Carlsbad and the split vote due to a current 4 seat Council, the priority to resolve financial uncertainties, and creative financial solutions.

Motion by Chair Haviland, seconded by Vice Chair Becker to continue work on a credit solution for the remaining CEA startup funding needs and return with options. **Motion carried unanimously 3/0**

Item 5: Clean Energy Alliance Inclusive & Sustainable Workforce Policy

RECOMMENDATION

Review, Provide Input and Approve Clean Energy Alliance Inclusive & Sustainable Workforce Policy.

Barbara Boswell, Interim CEO (Chief Executive Officer), prestented a PowerPoint (on file).

Angela Ivey, Acting Board Secretary, read 7 comment submittals from the public (on file).

Board Member Shumacker reviwed her suggested edits.

Council, Staff, and Consultant discussed consensus edits and defining 'local' as San Diego County and any other area served by a CCA .

Board Members discussed Board Member Schumacher's suggested edits for the three sections of the Workforce Policy, CEA Owned Generation Projects, CEA Feed-In Tariff Projects, and CEA Energy Efficiency Projects, the lack of support for the Project Labor Agreement (PLA) language of many jurisdictions, the language being too restrictive at this time before the launch of the CEA, that projects were several years down the road, and that other JPAs may join at a later date.

Board Member Shumacker stated that the City of Carlsbad's August 18, 2020 Council meeting included discussion on the disagreement that all projects should be subject to the PLA requirement, that Ms. Shumacker's proposed language was in alignment with the the Carlsbad City Council's discussion, the language was intended to be supportive and inclusive of workers, and that SDG&E was a unionized body.

Motion by Board Member Shumacker, seconded by Vice Chair Becker to approve the Schumacher draft of modifications to the Clean Energy Alliance Inclusive & Sustainable Workforce Policy, excluding CEA Owned Generation Projects, CEA Feed-In Tariff Projects, and CEA Energy Efficiency Projects sections, and adding in a definition of 'localized'. **Motion carried unanimously 3/0**

Motion by Chair Haviland, seconded by Vice Chair Becker to approve the Staff recommendation of the three remaining sections of the Workforce Policy, CEA Owned Generation Projects, CEA Feed-In Tariff Projects, and CEA Energy Efficiency Projects. **Motion carried. 2/1 (Noes: Schumacher)**

Item 6: Clean Energy Alliance Community Advisory Committee Workplan

RECOMMENDATION

Review, provide input, and approve Clean Energy Alliance Community Advisory Committee (CAC) initial scope of work and desired outcomes for the Workplan.

Barbara Boswell, Interim CEO (Chief Executive Officer), presented a PowerPoint (on file).

Angela Ivey, Acting Board Secretary, read 2 comment submittals from the public (on file).

Board Members discussed outreach to hard-to-reach communities, feedback on misinformation, addressing needs in marketing materials, keeping messaging on target, and a community advisory committee.

Motion by Chair Haviland, seconded by Vice Chair Becker to approve the Clean Energy Alliance Community Advisory Committee (CAC) initial scope of work and desired outcomes for the Workplan. **Motion carried unanimously 3/0**

Item 7: **Clean Energy Alliance Award Portfolio Manager Services**

RECOMMENDATION
Authorize Interim Chief Executive Officer to execute an agreement with Pacific Energy Advisors to provide Portfolio Management Services through June 30, 2023, for an amount not to exceed $120,000 annually, subject to General Counsel approval.

Motion by Chair Haviland, seconded by Vice Chair Becker to approve an agreement with Pacific Energy Advisors for Portfolio Management Services through June 30, 2023 for an amount not to exceed $120,000. **Motion carried unanimously 3/0**

Item 8: **Clean Energy Alliance Interim Treasurer**

RECOMMENDATION
Authorize Clean Energy Alliance Interim Chief Executive Officer to execute an agreement with Marie Berkuti for Interim Treasurer Services through June 30, 2021, for an amount not to exceed $10,000, subject to General Counsel approval.

Barbara Boswell, Interim CEO (Chief Executive Officer), introduced the item and stated that the current Interim CEA Treasurer, Marie Berkuti, was retiring from the City of Solana Beach but would be available to continue under a contractual basis with the CEA.

Motion by Chair Haviland, seconded by Vice Chair Becker to approve an agreement with Marie Berkuti for Interim Treasurer Services through June 30, 2021, for an amount not to exceed $10,000. **Motion carried unanimously 3/0**

BOARD MEMBER REQUESTS FOR FUTURE AGENDA ITEMS

Board Members discussed verifying the process to add items to the agendas and identifying how an alternate would be appointed to serve on the citizen advisory committee.

ADJOURN:
Chair Haviland adjourned the meeting at 4:18 p.m.

Angela Ivey, City Clerk of Solana Beach
Interim Acting Board Secretary

Approved: ______________________

Clean Energy Alliance
JOINT POWERS AUTHORITY

Staff Report

DATE: October 15, 2020

TO: Clean Energy Alliance Board of Directors

FROM: Marie Marron Berkuti, Interim Treasurer

ITEM 1: Clean Energy Alliance Treasurer's Report

RECOMMENDATION:

Receive and File Clean Energy Alliance Interim Treasurer's Report.

BACKGROUND AND DISCUSSION:

At its June 18, 2020 board meeting, the CEA Board adopted the Fiscal Year (FY) 2020/21 budget. This report provides the Board with the following financial information through September 30, 2020:

- Budget to Actuals – Reports actual revenues and expenditures compared to the adopted budget as of September 30, 2020.
- Statement of Financial Position – Reports assets and liabilities of CEA as of September 30, 2020
- List of Payments Issued – Reports payments issued for September 30, 2020

As of September 30, 2020, liabilities represent invoices received for services, but not yet paid. The noncurrent accounts payable are amounts due to the cities of Carlsbad, Del Mar and Solana Beach for services provided to the CEA for the period November 2019 to June 2020. These invoices are scheduled to be paid once the CEA is operational.

SEPTEMBER 30, 2020 REPORTS (FY 2020/21)

BUDGET TO ACTUALS

At its August 20, 2020 board meeting, the CEA Board approved a Promissory Note with Calpine Energy Solutions for $400,000 to provide funding for the FY 2020/21 budget through February 2021. CEA is still working towards obtaining the remaining CEA start-up funding from the proposed credit solution.

Of its approved $4,006,500.00 budgeted expenditures, $150,005.63 has been expended, leaving $3,856,494.37

Clean Energy Alliance
Budget to Actuals
for the three month period ended September 30, 2020

	BUDGET	ACTUALS	VARIANCE
Revenue			
Credit Solution	$ 4,006,500.00	$ -	(4,006,500.00)
Total Revenue	4,006,500.00	-	(4,006,500.00)
Expenditures			
Staffing/Consultants	$ 120,000.00	$ 30,187.50	$ 89,812.50
Legal Services	320,000.00	40,911.10	279,088.90
Professional Services	310,000.00	78,907.03	231,092.97
Memberships & Due	15,000.00	-	15,000.00
Print/Mail Services	132,000.00		132,000.00
Advertising	10,000.00		10,000.00
Graphic Design Services	10,000.00		10,000.00
Website Maintenance	2,500.00		2,500.00
Audit Services	40,000.00		40,000.00
CCA Bond	47,000.00		47,000.00
OPERATING EXPENSES	$ 1,006,500.00	$ 150,005.63	$ 856,494.37
CAISO Deposit	$ 500,000.00	$ -	$ 500,000.00
Cash-Flow & Lockbox Reserves	2,500,000.00		2,500,000.00
NON-OPERATING EXPENSES	$ 3,000,000.00	$ -	$ 3,000,000.00
TOTAL	$ 4,006,500.00	$ 150,005.63	$ 3,856,494.37
Net Results (Revenue - Expenditures)	$ -	$ (150,005.63)	$ (7,862,994.37)

STATEMENT OF FINANCIAL POSITION

CEA's Statement of Financial Position reports the assets and liabilities as of September 30, 2020.

Clean Energy Alliance
Statement of Financial Position
As of September 30, 2020

Assets		
River City Bank - Operating Account	$ 47,438.73	
Total Assets		$ 47,438.73
Liabilities		
Accounts Payable		
Current	$ 72,111.28	
Noncurrent	54,645.96	
Total Liabilities		$ 126,757.24
Reserve for Future Expenditures		$ (79,318.51)

LISTING OF PAYMENTS

The report below provides the detail of payments issued by CEA for September 2020. All payments were within approved budget.

09/04/20	ACH	RWG Law	July 2020 General Counsel Svcs	$ 13,467.00
09/04/20	ACH	Hall Energy	Aug 2020 Energy Procurement Counsel Svcs	833.00
09/04/20	ACH	Pacific Energy Advisors	Aug 2020 Technical Consulting Svcs	16,302.25
09/17/20	ACH	Tosdal APC	July 2020 Regulatory Counsel Svcs	8,786.00
09/17/20	ACH	Tosdal APC	Aug 2020 Regulatory Counsel Svcs	7,537.10
09/17/20	ACH	Keyes & Fox	Aug 2020 ERRA Forecast	4,503.50
			Total September Payments	$ 51,428.85

FISCAL IMPACT

There is no fiscal impact associated with this item.

Clean Energy Alliance
JOINT POWERS AUTHORITY

Staff Report

DATE: October 15, 2020

TO: Clean Energy Alliance Board of Directors

FROM: Barbara Boswell, Interim Chief Executive Officer

ITEM 2: Clean Energy Alliance Operational, Administrative and Regulatory Affairs Update

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RECOMMENDATION:

1) Receive and File Community Choice Aggregation Update Report from Interim CEO.
2) Receive Community Choice Aggregation Regulatory Affairs Report from Special Counsel.

BACKGROUND AND DISCUSSION:

This report provides an update to the Clean Energy Alliance (CEA) Board regarding the status of the operational, administrative and regulatory affairs activities.

OPERATIONAL UPDATE

CEA is meeting its milestones for the implementation of its community choice aggregation (CCA) program and is on track to begin serving customers in May 2021/June 2021. (Attachment A - Clean Energy Alliance Timeline of Implementation Action Items).

CEA Launch Schedule

San Diego Gas & Electric (SDG&E) has been working over the past several years on their Customer Information System replacement program, known as Envision. They had committed to, and were on track, for a January 4, 2021 go live, despite the challenges of working remote in the COVID-19 environment. With a January 2021 go live, SDG&E committed to supporting the CEA launch of May 2021. On Friday July 10, CEA staff, its regulatory attorney Ty Tosdal and data manager Calpine Energy Solutions participated in a call with San Diego Community Power and SDG&E regarding the recently approved California Public Utilities Commission (CPUC) Decision D. 20-06-003, which requires the Investor Owned Utilities (IOU) to adopt rules and policy changes designed to reduce the number of residential disconnections, provide assistance with debt forgiveness and offer extended payment plans. The decision is required to be implemented by the IOUs April 2021. This timing has presented a challenge to SDG&E to keep its go live date of January 4, 2021 while also meeting the requirements of the decision. SDG&E submitted a letter to the CPUC requesting an extension to September 30, 2021, for implementing the new procedures and policies required by the decision. This request was denied by the CPUC, resulting in SDG&E postponing implementation of its Envision project to April 2021.

CEA and its consultants have been working diligently with SDG&E to develop a launch schedule that minimized impact to CEA while also minimizing the risk of incorrect bills being sent to customers. SDG&E has proposed a two-phased schedule with accounts transitioning to CEA in May and June 2021. May 2021 Phase 1 would include the transition of Solana Energy Alliance customers to CEA as well as customers who do not have complex billing plans in Carlsbad and Del Mar. Those customers who have been identified with complex billing plans would transition in June 2021. CEA is working with its consultants, Pacific Energy Advisors and Calpine Energy Solutions to evaluate the impact of this two-phased approach from an operational and financial perspective. Preliminary analysis indicates that the proposed phasing does not have a material impact from a financial perspective. Staff continues to work with Calpine and SDG&E to fine tune the customer list for each phase.

Staff anticipates providing the Board with an updated pro forma reflecting this new phased approach, as well as updated rates related to the SDG&E ERRA Rate Proceeding at the November Board meeting.

The CEA Board is being asked to authorize the Interim Chief Executive Officer to execute a letter agreement with SDG&E for the two-phased implementation at today's meeting.

Expansion of Clean Energy Alliance
Staff has no update regarding CEA expansion.

Resource Adequacy Compliance
As a load serving entity, serving customers in 2021, CEA has an obligation to procure Resource Adequacy (RA), based on quantities allocated by CPUC and California Independent System Operator (CAISO). RA procurements does not supply any energy to CEA or its customers, rather it commits the seller to be available to supply energy to the grid if called upon by the CAISO and reduce the possibility of outages. This process is key to ensuring grid reliability. The RA compliance requirements, CEA has monthly and annual reporting requirements. Upcoming reporting requirements are:

- Year-Ahead Compliance Demonstration – October 31, 2020
    - Must demonstrate CEA has entered into contracts to meet CPUC requirements
- Monthly RA Compliance Reports begin in November 2020 (for January 2021 requirements)

CEA has been working diligently towards meeting CEA's Resource Adequacy procurement requirements that must be reported by October 31, 2020 and expects to be compliant with requirements.

Long-Term Renewable Procurement
As a load serving entity, CEA will be required to procure 65% of its minimum state required renewable portfolio standards in contracts of 10-years or longer. To ensure compliance with this requirement, CEA's initial renewable energy solicitation is underway. The solicitation process, from beginning through final execution can be lengthy, particularly in light of the impacts of COVID-19 on the renewable development industry. The solicitation opened on July 1, 2020 with proposals due July 27, 2020. CEA's consultant, Pacific Energy Advisors, has identified a short list of projects and negotiations are proceeding. It is anticipated final contracts will be before the Board in late 2020/early 2021.

Administrative and Operational Policies
During the coming months as CEA prepares for its implementation and operation, policies will be brought to the Board for consideration in future Board meetings. The policies as proposed will be based on Government Code or regulatory requirements and best practices of successfully operational CCAs.

The policies and timeline as currently anticipated are:

November 19 Board Meeting

- Energy Risk Management Policy Approval
- January 21 Board Meeting
- Investment Policy

Contracts $50,000 - $100,000 entered into by Interim Chief Executive Officer

VENDOR	DESCRIPTION	AMOUNT
None to report		

REGULATORY UPDATE

San Diego Gas & Electric Advice Letter 3605-E Requesting Approval of System Reliability Contracts

CEA filed a protest of the San Diego Gas & Electric Advice Letter 3605-E, Requesting Approval of System Reliability Contracts. The basis of the protest was related to SDG&E's procurement of long-term resources without taking into account the departing load related to CEA's implementation. CEA's customers would carry the burden of the costs of these long-term contracts. The protest is consistent with the adopted 2020 CEA Legislative and Regulatory Policy Platform that established that CEA would support regulatory actions that jeopardize CEA's ability to self-procure. The necessity to submit the protest came up after the last CEA Board meeting and prior to the October meeting. The filing of the protest was completed in consultation with the CEA Board Chair.

San Diego Gas & Electric Advice Letter 3257-E, Regarding CCA Financial Security Requirement

At its October 8, 2020 meeting, the CPUC adopted its Resolution 5059, approving SDG&E's Advice Letter (AL) 3257-E regarding the CCA Financial Security Requirement. Currently, CCAs were required to post a $100,000 "bond" (in CEA's case a cash deposit) to provide funds to cover SDG&E costs should CEA have an unplanned termination of service and return to customers to SDG&E service. SDG&E's AL 3257-E implements new rules concerning the deposits, which, among other things, establishes a minimum amount of $147,000, and provides the ability to satisfy the requirement with the option of a letter of credit, surety bond, or cash deposit held in escrow by a third party commercial bank. CEA will be required to fulfill the new requirements by December 7, 2020, and file an Advice Letter with the CPUC confirming that it has satisfied the requirement. Staff has begun working on options to determine the best course of action, and will provide a recommendation to the Board at its November Board meeting.

Attached is a regulatory report from Ty Tosdal, Special Counsel, providing a summary of key regulatory proceedings (Attachment B - Tosdal APC Energy Regulatory Update).

FISCAL IMPACT
There is no fiscal impact by this action.

ATTACHMENTS:
Attachment A - Clean Energy Alliance Timeline of Implementation Action Items
Attachment B – Tosdal APC Regulatory Update

Attachment A

Clean Energy Alliance
Timeline of Action Items
CCA Program Related

Timing	Description	3rd Qtr '20	4th Qtr '20	1st Qtr '21	Apr-21	May-21	Jun-21	Jul-21
9/1/20	Marketing/Customer Outreach Plan Development & Kickoff							
9/17/20	Bid Evaluation and Criteria Scoring System							
9/17/20	Award Scheduling Coordinator Services	Complete						
	Introduce/Adopt Energy Risk Management Policy		10/15 & 11/19					
10/15/20	Records Retention Policy							
	System Testing with SDG&E							
	Set up Call Center/Scripting/IVR Recordings							
11/19/20	Credit Solution							
12/17/20	CEA Default Products/programs/renewable energy policies							
1/1/21	Create Customer Pre- and Post-Enrollment Notices							
1/21/21	Investment Policy							
2/1/21	Rate Setting							
3/1/21	Customer Noticing							
5/1/21	Launch - 2 phases May & June 2021							

Key:

Board Actions/Activity
Staff/Consultant Activity
Marketing/Customer Outreach
CCA Launch

TOSDAL ENERGY & ENVIRONMENTAL LAW

ENERGY REGULATORY UPDATE

To: Barbara Boswell, Interim Executive Officer, Clean Energy Alliance

From: Ty Tosdal, Regulatory Counsel, Tosdal APC

Re: Energy Regulatory Update

Date: October 8, 2020

The energy regulatory update summarizes important decisions, orders, notices and other developments that have occurred at the California Public Utilities Commission ("Commission") and that may affect Clean Energy Alliance ("CEA"). The summary presented here describes high priority developments and is not an exhaustive list of the regulatory proceedings that are currently being monitored or the subject of active engagement by CEA. In addition to the proceedings discussed below, Tosdal APC monitors a number of other regulatory proceedings as well as related activity by San Diego Gas & Electric ("SDG&E") and other Investor-Owned Utilities ("IOUs").

1. SDG&E PCIA Trigger Application (A. 20-07-009)

SDG&E filed with the CPUC an update to their PCIA undercollection balancing account (CAPBA) as directed by a September 18, 2020 ALJ Ruling. SDG&E's CAPBA update is in Attachment A of this report. SDG&E states that nothing has occurred since their filing of the PCIA Trigger Application in July that would necessitate a change in the CAPBA balance amount. The PABA is a rolling true-up between the forecasted components of the Indifference Amount used to set the PCIA rates and the actual costs and revenues SDG&E experiences during the year.

As SDG&E explained at the August 27 prehearing conference, amortizing the recovery of the CAPBA undercollection from departing load customers for a period extending beyond 2020 creates logistical issues with respect to tracking, accounting and reimbursement that are unique to SDG&E. These "logistical issues" refer to the administrative difficulties that will occur due to CEA and SDCP launching service in early 2021 (with SDCP initiating service in several phases), as well as the re-opening of Direct Access (DA) in January of 2021. The combination of the large number of departing accounts and the unpredictability of how many customers will depart at various times throughout 2021, along with the fact that these load departures will take place after rates have been implemented on January 1, increases SDG&E's accounting complexities.

In order to accurately track, account for and issue reimbursements for the CAPBA balance, SDG&E would need to have a system that tracks the CAPBA balance at the individual customer level. However, SDG&E does not have CAPBA balances recorded at a customer level; it only records CAPBA balances by vintage. SDG&E states they may be able to accommodate an amortization period that extends beyond 2020 provided that bundled customers who depart during the amortization period agree to forfeit the remainder of their CAPBA refund.

2. SDG&E ERRA Forecast Proceeding (A. 20-04-014)

CEA and SDPC's counsel submitted to the CPUC a joint Opening Brief on September 25, 2020 which makes several requests of SDG&E. The Opening Brief is in Attachment A. First, the brief asks the Commission to require SDG&E to provide a greater level of transparency through substantially more detailed information regarding actual and forecasted PABA balances, and the background information and testimony that make up the components of the PABA calculations.

Second, the CCAs request that SDG&E correct an erroneous calculation of its Total Indifference Amount. SDG&E has already acknowledged this approximate $84.5 million mistake and has committed to correcting it prior to the November 2021 PABA revenue requirement forecast. If this calculation had been done correctly, following Commission guidance to include RA and RPS sales revenue as an offset to CRS Eligible Portfolio Costs, then SDG&E's forecasted Indifference Amount would decrease by $49.2 million for RA sales and $35.3 million for RPS sales, for a total reduction of $84.5 million.

Third, SDG&E's proposal to calculate the PCIA rate cap based on rates approved in the CAPBA Trigger application would undercut the Commission's clear policy preference to avoid rate shock for unbundled customers. If cap methodology is approved, it would result in capped rates that are more than three times what the capped rate would otherwise be. The CCAs ask that SDG&E rate cap methodology proposal is rejected.

Lastly, the CCAs request that the Commission conduct further review and clarification of SDG&E's Green Tariff Shared Renewables (GTSR) program, which is in direct competition with CCAs. Further review is needed because SDG&E has provided little to no information on the justification for its GTSR rate forecasts and customer consumption estimates. More detail on GTSP rates must be provided in this and future ERRA proceedings.

SDG&E's cooperation and transparency will be necessary to ensure that intervenors in this proceeding have adequate time to analyze the data and to ensure that the PABA balance SDG&E presents in the November Update is accurate and based on reasonable assumptions.

3. Direct Access Expansion (R. 19-03-009)

Phase 1 of the expansion (or "re-opening") of non-residential Direct Access (DA) will begin on January 1, 2021 with an additional 4,000 GWh opening up for DA providers, per the requirement of SB 237. On September 28, 2020 the CPUC Energy Division released a "Staff Report Providing Recommendations on the Schedule to Reopen Direct Access" (Staff Report) to inform the Legislature on issues concerning the *additional* expansion of the DA program (Phase 2). The Staff Report is in Attachment A.

The Staff Report makes multiple recommendations regarding pre-requisites to any further expansion of DA. Most notably, the report recommends that Direct Access NOT be reopened until at least 2024, after the next IRP Compliance Period.

Ongoing lack of transparency and poor compliance by a number of DA providers (Energy Service Providers) creates load uncertainly for both CCAs and IOUs. The report calls out the numerous compliance citations, penalties and reporting shortcomings of these ESPs and how the lack of transparency is detrimental to the planning and procurement activities of CCAs. Additionally, because most ESPs procure the minimum amount of mandated renewable energy, (as opposed to CCAs and IOUs that consistently exceed minimum RPS requirements) the expansion of DA may have a negative effect on state-wide criteria air pollutant and GHG reduction goals. The Staff Report calls for DA providers' compliance with IRP, RA and RPS requirements prior to any further expansion of the program.

Reopening DA would allow nearly two-thirds of existing non-residential load, including load that has recently migrated to CCA service, to freely migrate between IOU, ESP and CCA service. The report cites The Customer Choice Project, which found that a central procurement entity that procures on behalf of all load-serving entities may resolve some of the procurement challenges caused load migration, since central procurement would be indifferent to which load-serving entity is serving load. In addition, the Staff Report includes a recommendation of setting an initial re-opening schedule in increments equal to 10 percent of eligible non-residential load per year.

4. **Integrated Resources Planning (R. 20-05-003)**

CEA and SDCP submitted a Joint Protest (in Attachment A) to SDG&E's Advice Letter 3605-E on October 1, 2020. The protest is centered on SDG&E request to procure expensive, long-term energy contracts despite knowing that 60% of their load will migrate to CCAs and DA by 2022. This overprocurement will lead to increased non-bypassable charges for CCA customers. The protest asks that the procurement requests be denied, or at the very least, CCAs be permitted to purchase SDG&E's excess procurement.

5. **Disconnections and Reconnections (R. 18-07-005)**

The Joint IOUs submitted Advice Letter 3602-E in accordance with D. 20-06-003, the decision implementing the Arrearage Management Plan program (AMP). CalCCA filed a protest of AL 3602-E asking for clarification from the IOUs on (1) SDG&E's intent to render payments to CCAs forgiven amounts (2) the frequency of AMP data reporting to CCAs (3) when SDG&E will automate the AMP program. CalCCA's protest is in Attachment A.

Attachment A

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Expedited Application of San Diego Gas & Electric Company (U 902 E) Under the Power Charge Indifference Adjustment Account Trigger Mechanism.	Application 20-07-009 (Filed on July 10, 2020)

SAN DIEGO GAS & ELECTRIC COMPANY'S (U 902-E) UPDATE ON CAPBA BALANCE AND REPORT RE ACCOUNTING AND BILLING SYSTEM PURSUANT TO ALJ'S SEPTEMBER 18, 2020 RULING

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October 1, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Expedited Application of San Diego Gas & Electric Company (U 902 E) Under the Power Charge Indifference Adjustment Account Trigger Mechanism.	Application 20-07-009 (Filed on July 10, 2020)

SAN DIEGO GAS & ELECTRIC COMPANY'S (U 902-E) UPDATE ON CAPBA BALANCE AND REPORT RE ACCOUNTING AND BILLING SYSTEMS PURSUANT TO ALJ'S SEPTEMBER 18, 2020 RULING

I. INTRODUCTION

Pursuant to the September 18, 2020 email ruling issued by the Administrative Law Judge ("ALJ") in the above-captioned proceeding ("Ruling"), San Diego Gas & Electric Company ("SDG&E") hereby submits this report providing an update on its Power Charge Indifference Adjustment ("PCIA") undercollection balancing account ("CAPBA") balance, with the latest amount, including an explanation of any events that may have impacted that balance. In addition, as required by the ALJ's Ruling, SDG&E is also providing a more detailed explanation of "the limitations of its accounting and billing systems and how those limitations prevent it from collecting revenue in Calendar Year 2021 in order to bring the undercollection under seven percent."

II. UPDATED CAPBA BALANCE

Table 1 below shows SDG&E's recorded CAPBA data for January 2020 through August 2020 and presents, for illustrative purposes, its current forecast of the CAPBA balance for September 2020 through December 2020.

TABLE 1: CAPBA BALANCES

($ in Millions) CAPBA Monthly Summary	Beginning Balance	Exceeding Cap for DL (Including Interest)	Ending Balance	Calculated Trigger Percentage
ACTUAL January 31, 2020	$0.000	$0.000	$0.000	0.0%
ACTUAL February 29, 2020	$0.000	$0.752	$0.752	2.7%
ACTUAL March 31, 2020	$0.752	$0.737	$1.489	5.3%
ACTUAL April 30, 2020	$1.489	$0.728	$2.218	7.9%
ACTUAL May 31, 2020	$2.218	$0.741	$2.959	10.6%
ACTUAL June 30, 2020	$2.959	$0.782	$3.741	13.4%
ACTUAL July 31, 2020	$3.741	$0.867	$4.608	16.5%
ACTUAL August 31, 2020	$4.608	$0.883	$5.491	19.6%
FORECAST September 30, 2020	$5.491	$0.970	$6.461	23.1%
FORECAST October 31, 2020	$6.461	$0.866	$7.327	26.2%
FORECAST November 30, 2020	$7.327	$0.792	$8.120	29.0%
FORECAST December 31, 2020	$8.120	$0.801	$8.922	31.9%

As presented in Table 1, SDG&E's CAPBA balance through August 31, 2020 is undercollected by $5.49 million, or 19.61%.[1] Based on its forecasts and assumptions, SDG&E still expects the CAPBA undercollection to reach $8.92 million (or 32% of forecasted PCIA revenues of $28 million) by December 31, 2020.

Since the filing of the PCIA Trigger Application in July, there have been no particular events that have impacted or affected the CAPBA balance. This is because SDG&E records monthly departed load under-collections to CAPBA based on forecasted authorized departed load Portfolio Allocation Balancing Account ("PABA") revenues that are above the PCIA rate cap using electric seasonality factors. Since neither the forecasted authorized departed load

[1] SDG&E'S CAPBA balance for the period ending September 30, 2020 will not be available until approximately October 12, 2020 when SDG&E closes its September books.

PABA revenues that is above the PCIA rate cap or the electric seasonality factors have changed, there has been no material impact to SDG&E's forecast. Rather, for the most part, the CAPBA balance has continued to increase as SDG&E's forecasted it would. The only immaterial difference is in actual interest rates and forecasted interest rates.

III. SDG&E'S ACCOUNTING AND BILLING SYSTEMS

As SDG&E explained at the August 27 prehearing conference, amortizing the recovery of the CAPBA undercollection from Departing Load customers[2] for a period extending beyond Calendar Year 2020 creates logistical issues with respect to tracking, accounting and reimbursement that are unique to SDG&E. To understand why that is, it is helpful to first explain the events that are expected to occur in Calendar Year 2021 with respect to new Departing Load customers in SDG&E's service territory.

First, Direct Access ("DA") opens up in SDG&E's service territory on January 1, 2021 pursuant to D.19-05-043, which predetermined the number of non-residential megawatts ("MW") that will be departing from bundled service. However, it is unlikely that all of these DA customers will depart at the same time in 2021. Rather, their departures will likely occur on a rolling or staggered basis. Second, San Diego Community Power ("SDCP") is expected to depart a portion of their customers from bundled service throughout 2021.[3] Finally, Clean

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2 Departing Load customers include Direct Access, Community Choice Aggregation (CCA) and Green Tariff Shared Renewables (GTSR) customers. The CCA that is currently established in SDG&E's service territory is Solana Energy Alliance.

3 San Diego Community Power *Community Choice Aggregation Implementation Plan and Statement of Intent* at p.17.

Energy Alliance ("CEA") is expected to depart all customer classes from bundled service throughout 2021.[4]

What this means is that a significant number of bundled load customers will be departing in staggered phases throughout 2021[5] – which of course would occur during any extended amortization period. When bundled customers begin to depart, they would necessarily stop receiving the refund for the CAPBA undercollection through commodity rates and would start paying the PCIA rate.[6] It is the fact that these multiple departures are occurring *after* rates will have been implemented on January 1 that creates the logistical issues with respect to tracking, accounting and reimbursement. Moreover, SDG&E cannot change PCIA rates in the middle of the year because PCIA rates are established in the Energy Resource Recovery Account ("ERRA") Forecast (or CAPBA trigger) proceedings.

A. Accounting & Billing System "Limitations"

In order to accurately track, account for and issue reimbursements for the CAPBA balance, SDG&E would need to have a system that tracks the CAPBA balance at the individual customer level. However, SDG&E does not have CAPBA balances recorded at a customer level; it only records CAPBA balances by vintage. Furthermore, SDG&E does not develop rates at the customer level; rather rates are developed at either the class and vintage level (as is the case for PCIA rates) or at the rate schedule level (as is the case for commodity rates). These system

[4] Clean Energy Alliance *Community Choice Aggregation Implementation Plan and Statement of Intent* at p. 4.

[5] SDG&E estimates this to be about half a million customers.

[6] There is also a possibility that certain individual departing load customers return back to bundled service, which further complicates issues.

constraints make it nearly impossible to track, account for, and reimburse the CAPBA credits and refunds at a customer level.

Moreover, tracking the individual customers who depart (or return) in Calendar Year 2021 during the extended amortization period and adjusting who gets a credit, who gets a refund, how much, *etc.* is extremely difficult and ultimately unsupported by SDG&E's legacy billing system or its new billing system (Envision), which is expected to go live in 2021. From a logistical perspective, SDG&E's billing system is not able to handle this as it would require tracking this movement on an individual customer level (which SDG&E estimates to be about half a million customers). Moreover, SDG&E's legacy billing system, and its new Envision billing project, can only support one PCIA rate per vintage and per customer class, and one bundled commodity rate for the applicable rate schedule. For example, SDG&E's billing system cannot include separate PCIA rates for CAPBA versus PCIA rates resulting from its ERRA Forecast Application. Rather, CAPBA's PCIA rates need to be additive to the ERRA Forecast Application's PCIA rates in order to determine the total PCIA rate by vintage and by customer class.

B. SDG&E's Proposed Solution

SDG&E understands and appreciates the Commission's efforts to find a solution that would allow bundled customers to recover the CAPBA undercollection in Calendar Year 2021. To that end, SDG&E may be able to accommodate an amortization period that extends beyond Calendar Year 2020 *provided that* bundled customers who depart during the amortization period agree to forfeit the remainder of their CAPBA refund. Given the amount of the refund, SDG&E does not expect that the amount forfeited would be significant at an individual customer level. For example, as stated in SDG&E's application, under a 3 month amortization schedule a typical non-California Alternative Rates for Energy ("CARE") residential bundled customer in the inland climate zone using 400 kilowatt hours ("kWh") is estimated to receive a monthly refund of roughly $0.94 per month from the CAPBA Trigger refund.[7]

SDG&E has considered whether it is possible to establish a credit for the amount to be forfeited. However, SDG&E is not able to establish a credit for the amount forfeited because there is no way SDG&E would be able to transfer any of the CAPBA undercollection refund to the 2020 or 2021 PCIA vintages to account for the numerous and staggering departure dates for Departing Load customers (as described above). This is because the 2021 vintage does not exist today, as it is established in the 2021 ERRA Forecast Application, and the number of 2020 or 2021 departing load vintage customers is not known and/or finalized. SDCP's implementation plan would enroll customers in phases throughout 2021 — and even then, after service cutover, customers will have approximately 60 days (two billing cycles) to opt-out of SDCP without penalty and return to SDG&E bundled service.[8] Similarly, CEA will start enrollment in May 2021, but customers will have multiple opportunities to opt out and choose to remain full requirement ("bundled") customers of SDG&E, in which case they will not be enrolled.[9] In addition, DA customers may not all depart at the same time in 2021. As discussed above, SDG&E cannot change PCIA rates in the middle of the year because PCIA rates are established in the ERRA Forecast (or CAPBA trigger) proceedings.

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[7] Under any extended amortization period beyond 3 months (*e.g.*, a 12-month amortization schedule), the monthly refund bundled customers would receive would necessarily decrease. Actual savings would vary due to actual kWh usage by a customer and potential TOU pricing for the customer's applicable commodity rate schedule.

[8] San Diego Community Power *Community Choice Aggregation Implementation Plan and Statement of Intent* at p. 5.

[9] Clean Energy Alliance *Community Choice Aggregation Implementation Plan and Statement of Intent* at p. 4.

IV. CONCLUSION

SDG&E looks forward to working with the Commission and other parties to move this proceeding towards resolution.

Respectfully submitted,

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

Application of SAN DIEGO GAS & ELECTRIC COMPANY (U902E) for Approval of its 2021 Electric Procurement Revenue Requirement Forecasts and GHG Related Forecasts	Application 20-04-014

OPENING BRIEF OF SAN DIEGO COMMUNITY POWER AND CLEAN ENERGY ALLIANCE

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September 25, 2020

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OPENING BRIEF OF SAN DIEGO COMMUNITY POWER
AND CLEAN ENERGY ALLIANCE

Pursuant to Rule 13.11 of the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") and the July 6, 2020 Scoping Memo and Ruling setting the schedule for this proceeding, San Diego Community Power ("SDCP") and Clean Energy Alliance ("CEA"), hereby submit this Opening Brief regarding San Diego Gas and Electric Company's ("SDG&E") *Application for Approval of its 2021 Electric Procurement Revenue Requirement Forecasts and GHG Related Forecasts*, submitted on April 15, 2020 ("Application"). This Opening Brief adheres to the common briefing outline requested by assigned Administrative Law Judge Wercinski and agreed upon by all parties; however, SDCP and CEA have omitted references to scoping ruling issues outside the scope of SDCP and CEA comments.

I. INTRODUCTION

The Commission cannot approve SDG&E's Application as requested because, in its present form, SDG&E's presentation relies on inaccurate and inadequate evidence and calculations in support of its requested ERRA forecasts. Further, approval of certain of SDG&E's Portfolio Charge Indifference Amount ("PCIA") components would result in impermissible cost-shifting from bundled to unbundled customers, contrary to California law and Commission precedent.[1] Specifically, SDG&E's proposed changes to key components related to its PCIA rates, underlying PCIA-eligible costs, and the Portfolio Allocation Balancing Account ("PABA") would result in impermissibly high rates, including for those customers that will receive service from SDCP and CEA in 2021. Lastly, SDG&E's Application includes requests for approval of its proposed 2021 vintaged PCIA rates and proposed rate components for the Green Tariff Shared Renewables ("GTSR") program, a program that directly competes with CCA programs.

As explained below, SDG&E's Application cannot be approved as proposed; instead, the Commission should order the following:

- SDG&E must correct its erroneous calculation of its Total Indifference Amount;
- SDG&E must provide significantly more detail in this docket, and future ERRA Forecast applications, regarding its actual PABA balances, forecasted PABA Balances and SDG&E's underlying volumetric data to improve transparency and accuracy;
- Reject SDG&E's proposal to abandon the PCIA rate cap; and
- Conduct a further review and clarification of SDG&E's GTSR program.

II. LEGAL STANDARD

SDG&E, as the applicant, bears the burden of affirmatively establishing the reasonableness of all aspects of its application,[2] and that burden of proof generally is measured

[1] *See, e.g.*, Pub. Util. Code §§ 366.2(f)(2), (g); Rulemaking ("R.") 17-06-026, *Decision Modifying the Power Charge Indifference Adjustment Methodology*, p. 6 (October 19, 2018) ("D.18-10-019"); R.17-06-026, *Decision Refining the Method to Develop and True Up Market Price Benchmarks* (October 17, 2019) ("D.19-10-001"); Application ("A.") 12-01-008 et al, *Approving Green Tariff Shared Renewables Program for San Diego Gas & Electric Company, Pacific Gas and Electric Company, and Southern California Edison Company Pursuant to Senate Bill 43* (February 2, 2015) ("D.15-01-051").

based upon a preponderance of the evidence.[3] As further explained below, SDG&E fails to meet this standard because components of its Application are neither just nor reasonable, consistent with the law, or compliant with the rules and regulations set forth by the Commission.

III. BACKGROUND

Community Choice Aggregation ("CCA") customers receive generation services from their local CCA but receive transmission, distribution, billing, and other services from the incumbent for-profit utility—here, SDG&E. CCA rates vary and are partially influenced by local mandates to procure and maintain clean electricity portfolios that often exceed state requirements for renewable and greenhouse gas-free generation. CCA and other unbundled customers are also subject to several non-bypassable charges ("NBCs"), including the PCIA, the 2021 level of which will be determined in this proceeding, and which is also subject to $0.005 cap.

The Commission adopted the PCIA to ensure that when investor-owned utility ("IOU") customers depart from bundled service and opt into receiving certain electric services from a non-IOU provider, such as SDCP or CEA, those customers nevertheless remain responsible for costs that IOUs previously incurred for those customers—but only those costs.[4] To calculate the PCIA, the IOU must establish its "Total Indifference Amount," which is updated annually in

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[2] R.11-02-019, *Decision Mandating Pipeline Safety Implementation Plan, Disallowing Costs, Allocating Risk of Inefficient Construction Management to Shareholders, and Requiring Ongoing Improvement in Safety Engineering,* p. 42 (Dec. 28, 2012) ("D.12-12-030"); Pub. Util. Code § 451 (requiring that rates be "just and reasonable").

[3] D.18-10-019, p. 5; R.11-02-019, *Order Modifying Decision (D.) 12-12-030 and Denying Rehearing, as Modified,* p. 29 (July 27, 2015) ("D.15-07-044") (observing that the Commission has discretion to apply either the preponderance of evidence or clear and convincing standard in a ratesetting proceeding, 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.").

[4] D.18-10-019; *see also* R.17-06-026, *Scoping Memo and Ruling of Assigned Commissioner*, p. 2 (September 25, 2017).

each IOU's ERRA proceeding. The Total Indifference Amount is calculated by subtracting the market value of the IOU's supply portfolio from the Total Portfolio Cost.

Total Portfolio Costs includes Utility-Owned Generation ("UOG"), fixed maintenance costs, purchased power (including that from power purchase agreements ("PPAs")), fuel costs for UOG and PPAs with tolling agreements, and California Independent System Operator ("CAISO") grid charges and revenues, net of any sales.[5] The Portfolio Market Value is derived from total eligible generation portfolio multiplied by the Market Price Benchmark ("MPB"), which is an administratively determined set of proxy values that represents the market value of the IOU's resource portfolio.[6] A benchmark for each type of resource is applied to the forecasted energy use for each resource type to obtain a market value. The resource market value is calculated as follows:

- For non-Renewable Portfolio Standard ("RPS")-eligible power in an IOU's portfolio, the forecasted amount of energy from such resources in the portfolio is multiplied by the brown power benchmark.[7]

- For RPS-eligible power in an IOU's portfolio, the forecasted amount of energy from such resources in the portfolio is multiplied by the green power benchmark.[8]

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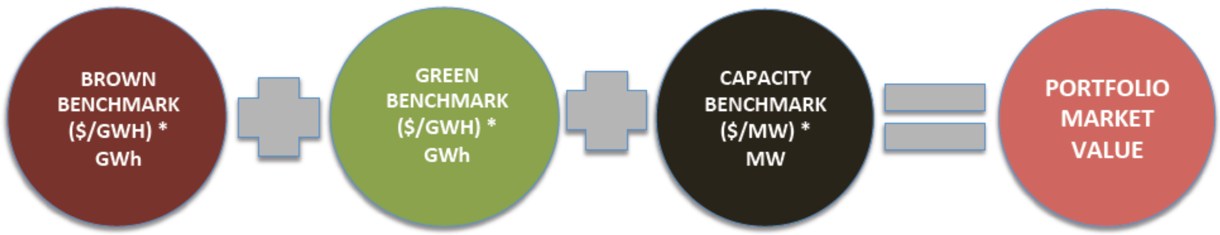
[5] R.07-05-025, *Decision Adopting Direct Access Reforms*, pp. 8-9 (December 1, 2011) ("D.11-12-018").
[6] D.19-10-001, p. 6 (October 10, 2019) ("Market Value is the estimated financial value, measured in dollars, that is attributed to a utility portfolio of energy resources for the purpose of calculating the Power Charge Indifference Adjustment for a given year.").
[7] *See* D.19-10-001, p. 7.
[8] *Id.*

- For RA capacity in an IOU's portfolio, the monthly average RA capacity in an IOU's portfolio is multiplied by a capacity or resource adequacy benchmark.[9]

Adjusting for line losses, the sum of the market value of the IOU portfolio's brown power, green power, and capacity creates the Portfolio Market Value.



Finally, each generation resource and departing customer is assigned a "vintage." A distinct portfolio of generation resources is identified for each vintage year based on when a commitment to procure each resource was made. Customers are assigned to vintage years according to the date they depart bundled IOU service.[10] Customers continuing to receive bundled service from the IOU are included in the latest vintage (e.g., vintage 2021 in the present Application). Each vintage is assigned a separate Indifference Amount,[11] and customers are responsible for the cumulative PCIA rates for their vintage.

Prior to Commission Decision ("D.") 18-10-019, the PCIA rate was set on a forecast basis and not trued-up for unbundled customers; only bundled customers' rates were subject to a true-up. In D.18-10-019, however, the Commission adopted a true-up for the PCIA rate to "ensure that

[9] *Id.*
[10] Unlike portfolio resources, customers are assigned to vintages using a July to June calendar period. For example, customers departing bundled service between July 2019 and June 2020 are assigned to the 2019 vintage.
[11] D.11-12-018, p. 9.

bundled and departing load customers pay equally for PCIA-eligible resources."[12] This true-up will occur via including the year-end PABA balance as part of this proceeding.[13]

In sum, SDG&E's PCIA rates for 2021 will be set based on two key components, prior to applying the cap: (1) the Indifference Amount, *i.e.*, the difference between the forecasted cost of SDG&E's generation portfolio in 2021 and the forecasted market value of SDG&E's generation portfolio in 2021; and (2) the 2020 year-end balance in the PABA, *i.e.*, the rolling true-up between (a) the forecasted costs and revenues used to set the 2020 PCIA last year and (b) the actual costs and revenues SDG&E is realizing this year. The Indifference Amount and the year-end PABA overcollection (or undercollection) are added together to form the PABA revenue requirement underlying PCIA rates.

As noted above, and especially germane to this proceeding, the Commission also adopted a price cap to "limit the change of the PCIA from one year to the next" and to "provide a degree of stability and predictability" for departing load customers.[14] The aim of this price cap, created in D.18-10-019, was to ensure rate stability for both bundled and departing load customers as related to PCIA rates.[15] The Commission established a balancing account and trigger mechanism to account for accumulated undercollection due to the PCIA cap, and IOUs are directed to file a trigger application if the PCIA Balancing Account ("CAPBA") balance exceeds the 7%

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[12] D.18-10-019, p. 72.
[13] *See* A.20-07-009, *Expedited Application of San Diego Gas & Electric Company (U 902 E) Under the Power Charge Indifference Adjustment Account Trigger Mechanism* (July 10, 2020) ("SDG&E Trigger Application"); SDG&E Advice Letter ("AL") 3436-E (establishing its PCIA undercollection balancing account, CAPBA).
[14] D.18-10-019, p. 72.
[15] *Id.*, p. 15 [stating that the price cap "should have reasonably predictable outcomes that promote certainty and stability for all customers within a reasonable planning horizon."]

threshold.[16] SDG&E recently filed such a trigger application in A.20-07-009, filed on July 10, 2020.

IV. DISCUSSION OF ISSUES IN SCOPING MEMO

C. Scoping Issue No. 3 – Whether the Commission should approve a 2021 Portfolio Allocation Balancing Account forecast revenue requirement of $373.828 million.

First, SDCP and CEA discuss the lack of information and support contained in SDG&E's initial application filing and testimony related to the 2020 PABA balance, which is an important component of the overall PABA revenue requirement calculation, and recommend process improvements for this case as well as future ERRA proceedings. Second, SDCP and CEA provide an explanation of an error it discovered in SDG&E's calculation of the Indifference Amount, which is another important input to the 2021 PABA revenue requirement. This error must be fixed in the November Update of the 2021 PABA revenue requirement forecast. To its credit, SDG&E has already acknowledged this approximate $84.5 million mistake and has committed to correcting it.

1. The Commission Should Require SDG&E to Provide Significantly More Detail Regarding Actual PABA balances, Forecasted PABA Balances and The Underlying Data Required to Analyze Their Accuracy.

As discussed above, the PABA constitutes a rolling true-up between the forecasted components of the Indifference Amount used to set the PCIA rates and the actual costs and revenues SDG&E experiences during the year. Any resulting over- or under-collection in the PABA at end of 2020 is added to the revenue requirement used to establish the 2021 PCIA

[16] *Id.*, pp. 86-87, OP 10.

rates.[17] However, in its amended testimony submitted at the end of April, SDG&E reports that its 2020 balances recorded to PABA are "$0 million."[18]

In fact, the rolling PABA balance at the time SDG&E filed its revised testimony was not $0 million. In discovery, SDG&E provided data demonstrating that its June monthly report showed a PABA balancing account under-collection of $271 million (without Franchise Fees and Uncollectables) as of the end of June.[19] Further, SDG&E provided in discovery, but not in its Application, a forecasted year end PABA under-collection of $167 million. In other words, SDG&E's Application understated the 2021 PABA revenue requirement in its direct case by at least $167 million.

By failing to provide a forecast of the PABA under-collection in its Application, SDG&E did not provide an accurate forecast of its PABA revenue requirement. Instead, SDG&E maintains that "the 2020 PABA account balance will be determined in SDG&E's 2021 ERRA November update."[20] Waiting until the November update to provide any forecast of the PABA balance creates the potential for huge shifts in forecasted PCIA rates between the Application and ultimate disposition of the proceeding, limits parties' ability to understand, forecast and plan for what those changes will be prior to the end of the proceeding, and fails to provide a reasonable estimate of the PABA revenue requirement.

[17] D.19-10-001, p. 11 ("The year-end overcollections or undercollections in the PABA subaccounts for year n are included in the vintage PCIA rate calculation for year (n+1) as part of each utility's ERRA Forecast Application.").
[18] Exhibit SDG&E-06 (Amended Prepared Direct Testimony of Stacy Fuhrer at SF-3, line 2).
[19] Exhibit SDCP-8 (San Diego Gas & Electric Company Response to SDCP Data Request 4.09); Confidential SDCP-18 (CONFIDENTIAL – SDG&E Response – PCIA Model_2021 ERRA Forecast SDCP DR 4 Question 9.xlsx).
[20] Exhibit SDCP-8 and Exhibit SDCP-9 (San Diego Gas & Electric Company Response to SDCP Data Request 4.10).

To remedy this lack of transparency in the future, the Commission should order SDG&E to include its year to date PABA balance as well as its forecasted year-end PABA balance in all future ERRA forecast applications. The year-end PABA balance is an important input to the overall PABA revenue requirement and by excluding it in its initial application, SDG&E paints an unrealistic picture of the actual PABA revenue requirement and resulting PCIA rates that CCA customers must pay. Including the balance for the first time in the November Update creates a major, last-minute update to one of the core issues in an EERA forecast proceeding (the PABA balance) and does not give intervenors adequate time to evaluate its impact on rates.

Moreover, the Commission, SDCP, CEA, and other intervenors do not currently have the tools necessary to understand the difference between forecasted PABA revenue requirements and actual PABA balances, the causes of an over- or under-collected balance, or the direction the balance is heading because SDG&E has not produced the underlying data necessary for such an evaluation. Such understanding is critical for the Commission and other parties to reach a conclusion that the proposed PCIA rates, which will include the PABA true up, are accurate and reasonable.

To remedy this lack of transparency the Commission should require that future ERRA Forecast applications include monthly forecast PABA balance dollar amounts and the underlying volumetric data (e.g,. MWh generation, kWh retail sales, etc.). As customer-facing load serving entities, it is imperative that CCAs are granted access to the data required to analyze the accumulating PABA balances on a timely basis in order to anticipate and plan for potential rate impacts on their customers and to operate their own programs to serve their customers.

Specifically, in future ERRA Forecast applications, the Commission should require SDG&E to provide in its confidential workpapers, and in routine updates throughout the proceeding, the data required to review actual PABA activity. Such data must include:

- Confidential versions of the monthly ERRA/PABA/CAPBA reports;
- Additional detail supporting the monthly PABA reports, including subcategories for summarized line items such as UOG costs and Contracts (e.g., provide by resource type, and whether RPS or non-RPS eligible);
- Actual volumetric quantities underlying each relevant dollar figure; such categories include UOG generation, power purchases and sales, CAISO market sales, and retail customer sales;
- Monthly volumes of Actual Sold, Retained, and Unsold RA;
- Monthly volumes of Actual Sold, Retained, and Unsold RPS.

Not only will requiring this data upfront increase transparency and understanding within this proceeding, it will diffuse controversy around the November Update. As has been seen in other IOUs' ERRA forecast cases,[21] coupling the short timeline for comments on the November Update with the large swings in revenue requirement can create substantial controversy and necessitate delays in the timely implementation of rates. Giving intervenors and the Commission a better understanding of the drivers of PABA balances will allow them to better predict the direction (rising or falling) of the balances as November approaches.

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[21] A.19-06-001, *Joint Motion of the Joint CCAs and DACC for Evidentiary Hearings and Additional Briefing, or, Alternatively, to Amend Proceeding Schedule, and to Shorten Time for Response*, (November 12, 2019); A.19-06-001, *Response of Pacific Gas and Electric Company (U 39 E) to Joint Motion for Evidentiary Hearings and Additional Briefing or To Amend Proceeding Schedule*, (November 14, 2019); A-19-06-001, *Email Ruling Revising the Schedule*, (November 15, 2019).

In *this* ERRA Forecast proceeding, SDCP and CEA have worked with SDG&E to gain an understanding of the impact the PABA balance will have on SDG&E's proposed PCIA rates.[22] SDCP and CEA will continue to request that SDG&E provide its rolling 2020 PABA balance as well as underlying data on an ongoing monthly basis via discovery.[23] SDG&E's cooperation and transparency will be necessary to ensure that intervenors in this proceeding have adequate time to analyze the data and to ensure that the PABA balance SDG&E presents in the November Update is accurate and based on reasonable assumptions.

2. The Commission Cannot Approve SDG&E's 2021 PABA Forecasted Revenue Requirement of $373.828 Million Until SDG&E Corrects its Erroneous Calculation of the Total Indifference Amount.

The Commission must consider SDG&E's admitted mistake in calculating its indifference amount and, accordingly, cannot approve SDG&E's 2021 PABA forecasted revenue requirement of $373.828 million until SDG&E corrects this error and supports the corrected value.

As detailed above, there are two main components to the PABA revenue requirement used to set PCIA rates: (1) the Total Indifference Amount and (2) the forecasted year-end balance in PABA, discussed above. The Total Indifference Amount is calculated by subtracting the market value of the IOU's supply portfolio from its Total Portfolio Cost. Here, SDG&E omitted key components from its portfolio market value. Specifically, SDG&E failed to include RA and RPS sales revenues when calculating its indifference amount.[24]

SDCP and CEA's review of SDG&E's Indifference Amount Calculation Table showed that SDG&E *removed* RA and RPS sales volumes from the market value calculation rather than

[22] Exhibit SDCP-8 and Exhibit SDCP-9.
[23] SDCP requested underlying volumetric data on an ongoing basis in this proceeding, but so far SDG&E has objected and refused to provide it.
[24] *See* Exhibit SDCP-15 (San Diego Gas & Electric Company Response to SDCP Data Request 6.04).

reflecting the value of such sales as an offset to portfolio costs.[25] In other words, SDG&E's filed application incorrectly calculated the Indifference Amount and thereby artificially increased PCIA rates. SDCP and CEA posit that if this calculation had been done correctly, following Commission guidance to include RA and RPS sales revenue as an offset to CRS Eligible Portfolio Costs, then SDG&E's forecasted Indifference Amount would decrease by $49.2 million for RA sales and $35.3 million for RPS sales, for a total reduction of $84.5 million.[26]

SDG&E acknowledged its error in a supplemental discovery response to SDCP and committed to correcting the error in its November Update.[27] Accordingly, Commission evaluation of this issue must wait until SDG&E presents its corrected calculation, which should result in an approximate $84.5 million reduction to the PABA revenue requirement.

I. Scoping Issue No. 9 – Whether the Commission Should Approve SDG&E's Proposed Vintage Power Charge Indifference Adjustment in Rates: Commission Approval of SDG&E's Vintage PCIA Rate Cap Proposal Would Run Contrary to Established Commission Policy.

Commission approval of SDG&E's stated method for capping vintaged PCIA rates would result in cost increases that exceed the price caps recently established by this Commission. Such price caps were established for sound policy reasons—to avoid customer rate shock. There is no reason for the Commission to abandon this price cap a mere two years after having put it in place, particularly since the policy concerns still apply. Moreover, even if justified, SDG&E's

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[25] Confidential Exhibit SDCP-20 (CONFIDENTIAL – PCIA Model_2021 ERRA Forecast April_Fuhrer.xlsx; Tab "Indifference Amount Calc", Rows 11, 15-17 Columns F:AB); Confidential Exhibit SDCP-21 (CONFIDENTIAL – SDG&E Response – SDCP DR_02 2021 ERRA Forecast Q2-10.xlsx; Tab "DR 2-Q5-7", Row 16, Columns C:U; Tab "DR 2-Q8-10", Rows 25-27, Columns C:U).
[26] Confidential Exhibit SDCP-21 (CONFIDENTIAL – SDG&E Response – SDCP DR_02 2021 ERRA Forecast Q2-10.xlsx; Tab "DR 2 – Q5-7", Row 14, Columns C:U; Tab "DR 2 – Q8-10", Rows 21-23, Columns C:U).
[27] Exhibit SDCP-10 (San Diego Gas & Electric Company Supplemental Response to SDCP Data Request 4.15) and SDCP-11 (San Diego Gas & Electric Company Supplemental Response to SDCP Data Request 4.17).

ERRA application is not the proper venue for the Commission to implement such a policy change. The Commission should not depart from its clearly stated policy objective of maintaining PCIA rate stability.

As noted above, the Commission has established a price cap limiting year-over-year changes to vintaged PCIA rates to no greater than $0.005 per kWh above the prior year's approved PCIA rates by vintage.[28] In D.18-10-019, the Commission lists its "Final Guiding Principles" regarding the PCIA rulemaking. In pertinent part, the Guiding Principles state that "[a]ny PCIA methodology adopted by the commission to prevent cost increases for either bundled or departing load… should have reasonably predictable outcomes that promote certainty and stability for all customers within a reasonable planning horizon.[29] Consistent with that principle, SDG&E's final implemented PCIA rates by vintage for forecast year 2020 were capped at $0.005 per kWh above the effective 2019 PCIA rates by vintage.[30]

Further, to ensure consistency with statutory directives against cost-shifting among bundled and unbundled customers, the Commission also directed each utility to establish an interest-bearing balancing account, here the CAPBA, to track any obligation that accrues for departing load customers if the cap is reached.[31] The Commission directed that if the difference between capped rates and costs reaches 7%, and the utility also forecasts that the balance will reach 10%, it shall, within 60 days, file an application to propose a rate that will bring the projected balance down below 7%.[32]

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[28] D.18-10-019, p. 133, OP 9; *see also* A.19-04-010, *Decision Adopting San Diego Gas & Electric Company's 2020 Electric Procurement Cost Revenue Requirement Forecast and 2020 Forecast of Greenhouse Gas Related Costs*, January 16, 2020 ("D.20-01-005"); Implemented via AL 3500-E.
[29] D.18-10-019, p. 15.
[30] D.20-01-005, Implemented via AL 3500-E.
[31] D.18-10-019, p. 86.
[32] *Id.*, pp. 86 -87.

Because of the capped rates for forecast year 2020, SDG&E's CAPBA balance grew above the 7% trigger threshold, leading SDG&E to file an expedited trigger application on July 10, 2020 ("SDG&E Trigger Application").[33] SDG&E's Trigger Application requested Commission authority to adjust its PCIA rates to allow for recovery of full CAPBA balance, rather than simply lowering it below 7%.[34] Specifically, SDG&E proposes increasing the "current effective vintage PCIA rates in order to bring the CAPBA account balance below 7%" and to refund bundled customers for the undercollection amount.[35] The propriety of that proposal is the subject of another proceeding, but is an important factor in considering the appropriate basis for calculating 2021 capped PCIA rates.

In its Application in this docket, SDG&E presents PCIA rates that are uncapped based on its forecasted revenue requirements, for which it seeks approval. However, in discovery SDG&E explained that if the Commission approves its CAPBA trigger application, it believed the rates approved in that docket would form the basis for determining whether the $0.005/kWh PCIA rate cap applies for 2021. In other words, rather than using the approved 2020 PCIA rates approved in the 2020 ERRA Forecast proceeding, which SDG&E presented in this proceeding, as the baseline to set the 20201 PCIA rate cap, SDG&E would use whatever rates the Commission approves in its CAPBA trigger application. As noted above, SDG&E proposes in its CAPBA trigger application to bring the CAPBA balance to zero, rather than just under the

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[33] A.20-07-009, *Expedited Application of San Diego Gas & Electric Company (U 902 E) Under the Power Charge Indifference Adjustment Account Trigger Mechanism* (July 10, 2020) ("SDG&E Trigger Application").
[34] A.20-07-009, SDG&E Trigger Application, *Prepared Direct Testimony of Eric L. Dalton on Behalf of SDG&E*, p. ED-3, lines 8-9 (July 10, 2020), https://www.sdge.com/sites/default/files/regulatory/SDGE%20CAPBA%20Trigger%20Testimony%20of%20Eric%20Dalton.pdf.
[35] SDG&E Trigger Application, p. 2.

7%, meaning the rates it proposes in that proceeding are as high as they could possibly be and are higher than what is required to meet Commission directives.

SDG&E's proposal to calculate the cap based on rates approved in the CAPBA Trigger application would entirely undercut the Commission's clear policy preference to create stability and avoid rate shock for unbundled customers. In fact, SDG&E's PCIA rate cap approach described in its discovery response, if approved, would result in capped rates that are more than three times what the capped rate would otherwise be.[36]

For example, using SDG&E's forecast year 2020 PCIA rates presented in this proceeding as the basis for the cap, the capped rate for vintage 2015 customers would be $0.035001.[37] In comparison, using the proposed PCIA rates in SDG&E's CAPBA Trigger Application as the basis for the cap, the capped rate for vintage 2015 customers would be $0.11125 per kWh – more than three times higher.[38] Thus, if the proposed PCIA rates in SDG&E's CAPBA trigger application are used as the basis for calculating the 2021 capped rates, the cap would be set *significantly* higher than $0.005 per kWh above the prior year's rate. This approach would entirely obliterate the purpose of the Commission-established cap mechanism, which is to ensure rate stability and predictability for departing load customers.[39]

SDG&E admitted in response to DR 6.01 and 6.02 that including the current PABA balance as well as the forecasted year-end PABA balance, respectively, would cause forecast year PCIA rates to capped when using the implemented forecast year 2020 PCIA rates as the basis for determining the cap. Thus, if the proposed PCIA rates in SDG&E's CAPBA Trigger

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[36] *See* Exhibit SDCP-7 (San Diego Gas & Electric Company Response to SDCP Data Request 3.26).
[37] Confidential Exhibit SDCP-17 (CONFIDENTIAL - PCIA Model_2020 CAPBA Trigger 3 Mo._Equal Cents Alloc_Fuhrer.xlsx) (Submitted with SDG&E response to SDCP Data Request 3.26). ($.005 was added to the rates presented to show what the capped rate would be under SDG&E's proposal).
[38] *Id.*
[39] D.18-10-019, p. 3.

Application are approved as the basis for determining the cap; the uncapped rates estimated for example in SDG&E's response to DR 4.09 and 4.10 would become effective because the basis for the cap would be well above the uncapped rates.[40] These rates are significantly higher than the forecasted PCIA rates presented in SDG&E's Application.

Overall, the unequivocal intent of implementing a price cap in D.18-10-019 was to provide rate stability and a degree of predictability to departing load customers. Allowing the basis for forecast year 2021's capped PCIA rates to be those proposed in SDG&E's CAPBA expedited trigger application, would be directly counter to this clear—and recent—Commission policy. Accordingly, if the PCIA rate must be capped based on updates provided in November, the Commission should order SDG&E to use the approved 2020 PCIA rates as the basis for establishing the $.005 cap for 2021 vintaged PCIA rates.

The cap and trigger mechanisms represent a standing policy requirement, which the Commisison prescribed in D.18-10-019. If SDG&E wishes to depart from the Commission established rate cap, it would need to file a petition for modification of D.18-10-019, pursuant to the Commisison's Rule 16.4. Thus, this ERRA Forecast application is not the proper venue for SDG&E to propose removal or modificaiton of the PCIA cap.

J. Scoping Issue No. 10 – Whether the Commission Should Approve SDG&E's Proposed 2021 Rate Components for the Green Tariff Shared Renewables Program

The GTSR program, similar to CCA programs, allows customers to purchase a greater proportion of their electricity from renewable resources. While SDCP and CEA support the goals of the GTSR program and its contribution to increased customer choice and renewable resource

[40] Exhibit SDCP-8; Exhibit SDCP-9; Confidential Exhibit SDCP-18 (CONFIDENTIAL – SDG&E Response – PCIA Model_2021 ERRA Forecast SDCP DR 4 Question 9.xlsx); Confidential Exhibit SDCP-19 (CONFIDENTIAL – SDG&E Response – PCIA Model_2021 ERRA Forecast SDCP DR 4 Question 10.xlsx).

development, the proposed Renewable Power Rate ("RPR") must reflect the actual costs of the renewable resources that will be utilized to serve GTSR customers.

In accordance with D.15-01-051 and Resolution E-5028, SDG&E requests approval in its Application for the forecast 2021 costs and proposed rate components for the GTSR Program.[41] For the Green Tariff ("GT") portion of the GTSR Program, SDG&E estimates total customer usage in 2021 to be 103.8 GWh resulting in a total estimated program cost of $6.35 million.[42] Among the proposed GT rates, SDG&E estimates the commodity rate component known as the RPR to be $56.27/MWh.[43] In D.15-01-051, the Commission set forth the GTSR generation rate structure comprised of credits, representing the benefits of GSTR Program generation and capacity, and charges, representing costs incurred on behalf of GTSR customers.[44] The commodity rate for the GT portion is called the RPR and calculated by averaging: (1) the incremental cost of local solar projects procured specifically for the program and (2) the weighted average cost of the power from the GTSR Interim Pool.[45] SDG&E proposes a 2021 RPR of $56.27/MWh, which is $13.08/MWh, or 23.2 %, cheaper than the currently approved 2020 RPR of $69.35.[46]

Through Discovery, SDCP sought to investigate and verify the expected resources to be included in the RPR, to ensure compliance with the ratemaking methodology set out in D.15-01-051. Discovery was necessary on this subject because SDG&E's testimony and Application did not provide this data clearly. Unfortunatley, SDG&E's data responses on this topic were

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[41] Resolution E-5028, *Approves Extension of, and modifications to, the Utilities' Green Tariff Shared Renewables Program*, pp. 31-32 (September 30, 2019).
[42] *Id*.
[43] Exhibit SDG&E-06 (Amended Prepared Direct Testimony of Stacy Fuhrer at SF-17)
[44] D.15-01-051, pp. 95-96.
[45] D.15-01-051, pp. 97-98; Exhibit SDG&E-06 (Amended Prepared Direct Testimony of Stacy Fuhrer at SF-17).
[46] Exhibit SDG&E-06 (Amended Prepared Direct Testimony of Stacy Fuhrer at SF-19).

incomplete and failed to include all of the data needed for SDCP and CEA to conduct their anlayis.

In SDCP's data request 5.02, it requested "unredacted copies of the pricing terms contained within the PPAs whose resources are being used to supply power to SDG&E's GTSR customers in 2021." In response SDG&E supplied all contracts for the Interim Pool resources and the dedicated Midway PPA, but it did not include the dedicated Wister PPA. It was not until SDG&E responded to SDCP's seventh data request that it provide information regarding the utilization and costs of Wister.

SDG&E's Application is also unclear as to whether total forecast 2021 GT customer usage accounts for the drop in the estimated 2021 RPR. SDG&E estimates that, based on consumption estimates for each customer class in conjunction with program enrollment targets, 2021 GT customer usage is estimated to be 103.8 GWh.[47] Though total GT subscribed capacity increased from 44.236 MW in December 2018 to 50.50 MW in December 2019, total GT subscribed capacity stayed about the same over the year, reported at 50.487 MW as of June 2020.[48]

SDG&E's Application provides no explanation as to how forecast usage was determined and whether that forecast impacted the reduction in the 2021 RPR. Given the lack of clarity surrounding forecast consumption, and the role that this forecast plays in calculating the RPR, SDG&E must make a more detailed showing in this and future ERRA proceedings to allow for a proper determination as to whether the proposed RPR was calculated in accordance with Commission requirements.

[47] Exhibit SDGE-03 (Prepared Direct Testimony of Stefan Covic SC-12 to SC-13).
[48] Exhibit SDCP-40 (*Annual GTSR Program Progress Report of San Diego Gas & Electric Company for Activities Occurring in 2018* at 4); Exhibit SDCP-41 (*Annual GTSR Program Progress Report of San Diego Gas & Electric Company for Activities Occurring in 2019* at 4); Exhibit SDCP-38 (*Quarterly GTSR Program Progress Report of San Diego Gas & Electric Company for Activities Occurring Q2 2020*, A.12-01-008, July 31, 2020 at 3).

V. CONCLUSION

For the foregoing reasons, SDG&E's SDG&E's Application cannot be approved as requested; rather, SDG&E should be directed to (1) provide more clarity on its underlying costs and data regarding its PABA balances; (2) correct its miscalculation of the Total Indifference Amount; (3) follow the Commission's established policy capping PCIA rate increases and (4) provide greater information and clarity in support of its rates for the GTSR program. Overall, SDG&E has not provided sufficient information and cost transparency in its Application to meet its burden of proof.

Respectfully submitted,

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September 25, 2020

Report Providing Recommendations on the Schedule to Reopen Direct Access

California Public Utilities Commission Staff Report

Pursuant to Senate Bill 237 (2018) and R. 19-03-009

September 28, 2020

Table of Contents

Key Acronyms

AB	Assembly Bill
CCA	Community Choice Aggregation
CEC	California Energy Commission
ESP	Electric Service Provider
GHG	Greenhouse Gas Emissions
IRP	Integrated Resource Planning
IOU	Investor-Owned Utility
LSE	Load Serving Entity (includes CCAs, ESPs, and IOUs)
LLTP	Long Term Procurement Planning
NEM	Net Energy Metering
PCIA	Power Charge Indifference Adjustment
POLR	Provider of Last Resort
SB	Senate Bill
RA	Resource Adequacy
REC	Renewable Energy Credits
RPS	Renewables Portfolio Standards

Executive Summary

In 2018 the Legislature approved Senate Bill (SB) 237 (Hertzberg), which required the California Public Utilities Commission (CPUC) to 1) increase the cap on the amount of demand that can be serviced by competitive Electricity Services Providers (ESPs) through Direct Access; and 2) provide recommendations to the Legislature on implementing further expansion of Direct Access, including, but not limited to, the phase-in period over which the further Direct Access shall occur for all remaining nonresidential customer accounts in each electrical corporation's service territory.

Consistent with the requirements of SB 237, this Staff Report provides an assessment of the provisions identified in Public Utilities (P.U.) Code Section 365.1 (f)(1) for the Legislature's consideration in its determination of further reopening. Should the Legislature elect to enact a further reopening of Direct Access, this report provides recommendations for the schedule of actions that should occur prior to the reopening, consistent with these provisions. In this document, the California Public Utilities Commission's (CPUC) Energy Division staff presents recommendations for the schedule. CPUC Energy Division staff recommends the following:

Prior to Further Direct Access Reopening:

Staff recommends that reopening be conditioned on ESPs' demonstrated compliance with the following obligations:

- ESPs submit robust, transparent Integrated Resource Planning (IRP) filings and meet all procurement requirements pursuant to Decision (D.) 19-11-016.
- ESPs meet their Renewables Procurement Standards (RPS) obligations for the 2021-2024 compliance period.
- ESPs comply with all Resource Adequacy (RA) requirements including multi-year local, year ahead flexible and system, and month ahead system and flexible obligations.

Recommended Schedule if Direct Access is Reopened:

If the Legislature directs further reopening of nonresidential Direct Access, the legislation should allow the CPUC to:

- Set an initial re-opening schedule in increments equal to 10 percent of eligible non-residential load per year.
- Condition each annual expansion on CPUC review and approval of compliance with IRP, RA and RPS requirements, as subject to CPUC approval.
- Order annual expansion to take place on a schedule that will allow Load Serving Entities (LSEs) the ability to fully comply with RA requirements.

Staff suggests that a re-opening schedule that raises the Direct Access cap by 10 percent of non-residential load per year should minimize planning disruptions associated with load departure and allow the CPUC and market actors sufficient time to develop the regulatory and market structures needed to ensure long-term resource development in a fragmented retail market.

Recommendations for Legislative Action:

If the Legislature establishes a schedule to reopen Direct Access to all non-residential customers, CPUC staff recommends that the following legislative actions be considered to ensure that the greenhouse gas (GHG) emissions, reliability and cost shifting provisions of SB 237 are met:

- Provide clear authority to enforce compliance with IRP GHG goals by all LSEs subject to P.U. Code Section 454.52 (b).

- Ensure that the CPUC continues to have clear authority to enforce the State's Resource Adequacy goals defined in P.U. Code Section 380.

- Amend P.U. Code Section 949.25 to provide the CPUC with the authority to revoke ESP licenses and CCA registration for repeated non-compliance with RA, RPS or IRP requirements.

- Consider provisions to ensure that no cost shifting as the result of customer moving between different Load Serving Entities (Electric Corporations, Community Choice Aggregators (CCAs), and ESPs) are applied equitable to all customers.

1. Introduction

1.1 Objectives and Scope

Pursuant to Senate Bill (SB) 237 (Hertzberg, 2018), the CPUC is required to provide the Legislature with recommendations on the further reopening of Direct Access, which is also referred to as direct transactions. Energy Division staff prepared this Staff Report in order to support the CPUC in meeting requirements of SB 237.

Public Utilities (P.U.) Code 365.1 (f) states that:

> (f)(1) On or before June 1, 2020,[1] the commission shall provide recommendations to the Legislature on implementing a further direct transactions reopening schedule, including, but not limited to, the phase-in period over which the further direct transactions shall occur for all remaining nonresidential customer accounts in each electrical corporation's service territory.
>
> (2) In developing the recommendations pursuant to paragraph (1), the commission shall find all of the following:
>
> (A) The recommendations are consistent with the State's greenhouse gas emission reduction goals.
>
> (B) The recommendations do not increase criteria air pollutants and toxic air contaminants.
>
> (C) The recommendations ensure electric system reliability.
>
> (D) The recommendations do not cause undue shifting of costs to bundled service customers of an electrical corporation or to direct transaction customers.

The intent of this Staff Report is to provide an assessment of the provisions identified in P.U. Code Section 365.1(f) for the Legislature's consideration in their determination of further reopening. Should the Legislature elect to enact a further reopening of Direct Access, this report provides recommendations for the schedule of actions that should occur prior to the reopening, consistent with these provisions.

Direct Access, originally adopted in 1996 as part of California's energy restructuring initiative and authorized by P.U. Code Section 365.1, is a retail electric service option whereby non-residential customers may purchase electricity from a competitive non-utility entity called an Electric Service Provider (ESP). The amount of electric load that can be serviced by Direct Access has been capped by statute since 2002. SB 237 required the CPUC to increase the allowable Direct Access load by 4,000 gigawatt-hour (GWh).

In 2002, Assembly Bill (AB) 117 added P.U. Code Section 331.1, which created CCAs as an alternative provider or retail electricity services. In 2014 CCAs served only around 0.5 percent of all load in IOU territory; in 2021 it is estimated that Community Choice Aggregators (CCAs) will account for approximately 29 percent of load in Investor Owned Utility (IOU) territory.

[1] Issuance of this report was delayed due to the Covid-19 and economic emergency.

While CCA growth is an important market context for assessing the possible effects of expanding the market for Direct Access, pursuant to SB 237, this report focuses specifically on an assessment of the likely effects and risks of expanding Direct Access and is not intended to assess the impacts of CCA growth.

Direct Access currently serves approximately 14 percent of load in IOU service territory and is projected to increase to over 16 percent by 2021 with the implementation SB 237. Figure 1 shows the estimated 2021 load shares served by Direct Access, CCAs, and IOUs and the load that will become eligible to switch to Direct Access in 2021 and 2022 with the 4,000 GWh increase allowed by SB 237.

Figure 1: 2021 Direct Access Load and Eligible Direct Access Load

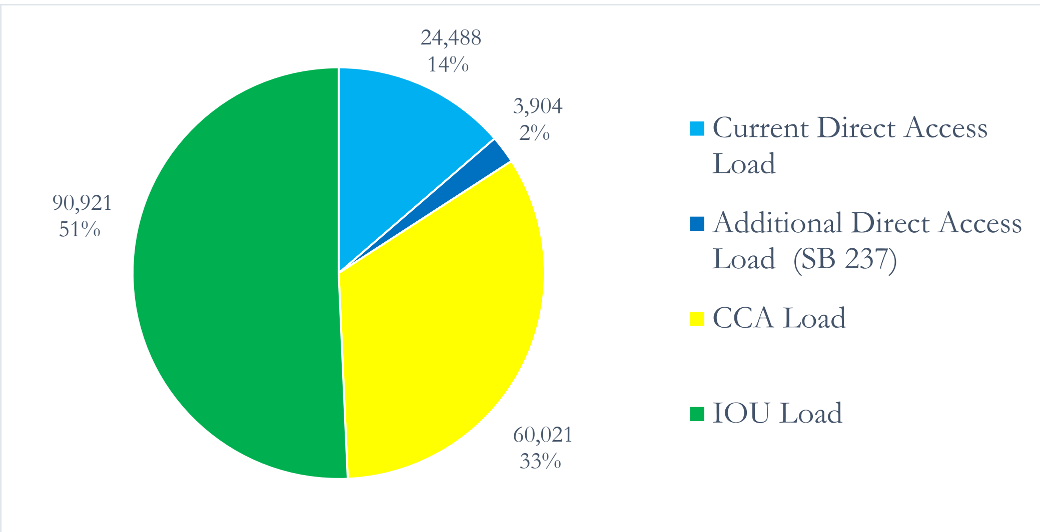
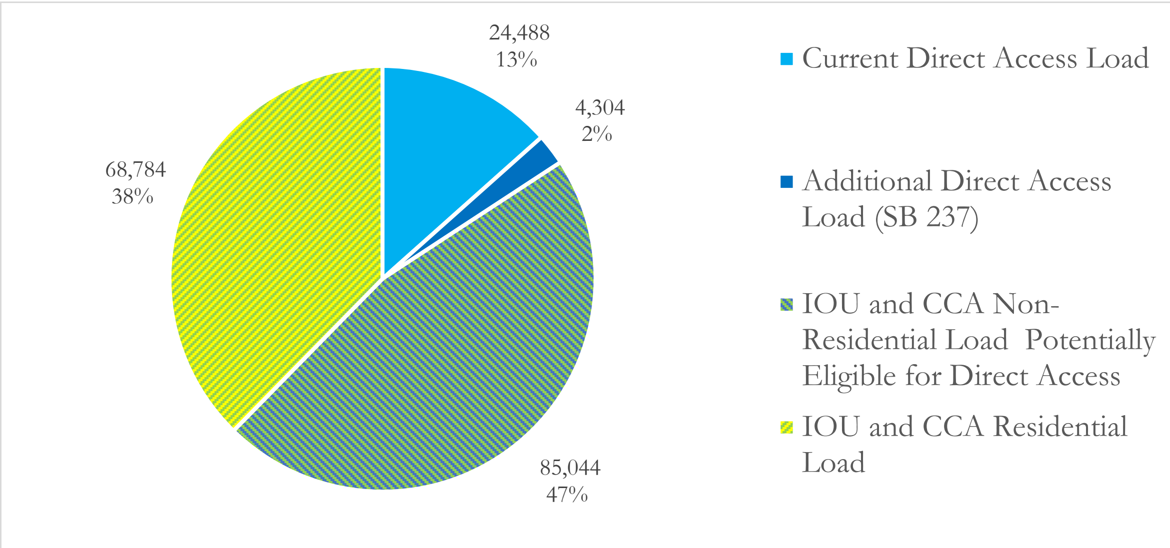


Figure 2 shows current Direct Access load and the additional load that could become eligible for Direct Access pursuant to SB 237. As Figure 2 shows, 47 percent of the current IOU and CCA load could move to Direct Access if the Legislature decides to re-open the entire non-residential market to Direct Access, as contemplated in SB 237. The 38 percent of IOU and CCA load that serves residential customers would not be eligible for Direct Access under SB 237.

Figure 2: Direct Access Load (GWh) and Direct Access Eligible Load (GWh) if Direct Access Becomes Eligible to All Non-Residential Load.



1.2 Background on Direct Access and Retail Choice

Direct Access was originally adopted in 1996 as part of California's Electric Utility Industry Restructuring Act, AB 1890 (Brulte, 1996). Prior to AB 1890, vertically integrated IOUs owned and operated generation, transmission, and distribution systems and provided retail services to all customers under regulation from the CPUC. Direct Access offered retail choice to customers by allowing them to purchase electricity directly from an ESP while the IOUs continued to supply the transmission and distribution services needed to transport power to the customer. AB 1890 opened Direct Access to both residential and non-residential customers.

In 2000-2001, market manipulation in a tight energy market led to large spikes in electricity costs and rolling blackouts across the state. The IOUs were unable to recover the costs of procuring electricity in the wholesale energy market due to fixed retail rates and mounting costs to procure generation. Ultimately, this led to PG&E's first bankruptcy in 2001. During this period, many Direct Access providers left the market, returning their customers to IOU service.

In response to the crisis, the Legislature approved AB1X (Keely, 2001) to resolve the shortage of energy available in the day ahead energy markets and stabilize energy prices. Among other actions, AB1X suspended additional Direct Access enrollment.

From 2001 to 2010, existing Direct Access customers were allowed to continue using Direct Access and to shift between ESPs, but no additional customers were allowed to move to Direct Access. SB 695 (Kehoe, 2009) opened Direct Access to a limited amount of new non-residential load, which would be phased in over several years. SB 695[2] created a capacity "cap" of electric load that ESPs may serve but otherwise retained the main aspects of Direct Access suspension until further legislative action. The cap set by SB 695 was equal to the peak amount of load served by Direct Access prior to the electricity crisis, roughly 13% of total load.

In 2002, AB 117[3] established P.U. Code Section 331.1, which authorizes the implementation of Community Choice Aggregation. AB 117 allows local government entities to form CCAs to purchase power for their communities from non-utility power suppliers. Per AB 117, customers are defaulted into CCA service when a CCA is formed in their service area, with an option to opt-out and return to utility service.

Following passage of SB 237 in 2018, the CPUC opened Rulemaking (R.) 19-03-009. In the first phase of the rulemaking, the CPUC allocated the additional 4,000 GWh Direct Access load from SB 237 among the three IOU territories according by load share. To provide sufficient time for ESPs to comply with current year-ahead Resource Adequacy requirements, the implementation of additional Direct Access load will not occur until January 1, 2021. In Phase 2 of R.19-03-009, the CPUC is addressing SB 237's requirement that Energy Division provide recommendations to the Legislature on further reopening of non-residential Direct Access.

Since 2001, the Legislature and the CPUC have implemented a series of new regulations to ensure there is sufficient generation capacity available for system reliability that have created new obligations for ESPs. Among the key requirements adopted were the creation of long-term and short-term procurement requirements for Load Serving Entities (LSEs) through the Long-Term Procurement Planning (LTPP) and Resource Adequacy proceedings. AB 380 (Nunez, 2005) established Resource Adequacy requirements to meet near-term capacity needs. Resource Adequacy requirements were updated by SB 1136 (Hertzberg, 2018) to ensure sufficient capacity to meet system, local and renewables integration (flexible) needs. Following SB 350 (de Leon, 2015), the CPUC moved long-term planning into the Integrated Resource Planning (IRP) process, which considers both reliability and greenhouse gas emissions reductions goals in a single proceeding and seeks to define an optimal path for realizing both goals.

1.2.1 California Customer Choice Project

In 2017, the CPUC initiated California Customer Choice Project to examine the rapid evolution of California's electric sector and develop a report evaluating competitive retail electricity options. The results of the project were published in August 2018 as *California Customer Choice: An Evaluation of Regulatory Framework Options for an Evolving Electricity Market* (Customer Choice Paper). The Customer Choice Paper identifies shifts occurring in the electricity sector as a result of expanding customer choice and assesses markets outside of California for lessons learned. The paper also raises fundamental questions on how California can simultaneously create more market choice for

[2] See P.U. Code Section 365.1(b)
[3] See P.U. Code Section 331.

consumers, meet statewide goals, and ensure California's energy policy core principles of affordability, reliability and decarbonization.

Following the Customer Choice Paper, CPUC staff published the *Choice Action Plan and Gap Analysis* (Action Plan) in December 2018 to identify critical policy issues associated with increased disaggregation of load and supply. CPUC staff also conducted an internal analysis to identify regulatory gaps that exist and actions that would help to ensure core principles are met if retail choice is pursued.

The Action Plan identified a list of policy areas and relevant proceedings that would be impacted by the expansion of retail choice. Some of these topics are relevant to the provisions required by SB 237 regarding a recommendation for Direct Access expansion. This report is informed by, and expands upon, the analysis of these topics in the Action Plan.

1. **Disclosure of Green House Gas (GHG) and Renewables Content for use in LSE Electricity Portfolios[4]:**

   The Action Plan raises the issue that consumers lack transparency into the power content of electricity sold by LSEs and identifies the need for clear disclosures for GHG emissions and Renewables Content from all LSEs. The California Energy Commission (CEC) provides "Power Content Labeling" and AB 1110 (Ting, 2016) requires that the CEC amend the Power Source Disclosure (PSD) to include GHG emissions intensity factors and guidance for disclosure of unbundled Renewable Energy Credits (RECs) beginning in 2020 for the 2019 calendar year.

   The Action Plan recommended that there be disclosure for all power content, including imports and unbundled RECs.

2. **Resource Adequacy[5]:**

   The Action Plan identifies challenges to maintaining adequate electric capacity to ensure reliability caused by structural changes to the energy market. These challenges include: the increasing use of intermittent renewable resources; the upcoming retirement of natural gas power plants due to once through cooling requirements; retirement requests from generators; and the rapid expansion of CCAs resulting in customer load migration. A competitive electricity market structure may cause uncertainty for market participants who must procure capacity for an unknown amount of load and generators who must now sell generation to new market entrants. Since publication of the Action Plan, R.17-09-020 has considered refinements to the Resource Adequacy program. This work is ongoing. Load migration and load fragmentation continue to create complex issues for electric system reliability that this Staff report will explore.

3. **Contracting for Reliability and Renewable Resource Requirements[6]:**

4 California Customer Choice Project: Choice Action Plan and Gap Analysis, December 2018, p. 27-28
5 Ibid. p. 50-53
6 Ibid. p. 57-61

> The Action Plan highlights the concern over resource procurement that is necessary for the state's long-term energy supply, particularly new renewable energy resources, noting that some LSEs rely almost exclusively on short-term contracts to meet energy needs. The CPUC uses the IRP process to evaluate the state's long-term contracting requirements to meet both its reliability and renewable procurement. Each LSE is required to file its own IRP with the CPUC so that the CPUC can ensure the that it will meet its obligations; however, the IRP process is relatively new and the CPUC still in the process of developing the needed compliance tools. The Action Plan also suggests potential solutions to address reliability and resource challenges with retail choice, including coordinated multi-party procurement and the creation of a central procurement entity.[7]

The remaining topics in the Action Plan are not within the scope of SB 237 and will not be assessed in this report, although they still need to be considered within their respective proceedings.

1.2.2 Public Input to Support Staff Report Recommendations

On January 8, 2020, staff held a workshop to solicit input from stakeholders and parties to R.19-03-009. Parties provided informal comments in response to the discussion. Comments were provided by the Alliance for Retail Energy Markets (AReM), California Large Energy Consumers Association (CLECA), Cogeneration Association of California (CAC), Commercial Energy of California (Commercial Energy), Direct Access Customer Coalition (DACC), Energy Producers and Users Coalition (EPUC), Pacific Gas & Electric (PG&E), Public Advocates Office (CalPA), Renewable Energy Buyers Alliance (REBA), Southern California Edison (SCE), The Utility Ratepayer Network (TURN). This report was informed by the comments and analysis of the participating parties, as well as past staff reports and decisions, which are cited below.

1.3 Potential Benefits of Expanding Direct Access

In their informal comments on the January 8th Energy Division workshop, parties discussed the potential benefits that expanding Direct Access can provide to commercial customers.

1.3.1 Expanded Direct Access will increase Choices for C&I customers

ESP representatives point out that many commercial and industrial customers desire the retail options that Direct Access can offer. Since caps on total participation were instituted, subscription to the Direct Access program has always been at the cap and there have been consistent waiting lists for the program. At the end of 2018, 6,951 GWh of customer load remained on the Direct Access waitlist.[8] While SB 237 increased the maximum allowable limit for Direct Access by 4,000 GWh, 2,000 GWh of which will come from the June 2020 Direct Access Lottery, it is reasonable to expect that demand for Direct Access service requests will increase if the cap is lifted.

[7] California Customer Choice Project: Choice Action Plan and Gap Analysis, December 2018, p. 62.
[8] 2018 Direct Access Lottery Enrollment Report

1.3.2 ESPs can tailor their service to customer needs

Companies seek Direct Access for various reasons. First, while the CPUC has no visibility into the rates ESPs charge their customers, it appears that ESPs have generally been able to provide power at a significant cost-advantage to IOUs, and many Direct Access customers choose Direct Access in order to lower their overall energy bills. Lower rates are appealing to all customers but may be particularly important to large commercial and industrial customers for whom energy is a major component of overall costs. For this class of customer, particularly industrial customers with some degree of locational freedom, the search for cheaper electricity could lead them to consider moving energy-intensive production activities out of California. Direct Access may provide these customers an incentive to keep production in the state.

Direct Access may also provide customers with competitive options and flexibility, allowing them to choose procurement products and rate designs. Customers may use Direct Access in order to pursue corporate GHG emission reduction initiatives. ESPs point out that they can provide customers with electricity services, such as load management, that are tailored to the customer's specific needs. Customers with multiple locations, such as large retailers, may seek Direct Access in order to aggregate load across different service territories and buy electricity services from a single provider. Buying from an ESP may facilitate customers who want to implement a unified energy management plan across jurisdictional boundaries and can facilitate the pursuit of corporate or institutional GHG goals by allowing companies to more efficiently plan and finance long-term, offsite investments in solar, wind, storage or other renewable assets.

1.4 Challenges of Expanding Direct Access

Large-scale load migration between LSEs may create structural challenges to California's system of electrical system planning. In recent years load migration has been driven primarily by the rapid growth of CCAs. Reopening Direct Access would allow nearly two-thirds of existing load, including load that has recently migrated to CCA service, to migrate between IOU, ESP and CCA service. Modeling in the 2019-2020 IRP cycle indicates a need for nearly 25,000 megawatts (MW) of new energy resources to be built by 2030. Accomplishing this rate of new build requires either that LSEs make long-term contracting commitments or that another entity do so on their behalf.

ESPs currently procure much of their energy in day-ahead and real-time markets or through short-term contracts and have little track record of signing long-term contracts. Because Direct Access customers make short term commitments to an ESP, generally signing 1 to 2-year contracts, multi-year contracts are risky for ESPs. However, since long-term contracts are needed to meet system reliability needs and develop new clean energy resources, expanding Direct Access increases the risks for long-term procurement contracting needed to meet system reliability and GHG reduction targets.

It is important to acknowledge that, to a certain degree, these long-term planning and contracting challenges are caused by load migration in general, which includes load migration due to CCA expansion. In their informal comments to the January 8th workshop, several Direct Access representatives raised the concern that ESPs are held to a separate standard than CCAs. They questioned whether this report should go beyond challenges that are specific to Direct Access expansion and consider load migration in general. While the rapid growth of CCAs has, in fact, made planning and procurement to meet system reliability more challenging, the current legislative mandate under P.U. Code 366.2 does not cap the amount of load that can be served by CCAs.

A rapid expansion of Direct Access is likely to exacerbate the challenges associated with load migration. Currently, the IOUs are experiencing a substantial amount of load departure annually with the launch and expansion of CCAs. There is also a small amount of load returning to IOUs or migrating to ESPs, to the extent allowed by the current cap. This migration has created planning challenges but has generally proven manageable. However, a rapid expansion of Direct Access would significantly increase the medium to long term planning uncertainty because customers may freely migrate between IOUs, CCAs and Direct Access providers. This increased load migration will make long-term procurement far more challenging for all LSEs. We describe those challenges further in Section 2.

1.4.1 Mechanism to address market risks related to load migration may be developed but do not currently exist

The Customer Choice Project found that a central procurement entity that procures on behalf of all LSEs may resolve some of the procurement challenges caused load migration, since central procurement would be indifferent to which LSE is serving load.[9] The CPUC has recently adopted central procurement for local Resource Adequacy in two IOU territories—Pacific Gas & Electric (PG&E) and Southern California Edison (SCE)—to be implemented beginning in 2023.[10]

Over time, market participants may also adapt to load migration and develop new ways to organize procurement to meet State planning requirements while also maintaining the flexibility they desire in competitive retail markets. However, currently these market-based approaches either do not currently exist or are in the very early stages of development.

2. Assessment of Statutory Provisions of Reopening Direct Access

This section provides an assessment of the four statutory provisions identified in Public Utilities Code Section Code 365.1 (f)(2) that must be met in setting a recommended schedule for reopening of Direct Access. The statute directs the CPUC to find that the recommendations are consistent with the State's GHG emission reduction, do not increase criteria and toxic air pollutants, ensure system reliability, and do not cause undue cost shifting to bundled customers. These provisions are considered below.

[9] California Customer Choice: An Evaluation of Regulatory Framework Options for an Evolving Electricity Market (August, 2018), p. 65.
[10] Decision (D.) 20-06-002 (June 11, 2020).

2.1 Impact of Direct Access Expansion on Greenhouse Gas Emission Reduction Goals

Under SB 32 (Pavley, 2016) the State must reduce GHG emission to 40 percent below 1990 levels by 2030. SB 350 (de Leon, 2015) requires the California Air Resources Board to establish emission reduction targets for the electricity sector and for the CPUC to use those targets in developing Integrated Resource Plans (IRP) for LSEs under its jurisdiction.

The IRP process sets an electric sector GHG reduction target[11] and identifies an optimal portfolio of resources needed to meet that target and maintain system reliability at least-cost. Each of the CPUC's jurisdictional LSEs are required to regularly submit IRP filings with the CPUC that are consistent with this portfolio. In their IRP filings, LSEs detail how they will meet GHG and reliability targets with new and existing resources. If the LSEs' IRP filings collectively show actual or potential deficiencies, the CPUC may order additional procurement.

The Renewables Portfolio Standards (RPS) program works in conjunction with the IRP as the primary driver to build new renewable resources. Originally adopted in 2002 and most recently updated by SB 100 (de Leon, 2018), the RPS program requires that the LSEs procure 60 percent of their total electricity retail sales from renewable energy resources by 2030. Additionally, SB 350 mandates that 65 percent of each LSE's RPS procurement must be derived from contracts of 10 or more years beginning in RPS Compliance Period 4, which will run from 2021 to 2024.[12] RPS mandates drive the build-out new renewable resources, which helps meet GHG emission reduction targets and system reliability needs set in the IRP.

To assess the impact of Direct Access expansion to all non-residential customers on GHG emissions, we evaluate the ESPs' current planning, procurement practices, and compliance with IRP and RPS requirements, and what they indicate about ESPs' likely market behavior in the future. We also consider the implications of additional load migration and Direct Access customers' short-term commitments to their ESP on the State's ability to accurately set and meet GHG reduction targets.

2.1.1 ESPs' Current Procurement Practices

ESPs' current energy procurement practices offer the best available indication of potential impacts of reopening Direct Access on GHG emissions. Figure 3 (below) shows each LSE's 2018 power content as reported to the CEC in 2018. The green wedge in Figure 3 shows the RPS eligible resources purchased by each LSE. The dark blue represents large hydro which, like nuclear (purple), is not RPS eligible but does qualify as GHG-free according to Power Content Labeling rules. The

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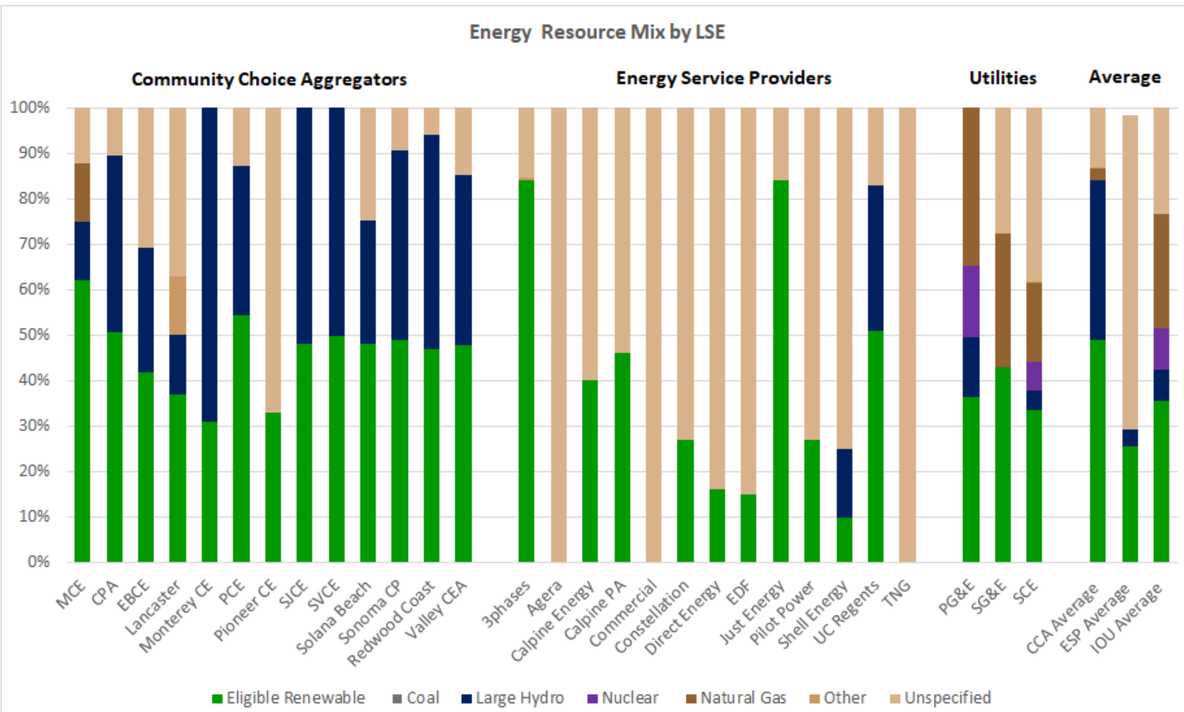
11 Electric sector GHG targets are set consistent with California Air Resources Board Scoping Plan ranges. Available: https://ww3.arb.ca.gov/cc/scopingplan/scopingplan.htm

12 RPS rules measure compliance as a percentage of energy used during the entire compliance period. This means that an LSE could fail to procure 65 percent of its RPS through 10-year or longer contracts but still meet program requirements if 65 of the RPS it procures during the 4 year compliance period comes from 10-year or longer contracts.

dark brown represents gas generation, while the lighter beige represents California Independent System Operator (CAISO) system power.

Figure 3 indicates that ESPs relied heavily on purchases of unspecified CAISO system power, with the exception of 3 Phases and the University of California (UC). This contrasts with the majority of CCAs, who procured large amounts of renewable and GHG-free resources and with the IOUs, who also outperformed ESPs in procuring GHG free energy. Unspecified CAISO system power, which includes energy from all resources including RPS eligible and gas generation, accounted for 69 percent of the ESPs' portfolio content.[13] Reliance on CAISO system power, which is generally cheaper and requires no long-term contracting, has been a source of competitive advantage for ESPs by allowing them to avoid higher costs and commitments of long-term contracts.

Figure 3: GHG free and System Power Used by each LSE[14]



ESP representatives have explained that the different resource mixes they procure reflect the differing priorities of their commercial customers. Some customers prioritize GHG emission reductions above energy prices and vice versa.[15] However, overall, the ESPs' general procurement

[13] For a full description of each LSE's power content label report for 2018, see Appendix 2 of this report.

[14] This chart is based on California Energy Commission Power Content Label data for 2018. A complete data set for each IOU, CCA, and ESP, including total retail sales, can be found in Appendix 2 at the end of this report.

[15] Informal Comments of the Alliance for Retail Energy Markets on the January 8, 2020 Workshop, p. 3.

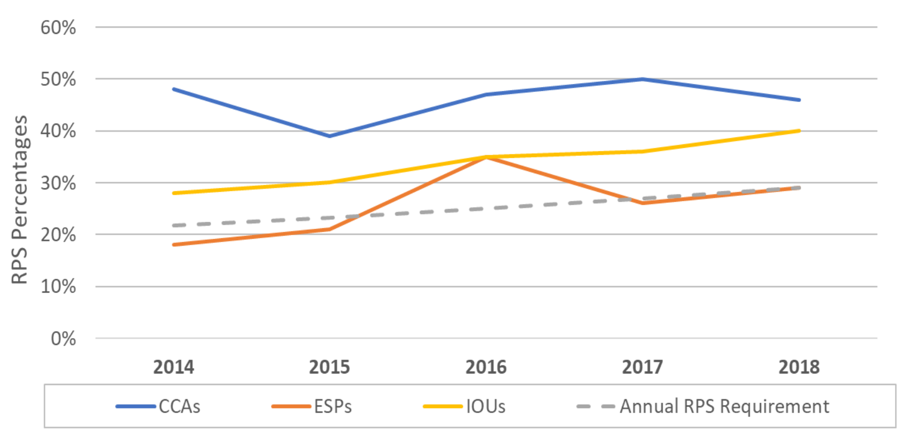
strategies, including a heavy reliance on CAISO system power, appear to increase GHG emissions relative to portfolios that rely on high amounts of RPS eligible resources.[16]

As will be further discussed in Section 2.1.4 (below) SB 350 requires all LSEs to procure a minimum 65 percent of their RPS compliance requirement with contracts of 10-years or longer starting in 2021. The ESPs' ability to comply with these requirements is untested to date. Based on past procurement trends, CPUC staff has concerns that some ESPs may not meet the new requirements.

2.1.2 Renewable Portfolio Standard Compliance

The *2019 California Renewables Portfolio Standard Annual Report* provides a comprehensive evaluation of each LSE's RPS compliance.[17] Figure 4 shows the trend in average RPS energy as a percentage of load by IOUs, CCAs and ESPs from 2014 to 2018. During this period, both CCAs and IOUs, on average, procured quantities of RPS well above mandated RPS requirements. In contrast, ESPs generally met their RPS requirements, but RPS represented a lower percentage of their procurement than it was for other LSE classes. The *2019 California Renewables Portfolio Standard Annual Report* found that while one ESP exceeded its target by more than 10 percent, the remaining 11 met or barely exceeded their RPS compliance target. 3 ESPs failed to meet RPS Period 2 (2014-16) RPS compliance targets.[18]

Figure 4. Average Actual LSE RPS Percentages (2014-2018)[19]



If the trends shown in Figure 4 are indicative of future practices, then load migration from IOUs or

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[16] The GHG content of CAISO system power varies from month-to-month and hour-to-hour depending on the availability of renewable resources. Emissions information can be found at the CAISO website.

[17] RPS requirements differ from Power Content Label since large hydro and nuclear are not included under RPS rules. Furthermore, RPS rules allow for the procurement Geothermal and Biopower, which are GHG emitting.

[18] 2019 California Renewables Portfolio Standard Annual Report, p. 25.

[19] From CalCCA's informal comments on Energy Division's January 8, 2020 workshop, p. 5, sent to the R.19-03-009 service list on January 21, 2020. Source data is from 2019 California Renewables Portfolio Standard Annual Report

CCAs to ESPs will likely lead to a net decline in RPS procurement since ESPs tend to procure proportionally less RPS resources than the CCAs and IOUs. Although RPS procurement is not precisely correlated with GHG reductions, a decline in the procurement of RPS resources would likely lead to an increase in GHG emissions.

2.1.3 Impact of Direct Access Expansion on setting GHG emission reduction targets in Integrated Resource Planning

The IRP process is a critical planning tool to reduce GHG emissions. The process starts by forecasting of long-term demand for each LSE. These LSE-specific demand forecasts are derived from CEC analysis in the *Integrated Energy Policy Report* (IEPR). The forecasts are adjusted to reflect near-term load migration, which is projected based on historical sales. However, while the IEPR sets targets for each IOU and CCA, it does not include individual load forecasts for ESPs. This is because ESP load data is confidential and fluctuates based on customers' commitments. Instead, the CPUC sets an aggregate GHG planning target for all ESPs within each IOU service territory and then requires each ESP to calculate its own confidential GHG Emissions Benchmark using its own load forecast.

In order to account for that uncertainty while forecasting load to set ESP targets, the IRP currently requires ESPs to utilize their most recent year-ahead load forecast submission in the CPUC Resource Adequacy proceeding and extend it out to 2030.[20] Using short-term forecasts from the Resource Adequacy proceeding for long-term planning could lead to setting inaccurate procurement targets in electric sector planning, and increases the risk that a potentially significant portion of Direct Access load will not be planned for in IRP.

This mismatch between short-term forecasts and long-term planning raises several potentially significant issues when integrating ESPs into the IRP process:

- **Uncertainty among ESPs**. As discussed in Section 1.4, ESPs do not have long-term customer commitments, which makes load forecasting and long-term planning highly uncertain. Load may shift between various ESPs on a year-to-year basis, which means that the load that an ESP plans for today may grow or shrink, potentially significantly, in the years ahead, leaving that portion of load unplanned for when it migrates to another ESP. In a competitive environment in which customers can always leave and seek service with a different ESP, ESPs will face challenges holding long-term contracts for resources that the IRP process identifies as necessary.

- **Load uncertainty for CCAs and IOUs**. With the expansion of Direct access, load uncertainty for ESPs leads to load uncertainty for CCAs and IOUs. Commercial and industrial customers currently make up about 57 percent of electric load in California. If that load becomes less predictable—more subject to moving between Direct Access and other LSE classes—then all LSEs will have less planning certainty. With less confidence in the load projections that they use in their IRPs, LSEs could be less willing to procure based on

20 ALJ Ruling dated January 24, 2020 describing IRP load forecasts available here: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M325/K033/325033751.PDF

identified planning needs.

- **ESP load aggregation**. Each ESP provides its own load forecast in IRP. Because ESP load is confidential, they do this without knowing the load forecast of other ESPs or how their load forecasts contribute to achieving the Direct Access cap. This creates a risk that the sum of individually provided ESP forecasts will not add up to the total Direct Access load cap, which is the portion of load that they must plan for in IRP. If ESPs do procure based on their identified IRP needs, their collective procurement may still not add up to the aggregate ESP procurement obligation, which would cause under-procurement and jeopardize the electric sector meeting its 2030 GHG and reliability goals. If the Legislature opens more load to Direct Access, this problem will be amplified.

To the extent that Direct Access providers serve a higher share of total load, the CPUC will need a mechanism to ensure that ESPs procure their share of resources that meet GHG emissions reduction targets. These challenges may be manageable, but they require a clear compliance and enforcement regime to align the incentives of ESPs and their customers with IRP objectives. CPUC authority to enforce the IRP planning requirements is limited at this time. Staff recommends that the Legislature consider extending the CPUC's authority to enforce compliance.

2.1.4 Impact of Direct Access Expansion on Long-term Contracting to Meet GHG Emission Reductions

In order to meet 2030 GHG emission targets, California will need to build nearly 25,000 MW of new GHG-free resources, including over 12,000 MW of storage. This new capacity will need to achieve commercial operation by 2026 to replace retiring gas generation.[21] As major capital investments, new renewables projects cannot generally find financing without long-term purchase agreements.

In the past, California has required the IOUs to sign the long-term power purchase agreements needed to finance new generation and guaranteed the IOUs cost-recovery for these purchases. However, IOUs will only be responsible for 50 percent of load by 2021, and the IOUs' portfolios currently include more RPS eligible resources than they need to meet RPS requirements for their current load. Meanwhile more RPS-eligible generation is still needed statewide for the California to reach its 2030 GHG emission reduction targets. SB 350 addressed the issue that other LSEs will be increasingly responsible for ensuring new RPS resources are built by requiring that all LSEs procure at least 65 percent of their RPS requirements through contracts of 10-years or longer. This requirement starts in the 2021-2024 RPS compliance period. The 10-year contracting requirement is necessary to ensure that RPS contracts cover the capital costs needed to finance new renewable projects.

In informal comments to the January 8, 2020 workshop, Direct Access representatives stated that

[21] (R.) 16-02-007, 2019-2020 Proposed Decision on Electric Resource Portfolios to Inform Integrated Resource Plans and Transmission Planning, Figure 2 (p. 36), mailed Feb. 22, 2020,.

ESPs are able to meet long-term contracting requirements and are on a pathway to compliance in 2024. Specifically, Shell Energy has announced a new 200 MW solar project and Direct Energy announced a 250 MW solar project.[22] Furthermore, Shell and Commercial Energy argue that expansion of the DA market will increase market liquidity and encourage LSEs to pursue long-term investments.[23]

Nevertheless, the ESPs have a limited record of entering long-term contacts. The *2019 California Renewable Portfolio Standard Annual Report* found that long-term contracts account for 9 percent of their total portfolio.[24] While the ESPs will not need to reach compliance with the 65 percent long-term contracting requirement until 2024, ESPs will need to make a significant investment in the near term for projects to come online between 2021-2024 to meet the 65 percent target.

CPUC staff is concerned that ESPs' short-term customer commitments may create an impediment to making long-term investments in GHG-reducing resources. Customers seeking lower energy costs will have an incentive to switch to the provider with lower cost portfolio. In a competitive market, this could also impact the CCAs' ability to hold long-term contracts. In their informal comments to the January 8, 2020 workshop, CalCCA stated that uncertainty caused by load migration could undermine the long-term contracts that they have entered into and leave them locked into a fixed price contract as they lose load to lower price competitors. CCAs, who are not guaranteed cost-recovery and risk losing non-residential customers if Direct Access is expanded, may delay investments in renewables and storage to avoid investing on behalf of customers who then depart their service. The risk that load may depart is likely to raise borrowing costs for those projects that CCAs do pursue.

In sum, reopening Direct Access to all non-residential customers, Energy Division staff is concerned that overall levels of renewable generation investment will decline and reduce GHG emission reductions. While the 10-year RPS contracting requirement provides a floor by requiring longer-term investment, reporting and enforcement occur at the end of the compliance period. This means that the CPUC will not be able to rectify the shortfall if LSEs fail to procure the long-term contracts needed to meet their compliance requirements.

2.2 Impact on Criteria Air Pollution and Toxic Air Contaminants

The Federal Clean Air Act requires the Environmental Protection Agency (EPA) to establish National Ambient Air Quality Standards (NAAQS) for the maximum allowable concentrations of six "criteria" pollutants in outdoor air to protect public health: carbon monoxide, lead, ground-level ozone, nitrogen dioxide, particulate matter, and sulfur dioxide.

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22 2018 RPS Compliance Reports filed August 1, 2019 provide detail for the amount and number of long-term contracts in place by ESPs as of the date of those filings

23 See Workshop Comments filed by Shell Energy.

24 See *2019 California Renewable Portfolio Standard Annual Report*, pg. 20

The CPUC has very limited jurisdiction over the emission of criteria pollutants and toxic air pollutants.[25] CPUC jurisdiction consists of setting emission standards for criteria air pollutants related to IOU owned Biomass facilities. The CPUC minimizes the emission of criteria air pollutants through the requirements established by SB 100, which, in addition to setting more ambitious RPS goals, requires that the State "Reduc[e] air pollution, particularly criteria pollutant emissions and toxic air contaminants."[26] Additionally, the CPUC requires that LSEs "minimize localized air pollutants" in their Integrated Resource Plans.

The CPUC's ability to assess the impact of expansion of Direct Access on criterial and toxic pollutants is limited by the fact that most emissions in the state's electric system occur as the result of unspecified transactions in the CAISO energy market. These unspecified energy purchases are not tied to a specific generator or even resource type. However, as was discussed in section 2.1.1 and illustrated in Figure 3, unspecified purchases are the primary source of brown power in the energy resource mix of the system. While it is not feasible to calculate the criteria air pollutants for each LSE, it can be reasonably concluded that air pollutant levels would be higher if LSEs primarily procure unspecified power rather than power from specified carbon-free resources through long-term renewable contracts.

As discussed in Section 2.1.4, new RPS standards require that LSEs procure 65 percent of their RPS through contracts of 10-years or more, and primarily from in-state resources. While the new compliance requirements adopted in RPS and IRP will likely require ESPs to shift toward a greener portfolio, we anticipate that ESPs will continue to rely on unspecified energy procurement to the extent they can. If Direct Access is further opened and ESPs continue their past practice of relying on unspecified power as a significant source of their procurement, this could lead to an increase in criteria air pollutants.

2.3 Ensuring Reliability with Expansion of Direct Access

2.3.1 How the CPUC Ensures Reliability

The CPUC manages electric reliability through the Resource Adequacy (R. 17-09-020) and IRP proceedings (R.16-02-007). The purpose of the Resource Adequacy program is to ensure that existing resources needed for reliability are kept online by requiring that CPUC jurisdictional LSEs have sufficient capacity under contract to meet their peak demand plus a 15 percent planning reserve margin. LSEs also are subject to local and flexible capacity obligations to ensure the resources needed for local grid reliability and renewable integration are under contract.

[25]Clean Air Act permitting is the shared responsibility of the California Air Resources Board (CARB), its 35 air pollution control agencies (districts), and EPA Region 9. California's 35 local Air Pollution Control Districts or Air Quality Management Districts are responsible for regional air quality planning, monitoring, and stationary source and facility permitting. The Air Quality Management Districts are responsible for the monitoring the criteria air pollutants emitted by California electricity generators

[26] Public Utilities Code Section 399.11 (a) (1)

The Resource Adequacy program began implementation in 2006 pursuant to AB 380 (Nunez, 2005). Current Resource Adequacy requirements are meant to provide the energy market with sufficient forward capacity to meet peak demand, ensure local area reliability and ensure reliable integration of renewable energy. LSEs are required to make annual and monthly showing to the CPUC reflecting that they meet their Resource Adequacy system, local and flexible Resource Adequacy requirements. In D. 20-06-002, the CPUC adopted a centralized procurement entity (CPE) that will be charged with procuring local RA on behalf of all LSEs in PG&E's and SCE's service territories.

Longer-run reliability is addressed through the IRP process, which identifies the mix of new and existing resources that will be needed to ensure reliability (as well as meet GHG targets) over the longer run. The IRP identifies long-run needs by modeling system resources ten years into the future to determine the level of procurement needed to meet forecasted demand. If the IRP identifies a shortfall, the CPUC may order new procurement based on those findings, as discussed in Section 2.1.

Investment in new generation benefits all customers by lowering the risks of Resource Adequacy shortfalls for all LSEs. However, because the costs of the investing in new resources are considerable and all LSEs receive the benefits, each LSE has a financial disincentive to invest in new generation. This creates a tendency for an unregulated market to underinvest in reliability, creating the potential for capacity shortages.

Beginning in 2006, California addressed this potential market failure by requiring the IOUs to procure new generation with independent generators on behalf of all LSEs. D.06-07-029 adopted a Cost Allocation Mechanism (CAM) to ensure that IOUs can recover the costs of these investments from other LSEs. The CAM works by allocating the net capacity costs of investments to all customers through a non-bypassable charge. The capacity benefits are then allocated to LSEs based on monthly peak load-shares. The guaranteed cost recovery provided by the CAM mechanism allows the IOUs to act as central procurement agents for the other LSEs in their service territory to ensure that the new resource needs identified through the Commission's long-term planning processes are built and paid for by all customers who will benefit, both bundled and unbundled.

D.20-06-002 adopted a more formal central procurement structure, the Central Procurement Entity (CPE) to ensure that local Resource Adequacy needs are met in PG&E and SCE's service territories. The CPE will procure local Resource Adequacy on behalf of all LSEs and make sure the costs are shared equitably. Initially the IOUs will fulfill the CPE function, but this function may be fulfilled by other entities in the future.

2.3.2 Current Reliability Shortfalls Identified in Resource Adequacy and IRP

Recent trends documented in Energy Division's 2019 *State of the Resource Adequacy Market Report*[27] indicate a tightening market for Resource Adequacy. The Market Report documents that for the 2019 Resource Adequacy compliance year, 11 LSEs had year ahead local deficiencies, 6 had year-ahead system deficiencies, and 5 had year-ahead flexible deficiencies in 2019. One reason reported for local waiver requests was that LSEs could not identify available local capacity at any price. Many

[27]Issued in R.17-09-020 Assigned Commissioner's ruling on September 3, 2019

of these deficiencies persisted through the year in 2019 month-ahead filings. These trends also continued into 2020 Year-ahead filings, where 20 LSE requested local waivers.[28] While the CPE adopted in D. 20-06-002 will procure local Resource Adequacy, system and flex Resource Adequacy requirements will remain the responsibility of the LSEs.

Appendix A includes the list of Resource Adequacy citations issued from 2006-2019. Of the 90 citations issued since 2006, 77 have been issued to ESPs, approximately 85 percent. Compliance with Resource Adequacy obligations is the CPUC's primary mechanism to ensure reliability. The ESPs' poor compliance record is an indication that expanding Direct Access to all non-residential customers could lead to shortfalls in resource adequacy.

Furthermore, the total citation penalties amounts increased sharply in 2018. Prior to 2018 the total annual citations issued averaged $27,518 per year. The CPUC issued $2.6 million in citations in 2018 and $9.5 million in 2019, plus an additional $8.8 million in enforcement penalties. The magnitude of this increase is an indicator of a short supply in Resource Adequacy market. The tightening Resource Adequacy market has made it difficult and more expensive to procure Resource Adequacy contracts, particularly for newer LSEs. LSEs will only pay Resource Adequacy citations if there is no available Resource Adequacy capacity to procure, or the needed Resource Adequacy costs more than the citations themselves. Either way, the LSE's failure to procure Resource Adequacy contracts creates a capacity shortfall for the entire system, which drives up energy prices for all customers and puts system reliability at risk.

The system capacity shortfall identified in the Resource Adequacy proceeding is being addressed in the IRP proceeding. D.19-11-016 ordered that 3,300 MW of additional capacity be procured by Summer 2021 and assigned each LSE a share of the procurement obligation based on their proportion of the total load.[29] D.19-11-016 further required that 50 percent of the required resources come online by August 1, 2021, 75 percent by August 1, 2022, and 100 percent by August 1, 2023. As a stopgap measure to ensure reliability until the new generation is online, the decision recommended to the State Water Board that generation contracts for several large Once Through Cooling generators that were slated to retire by December 31, 2020, be extended through 2022.[30]

CCAs and ESPs may choose to self-procure resources to meet their procurement obligations or may elect to have the IOU procure on their behalf. However, D.19-11-016 directed CPUC staff to develop a mechanism similar to CAM to address cost allocation associated with both LSEs that choose to opt out of self-procurement and with LSEs that opt in (to self-provide) but fail to meet their obligations.[31] This mechanism is still being developed in the IRP proceeding.[32]

28September 2020 Revised State of the Resource Adequacy Market Report.
29 D. 19-11-016, Finding of Fact 5, p.68 and Ordering Paragraph 3, pp. 80-81.
30 D. 19-11-016, Ordering Paragraph 1, pp. 79-80.
31 D. 19-11-016, Ordering Paragraph 5, p. 82.
32 R. 16-02-007

2.3.3 Challenges to Meeting Resource Adequacy Shortfall in a Disaggregated Market

D.19-11-016 is the first time that the CPUC has ordered non-IOU LSEs to directly procure new generation capacity. It represents a test of whether individual LSEs in a competitive, disaggregated market can effectively procure the resources needed to meet their long-term reliability obligations. As stated in D.19-11-016 "[t]his is also an appropriate place to test how well the obligated LSEs perform when given a procurement requirement for system reliability and renewable integration resources in the context of IRP."[33]

There are several challenges to addressing the reliability challenges identified in D.19-11-016. There are now over 40 LSEs that must build new generation. Even if each LSE is each able to meet its resource obligations, it is uncertain whether the state will obtain the most cost-effective mix of energy resources from up to 40 independent procurements that can meet GHG targets while meeting local and flexible resource adequacy.

As explained in Section 2.1.3, load migration makes it challenging for ESPs to accurately forecast load and therefore to sign the long-term contracts needed to finance new resource development. Staff acknowledges that several of the challenges with meeting reliability are not isolated to Direct Access but are also created by load migration from CCA formation. However, as stated in previous sections, reopening Direct Access will exacerbate these challenges since it creates planning and procurement uncertainty for CCAs.

Finally, the ESPs' procurement processes lack transparency when compared to IOUs' and CCAs' procurement processes. IOUs receive up-front authorization from the CPUC for their bundled procurement plans and submit all procurement contracts to the CPUC for review and approval. The CPUC does not approve CCA procurements, but the CCAs' procurement plans are reviewed by their boards at public meetings and agenda packets containing details of procurement transactions are published on their public websites. In contrast, ESPs generally do not make information about their procurement practices available to the public and claim privilege and confidentiality to avoid disclosing information to the CPUC. This lack of transparency means that the CPUC cannot check on the progress of ESP procurement activities towards compliance targets and propose remedies if it seems likely that an ESP will fail to meet its obligations.

While P.U. Code 394.25 provides the grounds for the CPUC to suspend or revoke an ESP's registration under certain conditions, it does not the CPUC the authority to revoke licenses of ESPs due to repeated failure to comply with procurement requirements. Staff recommends that the Legislature consider extending the authority provided by P.U. Code 394.25 to ensure that a few ESPs who are out of compliance do not undermine the competitive market and put system reliability at risk.

33 D.19-11-016 at 39

2.3.4 Mechanisms Under Development to Address Reliability in a More Fragmented Retail Market

The CPUC is currently considering new procurement and cost allocation mechanisms in the IRP and Resource Adequacy proceedings that could solve the challenges of meeting reliability requirements in a fragmented energy market. As discussed in Section 2.3.2, D.19-11-016 allows LSEs to self-procure to meet IRP requirements, while also directing the development a CAM-like mechanism for LSEs that opt out or fail to meet their procurement obligation. D.19-11-016 also creates a backstop procurement mechanism to be conducted by the IOU on behalf of LSEs that fail to self-provide may come at a higher cost. However, it remains to be seen whether a backstop procurement mechanism can deliver generation resources quickly enough to avoid near-term system reliability issues.

The CPUC is also considering new structures to ensure reliability despite the load uncertainty that characterizes the current market in the RA proceeding (R. 17-09-020). D.18-06-030 determined that multi-year local Resource Adequacy should be procured through a central buyer that will purchase all local Resource Adequacy contracts on behalf of all LSEs. D.20-02-006 directed PG&E and SCE to act as centralized procurements entities for Local Resource Adequacy in their respective service territories.

While central procurement has only been adopted for local Resource Adequacy,[34] a broader use of centralized procurement might be an effective way to overcome the challenges identified above related to load migration as these affect other kinds of procurement as well.

2.4 Ensuring Direct Access Expansion Does Not Result in Cost Shifting to Bundled Customers

P.U. Code Sections 366.1 and 366.2 require that customers leaving IOU bundled service do not burden remaining customers with stranded costs that were incurred to serve them. To ensure that bundled customers remain indifferent to the cost of load departures, CCA and Direct Access customers are required to pay the Power Charge Indifference Adjustment (PCIA) for the "stranded" or above market costs of resources procured by the IOUs on their behalf before they departed. The PCIA is intended to capture the largest potential cost-shifts between bundled and unbundled customers.

In 2018 and 2019, the CPUC refined the PCIA methodology,[35] adding mechanisms to cap the annual increase of the PCIA charge and to adjust the PCIA charge to reflect actual market prices for Resource Adequacy and RPS resources. The CPUC continues to consider further methods to fairly allocate costs and resources through Phase 2 of the PCIA Rulemaking (R.17-06-026). If Direct Access is expanded to more nonresidential customers, the PCIA refinements that the CPUC has already adopted and is still considering should address most of the cost-shifting concerns related to

[34] D.20-06-002, Ordering Paragraph 3, p. 91.
[35] See D.18-10-019 and D.19-10-001.

stranded investments in resources. However, in Sections 2.4.1 and 2.4.2 below, we consider other classes of potential cost shifts that are not addressed by the PCIA.

2.4.1 Failure to meet Procurement Obligations will lead to Cost Shifting

Procurement costs will be equitably allocated to customers if all LSEs meet their own procurement obligations. If LSEs request waivers to meeting their Resource Adequacy requirements, then backstop procurement will be needed, which drives up the overall market cost. In the event the LSE's failure to procure sufficient resources to ensure reliability, the CAISO may procure additional resources under its "Reliability Must Run" program. These CAISO out-of-market procurements are based on a “cost of service” rate that often times is much more expensive than competitive procurements. These costs are allocated to all customers and can lead to cost shifting. To minimize the need to rely on this costly mechanism, the CPUC has developed a backstop procurement mechanism to order procurement through the Resource Adequacy program when one or more LSE fails to meet its procurement obligations. As discussed in the Section 2.3, the CPUC backstop mechanism's costs are allocated to the LSE that is short on its obligation. Reliance on backstop procurement to meet system need will further tighten the market for all LSEs and continue to drive up energy prices, which would also drive up rates for bundled customers. California has experienced a significant increase in energy prices due to the tightening of the market since 2018, which will be exacerbated if LSEs fail to secure procurement for new generation.

The cost allocation accounting of new mechanisms such as backstop procurement is extremely complex, and it is not clear how these costs should be reallocated if an LSE goes bankrupt or its customers migrate to a new LSE. Staff is uncertain that these many different mechanisms will continue to function as designed if there are several different types of allocation mechanism layered in the IOU billing systems. If they do not function as designed, there is the potential for additional cost shifting.

2.4.2 Load Migration May Lead to Cost Shifting within Customer Classes

IOU tariffs group customers into different rate classes based on similar characteristics to serve that class. Despite recent reforms to rate structures such as the limited adoption of time-of-use rates, tariffs do not perfectly reflect the cost of serving each individual customer in that rate class. Rather, each IOU tariff class includes customers that have more attractive load-profiles, and thus are less expensive to serve, and other customers with load-profiles that are more costly to serve. When customers with a different cost to serve all pay the same rate, the low cost of service customers are essentially subsidizing those who are more expensive to serve.

Direct Access expansion could lead to cost shifting by changing the composition of customers within each rate class. This could occur because customers with a lower cost of service have an economic incentive to depart IOU service, leaving the IOUs with customers with a higher average cost-of-service. Under competitive market conditions we can expect that the customers with a lower cost-of-service will be more likely to choose ESP service since they can reap the greatest benefit in terms of cost savings. This migration would change the composition of IOU tariff classes, leaving the IOUs with a pool of higher cost customers. To cover the higher average cost of serving the remaining pool of customers, IOUs would need to increase their rates for affected rate classes.

2.4.3 CCAs Have No Mechanism to Recover Stranded Costs

While SB 237 is focused on the potential undue cost shifting between bundled customers and Direct Access customers, there is also the potential cost shifting impacts to CCA customers. With the long-term procurement obligations established in IRP and RPS, a rapid or unforeseeable departure of load departure from CCAs could leave them with significant stranded costs that they cannot fully recover through market transactions. If these stranded costs are significant enough that a CCA fails, residential customers of a CCA, including low-income customers, would be returned to either the IOU or the otherwise designated Provider of Last Resort (POLR).

At this this time, the legislature has not asked the CPUC to consider potential exit fees or negotiated compensation for the CCAs load obligations. However, Staff recommends that the Legislature consider the CPUC's authority in allowing CCAs to recover the costs of investments that are stranded because of unforeseen load departure to address these potential impacts.

3. Recommendations on the Schedule to Reopen Direct Access

The Staff recommendations below identify the key conditions and requirements that ESPs should meet prior to reopening any Direct Access services to nonresidential customers. Staff recommendations also address timing parameters that should be taken into account if the Legislature elects to reopen Direct Access. Should the Legislature enact an expansion of Direct Access to all non-residential customers, staff recommends that the expansion should proceed on a gradual basis to minimize planning disruptions associated with load departure.

Conditions and Demonstrations for Reopening Direct Access:

Determination of reopening Direct Access should be made no earlier than 2024, after the first phase of Direct Access expansion mandated by P.U. Code Section 365.1(f) is completed. This schedule will also allow the IRP procurement ordered by D.19-11-016 to be completed, and the ESPs to demonstrate that they will meet the RPS 10-year contracting requirements. This schedule also allows time for the CPUC to develop, adopt, and implement the procurement mechanisms, such as backstop procurement, that are needed in the event that LSEs fall short of fulfilling any of their procurement obligations.

If the Legislature chooses to open Direct Access, we recommend that reopening be conditioned on ESPs' demonstrated compliance with the following obligations:

- Integrated Resource Planning
    - ESPs submit robust, transparent IRPs that:
        - provide more certainty about individual ESP planning and forecasting over a 10-year time horizon, AND
        - can be meaningfully aggregated with plans from other LSEs to form an integrated resource plan for all CPUC-jurisdictional LSEs without causing reliability or renewable integration issues; AND
    - ESPs either:
        - meet all procurement requirements pursuant to D.19-11-016; OR
        - participate in successful cost allocation of their procurement obligation using the modified CAM and backstop procurement mechanism directed by D.19-11-016: AND
        - demonstrate a track record of procuring new resources in line with their submitted IRP portfolios.

- Renewable Portfolio Standard
    - ESPs meet their RPS obligations for 2021-2024 compliance period; AND
    - ESPs meet 10-year contracting obligations in RPS

- Resource Adequacy (RA)

- ESPs comply with all Resource Adequacy requirements including multi-year year ahead flexible and system, and month ahead system and flexible obligations.

Table 3 (below) provides a timeline for these various compliance obligations.

Table 3: Timeline of compliance obligations for IRP, Resource Adequacy, and RPS.

	2020	2021	2022	2023	2024
Phase One SB 237		4,000 GWh increase to the Direct Access Cap			
IRP Filing Requirements	July 1 LSEs must file long-term procurement and implementation plans		LSEs must file long-term procurement and implementation plans if IRP remains on a two-year cycle		
IRP Procurement (D.19-11-016)	CPUC develops and approves a modified CAM mechanism.	50 % of obligations by Aug, 2021	75 % of obligations by Aug, 2022	100% of obligations by Aug, 2023	
Resource Adequacy Requirements	Annual and Monthly local, system and flex obligations. Multi-year local RA obligations.	Annual and Monthly local, system and flex obligations. Multi-year local RA obligations.	Annual and Monthly local, system and flex obligations. Multi-year local RA obligations.	Annual and Monthly local, system and flex obligations. Multi-year local RA obligations.	Annual and Monthly local, system and flex obligations. Multi-year local RA obligations.
RPS Compliance	End of the second RPS Compliance Period.				End of the third RPS Compliance Period.

<u>Recommended Direct Access Reopening Schedule:</u>

Should the above conditions and demonstration be met and the Legislature choose to reopen direct access to non-residential customers, the CPUC Energy Division Staff recommends that the Legislature follow historical precedents from SB 695 and SB 237 and phase-in additional Direct Access load incrementally. Incremental phase-in will enable LSEs to better plan for potential load-departures and thus create fewer potential cost-shift and reliability issues. Additionally, a phased-in approach provides consistency and a planning horizon for customers and avoids snap decisions from customers rushing into Direct Access to take advantage of a one-time opportunity. We recommend the following phase-in schedule and conditions:

- Set an initial re-opening schedule of **increments equal to 10 percent of eligible non-residential load per year.**
- Condition each annual expansion on CPUC review and approval of compliance with IRP, Resource Adequacy and RPS requirements, as subject to CPUC approval.
- Order annual expansion to take place on a schedule that will allow Load Serving Entities (LSEs) the ability to fully comply with Resource Adequacy requirements.
- ESPs must comply with the requirements of D.18-06-030 requiring all LSEs (including ESPs) to participate in all aspects of the year-ahead Resource Adequacy process for load they plan to serve in the following year and the "binding load forecast process" adopted in D.19-06-026.

The migration of 10 percent of non-residential load per year will minimize the planning disruptions associated with load departure identified in this report and allow the CPUC and the market sufficient time to develop the structures needed for long-term resource development in a fragmented market.

Recommendations for Legislative Action:

The CPUC recommends that the following legislative action is considered in order to ensure that GHG emissions, reliability and cost shifting provisions are met:

- Provide CPUC clear authority to enforce compliance for IRP GHG goals for all LSEs subject to P.U. Code Section 454.52 (b).
- Ensure that the CPUC continues to have clear authority to enforce the state's Resource Adequacy goals defined in P.U. Code Section 380.
- Amend P.U. Code Section 949.25 to provide the CPUC with the authority to revoke ESP licenses and CCA registration for repeated non-compliance with Resource Adequacy, RPS or IRP requirements.
- Ensure that provisions to ensure that there is no cost shifting as the result of customer moving between different LSE (Electric Corporations, CCAs, and ESPs) are applied equitable to all customers.

Consumer Protection Enforcement Division Resource Adequacy Citations

Compliance Year	Citations Issued	Citations Issued on ESPs	LSEs Cited	Total Citation Penalties	Enforcement Cases	Enforcement Cases on ESPs	LSEs Enforced	Total Enforcement Penalties
2006	1	1	Commerce Energy	$1,500	0	0		0
2007	3	3	3Phases; Commerce Energy; Amer. Util. Network	$5,000	1	1	CNE	$107,500
2008	7	7	3Phases (2); Commerce Energy (2); Corona DWP; Sempra Energy; Shell Energy	$17,000	1	1	Calpine	$225,000
2009	4	4	Commerce Energy (3); CNE	$26,500	1	1	CNE	$300,000
2010	5	4	Commerce Energy; Pilot Power Group (2), Direct Energy Business, SDG&E	$25,500	0	0		0
2011	2	2	Liberty Power; Tiger Nat Gas	$7,000	1	0	PG&E	$215,000
2012	4	3	Glacial Energy of CA, Shell Energy, SDG&E, Direct Energy Business	$14,600	0	0		0
2013	5	4	SDG&E, Commerce Energy, 3 Phases, Liberty Power (2)	$26,500	0	0		0
2014	1	1	3 Phases	$5,000	0	0		0
2015	6	6	3 Phases (2), Commerce Energy (2), EDF Industrial, Glacial Energy	$38,000	0	0		0
2016	3	3	Tiger Natural Gas, Glacial Energy, Shell Energy	$13,500	0	0		0
2017	6	4	Commercial Energy of Montana (2), CleanPowerSF, Southern California Edison, Direct Energy Business, Tiger Natural Gas	$150,110	0	0		0
2018	10	8	AmericanPowerNet Management, Just Energy Solutions (5), Direct Energy Business, Pilot Power Group, Pioneer Community Energy (2)	$2,593,439	0	0		0
2019	33	27	Just Energy Solutions (12), Commercial Energy (8), Agera Energy (6), San Jose Clean Energy (3), East Bay Community Energy (2), Valley Clean Energy (2), Pioneer Community Energy	$9,549,716	21	18		$2,758,560
Total	90	77		$12,473,365	25	21		$3,606,061

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ENERGY & ENVIRONMENTAL LAW

October 1, 2020

Sent Via Email

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

RE: San Diego Community Power and Clean Energy Alliance's Protest of San Diego Gas & Electric Company's Advice Letter 3605-E Requesting Approval of System Reliability Contracts Resulting from San Diego Gas & Electric Company's Request for Offers Under D. 19-11-016

Dear Mr. Randolph:

Pursuant to General Order ("GO") 96-B, San Diego Community Power ("SDCP") and Clean Energy Alliance ("CEA") file this protest to San Diego Gas & Electric Company's ("SDG&E") Advice Letter ("AL") 3605-E titled *Request for Approval of System Reliability Contracts Resulting from SDG&E's Request for Offers Under D. 19-11-016*.[1] To fulfill its incremental procurement obligation ordered by Decision ("D.") 19-11-016, SDG&E seeks approval of two resources adequacy ("RA") purchase agreements and one power purchase agreement ("PPA") with a third-party owned battery energy storage system (together, the "Contracts"), as well as two battery energy storage systems to be constructed by a third-party and owned and operated by SDG&E (the "EPC Agreements").[2] SDG&E also seeks Commission authorization to recover the cost of the Contracts and the EPC Agreements through customer rates and to track and record net costs related to incremental procurement in a Resource Adequacy Procurement Memorandum Account ("RAPMA") until a modified Cost Allocation Mechanism ("CAM") is adopted in Rulemaking ("R.") 20-05-003.[3]

SDCP and CEA take issue with SDG&E choosing to procure from costly resources for extended terms despite the fact that a majority of SDG&E's bundled service customers will be departing for Community Choice Aggregation ("CCA") programs, like SDCP and CEA, next year.[4] While D. 19-11-016 required SDG&E to conduct an all-source solicitation, it required

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[1] AL-3605-E was submitted on September 11, 2020.

[2] AL-3605 at 1.

[3] Id.; Appendix A.

[4] AL-3605 at Appendix C, *SDG&E Independent Evaluator Report – 2021-2023 IRP Reliability RFO, Tranche 1*, Sep. 11, 2020 at 37.

consideration of existing *as well* as new resources and storage.[5] Contracts for existing resources are required to be of at least three years in length, while contracts for new resources were required to be at least ten years.[6] Given impending bundled customer departures beginning in 2021, SDG&E's solicitation should have given priority to existing, shorter-term resources. Instead, SDG&E used its incremental procurement obligation as an opportunity to invest in costly, long-term, lithium ion battery energy storage projects at ratepayer expense. Since these costs will be allocated to ratepayers, a majority of which will be soon departing from bundled service, on a non-bypassable basis, SDG&E will effectively shift these costs to its competitors while retaining the resources' long-term benefits.[7]

Accordingly, to prevent SDG&E from imposing unnecessarily high non-bypassable charges ("NBCs") on CCA customers, the Commission should deny AL-3605 and direct SDG&E to revise its solicitation methodology to prioritize existing, shorter term resources. Alternatively, in recognition of the unique circumstances around the application of D. 19-11-016's requirement that at least 50 percent of the new incremental capacity be delivered by August 1, 2021 in the San Diego region, SDCP and CEA request that SDG&E clarify whether the proposed contracts will be accessible to SDCP and CEA through allocation, assignment, or some other mechanism. For example, SDG&E should clarify whether the contracts contain a provision allowing for the assignment of the resources from the utility's portfolio to the newly formed CCA programs that had no chance to self-procure. [8] An assignment provision of this nature would permit SDCP, CEA and SDG&E to negotiate on a voluntary basis, or subject to a later Commission-approved process, for the orderly transfer of resources for fair value. SDG&E would retain the right to enter into any assignment and would not be prejudiced or otherwise harmed.

BACKGROUND

SDCP was formed by the participating cities of San Diego, Chula Vista, Encinitas, Imperial Beach and La Mesa in December 2019, one month after the Commission issued D. 19-11-016.[9] The CCA program will launch and begin serving load in 2021, and at full enrollment,

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[5] D. 19-11-016, *Decision Requiring Electric System Reliability Procurement for 2021-2023,* Rulemaking ("R.") 16-02-007, Nov. 7, 2019 at Ordering Paragraph ("OP") 7.

[6] D. 19-11-016 at OP 10.

[7] Id. at 67. "We also clarify that the capacity procured by the IOUs in response to this decision will be allocated on a non-bypassable basis through a modified cam mechanism and no PCIA. In other words, we will not reduce the cost allocation amounts to be recovered by the IOUs after load migrates."

[8] D. 19-11-016 at OP 3.

[9] See San Diego Community Power Community Choice Aggregation Implementation Plan and Statement of Intent ("SDCP Implementation Plan"), December 9, 2019.

SDCP will serve a total of approximately 740,000 customer accounts currently served by SDG&E.[10] CEA was formed in November 2019 and plans to initiate CCA customer service in early 2021, providing electric generation service to approximately 58,000 service accounts located within the member cities of Carlsbad, Del Mar and Solana Beach.[11] Both SDCP and CEA are actively engaged in a number of steps to develop their respective programs, including resource planning and rate structure finalization.

In D. 19-11-016, the Commission imposed an additional 3,300 megawatt ("MW") system resource adequacy ("RA") procurement obligation on all load serving entities ("LSE") to be met by August 2023.[12] Each LSEs' share of the 3,300 MW was allocated on a pro-rata basis using the 2018 Integrated Energy Policy Report ("IEPR") load forecast, adopted by the California Energy Commission ("CEC") in February 2019, with the 2021 projected load shares identified in Form 1.1c, "California Energy Demand Update Forecast 2018-2030, Mid Demand Baseline Case, Mid Additional Achievable Energy Efficiency and Additional Achievable Photovoltaics."[13]

With regard to LSE obligations in the SDG&E service territory, the Commission allocated 292.9 MW of capacity to SDG&E's bundled customers, 52.7 MW to SDG&E Direct Access ("DA"), and 1.1 MW to the Solana Energy Alliance.[14] Because this decision was issued prior to the formation of SDCP and CEA, no obligation was allocated to either CCA program.

Investor-owned utilities ("IOUs") were required to conduct an all-source solicitation to meet the incremental system RA obligation, and to consider existing as well as new resources, demand-side resources, combined heat and power, and storage.[15] The decision also set a ten year minimum for new resource procurement contracts, a five year minimum for energy efficiency resources, and a three year minimum for existing resources.[16]

In the event that a CCA or electric service provider ("ESP") declines or fails to fully procure their allocated obligation, the IOUs are required to procure on the LSE's behalf and allocate capacity to the LSE's customers on a non-bypassable basis through a modified Cost

[10] SDCP Implementation Plan at 22.
[11] See https://www.thecleanenergyalliance.org/studies-reports
[12] D. 19-11-016 at OP 3.
[13] Id. at Conclusion of Law 18, OP 3.
[14] Id. at OP 3.
[15] Id. at OP 7.
[16] Id. at OP 10.

Allocation Mechanism ("CAM").[17] The Commission clarified that, since the CAM, and not the Power Charge Indifference Adjustment ("PCIA"), will be used, an IOU's cost allocation amounts will not be reduced due to load migration.[18] As such, while neither SDCP nor CEA have the right to self-procure under D. 19-11-016, SDCP and CEA customers will be continue to be charged for their share of SDG&E's incremental procurement costs on a non-bypassable basis even after departing for CCA service.

The decision requires 50% of each LSE's portion to be online by August 1, 2021, 75% by August 1, 2022, and 100% by August 1, 2023.[19] Due to opt-out decisions by SEA and certain DA providers, SDG&E must procure an additional 8.4 MW of capacity, resulting in a total procurement obligation of 301.3 MW, with at least 150.65 MW to be put online by August 1, 2021.[20]

To fulfill its 301.3 MW obligation, SDG&E conducted a single all-source solicitation to procure resources for all three online delivery dates and provided specific protocols for offers from various preferred resources including Energy Efficiency, Demand Response, Renewable Generation, Combined Heat and Power, and Energy Storage.[21] In AL-3605, SDG&E proposes to procure from five lithium ion battery energy storage systems, two of which will be owned and operated by SDG&E.[22] The remaining three Contracts would be for a term of 15 years each.[23] Altogether, SDG&E's proposed transactions would provide 164 MW, approximately 13 MW more than the 50 percent target, of total capacity by August 1, 2021.[24]

PROTEST

SDCP and CEA file this protest against AL 3605-E on the grounds that the relief requested is unjust, unreasonable, or discriminatory.[25] SDCP and CEA customers will be forced to pay non-bypassable charges ("NBCs") to cover the cost of SDG&E's procurement even though SDCP and CEA had no ability to self-procure for the resources. SDG&E's decision to

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[17] Id. at OP 5.

[18] Id. at 67.

[19] Id. at OP 3.

[20] AL-3605 at 2.

[21] AL-3605 at Appendix C, SDG&E Independent Evaluator Report – 2021-2023 IRP Reliability RFO, Tranche 1, Sep. 11, 2020 at 1.

[22] Id. at 9.

[23] Id.

[24] AL-3605 at 2.

[25] *See* GO-96B, General Rule 7.4.2.

meet its procurement obligation through long-term new battery storage projects, rather than through short-term existing resources, will essentially require SDCP and CEA customers to assume the risk of SDG&E's investment. To prevent this unjust, unreasonable, and discriminatory outcome, the Commission should deny SDG&E's proposal and instruct SDG&E to procure shorter-term resources. Separately, SDG&E should be required to clarify whether the Contracts and the utility owned resources secured under the EPC Agreements are accessible to CCA programs through allocation, assignment or other mechanism.

A. SDCP and CEA Ratepayers will be Forced to Cover a Majority of SDG&E's Procurement Costs

The Commission issued D. 19-11-016 in recognition of a need for system RA and renewable integration resources beginning in 2021 and extending through at least 2023.[26] SDG&E's 292.9 MW capacity allocation represented load forecasts at the time showing that SDG&E would be serving the majority of the region's load in 2021.[27] Circumstances have changed, however, and a majority of SDG&E's bundled service customers will be departing for CCA service beginning in 2021. Despite this shift, SDG&E's obligation remains the same, and SDG&E will be required to procure incremental capacity on behalf of SDCP and CEA customers even after they depart. As with capacity procured for customers of opt-out LSEs, capacity procured in response to this decision and the resulting costs will be allocated on a non-bypassable basis to SDCP and CEA customers.

The Commission should not allow SDG&E to incur unnecessarily high procurement costs and pass a majority of the costs on to its competitor's customers without providing SDCP and CEA an opportunity to access the resources that are ultimately approved. After D.19-11-016 was issued, two new CCA programs, SDCP and CEA, were formed and plan to begin serving load in SDG&E service territory beginning in 2021.[28] The recent load forecast issued in the previous IRP proceeding reflected that approximately 61.60% of SDG&E's 2020 bundled service load will shift to new CCA or DA programs in the SDG&E Planning Area by 2022.[29] The forecast further reflects that a majority of that load departure is attributable to SDCP and

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[26] D. 19-11-016 at Finding of Fact 17.

[27] Id. at Finding of Fact 24.

[28] *See* San Diego Community Power Community Choice Aggregation Implementation Plan and Statement of Intent, December 9, 2019; Clean Energy Alliance Community Choice Aggregation Implementation Plan and Statement of Intent, December 19, 2019.

[29] *See Administrative Law Judge's Ruling Correcting April 15, 2020 Ruling Finalizing Load Forecasts and Greenhouse Gas Benchmarks for Individual 2020 Integrated Resource Plan Filings,* R. 16-02-007, dated May 20, 2020, Attachment A at 2. (The load forecast table shows that SDG&E's estimated load will fall from 13,959-Gigawatt Hours ("GWh") in 2020 to 5,359 GWh in 2022).

CEA as they begin serving customers in 2021.[30] As such, the majority of incremental capacity that SDG&E procures for 2021-2023 will be attributed to and paid for by SDCP and CEA customers while SDG&E—not SDCP or CEA—retains control over the contracts. This leaves SDCP and CEA in a position similar to an LSE that opts-out or fails to meet its obligation, despite SDCP and CEA having had no opportunity to self-procure. Such an outcome leaves SDCP and CEA powerless over SDG&E's procurement decisions and forces SDCP and CEA customers to pay the price.

B. The Solicitation Process was Unreasonable

SDG&E was imprudent in failing to take impending customer departures into account during the solicitation process. SDG&E's solicitation should have given priority to short-term contracts with existing resources because of impending bundled customer departures beginning in 2021. Instead, SDG&E set the minimum contract terms for all bids at 10 years, thus precluding the consideration of any short-term existing resources.[31] SDG&E also gave the same priority to energy efficiency projects, which were allowed to be set for five years, and energy storage projects.[32] Given SDG&E's forecast demand reduction over the next three years, it was unreasonable to not place a priority on shorter term contracts during the solicitation process or to even allow for existing resource bids to be set at the minimum allowed by D. 19-11-016. Though bids were set at a minimum of ten years, SDG&E's proposed Contracts are for terms of 15 years each.[33] Since these costs will be allocated to ratepayers, a majority of which will be soon departing from bundled service, on a non-bypassable basis, the Commission should not authorize SDG&E to enter into contracts for terms greater than the minimum required.

Further, despite its obligation to procure system RA, SDG&E inexplicably added RA value to offers with points of interconnection within the SD-IV Local Resource Area.[34] It appears as though such preferential treatment, not required by the Commission, further limited SDG&E's choices over projects.

C. Resources Under the Proposed Contracts Should be Accessible to SDCP and CEA through Allocation or Assignment

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[30] *See Id.* (By 2022, SDCP will serve 7,407 GWh, CEA will serve 929 GWh, and DA programs will serve 3,940 GWh).

[31] AL-3605, Appendix B.1 at 2. ("The minimum contract term for all bids was 10 years, except for energy efficiency bids, which had a minimum term of 5 years.")

[32] Id. at 6.

[33] Al-3605 at 9.

[34] Id.

Since SDCP and CEA customers will be liable for SDG&E's procured capacity and associated costs despite SDCP and CEA's inability to self-procure, the Commission should ensure that the proposed Contracts are accessible and can be assigned to SDCP or CEA, or resources can be allocated to SDCP and CEA at a later date. The Independent Evaluator's report that was included as Attachment C to AL-3605 indicates that SDG&E's model RA confirm would have allowed free assignment to a central procurement entity, California CCA, or Joint Powers Authority.[35] Since the remainder of that section is redacted, the AL is unclear as to whether SDG&E's proposed Contracts will allow for free assignment to SDCP and CEA. Given the circumstances described above, the Commission should not authorize SDG&E to enter into a contract that prevents SDG&E from assigning to a CCA.

CONCLUSION

While SDCP and CEA recognize that D. 19-11-016 provides a short procurement timeframe, SDG&E cannot be allowed to invest in costly energy storage systems at the expense of CCA customers without a means of accessing the resources. SDG&E engaged in a solicitation process that favored longer-term projects with full knowledge that the bulk of its customer load would be departing beginning in 2021 and that those customers would be allocated the capacity and costs on a non-bypassable basis. To prevent SDG&E from unjustly shifting imprudently incurred costs on CCA customers, the Commission should deny the proposed transactions or, in the very least, ensure that the procurement contracts contain provisions making the resources accessible to SDCP and CEA such as a reasonable assignment provision allowing customers of newly formed CCAs that were excluded from D. 19-11-016 to benefit from the power and capacity that was for all practical purposes purchased on their behalf.

Respectfully,

/s/ Ty Tosdal

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[35] Attachment C at 27.

Attorney for San Diego Community Power
and Clean Energy Alliance

Copy (via e-mail): CPUC Energy Division (EDTariffUnit@cpuc.ca.gov)
Gregory Anderson, SDG&E (ganderson@sdge.com)
SDGETariffs@sdge.com

CALCCA
ADVANCING LOCAL ENERGY CHOICE

September 29, 2020

CPUC Energy Division
Attn: Tariff Unit and Edward Randolph, Director
505 Van Ness Avenue
San Francisco, CA 94102

By email: EDTariffUnit@cpuc.ca.gov

Re CalCCA Protest to Southern California Edison's and San Diego Gas and Electric's AMP Advice Letters in response to Decision 20-06-003

Dear Tariff Unit and Mr. Randolph:

Pursuant to General Order 96-B, CalCCA[1] submits this protest to Southern California Edison Advice Letter 4287-E and San Diego Gas and Electric Advice Letter 3602-E / 2902-G ("Advice Letters").

Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) filed their Advice Letters on September 9, 2020 in response to Decision ("D") 20-06-003, Ordering Paragraph ("OP") 83 and OP 87.

> OP 83: To implement the arrearage management payment (AMP) plan, Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, and Southern California Gas Company must each file a Tier 2 Advice Letter within 90 days of this decision to implement the AMP plan.
>
> OP 87: The issue of concern raised by CalCCA as it relates to the allocation of proportional recovery shall be discussed in the AMP working group and a proposed resolution shall be set forth in the Tier 2 Advice Letters that Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southern California Edison Company, and Southern California Gas Company file.

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[1] CalCCA was formed in 2016 as a trade organization to facilitate joint participation in certain regulatory and legislative matters in which members share common interests. CalCCA's voting membership includes CCAs serving load and others in the process of implementing new service, including: Apple Valley Choice Energy, Baldwin Park Resident Owned Utility District, Central Coast Community Energy, CleanPowerSF, Clean Energy Alliance, Clean Power Alliance, Desert Community Energy, East Bay Community Energy, Lancaster Choice Energy, MCE, Peninsula Clean Energy, Pioneer Community Energy, Pico Rivera Innovative Municipal Energy, Pomona Choice Energy, Rancho Mirage Energy Authority, Redwood Coast Energy Authority, San Diego Community Power, San Jacinto Power, San José Clean Energy, Silicon Valley Clean Energy, Solana Energy Alliance, Sonoma Clean Power, Valley Clean Energy, and Western Community Energy.

While the Advice Letters adequately addresses the requirements established in D.20-06-003, certain provisions require further clarification.

1. **The Advice Letters should clarify how often SCE and SDG&E plan to remit amounts recovered for generation-related arrears to the CCA.**

CalCCA is supportive of SCE and SDG&E's proposals to have all debt forgiven through the AMP, including third-party charges, tracked in the residential uncollectibles balancing account and then recovered through the public purpose programs charge.[2] Additionally, SCE states that it "will render amounts recovered for CCAs' generation-related AMP subsidies to the CCA"[3] but does not clarify how often (e.g., on a monthly basis or quarterly basis) the amounts recovered would be transmitted to the CCA. SCE's Advice Letter should be re-filed to clarify this detail.

Furthermore, CalCCA is concerned that SDG&E does not make any statement that it plans to render amounts recovered for forgiven CCA arrears to CCAs in its Advice Letter. Thus, the Advice Letter should be re-filed to clarify SDG&E intends to render all amounts recovered for third-party charges that are forgiven to the third party to which they were owed, and clarify the frequency and process through which such amounts will be rendered. Specifically, SDG&E should clarify whether it plans to remit funds collected to recover debt-forgiveness costs to CCA programs using the same process and with the same frequency, i.e., daily, that it uses to process CCA program charges under SDG&E Rule 27. To the extent that the remittance process deviates from the process described in Rule 27, SDG&E should provide a detailed explanation regarding how its plan differs from that process.

2. **SCE and SDG&E should be required to provide program information at the intervals requested by the CCAs, and SDG&E should clarify what information it will provide CCAs that notify it that they intend to participate in the AMP.**

As described in the Advice Letters, SCE and SDG&E's proposals for additional information to-be reported to CCAs about the AMP differ significantly. SCE correctly describes that CalCCA requested the following information to-be able to track the status of unbundled customer who are enrolled in the AMP:

1. AMP Eligibility / Ineligibility Flag (requested weekly)
2. AMP Enrollment Flag (requested weekly)
3. AMP Start / End Date (requested weekly)
4. Missed Payments Tracking (requested daily)
5. Total Expected AMP Dollar Amount (requested daily)
    a. Total Expected Generation Dollar Amount

[2] SDG&E Advice Letter at pp. 6-7 and SCE Advice Letter at p. 12.
[3] SCE Advice Letter at p. 12.

    b. Total Expected Distribution Dollar Amount
6. Processed AMP Dollar Amount (requested daily)
    a. Processed Generation Dollar Amount
    b. Processed Distribution Dollar Amount.[4]

Although CalCCA requested the information on a daily or weekly basis, CalCCA understands that both SCE and SDG&E will be implementing AMP through manual processes until SCE can automate the AMP in its customer service system and SDG&E completes deployment of its customer information system ("CIS"). SCE and SDG&E should clarify when they plan to automate the AMP program in their customer service systems, and provide the requested information at frequencies requested as much as possible.[5] The information described above should be regularly provided to CCA programs on at least a weekly basis to provide timely information about AMP participation and avoid costly and time consuming account reconciliations that would be required if the data is provided on a less frequent basis.

Furthermore, SDG&E states that it "does not intend to deviate from any of the reports currently provided to its CCAs" and that it "will work with its current CCA, Solana Energy Alliance, to accommodate data requests prior to implementation of the new CIS system."[6] CalCCA find this troublesome because having to formally data request information for an ongoing program is not only slow and inefficient but also does not allow a CCA to have any visibility into which of its customers are eligible for or enrolled in the AMP because eligibility is determined based on both IOU and third-party arrears. Additionally, the dollar value of arrears that are expected to be forgiven, the value of forgiven amounts that have been processed, and whether a customer has made the monthly payment it was supposed to make and is still in good standing in the program must be communicated to the CCAs that participate in the program. It is essential for a CCA to have access to data about the arrearage amounts it is owed that will be forgiven in order to update its billing system logic and billing system reporting to coordinate the third-party billing side of an unbundled customer's bill.

3. SCE should clarify whether a CCAs notice of intent to participate in the AMP is requested 45 days from the date of approval of the Advice Letters.

SCE states that it "requests that the CCAs notify SCE within 45 days of this AL submittal regarding their intent to participate" in the AMP.[7] CalCCA requests that SCE modify the Advice Letter to state that it requests notification 45 days after the approval of the Advice Letter. CalCCA finds it unreasonable that CCAs are being asked to determine whether or not they will participate in the AMP without knowing exactly what the final Advice Letters that are approved by the Commission will state about the how the AMP will be implemented.

[4] SCE Advice Letter at p. 13.
[5] SCE Advice Letter at p. 13.
[6] SDG&E Advice Letter at p. 7.
[7] SCE Advice Letter at p. 13.

We thank the Commission for its consideration of this protest and urge the Commission to require SCE and SDG&E to re-file their Advice Letters to clarify the abovementioned issues.

Respectfully submitted,

Evelyn Kahl

Evelyn Kahl
General Counsel to the
California Community Choice Association

cc: AdviceTariffManager@sce.com
Karyn.Gansecki@sce.com
SDG&ETariffs@sdge.com
GAnderson@sdge.com
Service List R. 18-07-005

Clean Energy Alliance
JOINT POWERS AUTHORITY

Staff Report

DATE: October 15, 2020

TO: Clean Energy Alliance Board of Directors

FROM: Gregory Stepanicich, General Counsel

ITEM 3: Resolution Adopting Clean Energy Alliance Records Retention Schedule

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RECOMMENDATION:
Approve Resolution Adopting Clean Energy Alliance Records Retention Schedule.

BACKGROUND AND DISCUSSION:

The proposed Clean Energy Alliance (CEA) Records Retention Schedule (Schedule) establishes the length of time documents are to be retained. The Schedule has been drafted to be compliant with state and federal law, as well as industry best practices. The Schedule will be modified as necessary in the future to accommodate changes in law, best practices and CEA activities.

FISCAL IMPACT
There is no fiscal impact by this action.

ATTACHMENTS:
Resolution Adopting Clean Energy Alliance Records Retention Schedule

RESOLUTION NO.

A RESOLUTION OF THE BOARD OF DIRECTORS OF THE CLEAN ENERGY ALLIANCE ADOPTING A RECORDS RETENTION SCHEDULE

WHEREAS, the maintenance of numerous records is expensive, slows document retrieval, and is not necessary after a certain period of time for the effective and efficient operation of the Clean Energy Alliance ("CEA"); and

WHEREAS, Section 34090 et seq. of the Government Code of the State of California authorizes the destruction of certain public records within specified time periods; and

WHEREAS, the Board of Directors of the CEA desires to adopt a records retention schedule to ensure efficient and effective maintenance of its various documents and records in accordance with the requirements of state law.

NOW, THEREFORE, THE BOARD OF DIRECTORS OF THE CLEAN ENERGY ALLIANCE , DOES HEREBY RESOLVE AS FOLLOWS:

SECTION 1. The records of the CEA, as set forth in the Records Retention Schedule, attached hereto as "Exhibit A", are hereby authorized to be destroyed as provided by Section 34090 et seq. of the Government Code of the State of California and in accordance with the provision of said schedule upon the request of the Board Secretary and with the consent in writing of the General Counsel, without further action by the Board of Directors of CEA.

SECTION 2. With the consent of the Board Secretary and the General Counsel, updates are hereby authorized to be made to the Records Retention Schedule without further action by the Board of Directors.

SECTION 3. The term "records" as used in the attached Records Retention Schedule shall include any writing prepared by, owned, used or retained by CEA regardless of its physical form or characteristics, including writings prepared and/or maintained in an electronic format, as defined by the California Public Records Act.

SECTION 4. This resolution shall become effective immediately upon its passage and adoption.

The foregoing Resolution was passed and adopted this ________ day of _________________, 2020, by the following vote:

AYES:
NOES:
ABSENT:
ABSTAIN:

APPROVED:

____
Ellie Havilland, Chair

ATTEST:

____
Sheila Cobian, Secretary

Exhibit A

Clean Energy Alliance (CEA) Records Retention Schedule

Purpose: Implement a records retention schedule in order to ensure that CEA's records are kept as long as legally and operationally required and that obsolete records are disposed of in a systematic and controlled manner. The records retention schedule is intended to ensure that employees adhere to approved recordkeeping requirements, and that they do so consistently.

Policy: Records will be retained according to the following schedule. After the required retention date has passed, all documents or electronic files will be deleted or discarded unless there is specific reason in the interests of CEA to maintain the record for a longer period of time.

Record Type	Required Retention	Sample Descriptions
Board Documents		
Joint Powers Agreement and By-laws	In perpetuity	All versions
Board Approved Decisions	In perpetuity	Resolutions, meeting minutes, and other items approved at regular or special Board meetings
Board and Committee Meeting Materials	In perpetuity	Agendas, staff reports and other material provided to Board members in preparation for meetings
Board Approved Budgets	In perpetuity	Final, approved budgets
Contracts and Related Documents		
Executed Contracts	5 years after completion of contract	Power supply contracts, contracts with vendors or consultants
Non-Disclosure Agreements	In perpetuity	NDA with vendor, employee, Board member or advisor
Bids & Proposals (Awarded)	7 years after close of solicitation	Including Q & A and correspondence with bidders
Bids & Proposals (Unsuccessful)	2 years after close of solicitation	Including Q & A and correspondence with bidders
Published Solicitations	2 years after close of solicitation	
Financial Documents		
Audit Reports by Accountants	In perpetuity	Independent audit reports prepared by outside accountants

Exhibit A

Accounting Records	5 years after close of fiscal year	Unaudited financials, bank statements, payables/receivables and controls back up documentation, etc.
Invoices from Vendors - Energy	5 years after completion of contract	Vendor invoices for payment
Human Resources		
Personnel Information	3 years after termination	Offer letter, resume, evaluations, personnel records, payroll records, and 1-9 forms
Recruitment Materials	3 years after completion	Ads, responses
Payroll Tax Records	8 years from date tax paid	Tax returns, W-2s, and related back up
Other Records		
General Electronic or Written Correspondence	2 years	Emails and letters
Customer-Specific Usage Information and Data	5 years	Electronic information and reporting from Data Manager, bill analyses
Marketing Material	2 years after public distribution	Flyers, brochures, electronic advertisements
General Educational or Informational Material	2 years	Brochures, reports, electronic information

Clean Energy Alliance
JOINT POWERS AUTHORITY

Staff Report

DATE: October 15, 2020

TO: Clean Energy Alliance Board of Directors

FROM: Barbara Boswell, Interim Chief Executive Officer

ITEM 4: Clean Energy Alliance Draft Energy Risk Management Policy

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RECOMMENDATION:
Receive presentation and provide input into the Clean Energy Alliance Draft Energy Risk Management Policy.

BACKGROUND AND DISCUSSION:
As a load serving entity, Clean Energy Alliance (CEA) will be transacting in the wholesale energy market. These transactions include procurement of energy products needed to fulfill customer needs and meet regulatory compliance requirements, the negotiation of contracts for those products, review and validation of related invoices, payments of invoices, resolution of disputes and management of credit concerns.

These transactions have inherent risks that CEA will be required to manage. The draft Energy Risk Management (ERMP or Policy) provides a framework and related guidance, intended to establish procedures for administration of the tasks and responsibilities related to risk management, including identification of necessary roles and responsibilities assigned to those individuals and groups who will be involved in the energy transactions process and risk management activities. The draft ERMP as proposed reflects similar policies adopted by operating CCAs.

Energy market risks that the ERMP is intended to assist CEA in addressing include:

- Market Price Risk – exposure to changes in wholesale energy prices
- Counterparty Credit and Performance Risk – inability or unwillingness of a counterparty to perform according to its contractual obligations
- Load and Generation Volumetric Risk – inaccuracies in load forecasts resulting in over- or under-procurement of energy and/or customer rate revenues that deviate from projections
- Operational Risk – potential for failure to execute and control business activities relative to plan
- Liquidity Risk – risk that CEA will be unable to meet its financial obligations
- Regulatory/Legislative Risk – shifting state and federal regulatory policies, rules, and requirements that could negatively impact CEA

To mitigate CEA's exposure to such risks, the Policy has been drafted to focus on the following key principles:

- Risk Management Goals and Principles
    - CEA will manage its energy portfolio with the purpose of reducing energy-related greenhouse gas emissions, promoting electric rate stability and fostering local economic benefits while contemporaneously minimizing risks.
- Internal Control Principles
    - Internal control principles consist of business practices designed to prevent errors and improprieties, ensure accurate and timely reporting of operational results and information pertinent to management, and facilitate attainment of business objectives. Key principles include the segregation of duties between front, middle and back office functions, and delegation of authority related to procurement activities.
- Risk Management Business Practices
    - A key component of the Policy is the requirement to regularly report risk metrics such as open positions, value-at-risk, and credit exposure.
- Risk Management Policy Governance
    - After the Board approves the Policy, it will oversee Policy administration until a Risk Oversight Committee is formed.

As proposed, the draft ERMP recommends:

- Internal controls whereby certain responsibilities/functions will be segregated;
- CEA's Board will oversee initial implementation of the ERMP and adopt future amendments as necessary;
- A Risk Oversight Committee (ROC) be created to include:
    - One CEA Board Member
    - Chief Executive Officer
    - Chief Financial Officer
    - General Counsel
    - Chief Operating Officer/Procurement Director (If/When Hired)
    - Technical Consultants will serve an advisory role

The draft Policy recommends the ROC:

- Meet beginning in late 2020 or early 2021;
- Meet a minimum of once per quarter;
- Provide updates to the Board regarding its meetings at least once per quarter;
- Adopt/adapt risk management guidelines;
- Specify permitted transactions and set related risk limits;
- Report any material violations of the Policy to the Board;
- Periodically review the ERMP and recommend updates.

<u>Delegation of Authority</u>

Delegations of Authority (DOAs) allow for timely and efficient participation in energy transactions. Unlike most other transactions that agencies enter into, energy transactions frequently require quick approval, sometimes within a matter of hours. Included in the ERMP is a proposed DOA to guide CEA energy transactions execution.

The proposed DOA:

- Shall be set at amounts commensurate with expected procurement levels and inclusive of designated executive staff and leadership;
- Allows for timely authorization to procure products that require quick responses;
- Execute transactions will be reported at the next Board meeting.

The chart below reflects anticipated energy transactions, anticipated volumes and notional values of the transactions, which have been used to develop the proposed DOA:

DRAFT EXAMPLE
Estimated average transaction sizes and terms for individual confirmations
CEA estimated annual power supply costs are ≈$65 million annually

Resource Type	Typical Annual Total MWh or MW	Usual Term	Term Used for Calculation	Price ($/MWh or $/kW-mo)	Notional Value
System Power	400,000	1-3 years	3	$36.00	$43,200,000
Resource Adequacy	1,200	1-3 years	3	$7.50	$27,000,000
Short-term Renewables	200,000	1-3 years	3	$16.00	$9,600,000
GHG-free	100,000	1-3 years	3	$5.00	$1,500,000
Long-term Renewables (fixed price)	250,000	10 years +	15	$35.00	$131,250,000
Long-term Renewables (index plus)	250,000	10 years +	10	$14.00	$35,000,000
System Power (for launch, 2 counterparties)	500,000	1-3 years	3	$36.00	$54,000,000

The proposed DOA is shown below:

Delegation of Authority: Title/Governing Body	Product Type	Tenor Limit	Volumetric Limit	Notional Value Limit
Chief Executive Officer	System Power	Up to 1 year	400,000 MWh	$ 15,000,000
	Resource Adequacy	Up to 1 year	1,500 MW	$ 10,000,000
	Renewables	Up to 1 year	200,000 MWh	$ 3,500,000
	GHG-free	Up to 1 year	200,000 MWh	$ 1,000,000
Chief Executive Officer + CEA Board Chair	All Products	1 to 5 years	Unlimited	$ 75,000,000
CEA Board	All Products	Any	Unlimited	Unlimited

The adoption of the ERMP will set the course for CEA's effective and efficient operations in the energy market while providing controls and establishing procedures to mitigate and minimize the associated risks.

FISCAL IMPACT
There is no fiscal impact by this action.

ATTACHMENTS:
Draft Clean Energy Alliance Energy Risk Management Policy

Clean Energy Alliance
JOINT POWERS AUTHORITY

Draft
Energy Risk Management Policy

Version: 1.0
Approval Date: [TBD]

Energy Risk Management Policy
Table of Contents

Energy Risk Management Policy

1.0 General Provisions

1.1 Background and Purpose of Policy

Clean Energy Alliance (CEA) participates in energy markets for purposes of fulfilling its role as a Community Choice Aggregator serving retail electricity customers located within the San Diego region. This Energy Risk Management Policy (Policy) has been developed to facilitate the achievement of CEA's organizational objectives while adhering to policies established by CEA's Board of Directors (Board), power supply and related contractual commitments, good utility practice, and applicable laws and regulations.

This Policy defines CEA's general energy risk management framework and provides management with the authority to establish processes for monitoring, measuring, reporting, and controlling market and credit risks to which CEA is exposed in its normal course of business.

1.2 Scope of Business and Related Market Risks

Beginning in May 2021, CEA will provide electric energy to retail customers within its service territory, which requires completion of the following business activities: bilateral purchases and sales of electricity under short-, medium- and long- term contracts; scheduling of load and generation of electricity into California Independent System Operator (CAISO) markets; retail marketing of electricity to consumers within its service territory; compliance with voluntary objectives and regulatory requirements that relate to carbon-free and Renewables Portfolio Standard (RPS) compliance; participation in the CAISO-administered Congestion Revenue Rights ("CRRs") market; management of the balance between load and generation over the short-, medium- and long-term planning horizons; and compliance with California Public Utilities Commission (CPUC) Resource Adequacy (RA) requirements. Participation in such activities expose CEA to certain risks, which include, but are not limited to, the following:

- Market Price Risk
- Counterparty Credit and Performance Risk
- Load and Generation Volumetric Risk
- Operational Risk
- Liquidity Risk
- Regulatory/Legislative Risk

To mitigate CEA's exposure to such risks, this Policy has been drafted to focus on the following areas of concern:

- Risk Management Goals and Principles
- Definitions of Risks
- Internal Control Principles
- Risk Management Business Practices
- Risk Management Governance

This Policy does not address the following types of general business risk, which should be treated separately in other policies, ordinances and regulations pertaining to CEA: fire, accident and casualty; health, safety, and workers' compensation; general liability; and other such typically insurable perils. The term “risk management,” as used herein, is therefore understood to refer solely to market risks as defined herein, and not those other categories of risk.

1.3 Policy Administration

This version of the Energy Risk Management Policy was adopted by the CEA Board of Directors on [insert date]. This Policy may be amended as needed by CEA’s Board.

1.4 Policy Distribution and Acknowledgment

This Policy shall be distributed to all CEA employees and third-party contractors who are engaged in the planning, procurement, sale and scheduling of electricity on CEA’s behalf and/or in other CEA departments providing oversight and support for these activities. All such employees and contractors are required to confirm in writing on an annual basis that they:

- Have read CEA’s Risk Management Policy
- Understand pertinent terms and requirements of the Policy
- Affirm the intent to comply with the Policy
- Understand that any violation of the Policy shall be subject to employee discipline up to and including termination of employment.

1.5 Policy Interpretation

Questions about the interpretation of any matters related to the Policy should be referred to the Risk Oversight Committee (ROC) or, if the ROC has not yet been formed, CEA’s Board. All legal matters stemming from this Policy will be referred to General Counsel.

2.0 Risk Management Goals

The goals of CEA’s energy risk management practices are to:

[1] assist in achieving the business objectives of retail rate stability and competitiveness;

[2] avoid losses and excessive costs, which would materially impact the financial condition of CEA;

[3] establish the parameters for energy procurement and sales activity to minimize costs while ensuring compliance with approved risk limits and policy objectives;

[4] assist in assuring that market activities and transactions are undertaken in compliance with established procurement authorities, applicable laws, regulations and orders; and

[5] encourage the development and maintenance of a corporate culture at CEA in which the proper balance is struck between control and facilitation and in which professionalism, discipline, technical skills, and analytical rigor come together to achieve CEA objectives.

3.0 Risk Management Principles

3.1 General Risk Management Principles

CEA manages its energy resources and transactions with the objectives of reducing greenhouse gas emissions, supporting local economic development and providing customers with stable, competitive electric rates while contemporaneously minimizing risks. CEA's risk management principles include the identification of relevant risks, systematic risk measurement and reporting, and strict adherence to established risk policies. CEA will not engage in transactions without proper authorization or if such transactions are determined to be inconsistent with this Policy.

It is the policy of CEA that all personnel, including the Board, management, and agents, adhere to standards of integrity, ethics, conflicts of interest, compliance with statutory law and regulations and other applicable CEA standards of personal conduct while employed by or affiliated with CEA.

3.2 Conflicts of Interest

All CEA Directors, management, employees, consultants, and agents participating in any transaction or activity within the coverage of this Policy are obligated to give notice in writing to CEA of any financial interest such person has in any counterparty that seeks to do business with CEA, and to identify any real or potential conflict of interest such person has or may have with regard to any existing or potential contract or transaction with CEA. Further, all persons are prohibited from personally participating in any transaction or similar activity that is within the coverage of this Policy, or prohibited by California Government Code § 1090, and that is directly or indirectly related to the trading of electricity and/or environmental attributes as a commodity.

If there is any doubt as to whether a prohibited condition exists, then it is the employee's responsibility to discuss the possible prohibited condition with her/his manager or supervisor.

3.3 Adherence to Statutory Requirements

Compliance is required with rules promulgated by the state of California, California Public Utilities Commission, California Energy Commission, Federal Energy Regulatory Commission (FERC), Commodity Futures Trading Commission (CFTC), and other regulatory agencies.

Congress, FERC and CFTC have enacted laws, regulations, and rules that prohibit, among other things, any action or course of conduct that actually or potentially operates as a fraud or deceit upon any person in connection with the purchase or sale of electric energy or transmission services. These laws also prohibit any person or entity from making any untrue statement of fact or omitting to state a material fact where the omission would make a statement misleading. Violation of these laws can lead to both civil and criminal actions against the individual involved, as well as CEA. This Policy is intended to comply with these laws, regulations and rules and to avoid improper conduct on the part of anyone employed by CEA. These procedures may be modified from time to time by legal requirements, auditor recommendations, requests from the CEO and/or ROC, and other considerations.

In the event of an investigation or inquiry by a regulatory agency, CEA will provide legal counsel to employees. However, CEA will not appoint legal counsel to an employee if CEA's General Counsel and Chief Executive Officer determine that the employee was not acting in good faith within the scope of employment. CEA employees are prohibited from working for another power supplier, CCA or utility in a related position while they are simultaneously employed by CEA unless an exception is authorized by the Board. For clarity, this prohibition is not intended to prevent CEA staff from performing non-CCA activities on behalf of CEA in the normal course of its business.

3.4 System of Records

CEA will maintain a set of records for all transactions executed in association with CEA's procurement activities. The records will be maintained in US dollars and transactions will be separately recorded and categorized by type of transaction. This system of record shall be auditable.

4.0 Definitions of Market Risks

The term "market risks," as used herein, refers specifically to those categories of risk which relate to CEA's participation in wholesale and retail markets as a Load Serving Entity (LSE) as well as CEA's interests in certain long-term contracting opportunities. Market risks include market price risk, counterparty credit and performance risk, load and generation volumetric risk, operational risk and liquidity risk, as well as regulatory and legislative risk. These categories are defined and explained as follows.

4.1 Market Price Risk

Market price risk is defined as exposure to changes in wholesale energy prices. Market price risk is a function of price volatility and the volume of energy that is contracted at fixed prices over a defined period of time. Prices in electricity markets exhibit high volatility, and appropriate forward procurement and hedging approaches are necessary to manage exposure to pricing volatility within the CAISO or bilateral energy markets.

Market price risk is also impacted by market liquidity, which may be an issue for certain energy or capacity products that CEA procures. Illiquid markets are characterized by relatively few buyers or sellers, making it more difficult to buy or sell a commodity and often resulting in higher premiums on purchases or deeper discounts on sales.

Another dimension of market price risk is congestion or "basis" risk. Congestion risks arise from the locational differences in prices between the point of delivery of CEA's load (meaning, power consumed by customers) and its contracted supply.

For CEA, market price risk manifests in two types of exposure. The first type of market price risk exposure is the potential for variations in power costs that are related to CEA's "open positions", meaning the volume of energy that will ultimately be required for delivery to CEA customers but that has not yet been purchased. Increases in market prices will increase CEA's costs when those open positions are eventually filled at the higher prices. Incurrence of higher than anticipated power costs can reduce funds available for financial reserves or other planned uses and can lead to the need for rate increases. Market price risk exposure related to open positions are monitored through net open position valuations and value at risk metrics as described in Section 6.1 of this Policy.

The second type of market price risk exposure is the potential for wholesale trading positions, long-term supply contracts and generation resources to move "out of the money," that is, become less valuable when compared to similar positions, contracts or resources obtainable at present prices. These same positions can also be "in the money" if such positions become more valuable when compared to similar positions, contracts or resources obtainable at present market prices. This valuation methodology is commonly referred to as "Mark to Market." Transaction valuation and reporting of positions shall be based on objective, market-observed prices. If CEA is "out of the money" on a substantial portion of its contracts, it may have to charge higher retail rates relative to competitors. Such a situation could erode CEA's competitive position and market share if other market participants (e.g., Direct Access providers or SDG&E) are able to procure power at a lower cost and offer lower retail electric rates.

4.2 Counterparty Credit and Performance Risk

Performance and credit risk refer to the inability or unwillingness of a counterparty to perform according to its contractual obligations. Failure to perform may arise if an energy supplier fails to deliver energy as agreed. There are four general performance and credit risk scenarios:

[1] counterparties and wholesale suppliers may fail to deliver energy or environmental attributes, requiring CEA to purchase replacement products elsewhere, possibly at higher costs;

[2] counterparties may fail to take delivery of energy or environmental attributes sold to them, necessitating a quick resale of the product elsewhere, possibly at a lower price;

[3] counterparties may fail to pay for delivered energy or environmental attributes; and

[4] counterparties and suppliers may refuse to extend credit to CEA, possibly resulting in higher collateral posting costs, which could impact CEA's cash position and/or bank lines of credit.

An important subcategory of credit risk is concentration risk. When a portfolio of positions and resources is concentrated with one or a very small number of counterparties, generating resources, or geographic locations, it becomes more likely that major losses will be sustained in the event of non-performance by a counterparty/supplier or as a result of unexpected price fluctuations at one location.

4.3 Load and Generation Volumetric Risk

Energy deliveries must be planned in consideration of forecasted load. CEA forecasts load over the long and short term and enters into long- and short-term fixed price energy contracts to hedge its load consistent with the provisions of its Integrated Resource Plan (IRP).

Load forecasting risk arises from inaccurate load forecasts and may result in the over- or under-procurement of energy and/or customer rate revenues that deviate from approved budgets. Energy delivery risk occurs if a generator fails to deliver expected or forecasted energy volumes. Variations in wind speed and cloud cover, for example, can also impact the respective amount of electricity generated by wind and solar resources. Furthermore, the occasional oversupply of power on California's electric grid can lead to curtailment of energy deliveries or reduced revenue resulting from low or negative prices at certain energy delivery points. In general, weather is an important variable that can result in higher or lower electricity usage due to its impact of customer electricity usage (heating and cooling needs, for example) as well as energy production (by generators that are commonly impacted by ambient weather conditions).

In the CAISO markets this situation can result from both the oversupply and undersupply of electricity relative to CEA's load as well as the over- or under-scheduling of generation or load into the day ahead market (relative to actual energy consumed or delivered in the real-time market). Load and generation volumetric risk may result in unanticipated open positions and imbalance energy costs, which are assessed when actual and scheduled loads do not align. More specifically, imbalance energy costs result from temporal pricing differences that often exist in the day-ahead and real-time energy markets during discrete scheduling intervals. For example, if CEA's actual load is higher than scheduled in the day-ahead market, and real-time prices are comparatively high during such instances, then CEA bears the risk of higher-than-anticipated energy costs due to such variation. .

4.4 Operational Risk

Operational risk consists of the potential for failure to execute and control business activities relative to plan. Operational risk includes the potential for:

[1] organizational structure that proves to be ineffective in addressing risk, i.e., the lack of sufficient authority to make and execute decisions, inadequate supervision, ineffective internal checks and balances, incomplete, inaccurate and untimely forecasts or reporting, failure to separate incompatible functions, etc.;

[2] absence, shortage or loss of key personnel or lack of cross-functional training;

[3] lack or failure of facilities, equipment, systems and tools, such as computers, software, communications links and data services;

[4] exposure to litigation or sanctions resulting from violating laws and regulations, not meeting contractual obligations, failure to address legal issues and/or receive competent legal advice, not drafting and analyzing contracts effectively, etc.; and

[5] errors or omissions in the conduct of business, including failure to execute transactions, violation of guidelines and directives, etc.

4.5 Liquidity Risk

Liquidity Risk is the risk that CEA will be unable to meet its financial obligations. This can be caused by unexpected financial events and/or inaccurate pro forma calculations, rate analyses, and debt analyses. Some unexpected financial events impacting liquidity could include:

[1] breach of CEA credit covenants or thresholds – CEA has credit covenants included in its banking agreements and may, eventually, have similar covenants within its energy contracts. Breach of credit covenants or thresholds could result in the withdrawal of CEA's line of credit or may trigger the requirement to post collateral;

[2] contractual requirements to post collateral (with counterparties) due to a decline in market prices below the contract price; and

[3] from time to time CEA may be the subject of legal or other claims arising from the normal course of business. Payment of a claim by CEA could reduce CEA's liquidity if the cause of loss is not covered by CEA's insurance policies.

4.6 Regulatory/Legislative Risk

Regulatory risk encompasses market structure and operational risks associated with shifting state and federal regulatory policies, rules, and requirements that could negatively impact CEA. An example is the potential increase in exit fees for customers served by Community Choice Aggregators that could result in higher overall electricity costs for CEA customers (relative to SDG&E or DA service options).

Legislative risk is associated with actions by federal and state legislative bodies, which may impose adverse changes or requirements that could infringe upon CEA's autonomy, increase its costs, or otherwise negatively impact CEA's ability to fulfill its goals and objectives.

5.0 Internal Control Principles

Internal controls are based on proven principles that meet or exceed the requirements of financial institutions and credit rating agencies while also being considerate of good utility practice. The required controls shall include all customary and usual business practices designed to prevent errors and improprieties, ensure accurate and timely reporting of results of operations as well as information pertinent to management, and facilitate attainment of business objectives. These controls shall remain fully integrated in all activities of the business and shall be consistent with stated objectives. There shall be active participation by senior management in risk management processes.

The required controls include the following:

[1] Segregation of duties and functions between front, middle, and back office activities. In general terms, the designation of responsibilities shall be organized as follows:

- Front office is responsible for planning (e.g. preparation of the IRP and other planning activities) and procurement (e.g. solicitation management, contract negotiation, structuring and pricing as well as contract execution), contract management, compliance and oversight of scheduling coordinator functions with the CAISO;

- Middle office is responsible for controls and reporting (e.g., risk monitoring, risk measurement, risk reporting, procurement compliance, counterparty credit review, approval and monitoring); and

- Back office is responsible for settlements and processing (e.g., verification, validation, reconciliation and analysis of transactions, tracking, processing and settlement of transactions).

[2] Delegation of authority as defined in section 6.5 (below) that is commensurate with responsibility and capability, and relevant training to ensure adequate knowledge to operate in and comply with rules associated with the markets in which such personnel may transact (e.g., CAISO). Contract origination, commercial approval, legal review, invoice validation, and transaction auditing shall be performed by separate staff or contractors for each transaction. No individual staff member shall perform all of these functions on a single transaction.

[3] Defining authorized products and transactions. In general terms, authorized and prohibited transactions are defined as follows:

- Authorized transactions are those transactions directly related to the procurement and/or administration of electric energy, reserve capacity, transmission and distribution service, ancillary services, congestion revenue rights, renewable energy, renewable energy credits, scheduling activities, tolling agreements, and bilateral purchases of energy products. All transactions must be consistent with this Policy and the Board approved IRP.

- It is the expressed intent of this Policy to prohibit the acquisition of risk beyond that encountered in the efficient optimization of CEA's generation portfolio and execution of procurement strategies. Prohibited transactions are those transactions that are not related to serving retail electric load and/or reducing financial exposure. Speculative buying and selling of energy products or maintenance of open positions that do not conform with agreed upon thresholds is prohibited. Speculation is defined as buying energy in excess of forecasted load plus reasonable planning reserves, intentionally under procuring energy relative to minimum load hedging targets or selling energy or environmental attributes that are not yet owned by CEA. In no event shall speculative transactions be permitted. Any financial derivatives transaction including, but not limited to futures, swaps, options, and swap options are also prohibited. If any questions arise as to whether a proposed transaction(s) constitutes speculation, CEA shall conduct an analysis of the transaction and the Board shall review the transaction(s) to determine whether the transaction(s) would constitute speculation and document its finding in the meeting minutes.

[4] Defining proper process for executing power supply contracts. CEA will ensure power supply contracts are approved by pertinent technical personnel. Legal review will be required of various forms of agreement used by CEA.

[5] Accurately capturing transactions and other data, with standardization of electronic and hard copy documentation.

[6] Summarizing and reporting of transactions and other activity at regular intervals.

[7] Measuring risk and performance in a timely manner and at regular intervals.

[8] Regularly reviewing compliance to ensure that this Policy and related risk management guidelines are adhered to, with specific guidelines for resolving instances of noncompliance.

[9] Ensuring active participation by senior management in risk management processes.

6.0 Risk Management Business Practices

6.1 Risk Measurement Metrics and Reporting

A vital element of this Policy is the regular identification, measurement and communication of risk. To effectively communicate risk, all risk management activities must be monitored on a frequent basis using risk measurement methodologies that quantify the risks associated with CEA's procurement-related business activities and performance relative to stated goals.

CEA measures and updates its risks using a variety of tools that model programmatic financial projections, market exposure and risk metrics, as well as through short-term budget updates. The following items are measured, monitored and reported:

[1] Mark-to-Market Valuation – marking to market is the process of determining the current value of contracted supply. A mark-to-market valuation shall be performed at least once per quarter.

[2] Exposure Reporting – calculates the notional dollar risk exposure and value at risk of open portfolio positions at current market prices. The exposure risk calculations shall be performed at least once per quarter.

[3] Open Position Monitoring – on a monthly basis, CEA shall calculate/monitor its open positions for all energy and capacity products. If energy open positions for the month following the then current month (prompt month) exceed 10% of load, CEA will solicit market energy to close open positions and make a commercial decision to close the position. Open positions for terms beyond the prompt month will be monitored monthly and addressed in accordance with CEA's planning models and related policies.

[4] Counterparty Credit Exposure – calculates the notional and mark-to-market exposure to each CEA counterparty by deal and in aggregate. Counterparty credit exposure shall be reported on a quarterly basis. Counterparty exposure reporting includes contingent collateral posting risks arising from changes in market prices and other factors.

[5] Reserve Requirement Targets – no less than once per year, CEA staff will monitor CEA's reserves to ensure that they meet the targeted thresholds.

Consistent with the above, the Middle Office will develop reports and provide feedback to the Risk Oversight Committee. If a limit or control established by this Policy is violated, the Middle Office will send notification to the responsible party and the Risk Oversight Committee. The Risk Oversight Committee will discuss the cause and potential remediation of any violation to determine next steps for curing the violation.

Risk measurement methodologies shall be re-evaluated on a periodic basis to ensure CEA adjusts its methods to reflect the evolving competitive landscape.

6.2 Market Price Risk

CEA manages market price risk using its planning models which define forecasted load, energy under contract and CEA's open positions across various energy product types including renewable energy (Portfolio Content Category I and II; CEA does not anticipate procuring Portfolio Content Category III products), carbon-free energy and system power relative to CEA's procurement targets.

CEA determines the quantity of energy it intends to place under contract each year through the use of its planning models and in consideration of stated procurement targets. The planning models include an outline of the delivery term and quantity of each energy product that CEA intends to fill in the upcoming year. The planning models inform CEA's solicitation planning, including solicitation timing and strategy as well as the person/team responsible for related solicitations.

In general, CEA will seek to purchase some long-term renewable energy each year for purposes of diversifying market exposure while also avoiding potential "planning cliffs", which can occur when a significant portion of long-term contracts expire at or near the same point in time.

For products generally purchased through short- and medium-term contracts, CEA follows a similar temporal diversification strategy, with multiple procurement cycles occurring throughout the year.

Congestion risk is managed through the contracting process with a preference for day-ahead energy delivery at the SP 15 trading hub. Once energy is procured, CEA manages congestion risks through the application of CRRs consistent with its Congestion Revenue Rights Risk Management Guidelines. CRRs are financial instruments used to hedge against transmission congestion costs encountered in the CAISO day-ahead market. CEA uses a third-party scheduling coordinator to manage its CRR portfolio. CEA primarily uses CRRs to reduce its exposure to congestion charges.

6.3 Counterparty Credit and Performance Risk

CEA shall evaluate and monitor the financial strength of its suppliers in consideration of adopted Credit Guidelines. Generally, CEA manages its exposure to energy suppliers by exhibiting a preference for counterparties with Investment Grade Credit ratings as determined by Moody's or Standard and Poor's and through the use of security requirements in the form of cash and letters of credit. CEA measures its mark-to-market counterparty credit exposure consistent with industry best practices.

6.4 Load and Generation Volumetric Risk

CEA manages energy delivery risks by ensuring that contracts include appropriate contractual penalties for non-delivery, acquiring energy from a geographically and technologically diverse portfolio of generating assets (with a range of generation profiles that are generally complementary to the manner in which CEA's customers use electric power). Due to known production variability and supply uncertainty related to renewable and other carbon-free energy products, CEA includes planning margins in its procurement of such products to ensure that related targets/mandates are achieved.

CEA manages load forecasting and related weather risks by contracting with qualified data management and scheduling coordinators, which independently or jointly provide the systems and data necessary to forecast and schedule load using good utility practice. Load variability is also considered in establishing appropriate planning margins for renewable and other carbon free energy sources.

CEA's load scheduling strategy, as executed by its scheduling coordinator, shall be in accordance with adopted Load Bidding/Scheduling Guidelines. This strategy shall ensure that price risk in the day-ahead and real-time CAISO markets is managed effectively and is consistent with good utility practice.

6.5 Operational Risk

Operational risks are managed through:

- Adherence to this Policy, and oversight of procurement activity including delegation of authority;
- Conformance with applicable human resources policies and guidelines;
- Staff resources, expertise and/or training reinforcing a culture of compliance;
- Use of qualified, highly experienced contractors on an as-needed basis in the event that necessary expertise does not exist within CEA's own organization;
- Ongoing and timely internal and external audits; and
- Cross-training amongst staff

To ensure proper controls for executing energy transactions and to facilitate the efficient operation of CEA in its ordinary course of business, the Board delegates transactional authority that is commensurate with responsibility and capability. Accordingly, by approving this Policy, the Board delegates the following energy procurement authorities by product type, tenor, volume and notional value to its Chief Executive Officer and the ROC:

Delegation of Authority: Title/Governing Body	Product Type	Tenor Limit	Volumetric Limit	Notional Value Limit
Chief Executive Officer	System Power	Up to 1 year	400,000 MWh	$ 15,000,000
	Resource Adequacy	Up to 1 year	1,500 MW	$ 10,000,000
	Renewables	Up to 1 year	200,000 MWh	$ 3,500,000
	GHG-free	Up to 1 year	200,000 MWh	$ 1,000,000
Chief Executive Officer + CEA Board Chair	All Products	1 to 5 years	Unlimited	$ 75,000,000
CEA Board	All Products	Any	Unlimited	Unlimited

Any changes to the delegation of authority will require Board approval.

6.6 Liquidity Risk

CEA manages liquidity risk through adherence to its loan and power purchase agreement credit covenants; limiting commitments to provide security consistent with adopted Credit Guidelines; ensuring it has adequate loan facilities, prudent cash and investment management; and adherence to any applicable reserve policies. CEA monitors its liquidity (defined as unrestricted cash, investments, and unused bank lines of credit) no less than weekly. CEA utilizes scenario and sensitivity analyses while preparing budget, rate, and pro forma analyses to identify potential financial outcomes and ensure sufficient liquidity under adverse conditions.

6.7 Regulatory/Legislative Risk

CEA manages its regulatory and legislative risk through active participation in working groups and advocacy coalitions such as the California Community Choice Association. CEA regularly monitors and participates in, as necessary, regulatory rulemaking proceedings and legislative affairs to protect CEA's interests.

7.0 Risk Management Policy Governance

7.1 CEA Board of Directors

The CEA Board is responsible for adopting this Policy. The Board also approves CEA's annual budget, contracting authorities and delegated responsibilities for the management of CEA's operations to its Chief Executive Officer and staff. The Board is responsible for reviewing and recommending approval of substantive changes to this Policy, as needed, and for initiating and overseeing a review of the implementation of this Policy as it deems necessary. The Chief Executive Officer and Risk Oversight Committee (described below) may make reports and seek approval for any substantive changes to this Policy, and any such changes would be subject to Board approval.

7.2 Risk Oversight Committee (ROC)

To ensure the implementation of and compliance with this Policy, the Chief Executive Officer will establish a Risk Oversight Committee prior to the commencement of retail electric service by CEA.

The Chief Executive Officer will serve as the ROC's Chair. CEA's technical consultants will have standing invitations to the ROC meetings. The ROC will have authority to:

- Meet at least once per quarter, or as otherwise called to order by the ROC's Chair.
- No less than once per quarter, provide a report to the Board regarding its meetings, deliberations and any other areas of concern.
- From time to time, adopt and/or adapt risk management guidelines defining internal controls, strategies and processes for managing market risks incurred through or attendant upon wholesale trading, retail marketing, long-term contracting, CRR trading and load and generation scheduling.
- Specify the categories of permitted transactions and set risk limits for wholesale trading. The ROC will receive and review information and reports regarding risk management, wholesale trading transactions, and the administration of supply contracts.
- Have direct responsibility for enforcing compliance with this Policy. Any material violations of this Policy, as determined by the ROC, shall be reported to the Board for appropriate action.

Clean Energy Alliance
JOINT POWERS AUTHORITY

Staff Report

DATE: October 15, 2020

TO: Clean Energy Alliance Board of Directors

FROM: Barbara Boswell, Interim Chief Executive Officer

ITEM 5: Clean Energy Alliance Branding Update and Logo Options

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RECOMMENDATION:
Receive Clean Energy Alliance branding update and select preferred logo option.

BACKGROUND AND DISCUSSION:
Clean Energy Alliance (CEA) has engaged Tripepi Smith (TS) to provide Communications and Marketing services. As part of that engagement, TS has been tasked with developing a brand and logo for CEA. At its September 17, 2020 the CEA Board received a report and provided input into branding for CEA. This input, along with discussions with staff were utilized in developing the logo options reflected in the attached.

The CEA logo should:

- Positively reflect the goals of CEA
- Speak directly to CEA customers
- Build a reputation with community and key stakeholders

The black and white version of the logo options is presented to provide the ability to focus on the graphic representation of the options. Each option has been displayed in vertical and horizonal as well as with the CEA initials to demonstrate how it may be look in different print formats. Two different color palette options are provided for consideration.

FISCAL IMPACT
There is no fiscal impact by this action.

ATTACHMENTS:
Clean Energy Alliance Logo Options

CEA LOGO EXPLORATION

Draft-04
- 3 logo options
- Vertical (V), Horizontal (H), Initials (CEA)
- 3 color variations

Black & White
Dark | Medium | Accent
B&W helps you focus on text and shapes

View color set A (blue)
Dark 1 | Medium 2 | Accent 3

View color set B (purple)
Dark 7 | Medium 2 | Accent 3

Option 1

CLEAN ENERGY ALLIANCE
V

Raleway

CLEAN ENERGY ALLIANCE
H

CEA
CEA

Option 2

CLEAN ENERGY ALLIANCE
V

Raleway

CLEAN ENERGY ALLIANCE
H

CEA
CEA

Option 3

CLEAN ENERGY ALLIANCE
V

Raleway

CLEAN ENERGY ALLIANCE
H

CEA
CEA

CEA LOGO EXPLORATION

Draft-04

- 3 logo options
- Vertical (V), Horizontal (H), Initials (CEA)
- 3 color variations

Black & White

Dark | Medium | Accent

B&W helps you focus on text and shapes

View color set A (blue)

Dark 1 | Medium 2 | Accent 3

View color set B (purple)

Dark 7 | Medium 2 | Accent 3

Option 1

CLEAN ENERGY ALLIANCE

V

Raleway

CLEAN ENERGY ALLIANCE

H

CEA

CEA

Option 2

CLEAN ENERGY ALLIANCE

V

Raleway

CLEAN ENERGY ALLIANCE

H

CEA

CEA

Option 3

CLEAN ENERGY ALLIANCE

V

Raleway

CLEAN ENERGY ALLIANCE

H

CEA

CEA

CEA LOGO EXPLORATION

Draft-04

- 3 logo options
- Vertical (V), Horizontal (H), Initials (CEA)
- 3 color variations

Black & White

Dark Medium Accent

B&W helps you focus on text and shapes

View color set A (blue)

Dark 1 Medium 2 Accent 3

View color set B (purple)

Dark 7 Medium 2 Accent 3

	V	H	CEA
Option 1	CLEAN ENERGY ALLIANCE	CLEAN ENERGY ALLIANCE	CEA
Option 2	CLEAN ENERGY ALLIANCE	CLEAN ENERGY ALLIANCE	CEA
Option 3	CLEAN ENERGY ALLIANCE	CLEAN ENERGY ALLIANCE	CEA

Raleway

Raleway

Raleway

Clean Energy Alliance
JOINT POWERS AUTHORITY

Staff Report

DATE: October 15, 2020

TO: Clean Energy Alliance Board of Directors

FROM: Barbara Boswell, Interim Chief Executive Officer

ITEM 6: Clean Energy Alliance Approval of Community Advisory Committee Nominees, Work Plan and Meeting Schedule

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RECOMMENDATION:
1) Approve Clean Energy Alliance Community Advisory Committee Nominees for City of Carlsbad
2) Approve Clean Energy Alliance Community Advisory Committee Nominees for City of Del Mar
3) Approve Clean Energy Alliance Community Advisory Committee Nominees for City of Solana Beach
4) Approve Clean Energy Alliance Alternate Board Member to Serve on the Community Advisory Committee
5) Approve Clean Energy Alliance Community Advisory Committee Meeting Schedule and 2021 Work Plan

BACKGROUND AND DISCUSSION:
At its July 16, 2020 Board Meeting, the Clean Energy Alliance (CEA) Board approved the Community Advisory Committee (CAC) Policy and subsequently approved the following timeline for activating the CAC:

ACTIVITY	DATE	STATUS
Open Application Process	August 3, 2020	Applications Open
CEA Board Approve Initial CAC Workplan & Meeting Schedule	August 20, 2020	Approved
Applications due to CEA Board Secretary	August 28, 2020	Completed
Applications distributed to CEA Board Member	September 4, 2020	Completed
CEA Board Member Application Review & Evaluation	September 7 – October 2	Completed
CEA Board Meeting Review Recommendations & Approve Appointees	October 15, 2020	
First Meeting of CAC	November/December 2020	

Pursuant to the adopted CAC Policy the committee is made up of two appointees from each CEA member agency as well as one Board Alternate. To establish the committee rotation, one nominee shall be identified to serve a one-year term and the other nominee (including the Board Alternate) shall serve a two-year term.

Applications received by the CEA Board Secretary from individuals interested in serving on the CAC were provided to board members based on the community the applicant was from and CEA Board Members will nominate the CAC members from the respective pool of applicants.

CAC Meeting Schedule and Work Plan

The CEA Board has directed that the CAC shall meet quarterly and the meeting schedule and related work plan is shown below:

MEETING DATE	WORK PLAN/TOPICS
December 2020	Overview of Brown Act Requirements and Conflicts of Interest Form 700 Community Choice Aggregation Overview CEA Implementation & Goals
March 2021	Community Outreach Plan to support CEA Implementation
June 2021	CEA FY 21/22 Budget Overview & Goals
September 2021	Overview& Discussion of Member Agency Climate Action Plans & Goals
December 2021	Overview of Programs offered by CCAs throughout the State

FISCAL IMPACT

Costs related to administration of the Community Advisory Committee are anticipated to be minimal and can be covered within the adopted Fiscal Year 2020/21 Budget and existing contracts.

ATTACHMENTS:

None

Clean Energy Alliance
JOINT POWERS AUTHORITY

Staff Report

DATE: October 15, 2020

TO: Clean Energy Alliance Board of Directors

FROM: Barbara Boswell, Interim Chief Executive Officer

ITEM 7: Clean Energy Alliance Bid Evaluation Criteria Policy

RECOMMENDATION:
Approve Clean Energy Alliance Bid Evaluation Criteria Policy

BACKGROUND AND DISCUSSION:

At its September 17, 2020 regular meeting, the Clean Energy Alliance (CEA) Board considered the proposed Bid Evaluation Criteria Policy (Policy). The Board provided input and requested the Policy be revised and brought back to the October meeting for consideration.

Changes reflected in the revised Policy include:

- Change title of Local Economic Sustainability category to Environmental Stewardship
- Add Social Equity Category
- Revise Environmental Stewardship criteria to remove societal, health, and economic benefits
- Add Social Equity criteria that reflects societal, health and economic benefits that address social equity to be evaluated as High or Low
- Revise Local Job Growth criteria to add creation of new jobs to High rating; add a Medium rating to reflect employment of local workers and use of local businesses

All other aspects of the Policy as proposed on September 17, 2020 remain unchanged.

FISCAL IMPACT
There is no fiscal impact by this action.

ATTACHMENTS:
Attachment A - Proposed Clean Energy Alliance Bid Evaluation Criteria Policy – Redlined
Attachment B - Proposed Clean Energy Alliance Bid Evaluation Criteria Policy – Clean

Clean Energy Alliance
JOINT POWERS AUTHORITY

BID EVALUATION CRITERIA POLICY

Clean Energy Alliance (CEA) desires to establish a Bid Evaluation Criteria Policy (Policy) that establishes a process for comparing bids to select the best offer to achieve the goals of CEA as identified in the Joint Powers Authority Agreement and adopted policies.

CEA has identified the following evaluation criteria categories, for non-energy goods or services in excess of $100,000 requiring a formal bid, power purchase agreements with third parties and to the extent permitted by law, CEA owned generation projects:

$ Value
Innovation
Development Risk
Project Location
~~Local Economic Benefit~~Environmental Stewardship
Social Equity
Local Job Growth
Workforce Development

Projects will be ranked high, medium, low or neutral based as determined by applying the following criteria:

$ Value: Projects will be ranked based on the $ value as compared to other bids received and estimated costs in CEA financial pro forma

Innovation

- **High**: Project contains a novel, innovative, or otherwise meritorious concept, application, approach or method
- **Neutral**: Project does not contain a novel, innovative, or otherwise meritorious concept, application, approach or method

Development Risk: Projects will be ranked from high (good) to low (bad) based on:

- Site Control
- Interconnection status
- Environmental impacts
- Land use and permits

- Project financing
- Developer experience

Project Location

- **High**: In San Diego County and any additional area served by CEA
- **Medium:** Other areas within California
- **Low:** Out of state projects

~~Local Economic Sustainability~~Environmental Stewardship

- **High**: Demonstrates environmental benefits beyond the climate and GHG reduction benefits of renewable energy~~multiple benefits (provides additional societal, health, economic, or environmental benefits beyond the climate and GHG reduction benefits of renewable energy)~~
- **Low:** Project does not demonstrate ~~local economic sustainability~~environmental stewardship as defined above

Social Equity
- **High:** Demonstrates societal, health, or economic benefits that address social equity
- **Low:** Project does not demonstrate social equity benefits as defined above

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Local Job Growth

- **High:** ~~Employ~~ Creates new jobs that employ workers and uses businesses in San Diego County and any additional areas served by CEA
- **Medium:** Employs existing workers and uses businesses in San Diego County and any additional areas served by CEA
- **Low:** Employs workers and uses businesses outside San Diego County and any additional areas served by CEA

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Workforce Development

- **High:** Employ workers from San Diego County and any additional areas served by CEA; utilize apprenticeship programs; follows fair compensation practices including proper assignment of work to crafts that traditionally perform the work
- **Low:** Does not demonstrate workforce development as defined above

The evaluation criteria will be included in formal bid documents and requests for proposals, as appropriate.

Clean Energy Alliance
JOINT POWERS AUTHORITY

BID EVALUATION CRITERIA POLICY

Clean Energy Alliance (CEA) desires to establish a Bid Evaluation Criteria Policy (Policy) that establishes a process for comparing bids to select the best offer to achieve the goals of CEA as identified in the Joint Powers Authority Agreement and adopted policies.

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Innovation
Development Risk
Project Location
Environmental Stewardship
Social Equity
Local Job Growth
Workforce Development

Projects will be ranked high, medium, low or neutral based as determined by applying the following criteria:

$ Value: Projects will be ranked based on the $ value as compared to other bids received and estimated costs in CEA financial pro forma

Innovation

- **High**: Project contains a novel, innovative, or otherwise meritorious concept, application, approach or method
- **Neutral**: Project does not contain a novel, innovative, or otherwise meritorious concept, application, approach or method

Development Risk: Projects will be ranked from high (good) to low (bad) based on:

- Site Control
- Interconnection status
- Environmental impacts
- Land use and permits

- Project financing
- Developer experience

Project Location

- **High**: In San Diego County and any additional area served by CEA
- **Medium:** Other areas within California
- **Low:** Out of state projects

Environmental Stewardship

- **High**: Demonstrates environmental benefits beyond the climate and GHG reduction benefits of renewable energy
- **Low:** Project does not demonstrate environmental stewardship as defined above

Social Equity

- **High:** Demonstrates societal, health, or economic benefits that address social equity
- **Low:** Project does not demonstrate social equity benefits as defined above

Local Job Growth

- **High:** Creates new jobs that employ workers and uses businesses in San Diego County and any additional areas served by CEA
- **Medium:** Employs existing workers and uses businesses in San Diego County and any additional areas served by CEA
- **Low:** Employs workers and uses businesses outside San Diego County and any additional areas served by CEA

Workforce Development

- **High:** Employ workers from San Diego County and any additional areas served by CEA; utilize apprenticeship programs; follows fair compensation practices including proper assignment of work to crafts that traditionally perform the work
- **Low:** Does not demonstrate workforce development as defined above

The evaluation criteria will be included in formal bid documents and requests for proposals, as appropriate.

Clean Energy Alliance
JOINT POWERS AUTHORITY

Staff Report

DATE: October 15, 2020

TO: Clean Energy Alliance Board of Directors

FROM: Barbara Boswell, Interim Chief Executive Officer

ITEM 8: Clean Energy Alliance Implementation Phasing Update

RECOMMENDATION:
Authorize Interim Chief Executive Officer to execute letter agreement with San Diego Gas & Electric (SDG&E) memorializing the amended Clean Energy Alliance Implementation Schedule to accommodate the delay in SDG&E's billing system replacement project, subject to General Counsel approval.

BACKGROUND AND DISCUSSION:

The Clean Energy Alliance (CEA) Implementation Plan contemplates a single-phase launch, enrolling all customers and transitioning Solana Energy Alliance (SEA) customers in May 2021. In meetings with San Diego Gas & Electric (SDG&E) the CEA implementation date had been confirmed as achievable and the two agencies have been working towards that schedule. SDG&E has also had a billing system replacement project, Envision, that has been underway for several years. SDG&E has been on track for a "go live" date for the new system in January 2021. In July 2020, SDG&E notified CEA that due to new California Public Utilities Commission (CPUC) requirements that needed to be implemented in April 2021, the Envision project was being delayed to April 2021. This new go live date for the Envision project impacts the implementation of CEA.

CEA and SDG&E have been working together to determine an implementation schedule that would have the least amount of impact to CEA, while minimizing the potential for billing errors or issues for customers. Through this cooperative process, it has been determined that the majority of CEA's customers can enroll, and SEA's customers can transition, can remain in May 2021. A select group of customers that have more complex billing arrangements are recommended to be enrolled in June 2021. Doing so will enable SDG&E to have an additional billing period in the new system for these customers prior to the conversion to CCA service. The final list of customers to be delayed to June 2021 are yet to be finalized, however, the two-month enrollment will not have a material impact on CEA's pro forma and as a result, staff is comfortable with the proposal.

SDG&E proposes that the revised implementation schedule be memorialized in a letter agreement. CEA will then take appropriate action to notify the CPUC of the minor adjustment in CEA's implementation.

FISCAL IMPACT
There is no fiscal impact by this action.

ATTACHMENTS:
None