AGENDA

Regular Meeting of the Board of Directors of San Diego Community Power (SDCP)

October 22, 2020

5:00 p.m.

Due to the public health orders and guidelines in California and in accordance with the Governor's Executive Orders N-25-20 and N-29-20, there will be no location for in-person attendance. SDCP is providing alternatives to in-person attendance for viewing and participating in the meeting. Further details are below.

Note: Any member of the public may provide comments to the SDCP Board of Directors on any agenda item or on a matter not appearing on the agenda, but within the jurisdiction of the Board. **Written public comments or requests to speak during the meeting must be submitted at least one (1) hour before the start of the meeting by using this (web form).** Please indicate whether your comment is on a specific agenda item or a non-agenda item when submitting your comment or requesting to speak. When providing comments to the Board, it is requested that you provide your name and city of residence for the record. Commenters are requested to address their comments to the Board as a whole through the Chair. Comments may be provided in one of the following manners:

1. Written Comments. All written comments received at least one (1) hour before the meeting will be provided to the Board members in writing. In the discretion of the Chair, the first ten (10) submitted comments shall be stated into the record of the meeting. Comments received after the one (1) hour limit will be collected, sent to the Board members in writing, and be part of the public record.

2. Requests to Speak. Members of the public who have requested to speak at least one (1) hour before the meeting will be recognized at the appropriate time during the meeting. To allow the Chair to call on you, please provide the following minimum information with your request to speak: your name (if attending by videoconference) or telephone number (if attending by phone).

Comments shall be limited to either 400 words, or 3 minutes when speaking. If you have anything that you wish to be distributed to the Board, please provide it via info@sdcommunitypower.org, who will distribute the information to the Members.

The public may participate using the following remote options:

Teleconference Meeting Webinar

https://zoom.us/j/94786370471

Telephone (Audio Only)

(669) 900-6833 or (346) 248-7799 | Webinar ID: 947 8637 0471

Call to Order

Pledge of Allegiance

Roll Call

Items to be Added, Withdrawn, or Reordered on the Agenda

Public Comments
Opportunity for members of the public to address the Board on any items not on the agenda but within the jurisdiction of the Board. Members of the public may use the web form noted above to provide a comment or request to speak.

Consent Calendar
All matters are approved by one motion without discussion unless a member of the Board of Directors requests a specific item to be removed from the Consent Agenda for discussion. A member of the public may use the web form noted above to comment on any item on the Consent Calendar.

1. **Approval of the minutes of the Regular Meetings of the Board of Directors of San Diego Community Power held on August 27, 2020 and September 24, 2020**
2. **Adopt Resolution Designating Authorized Representatives to Sign Checks**
3. **Approval of Amendment to Contract Services Agreement with Tosdal Law APC**

REGULAR AGENDA
The following items call for discussion or action by the Board of Directors. The Board may discuss and/or take action on any item listed below if the Board is so inclined.

4. **Operations and Administration Report from the Interim Chief Executive Officer**

   Recommendation:
   1. Receive and file update on various operational and administration activities.
   2. Receive and file update on Regulatory Affairs.

5. **Update of Amended Organizational Chart and Staffing Plan**

   Recommendation: Receive staffing plan update and proposed SDCP organizational chart through year-end 2021.

6. **Receive Update and Provide Direction and Authorization Regarding San Diego Community Power Employee Benefits Program**

   Recommendation:
   1. Receive employee benefits report and provide feedback and direction.
   2. Authorize the Interim Chief Executive Officer to a) negotiate with employee benefit providers for group health coverage, b) implement a final employee benefit plan, and

c) perform ongoing maintenance of the employee benefit plan to accommodate changes in market conditions and benefit laws and regulations.

7. Approval of CCA Terms and Conditions in Substantive Form

Recommendation: Adopt CCA Terms and Conditions in Substantive Form.

Director Comments

Board Members may briefly provide information to other members of the Board and the public, ask questions of staff, request an item to be placed on a future agenda, or report on conferences, events, or activities related to SDCP business. There is to be no discussion or action taken on comments made by Directors unless authorized by law.

Reports by Management and General Counsel

SDCP Management and General Counsel may briefly provide information to the Board and the public. The Board may engage in discussion if the specific subject matter of the report is identified below, but the Board may not take any action other than to place the matter on a future agenda. Otherwise, there is to be no discussion or action taken unless authorized by law.

ADJOURNMENT

Compliance with the Americans with Disabilities Act

SDCP Board of Directors meetings comply with the protections and prohibitions of the Americans with Disabilities Act. Individuals with a disability who require a modification or accommodation, including auxiliary aids or services, in order to participate in the public meeting may contact (858) 492-6005 or info@sdcommunitypower.org. Requests for disability-related modifications or accommodations require different lead times and should be provided at least 72-hours in advance of the public meeting.

Availability of Board Documents

Copies of the agenda and agenda packet are available at www.sdcommunitypower.org/board-meetings. Late-arriving documents related to a Board meeting item which are distributed to a majority of the Members prior to or during the Board meeting are available for public review as required by law. Until SDCP obtains offices, those public records are available for inspection at the City of San Diego Sustainability Department, located at 1200 Third Ave., Suite 1800, San Diego, CA 92101. However, due to the Governor's Executive Orders N-25-20 and N-29-20 and the need for social distancing, that is now suspended and can instead be made available electronically at info@sdcommunitypower.org. The documents may also be posted at the above website. Late-arriving documents received during the meeting are available for review by making an electronic request to the Board Secretary via info@sdcommunitypower.org.

SAN DIEGO COMMUNITY POWER (SDCP)
BOARD OF DIRECTORS
San Diego City Administration Building, 12th Floor
202 “C” Street
San Diego, CA 92101

MINUTES

August 27, 2020

This meeting was conducted utilizing teleconferencing and electronic means consistent with State of California Executive Order N-29-20 dated March 17, 2020, regarding the COVID-19 pandemic.

The Board minutes are prepared and ordered to correspond to the Board Agenda. Agenda Items can be taken out of order during the meeting.

The Agenda Items were considered in the order presented except for Consent Calendar Item 1 which was considered prior to Public Comment.

CALL TO ORDER

Chair Mosca (Encinitas) called the SDCP Board of Directors meeting to order at 5:15 p.m.

Assistant General Counsel Norvell recommended the Board make a motion to reconvene into Closed Session following the SDCP Board of Directors Regular Meeting to discuss Items 1 and 2 on the Special Meeting Agenda.

ACTION: Motioned by Chair Mosca (Encinitas) and seconded by Vice Chair Padilla (Chula Vista) to reconvene into Closed Session following the SDCP Board of Directors Regular Meeting. The motion carried by the following vote:

Vote: 5-0

Yes:	Chair Mosca (Encinitas), Vice Chair Padilla (Chula Vista), Director Baber (La Mesa), Director Montgomery (San Diego), and Director West (Imperial Beach)
No:	None
Abstained:	None
Absent:	None

PLEDGE OF ALLEGIANCE

Chair Mosca (Encinitas) led the Pledge of Allegiance.

ROLL CALL

PRESENT: Chair Mosca (Encinitas), Vice Chair Padilla (Chula Vista), Director Baber (La Mesa), Director Montgomery (San Diego), and Director West (Imperial Beach)

ABSENT: None

Also Present: Interim Executive Officer Hooven, Assistant General Counsel Norvell, Interim Board Clerk Wiegelman

ITEMS TO BE ADDED, WITHDRAWN, OR REORDERED ON THE AGENDA

There were no additions or deletions to the agenda.

PUBLIC COMMENTS

James Whalen spoke regarding local procurement, project labor agreements, and a commitment to unions with training and local hiring.

CONSENT CALENDAR

(Item 1)

1. **Approval of the minutes for the Board of Directors of San Diego Community Power Regular Meeting held on the following dates: Thursday, May 28, June 25, and July 23, 2020.**

   ACTION: Motioned by Director Baber (La Mesa) and seconded by Director West (Imperial Beach) to approve Consent Calendar Item 1. The motion carried by the following vote:

   Vote: 5-0

   Yes: Chair Mosca (Encinitas), Vice Chair Padilla (Chula Vista), Director Baber (La Mesa), Director Montgomery (San Diego), and Director West (Imperial Beach)
   No: None
   Abstained: None
   Absent: None

REGULAR AGENDA

2. **Operations and Administration Report from the Interim Executive Officer**

   Interim Executive Officer Hooven provided an update on staffing needs, personnel recruitment efforts, the status of the various vendor requests for proposals (RFP) and other solicitations, the Committee meetings that were held since the last Board meeting, and staff discussions with San Diego Gas and Electric (SDG&E).

Board questions and comments ensued.

Ty Tosdal, Tosdal APC, provided an update on SDG&E's Power Charge Indifference Adjustment (PCIA) Trigger application that would substantially increase the PCIA rate for current CCA customers, SDG&E's Energy Resource Recovery Account (ERRA) forecasting proceedings, and other energy regulatory affairs as they relate to the interests of SDCP.

Board questions and comments continued.

Interim Board Clerk Wiegelman read aloud the first 400 words of the emailed public comments submitted by 3:00 p.m. the day of the Board meeting.

Matthew Vasilakis, Climate Action Campaign, submitted a comment regarding SDG&E's renewable energy solicitation and lack of cooperation with SDCP.

Following Board questions and comments, no action was taken.

3. Discussion on Potential Impacts from Changes to the SDG&E Customer Information System Rollout

Interim Executive Officer Hooven provided an update on the potential impacts the delay to SDG&E's Customer Information System roll out would have on SDCP's 2021 launch schedule.

Board questions and comments ensued.

Following Board questions and comments, no action was taken.

4. Informational Overview of Prospective Feed-In Tariff Program

Kirby Dusel, Pacific Energy Advisors (PEA), provided a PowerPoint presentation regarding a Feed-in Tariff (FIT) program, the key resource planning considerations, the near- and longer-term goals, the purpose and requirements of a FIT program, establishing eligibility, the benefits of a FIT program, and the next steps in administering a FIT program.

Board questions and comments ensued.

Interim Board Clerk Wiegelman read aloud the first 400 words of the emailed public comments submitted by 3:00 p.m. the day of the Board meeting.

Lauren Randall, Sunrun, submitted a comment in support of SDCP adopting a FIT program.

Following Board questions and comments, no action was taken.

5. **Approval of the San Diego Community Power 2020 Integrated Resource Plan**

John Dalessi, PEA, provided a PowerPoint presentation regarding the 2020 Integrated Resource Plan (IRP), the requirement to file an IRP with the California Public Utility Commission, the content, assessment, purpose and objectives of the IRP, the assigned greenhouse gas benchmarks, the preferred conforming portfolios, the planned capacity resources, and the filing deadline for the IRP.

Board questions and comments ensued.

Interim Board Clerk Wiegelman read aloud the first 400 words of the emailed public comments submitted by 3:00 p.m. the day of the Board meeting.

Jason Anderson, Cleantech San Diego, submitted a comment in support of SDCP's 2020 IRP.

Matthew Vasilakis, Climate Action Campaign, submitted a comment in support of SDCP's 2020 IRP and regarding the development of a long term roadmap to one hundred percent renewable energy by 2030 and 2035 in order for member cities to meet their individual Climate Action Plan goals.

ACTION: Motioned by Director West (Imperial Beach) and seconded by Director Montgomery (San Diego) to approve 2020 San Diego Community Power Integrated Resource Plan. The motion carried by the following vote:

Vote: 5-0

Yes:	Chair Mosca (Encinitas), Vice Chair Padilla (Chula Vista), Director Baber (La Mesa), Director Montgomery (San Diego), and Director West (Imperial Beach)
No:	None
Abstained:	None
Absent:	None

6. **Marketing and Messaging Presentation by Civilian**

Sean Connacher, Civilian, provided a PowerPoint presentation regarding the marketing roadmap, Civilian's brand building process , the key research involved in determining the appropriate marketing strategy, legacy perceptions and perceptions to target in messaging, and the next steps in the SDCP brand building process.

Board questions and comments ensued.

Following Board questions and comments, no action was taken.

7. **Approval of Community Advisory Committee Work Plan**

Program and Policy Coordinator Sarria explained the purpose of the Community Advisory Committee (CAC) Work Plan and stated the CAC would review a new Work Plan for the 2021 calendar year at its first meeting in 2021.

Board questions and comments ensued.

ACTION: Motioned by Director West (Imperial Beach) and seconded by Vice Chair Padilla (Chula Vista) to approve the Community Advisory Committee Work Plan for the remainder of the 2020 calendar year. The motion carried by the following vote:

Vote: 5-0

Yes: Chair Mosca (Encinitas), Vice Chair Padilla (Chula Vista), Director Baber (La Mesa), Director Montgomery (San Diego), and Director West (Imperial Beach)
No: None
Abstained: None
Absent: None

8. Approval of Amendment to BB&K Contract

Interim Executive Officer Hooven explained the purpose of the amendment to the Best Best &Krieger (BB&K) contract.

Board questions and comments ensued.

ACTION: Motioned by Vice Chair Padilla (Chula Vista) and seconded by Director Baber (La Mesa) to approve the amendment to the existing BB&K contract for the expansion and continuation of services to SDCP for a total amount not to exceed $240,000 through June 30, 2021. The motion carried by the following vote:

Vote: 5-0

Yes: Chair Mosca (Encinitas), Vice Chair Padilla (Chula Vista), Director Baber (La Mesa), Director Montgomery (San Diego), and Director West (Imperial Beach)
No: None
Abstained: None
Absent: None

DIRECTOR COMMENTS

There were no comments.

REPORTS BY MANAGEMENT AND GENERAL COUNSEL

There were no reports.

Chair Mosca (Encinitas) adjourned the meeting to Closed Session at 7:09 p.m.

ADJOURNMENT

Assistant General Counsel Norvell adjourned the meeting at 8:28 p.m.

Megan Wiegelman, CMC
Interim Board Clerk

SAN DIEGO COMMUNITY POWER (SDCP)
BOARD OF DIRECTORS
San Diego City Administration Building, 12th Floor
202 “C” Street
San Diego, CA 92101

MINUTES

September 24, 2020

This meeting was conducted utilizing teleconferencing and electronic means consistent with State of California Executive Order N-29-20 dated March 17, 2020, regarding the COVID-19 pandemic.

The Board minutes are prepared and ordered to correspond to the Board Agenda. Agenda Items can be taken out of order during the meeting.

The Agenda Items were considered in the order presented, except for Agenda Item No. 2 which was considered prior to Agenda Item No. 1.

CALL TO ORDER

Chair Mosca (Encinitas) called the SDCP Board of Directors meeting to order at 5:07 p.m.

PLEDGE OF ALLEGIANCE

Chair Mosca (Encinitas) led the Pledge of Allegiance.

General Counsel Baron announced there were no reportable actions from Closed Session.

ROLL CALL

PRESENT: Chair Mosca (Encinitas), Vice Chair Padilla (Chula Vista), Alternate Director Humora (La Mesa), Director Montgomery (San Diego), and Director West (Imperial Beach)

ABSENT: Director Baber (La Mesa)

Also Present: Interim Executive Officer Hooven, General Counsel Baron, Interim Board Clerk Wiegelman

ITEMS TO BE ADDED, WITHDRAWN, OR REORDERED ON THE AGENDA

There were no additions or deletions to the agenda.

PUBLIC COMMENTS

Interim Board Clerk Wiegelman read aloud the first 400 words of the emailed public comments submitted by 3:00 p.m. the day of the Board meeting.

Jason Anderson, Cleantech San Diego, submitted a comment regarding SDCP's recent solicitation for renewable energy and local renewable energy generation goals.

Matthew Bosse and family sang Happy Birthday to Chair Mosca (Encinitas).

CONSENT CALENDAR

There were no Consent Calendar Items for consideration.

REGULAR AGENDA

1. **Operations and Administration Report from the Interim Executive Officer**

   Interim Executive Officer Hooven provided an update on personnel recruitment efforts, the status of the various vendor requests for proposals (RFP) and other solicitations, the 2020 Policy Matrix, and staff discussions with San Diego Gas and Electric (SDG&E).

   Board questions and comments ensued.

   Ty Tosdal, Tosdal APC, provided an update on SDG&E's Advice Letter which provides a detailed description of an Arrearage Management Plan that is designed to protect customers at risk of disconnection for failure to make payments, SDG&E's Power Charge Indifference Adjustment (PCIA) Trigger application that would substantially increase the PCIA rate for current CCA customers, SDG&E's Energy Resource Recovery Account forecasting proceedings, SDG&E's request for approval of System Reliability Contracts resulting from SDG&E's Request for Offers under D. 19-11-016, and other energy regulatory affairs as they relate to the interests of SDCP.

   Board questions and comments continued.

   Following Board questions and comments, no action was taken.

2. **Appointment of Interim CEO and Approval of Employment Agreement**

   Chair Mosca (Encinitas) announced the SDCP Board of Directors had selected Bill Carnahan, a former public utility executive with Community Choice Aggregation and public power experience, as Interim Chief Executive Officer (CEO). Chair Mosca (Encinitas) provided an overview of the Interim CEO Employment Agreement.

The Employment Agreement was for a one year term with a base annual salary of two hundred ninety five thousand dollars ($295,000). The Employment Agreement included a gross monthly vehicle allowance of five hundred dollars ($500) per month, a SDCP owned cell phone and accompanying SDCP paid plan or a one hundred dollars ($100) monthly taxable technology allowance, and a gross monthly housing or hotel allowance to be negotiated at the time in-person attendance was required. In lieu of employee benefits, Mr. Carnahan would receive compensation equivalent to benefits he might otherwise be entitled to as a permanent SDCP employee in an amount equal to fifteen percent (15%) of his base annual salary.

Board comments ensued.

Interim Board Clerk Wiegelman read aloud the first 400 words of the emailed public comments submitted by 3:00 p.m. the day of the Board meeting.

Matthew Vasilakis, Climate Action Campaign, submitted a comment welcoming the new Interim CEO.

Tara, Hammond Climate Solutions, submitted a comment regarding the appointment of the Interim CEO and continuing to uphold the values of SDCP.

<u>ACTION</u>: Motioned by Chair Mosca (Encinitas) and seconded by Director West (Imperial Beach) to adopt Resolution No. 2020-06 appointing Bill Carnahan as Interim CEO and approving execution of an Employment Agreement with Bill Carnahan in substantially similar form, with non-substantive revisions approved by the Chair and reviewed and approved by General Counsel. The motion carried by the following vote:

<u>Vote</u>: 5-0

Yes:	Chair Mosca (Encinitas), Vice Chair Padilla (Chula Vista), Alternate Director Humora (La Mesa), Director Montgomery (San Diego), and Director West (Imperial Beach)
No:	None
Abstained:	None
Absent:	None

Chair Mosca (Encinitas) introduced Interim Chief Executive Officer Bill Carnahan.

Interim CEO Carnahan thanked the Board of Directors for the opportunity and expressed his commitment and motivation in helping SDCP create a path to one hundred percent renewable energy.

3. Approval of CEO Job Description and Initial SDCP Organizational Chart

Vice Chair Padilla (Chula Vista) left the meeting.

General Counsel Baron stated that in conjunction with the Interim CEO Employment Agreement, General Counsel recommends the SDCP Board of Directors adopt a formal job description for the CEO and an initial SDCP Organizational Chart to assist the Interim CEO in performing the initial hiring for SDCP.

Assistant General Counsel Norvell provided an overview of the CEO job description and initial SDCP Organizational Chart. Assistant General Counsel Norvell reviewed the Chief Financial Officer and Chief Operations Officer positions and the process for modifying or updating the SDCP Organizational Chart.

General Counsel Baron stated that regardless of the delegation of authority, it is the intent of Interim CEO Carnahan to bring any proposed changes to the SDCP Organizational Chart to the SDCP Board of Directors for consideration and approval.

Board questions and comments ensued.

ACTION: Motioned by Chair Mosca (Encinitas) and seconded by Director West (Imperial Beach) to (1) approve the CEO job description, subject to future changes by the Board of Directors; and (2) approve the initial SDCP Organizational Chart, subject to changes made in the discretion of the CEO and subsequent notice to the SDCP Board of Directors at a Regular Meeting. The motion carried by the following vote:

Vote: 4-0

Yes:	Chair Mosca (Encinitas), Alternate Director Humora (La Mesa), Director Montgomery (San Diego), and Director West (Imperial Beach)
No:	None
Abstained:	None
Absent:	Vice Chair Padilla (Chula Vista)

4. Approval of San Diego Community Power Brand Messaging and Logo

Interim Executive Officer Hooven provided opening comments and introduced Sean Connacher from Civilian.

Sean Connacher, Civilian, provided a PowerPoint presentation regarding the proposed messaging platform, the positioning and messaging goals, the umbrella positioning statement, the key messaging structure, the direction of the brand identity, the first component of the brand identity (logo), and the next steps in the SDCP brand building process.

Board questions and comments ensued.

Kim Coutts, Civilian, commented on the inclusion of environmental justice in the key messaging structure.

Board questions and comments continued.

ACTION: Motioned by Director West (Imperial Beach) and seconded by Director Montgomery (San Diego) to approve the brand messaging and logo concept from Civilian. The motion carried by the following vote:

Vote: 4-0

Yes: Chair Mosca (Encinitas), Alternate Director Humora (La Mesa), Director Montgomery (San Diego), and Director West (Imperial Beach)
No: None
Abstained: None
Absent: Vice Chair Padilla (Chula Vista)

5. Approval of Employee Handbook

Encinitas Human Resource Director Bokosky provided an overview of the Employee Handbook and the process for updating the Employee Handbook.

ACTION: Motioned by Chair Mosca (Encinitas) and seconded by Director West (Imperial Beach) to approve the employee handbook for San Diego Community Power. The motion carried by the following vote:

Vote: 5-0

Yes: Chair Mosca (Encinitas), Alternate Director Humora (La Mesa), Director Montgomery (San Diego), and Director West (Imperial Beach)
No: None
Abstained: None
Absent: Vice Chair Padilla (Chula Vista)

DIRECTOR COMMENTS

Director West (Imperial Beach) provided an update on the upcoming financial audit process required by the San Diego Regional Community Choice Energy Authority Joint Powers Agreement.

REPORTS BY MANAGEMENT AND GENERAL COUNSEL

There were no reports.

ADJOURNMENT

Chair Mosca (Encinitas) adjourned the meeting at 6:30p.m.

Megan Wiegelman, CMC
Interim Board Clerk

SAN DIEGO **COMMUNITY POWER**
Staff Report – Item 2

To: San Diego Community Power Board of Directors

From: Bill Carnahan, Interim CEO
Ryan Baron, General Counsel, Best Best & Krieger

Subject: Adopt Resolution Designating Authorized Representatives to Sign Checks

Date: October 22, 2020

Recommendation

Approve Resolution 2020-07, a Resolution Designating Authorized Representatives to Sign Checks.

Background

Section 7.2.3 of the JPA Agreement provides that all San Diego Community Power (SDCP) expenditures shall be made in accordance with the approved budget and upon the approval of any officer so authorized by the Board in accordance with its policies and procedures.

At previous meetings, the Board of Directors adopted a Procurement Policy to provide administrative procurement requirements and procedures and a Delegated Contract Authority Policy relating to execution of contracts and related documents. Frequently, public agencies' financial institutions request a copy of an adopted resolution identifying the individuals authorized to sign checks on behalf of the agency. The proposed resolution would identify such individuals for SDCP.

Analysis and Discussion

The proposed resolution would require that SDCP checks of $10,000 or more be signed by at least two individuals from a list that includes the Interim CEO and members of the Board of Directors. Checks for less than $10,000 may be signed by the Interim CEO. As SDCP hires additional officers/employees, including a Treasurer/CFO, the resolution would be updated to include such individuals as authorized signatories. At such time, members of the Board of Directors may be fully or partially removed from the list of authorized signatories.

The resolution provides that no checks are to be prepared or executed without compliance with applicable SDCP policies and procedures and appropriate support documentation for the expense (e.g., purchase order, packing slip, or invoice).

Fiscal Impact
None.

Attachments
Attachment A: Resolution 2020-07, a Resolution Designating Authorized Representatives to Sign Checks

RESOLUTION NO. 2020-07

**A RESOLUTION OF THE BOARD OF DIRECTORS
OF SAN DIEGO COMMUNITY POWER
DESIGNATING AUTHORIZED REPRESENTATIVES TO SIGN CHECKS**

A. San Diego Community Power ("SDCP") is a joint powers agency formed pursuant to the Joint Exercise of Powers Act, Cal. Gov. Code § 6500 *et seq.*, California Public Utilities Code § 366.2, and a Joint Powers Agreement effective on October 1, 2019 ("JPA Agreement").

B. Section 7.2.3 of the JPA Agreement provides that all SDCP expenditures shall be made in accordance with the approved budget and upon the approval of any officer so authorized by the Board in accordance with its policies and procedures.

C. SDCP has adopted a Procurement Policy providing administrative procurement practices and a Delegated Contract Authority Policy concerning execution of contracts and related documents, as each may be amended from time to time.

NOW, THEREFORE, BE IT RESOLVED by the Board of Directors of San Diego Community Power as follows:

Section 1. SDCP's depository institutions are instructed to honor checks written on SDCP accounts when executed by any two of the following authorized representatives:

Joe Mosca, Board Chair

Steve Padilla, Board Vice-Chair

William Baber, Board Member

Monica Montgomery Steppe, Board Member

Mark West, Board Member

Bill D. Carnahan, Interim Chief Executive Officer

Section 2. Notwithstanding the above, for checks in the amount of less than $10,000, SDCP's depository institutions are instructed to honor checks written on SDCP accounts when executed by Bill D. Carnahan, Interim Chief Executive Officer.

Section 3. No checks are to be prepared or executed without compliance with applicable SDCP policies and procedures and appropriate support documentation for the expense (e.g., purchase order, packing slip, or invoice).

Section 4. This resolution shall take effect immediately upon its adoption.

PASSED AND ADOPTED at a meeting of the Board of Directors of San Diego Community Power held on October 22, 2020.

Chair, Board of Directors
San Diego Community Power

ATTEST:

Secretary, Board of Directors
San Diego Community Power

SAN DIEGO **COMMUNITY POWER**
Staff Report – Item 3

To: San Diego Community Power Board of Directors

From: Bill Carnahan, Interim CEO
Cody Hooven, Director/Chief Sustainability Officer, City of San Diego

Subject: Approval of Amendment to Contract Services Agreement with Tosdal Law APC

Date: October 22, 2020

Recommendation
Approve amendment to existing Tosdal, APC. contract for the expansion and continuation of services to SDCP for a total amount not to exceed $300,000 through June 30, 2021.

Background
At the November 2019 meeting of the Board of Directors, Tosdal, APC. was approved to provide Energy Regulatory Counsel legal services for a not-to-exceed amount of $200,000. As noted at the November meeting, Tosdal, APC. has extensive experience in the energy and regulatory advocacy space with Community Choice Aggregation (CCA) programs in California.

Analysis and Discussion
SDCP's initial November 2019 agreement with Tosdal, APC. approved an amount not to exceed $200,000 for Energy Regulatory Counsel legal services. Staff recommends increasing Tosdal, APC.'s contract by $100,000. The reasons for this increase include efforts by Tosdal APC. above and beyond the efforts originally anticipated due to the critical nature of CPUC regulatory decisions to SDCP's financial position, as well as increased scope of work to include the following:

- Increased effort required by the ERRA proceeding and PCIA-related activities, such as forecast and reconciliation of proceedings.
- Increased effort related to RA procurement and SDGE's unique circumstances.
- Increased engagement in collaboration with SDGE.
- Increased effort in compliance filing support until full-time SDCP staff can be hired.

Fiscal Impact
Cost of this action includes a total amount not to exceed $300,000 until June 31, 2021. Funding is available in the FY21 budget approved by the Board.

Attachments
Attachment A: Amendment to Tosdal, APC. contract with SDCP.

FIRST AMENDMENT TO ENGAGEMENT LETTER BETWEEN SAN DIEGO COMMUNITY POWER AND TOSDAL, APC

THIS FIRST AMENDMENT (this "Amendment") is entered into as of this 22nd day of October, 2020, by and between SAN DIEGO COMMUNITY POWER, a California joint powers agency ("SDCP") and TOSDAL, APC, a professional corporation ("Tosdal APC"). SDCP and Tosdal APC are sometimes individually referred to herein as the "Party" and collectively as the "Parties."

RECITALS

WHEREAS, SDCP (then called the "San Diego Regional Community Choice Energy Authority") and Tosdal APC entered into that certain Engagement Letter dated November 18, 2019 (the "Agreement"); and

WHEREAS, pursuant to the Agreement, Tosdal APC provides advice and representation in connection with energy regulatory matters before the California Public Utilities Commission, California Energy Commission, and the California Independent System Operator, in addition to related issues facing community choice energy programs; and

WHEREAS, the Parties desire to amend the Agreement to extend the term of the Agreement and establish the maximum amount payable to Tosdal APC for its services during SDCP's current fiscal year.

NOW, THEREFORE, it is agreed by and between the Parties as follows:

1. Recitals. The Recitals set forth above are true and correct and are incorporated into the body of this Amendment as though expressly set forth herein.

2. Extension of Term. The term of the Agreement is hereby extended until June 30, 2021.

3. Not-To-Exceed Amount for Current Fiscal Year. For the period of SDCP's 2020-2021 fiscal year (July 1, 2020 – June 30, 2021), the not-to-exceed amount payable by SDCP to Tosdal APC under the Agreement shall be $300,000.

4. Effect of Amendment. Except as expressly set forth in this Amendment, all other sections, provisions, exhibits and commitments of the Agreement remain unchanged and in full force and effect.

5. Counterparts. This Amendment may be executed in one or more counterparts, including facsimile counterparts, each of which shall, for all purposes, be deemed an original and all such counterparts, taken together, shall constitute one and the same instrument.

IN WITNESS WHEREOF, the Parties have executed this First Amendment to the Engagement Letter between San Diego Community Power and Tosdal APC as of the date first set forth above.

SAN DIEGO COMMUNITY POWER

____
Name: Bill Carnahan
Title: Interim Chief Executive Officer
Date: __________________________________

TOSDAL APC

____
Name: Ty Tosdal
Title: Partner
Date: __________________________________

ATTEST:

____
Secretary, SDCP Board of Directors

APPROVED AS TO FORM:

____
SDCP General Counsel

SAN DIEGO **COMMUNITY POWER**
Staff Report – Item 4

To: San Diego Community Power Board of Directors

From: Bill Carnahan, Interim CEO
Cody Hooven, Director/Chief Sustainability Officer, City of San Diego

Subject: Operations and Administration Report from the Interim Chief Executive Officer

Date: October 22, 2020

Recommendation

1. Receive and file update on various operational and administration activities.
2. Receive and file update on Regulatory Affairs.

Analysis and Discussion

Staff will provide regular updates to the Board of Directors regarding San Diego Community Power's (SDCP) organizational development, administration and start-up activities. The following is a brief overview of this month's discussion items, which are informational only.

A) Staffing

On the agenda today will be an update on organization and staffing. However we have already opened recruitment for two positions; Power Services and Regulatory Affairs/Compliance. Job announcements were posted for Director level positions in each of these areas, closing on September 27th. Filling the positions has been on hold depending on the organization and fringe benefit programs development completion. It appears there is an immediate need to fill these positions so we expect to complete the process by screening candidates and conducting interviews soon.

B) Power Resource Solicitations

Renewable:

Negotiations for short-listed contracts selected through SDCP's first long-term renewables portfolio standard solicitation are still underway and contracts will be presented to the Board as needed in the coming months.

Staff, supported by Pacific Energy Advisors, submitted bids in response to SDG&E's Renewable Energy solicitation on June 22, 2020 for power to fill some of SDCP's initial resource needs. SDCP received notice on August 19, 2020 that our offers were not selected for further consideration by SDG&E. Staff have reached out to SDG&E to seek feedback on why SDCP's offers were rejected, and SDG&E staff have since agreed to entertain bilateral discussions on procurement. In a meeting on October 15, 2020 SDG&E proposed a schedule for bilateral dicussions beginning immediately, anticipated filing to the California Public Utilities Commission (CPUC) in February, and power deliveries commencing in June. This timeline is tentative and dependent on various items including CPUC approval and agreement between the parties. Staff will inform the Board of any changes.

Resource Adequacy:
As a load serving entity serving customers in 2021, SDCP 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 SDCP 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. SDCP has monthly and annual reporting requirements. Upcoming reporting requirements are:

- Year-Ahead Compliance Demonstration – October 31, 2020 (to be submitted Nov. 2)
  - Must demonstrate SDCP has entered into contracts to meet CPUC requirements
- Monthly RA Compliance Reports begin in November 2020 (for January 2021 requirements)

In order to meet these obligations, SDCP is completing its first 2021-2023 Local Resource Adequacy (RA) solicitation – negotiations and contracting efforts are underway with multiple suppliers. SDCP issued a second and third RA solicitation to ensure every effort is made to secure our allocated amount.

SDCP submitted bids in response to SDG&E's RA solicitation on June 15, 2020. SDG&E has postponed notifications for selected RA bids several times, receiving notice on September 14, 2020 that our bids were selected and we will be moving forward with negotiations. The two parties are currently exploring options for payment.

As of now, SDCP has either contracted for or is in late stage negotiations for about 94% of its RA obligations due on November 2nd, and SDCP continues to seek offers for its remaining RA needs. If SDCP is unable to obtain the remaining RA requirements, SDCP would make a filing with the CPUC seeking a waiver of local RA penalties, consistent with CPUC rules that allow for penalty waivers when good faith efforts to procure local RA yield insufficient supply. Waivers are not available for deficiencies in system RA, and uncured deficiencies are subject to penalties from the CPUC. SDCP will continue procurement efforts as necessary to cure any deficiencies that may exist as of the November 2nd filing with the goal of full compliance with its RA obligations. However, SDCP's ability to comply with RA requirements is subject to availability constraints in the San Diego area market.

C) Update on 2020 Policy Matrix

Interim SDCP staff and consultants continue to work on start-up policy items as time permits and as directed by the Board. These policies range from operational to customer-based to financial. An updated schedule of planned policies is attached for reference (Attachment A) and will evolve as items are completed or new items are contemplated. Staff will present two items for Board approval as part of this agenda. An additional internal policy item was recently developed to provide guidance to staff. In FY21, $25,000 was budgeted for sponsorships but staff felt the need to create guidance to use when determining which events to sponsor. A series of criteria were created addressing audience size, diversity of audience, timing of event, etc. Civilian, our marketing partner, as well as the Community Advisory Committee contributed to the policy.

D) Other Discussions with San Diego Gas & Electric (SDG&E)
As previously shared with the Board, SDG&E notified SDCP staff at a July 10, 2020 meeting of a potential delay in their Customer Information System (CIS) roll out which would delay SDCP's 2021 launch schedule, potentially by several months. SDG&E stated the reason for the delay is due to CPUC decision D. 20-06-003 which ordered the utilities to adopt programs and rules to reduce the number of residential customer disconnections due to nonpayment. The new mandates include protections against disconnections for low-income and other vulnerable populations, caps on the number of total disconnections, a new payment plan for arrears forgiveness, and the elimination of deposits and re-connection fees for all customers. The new rules and programs are ordered to go into effect in April 2021, upon the expiration of COVID-19 protections that are currently in place.

SDCP requested reaffirmation of SDG&E's original timeline and reiterated that a sudden, unilateral change in schedule or accounts has significant operational and financial impacts that are not acceptable. After these initial conversations beginning July 10, representatives from SDG&E, SDCP, and Calpine have established regular check in meetings on this subject and other topics as needed.

SDG&E has since stated they will be able to maintain the phases of SDCP's launch as planned but proposed altering the customer/account mix in those phases. SDCP has provided a counter proposal of customer phasing that maintains the schedule but adjusts the accounts in each phase and SDG&E is reviewing that now. SDCP staff continue to reinforce the need for timely agreement, in writing, on this issue. Staff are drafting an outline of an agreement based on discussions with SDG&E.

E) Regulatory Affairs
The CPUC has broad regulatory authority over the energy sector in California, including partial jurisdiction over CCA programs. SDCP and other CCA programs are regularly affected by CPUC decisions regarding power resources, rates, financial obligations and data retention among other things. SDCP continues to engage in regulatory matters in order to establish a position on key issues and/or provide input on various decisions or actions being considered by the PUC.

This month's regulatory update (Attachment B) includes CPUC proceedings that are currently active and will have an impact on SDCP. This is not an exhaustive list. Staff and Tosdal, APC will continue to monitor or engage in these proceedings and other regulatory activities as needed to ensure SDCP's interests are represented. Staff from Tosdal, APC will be available at the Board meeting to provide an overview of key actions and proceedings.

Attachments
Attachment A: Updated SDCP Policy Matrix
Attachment B: Tosdal APC Energy Regulatory Update

San Diego Community Power
2020 Policy Matrix

Purpose:

This matrix reflects the broader Implementation Timeline while focusing on an abbreviated overview of the policies staff is working on through 2020.

Notes:

1. Policies listed below are drawn from the most recent Implementation Timeline adopted at the January 30th Board of Directors meeting and 11 California CCAs[1]
2. Policies are intended to guide SDCP operations and procedures rather than set future or aspirational goals.
3. SDCP may wish to consider blending (or bundling) specific policies within general policy categories to reduce the number of individual policies it manages. It may also update completed policies or consider additional policies not included here as its program develops and operational needs evolve.

POLICY CATEGORY/SUBJECT	DESCRIPTION	2020 TIMING/STATUS
ADMINISTRATIVE & OPERATIONS		
SDCP Conflict of Interest Code	Standard C of I policy for seated Board members and relevant SDCP staff members.	DONE
CEO Spending Authority	Authorizes CEO signing authority without prior Board approval; SDCP may consider two policies – one for operational contracts and one for power supply contracts. Describes Board reporting requirements.	DONE
Delegation of Authority to CEO for Regulatory and Legislative Matters	Authorizes CEO to respond timely to requests for regulatory and legislative action that directly impact CCA and SDCP operations. Includes Board reporting requirement.	DONE
Enterprise Risk Management	Describes how operational/business risk is determined and mitigated; may also include energy risk management as a component.	DONE (Energy Risk)
Agency Vendor and Contracting Practices	Describes procurement/vendor contracting guidelines including but not limited to: issuance of RFPs and bid evaluation, local hire, diversity, sustainable and ethical vendor preferences, signing authorities, reporting etc.	DONE (addresses professional services)
Records Retention; Public Access	Compliant with state and federal law, the length of time records of various types will be retained and/or discarded; includes guidelines for public access to SDCP records.	DONE
Information Technology Security	Policies and standards developed by IT security team to manage regulatory compliance, ensure proper staff training and customer satisfaction and minimize legal and criminal risk related to data and information breach. Could also include the AMI data policy described below.	Q4+
Social Media	Describes purpose of using these channels and defines rights/reasons for comment or post removals.	Q4
JPA Expansion/New Members	Considerations when exploring program expansion to areas outside original service area and method of approving new JPA members.	Q4+
Process for Amending/Adopting Agency Policies and JPA Agreement Amendments	Procedures to review/adopt new or amend Agency policies and JPA Amendments. This could also be part of the bylaws.	Q4
PERSONNEL/WORKFORCE		

[1] *Clean Power Alliance, Clean Power SF, East Bay Community Energy, Monterey Bay Community Energy, MCE Clean Energy, Peninsula Clean Energy, Redwood Coast Energy Authority, San Jose Clean Energy, Silicon Valley Clean Energy, Sonoma Clean Power, Valley Clean Energy.*

Employee Handbook/Personnel Policies	Describes all legally required elements of an employee policy including fair employment practices, non- discrimination, standard business hours, paid and personal time off, holidays, sick leave, etc.	Q3 (In process – Handbook DONE in Sept 2020, Benefits presented Oct 2020)
Other Personnel Policies: Travel and expense reimbursement, laptop/cell phone usage, work from home, etc.	Could be included in the employee handbook or handled as separate policies.	Q3
Inclusive and Sustainable Workforce Policy	Describes SDCP goals and requirements related to sustainable workforce practices, local hire preferences, livable wages, union engagement/project labor agreements, gender and ethnic diversity, etc.	Q3 (In process)
CUSTOMER AND COMMUNITY		
Prohibition Against Dissemination of Untrue or Misleading Information	Prohibits dissemination, by SDCP or other organization, of SDCP rates, terms and conditions of service, or other operational elements that are untrue or misleading.	Q4+
Customer Data Confidentiality	How customer data is to be treated and how to deal with any privacy or security breaches. States that personal customer shall not be shared unless necessary to conduct specific Agency business. Ensures the privacy and security of Advance Metering Infrastructure (AMI) data and customer usage information pursuant to Attachment B of the California Public Utilities Commission Decision 12-08-045.	Q4
Terms and Conditions of Service	Publicly posted customer service policy that provides information on rates, billing, enrollment process, opting out, opting in and failure to pay. If applicable; articulates process for customers who wish to voluntarily enroll in the 100% renewable product in an earlier phase than otherwise scheduled.	Q3 (In process)
Customer Billing, Enrollment, Delinquent Accounts and Collections	Outlines procedures for customer billing and enrollments, physical address changes, and handling customer accounts that are past due.	Q4
FINANCIAL POLICIES		
Budget Policy	Describes process, reporting and principals for a balanced annual budget and its oversight.	Q1-2 2021 (prior to fiscal year end)
Rate Setting Procedures	Describes rate setting principals, goals and general process.	Q4/Q1 2021
Bad Debt	A set percentage revenue reserve to cover bad debt; usually reviewed annually. Could be included in general budget policy.	Q1-2 2021 (prior to fiscal year end)
Reserve Policy	Budgeting policy to allow for long-term financial stability, accounts receivable reserves, debt reduction and/or funding of new programs and projects.	Q2 2021
Signatories on SDCP checks and financial documents	Describes who is authorized to sign checks and legally binding financial documents on behalf of the Agency; could be part of the budget and finance policy.	DONE
Investment Policy	If needed; provides guidelines to consider Agency investments in real property or other investment vehicles.	Q1-2 2021 (prior to fiscal year end)
Sponsorship Guidelines	Provides guidance to staff when determining which events to sponsor.	Q3 (DONE)
POWER SUPPLY		
Energy Risk Management Policy/ Procedures and	Developed in partnership with power services vendor; Describes energy market strategy and processes to regularly monitor, report and	DONE

Controls for Supply Management and Transactions	manage risk such as credit, liquidity and market risk. Outlines participation in CAISO markets and monitoring transactions. Provides general overview of procurement approach, criteria and practices including open season RFOs and signing authorities. Could also be part of the overall energy risk management policy.	
Evaluation Criteria	**NEW** – Describes how proposals for power will be evaluated for selection.	Q3-4 (In process)
Power Content Guidelines	Provides description of renewable and carbon free content targets as well as types of power that may or may not be procured by SDCP	Done
Net Energy Metering Policy	Describes NEM rates, credits and participation process for NEM customers.	Q4+
Feed in Tariff	**NEW** – Describes a feed in tariff rate structure and participation process.	Q4 (In process)

TOSDAL
ENERGY & ENVIRONMENTAL LAW

ENERGY REGULATORY UPDATE

To: Bill Carnahan, Interim Executive Officer, San Diego Community Power

From: Ty Tosdal, Regulatory Counsel, Tosdal APC

Re: Energy Regulatory Update

Date: October 16, 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 San Diego Community Power ("SDCP"). 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 SDCP. 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 an update to its PCIA undercollection balancing account (CAPBA) as directed by an ALJ Ruling issued on September 18, 2020. SDG&E's CAPBA update can be found in Attachment A. SDG&E states that nothing has occurred since their filing of the PCIA Trigger Application in July that would require a change in the CAPBA balance amount. The CAPBA records the difference between the full 2020 PCIA revenue requirement for departing load customers and the reduced revenue requirement due to capping PCIA rates at a $0.005/kWh annual increase.

As SDG&E explained at the August 27, 2020, 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 SDCP and CEA 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, 2020, 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)

SDCP and CEA'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)

SDCP and CEA 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. Approval of SDG&E's proposal will lead to increased non-bypassable charges for CCA customers and rates for bundled 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.

6. Order Instituting Rulemaking to Revisit New Energy Metering Tariffs Pursuant to Decision 16-01-044 and to Address Other Issues Related to Net Energy Metering (R. 18-20-08-020)

The CPUC voted to open a new proceeding on August 27, 2020, to examine issues surrounding the current NEM tariff in order to develop a successor tariff, as required by D. 16-01-044. "NEM 3", as it is informally called by parties, is the successor to NEM 2.0 and the original NEM tariff. Rulemaking 20-08-020 is in Attachment A.

The full range of impacts of NEM 2.0 were examined in the comprehensive "NEM Lookback Study" commissioned by the CPUC and published in August 2020. Most notable, was the report's finding that NEM 2.0 residential customers benefited from the tariff, while in general, other ratepayers saw increased rates due to the tariff. Commercial customers, however, paid bills under NEM 2.0 that were slightly higher than their actual cost of service due to demand and other charges that solar production can't eliminate, and a lower ratio of PV system size to electric load.

Rulemaking 20-08-020 will be coordinated with several other related proceedings: Microgrids and Resiliency, Distribution Resources Planning, Integrated Distributed Energy Resources, and Resource Adequacy. The preliminary scope of this proceeding includes:

- Identification of guiding principles to assist in the development and evaluation of the NEM 2.0 successor tariff and other related tariffs.
- Identification of program elements that may be included in a NEM 2.0 successor tariff or contract, such as pricing mechanisms, fees or fee waivers, timing for meter reads and billing, or other items.
- Analysis of various possible options for a NEM successor tariff or contract that will meet the goals of AB 327.
- Modification of NEM tariff rate schedules, including but not limited to VNEM, VNEM for multifamily affordable housing, NEM aggregation, the Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) program, and other NEM tariffs applicable to different generation sources.

A Prehearing Conference will be scheduled for November 2020, with a Scoping Memo and Ruling to follow in December. The Commission expects the new NEM tariff to be adopted no later than December 31, 2021.

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

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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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BEFORE THE PUBLIC UTILITIES COMMISSION
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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:

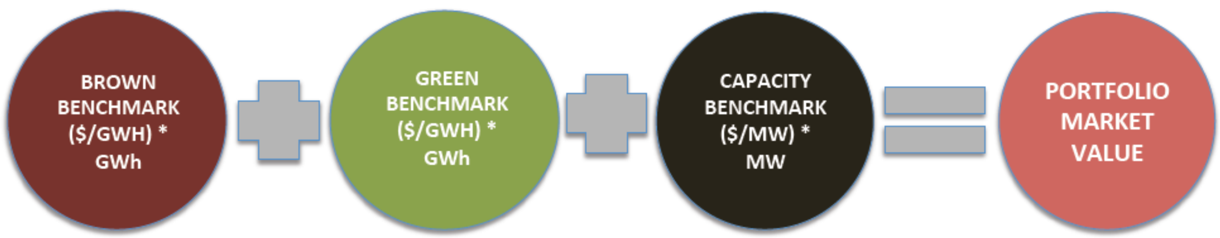
- For non-Renewable Portfolio Standard ("RPS")-eligible power in an IOU's portfolio, the forecasted amount of energy from such resources in the portfolio is multiplied by the brown power benchmark.[7]

- 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]

[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

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[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%

[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.

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[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.

[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.

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[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,

/s/ [signature]

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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

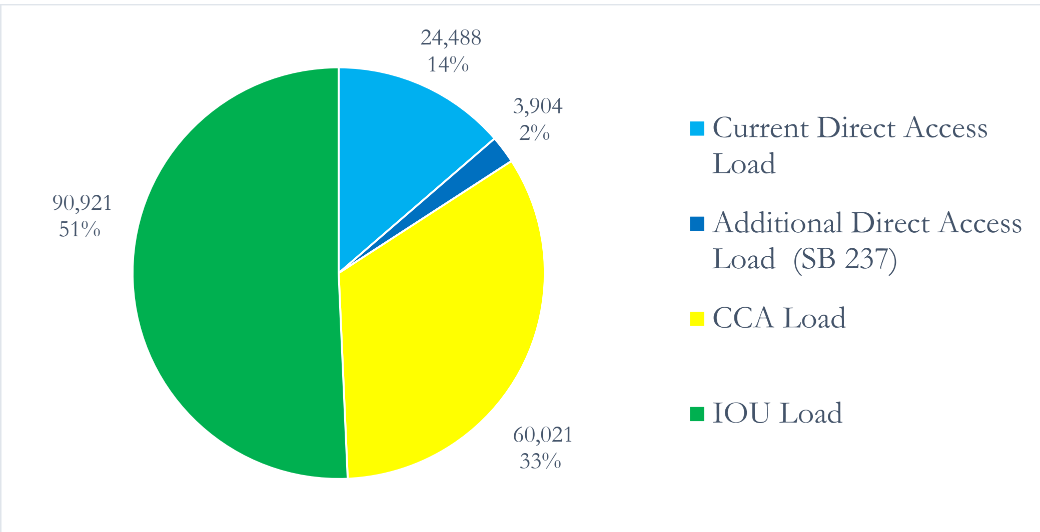
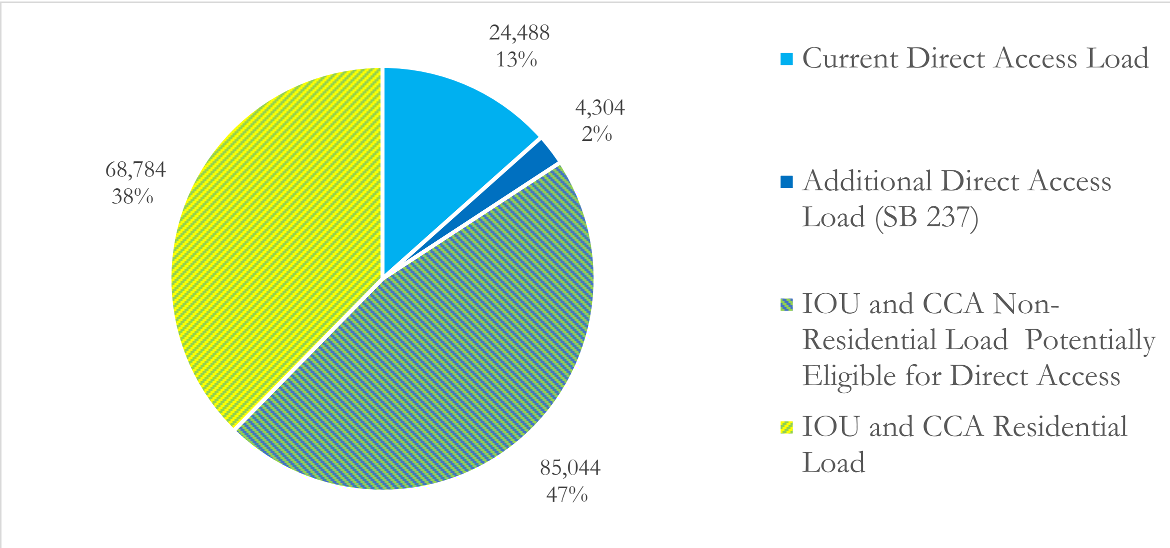


Figure 2 shows current Direct Access load and the additional load that could become eligible for Direct Access pursuant to SB 237. As Figure 2 shows, 47 percent of the current IOU and CCA load could move to Direct Access if the Legislature decides to re-open the entire non-residential market to Direct 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

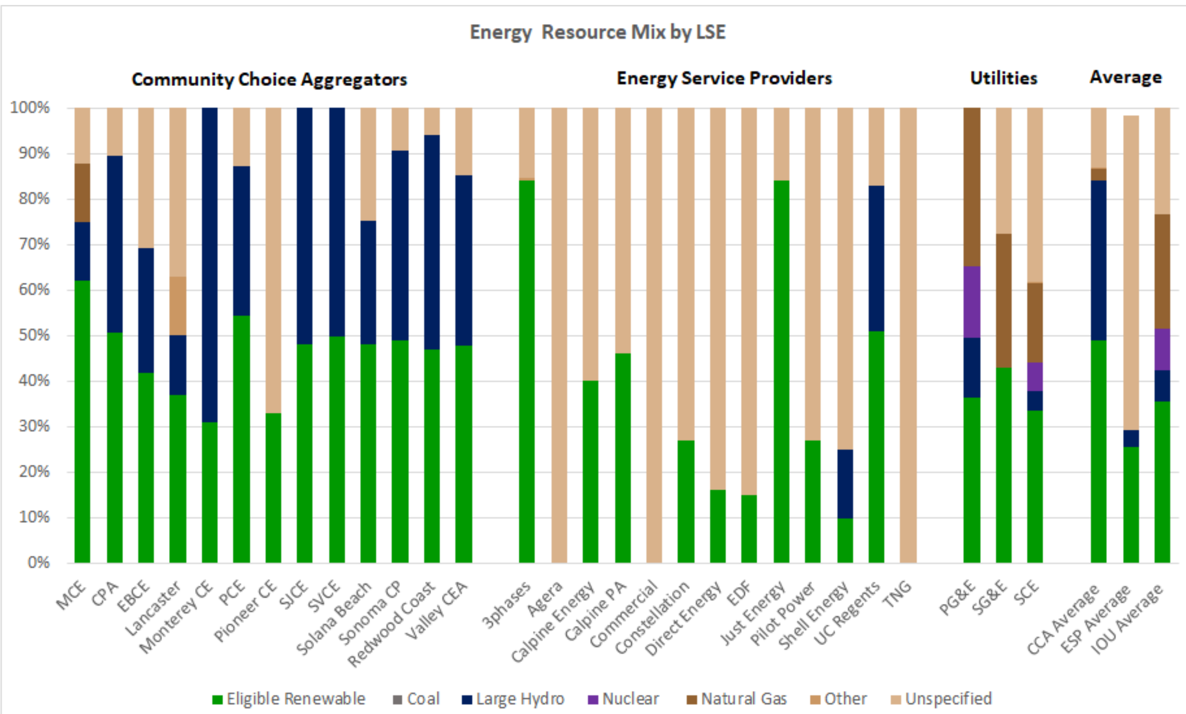
11 Electric sector GHG targets are set consistent with California Air Resources Board Scoping Plan ranges. Available: https://ww3.arb.ca.gov/cc/scopingplan/scopingplan.htm

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.

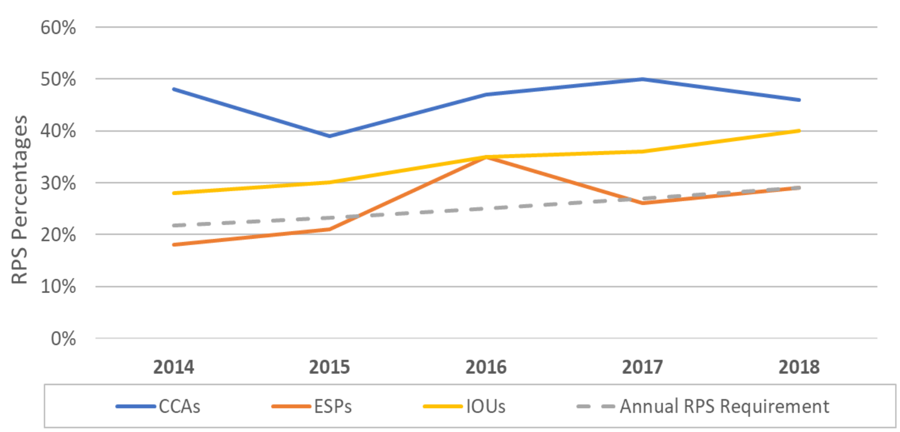
strategies, including a heavy reliance on CAISO system power, appear to increase GHG emissions relative to portfolios that rely on high amounts of RPS eligible resources.[16]

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

[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.

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.

Recommended Direct Access Reopening Schedule:

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.

<u>Recommendations for Legislative Action:</u>

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

[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.

[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.

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   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.

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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
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Service List R. 18-07-005

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision D.16-01-044, and to Address Other Issues Related to Net Energy Metering.	FILED PUBLIC UTILITIES COMMISSION AUGUST 27, 2020 SAN FRANCISCO, CALIFORNIA RULEMAKING 20-08-020

ORDER INSTITUTING RULEMAKING TO REVISIT NET ENERGY METERING TARIFFS PURSUANT TO DECISION 16-01-044, AND TO ADDRESS OTHER ISSUES RELATED TO NET ENERGY METERING

Summary

This rulemaking is initiated for two main purposes: 1) to revisit the existing net energy metering (NEM) tariffs as identified in Decision (D.)16-01-044 and 2) to retain issues related to NEM into a separate stand-alone rulemaking.

We intend to coordinate this rulemaking closely with other related proceedings including, but not limited to, Rulemaking (R.)12-11-005 and R.20-05-012 on renewable distributed generation programs, R.19-09-009 on Microgrids and Resiliency, R.14-08-013 on Distribution Resources Planning, R.17-07-007 on Rule 21 and the interconnection of distributed generation resources, R.14-10-003 on Integrated Distributed Energy Resources (IDER), R.19-11-009 on Resource Adequacy and R.14-07-002 on the development of a successor tariff to the original NEM tariff. Parties may file comments on the

preliminary scope and schedule established in this rulemaking according to the schedule set forth below.

1. Background

The NEM program is an electricity tariff-based billing mechanism designed to support the installation of customer-sited renewable generation. It was originally established in California with the adoption of Senate Bill (SB) 656 (Alquist, Stats. 1995, ch. 369), codified in Section 2827 of the Public Utilities Code. Under the original NEM tariff, customers who install and operate small (1 megawatt (MW) or less) renewable generation facilities (referred to as "customer-generators") that meet certain technical requirements may choose to participate in a NEM tariff. Previously, under the original NEM tariff, customer-generators received a full retail rate bill credit for power generated by their onsite systems that was fed back into the power grid during times when generation exceeds onsite energy demand. These credits were used to offset customers' electricity bills, and could be rolled over to subsequent bills for up to a year.

Currently, under the successor tariff (colloquially known as "NEM 2.0,") to the original NEM tariff, customers continue to receive full retail rate credit for energy exported to the grid up till the point when they start receiving Net Surplus Compensation. However, NEM 2.0 customers are required to pay charges that align NEM customer costs more closely with non-NEM customer costs than under the original structure. Specifically, customer-generators applying for and participating in NEM 2.0 pay a one-time interconnection fee and non-bypassable charges,[1] and must take service under a time-of-use (TOU) rate.

NEM continues to be an important element of the policy framework supporting customer and third-party investment in grid-tied customer-sited renewable energy generation, including solar photovoltaic (PV) and energy storage systems. The majority of NEM customers use onsite photovoltaic solar generators to provide some or all their electricity, and feed power back to the power grid when they generate more than they need at a given time.

1.1. Legislative Background

Since its creation, the NEM program has been modified numerous times by legislation. Modifications have generally focused on the number of MW of customer-sited renewable generation that may participate in the program, as well as changes to the terms and eligibility requirements for participation.

Assembly Bill (AB) 327 (Perea, Stats. 2013, ch. 611), which was signed into law by Governor Brown on October 7, 2013, sought to give the Commission the ability to "address current electricity rate inequities, protect low income energy users and maintain robust incentives for renewable energy investments."[2] Among the provisions of the bill was a mandate that the Commission adopt a successor to the existing NEM tariffs, to be implemented on July 1, 2017, or when a utility reaches the NEM enrollment limit for its territory (referred to here as the

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[1] Non-bypassable charges include the Department of Water Resources' bond charges, the public purpose program charge, nuclear decommissioning charge, and competition transition charge.

[2] Letter to State Assembly Members regarding AB 327, from Governor Edmund G. Brown Jr., October 7, 2013 (Governor's Signing Statement).

"transition trigger level"), whichever comes first.[3] With reference to developing a successor to the NEM tariff, AB 327 provides that the Commission should meet several objectives. Three of the main objectives are to ensure that customer-sited renewable generation "continues to grow sustainably and include specific alternatives designed for growth among residential customers in disadvantaged communities,"[4] to ensure that the new tariff "is based on the costs and benefits of the renewable electrical generation facility,"[5] and to "[e]nsure that the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs."[6]

In addition, AB 327 provided that customers who took service under NEM before July 1, 2017, or prior to reaching the statutory net metering transition trigger level, whichever is earlier, may continue to take service on existing NEM tariffs for a transition period determined by the Commission. In D.14-03-041, the Commission adopted a transition period of 20 years following interconnection of their system.

[3] Many parties to this proceeding refer to existing NEM tariff structures as NEM 1.0, to the successor tariffs required in AB 327 as NEM 2.0, and to a future successor tariff as NEM 3.0. We decline to refer to the future NEM tariff as "NEM 3.0" at this time because the details of that tariff have not yet been established. Instead, this decision refers to existing NEM tariff structures as NEM 1.0, NEM 2.0, and to the yet-to-be-developed replacement tariff as "the NEM 2.0 successor tariff."

[4] Pub. Util. Code § 2827.1(b)(1).

[5] Pub. Util. Code § 2827.1(b)(3).

[6] Pub. Util. Code § 2827.1(b)(4).

1.2. Procedural Background

On February 5, 2016, the Commission adopted D.16-01-044 that implements some of the provisions of AB 327. AB 327, among other things, added Section 2827.1 to the Public Utilities Code, requiring the Commission to develop "a standard contract or tariff, which may include NEM, for eligible customer-generators with a renewable electrical generation facility that is a customer of a large electrical corporation." D.16-01-044 implemented AB 327 by:

- Ensuring that customer-sited renewable distributed generation continues to grow sustainably through the creation of a successor to the existing NEM 1.0 tariff;
- Addressing the applicability of nonbypassable charges, minimum bills, demand charges, grid access charges, installed capacity fees, standby fees, or similar fixed charges on NEM 2.0 residential and non-residential customers;
- Continuing to require customers installing customer-sited renewable generation systems to pay a reasonable interconnection fee to the interconnecting investor-owned utility (IOU), with some exceptions; and
- Addressing alignment between NEM 2.0 customer eligibility and enrollment in default TOU rates.

Notably, D.16-01-044 established the Commission's commitment to review the NEM 2.0 tariff in 2019 (or later) citing interactive, yet unresolved, policy movements within the Commission, but outside the scope of the NEM proceeding. Specific proceedings cited included the Distribution Resources Planning proceeding, the IDER proceeding, and the residential rates proceedings. Similarly, the Decision pointed to actions occurring outside of the Commission's purview such as the work of the California Energy Commission on Zero Net Energy building goals and tax policies of the federal government that have significant impacts on the value, practicality, or effectiveness of the NEM tariffs.

2. Preliminary Scoping Memo

The Commission will conduct this rulemaking in accordance with Article 6 of the Commission's Rules of Practice and Procedure (Rules). As required by Rule 7.1(d), this Order Instituting Rulemaking (OIR) includes a preliminary scoping memo as set forth below, and preliminarily determines the category of this proceeding and the need for hearing.

2.1. Issues Generally

The scope of this proceeding encompasses any and all information necessary for: 1) development of a successor to the existing NEM 2.0 tariffs pursuant to the requirements of AB 327, and 2) issues related to existing NEM tariffs, including but not limited to questions about or modifications to specific provisions of the NEM tariffs. Section 2.2 discusses the issues and questions that we anticipate addressing related to the development of a successor to the existing NEM 2.0 tariff, and Section 2.3 outlines other NEM-related issues that may be addressed in this proceeding.

2.2. Development of a Successor to Existing NEM 2.0 Tariffs

The major focus of this proceeding will be on the development of a successor to existing NEM 2.0 tariffs. Pursuant to the requirements of AB 327, this successor will be a mechanism for providing customer-generators with credit or compensation for electricity generated by their renewable facilities that a) balances the costs and benefits of the renewable electrical generation facility and b) allows customer-sited renewable generation to grow sustainably among different types of customers and throughout California's diverse communities.

As part of the development of a successor tariff or contract, this proceeding will include an examination of the impacts of NEM 2.0,[7] the issues the Commission left until a future tariff review in D.16-01-044, possible tariff or contract provisions, and an evaluation of how those provisions meet the goals of AB 327 and other guiding principles consistent with California's energy policy and safety goals.

2.3. Other NEM Tariff Issues

We expect to address issues that arise related to existing NEM tariffs in this proceeding. The review and (if needed) potential modification of all NEM tariff schedules should be considered to be within the scope of this proceeding, including but not limited to Virtual Net Metering (VNEM), NEM aggregation (NEMA), and other NEM tariffs applicable to fuel cell customer-generators who use non-renewable fuel. We also expect to address issues related to consumer protection for customer-generators on NEM tariffs in this proceeding.

2.4. Coordination Between This Rulemaking and Other Related Proceedings

Because NEM functions as an overlay to a customer's otherwise applicable rate schedule, the costs and benefits of different NEM options or possible successors tariffs or contracts is largely dependent on the underlying rates on which NEM customers are served and their corresponding proceedings, as well

[7] The venue for the examination of the impacts of NEM 2.0 will be the "NEM 2.0 Lookback Study" scheduled to be posted on the CPUC website in 2020.

as other programs that incentivize and compensate renewable customer-sited generation. Because of this, the scope of this proceeding includes coordinating with other related proceedings including, but not limited to, R.12-11-005 and R.20-05-012 on renewable distributed generation programs, R.19-09-009 on Microgrids, R.14-08-013 on Distribution Resources Planning, R.17-07-007 on Rule 21 and the interconnection of distributed generation resources, R.14-10-003 on IDER, R.19-11-009 on Resource Adequacy, and R.14-07-002 on the development of a successor tariff to the original NEM tariff.

2.5. Preliminary Scope

In order to ensure a robust record for the development of a successor tariff, we anticipate that activities in this proceeding will include, but may not be limited to:

1. Identification of guiding principles, or goals, to assist in the development and evaluation of different tariff or contract options for the NEM 2.0 successor tariff.
2. Identification of "program elements," or specific features that may be included in a NEM 2.0 successor tariff or contract, such as pricing mechanisms, fees or fee waivers, timing for meter reads and billing, or other items.
3. Development of a variety of possible options for a NEM successor tariff or contract.
4. Analysis of the various elements of a potential NEM 2.0 successor tariff or contract to identify one or more tariff or contract options that will meet the goals of AB 327 and other guiding principles.
5. Modification of NEM tariff schedules, including but not limited to VNEM, VNEM for multifamily affordable

housing, NEM aggregation, the Renewable Energy Self-Generation Bill Credit Transfer (RES-BCT) program, and other NEM tariffs applicable to different generation sources such as fuel cell customer-generators.

D.18-09-044 authorized ratepayer funding for a consultant to conduct a formal and independent analysis of NEM 2.0. The study will analyze the costs and benefits of the tariff and assist the Commission in its development of a NEM 2.0 successor tariff.

The assigned Commissioner and assigned Administrative Law Judge (ALJ) may add to or modify these activities to ensure that there is a robust formal record on all issues relevant to the development of a successor to the NEM tariffs. If issues arise related to the review and possible modification of existing NEM tariffs, the assigned Commissioner and assigned ALJ(s) will determine the activities and schedule for addressing those issues.

3. Categorization; *Ex Parte* Communications; Need for Hearing

Rule 7.1(d) provides that an OIR shall preliminarily determine the category and need for hearing. This rulemaking is preliminarily determined to be ratesetting, as that term is defined in Rule 1.3(e). This preliminary determination is not appealable but shall be confirmed or changed by the assigned Commissioner's Scoping Memo and Ruling. The assigned Commissioner's determination as to category is subject to appeal pursuant to Rules 7.3 and 7.6.

We anticipate that the issues in this proceeding may be resolved through a combination of filed comments, workshops, and testimony, and that evidentiary hearings will not be necessary. Any person who objects to the preliminary hearing determination shall state the objections in their comments on this OIR. The assigned Commissioner will make a final determination on the need for hearing in the Scoping Memo and Ruling issued following a Prehearing Conference (PHC).

4. Preliminary Schedule

The preliminary schedule for this proceeding is set forth below and includes the provisions for the filing of comments on the OIR. The assigned Commissioner or ALJ may change the schedule and scope as necessary to provide full and fair development of the record.

Item	Date
Comments on the OIR filed and served	30 days from issuance of the OIR
Reply comments on the OIR filed and served	40 days from issuance of the OIR
PHC	November 2020
Scoping Memo and Ruling	December 2020
Development of guiding principles and program elements	Fall/Winter 2020
Development and analysis of successor tariff or contract options, additional activities to be determined	Spring/Summer 2021
Proposed decision on successor tariffs or contracts	November 2021

We expect to adopt a successor to existing NEM tariffs no later than December 31, 2021, and consistent with Public Utilities Code Section 1701.5, we expect this proceeding to be concluded within 18 months of the date of the scoping memo.

This schedule may be revised in the Scoping Memo and Ruling, and the assigned Commissioner or the assigned ALJs may modify this schedule to promote efficient and fair administration of this proceeding.

5. Invitation to Comment on Preliminary Scoping Memo and Schedule

Parties are invited to comment on the Preliminary Scoping Memo and schedule established in this OIR. Comments are due 30 days after the issuance of this OIR.

We direct parties to limit their comments to the schedule, the issues set forth in the preliminary scoping memo, the anticipated activities in this proceeding, and to objections to the preliminary determinations below. Comments directed to the issues identified within the scope of this proceeding may include whether to amend the issues and how to prioritize the issues to be resolved; how to procedurally address these issues; and the proposed timeline for resolving the issues identified, within the general schedule set forth in this OIR. Comments are limited to 15 pages per party, and will help to inform the PHC to be held in this proceeding.

6. Respondents

Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company, as large electrical corporations defined in Public Utilities Code Section 2827(b)(5), were required to make NEM tariffs available to their customers, and were required to implement the tariffs developed in R.14-07-002. For this reason, these three companies are hereby made respondents to this proceeding.

7. Service of OIR

This OIR shall be served on all respondents and on the electric corporations named in Attachment A. In addition, in the interest of broad notice, this rulemaking will be served on the official service lists of R.12-11-005 and R.20-05-012 on renewable distributed generation programs, R.19-09-009 on Microgrids, R.14-08-013 on Distribution Resources Planning, R.17-07-007 on Rule 21 and the interconnection of distributed generation resources, R.14-10-003 on IDER, R.14-07-002 on the development of a successor tariff to the original NEM tariff, and the former net surplus compensation proceeding Application (A.) 10-03-001 et al.

Service of the OIR does not confer party status or place a person who has received such service on the Official Service List for this proceeding.

8. Filing and Service of Comments and Other Documents

Filing and service of comments and other documents in the proceeding are governed by the Commission's Rules of Practice and Procedure. This proceeding will follow the electronic service protocol set forth in Rule 1.10. All parties to this proceeding shall serve documents and pleadings using electronic mail, whenever possible, transmitted no later than 5:00 p.m., on the date scheduled for service to occur. Rule 1.10. requires service on the ALJ of both an electronic and a paper copy of filed or served documents. When serving documents on Commissioners or their personal advisors, whether or not they are on the official service list, parties must only provide electronic service. Parties must not send hard copies of documents to Commissioners or their personal advisors unless specifically instructed to do so. In addition, pursuant to the COVID-19 Temporary Filing and Service Protocol for Formal Proceedings, the Rule 1.10(e) requirement to serve paper copies of all e-filed documents to the ALJ is suspended until further notice.

9. Addition to Official Service List

Addition to the official service list is governed by Rule 1.9(f) of the Commission's Rules of Practice and Procedure.

Respondents are parties to the proceeding (see Rule 1.4(d)) and will be immediately placed on the official service list.

Any person will be added to the "Information Only" category of the official service list upon request, for electronic service of all documents in the proceeding, and should do so promptly in order to ensure timely service of comments and other documents and correspondence in the proceeding. (*See* Rule 1.9(f).) The request must be sent to the Process Office by e-mail (process_office@cpuc.ca.gov) or letter (Process Office, California Public Utilities Commission, 505 Van Ness Avenue, San Francisco, California 94102). Please include the Docket Number of this rulemaking in the request.

Persons who appear at the PHC and request party status will become parties to the proceeding and will be added to the "Parties" category of the official service list. *In order to assure service of comments and other documents and correspondence in advance of obtaining party status, persons should promptly request addition to the "Information Only" category as described above;* they will be removed from that category upon obtaining party status.

10. Subscription Service

Persons may monitor the proceeding by subscribing to receive electronic copies of documents in this proceeding that are published on the Commission's website. There is no need to be on the official service list in order to use the subscription service. Instructions for enrolling in the subscription service are available on the Commission's website at http://subscribecpuc.cpuc.ca.gov/.

11. Intervenor Compensation

Intervenor Compensation is permitted in this proceeding. Any party that expects to claim intervenor compensation for its participation in this Rulemaking must file a timely notice of intent to claim intervenor compensation. (*See* Rule 17.1(a)(2).) Intervenor compensation rules are governed by Section 1801 *et seq*. of the Public Utilities Code. Parties new to participating in Commission proceedings may contact the Commission's Public Advisor.

12. Public Advisor

Any person interested in participating in this proceeding who is unfamiliar with the Commission's procedures or has questions about the electronic filing procedures is encouraged to obtain more information at consumers.cpuc.ca.gov/pao or contact the Commission's Public Advisor at 1-866-849-8390 or 866-836-7825 (TYY), or send an e-mail to public.advisor@cpuc.ca.gov.

Therefore, **IT IS ORDERED** that:

1. Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company are named as respondents and are

parties to this proceeding pursuant to Rule 1.4(d) of the Commission's Rules of Practice and Procedure.

2. The Executive Director will cause this Order Instituting Rulemaking to be served on all respondents and on the service lists for the following Commission proceedings: Rulemaking (R.) 12-11-005, R.20-05-012, R.19-09-009, R.14-08-013, R.17-07-007, R.14-10-003, R.14-07-002, and Application (A.) 10-03-001 et al., as well as the electric corporations identified in Attachment A.

3. Interested persons must follow the directions of this Order Instituting Rulemaking to become a party or to be placed on the official service list as information-only.

4. The assigned Commissioner or the assigned Administrative Law Judge(s) will have on-going oversight of the service list and may institute changes to the list or the rules governing it, as needed.

5. Parties may file comments on this Order Instituting Rulemaking (OIR) as provided in this OIR.

6. The assigned Commissioner or the assigned Administrative Law Judge may modify the activities and schedule established in this Order Instituting Rulemaking as necessary for the efficient conduct of this proceeding.

7. Parties serving documents in this proceeding must comply with Rule 1.10 of the Commission's Rules of Practice and Procedure regarding electronic mail (e-mail) service.

8. This Order Instituting Rulemaking is adopted pursuant to Rule 6.1 of the Commission's Rules of Practice and Procedure.

9. The preliminary categorization is ratesetting.

10. The preliminary determination is that a hearing is not needed.

11. The preliminarily scope of issues is as stated above.

12. Prehearing conference statements are due 30 days after the issuance of this Order Instituting Rulemaking.

13. The preliminary schedule for the proceeding is as set forth above.

14. Any party that expects to claim intervenor compensation for its participation in this Rulemaking must timely file its notice of intent to claim intervenor compensation. (*See* Rule 17.1(a)(2).)

This order is effective today.

Dated August 27, 2020, at San Francisco, California.

MARYBEL BATJER
President
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
Commissioners

SAN DIEGO **COMMUNITY POWER**
Staff Report – Item 5

To: San Diego Community Power (SDCP) Board of Directors

From: Bill Carnahan, Interim CEO

Subject: Update of Amended Organizational Chart and Staffing Plan

Date: October 22, 2020

Recommendation
Receive staffing plan update and proposed SDCP organizational chart through year-end 2021.

Background
As SDCP continues to mature, increased staffing will be required to replace the dependance on consultants. To assure all the duties and tasks are covered, SDCP needs an organization structure that is designed properly, has a plan for efficient staff additions, contains appropriate job descriptions, salary schedules and fringe benefits to attract qualified personnel to carry out the mission.

The FY 2020/2021 budget has allocated $1.5M for SDCP staffing through June 2021 to cover **8-9** full-time employees (Phase 1), with an additional **10-12** hires proposed in late 2021/early 2022 to support SDCP's major residential roll-out in Q1 2022 (Phase 2).

In preparing the attached organization chart, staff and consultants researched the staffing structures of five large operational CCAs including: Clean Power Alliance, East Bay Community Energy, Monterey Bay Community Power (now Central Coast Community Energy), MCE Clean Energy and Silicon Valley Community Energy while also considering the current capacity and near-term staffing needs of SDCP. This should be considered the near term (2-year) staffing plan and It is anticipated that SDCP staffing numbers will continue to grow once the Agency is fully operational, offering programs, and deepening its capacity in various Agency functions and state-level efforts.

Analysis and Discussion

At the last meeting the Board adopted an initial staffing plan while realizing there may need to changes. This organization plan primarily differs from the original plan by making the Power Services function a stand-alone Division with Director of Power Services directly reporting to the Chief Executive Officer.

The filling of positions will be spread over time in a defined priority based on the needs of SDCP. In the near term (Phase 1), the following positions have been deemed essential “first hires” to support, and in some cases transition, existing interim staff and augment existing consulting capacity to ensure that SDCP is ready for its phase 1 roll-out next spring. These positions include:

1) Chief Executive Officer (completed)
2) Chief Operating Officer
3) Director of Power Services
4) Director of Regulatory and Compliance
5) Executive Assistant/Board Clerk
6) Director of Marketing and Customer Care
7) Finance Manger
8) Policy and Programs Manager
9) Key Accounts Manager

It is anticipated that Phase 1 hires will occur starting in November and continue through Q1 2021. This will be a very busy period for SDCP and we need to build our internal capacity ASAP. Phase 2 hires will commence in early summer 2021 to coincide with the beginning of Agency revenues and the adoption of its FY 2021/2022 budget.

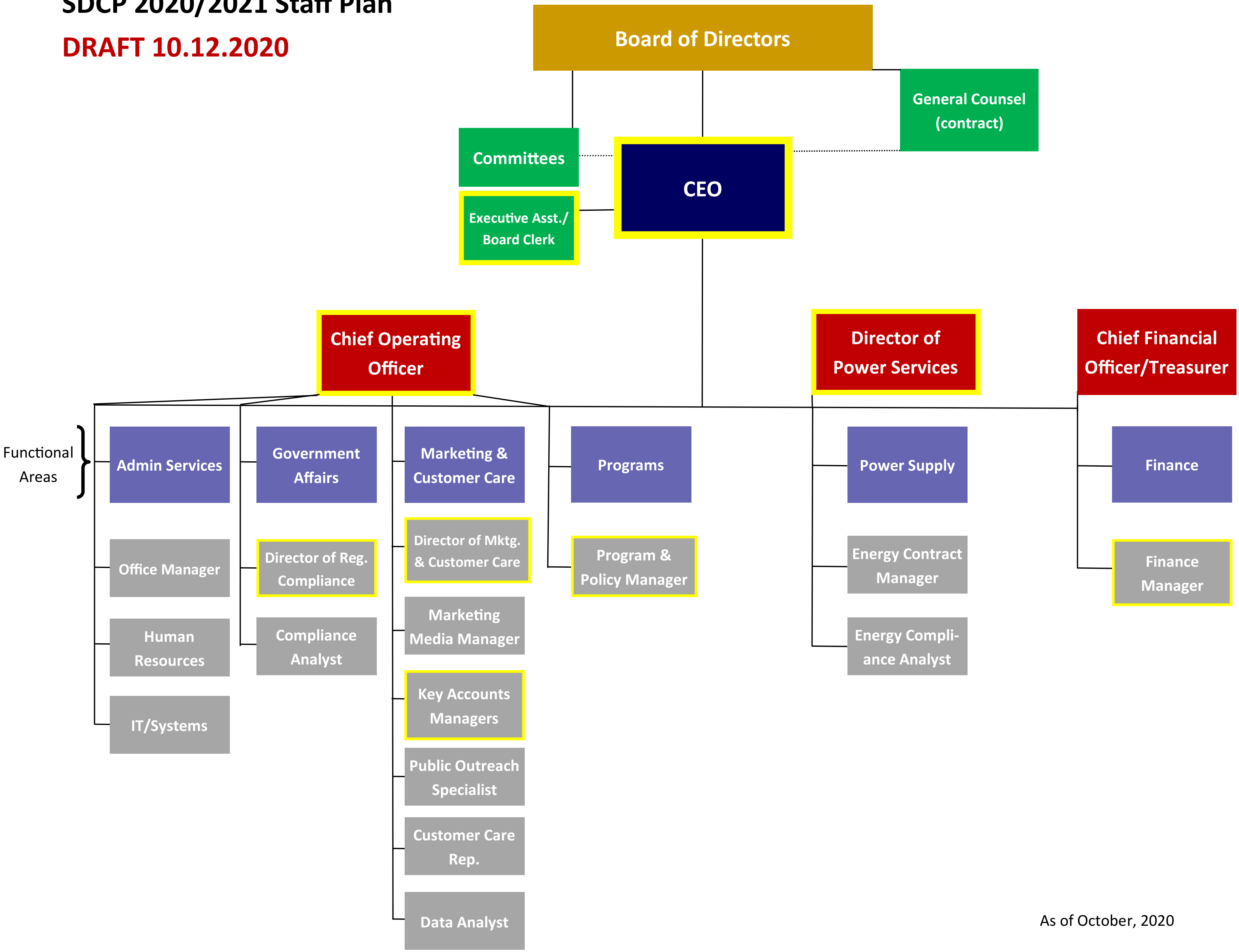
Staff will keep the Board apprised of any material changes to the attached organization chart. We are also conducting salary surveys for key positions to ensure compensation alignment within the industry as well as cost-of-living considerations for the San Diego metro region. The development of a fringe benefit package is also underway and will be updated at this meeting.

<u>Fiscal Impact</u>
$1.5M in FY 2020/2021 ending June 30, 2021. Cost of phase 2 hires will be researched and included in FY 2021/2022 budget starting July 1, 2021.

<u>Attachments</u>
Attachment A: SDCP Organization Chart as of October 12, 2020

SDCP 2020/2021 Staff Plan

DRAFT 10.12.2020



As of October, 2020

SAN DIEGO **COMMUNITY POWER**
Staff Report – Item 6

To: San Diego Community Power Board of Directors

From: Tom Bokosky, Director of Human Resources, City of Encinitas

Subject: Receive Update and Provide Direction and Authorization Regarding San Diego Community Power Employee Benefits Program

Date: October 22, 2020

Recommendations

1. Receive employee benefits report and provide feedback and direction.
2. Authorize the Interim Chief Executive Officer to a) negotiate with employee benefit providers for group health coverage, b) implement a final employee benefit plan, and c) perform ongoing maintenance of the employee benefit plan to accommodate changes in market conditions and benefit laws and regulations.

Background

SDCP is currently recruiting for staff positions and the employee benefit plan is critical in the recruitment and the retention of qualified candidates. Staff has completed a comparison of employee benefit plans (Attachment A) and has prepared a preliminary employee benefit plan for the Board's review and discussion.

Analysis and Discussion

The employee benefit plan consists of four categories: health cafeteria, retirement, paid time off and miscellaneous benefits. Attachment B outlines a preliminary San Diego Community Power employee benefit plan. The preliminary employee benefit plan was developed from the employee benefit comparisons in Attachment A. However, staff is still researching employer benefit plans from likely competitors such as, San Diego Gas & Electric, which will be presented to the CEO for consideration of a final employee benefit plan. The benefit plan will then be used in the recruitment notices and advertisements to help attract and retain highly qualified candidates.

There is a transition period between the hiring of the first SDCP employees and the implementation of a group benefit plan. Simply, we need a group of at least 2 employees before we can obtain group health insurance proposals. During this transition the initial employees will be paid a monthly stipend of $1,200 to cover the cost of any COBRA premiums or individual health benefit premiums. The Interim CEO and Interim Human Resources Director will negotiate group health coverage with employee benefit providers and bring those contracts back to the Board for approval.

Fiscal Impact
The estimated annual cost of the health cafeteria is $14,400 per employee, plus any retirement contribution match and employer paid benefits (basic life, disability, and employee assistance program).

Attachments
Attachment A: SDCP - CCA Benefits Comparison - As of October 13, 2020
Attachment B: San Diego Community Power Employee Benefits

SDCP - CCA Benefits Comparison
As of October 13, 2020

Benefit Category	San Diego	CPA	MBCP	EBCE
Medical	$1200/month cafeteria plan $600/month taxable if opt-out of city plans	Full medical at Kaiser Platinum; dental and vision from 3rd party providers. Employees pay the difference if they choose a diff option. Cash out option is $500/mo. Flex spending account (FSA)is offered as an option.	$1200/month to all employees with 7 insurance carrier options $600/month taxable added to base salary if opt-out Also optional health reimbursement account and FSA	For executive employees, 100% is covered. $1250/month for employees who use EBCE coverage. $600/month taxable salary for those who opt out. FSA also offered
Dental	Included in monthly amount above	As above	As above	Incl in $1250/month
Vision	Included in monthly amount above	As above	As above	Incl. in $1250/month
Retirement	10% employer salary match (vested after 3 years); any excess beyond IRS limits go to a 457	403(b) plan with 4% employee contribution. Employer contribution up to 6% of employee salary; employer vesting over 3 years.	401(a); 10% mandatory for employee, 10% match by employer 100% vested on day one	401(a); employer pays 8% of earned income that is vested immediately.
457(b)/Deferred Comp	See above	Employees have the option; max set by IRS	Employees have the option; max set by the IRS	Employees have the option; to facilitate participation, EBCE matches employee contributions up to 6% of salary 50% vesting after 1 year.
Life Insurance	Equal to 1 year salary	Equal to 1 year salary (capped at $500k) Employees can purchase additional	$25,000 included in medical plans plus $175,000 for all employees	Equal to 1 year salary
Disability Insurance	Equal to 60% of salary	L-T insurance equal to 60% of salary S-T disabilitiy provided thru CA State short term dis. insurance program	L-T: 70% of salary up to $10k/mo S-T: 66.66% of salary to max of $2k/wk	None stated
Time off: Vacation, Sick Leave, PTO, Other	4 weeks annual leave, incl. of sick time 2 weeks exec leave (Director and above) Last week of Dec closed with pay	Start at 80 hrs (2 weeks) annually plus last week of December; no cash out of vacation. After 3 years of service, one additional week. Sick leave = one day/month 40 hrs PTO after introductory period	PTO inclusive of vacation, sick, etc starts at 180 hours/year with an additional 8 hours/year not to exceed 10 years. Balance of PTO is paid to employee at time of termination.	Vacation - 5 hours/pay period or 120 hrs/year plus 8 hours for each year of employment up to 240 hours max. Sick- 4 hrs/pay period with max 96hrs per year. Other -16 hours of bereavement, 2 hours for voting, 40 hours for bone marrow and up to 240 hours for organ donation.
Unpaid Leave	None stated	None stated	None stated	For Pregnancy, disability accomodation, parental leave,

Holidays	12 standard holidays	12 holidays	10 holidays/year	10 holidays/year plus 40 hrs of floating holidays for folks hired prior to July 1
Technology/Equipment	Cell phone - $100/month or provided by SDCP Laptop, docking station, monitor, keyboard, mouse provided at hire	None stated	Cell phone - $50/month to all employees whose job requires one	None stated
EAP/Other Flex Wellness Benefits	$1,000 annually for gym memberships, health reimbursements, etc.	EAP; no details offered; voluntary employee benefits at employee expense	Up to $1,000 annually	Up to $1,000/year
Transportation	$100/month or 100% of transit pass	$200/month for non-auto commuting	None stated	Up to $150/month for non-auto commute or $75 stipend; Execs allowed up to $400/month
Misc/Other	Flex schedule (AWW+WFH as approved by supervisor)		COLA adjustment each October	

San Diego Community Power
Employee Benefits

Benefit Category	Description	Amount
Health Cafeteria • Medical • Dental • Vision	Pre-Tax Cafeteria Benefit Plan with opt out options if the employee has other group coverage. Flex spending for health and dependent care	$1,200 Per Month
Retirement	SDCP contribution with vesting on upon qualified years of service	Up to 10% match
Deferred Comp	Voluntary Deferred Compensation Plans 457b or 401a	Employees have the option; max set by IRS annually
Life Insurance	Basic term life insurance equal to 1.0 to 1.5 times the employee's base salary	Employer paid basic life with option for employees to purchase additional coverage
Disability Insurance	Equal to 2/3rds of the employee's monthly base salary	Employer paid
Paid Time Off	Employee accrues vacation and sick leave per pay period. CEO may authorize an initial beginning vacation balance. Exempt staff receive an annual administrative leave bank Non-exempt staff earn overtime of compensatory time off	Annual Leave Accrual Vacation -80 Hours Administrative Leave – 40 Hours Sick Leave – 96 Hours
Holidays	9 standard holidays plus New Years and Christmas Eve	11 Paid Holidays
Technology	Cell phone allowance & SDCP provided equipment	$100 per month
Employee Assistance Program	Provide counseling and support services to employees and all household members.	Employer paid
Transportation	Reimbursement incentive to utilize public transportation	Up to $150 per month

SAN DIEGO **COMMUNITY POWER**
Staff Report – Item 7

To: San Diego Community Power Board of Directors

From: Sebastian Sarria, Policy and Program Coordinator, LEAN Energy US

Subject: Approval of CCA Terms and Conditions in Substantive Form

Date: October 22, 2020

Recommendation
Adopt CCA Terms and Conditions in Substantive Form.

Background
As part of our phase launches starting on March 1, 2021, enrollment notices including SDCP's terms and conditions will need to be mailed out to our customers.

Analysis and Discussion
SDCP's terms and conditions of service are based on standard language from other CCAs and are adapted to reflect SDCP's eventual product offerings. The terms and conditions include information on rates, billing, enrollment, opting-out and customer failure to pay. SDCP customers are subject to San Diego Gas & Electric's (SDG&E's) terms and conditions if they opt-out. All customer enrollment notifications for our three phases will include SDCP's standard terms and conditions.

Since staff is still working on several pieces of information that will be included in our final terms and conditions, such as our customer service phone number and product names, we ask that this draft is approved in substantive form. The information to be finalized in the draft terms and conditions are highlighted within attachment A.

Fiscal Impact
There is no fiscal impact associated with this item.

Attachments
Attachment A: Terms and Conditions of Service

SAN DIEGO
COMMUNITY
POWER

Terms & Conditions of Service

San Diego Community Power electric generation rates are managed with the intention of providing cleaner electricity at competitive rates. Any changes to SDCP rates will be adopted at duly noticed public hearings of the San Diego Community Power Board of Directors. Changes to SDG&E or SDCP rates will impact cost comparisons between SDCP and SDG&E.

SDG&E charges SDCP customers a monthly Power Charge Indifference Adjustment (PCIA) and Franchise Fee Surcharge. SDCP has already accounted for these additional charges in calculating rates. View SDCP rates and SDG&E cost comparisons online at SDCommunityPower.org or by calling (###) ###-####.

BILLING: You will receive a single monthly bill from SDG&E that includes SDCP's electric generation charges. SDCP's electric generation charge replaces SDG&E's electric generation charge. SDCP's charge is not a duplicate charge or extra fee. SDG&E will continue to charge you for electric delivery services. If you opt out of SDCP, SDG&E will resume charging you for electric generation.

ENROLLMENT: As the default electricity provider for the cities of Chula Vista, Encinitas, Imperial Beach, La Mesa, and San Diego, you will be automatically enrolled into San Diego Community Power service unless you opt out at least five business days before your meter read date during the enrollment month. Accounts will be enrolled in SDCP's (insert default program name) on your regularly scheduled meter read on or after the first day of the enrollment month. You may choose to opt-up to (insert premium program name), which provides 100% renewable energy service at very competitive rates.

To sign up for the (insert premium program name), please visit SDCommunityPower.org or call SDCP at (###) ###-####.

DISCOUNT PROGRAMS: If you are currently enrolled in the California Alternative Rates for Energy (CARE) program, the Family Electric Rate Assistance (FERA) program, Medical Baseline, or Level Pay, you will continue to receive all benefits and discounts as a San Diego Community Power customer.

OPT OUT: You have the right to opt out without penalty at any time. You will not be charged any fees by SDCP if you opt-out or if you cancel electric service altogether (for example, if you move). However, if you decide to return to SDG&E after the 60-day opt out period, SDG&E will charge a one-time account processing fee. You will also be prevented by SDG&E from returning to San Diego Community Power for a minimum of twelve months. By opting out, you will also be subject to SDG&E's then current rates and terms and conditions of service. For details on SDG&E's rates, terms and conditions, please visit SDGE.com. You will not be charged any fees if you opt out within the first 60 days after your automatic enrollment with SDCP or if you cancel electric service altogether (for example, if you move). If you opt out, you will still be charged for all electricity you used before the transfer of electric service. Accounts will be transferred on the day the electric meter is read and cannot be transferred during the middle of a billing cycle. In order for your request to be processed on your next meter read date, your request must be received at least 5 business days prior to the date on which the meter is read. To opt out, please call SDCP at (###) ###-#### or visit SDCommunityPower.org. Have your electric bill handy so that we can process the request.

FAILURE TO PAY: San Diego Community Power may transfer your account to SDG&E upon 30 calendar days' written notice to you if you fail to pay any portion of the SDCP charges on your bill. If your service is transferred, you may be subject to additional requirements by SDG&E.

For more information, please call SDCP at (###) ###-####.