DESERT COMMUNITY ENERGY

Desert Community Energy
Board Meeting Agenda
Monday, June 18, 2018
2:30 p.m.

Coachella Valley Association of Governments
73-710 Fred Waring Drive, Palm Desert
Suite 200 Conference Room
(760) 346-1127

THIS MEETING IS HANDICAPPED ACCESSIBLE.
ACTION MAY RESULT ON ANY ITEMS ON THIS AGENDA.

1. **CALL TO ORDER**

2. **ROLL CALL**

A. **Member Roster** **P3**

3. **PUBLIC COMMENTS**

This is the time and place for any person wishing to address Desert Community Energy on items not appearing on the agenda to do so.

4. **BOARD MEMBER / DIRECTOR COMMENTS**

5. **CONSENT CALENDAR**

A. **Approve minutes of May 21, 2018 Desert Community Energy Board meeting** **P4**

B. **Approve the 1st Amendment to the cost-sharing agreement with Western Riverside Council of Governments and Los Angeles Community Choice Energy for legal services related to the Power Cost Indifference Adjustment, Resource Adequacy, and related regulatory matters, to increase the budget to $130,000, with a CVAG (DCE) share not to exceed $43,333.** **P7**

C. **Approve Amendment #1 to the Consulting Services Agreement between CVAG and Don Dame to provide implementation and operations support for Desert Community Energy, for a not to exceed amount of $30,000.** **P11**

6. **DISCUSSION / ACTION**

A. **Update on Our Progress**– Tom Kirk **P15**

Information only.

B. **Desert Community Energy Fiscal Year 2018/2019 Budget** – Don Dame **P17**

RECOMMENDATION: Approve Resolution No. 2018-02 adopting the 2018/2019 Fiscal Year Annual Budget

C. **Approve Net Energy Metering program for Desert Community Energy** – Benjamin Druyon **P34**

RECOMMENDATION: Approve Net Energy Metering (NEM) program that is equal to Southern California Edison's NEM program for existing and future solar customers, with the option to review a more robust program in the future, once financial uncertainties are made clear.

7. **INFORMATION**

1) Attendance Roster **P37**
2) Legislative Update – Erica Felci **P38**
    a. AB 813
    b. Other items
3) General Assembly Flyer **P55**

8. **ANNOUNCEMENTS**

Upcoming Meetings at Agua Caliente Casino Resort, 32-250 Bob Hope Drive, Rancho Mirage

- Executive Committee – Monday, June 25, 2018 at 4:30 p.m.
- General Assembly – Monday, June 25, 2018 at 6:00 p.m.

Upcoming Meetings at 73-710 Fred Waring Drive, Suite 200, Palm Desert

The next Board Meeting of Desert Community Energy will be on July 16, 2018 at 2:30 p.m.

9. **ADJOURNMENT**

ITEM 2A

DESERT COMMUNITY ENERGY

Board Meeting

June 18, 2018

Desert Community Energy Board Members	
City of Cathedral City	**Shelley Kaplan, Chair** Councilmember
City of Palm Desert	**Sabby Jonathan, Vice Chair** Mayor
City of Palm Springs	**Geoff Kors** Councilmember

Ex-Officio / Non-Voting Members	
City of Desert Hot Springs	Vacant

Staff
Tom Kirk, Executive Director
Katie Barrows, Director of Environmental Resources
Erica Felci, Governmental Projects Manager
Benjamin Druyon, Management Analyst

DESERT COMMUNITY ENERGY

Board Meeting Minutes

May 21, 2018

1. **CALL TO ORDER**
The meeting of the Desert Community Energy Board was called to order by Chair Kaplan at 2:30 p.m. on May 21, 2018.

2. **ROLL CALL**

Roll call was taken and it was determined that a quorum was present.

Members Present	**Agency**
Councilmember Shelley Kaplan, Chair	City of Cathedral City
Councilmember Kathleen Kelly	City of Palm Desert
Councilmember Geoff Kors	City of Palm Springs

Others Present	
Ryan Stendell	City of Palm Desert
David Herman	City of Palm Desert
Jay Virata	City of Palm Springs
Jeff Fuller	The Energy Authority/TEA
Don Dame	Consultant
Kim Floyd	Sierra Club

Ex-Officio / Non-Voting Member Absent	
Councilmember Yvonne Parks	City of Desert Hot Springs

CVAG Staff
Tom Kirk
Benjamin Druyon
Erica Felci
Linda Rogers

3. **PUBLIC COMMENTS**

Kim Floyd addressed AB 813 regarding regionalizing the management of energy across the west. Mr. Kirk indicated that he would check into AB 813 to see if this should be addressed at the next meeting for discussion.

4. **BOARD MEMBER / DIRECTOR COMMENTS**

Councilmember Kelly asked about whether the progress of the roll out would be included in the update progress report, and Mr. Kirk advised that it would be.

5. **CONSENT CALENDAR**

IT WAS MOVED BY COUNCILMEMBER KORS, SECONDED BY COUNCILMEMBER KELLY, TO:

A. **Approve minutes of April 16, 2018 Desert Community Energy Board meeting**

THE MOTION CARRIED WITH 3 AYES.

Councilmember Shelley Kaplan	**AYE**
Councilmember Kathleen Kelly	**AYE**
Councilmember Geoff Kors	**AYE**

6. **DISCUSSION / ACTION**

A. **Update on Our Progress**

Tom Kirk discussed the progress and upcoming activities of the roll out as outlined in the staff report. Erica Felci showed a short video clip that will target DCE customers in the three cities. The website will be interactive on June 12. Staff responded to questions regarding community outreach. Mr. Kirk added that staff will come back to the Board with more information on Net Energy Metering (NEM) once our team has been able to perform an adequate analysis of the NEM policy options. Jeff Fuller with The Energy Authority (TEA) updated the Board on procurement.

B. **Draft Desert Community Energy Fiscal Year 2018/2019 Budget**

The Draft Budget was developed by Don Dame with input from CVAG staff. Mr. Dame provided a presentation starting with the DCE pro forma. Mr. Dame reviewed the budget spreadsheets included in the staff report:

1) Draft Fiscal Year 2018/2019 budget identifying projected revenues and expenses for DCE
2) Draft 3-year summary of DCE revenues and costs for Fiscal Years 2019/2020/2021

The budget also identified the CVAG positions and allocation of time to DCE for administrative and operational support. Mr. Dame discussed next steps and responded to questions from the board.

No action was taken at this time. The final budget will be presented at the next meeting.

C. **Adoption of Energy Risk Management Policy**

IT WAS MOVED BY COUNCILMEMBER KELLY, SECONDED BY COUNCILMEMBER KORS, TO ADOPT DCE ENERGY RISK MANAGEMENT POLICY, NO 18-09.

THE MOTION CARRIED WITH 3 AYES.

Councilmember Shelley Kaplan	AYE
Councilmember Kathleen Kelly	AYE
Councilmember Geoff Kors	AYE

7. INFORMATION

1) Attendance Roster

8. ANNOUNCEMENTS

Upcoming Meetings at 73-710 Fred Waring Drive, Suite 200, Palm Desert

Next board meeting of **Desert Community Energy** – **Monday, June 18, 2018 at 2:30 p.m.**

Upcoming Meetings at Agua Caliente Casino Resort, 32-250 Bob Hope Drive, Rancho Mirage on Monday, June 25, 2018:

- **Executive Committee – at 4:30 p.m.**
- **General Assembly – at 6:00 p.m.**

9. ADJOURNMENT

The meeting adjourned at approximately 3:44 pm.

Respectfully submitted,

Linda Rogers
Program Assistant II

ITEM 5B

DESERT COMMUNITY ENERGY

Board Meeting

June 18, 2018

DRAFT

Subject: **Amendment to Cost-sharing Agreement between CVAG, Western Riverside Council of Governments and Los Angeles Community Choice Energy for legal services related to regulatory issues associated with community choice aggregation programs.**

Contact: Katie Barrows, Director of Environmental Resources (kbarrows@cvag.org)

Recommendation: Approve the 1st Amendment to the cost-sharing agreement with Western Riverside Council of Governments and Los Angeles Community Choice Energy for legal services related to the Power Cost Indifference Adjustment, Resource Adequacy, and related regulatory matters, to increase the budget to $130,000, with a CVAG (DCE) share not to exceed $43,333.

Background: In order to provide cost efficiencies, agreements were developed for cost-sharing of legal and technical services for the regulatory matters related to Community Choice Aggregation with Western Riverside Council of Governments (WRCOG) and Los Angeles Community Choice Energy (LACCE, now known as Clean Power Alliance). These agreements were approved by the DCE Board in October 2017 and by the CVAG Executive Committee in December 2017 for work on the PCIA and related matters, for CVAG's share of up to $20,00 for each agreement. The legal work necessary to participate in the PCIA proceeding and assist DCE with various regulatory matters exceeds that amount. WRCOG serves as the lead for the legal services agreement, using Best, Best, & Krieger. WRCOG has approved a 1st Amendment to the Cost-Sharing Agreement for Legal Services for not to exceed $130,000 (see Attachment 1). CVAG's share of this amount is estimated at one-third of the total, or approximately $43,333.

This staff report describes a proposed 1st Amendment to the cost-sharing agreement between CVAG, WRCOG, and LACCE, to increase the amount allocated for legal services related to CCA regulatory matters, including the PCIA. The original contract is with CVAG and staff recommends that it remain a CVAG contract until DCE is receiving revenues. This contract will be included in the funds to be reimbursed to CVAG by DCE.

The Power Charge Indifference Adjustment (PCIA), an "exit fee" charged by utilities to CCA customers, continues to be a key issue to emerging Community Choice Aggregation programs. The PCIA is the mechanism to ensure that customers who remain with the utility do not end up taking on the long-term financial obligations the utility incurred on behalf of now-departed customers.

Los Angeles Community Choice Energy serves as the lead for the technical services agreement for analysis and recommendations on PCIA charges and related regulatory matters, using EES Consulting, Inc. That work is nearly complete and CVAG's share of these costs is expected to be under $20,000, the amount approved by the DCE Board and CVAG Executive Committee. No amendment to the technical services agreement is needed at this time.

Staff recommends the DCE Board approve the staff recommendation, to approve the 1st Amendment to the cost-sharing agreement for legal services between CVAG, Western Riverside Council of Governments and Los Angeles Community Choice Energy. This item will be presented to the CVAG Executive Committee for their consideration at their June 25 meeting.

Fiscal Analysis: The current cost share for CVAG is for $20,000. Since October 2017, the share of legal costs attributed to Desert Community Energy is $37,824.49. Invoices from WRCOG indicate whether costs are shared among the three parties or billed specifically to one of the parties. Costs shared by the three parties are split evenly three ways, then agency specific charges are added. All costs associated with this contract will be reimbursed by DCE to CVAG and are included in Desert Community Energy's FY 2018/2019 budget. These costs will be fully reimbursable to CVAG once Desert Community Energy is operational and begins collecting revenues.

Attachments:

1. First Amendment to Cost Sharing Agreement for legal consulting services between CVAG, WRCOG and LACCE.

Contract Finalization: The Executive Director and/or legal counsel are authorized to make non-substantive changes or revisions to the agreement as necessary to address minor issues.

California Public Utilities Commission Proceeding (17-06-026) Review of the Power Cost Indifference Adjustment, adding work on the Resource Adequacy Proceeding (17-09-020), and Investor-Owned Utilities Petition to Modify Code of Conduct (12-02-009),

1st AMENDMENT TO COST SHARING AGREEMENT
FOR LEGAL SERVICES

THIS FIRST AMENDMENT TO THE LEGAL SERVICES COST-SHARING AGREEMENT ("**Amendment**") is made as of ______________, 2018 ("**Effective Date**"), by and between the WESTERN RIVERSIDE COUNCIL OF GOVERNMENTS ("**WRCOG**"), a California joint powers authority, COACHELLA VALLEY ASSOCIATION OF GOVERNMENTS ("**CVAG**"), a California joint powers authority, and LOS ANGELES COMMUNITY CHOICE ENERGY ("**LACCE**"), a California joint powers authority.

RECITALS

A. WRCOG, CVAG and LACCE have previously entered into that certain agreement entitled *Cost Sharing Agreement for Legal Services*, dated November 1, 2017, agreeing to share certain costs for legal services with respect to regulatory issues associated with the respective development and implementation of their community choice aggregation programs.

B. The Parties are affected by and are parties to several California Public Utilities Commission proceedings that have a direct impact on the launch of their programs, and they desire to increase the budget for legal services.

AGREEMENT

NOW, THEREFORE, the Parties hereby agree as follows:

1. Shared Costs. The Parties hereby agree to increase the budget for legal counsel to $130,000.

2. Capitalized Terms. Any capitalized terms not defined herein shall have the meanings set forth in the Agreement.

3. Counterparts. This Amendment may be executed in two or more counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same instrument.

4. Full Force. Except as expressly set forth herein, the Agreement shall remain unmodified and in full force and effect.

IN WITNESS WHEREOF, the Parties hereto have executed this Agreement as of the Effective Date.

WESTERN RIVERSIDE COUNCIL OF GOVERNMENTS
Approved By:

____
Rick Bishop, Executive Director

____
Date

Approved As To Form:

____
General Counsel

COACHELLA VALLEY ASSOCIATION OF GOVERNMENTS
Approved By:

____
Tom Kirk, Executive Director

____
Date

Approved As To Form:

____
General Counsel

LOS ANGELES COMMUNITY CHOICE ENERGY
Approved By:

____
Ted Bardacke, Executive Director

____
Date

Approved As To Form:

____
General Counsel

ITEM 5C

DESERT COMMUNITY ENERGY
Board Meeting
June 18, 2018

Staff Report

Subject: **Contract Amendment with Don Dame for Community Choice Aggregation Services with Desert Community Energy**

Contact: Katie Barrows, Director of Environmental Resources (kbarrows@cvag.org)

Recommendation: Approve Amendment #1 to the Consulting Services Agreement between CVAG and Don Dame to provide implementation and operations support for Desert Community Energy, for a not to exceed amount of $30,000.

Background: In April 2017, the CVAG Executive Committee approved a contract with independent consultant Don Dame for not to exceed $40,000. Mr. Dame is an energy consultant with considerable expertise on energy issues and CCAs. His assistance has been invaluable to CVAG and DCE; he has assisted staff at every step of the process and most recently has prepared the DCE budget. Because of the technical nature of community choice issues and the need for technical assistance and expertise, staff would like to continue the contract with Mr. Dame. The original contract is with CVAG and staff recommends that it remain a CVAG contract until DCE is receiving revenues. This contract will be included in the funds to reimbursed to CVAG by DCE. Staff will request at the June 25 Executive Committee meeting that they approve this contract Amendment #1 with Mr. Dame for a not to exceed amount of $30,000. The Amendment #1 and revised scope of work are attached for your review. Staff requests that the DCE Board approve the proposed Amendment #1, indicating your support to the CVAG Executive Committee.

Fiscal Analysis: The current contract is for $40,000. Since April 2017, $32,429.76 has been billed to the contract, with $7,570.24 remaining. The additional $30,000 will bring the total contract amount to $70,000. Mr. Dame bills CVAG on a monthly basis for time, travel and direct expenses base on the Fee Schedule included in Exhibit B. All costs associated with this contract will be reimbursed by DCE to CVAG and are included in Desert Community Energy's FY 2018/2019 budget.

Contract Finalization: Minor changes/revisions may be made for clarification purposes by CVAG's Executive Director and Legal Counsel prior to execution.

Attachments:
1. Amendment #1 to Consulting Services Agreement between CVAG and Don Dame
2. Exhibit A, Scope of Work and Exhibit B, Fee Schedule from original Consulting Services Agreement

COACHELLA VALLEY ASSOCIATION OF GOVERNMENTS

CONSULTING SERVICES AGREEMENT
AMENDMENT #1
with
DON DAME

The Consulting Services Agreement (the “Contract”) by and between the Coachella Valley Association of Governments (CVAG) and Don Dame, Independent Consultant (Contractor), is amended, effective June 25, 2018, as follows:

1) The contract amount for fiscal year 2018/2019 is amended to add a not to exceed amount of $30,000 for professional consulting services to Desert Community Energy as described in Exhibit A of the original contract, incorporated herein by reference.

2) The contract Project Reference is revised from “CVAG CCA Investigation and Analysis” to “DCE CCA Operations Support.” The Scope of Work is amended to reflect the focus on implementation and operations support as shown in Exhibit A.

3) All other terms and conditions shall remain the same as stated in the original Contract.

_____________________________	_____________________________
Don Dame	Marion Ashley
Consultant	Chair, Executive Committee
	Coachella Valley Association of Governments

Exhibit A
Scope of Work

DCE requires professional consulting services from a qualified party to provide technical review, electric utility expertise and governance structure recommendations regarding CVAG's investigation, evaluation and implementation of DCE's ~~creating a new or joining an existing~~ CCA program which is scheduled to commence commercial operation on August 1, 2018. ~~CVAG may also require CCA program implementation assistance if and when CVAG makes a firm decision to develop or participate in a CCA program~~. Consultant's tasks on behalf of DCE include, but are not limited to, the following:

- Evaluate CCA program options available to CVAG/DCE members and present results to CVAG/DCE staffs and, as directed, to the CVAG/DCE Board(s) and applicable committees.
- Assist DCE, as directed, in establishing and revising goals and objectives of a DCE's CCA program.
- ~~Assist CVAG in evaluating the results of the WRCOG RFP for CCA services when such responses are received by WRCOG and conveyed to CVAG~~.
- Work together with CVAG and DCE staffs, General Counsel, and other DCE vendors and or consultants, as directed, to identify and define various CCA related business risk exposures and outline and discuss actions which may mitigate such exposures.
- Prepare, review and or otherwise assist DCE in the preparation of materials for DCE committee meetings, or other CCA related activities as requested by CVAG/DCE. Present such materials as requested by DCE staff and management.
- Assist CVAG/DCE staff with the preparation of draft CCA related documents which may include pro forma JPA materials, by-laws, and other policies and procedures applicable to a CCA program.
- Prepare materials and make recommendations with regard to potential governance and voting practices applicable to a JPA created CCA program.
- Advise DCE staff and members regarding the status of other existing and incipient CCAs throughout California. Assist CVAG in outreach to and coordination with other CCAs, CCA organizations.
- Make recommendations to DCE from time to time that Consultant deems may ~~enhance~~ improve DCE's energy risk practices.
- Provide DCE ongoing information and support regarding the necessary steps to ~~initiate, implement and~~ operate a CCA program.
- Provide other CCA related consulting services as requested and/or directed by DCE.

Exhibit B
Fee Schedule

The Scope of Work shall be performed on an individual task, consulting time, travel time, materials, and actual direct expense basis with work assigned as needed.

Designated Employees and Rates:

Professional/Title	Hourly Consulting Rate
Donald B. Dame	$175.00

Other Applicable Reimbursement Rates:

Particulars	Rate
Air Travel Time	$87.50 / hour
Auto Travel Time (one hour or more)	$87.50 / hour
Auto Mileage Rate (or current IRS reimbursement rate)	$0.545 / mile
Actual Direct Expenses (Receipts required above $25.00)	Actual Expense
Phone/postage/printing/office materials	No Charge

Total Not to Exceed Amount: $70,000
($40,000 from prior contract and $30,000 through this amendment).

ITEM 6A

DESERT COMMUNITY ENERGY

Board Meeting

June 18, 2018

Staff Report

Subject: **Update on Our Progress**

Contact: Tom Kirk, Executive Director (tkirk@cvag.org)

Recommendation: Information only.

Background: Here is a summary of our progress and upcoming activities.

CPUC Resolution E-4907 and Waiver Process: The CPUC waiver process was completed with the May 9 joint filing by SCE and DCE of a joint Tier 1 Advice Letter. The completion of this process with SCE and the CPUC allows Desert Community Energy to proceed with our planned launch, when we start serving customers, in August 2018.

PCIA/Exit Fee – CPUC Proceeding R. 17-06-026: The CPUC concluded hearings on the Power Cost Indifference Adjustment (PCIA) in June 2018. The intent of the proceeding is to revise the methodology for calculating the PCIA. DCE is a party to the proceeding. Our legal counsel, Ryan Baron, filed a Joint Opening Brief on June 1, 2018, on behalf of CVAG/DCE, WRCOG and Los Angeles Community Choice Energy. The Joint Brief supported the CalCCA proposal for determination of the exit fee. CalCCA and the Joint Utilities are also preparing a briefing outline.

Other Steps to CCA Implementation. We continue to move toward our goal of launching the program in August 2018 and are on track. Weekly conference calls are held with SCE and our consultant team to coordinate key launch activities and keep us on schedule for our launch date. This coordination involves customer data testing and management to ensure that when DCE starts serving customers, a smooth transition in customer service and billing will occur.

The following is a summary of recent actions since the last update:

- ✓ **June 6, 2018** – Palm Springs City Council votes unanimously to opt up to 100% Carbon Free option.
- ✓ **June 11, 2018** – First batch of Customer Enrollment Notices mailed to DCE Customers
- ✓ **June 12, 2018** – Desert Community Energy website goes live and Customer Contact Center opens

Staffing. Applications for two new CVAG positions to support DCE -- an accounting manager and a program manager – closed on June 1, 2018. Numerous applications were received, and staff is scheduling interviews with potential candidates. The positions can be filled pending approval of the CVAG Budget at the June 25 Executive Committee meeting. We anticipate the new staff will begin in July 2018 or soon thereafter.

Community Outreach: Community outreach and engagement efforts are progressing well to support the launch in August. Notices to customers informing them of their transition to DCE will be mailed, starting the 11th of June, with a second notice going out starting on July 2nd. A full website went live on June 12 (www.DesertCommunityEnergy.org) and looks great. Potential customers can easily opt up from Desert Saver to 100% Carbon Free online, by telephone or by mail. The brochure is complete, we have a short video, and social media outreach will target DCE customers. City staff have included links to Desert Community Energy's website and DCE information will appear in city newsletters. Key stakeholders and large commercial customers have been contacted individually to let them know about DCE and answer any questions they may have about their account.

Community Advisory Committee. At a prior meeting, the Board suggested that staff look into the potential for formation of a Community Advisory Committee. A number of existing CCA programs statewide have established Community Advisory Committees to provide input and guidance, assist with community outreach, and involve stakeholders in CCA implementation. Staff is researching the community advisory approaches used by other CCAs and will request input from the Board.

CVAG staff appreciates the commitment of time and valuable input by elected officials and jurisdiction staff throughout this process

Fiscal Analysis: No impact.

ITEM 6B

DESERT COMMUNITY ENERGY

Board Meeting

June 18, 2018

Staff Report

Subject: Desert Community Energy Fiscal Year 2018/2019 Budget

Contact: Don Dame, Energy Consultant

Recommendation: Approve Resolution No. 2018-02 adopting the Desert Community Energy Fiscal Year 2018/2019 Budget

Background: The Desert Community Energy (DCE) draft Fiscal Year 2018/2019 Budget was presented and discussed at the May 2018 Board meeting. The May draft Budget review provided the Board opportunity to ask questions, make comments, and provide input to staff before preparation of the final budget for Board consideration and approval at the June Board meeting. Staff indicated it would coordinate with TEA to refine estimated power supply costs and projected retail sales revenues based on the most currently available information. The Board also suggested including additional detail on funds expended and or deferred during the pre-launch and early post start-up periods, together with a table displaying anticipated repayment schedules. This information is included below and in the attached budget summary document.

The FY 2018/2019 Budget has been assembled by energy consultant Don Dame with significant input from CVAG staff, The Energy Authority (TEA), and LEAN Executive Director Shawn Marshall.

Proposed Budget: The attached Desert Community Energy Fiscal Year 2018/2019 Budget ("Budget') is presented for your consideration. It is comprised of multiple spreadsheets including:

1. Fiscal Year 2018/2019 Budget summary outlining projected revenues and expenses.
2. A monthly tabulation of FY 2018/2019 projected revenues and expenses.
3. A tabulation and associated chart displaying pre- and post-launch borrowings and deferrals together with anticipated repayment schedule.
4. Summary of projected revenues and costs for FYs 2019/2020 and 2020/2021.
5. A composite summary of projected revenues, costs and residuals for DCE at the end of DCE's first three operating years.

Figure 1. FY 2018/2019 Macro Budget Summary:

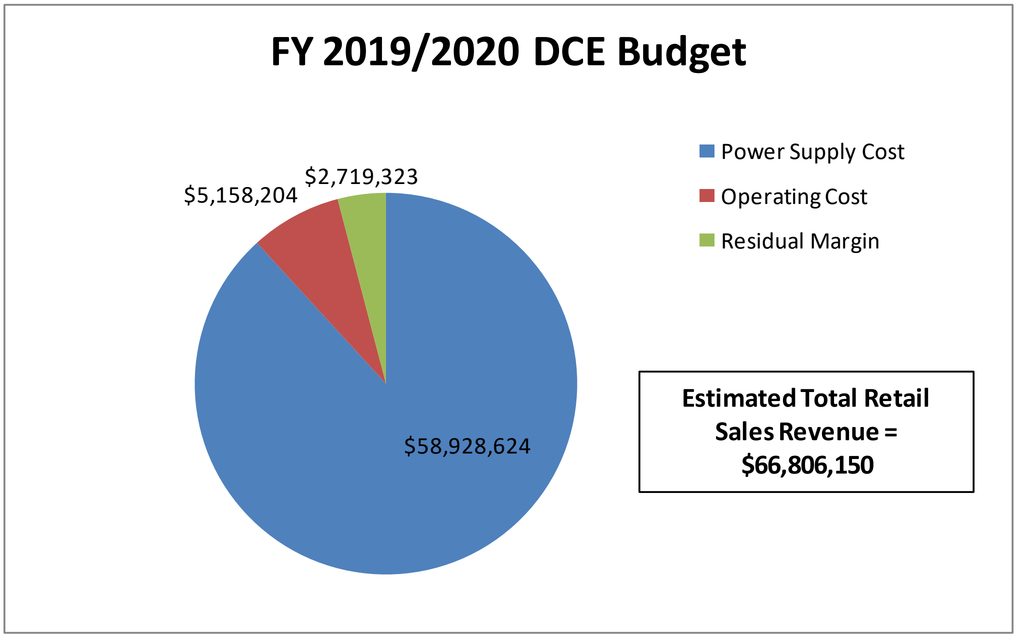


Table 1. FY 2018/2019 Budget Summary Table:
FY 2018/2018, July 1, 2018 – June 30, 2019 DCE Projected Revenues and Costs
(accrual basis, no working capital loan, other repayments starting Nov. 2018

Revenues and Any Working Capital Infusion	FY18-19	Avg $/Month	Avg $/MW/h
SCE 100% Genr. Chg (no lag, "inst." Rcpt, 50% Aug '18 load)	$ 88,313,034	$ 8,028,458	$ 80.40
DCE "Revenue" @ 3% Discount (no lag, "inst." Recpt)	$ 85,663,643	$ 7,787,604	$ 77.99
DCE Rev @ 3% Disc, no rev lag, w/o PCIA, FF, Unc. Accts	$ 66,806,150	$ 6,073,286	$ 60.82
DCE FY19 Working Capital Loan Rcd (if any)	$ -	na	$ -
Total DCE Rev @ 3% Disc v. SCE	**$ 66,806,150**	**$ 6,073,286**	**$ 60.82**

Power Costs (No Delay Aug/Sep)	FY18-19	Avg $/Month	Avg $/MW/h
DCE Wholesale Power (Incl. RPS, RA, LC, FC, energy)	**$ 58,928,624**	**$ 5,357,148**	**$ 53.65**

Operating Costs (Delay TEA/Calp Aug/Sep/Oct Svc fees)	FY18-19	Avg $/Month	Avg $/MW/h
DCE staff and p/t General Counsel svcs	$ 494,426	$ 44,948	**$ 0.45**
Other Contract labor / Mkting Outreach / Mailings	$ 321,500	$ 29,227	**$ 0.29**
CVAG Related Staff and facilities support	$ 174,432	$ 15,857	**$ 0.16**
Direct Business Support (TEA, Calpine, Mkting, SCE chgs, etc)	$ 3,767,409	$ 342,492	**$ 3.43**
Launch Sup, TEA/Calp $ delays, wrking cap and other repays	$ 38,170	$ 3,470	**$ 0.03**
Misc. Items (Memberships, CalCCA, etc.)	$ 142,267	$ 12,933	**$ 0.13**
Contingency	$ 220,000	$ 20,000	**$ 0.20**
DCE Total non-power Operating Costs	**$ 5,158,204**	**$ 468,928**	**$ 4.70**

Total Power and Operating Costs	**$ 64,086,827**	**$ 5,826,075**	**$ 58.35**
Estimated Residual Available for Reserves & Other	**$ 2,719,323**	**$ 247,211**	**$ 2.48**

The corresponding monthly budget spreadsheet (in attached Budget Summary) covers the period from July 1, 2018 through June 30, 2019. Cost incurrence accelerates in August 2018 when DCE begins serving retail customers; however, CVAG staff time and administrative expenses are included in July 2018 to convey CVAG's ongoing support to DCE to ensure a successful launch. The Budget reflects current estimated power prices including TEA forward power procurement for DCE which started in mid-April 2018. Notably, approximately a 5% overall power cost increase and a similar percentage reduction in expected retail revenues have occurred since early budget estimates were developed. The projected power cost increase is primarily attributable to issues associated with the Aliso Canyon Gas Storage facility and the procurement of RA capacity from SCE. The revenue adjustment largely reflects a budget format change from calendar year to fiscal year.

The Budget was developed based on assumptions and forecasts including:

1. DCE retail sales commence on August 1, 2018.
2. DCE's retail generation rate will be set 3% less than SCE's comparable rate.
3. Revenues, power supply and operating costs are accrued during the service month.
4. Addition of two full time staff positions for DCE, hired through CVAG.
5. Repayment of TEA, Calpine and CVAG pre-launch costs over 48 months starting November 2018 (including the $100,000 CPUC bond provided initially by Calpine).
6. Repayment of DCE's required $500,000 CAISO deposit posted by TEA per corresponding DCE/TEA Task Order.

Staff assembled the Budget assuming DCE's first fiscal year financial goals include:

1. Develop and implement a formal "actual" versus Budget monthly tracking and reporting system.
2. Monitor and report timing of revenue receipts and payment obligations.
3. Establish adequate financial reserves.
4. Ensure timely repayment of pre- and post-launch borrowings and deferrals (subject to cash-flow considerations).
5. Follow sound business practices and establish creditworthiness.
6. Keep Board, management and staff informed of business financial conditions.
7. Serve Member and customer interests.
8. Adhere to adopted Board policies and directives.

Again, the Budget assumes DCE's revenues and costs are accrued during the month power is delivered/sold to DCE customers. However, power supply costs are typically due toward the end of the month immediately following the given service month and revenues are typically received 45-60 days following the given service month. DCE will need to closely monitor resulting monthly cash-flows, track actual outcomes to Budget estimates and periodically report financial and operating results to the Board.

The Budget identifies various CVAG staff positions and allocations of effort to DCE for administrative and operational support. The Budget assumes two full-time equivalent DCE positions to be hired by CVAG: a DCE Program Manager and a DCE Accounting Specialist. These positions are currently under active recruitment and, if successful, DCE may have selected individuals on board in July, given CVAG and DCE budget approvals. Outreach to key accounts/larger commercial customers will be handled by existing CVAG staff and consultants. During the first three years of operation, other support needs are assumed to be met through a combination of consultants, vendors, and shared resources with CVAG or other operating CCAs. The Budget also assumes the continuing involvement of Don Dame as a consultant to DCE. If other pressing skill set needs arise, the Executive Director will have the ability to address these needs on an as required basis in consultation with the Board.

DCE's agreement with TEA and Calpine provides for DCE to defer payments for services until DCE is receiving steady revenues. The pre-launch start-up costs are assumed to be paid back to both firms over a 48-month period starting in November 2018, cash-flow permitting. CVAG will also be reimbursed for pre- and post-launch staffing and support costs incurred on behalf of DCE, consistent with the DCE-CVAG contract. The repayment of these costs to TEA, Calpine, and CVAG are identified under "Launch Support" in the Budget and the corresponding repayment table and graph. The Budget also includes a contingency amount of $240,000 to allow for unanticipated potential events and expenditures.

The 3-year budget summary provides projected cumulative cost and revenue streams over DCE's first three fiscal years starting with Fiscal Year 2019. This three-year summary estimates the costs for FY 2020 and FY 2021 based on costs for FY 2019, adjusted for inflation (3% per year as applicable), coupled with revenue and power supply costs estimated by TEA. Over the July 2018 – June 2021 three-year period, net DCE funds available for reserves and other uses (after paying all power and operating costs) cumulate to approximately $2.7 million, $12.6 million, and $22.7 million, respectively at the end of each of DCE's first 3 fiscal years.

Table 2. DCE cumulated total projected revenues, costs and residuals for FYs 2018/2019, 2019/2020, and 2020/2021:

Combining Revenue and Cost Estimates through June 30, 2021

Revenues	**$251,617,579**
Power Costs	**$211,018,780**
Non Power Operating Costs	**$17,931,644**
Total Residual Available for Reserves & Other	**$22,667,155**

<u>Borrowings and Repayments</u>: The formation of DCE required the expenditure of effort and funds prior to DCE commercial operation. CVAG, TEA and Calpine advanced funds to DCE prior to service commencement and such obligations are to be repaid over time from DCE revenue streams. The below representations assume DCE will be able to repay such amounts via a scheduled stream of payments. Actual repayment streams may be adjusted to account for possible cash-flow constraints and or other intervening events. TEA has expressed a willingness to adjust repayments as may be necessary to assure sufficient liquidity remains available to DCE. The following graph and table shows pre-launch funding and repayments streams contained in the Budget:

Figure 2. DCE pre-launch borrowings:

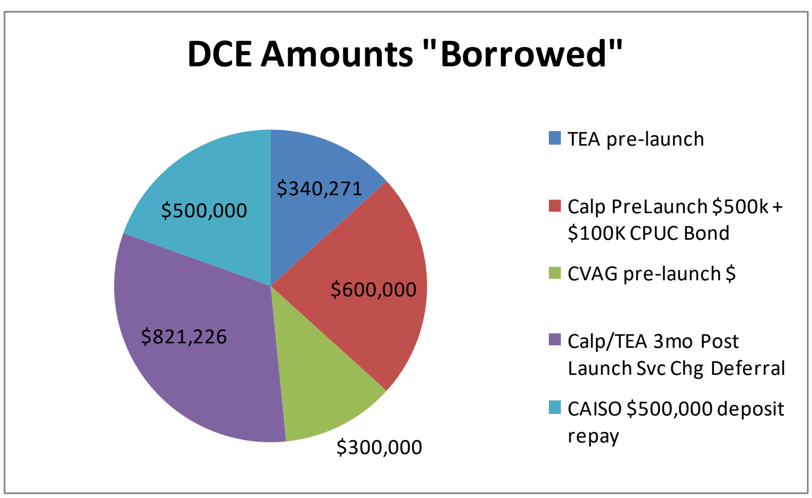


Table 3. DCE Borrowings, Deferrals and Repayment Schedule for FY19:

	Particulars		FY2019	Jul 2018	Aug 2018	Sep 2018	Oct 2018	Nov 2018	Dec 2018	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019
	Launch Support / Calp/TEA svc de	Principal Amt	$ 38,170	$ -	$ (273,741)	$ (273,741)	$ (273,741)	$ 44,924	$ 44,924	$ 44,924	$ 544,924	$ 44,924	$ 44,924	$ 44,924	$ 44,924
1	TEA pre-launch	$ 340,271	$ 56,712	$ -	$ -	$ -	$ -	$ 7,089	$ 7,089	$ 7,089	$ 7,089	$ 7,089	$ 7,089	$ 7,089	$ 7,089
2	Calp PreLaunch $500k + $100K CPUC Bond	$ 600,000	$ 55,270	$ -	$ -	$ -	$ -	$ 6,909	$ 6,909	$ 6,909	$ 6,909	$ 6,909	$ 6,909	$ 6,909	$ 6,909
3	CVAG pre-launch $	$ 300,000	$ 110,541	$ -	$ -	$ -	$ -	$ 13,818	$ 13,818	$ 13,818	$ 13,818	$ 13,818	$ 13,818	$ 13,818	$ 13,818
4	Calp/TEA 3mo Post Launch Svc Chg Deferral	$ 821,226	$ (684,353)	$ -	$ (273,741)	$ (273,741)	$ (273,741)	$ 17,109	$ 17,109	$ 17,109	$ 17,109	$ 17,109	$ 17,109	$ 17,109	$ 17,109
5	CAISO $500,000 deposit repay	$ 500,000	$ 500,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 500,000	$ -	$ -	$ -	$ -
6	Working Capital Loan Repayment (if any)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

1 Assumed paid in 48 equal payments at 0% interest starting Nov 2018
2 Assumed paid in 48 equal payments at 5% interest starting Nov 2018
3 Assumed paid in 48 equal payments at 5% interest starting Nov 2018
4 Assumed paid in 48 equal payments at 0% interest starting Nov 2018
5 Assumed paid in full Feb 2019, one payment no interest
6 Assumed paid in 48 equal payments at 5% interest starting Nov 2018

Related Budget Figures (excerpted from Budget):

Figure 3. Cumulative DCE revenues and costs over FY 2019-FY 2021 (the "top" of the curve indicates cumulative revenues).

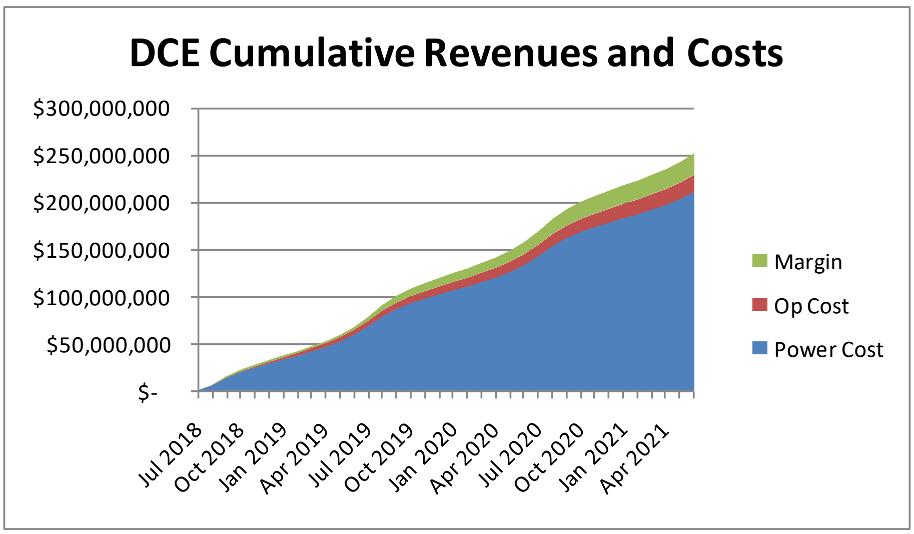


Figure 4. Cumulative funds/margin available for reserves and other uses.

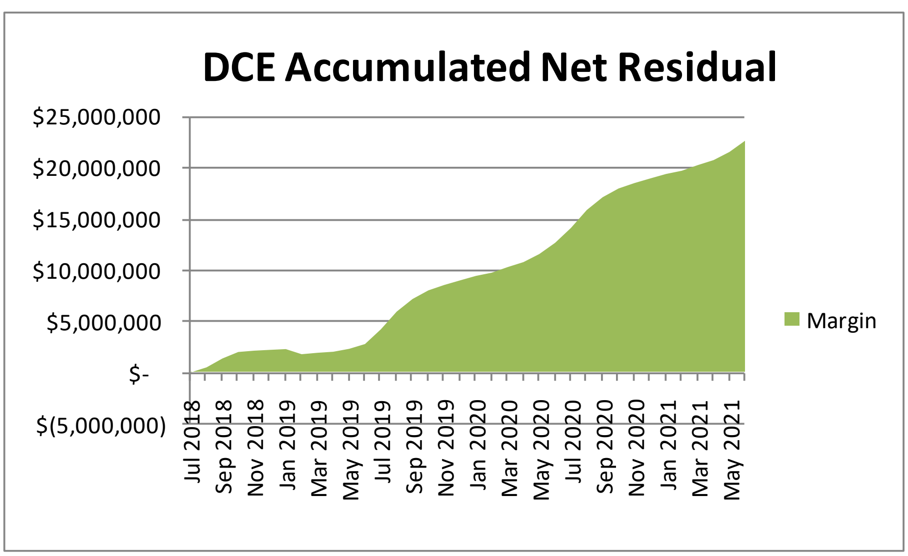
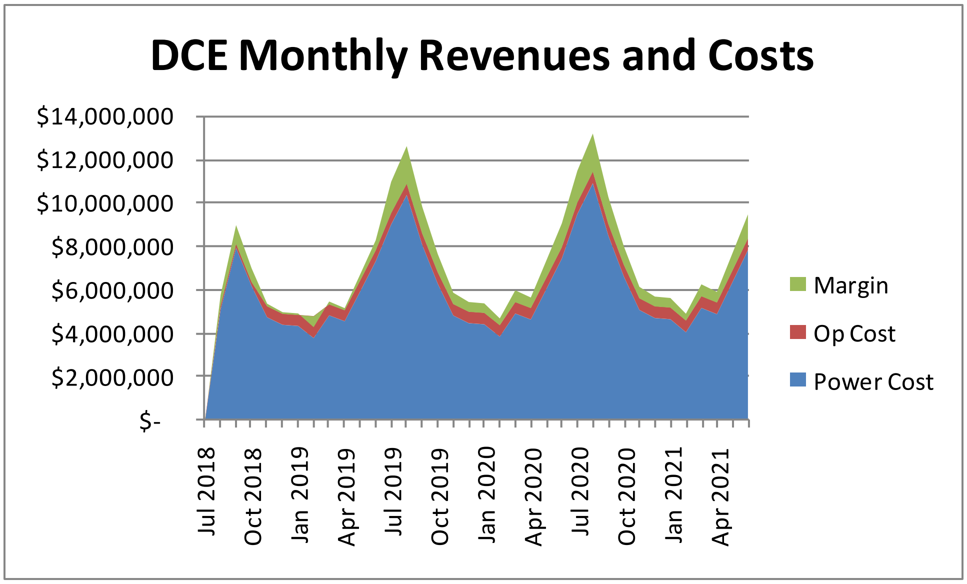


Figure 5. Monthly DCE costs and revenues.



One advantage for DCE is the availability of credit and contracts support provided by TEA which allowed DCE to start up without significant institutionally borrowed or other source funding. As an example, subject to actual DCE cash-flow conditions, TEA may defer DCE's repayment of August and September power costs at zero interest. TEA has long served public power agencies and CCAs and has excellent credit. The "credit and contracts" service provided by TEA is included within the $1/MWh charge as part of the DCE-TEA Resources Management Agreement. As a new agency without initial funding or established credit, DCE will have to develop credit credentials over time. This could take up to three years, or perhaps longer. However, once adequate reserves are accumulated and DCE establishes a responsible business track record, DCE may develop bi-lateral agreements with local or other power suppliers (e.g. wind, solar, geothermal) to serve a portion of its load. TEA would then commensurately reduce the amount DCE incurs for credit support.

Don Dame will be attending the meeting by phone to review the Budget with the Board and answer any questions. Jeff Fuller from TEA will also be available by phone. Both Mr. Dame and Mr. Fuller are available prior to the meeting if members would like to review Budget particulars over the phone prior to the Board meeting.

Fiscal Analysis: Per presented Budget.

Attachments:

1. Resolution No. 2018-02, adopting Desert Community Energy 2018/2019 Fiscal Year Budget
2. DCE Fiscal Year 2018/2019 Budget

RESOLUTION NO. 2018-02

A RESOLUTION OF THE BOARD OF DIRECTORS OF DESERT COMMUNITY ENERGY ADOPTING THE FISCAL YEAR 2018/2018 ANNUAL BUDGET

WHEREAS, Desert Community Energy ("DCE") is a joint powers authority established on October 30, 2017 for the purpose of implementing a community choice aggregation program under Public Utilities Code Section 366.2.0

WHEREAS, under Section 5.3.1 of the Joint Powers Agreement creating Desert Community Energy, the Board of Directors must approve the initial budget; and

WHEREAS, this budget covers the fiscal year July 1, 2018 through June 30, 2019.

WHEREAS, the DCE Fiscal Year 2018/2019 Budget was presented to the Board of Directors at a duly noticed public hearing for its consideration and adoption.

NOW THEREFORE BE IT RESOLVED as follows:

1. The Board of Directors hereby adopts the DCE 2018/2019 Fiscal Year Budget.

ADOPTED AND APPROVED by the Board of Directors of Desert Community Energy on this 18th day of June 2018.

AYES:
NOES:
ABSTAIN:
ABSENT:

Shelley Kaplan
Chair, Desert Community Energy

Attest:

Tom Kirk
Secretary, Desert Community Energy

DESERT COMMUNITY ENERGY

The POWER of choice

FISCAL YEAR 2018/2019 BUDGET

June 18, 2018

Desert Community Energy
FY 2018/2019 Budget

1. Introduction:

Desert Community Energy (DCE) is a California joint powers agency formed during latter 2017 to establish and operate a Community Choice Aggregation Program for the Cities of Cathedral City, Palm Desert and Palm Springs. DCE has completed all regulatory required filings, submittals and postings in preparation for its scheduled commencement of retail electric power sales to member cities' customers on August 1, 2018.

In addition, DCE has contracted with multiple vendors and service providers to attain the necessary financial and technical skills to establish, operate and maintain requisite business functions in a professional, best-practices manner. Vendors and service providers utilized by DCE include The Energy Authority (TEA), Calpine Energy Services (CES), Coachella Valley Association of Governments (CVAG), LEAN Energy US, Burke-Rix Communications, River City Bank, and others. Notably, CVAG provided initial investigatory funding and staff support during DCE implementation phases and will continue to provide ongoing staff, operations and facilities assistance pursuant to a DCE-CVAG cost sharing arrangement. TEA and CES continue to provide significant pre-launch technical and financial support/deferrals and made required CPUC and CAISO deposits. The FY 2018/2019 Budget includes amounts advanced and or posted on behalf of DCE and together with a schedule for repayment of such amounts.

2. Overall Summary:

The DCE Budget assumes all revenues and costs are incurred on an accrual basis. DCE intends to set its retail generation rates 3% below Southern California Edison's (SCE's) comparable generation rates. For FY19/20 SCE's average retail generation rate is projected to be \$80.40 / MWh. Thus, for budget purposes, DCE's estimated corresponding equivalent rate to be incurred by DCE customers is \$77.99 / MWh (\$80.40 x 0.97 = \$77.99). This \$77.99 / MWh rate must be adjusted for the Power Charge Indifference Adjustment (PCIA) and Franchise Fees (FF), both of which will be collected on SCE's portion of retail electric bills, as well an estimated deduction related to potential uncollectable accounts. The resulting net retail rate target attributable and collected on DCE's portion of customer billing is \$60.82 / MWh. DCE's retail service load for FY19/20, given a 10% customer opt-out rate, is assumed to be 1,098,390 MWh. Multiplying DCE's average retail rate by total FY19/20 load results in total FY18/19 Budget revenues of \$<u>66,806,150</u> (\$60.82 / MWh x

1,098,390 MWhs, with slight rounding adjustment). Power supply costs are expected to average $53.65 / MWh or a total of $58,928,624; and total DCE operating costs are assumed to average $4.70 / MWh or a total of $5,158,204 (including vendors, DCE staff, CVAG support and scheduled repays). Subtracting power supply and operating costs from revenues yields a projected end of FY19/20 residual balance (for reserves and other uses) of $2,719,323. In sum, the DCE FY18/19 Budget of $66,806,150 is comprised of power supply costs of $58,828,624 (88.2%), operating costs of $5,158,204 (7.7%), and residual/reserves of $2,719,323 (4.1%).

Figure 1. DCE Revenue and cost summary.

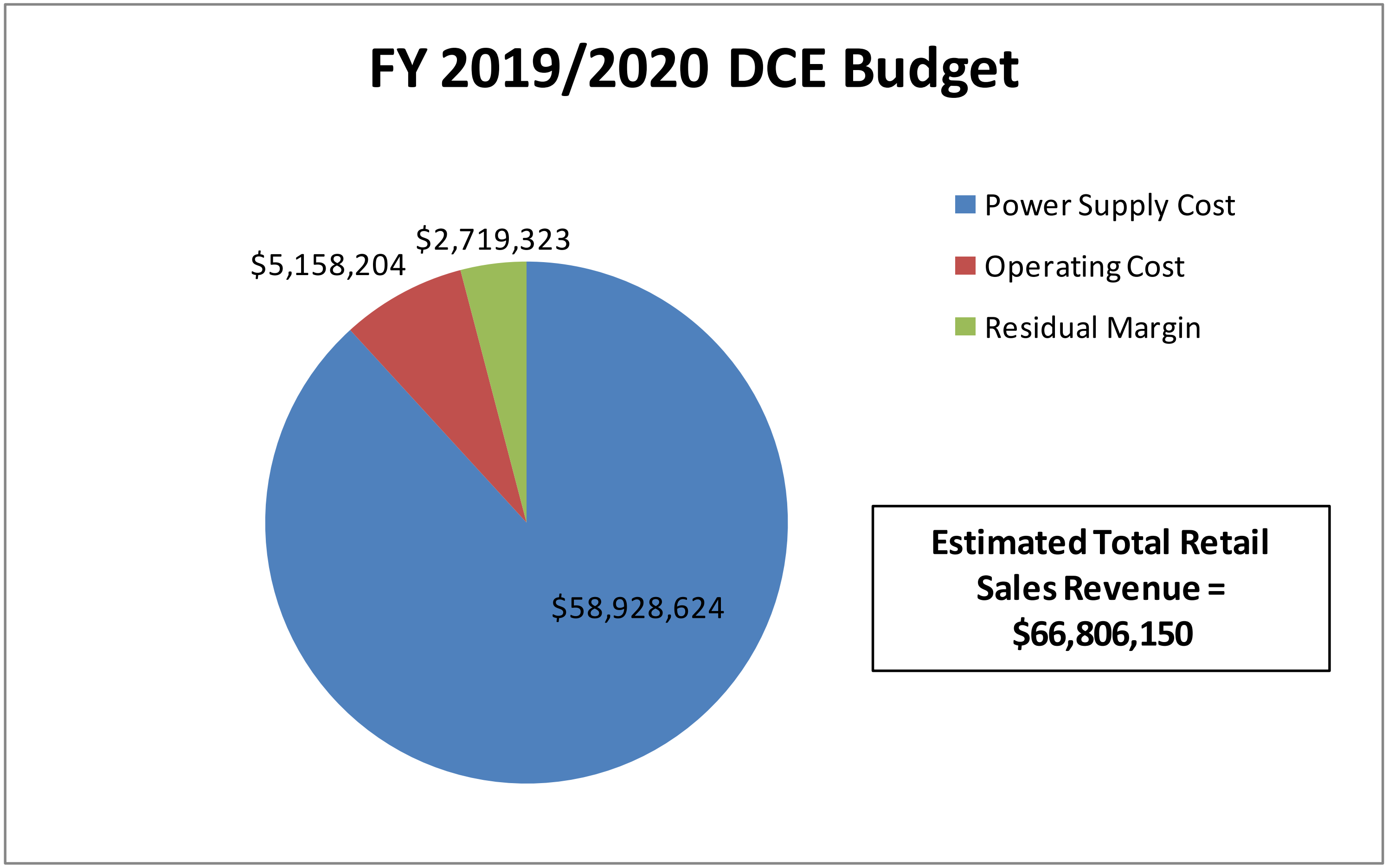


Table 1. Desert Community Energy FY 2018/2019 Budget at summary detail level.

FY 2018/2019, July 1, 2018 - June 30, 2019 DCE Projected Revenues and Costs

(accrual basis, no working capital loan, other repayments starting Nov 2018)

Revenues and Any Working Capital Infusion	FY18-19	Avg $/Month	Avg $/MW/h
SCE 100% Genr. Chg (no lag, "inst." Rcpt, 50% Aug '18 load)	$ 88,313,034	$ 8,028,458	$ 80.40
DCE "Revenue" @ 3% Discount (no lag, "inst." Recpt)	$ 85,663,643	$ 7,787,604	$ 77.99
DCE Rev @ 3% Disc, no rev lag, w/o PCIA, FF, Unc. Accts	$ 66,806,150	$ 6,073,286	$ 60.82
DCE FY19 Working Capital Loan Rcd (if any)	$ -	na	$ -
Total DCE Rev @ 3% Disc v. SCE	**$ 66,806,150**	**$ 6,073,286**	**$ 60.82**

Power Costs (No Delay Aug/Sep)	FY18-19	Avg $/Month	Avg $/MW/h
DCE Wholesale Power (Incl. RPS, RA, LC, FC, energy)	**$ 58,928,624**	**$ 5,357,148**	**$ 53.65**

Operating Costs (Delay TEA/Calp Aug/Sep/Oct Svc fees)	FY18-19	Avg $/Month	Avg $/MW/h
DCE staff and p/t General Counsel svcs	$ 494,426	$ 44,948	**$ 0.45**
Other Contract labor / Mkting Outreach / Mailings	$ 321,500	$ 29,227	**$ 0.29**
CVAG Related Staff and facilities support	$ 174,432	$ 15,857	**$ 0.16**
Direct Business Support (TEA, Calpine, Mkting, SCE chgs, etc)	$ 3,767,409	$ 342,492	**$ 3.43**
Launch Sup, TEA/Calp $ delays, wrking cap and other repays	$ 38,170	$ 3,470	**$ 0.03**
Misc. Items (Memberships, CalCCA, etc.)	$ 142,267	$ 12,933	**$ 0.13**
Contingency	$ 220,000	$ 20,000	**$ 0.20**
DCE Total non-power Operating Costs	**$ 5,158,204**	**$ 468,928**	**$ 4.70**

Total Power and Operating Costs	**$ 64,086,827**	**$ 5,826,075**	**$ 58.35**
Estimated Residual Available for Reserves & Other	**$ 2,719,323**	**$ 247,211**	**$ 2.48**

3. FY 2018/2019 Monthly Budget Spreadsheets:

Table 2.A. DCE FY 2018/2019 Budget related Loads, Revenues and Power Costs by Month.

Fiscal Year 2018-2019 Budget Estimate by Month

		FY2019 Total	Jul 2018	Aug 2018	Sep 2018	Oct 2018	Nov 2018	Dec 2018	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019
"Full Load" per TEA PF (MWh)		1,220,433		105,077	163,738	127,557	97,920	90,771	89,740	78,216	99,739	94,208	122,489	150,976
DCE Retail Load (MWh) net of opt-outs, Aug 50% Phase-In		1,098,390		94,570	147,364	114,801	88,128	81,694	80,766	70,395	89,765	84,788	110,240	135,879
DCE Wholesale Load (MWh, retail load+ losses)		1,150,014		99,014	154,291	120,197	92,270	85,534	84,562	73,703	93,984	88,773	115,422	142,265
Estimated Distribution Losses (%)		4.7%		4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%	4.7%
DCE No. Customer Accounts @ Month End		91,912		91,414	91,414	91,414	91,414	91,414	92,328	92,328	92,328	92,328	92,328	92,328
Average SCE Annual $/MWh Retail Genr. Revenue		$ 80.40	$ -	$ 80.40	$ 80.40	$ 80.40	$ 80.40	$ 80.40	$ 80.40	$ 80.40	$ 80.40	$ 80.40	$ 80.40	$ 80.40
SCE Revenues Given SCE Bundled Service, No Disc.		$ 88,313,034	$ -	$ 7,603,611	$ 11,848,438	$ 9,230,282	$ 7,085,681	$ 6,568,406	$ 6,493,751	$ 5,659,897	$ 7,217,343	$ 6,817,110	$ 8,863,563	$ 10,924,953
DCE Rev Bogie (Inst. Rec, 3% disc v.SCE)	77.99	$ 85,663,643	$ -	$ 7,375,503	$ 11,492,985	$ 8,953,373	$ 6,873,111	$ 6,371,354	$ 6,298,938	$ 5,490,100	$ 7,000,823	$ 6,612,596	$ 8,597,656	$ 10,597,205
Less PCIA Paid by Customer (w/ 50% August)	(16.37)	$ (17,985,148)	$ -	$ (1,548,492)	$ (2,412,961)	$ (1,879,768)	$ (1,443,015)	$ (1,337,671)	$ (1,322,467)	$ (1,152,651)	$ (1,469,828)	$ (1,388,320)	$ (1,805,085)	$ (2,224,891)
Less Franchise Fees Paid by Customer (w/ 50% August)	(0.61)	$ (671,324)	$ -	$ (57,800)	$ (90,068)	$ (70,165)	$ (53,863)	$ (49,931)	$ (49,363)	$ (43,024)	$ (54,864)	$ (51,821)	$ (67,378)	$ (83,048)
Less Uncollectable Accounts	(0.18)	$ (201,022)	$ -	$ (17,308)	$ (26,970)	$ (21,010)	$ (16,129)	$ (14,951)	$ (14,781)	$ (12,883)	$ (16,428)	$ (15,517)	$ (20,176)	$ (24,868)
Net DCE Rev Bogie (w/o PCIA and FF, lags)	60.82	$ 66,806,150	$ -	$ 5,751,903	$ 8,962,986	$ 6,982,430	$ 5,360,104	$ 4,968,801	$ 4,912,327	$ 4,281,541	$ 5,459,703	$ 5,156,938	$ 6,705,019	$ 8,264,398
Average Max DCE Rev Bogie $/MWh		$ 60.82	$ -	$ 60.82	$ 60.82	$ 60.82	$ 60.82	$ 60.82	$ 60.82	$ 60.82	$ 60.82	$ 60.82	$ 60.82	$ 60.82
Accrual Adjusted Revs (w/o lag, 50%Aug load)		$ 66,806,150	$ -	$ 5,751,903	$ 8,962,986	$ 6,982,430	$ 5,360,104	$ 4,968,801	$ 4,912,327	$ 4,281,541	$ 5,459,703	$ 5,156,938	$ 6,705,019	$ 8,264,398
Delta if shifted Rev Stream		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total DCE Power Cost (TEA PF, 50% August)	53.65	$ 58,928,624	$ -	$ 5,073,660	$ 7,906,105	$ 6,159,089	$ 4,728,061	$ 4,382,899	$ 4,333,084	$ 3,776,678	$ 4,815,916	$ 4,548,852	$ 5,914,388	$ 7,289,892
Pwr Cost Deferral if Any		$ -												
Repay Pwr Cost Adjust Ovr 12 mos, if any		$ -					$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DCE Net Power Cost as Accrued		$ 58,928,624	$ -	$ 5,073,660	$ 7,906,105	$ 6,159,089	$ 4,728,061	$ 4,382,899	$ 4,333,084	$ 3,776,678	$ 4,815,916	$ 4,548,852	$ 5,914,388	$ 7,289,892
Average Power Cost $/MWh Retail Load, w/adjust		$ 53.65		$ 53.65	$ 53.65	$ 53.65	$ 53.65	$ 53.65	$ 53.65	$ 53.65	$ 53.65	$ 53.65	$ 53.65	$ 53.65
Work Cap Loan "Revenues" Rcd @ August 1 Launch		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gross Margin before Op. Exp. (w/loan, if any)		$ 7,877,527	$ -	$ 678,242	$ 1,056,881	$ 823,342	$ 632,043	$ 585,902	$ 579,243	$ 504,863	$ 643,787	$ 608,087	$ 790,630	$ 974,506
Avg $/MWh Gross Margin before Expenses		$ 7.17		$ 7.17	$ 7.17	$ 7.17	$ 7.17	$ 7.17	$ 7.17	$ 7.17	$ 7.17	$ 7.17	$ 7.17	$ 7.17

Table 2.B. DCE FY 2018/2019 Line Item Operating Costs and Residual Margin by Month:

Estimated Operating Expenses	FY2019	Jul 2018	Aug 2018	Sep 2018	Oct 2018	Nov 2018	Dec 2018	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019
DCE Positions (Hired thru CVAG)	$ 494,426	$ 41,202	$ 41,202	$ 41,202	$ 41,202	$ 41,202	$ 41,202	$ 41,202	$ 41,202	$ 41,202	$ 41,202	$ 41,202	$ 41,202
Executive Director	$ 65,382	$ 5,448	$ 5,448	$ 5,448	$ 5,448	$ 5,448	$ 5,448	$ 5,448	$ 5,448	$ 5,448	$ 5,448	$ 5,448	$ 5,448
Director II - DCE	$ 185,964	$ 15,497	$ 15,497	$ 15,497	$ 15,497	$ 15,497	$ 15,497	$ 15,497	$ 15,497	$ 15,497	$ 15,497	$ 15,497	$ 15,497
Finance Director	$ 13,589	$ 1,132	$ 1,132	$ 1,132	$ 1,132	$ 1,132	$ 1,132	$ 1,132	$ 1,132	$ 1,132	$ 1,132	$ 1,132	$ 1,132
Accounting Manager	$ 104,138	$ 8,678	$ 8,678	$ 8,678	$ 8,678	$ 8,678	$ 8,678	$ 8,678	$ 8,678	$ 8,678	$ 8,678	$ 8,678	$ 8,678
Director - CVAG	$ 47,703	$ 3,975	$ 3,975	$ 3,975	$ 3,975	$ 3,975	$ 3,975	$ 3,975	$ 3,975	$ 3,975	$ 3,975	$ 3,975	$ 3,975
Management Analyst	$ 60,999	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083
Program Assistant II	$ 8,480	$ 707	$ 707	$ 707	$ 707	$ 707	$ 707	$ 707	$ 707	$ 707	$ 707	$ 707	$ 707
Governmental Projects Manager	$ 4,194	$ 350	$ 350	$ 350	$ 350	$ 350	$ 350	$ 350	$ 350	$ 350	$ 350	$ 350	$ 350
Accounting Assistant	$ 3,978	$ 331	$ 331	$ 331	$ 331	$ 331	$ 331	$ 331	$ 331	$ 331	$ 331	$ 331	$ 331
Contracts and Contract Labor (not incl. elsewhere)	$ 321,500	$ 2,500	$ 29,000	$ 29,000	$ 29,000	$ 29,000	$ 29,000	$ 29,000	$ 29,000	$ 29,000	$ 29,000	$ 29,000	$ 29,000
Legal Counsel (General Counsel/Special Counsel)	$ 82,500	$ -	$ 7,500	$ 7,500	$ 7,500	$ 7,500	$ 7,500	$ 7,500	$ 7,500	$ 7,500	$ 7,500	$ 7,500	$ 7,500
Power Contracts Legal Support	$ 27,500	$ -	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500
D. Dame CCA Consulting Support	$ 30,000	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500
Rate Design Support	$ 11,000	$ -	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000
External ROC Participation	$ 5,500	$ -	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500
Marketing Outreach / Mailing	$ 165,000	$ -	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000	$ 15,000
CVAG Related Support	$ 174,432	$ 14,536	$ 14,536	$ 14,536	$ 14,536	$ 14,536	$ 14,536	$ 14,536	$ 14,536	$ 14,536	$ 14,536	$ 14,536	$ 14,536
Rent/ Maintenance / Insurance	$ 41,688	$ 3,474	$ 3,474	$ 3,474	$ 3,474	$ 3,474	$ 3,474	$ 3,474	$ 3,474	$ 3,474	$ 3,474	$ 3,474	$ 3,474
Accounting Services /Software	$ 10,236	$ 853	$ 853	$ 853	$ 853	$ 853	$ 853	$ 853	$ 853	$ 853	$ 853	$ 853	$ 853
CVAG Facilities Usage Charge	$ 12,852	$ 1,071	$ 1,071	$ 1,071	$ 1,071	$ 1,071	$ 1,071	$ 1,071	$ 1,071	$ 1,071	$ 1,071	$ 1,071	$ 1,071
Meetings / Travel /Training	$ 6,720	$ 560	$ 560	$ 560	$ 560	$ 560	$ 560	$ 560	$ 560	$ 560	$ 560	$ 560	$ 560
Overhead Allocation	$ 102,936	$ 8,578	$ 8,578	$ 8,578	$ 8,578	$ 8,578	$ 8,578	$ 8,578	$ 8,578	$ 8,578	$ 8,578	$ 8,578	$ 8,578
Direct Business Support and Transactions Costs	$ 3,767,409	$ -	$ 342,492	$ 342,492	$ 342,492	$ 342,492	$ 342,492	$ 342,492	$ 342,492	$ 342,492	$ 342,492	$ 342,492	$ 342,492
Banking Services	$ 3,850	$ -	$ 350	$ 350	$ 350	$ 350	$ 350	$ 350	$ 350	$ 350	$ 350	$ 350	$ 350
Audit Svcs	$ 33,000	$ -	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000
SCE Billing Charges	$ 533,905	$ -	$ 48,537	$ 48,537	$ 48,537	$ 48,537	$ 48,537	$ 48,537	$ 48,537	$ 48,537	$ 48,537	$ 48,537	$ 48,537
Calpine Data Svcs / Call Center / CIS ($1.15/acct/mo)	$ 1,181,802	$ -	$ 107,437	$ 107,437	$ 107,437	$ 107,437	$ 107,437	$ 107,437	$ 107,437	$ 107,437	$ 107,437	$ 107,437	$ 107,437
TEA SC Services (@1/3 fixed amount)	$ 609,784	$ -	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435
TEA Power Procurement (@1/3 fixed amount)	$ 609,784	$ -	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435
TEA LT Planning /Risk Mgmt (@1/3 fixed amount)	$ 609,784	$ -	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435	$ 55,435
Estimated LEAN Services (Post Launch)	$ 70,000	$ -	$ 6,364	$ 6,364	$ 6,364	$ 6,364	$ 6,364	$ 6,364	$ 6,364	$ 6,364	$ 6,364	$ 6,364	$ 6,364
Other Wholesale Services (Rates / Consultant / etc.)	$ 55,000	$ -	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000
Website Hosting	$ 5,500	$ -	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500
Marketing / Public Outreach	$ 55,000	$ -	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000
Launch Support / Calp/TEA svc delay/ other repays	$ 38,170	$ -	$ (273,741)	$ (273,741)	$ (273,741)	$ 44,924	$ 44,924	$ 44,924	$ 544,924	$ 44,924	$ 44,924	$ 44,924	$ 44,924
TEA pre-launch	$ 56,712	$ -	$ -	$ -	$ -	$ 7,089	$ 7,089	$ 7,089	$ 7,089	$ 7,089	$ 7,089	$ 7,089	$ 7,089
Calpine PreLaunch $500k + $100K CPUC Bond	$ 55,270	$ -	$ -	$ -	$ -	$ 6,909	$ 6,909	$ 6,909	$ 6,909	$ 6,909	$ 6,909	$ 6,909	$ 6,909
CVAG pre-launch cumulated $ and D. Dame	$ 110,541	$ -	$ -	$ -	$ -	$ 13,818	$ 13,818	$ 13,818	$ 13,818	$ 13,818	$ 13,818	$ 13,818	$ 13,818
Calp/TEA 3mo Post Launch Svc Chg Deferral	$ (684,353)	$ -	$ (273,741)	$ (273,741)	$ (273,741)	$ 17,109	$ 17,109	$ 17,109	$ 17,109	$ 17,109	$ 17,109	$ 17,109	$ 17,109
CAISO $500,000 deposit repay	$ 500,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 500,000	$ -	$ -	$ -	$ -
Working Capital Loan Repayment (if any)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Miscellaneous Budget Items	$ 142,267	$ -	$ 12,933	$ 12,933	$ 12,933	$ 12,933	$ 12,933	$ 12,933	$ 12,933	$ 12,933	$ 12,933	$ 12,933	$ 12,933
Office Supplies	$ 1,100	$ -	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100
Community Engagement / Sponsorships	$ 11,000	$ -	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000
Travel Expenses	$ 27,500	$ -	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500	$ 2,500
CalCCA Dues (est @ $100,000 / year)	$ 91,667	$ -	$ 8,333	$ 8,333	$ 8,333	$ 8,333	$ 8,333	$ 8,333	$ 8,333	$ 8,333	$ 8,333	$ 8,333	$ 8,333
Other Memberships	$ 11,000	$ -	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ 1,000
Contingency	$ 220,000		$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000
Total Operating Expenses (net of deferrals)	$ 5,158,204	$ 58,238	$ 186,422	$ 186,422	$ 186,422	$ 505,087	$ 505,087	$ 505,087	$ 1,005,087	$ 505,087	$ 505,087	$ 505,087	$ 505,087
Operating Expenses $/MWh	$ 4.70	$ -	$ 1.97	$ 1.27	$ 1.62	$ 5.73	$ 6.18	$ 6.25	$ 14.28	$ 5.63	$ 5.96	$ 4.58	$ 3.72
Total Opr + Power Cost	$ 64,086,827	$ 58,238	$ 5,260,082	$ 8,092,527	$ 6,345,511	$ 5,233,149	$ 4,887,987	$ 4,838,171	$ 4,781,766	$ 5,321,003	$ 5,053,939	$ 6,419,476	$ 7,794,979
Gross Mrgn Avail. For More Disc, Reserves, Pgms	$ 2,719,323	$ (58,238)	$ 491,821	$ 870,459	$ 636,920	$ 126,956	$ 80,815	$ 74,155	$ (500,224)	$ 138,700	$ 102,999	$ 285,543	$ 469,419
Gross Available $/MWh	$ 2.48	$ -	$ 5.20	$ 5.91	$ 5.55	$ 1.44	$ 0.99	$ 0.92	$ (7.11)	$ 1.55	$ 1.21	$ 2.59	$ 3.45

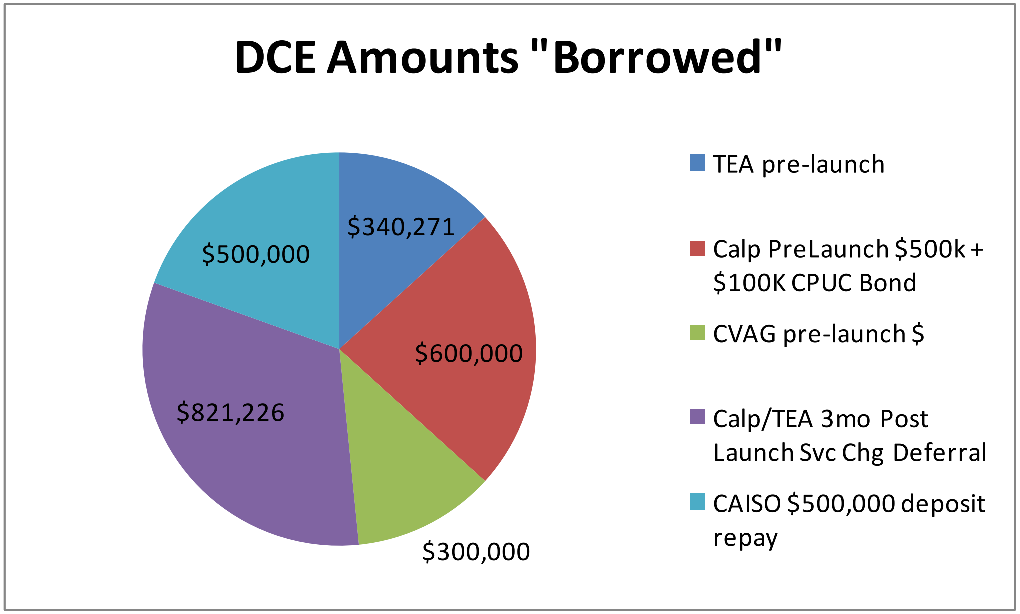
4. DCE Borrowings/Deferrals and Repayment Schedule:

Table 3. DCE borrowing, deferrals and repayments included in the Budget:

	Particulars		FY2019	Jul 2018	Aug 2018	Sep 2018	Oct 2018	Nov 2018	Dec 2018	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019
Item	Launch Support / Calp/TEA svc de	Principal Amt	$ 38,170	$ -	$ (273,741)	$ (273,741)	$ (273,741)	$ 44,924	$ 44,924	$ 44,924	$ 544,924	$ 44,924	$ 44,924	$ 44,924	$ 44,924
1	TEA pre-launch	$ 340,271	$ 56,712	$ -	$ -	$ -	$ -	$ 7,089	$ 7,089	$ 7,089	$ 7,089	$ 7,089	$ 7,089	$ 7,089	$ 7,089
2	Calp PreLaunch $500k + $100K CPUC Bond	$ 600,000	$ 55,270	$ -	$ -	$ -	$ -	$ 6,909	$ 6,909	$ 6,909	$ 6,909	$ 6,909	$ 6,909	$ 6,909	$ 6,909
3	CVAG pre-launch $	$ 300,000	$ 110,541	$ -	$ -	$ -	$ -	$ 13,818	$ 13,818	$ 13,818	$ 13,818	$ 13,818	$ 13,818	$ 13,818	$ 13,818
4	Calp/TEA 3mo Post Launch Svc Chg Deferral	$ 821,226	$ (684,353)	$ -	$ (273,741)	$ (273,741)	$ (273,741)	$ 17,109	$ 17,109	$ 17,109	$ 17,109	$ 17,109	$ 17,109	$ 17,109	$ 17,109
5	CAISO $500,000 deposit repay	$ 500,000	$ 500,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 500,000	$ -	$ -	$ -	$ -
6	Working Capital Loan Repayment (if any)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

1	Assumed paid in 48 equal payments at 0% interest starting Nov 2018
2	Assumed paid in 48 equal payments at 5% interest starting Nov 2018
3	Assumed paid in 48 equal payments at 5% interest starting Nov 2018
4	Assumed paid in 48 equal payments at 0% interest starting Nov 2018
5	Assumed paid in full Feb 2019, one payment no interest
6	Assumed paid in 48 equal payments at 5% interest starting Nov 2018

Figure 2. Proportional allocation of DCE borrowing, deferrals and repayments



5. DCE Budget projections for FY 2019/2020 and FY 2020/2021:

Where applicable, operating costs were escalated at 3% year-over-year; out-year power supply costs and expected sales revenues were taken from TEA's most current forecast.

Table 4. FY 2019/2020 Summary Budget Projection

Estimated FY2019-2020 DCE Revenues and Costs

(accrual basis, no working capital loan, other repayments starting Nov 2018)

Revenues and Any Working Capital Infusion	FY19-20	Avg $/Month	Avg $/MW/h
SCE 100% Genr. Chg (no lag, "inst." Rcpt)	$ 119,379,188	$ 9,948,266	$ 84.66
DCE "Revenue" @ 3% Discount (no lag, "inst." Recpt)	$ 115,797,812	$ 9,649,818	$ 82.12
DCE Rev @ 3% Disc, no rev lag, w/o PCIA, FF, Unc. Accts	$ 90,339,262	$ 7,528,272	$ 64.07
DCE FY20 Working Capital Loan Rcd (if any)	$ -	$ -	$ -
Total DCE Rev @ 3% Disc v. SCE	**$ 90,339,262**	**$ 7,528,272**	**$ 64.07**

Power Costs	FY19-20	Avg $/Month	Avg $/MW/h
DCE Total Power Related Supply Costs	**$ 74,100,830**	**$ 6,175,069**	**$ 52.55**

Operating Costs	FY19-20	Avg $/Month	Avg $/MW/h
DCE staff and p/t General Counsel svcs	$ 509,259	$ 42,438	**$ 0.36**
Other Contract labor / LEAN / Mkting Outreach / Mailings	$ 355,865	$ 29,655	**$ 0.25**
CVAG Related Staff and facilities support	$ 179,088	$ 14,924	**$ 0.13**
Direct Business Support (TEA, Calpine, Mkting, SCE chgs, etc)	$ 4,320,591	$ 360,049	**$ 3.06**
Launch Sup, TEA/Calp bill delay, wrking cap and other repays	$ 539,091	$ 44,924	**$ 0.38**
Misc. Items (Memberships, CalCCA, etc.)	$ 159,856	$ 13,321	**$ 0.11**
Staffing, Contractor, Ofc Exp, Insurance Contingency	$ 247,200	$ 20,600	**$ 0.18**
DCE Total non-power Operating Costs	**$ 6,310,949**	**$ 525,912**	**$ 4.48**
Total Power and Operating Costs	**$ 80,411,780**	**$ 6,700,982**	**$ 57.03**
Estimated Residual Available for Reserves & Other	**$ 9,927,482**	**$ 827,290**	**$ 7.04**

Table 5. FY 2020/2021 Summary Budget Projection

Estimated FY2020-2021 DCE Revenues and Costs

(accrual basis, no working capital loan, other repayments starting Nov 2018)

Revenues and Any Working Capital Infusion	FY 20-21	Avg $/Month	Avg $/MW/h
SCE 100% Genr. Chg (no lag, "inst." Rcpt)	$ 124,375,600	$ 10,364,633	$ 87.33
DCE "Revenue" @ 3% Discount (no lag, "inst." Recpt)	$ 120,644,332	$ 10,053,694	$ 84.71
DCE Rev @ 3% Disc, no rev lag, w/o PCIA, FF, Unc. Accts	$ 94,472,166	$ 7,872,681	$ 66.33
DCE FY21 Working Capital Loan Rcd (if any)	$ -	$ -	$ -
Total DCE Rev @ 3% Disc v. SCE	**$ 94,472,166**	**$ 7,872,681**	**$ 66.33**

Power Costs	FY 20-21	Avg $/Month	Avg $/MW/h
DCE Total Power Related Supply Costs	**$ 77,989,326**	**$ 6,499,111**	**$ 54.76**

Operating Costs	FY 20-21	Avg $/Month	Avg $/MW/h
DCE staff and p/t General Counsel svcs	$ 524,537	$ 43,711	**$ 0.37**
Other Contract labor / LEAN / Mkting Outreach / Mailings	$ 366,541	$ 30,545	**$ 0.26**
CVAG Related Staff and facilities support	$ 184,461	$ 15,372	**$ 0.13**
Direct Business Support (TEA, Calpine, Mkting, SCE chgs, etc)	$ 4,428,594	$ 369,049	**$ 3.11**
Launch Sup, TEA/Calp bill delay, wrking cap and other repays	$ 539,091	$ 44,924	**$ 0.38**
Misc. Items (Memberships, CalCCA, etc.)	$ 164,652	$ 13,721	**$ 0.12**
Staffing, Contractor, Ofc Exp, Insurance Contingency	$ 254,616	$ 21,218	**$ 0.18**
DCE Total non-power Operating Costs	**$ 6,462,490**	**$ 538,541**	**$ 4.54**
Total Power and Operating Costs	**$ 84,451,817**	**$ 7,037,651**	**$ 59.89**
Estimated Residual Available for Reserves & Other	**$ 10,020,349**	**$ 835,029**	**$ 7.11**

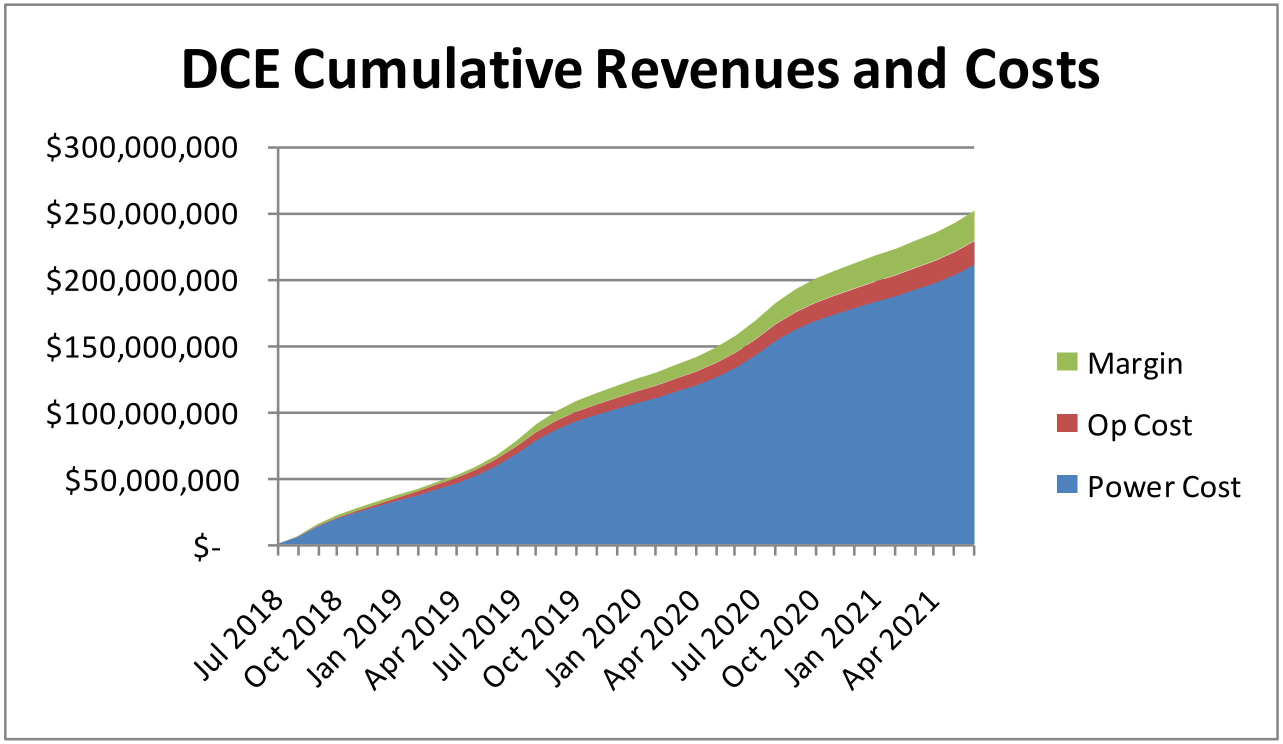
6. Aggregated 3-Year Projection as of End of FY2020/2021:

Table 6. Projected 3-Year DCE Budget Outcome

Combining FY19, FY20 and FY21 @ June 30, 2021 DCE Revenues and Costs Estimates

Revenues	$251,617,579
Power Costs	$211,018,780
Non Power Operating Costs	$17,931,644
Total Residual Available for Reserves & Other	**$22,667,155**

Figure 3. Cumulative 3-Year DCE Revenues and Costs



ITEM 6C

DESERT COMMUNITY ENERGY

Board Meeting

June 18, 2018

Staff Report

Subject: Approve Net Energy Metering program for Desert Community Energy

Contact: Benjamin Druyon, Management Analyst (bdruyon@cvag.org)

Recommendation: Approve Net Energy Metering (NEM) program that is equal to Southern California Edison's NEM program for existing and future solar customers, with the option to review a more robust program in the future, once financial uncertainties are made clear.

Background: Desert Community Energy formed in 2017 for the purpose of offering rate savings to electricity customers and developing and implementing sustainable energy initiatives that reduce energy demand, increase energy efficiency, and advance the use of clean, efficient and renewable resources available in the region. A Net Energy Metering program is one way to provide support for these goals.

At the April 16 DCE Board meeting, the Board approved a conceptual NEM Policy that would, at minimum, be equal to the current NEM program offered by Southern California Edison (SCE). The Board asked that staff bring additional information back to the next DCE Board meeting, along with some options for a NEM program. The Board requested that the information include an analysis of the financial implications of the Net Energy Metering Program.

DCE Net Energy Metering Program: One of the opportunities for DCE to achieve its goals is to incentivize rooftop solar and benefit existing solar customers through a Net Energy Metering (NEM) program. Currently, customers who install solar on their homes or businesses participate in SCE's NEM program. NEM customers can receive credit for excess solar generation at a retail rate. Each month, the amount of energy consumed and contributed to the grid is tallied. Customers who use less than they generate receive a credit that can be applied against amounts that would otherwise be owed in a subsequent month. Think of it as an energy bank account where the NEM customer can deposit energy if they overproduce or withdraw energy if they underproduce, each month for 12 months. On an annual true-up date, the amount of energy production (in kilowatt hours = kWh) that exceeds consumption over the preceding 12-month period is eligible for a rebate. SCE's NEM rate is approximately 3 cents/kWh. This rate is updated monthly based on a rolling 18-month lookback of the wholesale value of electricity.

Staff has worked with TEA, Don Dame and Shawn Marshall to evaluate the benefits and financial impacts of a NEM incentive in comparison with NEM programs offered by other CCA's and by SCE. The TEA analysis was based on information from SCE verifying the net consumption and generation amounts for DCE customers. Before offering the three choices before you, staff considered variables such as the number of current NEM customers who would be served by DCE and their energy production, how many solar projects were installed in the past 12 months in DCE territory, and how many solar projects we could anticipate for DCE for the next 12 months.

DCE has approximately 8,765 NEM solar customers, which includes 2,616 in Cathedral City, 2,947 in Palm Springs, and 3,202 in Palm Desert. The NEM customers in these three cities produce a net surplus of 8.1 million kWh of energy each year.

From the analysis, staff presents the following options for your consideration:

1. DCE does not offer a NEM program at this time until staff can further assess benefits to both customers and DCE.
2. DCE offers a NEM program at the same rate as SCE provides to NEM customers (staff's recommendation).
3. DCE offers a NEM program with an added incentive of $.005 to $.03 above SCE's rates.

Under option #1, DCE would not enroll any NEM customers at this time. By choosing this option, DCE would not be responsible for paying any additional costs for net surplus generation customers in the NEM program. This option would not allow SCE NEM customers to enroll in DCE and benefit from DCE's lower rates.

Under staff's recommended option #2, DCE would compensate NEM customers at the same rate as SCE. By doing this, there would be no additional costs associated with paying out net surplus generation customers and it would allow NEM customers to benefit from DCE's lower rates. DCE would duplicate SCE's NEM policy by including the following:

- ✓ Credit net surplus monthly generation at applicable retail rate
- ✓ Surplus $ credits in one month may be applied to charges in subsequent month until annual true-up
- ✓ Compensate net surplus annual generation (measured on a kWh basis) at SCE's wholesale rate per kWh on an annual basis

Due to the uncertainty with the PCIA costs and shifting energy market, staff recommends this conservative approach until after we launch and begin building reserves. At a later date, we can re-evaluate our NEM program to determine what additional incentives we may be able to include to help increase solar growth within the community. This option would allow customers to participate in DCE and take advantage of DCE's lower rates for any power needs above the capacity of their solar system.

Under option #3, DCE would offer a NEM program the same as SCE's but with additional incentives. This approach is similar to what is being offered by other Southern California CCAs. Table 1 illustrates the additional annual costs to DCE under option #3 with various "adders" above the approximately $0.03 offered by SCE by ½ cent, 1 cent, and 3 cents, respectively.

NEM Rate (cost/kWh)	Additional Annual Cost to DCE
$ 0.035	$ 40,578
$ 0.04	$ 81,156
$ 0.06	$ 243,469

Table 1. Cost to DCE of various NEM incentive rates as an "adder" to the SCE rate based on reported data from SCE.

If the Board chose option #3, it may be appropriate to consider a monetary cap on the amount offered to NEM customers for excess generation.

Staff also evaluated the option for a one-time incentive of $500 to new solar installations. Staff analyzed the number of solar building permits issued in the last 12 months for Palm Springs, Cathedral City, and Palm Desert to assess the potential number of new solar projects for the next 12 months. A total of 1,573 solar permits were issued within the last 12 months. If we estimate 1,500 new solar installations for the next 12 months, it would cost DCE $750,000 in incentives at $500 per installation. Staff determined this one-time incentive was fiscally infeasible at this time.

As part of the Desert Community Energy enrollment process, should the Board choose option #2 or option #3, these NEM customers will be transferred to DCE separately from most customers. Prior to the date they are transferred and enrolled in DCE, they will receive 2 notices about our Net Energy Metering program, followed by two notices after enrollment.

Staff recommends the board approve Net Energy Metering (NEM) program that is equal to Southern California Edison's NEM program for existing and future solar customers, with the option to review a more robust program in the future, once the program has launched and financial uncertainties are made clear.

Fiscal Analysis: If the Board chose the staff recommended option #2, there would be no additional costs to DCE since without these NEM generators DCE would have to purchase that electricity on the market. If the Board chose option #1, there would be no costs to DCE. If the Board chose option #3, it could cost DCE between $284,807 and $1,236,938 each year depending on the choices for this option.

ITEM 7.1

Desert Community Energy
Attendance Roster
2018

Jurisdictions											
Voting Members	**Jan**	**Feb**	**Mar**	**April**	**May**	**June**	**July**	**Sept**	**Oct**	**Nov**	**Dec**
Cathedral City	x	x	x	x	x						
Palm Desert	x	x	x	x	x						
Palm Springs	x	x	x	x	x						

Ex Officio Member											
Desert Hot Springs											

(X)	Voting member present
(X)	Ex Officio member present
	Absent

Updated on 6/7/18

ITEM 7.2

DESERT COMMUNITY ENERGY

Board Meeting

June 18, 2018

Staff Report

Subject: **Update on AB 813**

Contact: Erica Felci, Governmental Projects Manager (efelci@cvag.org)

Recommendation: Information

Background: At the May 21, 2018 DCE Board meeting, staff was asked to prepare information about Assembly Bill 813 and the creation of a multistate regional transmission system organization. AB 813 is authored by Assemblyman Chris Holden (D-Pasadena). According to a legislative summary provided by his office, AB 813 "creates a framework for any future expansion of the California Independent System Operator (CAISO) to include additional transmission owners in the 14 western states that currently make up the Western Regional Coordinating Council." It also would require that any regional transmission operator (RTO), which community choice aggregators and retail sellers join, needs to recognize and comply the state's standards for reducing greenhouse gases. As part of the expansion of CAISO— which runs the grid for 80 percent of the state —the board makeup would also change to include representation of other balancing authorities.

AB 813 was pursued last year in conjunction with AB 726 as part of an effort to regionalize the grid. California Gov. Jerry Brown and others have argued that sharing renewable energy with neighboring states is an important part of achieving the state's clean energy goals. However, both AB 813 and AB 726 were tabled at the end of the 2017 legislative session amid concerns that regionalism would mean California was giving up sole control of its power grid and allowing political interests in other states to gain influence.

The current form of AB 813 faces its first major hurdle when it is heard by the Senate Energy, Utilities and Communications Committee, which could take up the bill as soon as June 19. A list of the bill's support and opposition, as provided by Assemblyman Holden's office on June 5, is attached. The California Community Choice Association (CalCCA), of which DCE is a member, took a support position on the bill as it was amended in March. However, they are tracking the amendments and told DCE staff that they reserve their right to withdraw support if a change is proposed that they disagree with. DCE staff has also received a joint letter that the Sierra Club and other environmental and labor organizations sent on June 4. (These groups had not yet been added to the formal opposition list sent to DCE.)

In March, the DCE Board adopted Policy #18-03, which allows the Executive Officer/Executive Director to take action on time sensitive legislative and regulatory matters. DCE staff will continue to track the bill and inform the board if any positions should be taken.

Attachments:

1. Fact Sheet on AB 813
2. Support and Opposition List for AB 813, as of June 5, 2018
3. CalCCA Letter of Support for AB 813, May 11, 2018
4. Environmental/ Labor Groups' Joint Letter of Opposition, June 4, 2018

AB 813 (Holden) Multistate regional transmission system organization

SUMMARY

Assembly Bill 813 creates a framework for any future expansion of the California Independent System Operator (CAISO) to include additional transmission owners in the 14 western states that currently make up the Western Regional Coordinating Council. The bill also ensures that any regional transmission operator (RTO) which a California-based investor-owned utility, energy service provider, or community choice aggregator (collectively referred to as retail sellers), publicly owned utility (POU) or transmission operator joins, recognizes and complies with California's market-based compliance mechanism for limiting emissions of greenhouse gases when serving electric load in California and adherence to other standards and protocols regarding transparency and support of state procurement policies.

BACKGROUND

The CAISO is one of nine independent system or RTOs in North America. Although transmission in California is interconnected across 14 western states, British Columbia, Alberta, and a portion of Baja California, the CAISO is the only balancing authority (BA) that operates competitive wholesale electricity markets. (A balancing authority is the responsible entity that integrates electric generation plans ahead of time, maintains load-interchange-generation balance within a geographic area, and supports interconnection frequency in real time. Balancing authorities are typically a utility but can also be an RTO or a federal entity like the Bonneville Power Authority.)

The CAISO is one of 38 balancing authorities. Except for RTOs like the CAISO, balancing authorities are generally vertically integrated with each entity managing the electricity that flows across its transmission lines and managing generation largely through bilateral contracts.

California has been tremendously successful in its quest for a carbon-free and renewable electric grid. But to meet more aggressive goals, it will take a broader mix of carbon-free electricity and renewables. Not just the type of power, but the timing and availability of that electricity is key to California's success. Moving electricity across the West and its 38 balancing authorities, such as selling excess solar, results in the assessment of transmission charges every time the power moves across the lines of a different BA or transmission owner which drives up costs for ratepayers. Moreover, the fractured management by the 38 different BAs impedes the sharing of electric resources across the states which would help manage different types of electricity, most of which have varying generation characteristics, more efficiently.
Expanding CAISO's participating transmission owners (aka balancing

authorities) will allow electricity to be traded more efficiently across the West through CAISO's markets as more of those 37 balancing authorities join and without the layering of multiple transmission charges. This will facilitate transactions such as exporting unused renewable power, like solar, throughout the region, and importing power in the evening to meet California's steep ramp as the sun goes down. The CAISO would also facilitate the efficient planning of transmission lines across the participating transmission owners to minimize new transmission lines and costs.

The CAISO reports that several other balancing authorities have expressed an interest in joining the CAISO but must see a statutory change in the appointment of its governing board to facilitate the formation of leadership that balances the policies of all participating balancing authorities.

EXISTING LAW

PUC §345 et seq: The CAISO, a nonprofit, public benefit corporation, is required to conduct its operations consistent with applicable state and federal laws and to manage the transmission grid and related energy markets consistent with the interests of the people of the state.

PUC § 337: Vests with the Governor, the responsibility to appoint five members to the governing board of the CAISO which are confirmed by the State Senate.

PUC §§ 359, 359.5: Expresses the intent of the Legislature to provide for the transformation of the CAISO into a regional organization to promote the development of regional electricity transmission markets in the western states and to improve the access of consumers served by the CAISO to those markets. The transformation should only occur where it is in the best interests of California and its ratepayers.

THE SOLUTION

Ensure that any RTO, including the CAISO, which a California transmission owner, retail seller or POU joins, adheres to California's GHG protocols, open meetings and records standards, and state procurement decisions. An entity that chooses to join an RTO would be required to submit the RTO governing documents to the California Energy Commission for review, hearing and affirmation that the documents reflect California's standards. If a transmission owner, retail seller or POU found itself in an RTO that departed from those standards and protocols, it would be required to withdraw.

The bill also facilitates expansion of the CAISO to expand its membership to include other balancing authorities across the western states. Specifically, if the CAISO showed compliance with the operating standards and protocols described above, and those are confirmed to be in compliance with California law by the California Energy Commission, and the CAISO reported an agreement with one or more balancing authorities to join the CAISO, then a western states committee of the CAISO would be created with three appointments by the Governor and confirmed by the Senate. The current board of CAISO board of governors would be suspended.

Contact: Kellie Smith
Kellie.Smith@asm.ca.gov or 916-319-2083

AB 813 (Holden) Multistate regional transmission system organization

Support and Opposition

Support
Advanced Energy Economy
American Association of Blacks in Energy
American Council on Renewable Energy (ACORE)
American Wind Energy Association California Caucus
Bay Area Council
California Community Choice Association (CalCCA)
EDF Renewable Energy
EDP Renewables
Environmental Defense Fund
E2 – Environmental Entrepreneurs
Independent Energy Producers Association
League of Women Voters
Monterey Bay Community Power
Natural Resources Defense Council
Solar Energy Industries Association
Silicon Valley Leadership Group
Sonoma Clean Power
Stem, Inc.
SunPower
Union of Concerned Scientists
Vote Solar

Oppose
City of Lake Forest
The San Diego Community Choice Alliance (SDCCA)

CalCCA
California Community
Choice Association

Apple Valley Choice Energy

Clean Power Alliance

CleanPowerSF

Desert Community Energy

East Bay Community Energy Authority

Lancaster Choice Energy

MCE

Monterey Bay Community Power Authority

Peninsula Clean Energy

Pioneer Community Energy

PRIME

Redwood Coast Energy Authority

San Jose Clean Energy

Silicon Valley Clean Energy Authority

Sonoma Clean Power

Valley Clean Energy Alliance

May 11, 2018

Assemblymember Holden
Member, California State Legislature
State Capitol, Room 5132
Sacramento, CA. 95814

RE: AB 813 (Holden) – Support as Amended on March 8, 2018

Dear Assemblymember Holden,

The California Community Choice Association (CalCCA) writes in support of AB 813 as amended on March 8, 2018.

CalCCA members are local, non-profit agencies formed to respond to and invest in the specific needs of our communities. We believe that the bill in its current form sets out a transparent process for creating and evaluating proposals to regionalize the independent system operator and ensure California can continue its ambitious renewable energy goals. CalCCA believes that a well-crafted plan will support the ability of CalCCA members to procure and build local renewable resources by creating a stronger renewable energy market, reduce curtailment of renewable resources, and make bills more affordable for California ratepayers. Regionalization is also likely to further reduce greenhouse gas emissions by exposing coal-fired power plants to competition from cheaper clean sources.

We appreciate your attention to CalCCA's concerns by removing language found in the September 8, 2017 version of AB 813 that would have prevented public community choice providers from administering demand response programs. The ability to administer programs including demand response is an important programmatic element of local service for our CCA members.

It is for these reasons that CalCCA supports AB 813 and we look forward to working with you in the coming months on this effort.

Sincerely,

Beth Vaughan
Executive Director

Advancing local energy choice

1125 Tamalpais Avenue, San Rafael, CA 94901 • 415-464-6189 • cal-cca.org

June 4, 2018

The Honorable Christopher Holden
Chair, Assembly Committee on Utilities and Energy
State Capitol Room 5136
Sacramento, CA 95814

Re: AB 813 (CAISO regional expansion) -- OPPOSE

Assembly Member Holden,

On behalf of consumer, environmental and labor interests, we write to express our shared opposition to changing the governance structure of the California Independent System Operator (CAISO) and authorizing its expansion into a Regional Transmission Organization (RTO) as proposed in AB 813 (Holden). The proposal is not ripe for consideration in light of significant risks that the contemplated regional expansion proposal could substantially harm California. Instead of rushing to authorize a decision that cannot be reversed, we urge the Legislature to consider alternative approaches to regional coordination that could harness the promised benefits of CAISO expansion without abandoning state oversight and jeopardizing California's ability to continue its clean energy leadership.

Our organizations have been involved in discussions relating to CAISO expansion over the past several years and see little progress towards addressing the many legitimate concerns that have been raised. Moreover, the election of Donald Trump and his appointment of a new majority at the Federal Energy Regulatory Commission (FERC) establishes new risks that regional wholesale markets could be used to frustrate California's energy policy goals, devalue renewable energy resources, and force California customers to subsidize the continued operation of coal-fired generation located in other parts of the West.

The proposed expansion could raise costs for California consumers, increase utilization of coal and gas-fired power plants, produce higher in-state emissions of Greenhouse Gases (GHGs) and criteria pollutants, and, according to the CAISO's own analysis, cost ***more than 110,000 California middle class, union solar construction jobs***. Regional expansion would also irrevocably alter the state's landmark Renewables Portfolio Standard (RPS) program in a manner that could result in less new renewable energy development, greater reliance on distant renewable energy resources that never deliver their electricity to California, and fewer in-state environmental and public health benefits. Finally, CAISO expansion increases the risks that cutting-edge state policies will be subject to federal preemption and that California consumers would be forced to subsidize out-of-state coal-fired generation.

The question before the Legislature is not whether California will opt for isolationism or participation in regional electricity markets. California is already part of a regional market where in-state buyers and sellers transact with other western entities every hour of every day. Our organizations support greater regional coordination to enhance electricity exports, optimize grid operations, minimize uneconomic curtailment of in-state renewable generation, and reduce Greenhouse Gas Emissions. These outcomes can be achieved through modifications to the current Energy Imbalance Market and other efforts to facilitate exports, interstate exchanges of zero-GHG electricity and multi-state reserve sharing arrangements. None of these measures would jeopardize the RPS program or increase the risks of federal preemption.

Despite lacking key details, the proposed CAISO expansion authorized by AB 813 would not undergo any further review by elected officials prior to being finalized. It would be a mistake for the Legislature to endorse irrevocable change to California's energy markets given the potential for the Trump Administration to move to preempt California's leadership.

The attached document outlines a series of concerns with the current proposal for CAISO expansion and the assumptions that are often cited by proponents. We also identify alternative measures for California to achieve its clean energy and low-carbon grid objectives without eliminating state control over CAISO.

Thank you for your consideration of our comments and concerns.

Sincerely,

Matthew Freedman
Staff Attorney
The Utility Reform Network

Kathryn Phillips
Director
Sierra Club California

Robbie Hunter
President
State Building and Construction Trades Council of California

Greg Partch
Executive Director
California State Pipe Trades Council
Executive Director

Dion Abril
Executive Administrator
Western States SMART

Richard Samaniego
Secretary/Treasurer
California State Association of Electrical Workers

Cc: Members and Chair, Senate Energy Utilities and Communications committee

CAISO Regional Expansion

Concerns and Alternatives

New governance structure eliminates accountability to the California Legislature

The current CAISO Board of Governors is appointed by the California Governor and subject to confirmation by the California Senate. Under the expansion proposal, California's elected leadership would be stripped of any direct role in selecting or approving Board members. The resulting Board would have no obligations or accountability to the California Governor or Legislature. The lack of any state role in selecting board members is made worse by the apparent backtracking of any commitment to give states any formal power to review and approve major new tariffs and policy proposals under consideration by CAISO. Draft proposals circulated by CAISO in 2016 would have provided California a seat on the Western States Committee and required all major proposals to be approved by that Committee prior to any tariff filing at FERC. AB 813 limits this committee's function to providing "input" rather than empowering states with any formal role in approving or rejecting regional market design initiatives.

Promised State Protections are not Durable

It is virtually impossible for California to relinquish control over CAISO while securing meaningful and durable commitments that subsequent actions taken by FERC and a multistate RTO would not undermine current and future state resource planning and procurement policies. There is no clear method for enforcing commitments made by CAISO in exchange for eliminating accountability to the Legislature, the Governor and state regulators. California runs the risk that any promises made prior to regional expansion will be abandoned or eliminated through FERC action. The Legislature would be powerless to reverse such an outcome.

Maryland and New Jersey discovered this hard truth when commitments made to these states in exchange for their support of a regional capacity market were rescinded after the market was created, leaving these states without the ability to protect their consumers through the development of in-state generation. Promises made to the states by PJM (a Regional Transmission Organization) were later withdrawn, leaving state efforts to promote local generation to be challenged in federal court and ultimately struck down by the US Supreme Court.[1]

CAISO Expansion is a one-way ticket that cannot be undone

Expansion of CAISO will result in irrevocable changes to regional markets that cannot be undone by a future act of the Legislature. Under AB 813, the Legislature would relinquish its authority to set conditions for the ongoing management and operation of wholesale markets and the governance of the grid. Although California utilities would retain the right to unilaterally withdraw from the multistate RTO "with or without cause" so long as they provide 2-years of advance notice, any effort to exercise this right would be fraught with huge

[1] *Hughes v. Talen, 136 S. Ct. 1288 (2016)*.

challenges and substantial costs. California utilities would be forced to establish new systems for managing their own transmission networks and wholesale transactions that would be complex and costly. These obstacles make it extremely difficult and expensive for California to extract itself from a hostile wholesale market.

<u>The CAISO SB 350 Study Estimates higher in-state GHG emissions, greater utilization of gas-fired generation, and more coal generation under regional expansion</u>

Despite claims by proponents that the switch to a single regional market would reduce the use of coal-fired generation and cause GHG emissions to significantly decline, the results of recent studies do not support this conclusion under the most realistic modeled scenario. The move to regional markets <u>*could result in an increase in the utilization of cheap coal-fired generation*</u> and higher overall GHG emissions than would have occurred absent regional expansion. The CAISO SB 350 study found that, by 2030, the following results should be expected under regional expansion:[2]

- GHG emissions are forecasted to increase by 0.6% <u>within California</u> and decrease across the entire Western footprint by as little as 0.1%.
- Total regional coal generation increases by 1.1%
- Gas-fired generation in California increases by 1.4%

These results show that increases in cheap coal-fired generation are expected to displace some gas-fired generation outside California. Most importantly, these results have not taken into account new federal policies under the Trump administration that may increase coal-fired generation in the West.

<u>The CAISO SB 350 study forecasts that regional expansion would cost California 110,000 renewable energy construction jobs</u>

The CAISO's SB 350 study examined the effect of regional expansion on California solar construction jobs. The study analyzed the effect on jobs of regional expansion with and without the existing RPS preference for renewable generation directly connected or delivering energy to a California Balancing Authority. Retaining the RPS preference (known as the "bucket system") would yield 110,000 additional renewable energy construction jobs in California from 2020 through 2030. Without the RPS bucket system, those jobs would be lost to other states.

CAISO regional expansion would eviscerate the RPS bucket system. No valid replacement approach has been identified to continue the current preference approach. This means approving AB 813 would cause California to forfeit these 110,000 jobs. This estimate of jobs lost, while enormous, does not tell the full story. Nearly all of the solar construction jobs in California are good, middle class, career union jobs. Many are gateway jobs that provide a first job in rural areas to people with few other opportunities. They lead to apprenticeships that

[2] CAISO SB 350 results comparing Scenario 1a (base case) to Scenario 3 *without* "beyond RPS wind".

provide training for a lifetime career, benefiting both the individual and the California construction industry.

The CAISO SB 350 study underestimates the total job losses by assuming that achieving a 50% RPS target is the endpoint of state policy. Many local governments, community choice aggregators and state agencies are already committed to higher renewable generation penetration. This means that the count of lost jobs and the damage to the California economy from regional expansion would be even worse.

Expanding CAISO's footprint would undermine the Renewable Portfolio Standard program focus on providing in-state and local environmental, economic and public health benefits

Expanding the CAISO would eliminate the existing preference under the Renewables Portfolio Standard (RPS) for renewable energy projects that directly deliver energy to California customers, displace fossil fuel usage within the state, and provide local environmental and public health benefits. The RPS program requires that 75% of all procurement be sourced from products that have a first point of interconnection within a "California Balancing Authority" or can directly deliver their electricity (without substitution) into a California Balancing Authority.[3]

CAISO expansion would allow remote renewable energy projects throughout the Western US, Canada, or Mexico to become automatically eligible to satisfy up to 100% of RPS compliance. This outcome would reduce the value of local resources and encourage the use of existing, surplus resources outside the state (and the country) that do not actually provide many of the key benefits to California customers are promised under the RPS program. Substituting existing resources for new development would defeat the key objectives of the RPS program and the state's GHG objectives.

No protections against rate increases for California customers caused by new out-of-state transmission investments

Revised cost allocation protocols under a multi-state CAISO are likely to force California customers to absorb a significant percentage of several billion dollars in new transmission investments in other parts of the West sought by PacifiCorp and other private developers (along with a higher FERC-authorized rate of return for any new transmission operated by the ISO). If California is forced to bear both the full costs of the existing CAISO transmission grid plus a significant share (80% or more) of new investments outside the state, the net impact would be an increase in Transmission Access Charges and higher retail rates for California customers. In this event, the Legislature would have no ability to protect California customers from escalating transmission rates attributable to out-of-state investments that provide no real benefits to California.

[3] Existing California Balancing Authorities include CAISO, Los Angeles Department of Water and Power, Balancing Authority of Northern California, Imperial Irrigation District, and Turlock Irrigation District.

<u>CAISO's recent efforts to establish Centralized Capacity Markets and require the development of 4,600 MW of new in-state gas generation were only prevented due to state oversight that would be eliminated under regional expansion</u>

Relieving the CAISO of any state oversight would open the door to new market design concepts and resource requirements that were previously rejected by state agencies. This change is problematic in light of CAISO's prior efforts to establish centralized capacity markets and establish the need for substantial volumes of new gas-fired generation. In 2007, CAISO proposed a "Centralized Forward Capacity Market" despite opposition from many state interests over concerns about cost and the potential for diluting state control over resource planning. Because the California Public Utilities Commission (CPUC) rejected this central capacity market proposal, it did not move forward.

In 2011, the CAISO argued that California needed 4,600 MW of new gas-fired plants by 2020 to maintain reliable service.[4] The CPUC declined to require this additional procurement by the Investor-Owned Utilities. Today, there is no longer any support for the claim that 4,600 MW of new gas capacity is needed. Had CAISO been able to enforce its preferred assessment of need in 2011, California would now be saddled with substantial excess gas-fired generation with these new costs being collected from retail customers and driving up electricity rates.

Under regional expansion, CAISO would not need any approval from the California Legislature or any state agency to move forward with these and other controversial proposals. Decisions would be made by management, subject to approval by an independent Board of Governors (not tied to California) and FERC. Since FERC Commissioners may have little sympathy for the state's progressive energy policy goals, any concerns raised by California are unlikely to receive serious consideration.

<u>Expansion would increase the potential for successful federal court challenges of cutting-edge state policies</u>

CAISO expansion would increase the likelihood of successful federal preemption challenges when state procurement and resource planning policies directly affect multi-state RTO wholesale markets. To the extent that CAISO's preferred regional energy market design or other regional requirements conflict with state policies, California could be forced to defend its laws and regulations against challenges that would be adjudicated at FERC or in federal court. Conflicts in other regional markets have led to a variety of state laws being challenged by private interests with a number of high-profile state initiatives being struck down by federal courts on the basis of federal preemption.[5] In at least one major case, the court relied heavily on the fact that the state was part of a multi-state RTO as the basis for striking down its efforts to reduce reliance on coal-fired generation.[6]

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[4] See August 18, 2011 Briefing on Renewable Integration to ISO Board of Governors, available at http://www.caiso.com/Documents/110825BriefingonRenewableIntegration-Memo.pdf. The CPUC rejected this view of "need" in Decision 12-04-046 based on a settlement among major parties – including the CAISO.

[5] *Hughes v. Talen, 136 S. Ct. 1288 (2016), State of North Dakota v. Heydinger,* No. 14-2156, 14-2251 (8th Cir. 2016).

[6] *State of North Dakota v. Heydinger,* No. 14-2156, 14-2251 (8th Cir. 2016).

Contentious issues litigated to date include the validity of state laws to promote local generation, limitations on imports of coal-fired electricity produced within the same regional ISO, and whether state policies to incentivize renewable energy are incompatible with the development of competitive wholesale markets.[7] Moreover, FERC could attach other conditions to regional expansion adverse to California interests. Recent efforts of the Trump Administration to rollback state authority on other environmental matters demonstrate that the risks of aggressive preemption by FERC should not be underestimated.[8]

The risks will increase if CAISO is expanded to include additional out-of-state market participants who may feel disadvantaged by California's numerous policies designed to minimize the use of fossil fuels and increase reliance on preferred resources and locally-sited distributed energy resources. These out-of-state utilities and generators would directly experience the impact of California policies on wholesale markets and be motivated to challenge any mechanism that could be deemed to impermissibly discriminate against other resources located within the same RTO footprint. For example, the state of Utah has already set aside $1.6 million to sue California over its GHG policies, a lawsuit that is more likely to succeed if both states are within the same RTO.

Efforts by the Trump Administration to subsidize coal-fired generation through wholesale markets will affect California customers only if CAISO expansion occurs

President Trump has identified preservation of existing coal-fired generation, and opposition to GHG regulation, as top energy and environmental priorities for his regulatory agencies. Following this direction, the new Trump majority at FERC has already taken actions that demonstrate hostility to California's energy and climate policies. These actions include the establishment of a policy that could devalue renewable resources, directing RTOs to assess their efforts to promote grid resiliency, and declining to consider GHG impacts in the approval of new natural gas pipelines.[9] Secretary of Energy Rick Perry is considering emergency measures to subsidize existing nuclear and coal plants.[10] A recent Administration memo calls

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[7] In *Hughes v. Talen at 1291*, the US Supreme Court identified a variety of "competitive wholesale auctions" that could justify federal preemption of state policy. These include "a 'same-day auction' for immediate delivery of electricity to LSEs facing a sudden spike in demand; a 'next-day auction' to satisfy LSEs' anticipated near-term demand; and a 'capacity auction' to ensure the availability of an adequate supply of power at some point far in the future". The CAISO already runs two of these three types of "wholesale auctions" in the form of day ahead and real-time energy markets. Any state policies that direct load-serving entities to procure specific resources and have a direct effect on prices in these markets could be subject to challenge even if no centralized market for the forward procurement of capacity is established.

[8] For example, the US Environmental Protection Agency appears poised to withdraw the Clean Air Act waiver that allows California enact stricter emission standards for new motor vehicles.

[9] FERC recently stated an intention to apply a "Minimum Offer Price Rule" that would adversely affect the participation of renewable resources in wholesale markets (162 FERC ¶61,205, March 9, 2018 / "we intend to use the MOPR to address the impacts of state policies on the wholesale capacity markets"); FERC also recently ordered each ISO and RTO to identify challenges relating to "grid resilience" including broader consideration of the impact of "wholesale market rules, planning and coordination, and NERC standards" on resiliency and evaluating "options to mitigate any risks" (*Order Terminating Rulemaking Proceeding, Initiating New Proceeding, And Establishing Additional Procedures*, 162 FERC ¶ 61,012, January 8, 2018.)

[10] These measures would be undertaken pursuant to §202(c) of the Federal Power Act.

for the US Department of Energy to require all ISOs/RTOs to purchase electricity or capacity from existing coal or nuclear plants at risk of retirement.[11] President Trump directed Energy Secretary Perry to prepare "immediate steps" to pursue this policy.[12]

Because the CAISO footprint includes very limited legacy coal generation, the Trump administration cannot currently force California customers to subsidize dirty power plants located in other parts of the West. An expanded CAISO would include substantial amounts of Western coal-fired generation that could become eligible for new subsidies ordered by FERC or DOE. CAISO expansion could thereby force California ratepayers to subsidize out-of-state coal generation and extend the lives of these facilities even if such outcomes are contrary to the objectives of state regulators and the Legislature.

CAISO processes allow limited meaningful participation by California interests

Unlike state agencies, CAISO has no formal process for considering evidence and weighing comments submitted by individuals and organized interests. Instead, CAISO typically oversees informal stakeholder processes but has no obligation to respond to comments, give weight to alternative perspectives, justify its own factual assumptions, or explain what comments were relied upon in making final decisions. There is no process for seeking rehearing of CAISO decisions and no judicial review possible in any state court. Parties with concerns about CAISO process or outcomes can only pursue factual or legal issues at FERC.

If CAISO is freed from its state law obligations and permitted to assume greater authority for the design and operation of western electricity markets, California stakeholders will be left with limited options to influence outcomes and contest any decisions adverse to California interests. The costs of participating at CAISO can be significant, leaving only well-funded companies (*i.e.* utilities and independent generators) with sufficient resources to comprehensively engage in stakeholder processes and pursue challenges at FERC. Bestowing increased authority on an expanded CAISO would effectively remove a wide array of public interest stakeholders (such as environmental, low-income, and consumer organizations) from effective participation in critical electricity policy debates and tilt the playing field even more strongly towards powerful private interests.

Estimates of economic and environmental benefits of regional expansion developed by CAISO are based on flawed assumptions and misleading calculations

Pursuant to SB 350 (DeLeon), CAISO prepared a study assessing the potential benefits of creating a single regional balancing authority. Unfortunately, the study included a variety of unrealistic assumptions and raises concerns about the value of regional expansion. Key problems, omissions or misrepresentations include the following:

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[11] https://www.bloomberg.com/news/articles/2018-06-01/trump-said-to-grant-lifeline-to-money-losing-coal-power-plants-jhv94ghl.

[12] http://www.latimes.com/business/la-fi-trump-coal-20180601-story.html.

• The greatest job creation would result under a scenario where regional expansion does not occur but California increases coordination with other parts of the West to enable greater exports of electricity. This approach would yield an additional 10,000 in-state jobs by 2030.[13] These results were withheld from the original results presented to stakeholders, are omitted from the main volume of the final report and can only be found through careful review of a cryptic table buried within the 688-page document.[14]

• The study double counts the savings that could be achieved through the recently expanded Energy Imbalance Market and does not attempt to identify any incremental benefits from regional expansion.[15]

• CAISO assumes that the cost of California-based solar energy in 2030 will be 30-50% higher (in real terms) than actual 2018 market prices and substantially above long-term industry forecasts. This assumption inflates the value of alternatives to solar located in Wyoming and New Mexico.

• Although reductions in the curtailment of in-state renewable resources are often cited as a key benefit of CAISO expansion, the study finds that approximately 75% of the assumed reductions could be realized through enhanced bilateral coordination without any need to transform CAISO into a regional entity.[16] The study did not review the extent to which the recently expanded Energy Imbalance Market (EIM) could reduce curtailment despite the fact that prior CAISO studies identified significant reductions in curtailment as a key benefit of the EIM.

• Approximately 70% of the estimated benefits to California customers in 2020 are assumed to result from PacifiCorp paying a full share of CAISO operational costs. The study ignores the fact that PacifiCorp has insisted that it will pay little or none of these costs even after joining CAISO.

• Expected economic benefits for California communities fail to account for the manner in which costs and savings are actually distributed, including the fact that low-income

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[13] SB 350 Study: The Impacts of a Regional ISO-Operated Power Market on California, Prepared for CAISO, July 8, 2016, Electronic workpapers of Berkeley Economic Advising and Research.

[14] The reference to Scenario 1b is buried at the end of Volume VIII of the study (page VIII-19) and is not shown in any of the summary results. A wide range of stakeholders (including the major utilities) expressed support for using Scenario 1b (enhanced exports) as a proper base case.

[15] CAISO response to SB 350 comments, page 29 (*"the benefits analyzed and quantified in the SB 350 study do not include any that could be (or would be) achieved by expanding the EIM to the geographic market footprint analyzed for 2030")*

[16] CAISO forecasts a base case in which renewable resources are curtailed in 4.5% of all hours in 2030 but estimates that curtailment declines to 2.0% of hours if enhanced bilateral coordination occurs and to 1.2% under full regional expansion. The enhanced bilateral coordination scenario (Scenario 1b) was endorsed as the most realistic 2030 base case by TURN, Southern California Edison, Pacific Gas & Electric, San Diego Gas & Electric, the CA Department of Water Resources, and the California Large Energy Consumers Association.

customers will not receive the same share of utility bill savings as higher-income customers.

• The results frequently cited by CAISO include a key assumption that 5,000 MW of new "beyond RPS" wind would be installed in Wyoming and New Mexico due to favorable economics resulting from a single regional market. CAISO assumes that California customers pay none of the costs for this generation but receive many of the benefits. This assumption was added to the model at the direction of CAISO management at the last-minute in an effort to boost the claimed economic and environmental benefits. A review of the model shows that 2,500 MW of wind power in New Mexico would be a money-losing proposition for developers, thereby making it impossible to justify the reasonableness of this last-minute addition to the study inputs.[17]

• Economic benefits to California do not properly take into account pricing differences across the West and the costs of congestion associated with the "delivery" of a large quantity of out-of-state renewable energy to California customers.

• Based on experience with the Energy Imbalance Market (EIM), the economic benefits to California customers may be significantly overstated. Although initial studies estimated that California would receive most of the economic benefits from this market, the real-world experience shows that other Western utilities are the biggest winners. To date, California customers have realized approximately 28% of total EIM savings despite constituting the majority of the overall market.[18] In 2017, California's share of total savings dropped to 25%.[19] This disconnect suggests that California's share of savings from a fully expanded CAISO market will be lower than projected and that the economic benefits may primarily flow to utilities and customers outside of California.

Perhaps most troubling is the fact that CAISO ignored thoughtful critiques of the study submitted by consumer groups, utilities, generators and other state agencies. Despite receiving comments from 35 stakeholders raising a variety of concerns about the study inputs and methodology, CAISO rejected almost every critique and made no significant changes to the final study. This behavior highlights the fact that the study was not designed to develop an unbiased assessment of the costs and benefits of regional expansion.

[17] The CAISO model forecasts negative pricing in 40% of total hours when the wind is assumed to be generating leading to an average price (across all hours of generation) of -$11/MWh. This means that the generator is assumed to be paying for the grid to accept its output rather than actually making money on the sale of power.
[18] CAISO EIM Quarterly Benefits Reports, 4Q2014 through 1Q2018 (showing CAISO receiving $94.05 million in savings out of $330.5 million in savings for all EIM participants).
[19] CAISO EIM Quarterly Benefits Reports, 1Q2017 through 4Q2017 (showing CAISO receiving $36.96 million in savings out of $145.82 million in savings for all EIM participants).

California can achieve its clean energy and low-carbon grid objectives without eliminating state control over CAISO

The Legislature can avoid these consequences, reduce the risk of federal preemption, and direct CAISO to focus on measures that will assist the state in meeting is ambitious energy objectives. Rather than removing California authority over CAISO and eliminating a board appointed by the Governor and subject to Senate confirmation, the Legislature should direct CAISO to explore other measures that serve the goal of optimizing system operations, reducing GHG emissions, and addressing concerns about overgeneration and curtailment. These options include:

- Expanding the voluntary Energy Imbalance Market (EIM) to permit transactions with other western balancing authorities that go beyond real-time and allow day ahead scheduling. Previous CAISO studies found that participation by other Western utilities in the EIM could significantly reduce, or even eliminate, all expected curtailments of renewable resources within California.[20] CAISO identified this potential change in its most recent policy initiatives roadmap and notes that an expanded EIM would improve market efficiency and more effectively integrate renewable generation while allowing each state to retain control over reliability responsibilities, integrated resource planning, resource adequacy and transmission planning and investment.[21]

- Coordinating with the Bonneville Power Administration and other Northwest utilities to facilitate exchanges of excess California renewable power and northwest hydroelectric power. This approach could assist with managing mid-day surpluses in California and helping with late afternoon ramping needs.

- Taking steps to enable greater exports of surplus in-state renewable generation including obtaining an assessment from the Western Electricity Coordinating Council regarding the feasibility of increasing net export limits.

- Investigating the establishment of a regional planning reserve sharing agreement amongst Western Balancing Authorities to reduce overall reserve requirements.

- Work with other western balancing authorities to reduce barriers to exporting excess power produced by in-state renewable resources.

These options should be explored along with other measures that do not require eliminating California control over CAISO governance and expanding the footprint of its balancing authority. Before pursuing the only action that is almost impossible to reverse, the Legislature should actively explore alternatives that do not pose the same risks to California consumers and state policy.

[20] These findings appeared in the studies performed by CAISO regarding the potential participation of PacifiCorp, NV Energy and Arizona Public Service in the EIM market.

[21] CAISO 2018 Policy Initiatives Roadmap, January 12, 2018, pages 20-22.

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COACHELLA VALLEY ASSOCIATION OF GOVERNMENTS

2018 GENERAL ASSEMBLY

Presented By:

ADVANTEC Consulting Engineers

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6:00 P.M.

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